NEWS RELEASE

October 25, 2023

WHITECAP RESOURCES INC. ANNOUNCES THIRD QUARTER RESULTS AND 2024 BUDGET

CALGARY, ALBERTA – Whitecap Resources Inc. ("Whitecap" or the "Company") (TSX: WCP) is pleased to report its operating and unaudited financial results for the three and nine months ended September 30, 2023.

Selected financial and operating information is outlined below and should be read with Whitecap's unaudited interim consolidated financial statements and related management's discussion and analysis for the three and nine months ended September 30, 2023 which are available at www.sedarplus.ca and on our website at www.wcap.ca.

Financial ($ millions except for share amounts and percentages)	Three months ended Sept. 30 2023	2022	Nine months ended Sept. 30 2023	2022
Petroleum and natural gas revenues	955.9	1,070.5	2,637.5	3,336.4
Net income	152.7	324.5	590.7	1,357.5
Basic ($/share)	0.25	0.53	0.98	2.19
Diluted ($/share)	0.25	0.53	0.97	2.17
Funds flow [1]	466.0	546.8	1,329.1	1,729.1
Basic ($/share) [1]	0.77	0.89	2.19	2.80
Diluted ($/share) [1]	0.76	0.88	2.18	2.77
Dividends declared	87.8	67.2	263.2	170.0
Per share	0.15	0.11	0.43	0.28
Expenditures on property, plant and equipment [2]	281.9	208.0	753.3	507.5
Total payout ratio (%) [1]	79	50	76	39
Net Debt [1]	1,260.2	2,192.3	1,260.2	2,192.3
Operating				
Average daily production				
Crude oil (bbls/d)	85,238	85,137	84,717	84,599
NGLs (bbls/d)	17,804	16,513	16,640	14,863
Natural gas (Mcf/d)	323,903	264,886	310,531	225,076
Total (boe/d) [3]	157,026	145,798	153,112	136,975
Average realized Price [1,4]				
Crude oil ($/bbl)	103.72	111.64	95.43	119.13
NGLs ($/bbl)	36.75	55.87	39.32	58.65
Natural gas ($/Mcf)	2.76	4.56	2.97	5.65
Petroleum and natural gas revenues ($/boe) [1]	66.17	79.81	63.10	89.22
Operating Netback ($/boe) [1]				
Petroleum and natural gas revenues	66.17	79.81	63.10	89.22
Tariffs [1]	(0.50)	(0.39)	(0.51)	(0.44)
Processing & other income [1]	0.79	0.74	0.90	0.64
Marketing revenues [1]	5.04	6.03	4.91	6.02
Petroleum and natural gas sales [1]	71.50	86.19	68.40	95.44
Realized gain/(loss) on commodity contracts [1]	0.04	(2.20)	0.52	(5.98)
Royalties [1]	(11.53)	(16.29)	(10.90)	(17.58)
Operating expenses [1]	(13.97)	(14.85)	(14.35)	(14.71)
Transportation expenses [1]	(2.22)	(2.27)	(2.19)	(2.20)
Marketing expenses [1]	(4.99)	(6.00)	(4.89)	(5.97)
Operating netbacks	38.83	44.58	36.59	49.00
Share information (millions)				
Common shares outstanding, end of period	606.2	610.6	606.2	610.6
Weighted average basic shares outstanding	606.0	611.9	605.8	618.5
Weighted average diluted shares outstanding	610.0	617.9	609.5	624.5

MESSAGE TO SHAREHOLDERS

We are pleased to report Whitecap's strong third quarter operating results that have culminated with the achievement of our $1.3 billion net debt milestone and the planned enhancement to our return of capital framework. Having achieved this milestone, we will now return 75% of free funds flow[1] to shareholders which includes a sustainable base dividend ($0.73 per share annually) and share repurchases through our normal course issuer bid ("NCIB"). Since acquiring XTO Energy Canada for $1.9 billion in the third quarter of 2022, we have reduced net debt by over $900 million and, at the same time, have returned $447 million ($0.73 per share) to shareholders through our base dividend and share repurchases.

Whitecap's third quarter production of 157,026 boe/d included 103,042 bbl/d of light oil, condensate and NGLs and 323,903 mcf/d of natural gas. We completed an active third quarter drilling program including the drilling of 76 (63.7 net) wells in our light oil weighted East Division and 13 (11.8 net) wells in our West Division with 100% success.

Funds flow of $466 million ($0.76 per share) increased 12% on a per share basis relative to the second quarter and. after capital expenditures of $282 million, resulted in free funds flow of $184 million ($0.30 per share[1]). Third quarter dividends of $88 million ($0.15 per share) resulted in approximately 50% of free funds flow being returned to shareholders.

Our full year 2023 guidance is for average production of 157,000 – 159,000 boe/d and capital spending of $900 – $950 million, and we currently expect to be at the low end of our production guidance range and the high end of our capital spending range. In the fourth quarter we plan to bring on a total of 19 (13.2 net) wells across both Divisions, including 5 (5.0 net) Montney wells at Kakwa and Lator and 4 (4.0 net) Duvernay wells at Kaybob, with 10 (9.7 net) wells to be brought on stream in 2024 from our 2023 drilling program.

We provide the following third quarter 2023 financial and operating highlights:

- **Funds Flow.** Whitecap's third quarter funds flow of $466 million ($0.76 per share) benefitted from strong crude oil production and prices, with WTI in Canadian dollars averaging over $110/bbl during the quarter.

- **Liquids Production Outperformance.** Since re-allocating portions of our capital program earlier this year to higher netback oil weighted projects, our results have outperformed original expectations with third quarter oil and condensate production of 85,238 bbl/d. Our oil weighted assets across our East Division have continued to achieve strong results, contributing to higher liquids production and funds flow.

- **Return of Capital Focus.** Whitecap's third quarter dividends of $0.15 per share totalled $88 million, with dividends and share repurchases under our NCIB for the nine months ended September 30th, 2023 totalling $296 million ($0.49 per share).

- **Balance Sheet Strength.** Quarter end net debt of $1.26 billion equated to a debt to EBITDA ratio of 0.6 times and an EBITDA to interest expense ratio[5] of 26.2 times, both well within our debt covenants of not greater than 4.0 times and not less than 3.5 times, respectively. Our balance sheet is in excellent condition, with $3.1 billion of total capacity and a weighted average fixed interest rate of 3.3% on approximately $800 million of our total outstanding debt.

2024 BUDGET

Whitecap's 2024 budget reflects our focus on long-term sustainability and profitability to drive increasing returns for shareholders. Our Board of Directors has approved a capital budget of $1.0 – $1.2 billion which includes the drilling of approximately 258 (222.7 net) wells and is expected to generate average production of 162,000 – 168,000 boe/d or 5% production per share growth[6] at the mid-point. Our forecast production growth in 2024 represents meaningful progress towards our organic production growth target of 200,000 boe/d by the end of 2027.

Our asset base is split into two divisions - East and West. Our East Division is primarily comprised of low decline/high netback light oil weighted assets that generate significant operating free funds flow. Our West Division has substantial high-quality liquids-rich inventory in the Montney and Duvernay and will be the source of our corporate production growth, with increasing free funds flow capabilities as even greater scale is achieved and continual efficiency improvements are realized. The combined asset base is unique and can sustainably support strong return of capital to shareholders while capitalizing on growth opportunities for increased profitability over the long term.

We expect to allocate approximately $600 million to the West Division, $500 million to the East Division and a nominal $7 million to our New Energy projects to advance our four carbon hubs across Alberta and Saskatchewan towards final investment decisions. It is important to note that included in our capital budget are investments in facilities and infrastructure totaling $165 million that will support incremental production growth capacity in 2024 and beyond. We also plan on spending $150 million on enhanced oil recovery ("EOR") projects in our East Division. These capital plans for infrastructure and EOR are up 27% and 38% relative to 2023, respectively.

West Division

Driven by our extensive top tier unconventional inventory in the Montney and Duvernay, where most of our capital investments will be allocated, our West Division will be the primary source of production growth for 2024 and beyond, growing production from approximately 70,000 boe/d currently to 110,000 boe/d by the end of 2027. The West Division has 3,022 (2,701 net) drilling locations[7] across 800,000 (700,000 net) undeveloped acres (over 75% comprised of Montney and Duvernay lands) which we believe can support an average 10% divisional production growth rate for 25 years.

Our 2024 unconventional drilling program is designed to run two rigs continuously throughout the year, with plans to spud 17 (15.2 net) unconventional Montney wells and 11 (11.0 net) Duvernay wells at Kaybob. In addition, we plan on drilling 14 (12.0 net) wells at Valhalla and Wapiti in 2024.

The majority of our unconventional Montney development will be focused in the Musreau area as our infrastructure buildout, including a 20,000 boe/d battery, is expected to be completed in the second quarter of 2024. The facilities portion of our 2024 capital program in the West Division has increased by 45% relative to 2023 and includes the completion of the Musreau battery, as well as initial engineering work for future new-build or facility expansions and additional gathering lines at Kaybob.

Our Montney assets at Musreau are located just north of our main Kakwa development where results continue to prove the deliverability of our asset base. In the third quarter, we brought 3 (3.0 net) wells on production with initial 30-day production rates of approximately 1,600 boe/d per well (31% liquids) which is consistent with our historical results in the area. We are looking forward to our development program at Musreau, where high liquids rates are expected to drive strong economics.

During the third quarter, we also completed and brought on production 2 (2.0 net) Montney wells at Berland which were drilled by the previous operator in 2019 and left uncompleted. The wells have been on for over 30 days and post the clean-up period, current production rates are above expectations at 1,000 boe/d per well (65% liquids). We do not have any wells at Berland planned for 2024, however, we are encouraged by these early production rates and, given existing infrastructure in the area, the return characteristics of this asset may compete for future capital allocation.

The extensive technical review we had undertaken prior to our initial Duvernay drilling program is proving to be beneficial as results from our first 3 (3.0 net) wells at Kaybob are strong. Average production over the first 90 days is approximately 1,500 boe/d per well (39% liquids) which is above our internal expectations including liquids production of 580 bbl/d that is approximately 15% higher than initial expectations. Higher liquids production as well as a quicker clean-up period are contributing to the strong economics of these wells, which are expected to reach half-cycle payout in approximately 10 months (or two months quicker than forecast) at current strip prices[8].

We most recently brought our next 4 (4.0 net) Duvernay wells on production in mid-October and are very encouraged with initial rates. Our plans include an additional 11 (11.0 net) wells in 2024, and we forecast that utilization of our 100% owned 15-07 gas processing facility will increase to 70% in 2024. Increased utilization of this facility improves the profitability of our Duvernay assets and with continued successful development, we forecast the facility to be over 90% utilized by the end of 2025.

East Division

Our 2024 capital program in the East Division is focused on long-term sustainability and free funds flow generation, with plans to drill approximately 215 (184.1 net) wells. The East Division has 3,562 (2,974 net) drilling locations across 500,000 (400,000 net) undeveloped acres, which we believe can support holding production flat at approximately 90,000 boe/d for the next 10 years, while generating significant free funds flow.

2024 development capital in the East Division will be focused on both short-cycle, high netback, light oil weighted Cardium, Frobisher, Glauconite, Shaunavon and Viking assets along with increased spending on long-term EOR initiatives across the asset base. In the current oil price environment[8], the short-cycle light oil weighted Frobisher and Viking assets have an average half-cycle payout of only five months, highlighting the robust economics of these assets. Our technical team continues to test and implement several development initiatives such as extended reach horizontals ("ERH") and multi-leg laterals in each of our play types. Upon success, these initiatives will further enhance the long-term sustainability of our asset base.

In Eastern Saskatchewan, we plan to drill 48 (43.3 net) conventional Mississippian wells, the majority of which will target the Frobisher formation. Our 2023 Mississippian program has been very successful to-date with well design changes expected to further enhance long-term value in the play. Our well design changes have focused on increasing

reservoir contact with longer lateral lengths, as well as lateral additions into secondary zones within the Frobisher formation. The majority of our 2024 Mississippian program will be dual and triple-leg laterals.
In Western Saskatchewan, we plan to drill 91 (81.7 net) Viking wells and 28 (24.1 net) wells in Southwest Saskatchewan primarily targeting the Lower Shaunavon and Success formations. The evolution of our Viking program continues as we drilled an open hole multi-lateral pilot well in the Elrose area in the third quarter. Drilling was executed successfully, and the well was brought on production in October. We look forward to the results and the potential expansion of these technical advancements to our drilling inventory across our Viking and other conventional assets.

For 2024, we plan to spend $150 million on EOR initiatives primarily at our Weyburn carbon dioxide ("CO_2") EOR project as well as our Southwest Saskatchewan, Viking, and West Pembina EOR assets. During the third quarter, we signed a CO_2 purchase and sale extension agreement with SaskPower to December 31, 2034, for CO_2 supply to the Weyburn project. The Weyburn project provides significant benefits to various stakeholders beyond the strong free cash flow generating capabilities of the asset. We plan to drill 19 (12.7 net) wells at Weyburn in 2024, 11 (7.5 net) producers and 8 (5.2 net) injectors.

Our Central Alberta Cardium and Glauconite programs have also benefited from greater use of extended lateral lengths and increased utilization of owned and operated infrastructure. Of the 29 (22.5 net) wells planned for Central Alberta in 2024, 27 (20.5 net) are ERH wells. Continued success with ERH wells will improve the current and long-term profitability of our Central Alberta assets.

OUTLOOK

In 2024 we are expecting commodity prices to remain robust but volatile, given the macro environment. We believe that crude oil prices will remain strong due to continued growth in worldwide demand combined with limited production growth as a result of global underinvestment in our sector over the past several years. The incremental pipeline capacity that the Trans Mountain Expansion Project will provide when fully operational in early 2024 will ensure that Canadian crude oil price realizations remain strong with improving price differentials.

On the natural gas side, we look forward to the completion of LNG Canada in 2025, the country's first LNG project that, along with other recently announced projects, will provide additional market diversification for Canadian natural gas. These incremental projects will also advance Canada's leadership role in moving towards a lower carbon economy.

Our disciplined capital budget for 2024 is expected to generate $1.8 billion of funds flow and $700 million of free funds flow after capital expenditures, based on current strip prices[8]. We have also stress tested our budget down to US$50/bbl WTI and $3.00/GJ AECO to ensure that our dividend and maintenance capital are fully funded. Our balance sheet continues to strengthen with net debt currently less than $1.3 billion and decreasing to $1 billion in 2024 (Debt/EBITDA[5] ratio of 0.5x) which provides us with significant financial flexibility for enhanced shareholder returns.

We look forward to the continued execution and profitable development of our strong asset base through 2024 and for many years to come. Our balanced portfolio of high-quality drilling opportunities supports our anticipated strong free funds flow generation and sustainable organic production growth to 200,000 boe/d by the end of 2027. Through technological advancements, efficiency improvements and acreage optimizations, our teams are constantly improving the long-term profitability of our remaining drilling inventory to support our targeted 3% – 8% organic production growth rate for at least the next 25 years.

On behalf of our employees, management team and Board of Directors, we would like to thank our shareholders for their support and look forward to the remainder of this year and an exciting 2024 and beyond.

NOTES

1 Funds flow, funds flow basic ($/share), funds flow diluted ($/share) and net debt are capital management measures. Total payout ratio, average realized price and per boe disclosure figures are supplementary financial measures. Operating netback and free funds flow are non-GAAP financial measures. Operating netbacks ($/boe) and free funds flow diluted ($/share) are non-GAAP ratios. Refer to the Specified Financial Measures section in this press release for additional disclosure and assumptions.
2 Also referred to herein as "capital expenditures" and "capital spending".
3 Disclosure of production on a per boe basis in this press release consists of the constituent product types and their respective quantities disclosed herein. Refer to Barrel of Oil Equivalency and Production, Initial Production Rates and Product Type Information in this press release for additional disclosure.
4 Prior to the impact of risk management activities and tariffs.
5 Debt to EBITDA ratio and EBITDA to interest expense ratio are specified financial measures that are calculated in accordance with the financial covenants in our credit agreement.
6 Production per share is the Company's total crude oil, NGL and natural gas production volumes for the applicable period divided by the weighted average number of diluted shares outstanding for the applicable period. Production per share growth is determined in comparison to the applicable comparative period adjusted for acquisitions and dispositions.
7 Disclosure of drilling locations in this press release consists of proved, probable, and unbooked locations and their respective quantities on a gross and net basis as disclosed herein. Refer to Drilling Locations in this press release for additional disclosure.
8 Based on the following strip commodity pricing and exchange rate assumptions for the fourth quarter of 2023: US$84/bbl WTI, $2.60/GJ AECO, USD/CAD of $1.37. And for 2024: US$79/bbl WTI, $2.85/GJ AECO, USD/CAD of $1.37.

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, October 26, 2023.

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.

For further information:

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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, priorities and position.

In particular, and without limiting the generality of the foregoing, this press release contains forward-looking information with respect to: our plan to return 75% of free funds flow back to shareholders through our base dividend and NCIB; our plan to bring on 5 (5.0 net) Montney wells at Kakwa and Lator and 4 (4.0 net) Duvernay wells at Kaybob as part of the 19 (13.2 net) wells, across both Divisions, brought on production during the fourth quarter; our expectation that production will be at the low end of our full year 2023 production guidance range; our expectation that capital will be at the high end of our full year 2023 capital guidance range; that our focus on long-term sustainability and profitability drives increasing returns to shareholders; our forecasts for average daily production (including by product type) and capital expenditures (including by Division) for 2023 and 2024; the number of gross and net wells that we plan to drill in 2024; our expectation to achieve 5% production per share growth in 2024 at the mid-point of our 2024 production guidance; that our forecast production growth in 2024 will represent meaningful progress towards our organic production growth target of 200,000 boe/d by the end of 2027; our belief that our East Division is primarily comprised of low decline/high netback light oil weighted assets that generate significant operating free funds flow; our belief that our West Division has substantial high quality liquids-rich inventory in the Montney and Duvernay and will be the source of corporate production growth with increasing free funds flow capabilities as greater scale is achieved and continual efficiency improvements are realized; our belief that our asset base is able to sustainably support strong return of capital to shareholders while capitalizing on growth opportunities for increased profitability over the long-term; the amount of capital expenditures in 2024 budgeted for New Energy projects, investments in facilities and infrastructure and EOR projects in our East Division, and the benefits anticipated to be derived therefrom; that driven by our extensive top tier unconventional inventory in the Montney and Duvernay, where most of our capital investments will be allocated, our West Division will be the primary source of production growth for 2024 and beyond; that we will grow production in the West Division from 70,000 boe/d currently to 110,000 boe/d by the end of 2027; our belief that we have 3,022 (2,701 net) drilling locations in inventory in our West Division, which we believe will support an average 10% divisional production growth rate for 25 years; our plan to spud 17 (15.2 net) unconventional Montney wells, 11 (11.0 net) Duvernay wells at Kaybob, and 14 (12.0 net) wells at Valhalla and Wapiti in 2024; our plan to focus our unconventional Montney development in the Musreau area in 2024 and that our infrastructure buildout, including a 20,000 boe/d battery, is expected to be completed in the second quarter of 2024; our expectation that the Musreau area will generate strong economics due to high condensate rates; that our first 3 (3.0 net) Duvernay wells are expected to reach half-cycle payout in approximately 10 months at current strip prices; our plan to drill 11 (11.0 net) Duvernay wells in 2024; our forecast that utilization of our 15-07 gas processing facility will increase to 70% in 2024 and over 90% by the end 2025; that increased utilization of our 15-07 facility improves the profitability of our Duvernay assets; that our 2024 capital program in the East Division is focused on long-term sustainability and free funds flow generation; our plan to drill 215 (184.1 net) wells in our East Division in 2024; our belief that we have 3,562 (2,974 net) drilling locations in inventory in our East Division, which we believe will support holding production flat in the East Division at 90,000 boe/d for the next 10 years and generate significant free funds flow; our plan for 2024 development capital in the East Division to be focused on both short-cycle, high netback, light oil weighted Cardium, Frobisher, Glauconite, Shaunavon and Viking assets along with increased spending on long-term EOR initiatives across the asset base; our expectation that in the current oil price environment, the short-cycle light oil weighted Frobisher and Viking assets have an average half-cycle payout of only five months; our belief that ERH wells and multi-leg laterals will further enhance the long-term sustainability of our asset base in our East Division; our plan to drill 48 (43.3 net) conventional Mississippian wells, with the majority targeting the Frobisher formation, in Eastern Saskatchewan; our expectation that well design changes will further enhance long-term value in our Eastern Saskatchewan assets; our plan for the majority of our 2024 Mississippian program to be dual and triple-leg laterals; our plan to drill 91 (81.7 net) Viking wells in Western Saskatchewan and 28 (24.1 net) wells in Southwest Saskatchewan in 2024; that results from a multi-lateral pilot well in the Viking may expand our drilling inventory across our Viking and other conventional assets; our plan to spend $150 million on EOR initiatives primarily at our Weyburn CO_2 EOR project as well as our Southwest Saskatchewan, Viking and West Pembina EOR assets in 2024; our plan to drill 19 (12.7 net) wells in Weyburn in 2024, which includes 11 (7.5 net) producers and 8 (5.2 net) injectors; our plan to drill 27 (20.5 net) ERH wells in Central Alberta out of a total of 29 (22.5 net) wells planned in the area in 2024; our belief that continued success with ERH wells will improve the current and long-term profitability of our Central Alberta assets; our expectation for commodity prices to remain robust but volatile in 2024; our belief that crude oil prices will remain strong due to continued growth in worldwide demand combined with limited production growth because of the global underinvestment in the sector over the past several years; our belief that the incremental pipeline capacity that the Trans Mountain Expansion Project will provide when fully operational in early 2024 will ensure that Canadian crude oil price realizations remain strong with improving price differentials; that the LNG projects being developed in Western Canada will advance Canada's leadership role in moving towards a lower carbon economy; our expectation that our 2024 capital budget will generate $1.8 billion of funds flow and $700 million of free funds flow after capital expenditures, based on current strip prices; our belief that our dividend and maintenance capital are fully funded under our 2024 budget down to US$50/bbl WTI and $3.00/GJ AECO; our expectation for net debt to decrease to $1.0 billion in 2024 which provides us with significant financial flexibility for enhanced shareholder returns; our belief that our balanced portfolio of high-quality drilling opportunities proves us with strong free funds flow generation and sustainable organic production growth to 200,000 boe/d by the end of 2027; and our belief that we are constantly improving the long-term profitability of our remaining drilling inventory to support our targeted 3% - 8% organic production growth rate for at least the next 25 years.

The forward-looking information is based on certain key expectations and assumptions made by our management, including: that we will continue to conduct our operations in a manner consistent with past operations except as specifically noted herein (and for greater certainty, the forward-looking information contained herein excludes the potential impact of any acquisitions or dispositions that we may complete in the future); the general continuance or improvement in current industry conditions; the continuance of existing (and in certain circumstances, the implementation of proposed) tax, royalty and regulatory regimes; expectations and assumptions concerning prevailing and forecast commodity prices, exchange rates, interest rates, inflation rates, applicable royalty rates and tax laws, including the assumptions specifically set forth herein; that going forward the COVID-19, or any other, pandemic will not have a material impact on (i) the demand for crude oil, NGLs and natural gas, (ii) our supply chain, including our ability to obtain the equipment and services we require, and (iii) our ability to produce, transport and/or sell our crude oil, NGLs and natural gas; the ability of OPEC+ nations and other major producers of crude oil to adjust crude oil production levels and thereby manage world crude oil prices; the impact (and the duration thereof) of the ongoing military actions between Russia and Ukraine and related sanctions on crude oil, NGLs and natural gas prices; the impact of rising and/or sustained high inflation rates and interest rates on the North American and world economies and the corresponding impact on our costs, our profitability, and on crude oil, NGLs and natural gas prices; future production rates and estimates of operating costs and development capital, including as specifically set forth herein; performance of existing and future wells; reserve volumes and net present values thereof; anticipated timing and results of capital expenditures / development capital, including as specifically set forth herein; 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; future dividend levels and share repurchase levels; the impact of increasing competition; ability to efficiently integrate assets and employees acquired through acquisitions or asset exchange transactions; ability to market oil and natural gas successfully; our ability to access capital and the cost and terms thereof; that we will not be forced to shut-in production due to weather events such as wildfires, floods or extreme hot or cold temperatures; the commodity pricing and exchange rate forecasts for the fourth quarter of 2023 and for 2024 specifically set forth herein; and that we will be successful in defending against previously disclosed and ongoing reassessments received from the Canada Revenue Agency and assessments received from the Alberta Tax and Revenue Administration.

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 it involves inherent risks and uncertainties. These include, but are not limited to: the risk that the funds that we ultimately return to shareholders through dividends and/or share repurchases is less than currently anticipated and/or is delayed, whether due to the risks identified herein or otherwise; the risk that any of our material assumptions prove to be materially inaccurate, including our 2023 and 2024 forecasts (including for commodity prices and exchange rates); the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production, including the risk that weather events such as wildfires, flooding or extreme hot or cold temperatures forces us to shut-in production or otherwise adversely affects our operations; pandemics and epidemics; 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; risks associated with increasing costs, whether due to high inflation rates, high interest rates, supply chain disruptions or other factors; health, safety and environmental risks; commodity price and exchange rate fluctuations; interest rate fluctuations; inflation 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 on acceptable terms or at all; failure to obtain required regulatory and other approvals; reliance on third parties and pipeline systems; changes in legislation, including but not limited to tax laws, production curtailment, royalties and environmental regulations; the risk that we do not successfully defend against previously disclosed and ongoing reassessments received from the Canada Revenue Agency and assessments received from the Alberta Tax and Revenue Administration and are required to pay additional taxes, interest and penalties as a result; and the risk that the amount of future cash dividends paid by us and/or shares repurchased for cancellation by us, if any, will be subject to the discretion of our Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including, among other things, fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, contractual restrictions contained in our debt agreements, and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends and/or the repurchase of shares – depending on these and various other factors, many of which will be beyond our control, our dividend policy and/or share buyback policy and, as a result, future cash dividends and/or share buybacks, could be reduced or suspended entirely. 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.sedarplus.ca).

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.

This press release contains future-oriented financial information and financial outlook information (collectively, "FOFI") about our forecast 2023 and 2024 capital expenditures, the percent of free funds flow to be returned to shareholders, the allocation of our 2024 capital expenditures to the West Division, East Division and New Energy initiatives, the allocation of our 2024 capital expenditures to facilities and infrastructure and EOR initiatives, our forecast for reaching total payout in 10 months for our recent 3 (3.0 net) Duvernay wells at current strip prices, our forecast for average half-cycle payout in 5 months on our Frobisher and Viking assets in the current oil price environment, our forecast for $1.8 billion of funds flow and $700 million of free funds flow in 2024 after capital expenditures based on current strip prices, our forecast that our dividend and maintenance capital are fully funded at US$50/bbl WTI and $3.00/GJ AECO, and our forecast for net debt to decrease to $1 billion in 2024, all of which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth in the above paragraphs. The actual results of operations of Whitecap and the resulting financial results will likely vary from the amounts set forth herein and such variation may be material. Whitecap and its management believe that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments. However, because this information is subjective and subject to numerous risks, it should not be relied on as necessarily indicative of future results. Except as required by applicable securities laws, Whitecap undertakes no obligation to update such FOFI. FOFI contained in this press release was made as of the date of this press release and was provided for the purpose of providing further information about Whitecap's anticipated future business operations. Readers are cautioned that the FOFI contained in this press release should not be used for purposes other than for which it is disclosed herein.

OIL AND GAS ADVISORIES

Barrel of Oil Equivalency

"Boe" means barrel of oil equivalent. All boe conversions in this press release are derived by converting gas to oil at the ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of oil. Boe may be misleading, particularly if used in isolation. A Boe conversion rate of 1 Bbl : 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio of oil compared to natural gas based on currently prevailing prices is significantly different than the energy equivalency ratio of 1 Bbl : 6 Mcf, utilizing a conversion ratio of 1 Bbl : 6 Mcf may be misleading as an indication of value.

Drilling Locations

This press release discloses drilling inventory in two categories: (i) booked locations (proved and probable); and (ii) unbooked locations. Booked locations represent the summation of proved and probable locations, which are derived from McDaniel & Associates Consultants Ltd.'s reserves evaluation effective December 31, 2022 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 3,562 (2,974 net) East Division drilling locations identified herein, 1,078 (917 net) are proved locations, 155 (123 net) are probable locations, and 2,329 (1,934 net) are unbooked locations.
- Of the 3,022 (2,701 net) West Division drilling locations identified herein, 362 (321 net) are proved locations, 154 (131 net) are probable locations, and 2,506 (2,249 net) are unbooked locations.

Unbooked locations consist of drilling locations that 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 of these 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, Initial Production Rates & Product Type Information

References to petroleum, crude oil, natural gas liquids ("NGLs"), natural gas and average daily production in this press release refer to the light and medium crude oil, tight crude oil, conventional natural gas, shale gas and NGLs product types, as applicable, as defined in National Instrument 51-101 ("NI 51-101"), except as noted below.

NI 51-101 includes condensate within the NGLs product type. The Company has disclosed condensate as combined with crude oil and separately from other NGLs since the price of condensate as compared to other NGLs is currently significantly higher and the Company believes that this crude oil and condensate presentation provides a more accurate description of its operations and results therefrom. Crude oil therefore refers to light oil, medium oil, tight oil and condensate. NGLs refers to ethane, propane, butane and pentane combined. Natural gas refers to conventional natural gas and shale gas combined.

Any reference in this news release to initial production rates (current, IP(30), IP(90)) 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 rate in calculating the aggregate production for Whitecap.

The Company's average daily production for the three and nine months ended September 30, 2023 and 2022, the forecast average daily production for 2023 and for 2024 (low-end and midpoint), and the average daily production rate per well for (1) the recent 3 (3.0 net) Montney wells at Kakwa (IP(30)), (2) the recent 2 (2.0 net) Montney wells at Berland (over 30 days - current), and (3) the recent 3 (3.0 net) Duvernay wells at Kaybob (IP(90)) disclosed in this press release consists of the following product types, as defined in NI 51-101 (other than as noted above with respect to condensate) and using a conversion ratio of 1 Bbl : 6 Mcf where applicable:

Whitecap Corporate	Q3/2023	Q3/2022	YTD/2023	YTD/2022
Light and medium oil (bbls/d)	74,981	79,180	74,924	80,328
Tight oil (bbls/d)	10,257	5,957	9,793	4,271
Crude oil (bbls/d)	85,238	85,137	84,717	84,599
NGLs (bbls/d)	17,804	16,513	16,640	14,863
Shale gas (Mcf/d)	172,384	104,358	162,632	68,931
Conventional natural gas (Mcf/d)	151,519	160,528	147,899	156,145
Natural gas (Mcf/d)	323,903	264,886	310,531	225,076
Total (boe/d)	157,026	145,798	153,112	136,975

Whitecap Corporate	2024 Guidance (Mid-Point)	2023 Guidance (Low-end)
Light and medium oil (bbls/d)	71,500	75,000
Tight oil (bbls/d)	14,500	10,250
Crude oil (bbls/d)	86,000	85,250
NGLs (bbls/d)	18,000	17,250
Shale gas (Mcf/d)	220,000	189,400
Conventional natural gas (Mcf/d)	146,000	137,600
Natural gas (Mcf/d)	366,000	327,000
Total (boe/d)	165,000	157,000

Whitecap Initial Production Rates	Kakwa (IP(30))	Berland (Over 30 – Current)	Kaybob (IP(90))
Light and medium oil (bbls/d)	-	-	-
Tight oil (bbls/d)	330	540	420
Crude oil (bbls/d)	330	540	420
NGLs (bbls/d)	145	105	145
Shale gas (Mcf/d)	6,750	2,130	5,610
Conventional natural gas (Mcf/d)	-	-	-
Natural gas (Mcf/d)	6,750	2,130	5,610
Total (boe/d)	1,600	1,000	1,500

"Half-cycle payout" is calculated by the time period for the operating netback of a well to equate to the individual cost of the well. Management uses payout as a measure of capital efficiency of a well to make capital allocation decisions.

This term does 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. Management uses 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.

SPECIFIED FINANCIAL MEASURES

This press release includes various specified financial measures, including non-GAAP financial measures, non-GAAP ratios, capital management measures and supplementary financial measures as further described herein. These financial measures are not standardized financial measures under International Financial Reporting Standards ("IFRS" or, alternatively, "GAAP") and, therefore, may not be comparable with the calculation of similar financial measures disclosed by other companies.

"Average realized prices" for crude oil, NGLs and natural gas are supplementary financial measures calculated by dividing each of these components of petroleum and natural gas revenues, disclosed in Note 15 "Revenue" to the Company's unaudited interim consolidated financial statements for the three and nine months ended September 30, 2023, by their respective production volumes for the period.

"Free funds flow" is a non-GAAP financial measure calculated as 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. Free funds flow is not a standardized financial measure under IFRS and, therefore, may not be comparable with the calculation of similar financial measures disclosed by other entities. The most directly comparable financial measure to free funds flow disclosed in the Company's primary financial statements is cash flow from operating activities. Refer to the "Cash Flow from Operating Activities, Funds Flow and Payout Ratios" section of our management's discussion and analysis for the three and nine months ended September 30, 2023 which is incorporated herein by reference, and available on SEDAR+ at www.sedarplus.ca. In addition, see the following table which reconciles cash flow from operating activities to funds flow and free funds flow:

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)	**2023**	**2022**	**2023**	**2022**
Cash flow from operating activities	382.8	559.9	1,266.3	1,627.2
Net change in non-cash working capital items	83.2	(13.1)	62.8	101.9
Funds flow	466.0	546.8	1,329.1	1,729.1
Expenditures on PP&E	281.9	208.0	753.3	507.5
Free funds flow	184.1	338.8	575.8	1,221.6
Total payout ratio (%)	79	50	76	39
Funds flow per share, basic	0.77	0.89	2.19	2.80
Funds flow per share, diluted	0.76	0.88	2.18	2.77

**"Free funds flow ($/share)"** is a non-GAAP ratio calculated by dividing free funds flow by the weighted average number of diluted shares outstanding for the relevant period. Free funds flow is a non-GAAP financial measure component of free funds flow ($/share). Free funds flow ($/share) is not a standardized financial measure under IFRS and therefore may not be comparable with the calculation of similar financial measures disclosed by other entities.

"Funds flow", **"funds flow basic ($/share)" and "funds flow diluted ($/share)"** are capital management measures and are key measures of operating performance as they demonstrate Whitecap's ability to generate the cash necessary to pay dividends, repay debt, make capital investments, and/or to repurchase common shares under the Company's normal course issuer bid. Management believes that by excluding the temporary impact of changes in non-cash operating working capital, funds flow, funds flow basic ($/share) and funds flow diluted ($/share) provide useful measures of Whitecap's ability to generate cash that are not subject to short-term movements in non-cash operating working capital. Whitecap reports funds flow in total and on a per share basis (basic and diluted), which is calculated by dividing funds flow by the weighted average number of basic shares and weighted average number of diluted shares outstanding for the relevant period. See Note 5(e)(ii) "Capital Management – Funds Flow" in the Company's unaudited interim consolidated financial statements for the three and nine months ended September 30, 2023 for additional disclosures.

"Net Debt" is a capital management measure that management considers to be key to assessing the Company's liquidity. See Note 5(e)(i) "Capital Management – Net Debt and Total Capitalization" in the Company's unaudited interim consolidated financial statements for the three and nine months ended September 30, 2023 for additional disclosures. The following table reconciles the Company's long-term debt to net debt:

Net Debt ($ millions)	**Sept. 30, 2023**	**Dec. 31, 2022**
Long-term debt	1,177.1	1,844.6
Accounts receivable	(452.3)	(480.2)
Deposits and prepaid expenses	(44.9)	(22.7)
Non-current deposits	(65.3)	-
Accounts payable and accrued liabilities	616.4	549.1
Dividends payable	29.2	22.3
Net Debt	1,260.2	1,913.1

"Operating netback" is a non-GAAP financial measure determined by adding marketing revenues and processing & other income, deducting realized losses on commodity risk management contracts or adding realized gains on commodity risk management contracts and deducting tariffs, royalties, operating expenses, transportation expenses and marketing expenses from petroleum and natural gas revenues. The most directly comparable financial measure to operating netback disclosed in the Company's primary financial statements is petroleum and natural gas sales. Operating netback is a measure used in operational and capital allocation decisions. Operating netback is not a standardized financial measure under IFRS and, therefore, may not be comparable with the calculation of similar financial measures disclosed by other entities. For further information, refer to the "Operating Netbacks" section of our management's discussion and analysis for the three and nine months ended September 30, 2023, which is incorporated herein by reference, and available on SEDAR+ at www.sedarplus.ca. A reconciliation of operating netbacks to petroleum and natural gas revenues is set out below:

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
Operating Netbacks ($ millions)	**2023**	**2022**	**2023**	**2022**
Petroleum and natural gas revenues	955.9	1,070.5	2,637.5	3,336.4
Tariffs	(7.2)	(5.2)	(21.5)	(16.6)
Processing & other income	11.4	9.9	37.6	24.1
Marketing revenues	72.8	80.9	205.3	225.0
Petroleum and natural gas sales	1,032.9	1,156.0	2,858.9	3,568.8
Realized gain (loss) on commodity contracts	0.6	(29.5)	21.6	(223.6)
Royalties	(166.6)	(218.5)	(455.5)	(657.6)
Operating expenses	(201.8)	(199.2)	(599.9)	(550.0)
Transportation expenses	(32.1)	(30.5)	(91.7)	(82.3)
Marketing expenses	(72.1)	(80.5)	(204.3)	(223.3)
Operating netbacks	560.9	598.0	1,529.1	1,832.0

"Operating netback ($/boe)" is a non-GAAP ratio calculated by dividing operating netbacks by the total production for the period. Operating netback is a non-GAAP financial measure component of operating netback per boe. Operating netback per boe is not a standardized financial measure under IFRS and, therefore may not be comparable with the calculation of similar financial measures disclosed by other entities. Presenting operating netback on a per boe basis allows management to better analyze performance against prior periods on a comparable basis.

"Petroleum and natural gas revenues ($/boe)", "Tariffs ($/boe)", "Processing and other income ($/boe)" and "Marketing revenues ($/boe)" are supplementary financial measures calculated by dividing each of these components of petroleum and natural gas sales, disclosed in Note 15 "Revenue" to the Company's unaudited interim consolidated financial statements for the three and nine months ended September 30, 2023, by the Company's total production volumes for the period.

"Per boe" or "($/boe)" disclosures for petroleum and natural gas sales, royalties, operating expenses, transportation expenses and marketing expenses are supplementary financial measures that are calculated by dividing each of these respective GAAP measures by the Company's total production volumes for the period.

"Realized gain (loss) on commodity contracts ($/boe)" is a supplementary financial measure calculated by dividing realized gain (loss) on commodity contracts, disclosed in Note 5(d) "Financial Instruments and Risk Management – Market Risk" to the Company's unaudited interim consolidated financial statements for the three and nine months ended September 30, 2023, by the Company's total production volumes for the period.

"Total payout ratio" is a supplementary financial measure calculated as dividends 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.

Per Share Amounts

Per share amounts noted in this press release are based on fully diluted shares outstanding unless noted otherwise.