



NEWS RELEASE

October 22, 2025

WHITECAP RESOURCES INC. DELIVERS STRONG THIRD QUARTER PERFORMANCE, RAISES 2025 PRODUCTION OUTLOOK AND SETS 2026 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, 2025.

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, 2025 which are available at [sedarplus.ca](https://www.sedarplus.ca) and on our website at [wcap.ca](https://www.wcap.ca).

	Three Months ended Sep. 30		Nine Months ended Sep. 30	
Financial (\$ millions except for share amounts)	2025	2024	2025	2024
Petroleum and natural gas revenues	1,660.3	890.9	3,967.8	2,739.6
Net income	204.2	274.2	677.4	578.5
Basic (\$/share)	0.17	0.46	0.74	0.97
Diluted (\$/share)	0.17	0.46	0.73	0.96
Funds flow ¹	896.6	409.0	2,055.7	1,219.4
Basic (\$/share) ¹	0.73	0.69	2.24	2.04
Diluted (\$/share) ¹	0.73	0.68	2.23	2.03
Dividends declared	221.5	107.9	514.1	326.2
Per share	0.18	0.18	0.55	0.55
Expenditures on property, plant and equipment ²	546.3	272.7	1,353.2	869.7
Free funds flow ¹	350.3	136.3	702.5	349.7
Net debt ¹	3,317.7	1,361.8	3,317.7	1,361.8
Operating				
Average daily production				
Crude oil (bbls/d)	179,918	92,335	142,240	91,604
NGLs (bbls/d)	47,501	20,578	35,009	20,228
Natural gas (Mcf/d)	883,224	362,332	633,665	369,551
Total (boe/d) ³	374,623	173,302	282,860	173,424
Average realized price ^{1,4}				
Crude oil (\$/bbl)	84.27	94.29	85.76	95.23
NGLs (\$/bbl)	36.43	34.02	35.92	34.55
Natural gas (\$/Mcf)	1.31	0.76	1.70	1.56
Petroleum and natural gas revenues (\$/boe) ¹	48.17	55.88	51.38	57.65
Operating netback (\$/boe) ¹				
Petroleum and natural gas revenues ¹	48.17	55.88	51.38	57.65
Tariffs ¹	(0.21)	(0.43)	(0.30)	(0.43)
Processing & other income ¹	0.39	0.67	0.50	0.72
Marketing revenues ¹	2.43	3.79	2.94	3.87
Petroleum and natural gas sales ¹	50.78	59.91	54.52	61.81
Realized gain on commodity contracts ¹	1.38	0.93	1.35	0.53
Royalties ¹	(5.88)	(9.01)	(7.07)	(9.51)
Operating expenses ¹	(12.49)	(13.38)	(13.09)	(13.71)
Transportation expenses ¹	(3.41)	(2.10)	(2.98)	(2.09)
Marketing expenses ¹	(2.36)	(3.76)	(2.89)	(3.84)
Operating netbacks	28.02	32.59	29.84	33.19
Share information (millions)				
Common shares outstanding, end of period	1,213.8	588.0	1,213.8	588.0
Weighted average basic shares outstanding	1,220.5	595.2	918.8	597.3
Weighted average diluted shares outstanding	1,225.7	599.2	923.1	600.7

MESSAGE TO SHAREHOLDERS

Since completing the strategic combination with Veren Inc. ("Veren") on May 12, 2025, the Company has executed exceptionally well across all areas of the business. Our teams have focused on seamless integration, consistent execution and the adoption of best practices across our expanded asset base. These efforts are already driving meaningful value for shareholders.

In our first full quarter following the transaction, we delivered outstanding operating and financial results, building on the strong momentum achieved year to date.

Average third quarter production was 374,623 boe/d which exceeded our internal expectations, including 227,419 bbls/d of oil, condensate and NGLs, and 883,224 mcf/d of natural gas. This outperformance reflects exceptional operational execution, with teams accelerating production additions and achieving sustained efficiency gains.

In a remarkably short period, the Company has captured operational synergies well ahead of schedule. Third quarter operating costs averaged \$12.49/boe, an 8% improvement compared to the prior quarter, underscoring the benefits of streamlined workflows, optimized production practices and enhanced infrastructure utilization. Progress on capital synergies has also been strong, driven by procurement efficiencies and rig line optimization.

Supported by robust operational performance and early synergy realization, the Company generated funds flow of \$897 million (\$0.73 per share) in the third quarter. With disciplined capital investments of \$546 million, this resulted in \$350 million of free funds flow, demonstrating the strength of our asset base and our commitment to efficient capital allocation.

As a result of year to date production outperformance, we are increasing 2025 full year average production guidance to 305,000 boe/d which is above the high end of our previous range of 295,000 – 300,000 boe/d. The updated production guidance reflects fourth quarter production of approximately 370,000 boe/d (61% liquids). Our 2025 capital spending guidance of \$2.0 billion remains unchanged.

At the end of the quarter, net debt was \$3.3 billion, representing a 1.0 times net debt to annualized funds flow ratio¹ and provides the Company with \$1.6 billion of available liquidity. Our financial position remains a cornerstone of the Company's long-term value creation strategy and positions us well for sustained success through 2026 and beyond.

For 2026, our Board of Directors has approved a capital budget of \$2.0 – \$2.1 billion, targeting average annual production of 370,000 – 375,000 boe/d (60% liquids) and a fourth quarter average production rate exceeding 380,000 boe/d. The 2026 capital budget reflects enhanced operational execution, disciplined asset allocation, moderate production growth and realized synergies.

The Company has made significant progress integrating assets and personnel. Embedded in our 2026 forecast are \$300 million in annual capital, operating and corporate synergies which is 40% higher than our original estimate of \$210 million at the time we announced the Veren combination.

OPERATIONAL UPDATES AND 2026 BUDGET

Unconventional

Operational performance on our unconventional assets was strong during the third quarter as we transitioned from integration to optimizing our expanded asset base. Initial optimization initiatives were identified, executed and, along with improvements to drilling and completion performance, led to compressed cycle times and capital efficiency gains. Together, these improvements are driving sustained value creation across our assets.

Approximately 75% of our 2026 capital program is directed towards the unconventional division, building directly on this momentum. The application of our unconventional workflow has resulted in measurable improvements in drilling and completion efficiency, well design and operating practices across our entire unconventional asset base. The program features a steady seven rig drilling program across our Duvernay and Montney assets. 2026 will be highlighted by our first development drilling at Lator in advance of the 04-13 facility startup.

Duvernay

At Kaybob, Duvernay production benefited from faster drilling times and more effective completion operations during the quarter. By leveraging enhanced workflows and consistent rig utilization, our operations team improved metres/day drilling performance by approximately 20% year-over-year and achieved a new pacesetter result of approximately 600 metres/day on a recent pad. Refinements to completion parameters, including perforation cluster design, pumping rates and an updated wellbore casing design, have improved average completion time by approximately 8% across the asset.

We reached the debottlenecked operating capacity of approximately 42,000 boe/d at our 15-07 gas processing facility at Kaybob in the third quarter, a 16% increase from prior operating capacity. This expansion has lowered per unit operating costs and enhanced the profitability of our Duvernay asset. Through these targeted debottlenecking projects and the commissioning of a new connection to a nearby third party processing facility, we are optimizing area throughput, resulting in a projected 40% increase in total processing capacity compared to our original expectations. These strategic initiatives support continued production growth, with area capacity expected to exceed 50,000 boe/d by the third quarter of 2026.

In 2026, approximately 45% of our unconventional capital program will be directed toward the Duvernay. We plan to drill 45 (45.0 net) wells with a three-rig program and bring on production 55 (52.5 net) wells from our 2025 and 2026 programs at Kaybob. Of the 2026 pads, approximately half will utilize a wine rack development design, and our program will focus on the development of our core assets to utilize expanded infrastructure capacity in the area. The 2026 program also includes \$55 million of targeted infrastructure spending to modestly expand, debottleneck and connect existing infrastructure. Following these efforts, total production capacity in the Kaybob region will be approximately 115,000 – 120,000 boe/d in the second half of 2026 which is expected to be operating at capacity in the second half of 2027.

Montney

Our combined Montney assets also exceeded expectations, with gains coming from the optimization of our base production along with strong performance from new wells.

At Gold Creek and Karr, Montney volumes averaged 4,000 boe/d above forecast in the third quarter, driven by strong base production performance following optimization of gas lift systems, gathering infrastructure and other best operational practices. Per-well recoveries from recently developed lands remain consistent with our initial reservoir assessments, reinforcing the long-term potential of these assets. In the fourth quarter, we commenced drilling on the first of two Karr pads to pilot a plug-and-perforation ("P&P") completion design. These two pads will include 7 (7.0 net) Montney wells and results from this pilot will inform future well designs as we continue to enhance risk-adjusted returns.

At Musreau, drilling operations on our most recent 6-well (6.0 net) pad achieved a 20% decrease in costs as a result of improved drilling performance compared to the first sixteen wells in the area. Performance gains were achieved through drilling design optimization, including refinements to pad layout, landing depth and casing design. We are now applying these learnings to our next 3-well (3.0 net) pad at Musreau and another 3-well (3.0 net) pad on the eastern portion of our Lator acreage, both of which commenced drilling operations in the fourth quarter of 2025.

Our 2026 Montney program will see the deployment of the remaining 55% of our unconventional capital to drill 53 (53.0 net) wells with a four-rig program and bring on production 74 (74.0 net) operated wells from our 2025 and 2026 programs.

At Gold Creek and Karr, two of our four Montney rigs will target development in well-understood areas with established infrastructure, focusing on consistent execution of an optimized drilling and completion design. In 2026, we plan to drill 29 (29.0 net) wells and bring 48 (48.0 net) wells on production. As we advance toward piloting P&P, we will continue to pursue opportunities to enhance capital efficiency by reducing capital costs and implementing disciplined controls to evaluate both technical and commercial performance. The first two P&P pilot pads at Karr are expected to come on production in the first half of 2026, followed by a P&P pilot pad at Gold Creek drilled in the second half of 2026 after a detailed technical assessment. With existing infrastructure capacity at both Gold Creek and Karr supporting future growth, only minimal infrastructure investment is planned for 2026.

In 2026, we plan to spud 24 (24.0 net) wells and bring on production 26 (26.0 net) wells in our Smoky region, which is comprised of Kakwa, Lator, Musreau and Resthaven. The area is characterized by varying levels of development maturity, with our Kakwa and Musreau assets largely de-risked and near-term efforts focused on operational execution and maximizing existing infrastructure capacity. Our Lator asset will advance to development mode in 2026, while our Resthaven asset will receive capital for a two-well (2.0 net) delineation program.

We plan to drill 11 (11.0 net) wells at Musreau in 2026 and allocate approximately \$5 million to enhance gas lift capabilities at our 05-09 facility in the second half of 2026, supporting further optimization of the strong condensate volumes being realized from this asset. Our 2026 development program will continue to leverage multi-bench development and employ controlled drawdown practices, both of which have contributed to the strong results observed to date.

At Lator, we plan to allocate approximately \$180 million of capital in 2026, including \$60 million towards supporting infrastructure (water disposal and gathering lines) to enable the ramp-up of this asset. We plan to drill 11 (11.0 net) wells in 2026. Following a successful engineering, design and permitting process, construction on the 04-13 Lator facility has been progressing ahead of schedule and within budgeted capital expectations. As a result, we now expect the facility to commence production in the fourth quarter of 2026, advanced from the prior target of late 2026 to early 2027. Production is expected to ramp up to the designed capacity of 35,000 – 40,000 boe/d (40% – 50% liquids) throughout 2027 at a measured pace, allowing for continued optimization of development plans where warranted.

Conventional

Our conventional portfolio continued to deliver strong, repeatable performance in the third quarter, with production meeting or exceeding internal expectations. The conventional division moved quickly to integrate and enhance our expanded asset base in the second half of 2025, realizing early efficiency gains in optimizing fragmented rig lines to enhance the continuity of our existing operations, along with improved service rig utilization across Saskatchewan field operations.

Our 2026 conventional drilling program will focus on plays with short cycle times, quick payouts and high netbacks to further support our low decline, stabilizing, light oil asset base. We plan to drill 156 (133.6 net) wells including the Cardium, Charlie Lake and Glauconite in Alberta, Atlas, Success and Viking in West Saskatchewan, and Bakken and Frobisher in East Saskatchewan. The short cycle nature of our conventional portfolio provides for significant flexibility to alter our capital program if commodity prices warrant. We continue to have strong confidence in the consistency and operational excellence across our conventional portfolio.

Saskatchewan

Our East Saskatchewan Frobisher wells continue to outperform expectations, with our 2025 program achieving an average IP90³ rate 40% above forecast. Strong results have been supported by improved well design and drilling performance, including the addition of lateral legs to maximize reservoir exposure executed in a highly capital-efficient manner.

We advanced our open-hole multi-lateral ("OHML") program at Viewfield during the quarter, bringing 6 (3.5 net) Bakken wells on production, including a 3.0-mile eight leg pilot well completed late in the quarter. This well, which set a new Saskatchewan record for the longest lateral leg drilled at over 6,400 metres, also represented the longest total lateral length on a single well in Saskatchewan at over 34,600 metres. Based on the success of these recent wells, we are assessing the further application of extended laterals to maximize reservoir contact and optimize our drilling inventory in the play. This is another example of how we continue to drive advancement initiatives to enhance and upgrade our portfolio of high quality, light oil focused opportunities.

In 2026, we plan to drill 79 (66.0 net) wells in East Saskatchewan focused on the Bakken and Frobisher. At Viewfield, we will continue to pursue capital efficiency enhancements through our OHML Bakken program, pushing lateral length where appropriate to maximize the economics. As part of our ongoing technical review, we are evaluating our OHML and multi-stage frac Bakken locations in inventory to determine the optimal development program.

Our 2026 Frobisher drilling program will look to carry momentum from strong 2024 and 2025 programs where results have consistently exceeded expectations and capital efficiency has improved through drilling multi-leg wells. We plan to drill triple leg wells on 15 (13.0 net) of our planned 49 (44.6 net) Frobisher locations, where the economics of certain locations are vastly improved due to drilling efficiencies and available royalty holidays. In aggregate, we added over 1,500 (1,350 net) Bakken and Frobisher locations⁵ to our portfolio in 2025, and our technical team is working to enhance this inventory through recent advancements in drilling design and execution.

In West Saskatchewan, we plan to drill 47 (44.7 net) wells primarily targeting the Atlas, Success and Viking. We plan to utilize one rig across both our Viking and Southwest Saskatchewan assets during 2026, with our focus being on improving the efficiency and long-term sustainability of the assets and the maximization of free funds flow. Recent capital efficiency enhancements include well design optimizations, frac stage spacing to reduce completion costs and the continued use of extended reach horizontal wells.

Alberta

Our 2026 Alberta conventional activity is focused on the Cardium at both Wapiti and West Pembina and the Glauconite at Westward Ho. At Wapiti, we plan to drill 4 (4.0 net) wells as a follow up to our successful 2025 program, including a three well pad in the Northwest portion of our acreage that will be drilled with 2-mile laterals. This pad will offset our 09-08 three well pad drilled in 2025 where updates to our completion design yielded strong results and improvements in profitability, aided by shared learnings from our unconventional workflow

Our 2026 Glauconite program includes 10 (8.7 net) wells at Westward Ho where strong results and improved access to infrastructure has aided significant growth in this asset since our first wells were drilled in 2021. All ten wells planned for 2026 will utilize a monobore drilling design which has reduced costs and improved the profitability of this asset. Our team has also started incorporating the unconventional workflow into the Glauconite program, creating opportunities for improved completions design to further increase area level profitability.

OUTLOOK

Our business outlook remains strong, underpinned by the synergies we have realized and ongoing improvements to our profitability. We continue to take a counter-cyclical approach to capital allocation, prioritizing share repurchases to enhance per share growth while placing less emphasis on expanding organic production in a lower pricing environment. These repurchases provide an additional return of capital beyond our annual base dividend of \$0.73 per share, contributing to a more efficient capital structure and a lower payout ratio. In a higher commodity price environment, our strong inventory depth and commodity optionality position us to achieve measured growth while continuing to strengthen our balance sheet for long-term flexibility and supporting sustained per share growth.

Balance sheet strength remains the cornerstone of our value creation strategy, ensuring we are well positioned to maintain financial resilience and capitalize on opportunities as they arise.

With a deep and diversified portfolio of high-return drilling inventory across light oil, liquids-rich and natural gas plays, we are well positioned to deliver sustainable value and robust returns for decades to come.

On behalf of our employees, management team and Board of Directors, we thank our shareholders for their continued trust and support.

NOTES

- ¹ Funds flow, funds flow basic (\$/share), funds flow diluted (\$/share), annualized funds flow, and net debt are capital management measures. Average realized price, net debt to annualized funds flow ratio, and per boe disclosure figures are supplementary financial measures. Operating netback and free funds flow are non-GAAP financial measures. Operating netbacks (\$/boe) is a non-GAAP ratio. Refer to the Specified Financial Measures section in this press release for additional disclosure and assumptions.
- ² Also referred to herein as "capital expenditure", "capital spending", "capital investment" and "capital budget".
- 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 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.

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 23, 2025.

The conference call dial-in number is: 1-888-510-2154 or (403) 910-0389 or (437) 900-0527

A live webcast of the conference call will be accessible on Whitecap's website at 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 forecast for fourth quarter of 2025, full-year 2025 and 2026 capital expenditures and production, including by product type; our belief that our financial position remains a cornerstone of the Company's long-term value creation strategy and positions us well for sustained success through 2026 and beyond; our forecasted fourth quarter of 2026 average production rate; our belief that the 2026 capital budget reflects enhanced operational execution, disciplined capital allocation, moderate production growth, and realized synergies; our expectation of annual capital, operating, and corporate synergies embedded in our 2026 forecast and the expected change compared to our original estimate; our belief that initial optimization initiatives, along with improvements to drilling and completions performance are driving sustained value creation across our unconventional assets; our forecasts for the allocation of our 2026 capital program to our unconventional and conventional divisions, and the anticipated benefits in connection therewith; including the expected wells drilled and brought on production in total and by region and the anticipated timing thereof; our forecasts for the number of rigs utilized in 2026 in our unconventional and conventional divisions in total and by region; our forecasts for the number of unconventional wells to come on production in 2026 by region and the anticipated timing thereof; our belief that 2026 will be highlighted by our first development drilling at Lator in advance of the 04-13 facility startup; our expectation that debottlenecking initiatives at our 15-07 gas processing facility support continued production growth and that area capacity is expected to exceed 50,000 boe/d by the third quarter of 2026; our expectation that approximately half of our Kaybob 2026 pads will utilize a wine rack development design and that our program will focus on the development of our core assets to utilize expanded infrastructure capacity in the area; our plans to spend approximately \$55 million to modestly expand, debottleneck and connect existing infrastructure in the Kaybob region and our expectation that total capacity will be approximately 115,000 to 120,000 boe/d in the second half of 2026 and is expected to be operating at capacity in the second half of 2027; our belief that per-well recoveries from our recently developed Gold Creek and Karr lands remain consistent with our initial reservoir assessments, reinforcing the long-term potential of these assets; our plans to pilot a P&P completions design on two Karr pads, anticipated timing to bring the 7 (7.0 net) Montney wells on production, and our expectation that results from the P&P pilot will inform future well designs as we continue to enhance risk-adjusted returns; our plan to apply learnings from drilling operations on our recent 6-well (6.0 net) Musreau pad to our next 3-well (3.0 net) pad at Musreau and another 3-well (3.0 net) pad on the eastern portion of our Lator acreage; our expectation that two of the four Montney rigs at Gold Creek and Karr will target development in well-understood areas with established infrastructure and focus on consistent execution of an optimized drilling and completion design; our expectation that as we advance toward piloting P&P at Gold Creek and Karr, we will continue to pursue opportunities to enhance capital efficiency by reducing capital costs and implementing disciplined controls to evaluate both technical and commercial performance; our belief that existing infrastructure capacity at both Gold Creek and Karr supports future growth, our expectation that only minimal infrastructure investment is planned for 2026; our belief that our Kakwa and Musreau assets are largely de-risked and near-term efforts focused on operational execution and maximizing existing infrastructure capacity; our belief that Lator will advance to development mode in 2026; our plan to allocate \$5 million to enhance gas lift capabilities at our 05-09 facility in the second half of 2026, supporting further optimization of the strong condensate volumes being realized from this asset; our expectation that our 2026 Musreau development program will continue to leverage multi-bench development and employ controlled drawdown practices; our plan to allocate approximately \$180 million of capital to Lator in 2026, including \$60 million towards supporting infrastructure (water disposal and gathering lines) to enable the ramp-up of this asset; our belief that construction on the 04-13 Lator facility has been progressing ahead of schedule and within budgeted expectations and our expectation that the facility will now commence production in the fourth quarter of 2026; our expectation that production will ramp to the designed capacity of 35,000 – 40,000 boe/d (40 – 50% liquids) throughout 2027 at a measured pace, allowing for refinements in development plans where warranted; our belief that our 2026 conventional drilling program will focus on plays with short cycle times, quick payouts and high netbacks to further support our low decline, stabilizing, light oil asset base; our belief in the consistency and operational excellence across our conventional portfolio; that the short cycle nature of our conventional portfolio provides for significant flexibility to alter our capital program if commodity prices warrant; that our East Saskatchewan Frobisher wells continue to outperform expectations; our plan to assess the further application of extended laterals in our OHML Bakken program and the anticipated benefits thereof; our plan to evaluate our OHML and multi-stage frac Bakken locations in inventory to determine the optimal development program; the expectation that our 2026 Frobisher drilling program will look to carry momentum from strong 2024 and 2025 programs; our plan to drill triple leg wells on 15 (13.0 net) of our planned Frobisher locations in 2026 and the benefits thereof; our plan to drill a pad in the Northwest portion of our Wapiti acreage that will be drilled with 2-mile laterals; our plans to utilize a monobore drilling design within our Glauconite program, and the benefits thereof, including our expectation that incorporating the unconventional workflow process into our drilling program will further increase area level profitability; our plan to focus on improving the efficiency

and long-term sustainability of our Viking and Southwest Saskatchewan assets and the maximization of free funds flow in 2026; our belief that our business outlook remains strong, underpinned by the synergies we have realized and ongoing improvements to our profitability; our expectation we will continue to take a counter-cyclical approach to capital allocation, including prioritizing share repurchases to enhance per share growth while placing less emphasis on expanding organic production in a lower pricing environment; our belief that share repurchases provide an additional return of capital beyond our annual base, contributing to a more efficient capital structure and a lower payout ratio; our belief that in a higher commodity price environment, our strong inventory depth and commodity optionality position us to achieve measured growth while continuing to strengthen our balance sheet for long term flexibility and supporting sustained per-share growth; our belief that balance sheet strength remains the cornerstone of our value creation strategy, ensuring we are well positioned to maintain financial resilience and capitalize on opportunities as they arise; and our belief that with a deep and diversified portfolio of high-return drilling inventory across light oil, liquids-rich and natural gas plays, we are well positioned to deliver sustainable value and robust returns for decades to come.

The forward-looking information is based on certain key expectations and assumptions made by our management, including: the duration and impact of tariffs that are currently in effect on goods exported from or imported into Canada, and that other than the tariffs that are currently in effect, neither the U.S. nor Canada (i) increases the rate or scope of such tariffs, reenacts tariffs that are currently suspended, or imposes new tariffs, on the import of goods from one country to the other, including on oil and natural gas, and/or (ii) imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas; 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; 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 in the Middle East and between Russia and Ukraine and related sanctions on crude oil, NGLs and natural gas prices; the impact of current and forecast exchange rates, inflation rates and/or 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; reserves 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 timing and costs of pipeline, storage and facility construction and expansion; the state of the economy and the exploration and production business; 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, including the assets and employees acquired in connection with the business combination with Veren; 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, droughts or extreme hot or cold temperatures; the commodity pricing and exchange rate forecasts for fourth quarter 2025 referred to 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 fourth quarter 2025, 2025 and 2026 forecasts (including for production levels, capital expenditure levels, commodity prices and exchange rates); the risk that (i) the tariffs that are currently in effect on goods exported from or imported into Canada continue in effect for an extended period of time, the tariffs that have been threatened are implemented, that tariffs that are currently suspended are reactivated, the rate or scope of tariffs are increased, or new tariffs are imposed, including on oil and natural gas, (ii) the U.S. and/or Canada imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas, and (iii) the tariffs imposed or threatened to be imposed by the U.S. on other countries and retaliatory tariffs imposed or threatened to be imposed by other countries on the U.S., will trigger a broader global trade war which could have a material adverse effect on the Canadian, U.S. and global economies, and by extension the Canadian oil and natural gas industry and the Company including by decreasing demand for (and the price of) oil and natural gas, disrupting supply chains, increasing costs, causing volatility in global financial markets, and limiting access to financing; 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, droughts 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 elevated inflation rates, elevated 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 risks; 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, including the anticipated benefits of the business combination with Veren; the risk that going forward we may be unable 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, tariffs, import or export restrictions or prohibitions, production curtailment, royalties and environmental (including emissions and "greenwashing") 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 (including pursuant to our normal course issuer bid ("NCIB")), 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 (including pursuant to the NCIB) – depending on these and various other factors as disclosed herein or otherwise, 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 (including pursuant to the NCIB), 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 (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 2025 and 2026 capital expenditures, the allocation of our 2026 capital expenditures to the unconventional and conventional divisions, and the amount of funds flow allocated to specific regions and operations in 2026; our forecast of average daily production for the fourth quarter of 2025, and full-year 2025 and 2026 (and liquids weighting); our forecast fourth quarter of 2026 average production rate; the annual capital, operating, and corporate synergies embedded in our 2026 forecast arising from the Veren business combination; our net debt to annualized funds flow ratio of 1.0 times; our forecast for funds flow of \$800 million for the fourth quarter of 2025, which equates to an estimated annualized funds flow of \$3.2 billion; the amount of our annual base dividend; and our forecast for commodity prices and the USD/CAD exchange rate for fourth quarter of 2025; 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 evaluations effective December 31, 2024 for both Whitecap and Veren, respectively, which were each evaluated or audited in accordance with the Canadian Oil and Gas Evaluation Handbook 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 over 1,500 (1,350 net) Bakken and Frobisher drilling locations identified herein, 334 (317 net) are proved locations, 201 (184 net) are probable locations, and 965 (849 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 and 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 (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 rates in calculating the aggregate production for Whitecap.

The Company's average daily production for the three and nine months ended September 30, 2025 and 2024, and the forecast average daily production for the fourth quarter of 2025, full year 2025 and 2026 (mid-point), and the fourth quarter of 2026 and 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 (Historical)	9M 2025	9M 2024	Q3/2025	Q3/2024
Light and medium oil (bbls/d)	87,827	75,528	95,611	73,900
Tight oil (bbls/d)	54,413	16,076	84,307	18,435
Crude oil (bbls/d)	142,240	91,604	179,918	92,335
NGLs (bbls/d)	35,009	20,228	47,501	20,578
Shale gas (Mcf/d)	458,747	221,140	692,046	215,309
Conventional natural gas (Mcf/d)	174,918	148,411	191,178	147,023
Natural gas (Mcf/d)	633,665	369,551	833,224	362,332
Total (boe/d)	282,860	173,424	374,623	173,302
Whitecap Corporate (Forecast)	Q4/2025 Forecast	2025 Guidance	2026 Guidance (mid-point)	Q4/2026 Forecast
Light and medium oil (bbls/d)	94,000	89,000	90,000	90,000
Tight oil (bbls/d)	87,000	63,000	91,000	93,500
Crude oil (bbls/d)	181,000	152,000	181,000	183,500
NGLs (bbls/d)	45,000	37,550	44,000	45,000
Shale gas (Mcf/d)	690,000	518,000	720,000	749,000
Conventional natural gas (Mcf/d)	174,000	174,700	165,000	160,000
Natural gas (Mcf/d)	864,000	692,700	885,000	909,000
Total (boe/d)	370,000	305,000	372,500	380,000

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 Accounting Standards" or, alternatively, "GAAP") and, therefore, may not be comparable with the calculation of similar financial measures disclosed by other companies.

"Annualized funds flow" is a capital management measure that is used by management as a substitute for annual funds flow when a material transaction (such as the strategic combination with Veren) or other material change occurs during the middle of the year and as a result annual funds flow is less meaningful. It is calculated by grossing up the applicable number of days being analyzed (such as a quarter or half year) to 365. Annualized funds flow referred to in this press release is calculated based on Whitecap's estimated funds flow for the fourth quarter of 2025 of approximately \$800 million, which equates to an estimated annualized funds flow of \$3.2 billion, based on the following commodity pricing and exchange rate assumptions for the fourth quarter of 2025: US\$60/bbl WTI, \$2.00/GJ AECO and USD/CAD of \$1.39.

"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, 2025, 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 Accounting Standards 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 Free Funds Flow" section of our management's discussion and analysis for the three and nine months ended September 30, 2025 which is incorporated herein by reference, and available on SEDAR+ at 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 Sep. 30,		Nine months ended Sep. 30,	
(\$ millions, except per share amounts)	2025	2024	2025	2024
Cash flow from operating activities	897.5	556.2	1,861.3	1,413.7
Net change in non-cash working capital items	(0.9)	(147.2)	194.4	(194.3)
Funds flow	896.6	409.0	2,055.7	1,219.4
Expenditures on PP&E	546.3	272.7	1,353.2	869.7
Free funds flow	350.3	136.3	702.5	349.7
Funds flow per share, basic	0.73	0.69	2.24	2.04
Funds flow per share, diluted	0.73	0.68	2.23	2.03

"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 shares (basic and diluted) 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, 2025 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, 2025 for additional disclosures. The following table reconciles the Company's long-term debt to net debt:

Net Debt (\$ millions)	Sep. 30, 2025	Sep. 30, 2024	Dec. 31, 2024
Long-term debt	2,931.7	1,095.6	1,023.8
Cash	-	-	(362.3)
Accounts receivable	(877.9)	(355.4)	(422.2)
Deposits and prepaid expenses	(93.1)	(32.9)	(22.4)
Non-current deposits	(86.6)	(82.9)	(86.6)
Accounts payable and accrued liabilities	1,369.8	701.6	767.1
Dividends payable	73.8	35.8	35.7
Net Debt	3,317.7	1,361.8	933.1

"Net Debt to annualized funds flow ratio" is a supplementary financial measure determined by dividing net debt for the applicable period by annualized funds flow. Net debt to annualized funds flow is not a standardized measure and, therefore, may not be comparable with the calculation of similar measures by other entities.

"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 Accounting Standards 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, 2025, which is incorporated herein by reference, and available on SEDAR+ at [sedarplus.ca](https://www.sedarplus.ca). A reconciliation of operating netbacks to petroleum and natural gas revenues is set out below:

Operating Netbacks (\$ millions)	Three months ended Sep. 30,		Nine months ended Sep. 30,	
	2025	2024	2025	2024
Petroleum and natural gas revenues	1,660.3	890.9	3,967.8	2,739.6
Tariffs	(7.1)	(6.8)	(23.4)	(20.4)
Processing & other income	13.3	10.7	38.5	34.2
Marketing revenues	83.8	60.4	227.3	184.0
Petroleum and natural gas sales	1,750.3	955.2	4,210.2	2,937.4
Realized gain on commodity contracts	47.4	14.9	104.2	25.0
Royalties	(202.5)	(143.6)	(546.2)	(452.0)
Operating expenses	(430.4)	(213.4)	(1,010.9)	(651.4)
Transportation expenses	(117.4)	(33.5)	(229.8)	(99.5)
Marketing expenses	(81.3)	(59.9)	(223.4)	(182.3)
Operating netbacks	966.1	519.7	2,304.1	1,577.2

"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 Accounting Standards 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.

"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.

"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, 2025, by the Company's total production volumes for the period.

"Realized gain on commodity contracts (\$/boe)" is a supplementary financial measure calculated by dividing realized gain 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, 2025, by the Company's total production volumes for the period.

Per Share Amounts

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