WHITECAP RESOURCES INC

NEWS RELEASE

February 27, 2020

WHITECAP RESOURCES INC. ANNOUNCES 2019 FOURTH QUARTER / YEAR END RESULTS AND 2019 RESERVES EVALUATION

CALGARY, ALBERTA – Whitecap Resources Inc. ("Whitecap" or the "Company") (TSX: WCP) is pleased to report its operating and audited financial results for the quarter and year ended December 31, 2019.

Selected financial and operating information is outlined below and should be read with Whitecap's audited annual consolidated financial statements and related Management's Discussion and Analysis which are available at www.sedar.com and on our website at www.wcap.ca.

FINANCIAL AND OPERATING HIGHLIGHTS

	Three months ended December 31		Twelve months ended December 31	
Financial ($000s except per share amounts)	2019	2018	2019	2018
Petroleum and natural gas revenues	369,190	272,397	1,418,476	1,519,845
Net income (loss)	(203,946)	6,966	(155,873)	65,128
Basic ($/share)	(0.50)	(0.02)	(0.38)	0.16
Diluted ($/share)	(0.50)	(0.02)	(0.38)	0.15
Funds flow	184,546	138,810	675,610	704,420
Basic ($/share)	0.45	0.33	1.64	1.69
Diluted ($/share)	0.45	0.33	1.63	1.67
Dividends paid or declared	35,018	33,611	138,341	132,295
Per share	0.09	0.08	0.34	0.32
Expenditures on PP&E	98,762	76,485	403,977	440,499
Total payout ratio (%) (1)	72	79	80	81
Property acquisitions	410	15,157	4,016	35,249
Property dispositions	(266)	(205)	(978)	(11,681)
Corporate acquisition	-	-	-	53,916
Net debt	1,193,267	1,296,330	1,193,267	1,296,330
Operating				
Average daily production				
Crude oil (bbls/d)	58,044	57,072	55,413	58,511
NGLs (bbls/d)	4,805	4,656	4,503	4,397
Natural gas (Mcf/d)	70,811	68,739	66,801	69,042
Total (boe/d) (2)	74,651	73,185	71,050	74,415
Average realized price (3)				
Crude oil ($/bbl)	64.42	47.22	66.11	66.46
NGLs ($/bbl)	17.56	29.52	20.58	35.90
Natural gas ($/Mcf)	2.68	1.87	1.95	1.70
Total ($/boe)	53.76	40.46	54.70	55.96
Netbacks ($/boe)				
Petroleum and natural gas revenues	53.76	40.46	54.70	55.96
Tariffs	(0.42)	(0.60)	(0.48)	(0.72)
Processing and other income	0.50	0.44	0.69	0.45
Blending revenue	1.05	1.13	1.17	0.47
Petroleum and natural gas sales	54.89	41.43	56.08	56.16
Realized hedging loss	(0.37)	4.77	(0.78)	(2.36)
Royalties	(8.88)	(6.77)	(9.79)	(9.87)
Operating expenses	(11.85)	(12.28)	(12.38)	(12.05)
Transportation expenses	(2.40)	(2.20)	(2.26)	(2.17)
Blending expenses	(1.05)	(0.92)	(1.14)	(0.38)
Operating netbacks (1)	30.34	24.03	29.73	29.33
Share information (000s)				
Common shares outstanding, end of period	409,619	414,063	409,619	414,063
Weighted average basic shares outstanding	409,579	415,714	412,000	417,061
Weighted average diluted shares outstanding	412,026	418,784	414,072	420,587

Notes:

(1) Total payout ratio and operating netbacks do not have a standardized meaning under GAAP. Refer to non-GAAP measures in this press release for additional disclosure and assumptions.

(2) Disclosure of production on a per boe basis in this press release consists of the constituent product types and their respective quantities disclosed in this table.

(3) Prior to the impact of hedging activities and tariffs.

MESSAGE TO SHAREHOLDERS

We are pleased to report strong financial and operating results for 2019. We achieved average production of 71,050 boe/d on capital expenditures of $404 million compared to our guidance of 70,000 – 72,000 boe/d on capital expenditures of $425 - $475 million as press released on December 18, 2018. We subsequently reduced our capital budget on August 26, 2019 to $400 million with no change to our 2019 average production. We achieved mid case production guidance on much lower capital spending through the efficient execution of our capital program and reduced our net debt by $103.1 million. Our commitment to returning capital to shareholders in 2019 resulted in $19.6 million spent on share repurchases and a 5.6% increase to the annual dividend with total dividends paid in 2019 of $138.3 million.

In addition to the success of our capital program, we have been actively advancing our organic growth initiatives which resulted in enhanced economics on 27 (20.2 net) existing drilling locations and the identification of 244 (184.2 net) new drilling locations, of which 144 (84.2 net) were the result of the recent Montney oil joint venture in Karr. We have been able to organically replace 126% of the 193 (166.3 net) wells we drilled in 2019. Our drilling inventory was also upgraded in quality as reserves per location added were 1.8 times higher than reserves per location drilled.

With respect to our reserves over the past year, we remained focused on profitably converting undeveloped reserves to proved developed reserves ("PDP") and funds flow and, at the same time, growing our total proved ("TP") and total proved plus probable ("TPP") reserves to support future funds flow growth. Undeveloped reserves were converted to PDP reserves and funds flow at a low cost of $14.33/boe, resulting in a very profitable recycle ratio of 2.1 times. PDP, TP and TPP reserves increased per debt adjusted share by 7%, 9% and 11%, respectively.

In 2019, as part of our commitment to responsible development of our assets, we created a board level sustainability committee focused on evaluating risk, understanding our emissions and expanding the breadth and depth of our disclosures. Whitecap operates one of the largest carbon capture, utilization and storage ("CCUS") projects in the world. At Weyburn, we store 1.8 million tonnes of CO_2 annually which is more CO_2 than we emit corporately on an annual basis. Whitecap continues to focus on reducing our direct and indirect emissions through optimization of our current operations and advancing low emission growth opportunities.

As a tangible demonstration of our commitment to continual improvement, Whitecap has reduced direct greenhouse gas emissions intensity each year since 2015 posting an overall intensity reduction of 40% during that time. We continue to look for additional opportunities to improve carbon efficiency and are in the process of setting specific targets to ensure our downward trend continues into the future. By mid-2020, we anticipate releasing our bi-annual sustainability report that will include a more thorough presentation of key metrics, differentiators and sustainability targets. We have also launched our new website featuring our CO_2 carbon capture project which can be viewed at www.wcap.ca.

Whitecap's balance sheet remains in strong condition with net debt at $1.19 billion on total credit capacity of $1.77 billion providing significant financial flexibility and liquidity. All of our debt has been termed out with no near-term maturities and the average effective cost of borrowing is low at 3.6% per annum. Whitecap's debt to earnings before interest, taxes, depreciation and amortization ("EBITDA") ratio was 1.6x for 2019. (1)

(1) Refer to Note 12(a) "Bank Debt" in the audited annual consolidated financial statements.

FOURTH QUARTER FINANCIAL HIGHLIGHTS

- Funds flow was $184.5 million ($0.45 per share) compared to $138.8 million ($0.33 per share) in the prior year quarter, an increase of 33%. The funds flow increase of $45.7 million was attributed to $42.9 million from higher funds flow netbacks and $2.8 million from higher production volumes.

- Operating netbacks improved to $30.34/boe compared to $24.03/boe in the prior year quarter primarily due to higher realized crude oil prices.

- Production averaged 74,651 boe/d in the fourth quarter, an increase of 2% (5% per debt-adjusted share) from 73,185 boe/d in the prior year quarter.

- Capital expenditures were $98.8 million in the quarter, compared to $76.5 million in the prior year quarter.

- The Company returned $35.0 million in cash dividends to shareholders in the fourth quarter.

FOURTH QUARTER OPERATIONAL HIGHLIGHTS AND 2019 UPDATE

Southeast Saskatchewan

At Weyburn, we drilled 6 (3.4 net) infills wells in the fourth quarter. Production results for five wells with 30 days production history averaged 147 bopd or 2.4 times greater than our expectations. The property averaged 14,304 boe/d in 2019 and maintained a production decline rate of less than 3% while reinvesting only 23% ($37 million) of its operating income.

This asset continues to be a significant free funds flow engine for the Company generating $124 million of operating income after capital expenditures. We plan to complete our winter program in the first quarter of 2020 with the drilling of 10 (6.2 net) wells, including 2 (1.2 net) injection wells.

Southwest Saskatchewan

In southwest Saskatchewan, we drilled 6 (4.4 net) oil wells in the fourth quarter for a total of 48 (37.0 net) wells including 3 (1.7 net) injection wells for the year. We had exceptional results from our Atlas program, drilling 19 (15.5 net) wells of which 17 have been on production for 90 days with average IP(90) rates of 179 boe/d or 37% above our expectations. We drilled 13 (10.8 net) wells in the Lower Shaunavon with average IP(90) rates of 124 boe/d or 36% higher than our expectations.

We have recently placed into service our new Carmichael battery to handle production from our Lower Shaunavon development. By processing volumes through this new 100% working interest facility, we anticipate operating netbacks to increase by $3.50/boe in the area in 2020. The southwest Saskatchewan business unit continues to generate significant operating income after capital expenditures as we only invested $80 million to maintain average production of approximately 15,000 boe/d resulting in operating income after capital expenditures of $109 million in 2019.

West Central Saskatchewan

We drilled 10 (8.6 net) horizontal Viking wells in west central Saskatchewan in the fourth quarter for a total of 95 (87.8 net) wells for the year, including 2 (2.0 net) injection wells to support our Kerrobert waterflood project.

The early time IP(30) performance of the wells is meeting budget expectations with lower production declines than forecasted with our average IP(180) wells performing 11% above our expectations. The shallower production decline profile is a direct result of maintaining and optimizing our waterfloods and drilling a higher percentage of wells in our revitalized waterflood areas.

Fourth quarter production increased 13% to 12,681 boe/d compared to 11,257 boe/d in the prior year quarter. The area averaged 10,777 boe/d in 2019 and generated operating income of $164 million on capital expenditures of $99 million.

Northwest Alberta and British Columbia

In northwest Alberta and British Columbia, we drilled 4 (3.4 net) wells in the fourth quarter including 1 (1.0 net) horizontal oil well in Boundary Lake, 1 (0.4 net) non-operated Charlie Lake horizontal oil well in the Peace River Arch area and 2 (2.0 net) earning wells in our Karr Montney oil joint venture (1.3 net wells post earning). In 2019, we drilled 26 (21.0 net wells) including 21 (15.6 net) Wapiti Cardium horizonal oil wells in this area.

We have now drilled all 3 of our earning wells for the Karr Montney oil joint venture of which one is on production and the second well is expected to be on stream by the end of March. We will have fully earned on 34 (21.5 net) sections of Montney rights once the third well is completed after break-up. In addition, we are currently participating in a fourth non-operated well (50% working interest) in the immediate area. We anticipate the remaining 2 (1.15 net) wells to be on production by the fourth quarter of 2020. Well performance and capital costs are within expectation at the early stage of development for this area.

Production at Wapiti is meeting expectations and currently producing approximately 7,000 boe/d. An additional 6 (5.2 net) wells are anticipated to be drilled in the first quarter of 2020. Our gas flood commenced injection in early 2020 and performance has been as expected.

The overall business unit continues to be a growth engine for the Company with fourth quarter average production increasing 9% to 17,235 boe/d compared to 15,847 boe/d in the prior year quarter. The business unit averaged 15,938 boe/d in 2019 and generated operating income of $132 million on capital expenditures of $111 million.

West Central Alberta

There was no drilling in this business unit in the fourth quarter. In 2019, we drilled a total of 18 (17.1 net) Cardium horizontal wells including 8 (8.0 net) wells in Ferrier, 8 (7.1 net) wells in West Pembina and 2 (2.0 net) wells in Willesden Green. On average, well performance has been at or above expectations in all areas.

Our focus continues to be on the waterflood redevelopment in West Pembina which to date has been performing above expectations. The waterflood performance has been partially recognized by our independent reserves evaluator in our 2019 year end reserves.

The business unit averaged 15,045 boe/d in 2019 and generated operating income of $144 million on capital expenditures of $69 million.

2019 RESERVE HIGHLIGHTS

Proved Developed Producing

- Increased PDP reserves by 7% per debt-adjusted share to 225.3 MMboe.
- Total PDP reserve additions of 25.9 MMboe replaced 100% of production at a finding, development and acquisition ("FD&A") cost of $14.45/boe, including changes in future development cost ("FDC"), which results in a recycle ratio of 2.1 times ($15.42/boe, excluding changes in FDC resulting in a recycle ratio of 1.9 times)
- PDP reserves represent 62% of the TP reserves, consistent with the prior year.

Total Proved

- Increased TP reserves by 9% per debt-adjusted share to 363.1 MMboe.
- Total TP reserve additions of 34.4 MMboe replaced 133% of production at an FD&A cost of $17.95/boe, including FDC, which results in a recycle ratio of 1.7 times ($11.59/boe, excluding FDC, which results in a recycle ratio of 2.6 times).
- TP reserves represent 72% of the TPP reserves consistent with the prior year.

Total Proved Plus Probable

- Increased TPP reserves by 11% per debt-adjusted share to 507.4 MMboe.
- Total TPP reserve additions of 43.8 MMboe replaced 169% of production at an FD&A cost of $21.06/boe, including FDC, which results in a recycle ratio of 1.4 times ($9.10/boe, excluding FDC, which results in a recycle ratio of 3.3 times)

OUTLOOK

The start to 2020 has been a busy one for Whitecap. In addition to an active drilling program with 10 drilling rigs currently in operation, we recently closed the acquisition of a private company with assets synergistic with our core southwest Saskatchewan business unit for $16.2 million. The acquisition includes current production of approximately 600 boe/d with a production decline rate of less than 15%, injection facilities and tax pools of $131.0 million including $80.5 million of non-capital losses. We see upside opportunities that include reactivation and recompletion opportunities in the enhanced oil recovery projects currently in operation as well as extending our resource plays on this acreage.

Our corporate average production guidance for 2020 of 71,000 – 72,000 boe/d remains unchanged. We reduced our first quarter capital program by approximately $10 million (primarily in the Viking program) to partially fund the acquisition and now expect capital expenditures in 2020 to be $350 - $370 million excluding the corporate acquisition.

We believe the current environment, wherein new equity financings are challenging and debt financings are limited and increasingly restrictive, provides opportunities for Whitecap to use our free funds flow and balance sheet as strategic assets to further enhance the return profile to our shareholders. We have the internal expertise to identify, evaluate and execute on these potential opportunities using a combination of joint venture transactions, acquisitions, partnerships and organic growth. In addition, we intend to accelerate the application of our technical expertise in CO_2 sequestration and enhanced oil recovery, whether in Canada or globally, to continue to improve upon our standing as one of the lowest net greenhouse gas ("GHG") emitters in the oil and gas industry and to invest in renewable projects that can complement our existing operations.

We will continue to differentiate ourselves with a business strategy that is sustainable for the long term and is focused on developing and growing our crude oil and natural gas resources in a manner that enhances our position as a leader in energy production with low GHG emissions intensity. This, combined with our production and funds flow growth targets and our disciplined approach to capital allocation, positions us to continue to increase the return of capital to our shareholders.

On behalf of our management team and board of directors, we would like to thank our shareholders for their ongoing support and look forward to providing updates as we progress through the year.

2019 RESERVES REVIEW

Our 2019 year end reserves were evaluated by independent reserves evaluator McDaniel & Associates Consultants Ltd. ("McDaniel") in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") as of December 31, 2019. The reserves evaluation was based on the average forecast pricing of McDaniel's, GLJ Petroleum Consultants and Sproule Associates Limited and foreign exchange rates at January 1, 2020 which is available on McDaniel's website at www.mcdan.com.

Reserves included are Company share reserves which are the Company's total working interest reserves before the deduction of any royalties and including any royalty interests payable to the Company. Additional reserve information as required under NI 51-101 will be included in our Annual Information Form which will be filed on SEDAR on or before March 30, 2020. The numbers in the tables below may not add due to rounding.

Summary of Reserves

Reserves as at December 31, 2019

	Company Share Reserves			
Description	Oil (Mbbl)	Gas (MMcf)	NGL (Mbbl)	Total (Mboe)
Proved producing	180,317	190,532	13,250	225,322
Proved non-producing	2,107	1,427	44	2,388
Proved undeveloped	101,691	143,187	9,788	135,343
Total proved	284,115	335,145	23,081	363,053
Probable	101,281	180,433	12,959	144,312
Total proved plus probable	385,396	515,578	36,040	507,365

Net Present Values

Summary of Before Tax Net Present Values (Forecast Pricing)
As at December 31, 2019

	Before Tax Net Present Value ($MM) [1]				
	Discount Rate				
Description	0%	5%	10%	15%	20%
Proved producing	5,822	4,202	3,283	2,713	2,327
Proved non-producing	89	62	47	37	30
Undeveloped	2,959	1,822	1,168	769	514
Total proved	8,871	6,086	4,497	3,519	2,871
Probable	5,496	2,860	1,778	1,229	910
Total proved plus probable	14,367	8,947	6,275	4,748	3,781
Per fully diluted share	34.44	21.45	15.04	11.38	9.07

(1) Includes abandonment and reclamation costs as defined in NI 51-101 for all of our facilities, pipelines and wells including those without reserves.

Future Development Costs

FDC reflects the best estimate of the capital cost to develop and produce reserves. FDC associated with our TPP reserves at year end 2019 is $4.0 billion undiscounted ($2.5 billion discounted at 10%) and includes polymer and CO_2 purchases for our southwest and southeast Saskatchewan enhanced oil recovery projects. The TPP and TP FDC for these two items is $788 million undiscounted ($296 million discounted at 10%).

Also included in FDC are 1,494 (1,229.4 net) proved plus probable booked locations.

($000s)	Total Proved	Total Proved plus Probable
2020	310,312	337,325
2021	467,873	486,361
2022	570,917	650,445
2023	512,521	634,590
2024	532,365	648,252
Remainder	1,007,026	1,209,584
Total FDC, Undiscounted	3,401,014	3,966,556
Total FDC, Discounted at 10%	2,174,452	2,545,469

Performance Measures (Including FDC)

The following table highlights our F&D and FD&A costs and associated recycle ratios, including FDC, based on the evaluation of our petroleum and natural gas reserves prepared by McDaniel:

	2019	2018	2017	Three Year Weighted Average
Proved Developed Producing				
F&D costs (1)	$14.33	$13.06	$11.25	$12.90
F&D recycle ratio (2)	2.1x	2.2x	2.4x	2.2x
FD&A costs (3)	$14.45	$15.15	$21.68	$17.04
FD&A recycle ratio (2)	2.1x	1.9x	1.3x	1.8x
Total Proved				
F&D costs (1)	$17.87	$22.70	$13.37	$18.00
F&D recycle ratio (2)	1.7x	1.3x	2.1x	1.7x
FD&A costs (3)	$17.95	$23.30	$21.53	$20.89
FD&A recycle ratio (2)	1.7x	1.3x	1.3x	1.4x
Total Proved Plus Probable				
F&D costs (1)	$21.00	$24.83	$12.66	$19.54
F&D recycle ratio (2)	1.4x	1.2x	2.2x	1.6x
FD&A costs (3)	$21.06	$24.04	$17.05	$20.74
FD&A recycle ratio (2)	1.4x	1.2x	1.6x	1.4x

(1) F&D costs are calculated as the sum of development capital of $396.1 million plus the change in FDC for the period of -$25.1 million (PDP), $218.8 million (TP) and $524.2 million (TPP), divided by the change in reserves that are characterized as development for the period.
(2) Recycle ratio is calculated as operating netback divided by F&D or FD&A costs. Our operating netback in 2019 was $29.73/boe.
(3) FD&A costs are calculated as the sum of development capital of $396.1 million plus acquisition capital of $3.1 million plus the change in FDC for the period of -$25.1 million (PDP), $218.8 million (TP) and $524.2 million (TPP), divided by the change in total reserves, other than from production, for the period.

Performance Measures (Excluding FDC)

The following table highlights our finding and development ("F&D") and FD&A costs and associated recycle ratios, excluding FDC, based on the evaluation of our petroleum and natural gas reserves prepared by McDaniel:

	2019	2018	2017	Three Year Weighted Average
Proved Developed Producing				
F&D costs (1)	$15.30	$15.06	$12.48	$14.30
F&D recycle ratio (2)	1.9x	1.9x	2.2x	2.0x
FD&A costs (3)	$15.42	$17.01	$13.55	$15.34
FD&A recycle ratio (2)	1.9x	1.7x	2.0x	1.9x
Total Proved				
F&D costs (1)	$11.51	$14.28	$13.71	$13.14
F&D recycle ratio (2)	2.6x	2.1x	2.0x	2.2x
FD&A costs (3)	$11.59	$14.94	$10.97	$12.50
FD&A recycle ratio (2)	2.6x	2.0x	2.5x	2.4x
Total Proved Plus Probable				
F&D costs (1)	$9.04	$15.67	$12.71	$12.43
F&D recycle ratio (2)	3.3x	1.9x	2.2x	2.5x
FD&A costs (3)	$9.10	$15.37	$8.61	$11.01
FD&A recycle ratio (2)	3.3x	1.9x	3.2x	2.8x

(1) F&D costs are calculated as development capital of $396.1 million divided by the change in reserves that are characterized as development for the period.
(2) Recycle ratio is calculated as operating netback divided by F&D or FD&A costs. Our operating netback in 2019 was $29.73/boe.
(3) FD&A costs are calculated as the sum of development capital of $396.1 million plus acquisition capital of $3.1 million, divided by the change in total reserves, other than from production, for the period.

Production Replacement and Reserve Life Index

The following table highlights our production replacement and reserve life index ("RLI") based on the evaluation of our petroleum and natural gas reserves prepared by McDaniel:

	2019	2018	2017	Three Year Weighted Average
Proved Developed Producing				
Production replacement [1]	100%	112%	449%	218%
RLI (years) [2]	8.3	8.4	10.2	9.0
Total Proved				
Production replacement [1]	133%	128%	555%	269%
RLI (years) [2]	13.3	13.3	15.9	14.1
Total Proved Plus Probable				
Production replacement [1]	169%	124%	707%	330%
RLI (years) [2]	18.6	18.3	22.2	19.7

(1) Production replacement ratio is calculated as total reserve additions (including acquisitions net of dispositions) divided by annual production. Whitecap's production averaged 71,050 boe/d in 2019.

(2) RLI is calculated as total Company share reserves divided by the annualized fourth quarter actual production of 74,651 boe/d.

Conference Call and Webcast

Whitecap has scheduled a conference call and webcast to begin promptly at 9:00 am MT (11:00 am ET) on Thursday, February 27, 2020.

The conference call dial-in number is: 1-888-390-0605 or (587) 880-2175 or (416) 764-8609

A live webcast of the conference call will be accessible on Whitecap's website at www.wcap.ca by selecting *"Investors"*, then *"Presentations & Events"*. Shortly after the live webcast, an archived version will be available for approximately 14 days.

Note Regarding Forward-Looking Statements

This press release contains forward-looking statements and forward-looking information (collectively "forward-looking information") within the meaning of applicable securities laws relating to the Company's plans and other aspects of our anticipated future operations, management focus, strategies, financial, operating and production results and business opportunities. Forward-looking information typically uses words such as "anticipate", "believe", "continue", "trend", "sustain", "project", "expect", "forecast", "budget", "goal", "guidance", "plan", "objective", "strategy", "target", "intend", "estimate", "potential", or similar words suggesting future outcomes, statements that actions, events or conditions "may", "would", "could" or "will" be taken or occur in the future, including statements about our strategy, plans, focus, objectives and priorities; anticipated benefits of our CCUS project; the ability to reduce our direct and indirect emissions through optimization of our current operations and advancing low emission growth opportunities; anticipated timing of releasing our bi-annual sustainability report; the anticipated increase to our operating netbacks from the construction of the Carmichael battery; the number and timing of wells to be drilled in Southeast Saskatchewan in the first quarter of 2020; the number and timing of wells to be drilled under the Karr Montney oil joint venture in 2020; the number and timing of wells to be drilled at Boundary Lake in the first quarter of 2020; the anticipated benefits of the private company acquired subsequent to year end; our 2020 production guidance and capital budget; the availability of debt and equity financings; and our ability to use our free funds flow and balance sheet as strategic assets to enhance the return profile to our shareholders. Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

The forward-looking information is based on certain key expectations and assumptions made by our management, including expectations and assumptions concerning prevailing commodity prices, exchange rates, interest rates, applicable royalty rates and tax laws; future production rates and estimates of operating costs; performance of existing and future wells; reserve volumes; anticipated timing and results of capital expenditures; the success obtained in drilling new wells; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the state of the economy and the exploration and production business; results of operations; performance; business prospects and opportunities; the availability and cost of financing, labour and services; the impact of increasing competition; ability to efficiently integrate assets and employees acquired through acquisitions, ability to market oil and natural gas successfully and our ability to access capital.

Although we believe that the expectations and assumptions on which such forward-looking information is based are reasonable, undue reliance should not be placed on the forward-looking information because Whitecap can give no assurance that they will prove to be correct. Since forward-looking information addresses future events and conditions, by its very nature they involve inherent risks and uncertainties. These include, but are not limited to: the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of estimates and projections relating to reserves, production, costs and expenses; health, safety and environmental risks; commodity price and exchange rate fluctuations; interest rate fluctuations; marketing and transportation; loss of markets; environmental risks; competition; incorrect assessment of the value of acquisitions; failure to complete or realize the anticipated benefits of acquisitions or dispositions; ability to access sufficient capital from internal and external sources; failure to obtain required regulatory and other approvals; reliance on third parties and pipeline systems; and changes in legislation, including but not limited to tax laws, production curtailment, royalties and environmental regulations. Our actual results, performance or achievement could differ materially from those expressed in, or implied by, the forward-looking information and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking information will transpire or occur, or if any of them do so, what benefits that we will derive therefrom. Management has included the above summary of assumptions and risks related to forward-looking information provided in this press release in order to provide security holders with a more complete perspective on our future operations and such information may not be appropriate for other purposes.

Readers are cautioned that the foregoing lists of factors are not exhaustive. Additional information on these and other factors that could affect our operations or financial results are included in reports on file with applicable securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com).

These forward-looking statements are made as of the date of this press release and we disclaim any intent or obligation to update publicly any forward-looking information, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

Oil and Gas Advisories

All reserve references in this press release are "Company share reserves". Company share reserves are the Company's total working interest reserves before the deduction of any royalties and including any royalty interests payable to the Company.

It should not be assumed that the present worth of estimated future amounts presented in the tables above represents the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of Whitecap's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

References to crude oil or natural gas production in this press release refer to the light and medium crude oil and conventional natural gas, respectively, product types as defined in NI 51-101.

"Boe" means barrel of oil equivalent based on 6 mcf of natural gas to 1 bbl of oil. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

This press release contains metrics commonly used in the oil and natural gas industry which have been prepared by management, such as "recycle ratio", "operating netback", "F&D costs", "FD&A costs", "production replacement ratio", "reserve life index", "development capital", "acquisition capital"; “production per debt-adjusted share”, and “reserves per debt-adjusted share”. These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons.

"**Acquisition capital**" includes net property acquisitions less any non-cash amounts and the announced purchase price of corporate acquisition including any estimated working capital deficit or surplus rather than the amounts allocated to property, plant and equipment for accounting purposes and the aggregate exploration and development capital spending within the year on reserves that are categorized as acquisitions less the disposition of certain processing facilities.

"**Development capital**" means the aggregate exploration and development costs incurred in the financial year on reserves that are categorized as development. Development capital excludes capitalized administration costs.

“**F&D costs**” are calculated as the sum of development capital plus the change in FDC for the period when appropriate, divided by the change in reserves that are characterized as development for the period.

“**FD&A costs**” are calculated as the sum of development capital plus acquisition capital plus the change in FDC for the period when appropriate, divided by the change in total reserves, other than from production, for the period

"**Operating netback**" see "Non-GAAP Measures".

“**Production per debt-adjusted share**" is calculated by dividing production for the period by debt adjusted weighted average fully diluted shares. Debt adjusted weighted average fully diluted shares is calculated by dividing the change in net debt in the period by the average share price for the period. A further adjustment is made to normalize for the impact of the Southeast Saskatchewan acquisition which closed on December 14, 2017. The adjustment to production and weighted average fully diluted shares assumes the acquisition occurred at the beginning of the period.

"**Production replacement ratio**" is calculated as total reserve additions (including acquisitions net of dispositions) divided by annual production.

"**Recycle ratio**" is measured by dividing operating netback by F&D or FD&A cost per boe for the year.

"**Reserve life index**" or “**RLI**” is calculated as total Company share reserves divided by annualized fourth quarter actual production.

“**Reserves per debt-adjusted share**” is calculated by dividing reserves by debt adjusted shares. Debt adjusted shares is calculated by dividing the change in net debt in the period by the average share price for the period.

Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare our operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this press release, should not be relied upon for investment or other purposes.

Production Rates

Any references in this news release to initial production rates (IP(30), IP(90) or IP(180)) are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for Whitecap.

Drilling Locations

This press release discloses drilling inventory in three categories: (i) proved locations; (ii) probable locations; and (iii) unbooked locations. Proved locations and probable locations are derived from McDaniel’s reserves evaluation effective December 31, 2019 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources.

- Of the 27 (20.2 net) existing drilling locations identified herein, 15 (8.2 net) are proved locations, and 12 (12.0 net) are unbooked locations.
- Of the 244 (184.2 net) new drilling locations identified herein, 71 (63.3 net) are proved locations, 37 (24.1 net) are probable locations and 136 (96.8 net) are unbooked locations.
- Of the 144 (84.2 net) Montney joint venture drilling locations identified herein, all are unbooked locations.

Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that we will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which we drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been de-risked by drilling existing wells in relative close proximity to such unbooked drilling locations, other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Production History

The following table indicates our average daily production (including production from our major areas):

	Crude oil (bbls/d)	NGLs (bbls/d)	Natural gas (Mcf/d)	Total (boe/d) [1]
Three months ended December 31, 2019				
Northwest Alberta and British Columbia	10,132	2,055	30,289	17,235
Southeast Saskatchewan	13,815	429	29	14,249
Southwest Saskatchewan	14,943	8	2,731	15,406
West Central Alberta	8,247	1,968	29,103	15,065
West Central Saskatchewan	10,896	344	8,644	12,681
Other minor areas	11	1	15	15
Total	58,044	4,805	70,811	74,651
Three months ended December 31, 2018				
Northwest Alberta and British Columbia	9,761	1,701	26,308	15,847
Southeast Saskatchewan	14,093	505	6	14,599
Southwest Saskatchewan	15,243	9	2,181	15,616
West Central Alberta	8,650	2,192	29,854	15,817
West Central Saskatchewan	9,305	245	10,244	11,257
Other minor areas	20	4	146	49
Total	57,072	4,656	68,739	73,185
Twelve months ended December 31, 2019				
Northwest Alberta and British Columbia	9,506	1,819	27,677	15,938
Southeast Saskatchewan	13,845	457	15	14,304
Southwest Saskatchewan	14,599	7	2,213	14,975
West Central Alberta	8,269	1,933	29,062	15,045
West Central Saskatchewan	9,180	288	7,856	10,777
Other minor areas	14	(1)	(22)	11
Total	55,413	4,503	66,801	71,050
Twelve months ended December 31, 2018				
Northwest Alberta and British Columbia	9,701	1,439	26,144	15,498
Southeast Saskatchewan	14,203	475	8	14,679
Southwest Saskatchewan	14,716	7	1,953	15,049
West Central Alberta	9,668	2,225	30,711	17,011
West Central Saskatchewan	10,206	249	10,129	12,144
Other minor areas	17	2	97	34
Total	58,511	4,397	69,042	74,415

Note:
(1) Disclosure of production on a per boe basis of amounts in the above table in this press release consists of the constituent product types and their respective quantities disclosed in this table.

	Crude oil (bbls/d)	NGLs (bbls/d)	Natural gas (Mcf/d)	Total (boe/d) [1]
Weyburn IP(30)	147	-	-	147
Atlas IP(90)	173	-	36	179
Lower Shaunavon IP(90)	122	-	12	124
Wapiti, current production	3,736	1,456	10,848	7,000
Boundary Lake, horizontal multi-fractured IP(60)	240	-	414	309
Boundary Lake, unstimulated IP(60)	130	-	48	138
Production Guidance - 2020	56,090 – 56,880	4,260 – 4,320	63,900 – 64,800	71,000 – 72,000
Private company	600	-	-	600

Note:
(1) Disclosure of production on a per boe basis of amounts in the above table in this press release consists of the constituent product types and their respective quantities disclosed in this table.

Non-GAAP Measures

This press release includes non-GAAP measures as further described herein. These non-GAAP measures do not have a standardized meaning prescribed by International Financial Reporting Standards (“IFRS” or, alternatively, “GAAP”) and, therefore, may not be comparable with the calculation of similar measures by other companies. See the Company’s Management’s Discussion and Analysis of financial condition and results of operation for the period ended December 31, 2019 for a reconciliation of the non-GAAP measures.

“Free funds flow” represents funds flow less expenditures on property, plant and equipment (“PP&E”). Management believes that free funds flow provides a useful measure of Whitecap’s ability to increase returns to shareholders and to grow the Company’s business. Previously, Whitecap also deducted dividends paid or declared in the calculation of free funds flow. The Company believes the change in presentation better allows comparison with both dividend paying and non-dividend paying peers.

“Operating income” is determined by adding blending revenue and processing & other income, deducting realized hedging losses or adding realized hedging gains and deducting tariffs, royalties, operating expenses, transportation expenses and blending expenses from petroleum and natural gas revenues. Operating income is used in operational and capital allocation decisions. Management uses operating income to better analyze performance among its management units.

“Operating netbacks” are determined by adding blending revenue and processing & other income, deducting realized hedging losses or adding realized hedging gains and deducting tariffs, royalties, operating expenses, transportation expenses and blending expenses from petroleum and natural gas revenues. Operating netbacks are per boe measures used in operational and capital allocation decisions. Presenting operating netbacks on a per boe basis allows management to better analyze performance against prior periods on a comparative basis.

“Operating income after capital expenditures” represents operating income less expenditures on PP&E. Management believes that operating income after capital expenditures provides a useful measure of Whitecap’s operational and capital allocation decisions.

“Total payout ratio” is calculated as dividends paid or declared plus expenditures on PP&E, divided by funds flow. Management believes that total payout ratio provides a useful measure of Whitecap’s capital reinvestment and dividend policy, as a percentage of the amount of funds flow.

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