CORPORATE PRESENTATION

Capital Discipline Driving Sustainable Growth

December 2024

CORPORATE OVERVIEW

$5.8 Billion *Market Capitalization*	**$6.8 Billion** *Enterprise Value*
178,000 boe/d *2025 Production Guidance*	**$1.65 Billion** *2025 Funds Flow*
$1.15 Billion *2025 Capital Investment*	**$0.0608 per Share** *Monthly Dividend ($0.73 annually)*
$1.0 Billion *Pro Forma Net Debt*	**0.5x** *Pro Forma Debt/EBITDA*

2024 OPERATIONAL HIGHLIGHTS

2024 Production of 174,000 boe/d

- 13% production per share growth year-over-year
- 5% above original guidance of 165,000 boe/d

Montney & Duvernay Highlights

- Musreau Development
  - Infrastructure buildout completed early and below budget
  - Increased area production from zero to 17,000 – 18,000 boe/d
  - Higher than expected condensate production
- Wider interwell spacing improving capital efficiency at Kakwa
- Targeted delineation program at Lator for future development
- Longer laterals and benching pilot at Kaybob

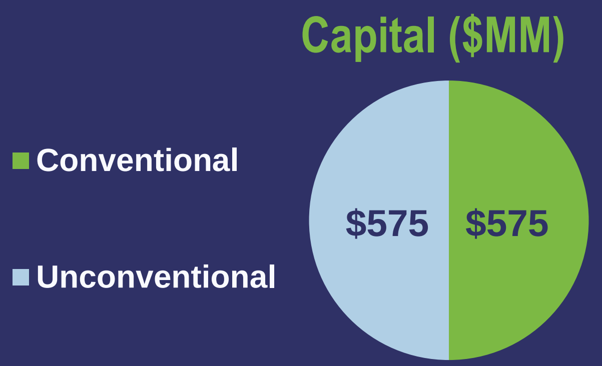
Conventional Inventory Enhancements

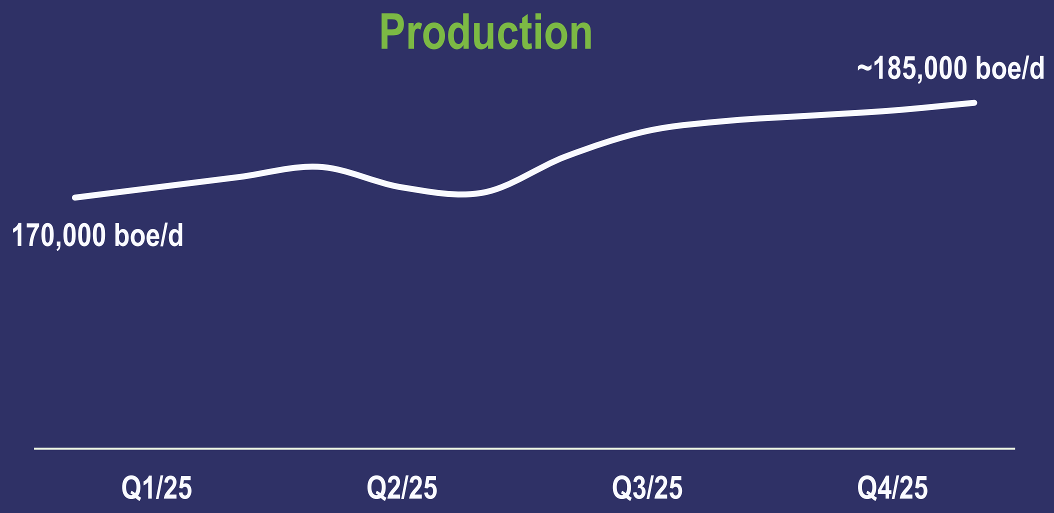
- Open Hole Multi-Lateral pilots to upgrade drilling inventory
- Monobore drilling design has reduced capital and increase well economics

Refer to Slide Notes and Advisories

DISCIPLINED 2025 BUDGET

PRUDENT CAPITAL ALLOCATION WITH UPSIDE POTENTIAL





2025 Guidance

Production (5% per share)

- 176,000 – 180,000 boe/d (63% liquids)

Capital Expenditures

- $1.1 – $1.2 billion

Financial Highlights

$1.65 billion of Funds Flow

- $2.81 per share

Fully Funded at US$50/bbl & $2.00/GJ

- Base dividend and maintenance capital

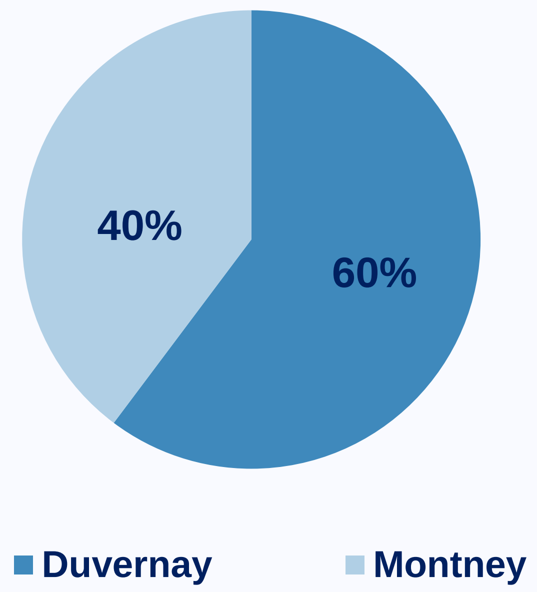
Refer to Slide Notes and Advisories

BALANCED CAPITAL ALLOCATION STRATEGY

Unconventional

- **2025 Budget Allocation:** ~$575 million
    - ~40% condensate and liquids
- **Duvernay**
    - 20 (20.0 net) Kaybob wells
        - 15-07 gas processing facility full by second half of 2025
- **Montney**
    - 4 (4.0 net) Musreau wells
        - Maintain 05-09 Battery at capacity
    - 4 (4.0 net) Kakwa wells
        - Build on continued success
    - 2 (2.0 net) Lator wells
        - Planning and engineering work for 04-13 Battery start-up in late 2026/early 2027

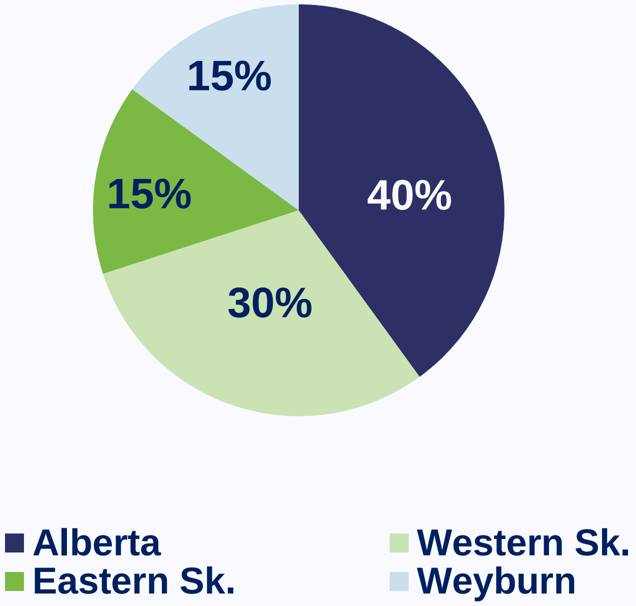
Capital Allocation



Refer to Slide Notes and Advisories

BALANCED CAPITAL ALLOCATION STRATEGY

Capital Allocation



Conventional

- **2025 Budget Allocation:** ~$575 million
  - 75% – 80% oil and liquids
- **Alberta**
  - 30 (23.7 net) wells
  - Glauconite monobore design to reduce costs
- **Western Saskatchewan**
  - 100 (98.8 net) wells
  - Longer laterals to improve capital efficiencies
- **Eastern Saskatchewan**
  - 39 (35.3 net) wells
  - Open hole multi-lateral pilots
- **Weyburn**
  - 21 (14.2 net) wells
  - New phase rollouts and infill wells

Refer to Slide Notes and Advisories

WHITECAP VALUE CREATION

Low Debt / EBITDA ratio with significant undrawn capacity

Disciplined capital allocation improving capital efficiency and profitability

Balance Sheet Strength

Maximize Resource Potential

Shareholder Value

Returns to Shareholders

Strategic Opportunities

Sustainable dividends enhanced through share repurchases

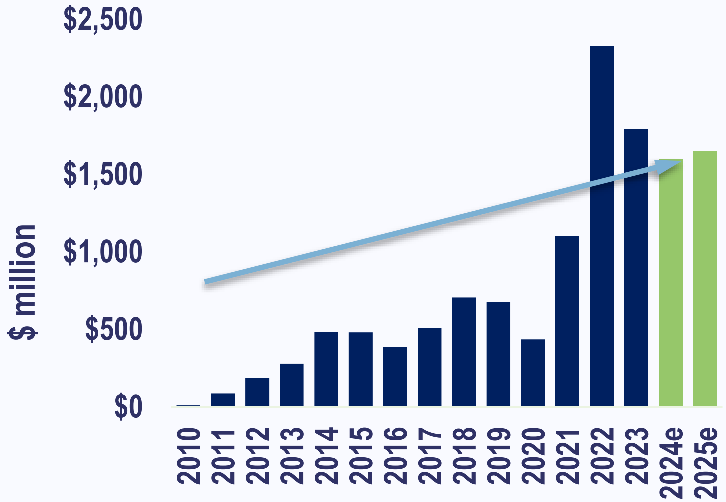
Strengthens WCP through financial and operational accretion in core areas

MANAGEMENT TRACK RECORD OF EXECUTION

Organic growth enhanced by strategic acquisitions

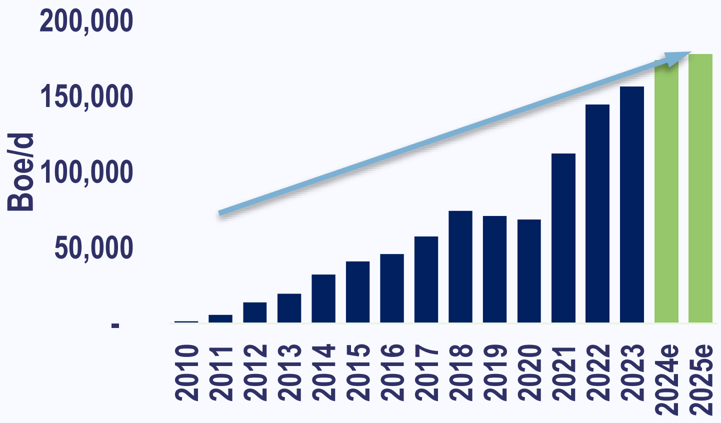
12% CAGR per share

Funds Flow



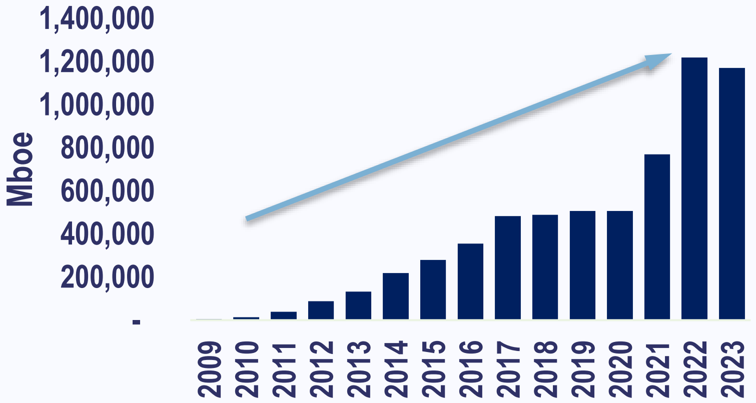
11% CAGR per share

Production



13% CAGR per share

TPP Reserves



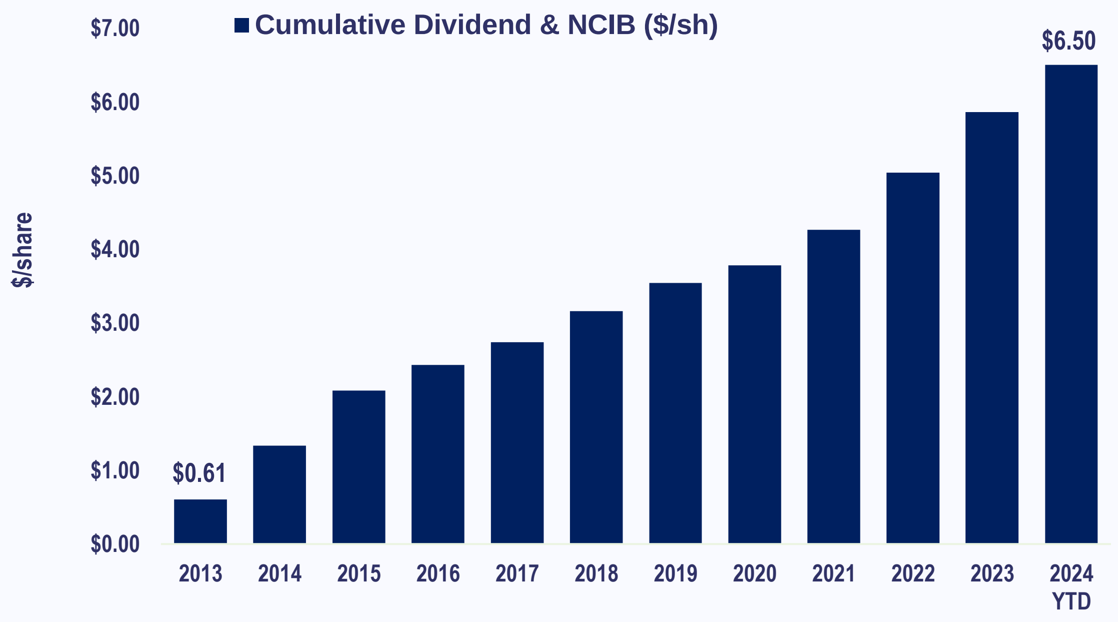
DISCIPLINED RETURN OF CAPITAL TO SHAREHOLDERS

$2.1 billion

Total dividends paid ($5.33/share) (Jan. 2013 - Sep. 2024)

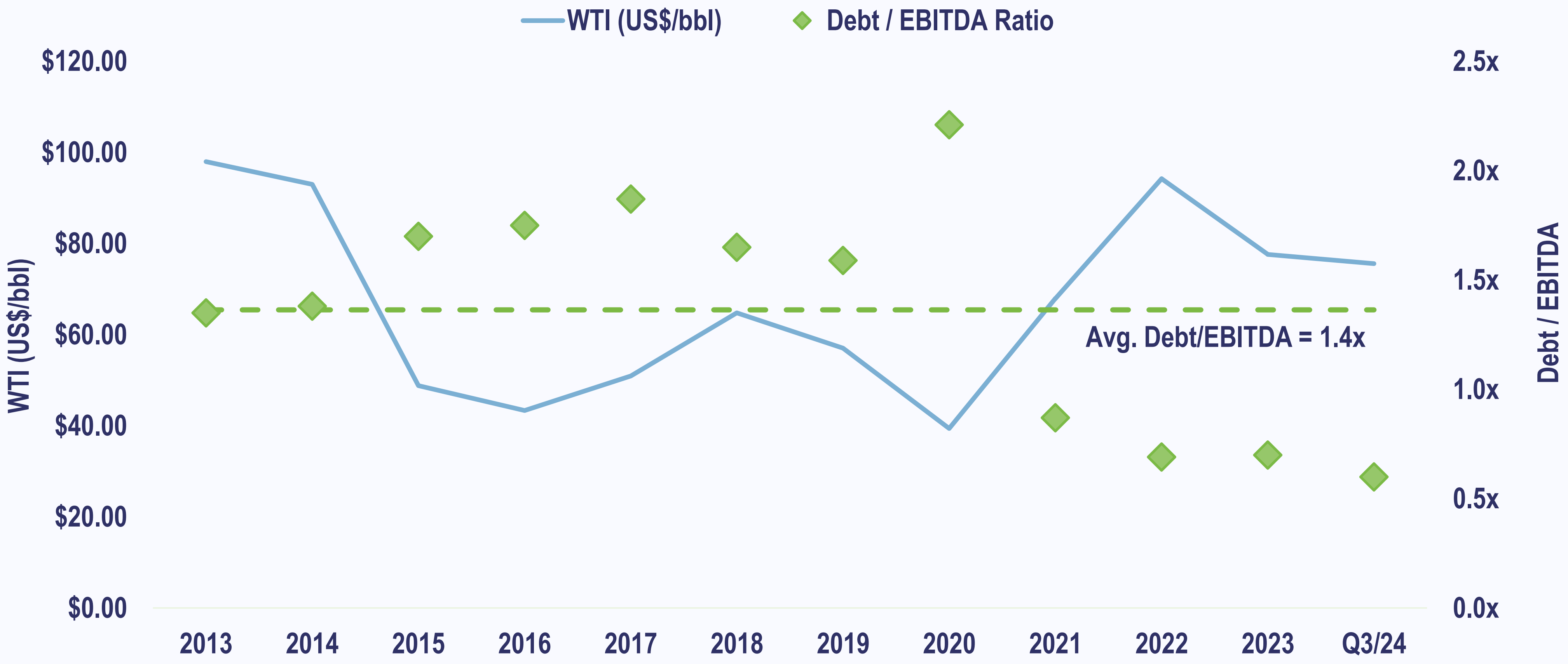
$731 million

Share repurchases completed (May 18, 2017 - Sep. 30, 2024)



PRUDENT BALANCE SHEET MANAGEMENT

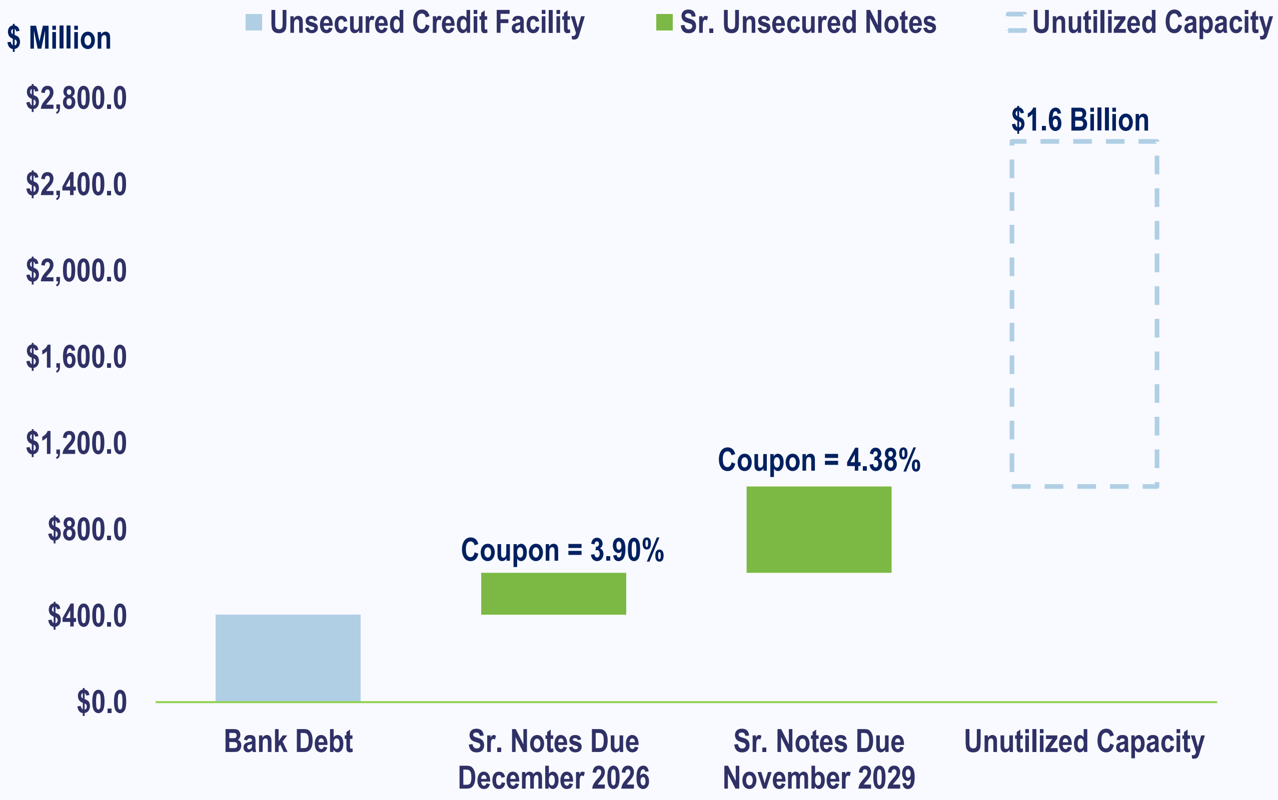
Low leverage through commodity price cycles



Refer to Slide Notes and Advisories

BALANCE SHEET STRENGTH

Investment Grade balance sheet with **low Debt/EBITDA ratios** and significant liquidity



Current net debt of $1.4 Billion (0.6x Debt/EBITDA)

Pro forma net debt of $1.0 Billion (0.5x Debt/EBITDA)

Well below credit facility covenants of Debt/EBITDA < 4.0x, EBITDA/Interest > 3.5x and Debt to Capitalization < 60%

Investment grade rating of BBB (low), with a stable trend, by DBRS Inc.

Refer to Slide Notes and Advisories

WHITECAP RESOURCES INC

RISK MANAGEMENT

Downside protection to support dividend and maintenance production

Target 25% - 35% hedged

Oil hedges	Q4/24	2025	2026
Production hedged	***16%***	***27%***	***22%***
Swaps hedged (bbl/d)	9,000	23,471	20,000
Average swap price (C$/B)	$106.20	$102.17	$91.52
Collars hedged (bbl/d)	5,000	-	-
Average collar price (C$/B)	$82.00 x $116.98	-	-

Natural gas hedges	Q4/24	2025	2026
Production hedged	***15%***	***29%***	***25%***
Swaps hedged (GJ/d)	52,054	107,466	30,000
Average swap price (C$/GJ)	$3.11	$3.35	$3.58
Collars hedged (GJ/d)	-	-	68,500
Average collar price (C$/GJ)	-	-	$2.25 - $3.52

Refer to Slide Notes and Advisories

PREMIUM ASSETS

BALANCED PORTFOLIO REDUCES RISK AND MAXIMIZES RETURNS

Montney/Duvernay

10% – 15% Annual Growth
Area optionality supported by new infrastructure

Liquids Rich Assets
High condensate production and pad drilling efficiencies resulting in top tier economics

Greater Scale Increases Profitability
Significant growth on assets will lower cost structure and enhance future profitability

Conventional

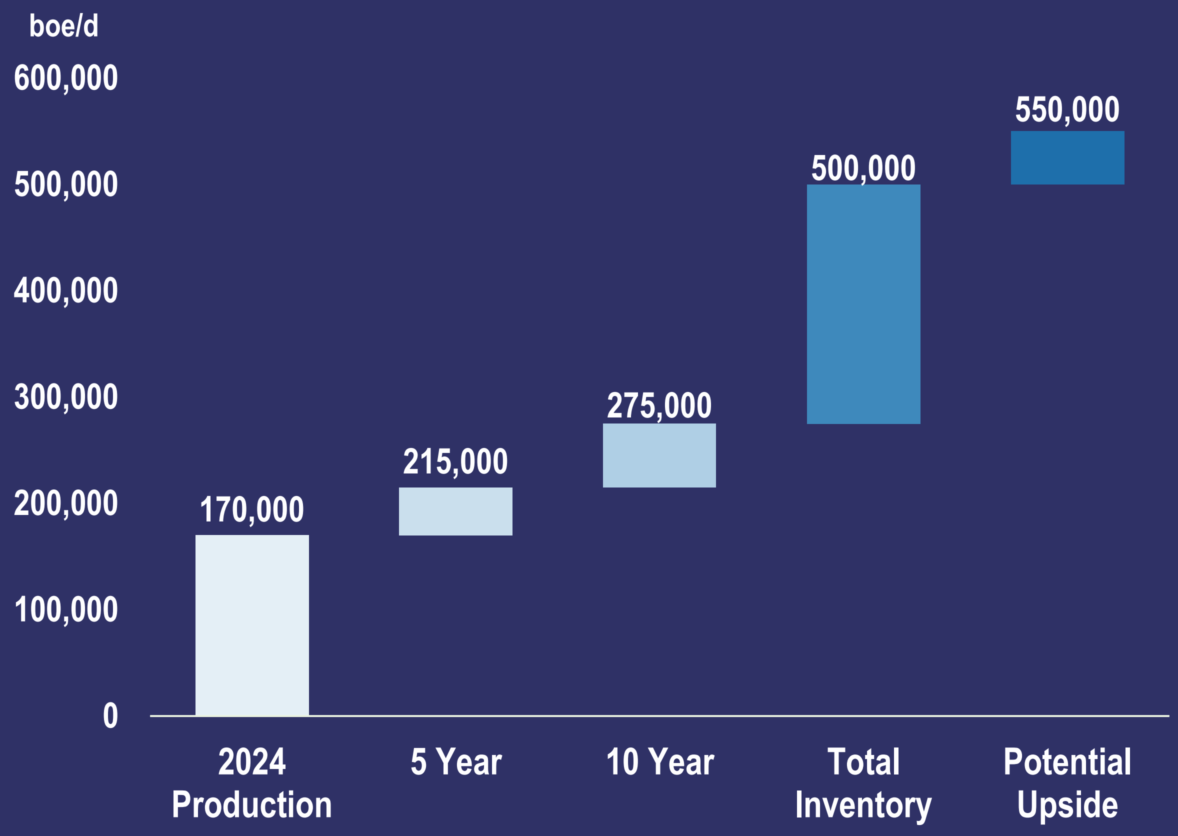
~20% Base Decline
Lowers our maintenance capital requirements

High Netback Light Oil
Operating netback of ~$40/boe driving strong profitability

Infrastructure Availability
Reliable downstream accessibility through advantaged locations and firm transportation contracts

Refer to Slide Notes and Advisories

TOTAL RESOURCE POTENTIAL



6,442 (5,619 net)
Total Drilling Locations

2.5 million net acres
Including 700,000 acres of Montney & Duvernay Rights

550,000 boe/d
Long Term Organic Production Potential

Refer to Slide Notes and Advisories

MONTNEY & DUVERNAY

700,000 ACRES

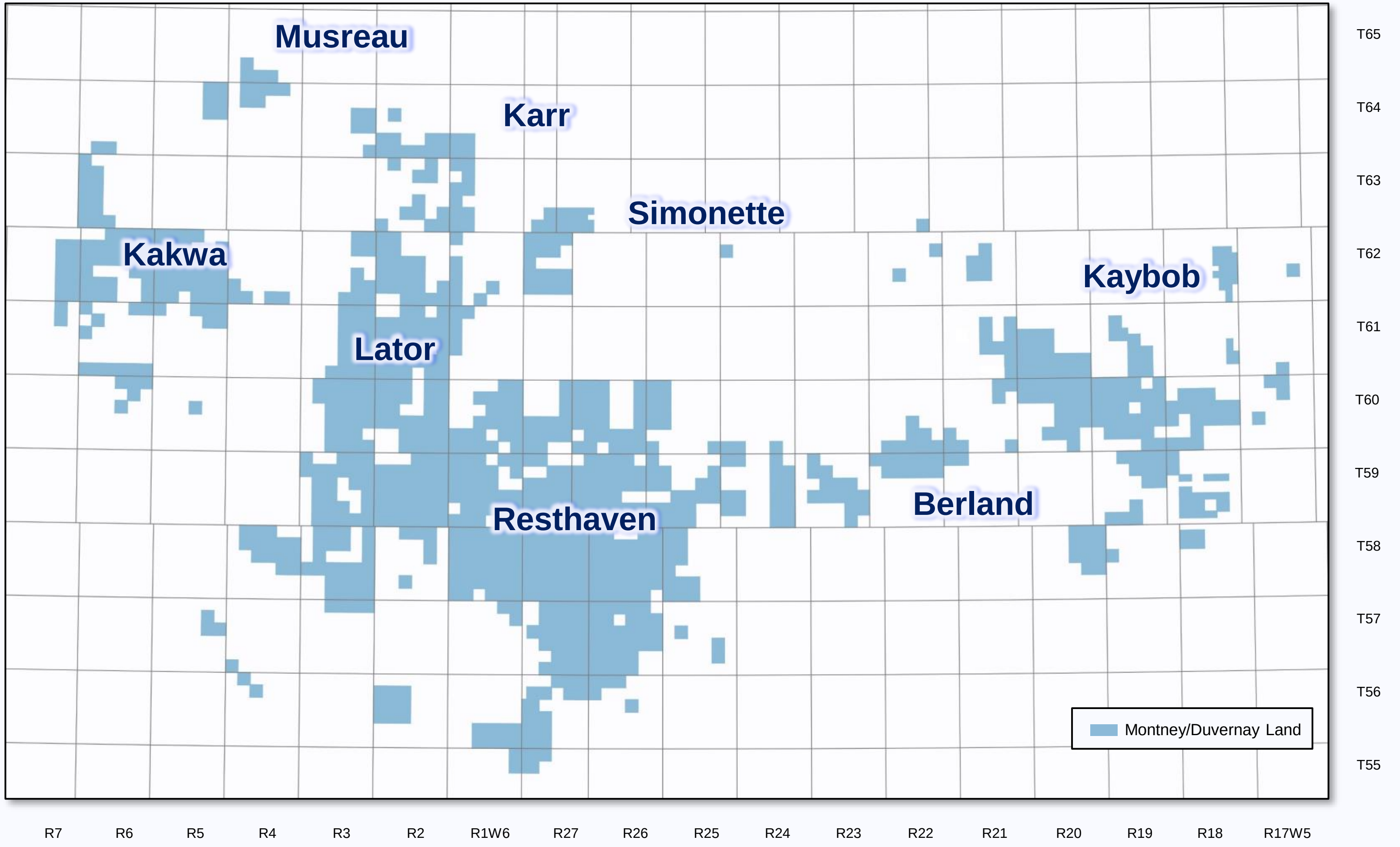
- Montney & Duvernay rights
- Second largest Alberta Montney acreage

2,462 LOCATIONS

- Highly economic Montney & Duvernay locations in inventory

15% BOOKED

- Limited inventory booked
- Significant upside beyond TPP value

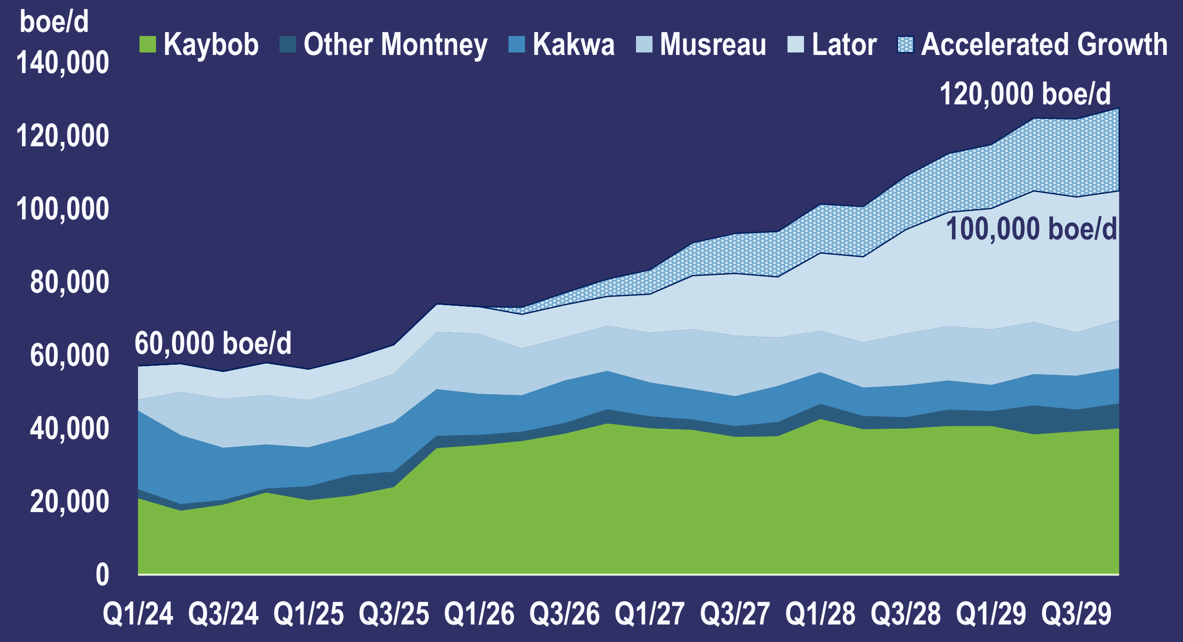


2025 Production

65,000 – 70,000 BOE/d, 39% Liquids

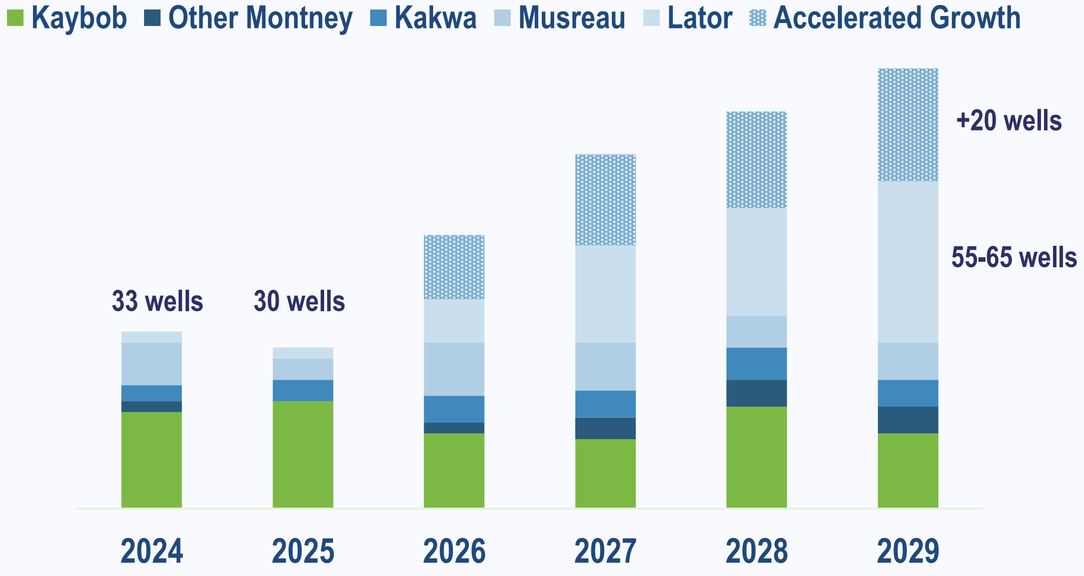
Refer to Slide Notes and Advisories

SIGNIFICANT GROWTH POTENTIAL



- Near term growth focus at Kaybob, Kakwa and Musreau
- Medium term growth driven by Lator
- Option to accelerate growth in late 2026
- Long term growth driven by Resthaven

WELLS DRILLED

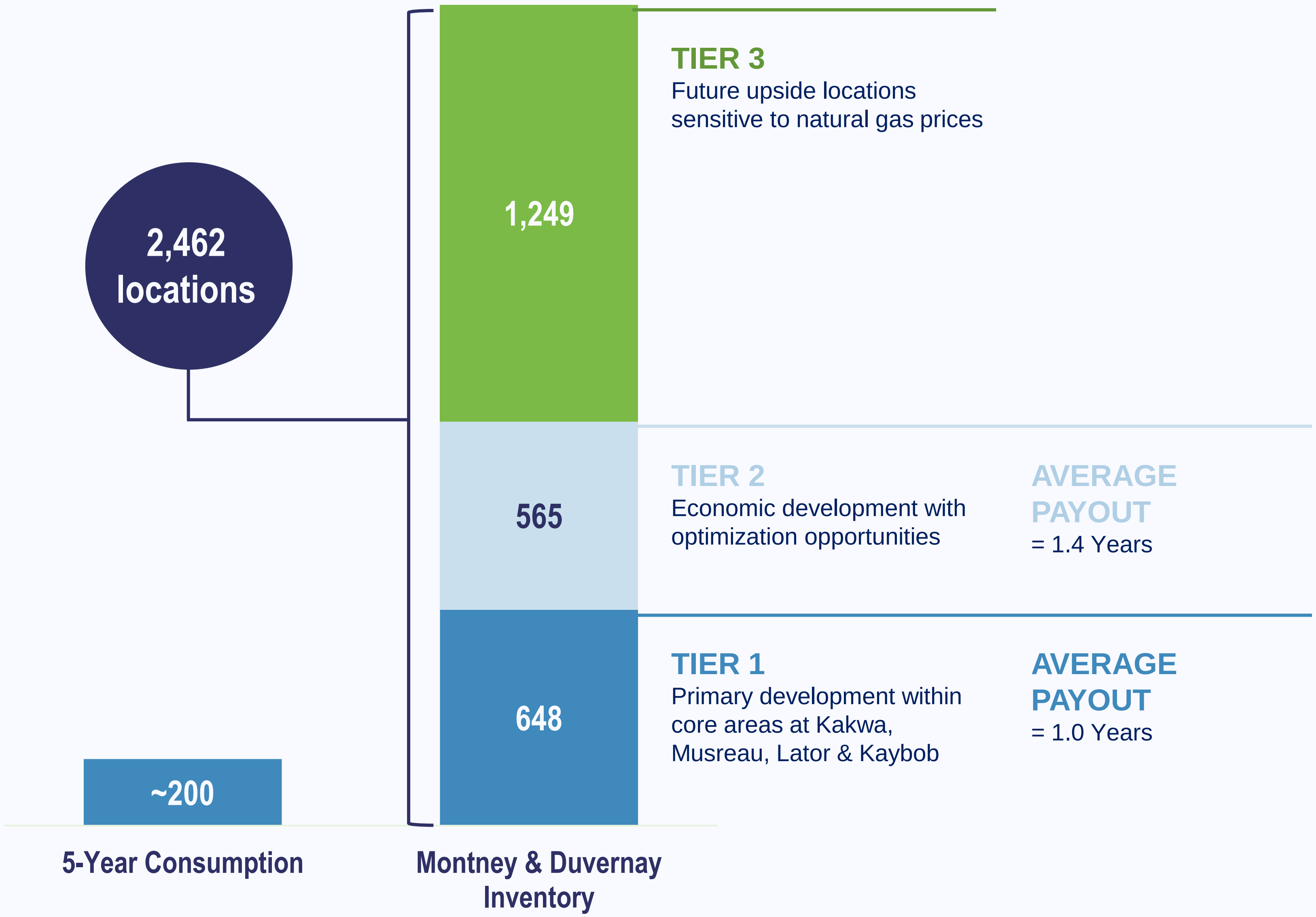


Refer to Slide Notes and Advisories

MONTNEY & DUVERNAY INVENTORY

Decades of Top Tier Inventory

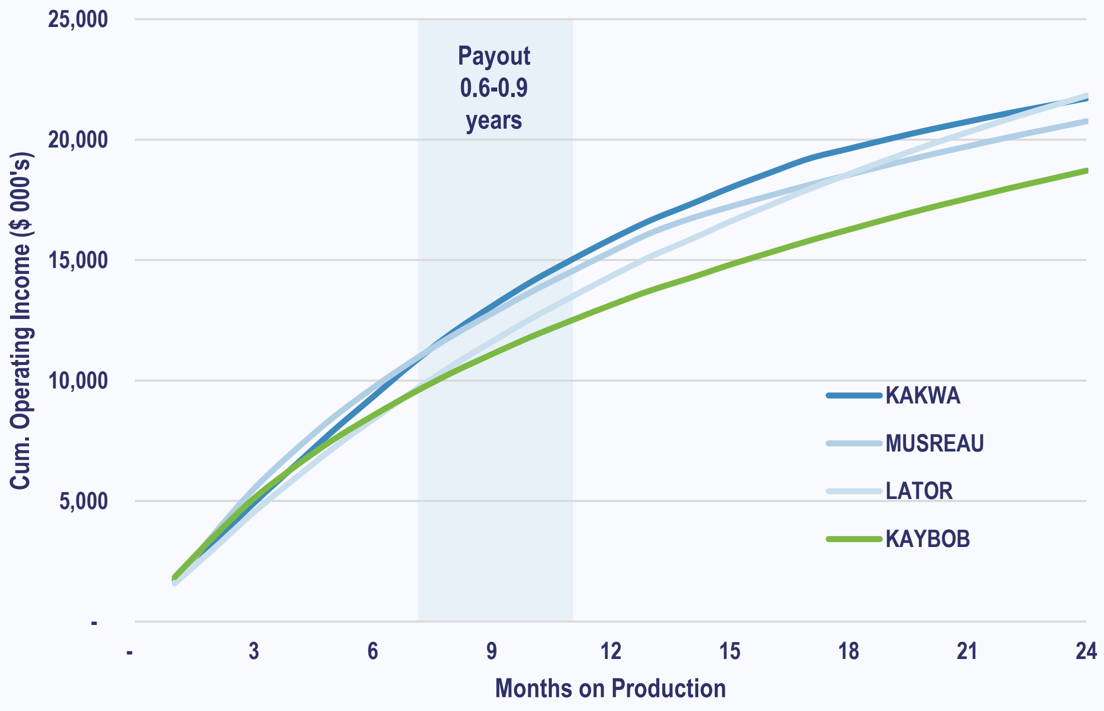
5 Year Plan consumes <10% of Montney and Duvernay inventory



Refer to Slide Notes and Advisories

US$75/bbl WTI, $3.00/GJ AECO, $1.37 USD/CAD

A REPEATABLE, HIGH-QUALITY INVENTORY



		KAKWA	MUSREAU	LATOR	KAYBOB
DCE&T Costs	($mm)	**$11.20**	**$11.20**	**$11.20**	**$12.30**
P+P Reserves	(mboe)	**1,000 - 1,600** (25-45% liquids)	**1,000 - 1,300** (45-55% liquids)	**1,000 - 2,000** (20-50% liquids)	**1,100 - 1,650** (30-40% liquids)
IP90	(boe/d)	**1,100 - 1,750** (30-50% liquids)	**900 - 1,550** (55-75% liquids)	**1,000 - 1,900** (25-60% liquids)	**1,100 - 1,650** (35-55% liquids)
Payout	(years)	**0.6**	**0.6**	**0.8**	**0.9**
P/I	(x)	**1.6x**	**1.3x**	**1.7x**	**1.2x**
IRR	(%)	**>200%**	**>200%**	**175%**	**119%**
NPV (10% disc.)	($mm)	**$17.3**	**$14.4**	**$18.9**	**$14.3**

Assumptions: US $75/bbl WTI, $3.00/GJ AECO, 1.37 USD/CAD

Refer to Slide Notes and Advisories

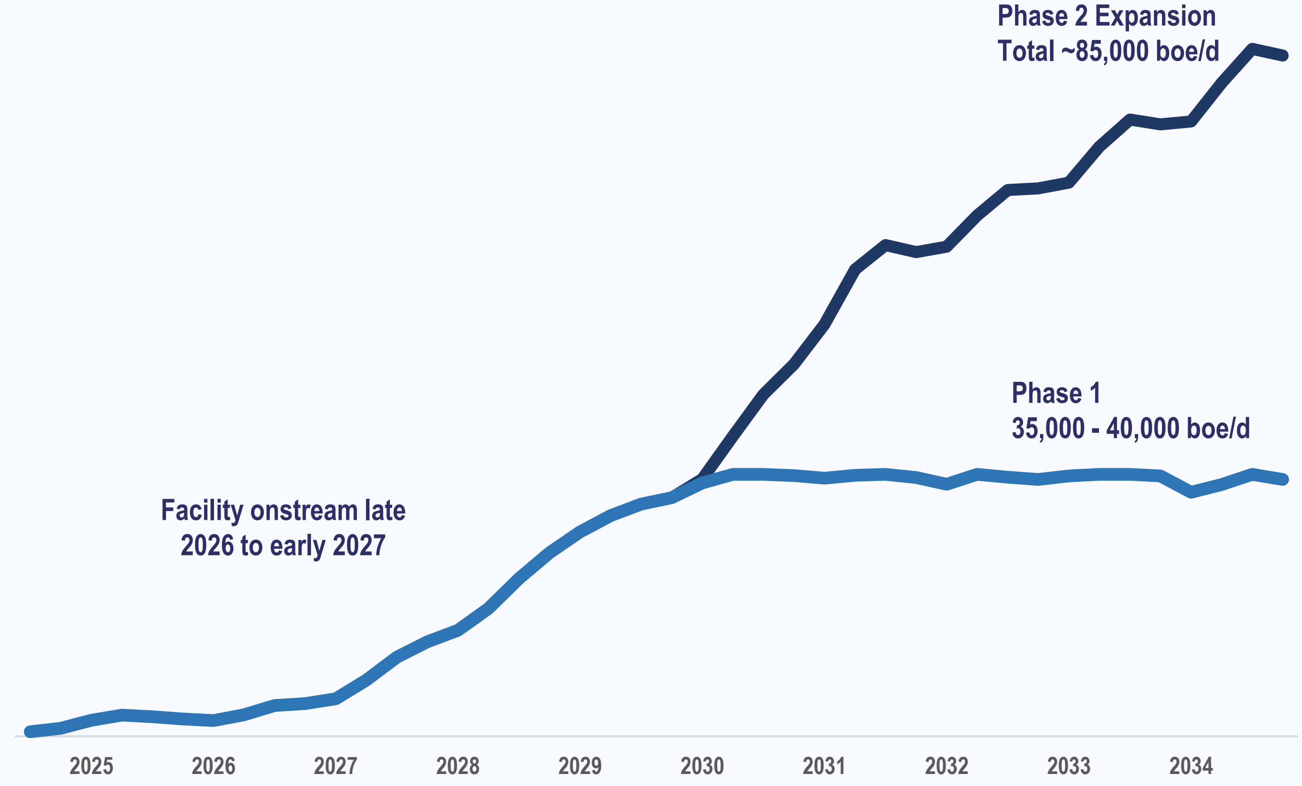
LATOR – AN ORGANIC GROWTH STORY COMING IN 2026

300 – 450
Inventory locations to backstop growth profile

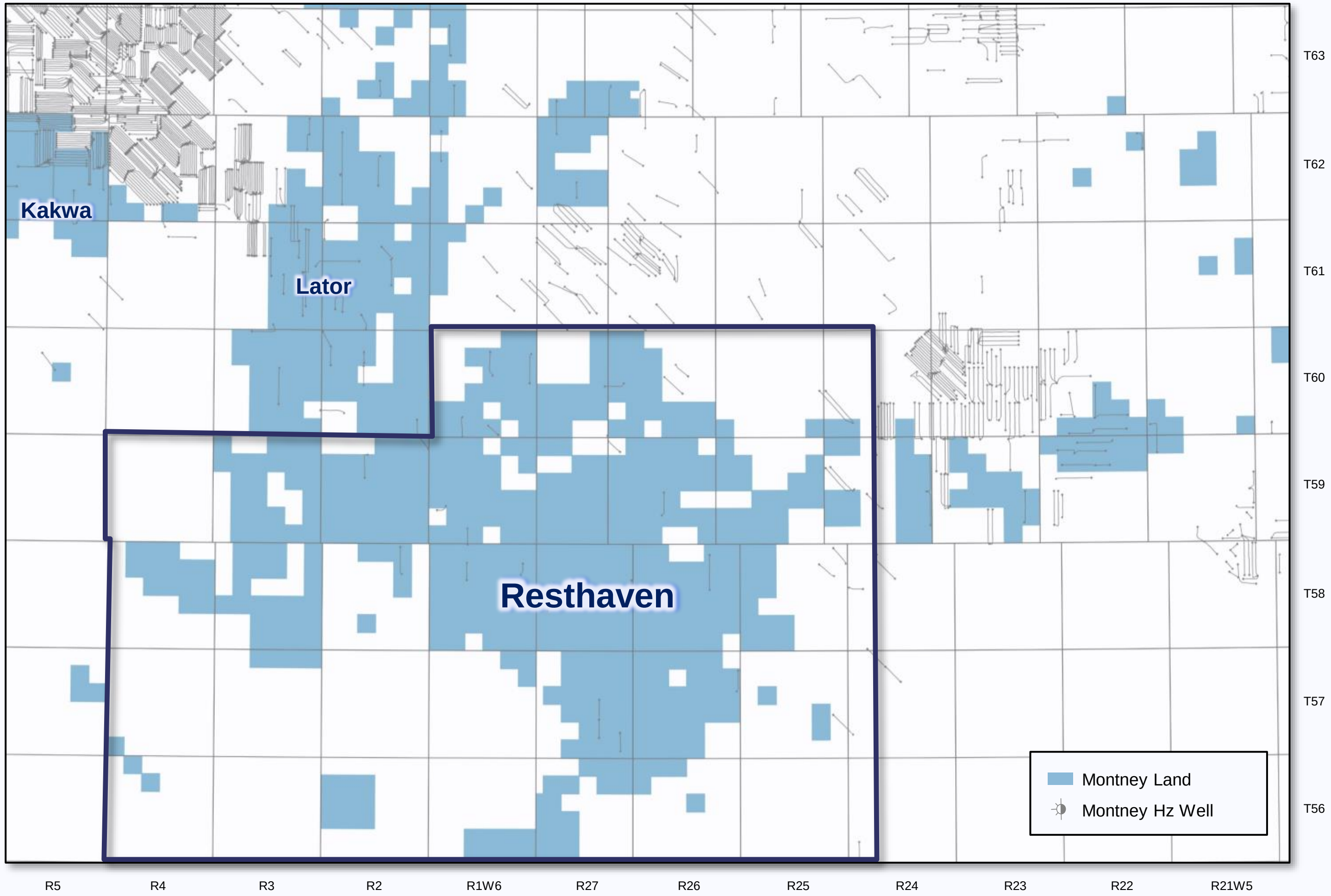
>25 years
Of stay-flat inventory at Phase 1 capacity

85,000 boe/d
Ability to increase overall facility throughput with second train, bringing area capacity to ~85,000 boe/d

LATOR DEVELOPMENT PROFILE



RESTHAVEN MONTNEY



~1,000 Locations

Identified across >300,000 acres of prolific, high-deliverability gas-weighted lands

Technical and economic evaluation underway

Capture efficiencies and optimization from development on current focus areas to enhance economic returns

Refer to Slide Notes and Advisories

STRATEGIC INFRASTRUCTURE

Established Partnership with Pembina Gas Infrastructure to fund future strategic projects

Whitecap operated to control cost and operations

FACILITY	CAPACITY	COST	TIMING
Kaybob 15-07 ***(50% owned by PGI)***	*36,500 boe/d* *(32% liquids)*	*In service*	
Musreau 05-09 ***(50% owned by Topaz)***	*20,000 boe/d* *(65% liquids)*	*In service*	
Lator Phase 1	*35,000 – 40,000 boe/d* *(40 – 50% liquids)*	**\$250 – \$300 million** **Funded by PGI**	Late 2026/ Early 2027
Lator Phase 2	*30,000 – 50,000 boe/d* *(30 – 35% liquids)*	\$150 – \$300 million	2029+

Refer to Slide Notes and Advisories

PARTIAL INFRASTRUCTURE MONETIZATION

Musreau Facility & Kaybob Complex

- 50% working interest disposed for **$520 million proceeds**

Strategic Partnership with PGI creates **$190 million in operational and financial synergies**

PGI funds $250 – $300 million Lator Facility

- Whitecap to design, construct and operate

Total value creation of ~$1 Billion

Enhanced processing, transportation, fractionation and marketing fees from PGI strategic partnership and lower interest expense result in minimal funds flow impact

TRANSACTION METRICS	($ MM)	($/boe)
Gross Proceeds	**$520**	
After Tax Proceeds	**$480**	
2025 EBITDA Impact	**($37)**	**($0.57)**
2025 Funds Flow Impact	**($11)**	**($0.17)**
Avg. 2025-2029 EBITDA Impact	**($37)**	**($0.52)**
Avg. 2025-2029 Funds Flow Impact	**$0**	**$0.00**

Refer to Slide Notes and Advisories

CONVENTIONAL OVERVIEW

2.4 million acres

3,980 drilling locations

Foundation that supports long term sustainability

2025 Production

110,000 – 115,000 BOE/d, 77% Liquids

Low Decline & High Netback Light Oil Assets

Significant Free Cash Flow Generation

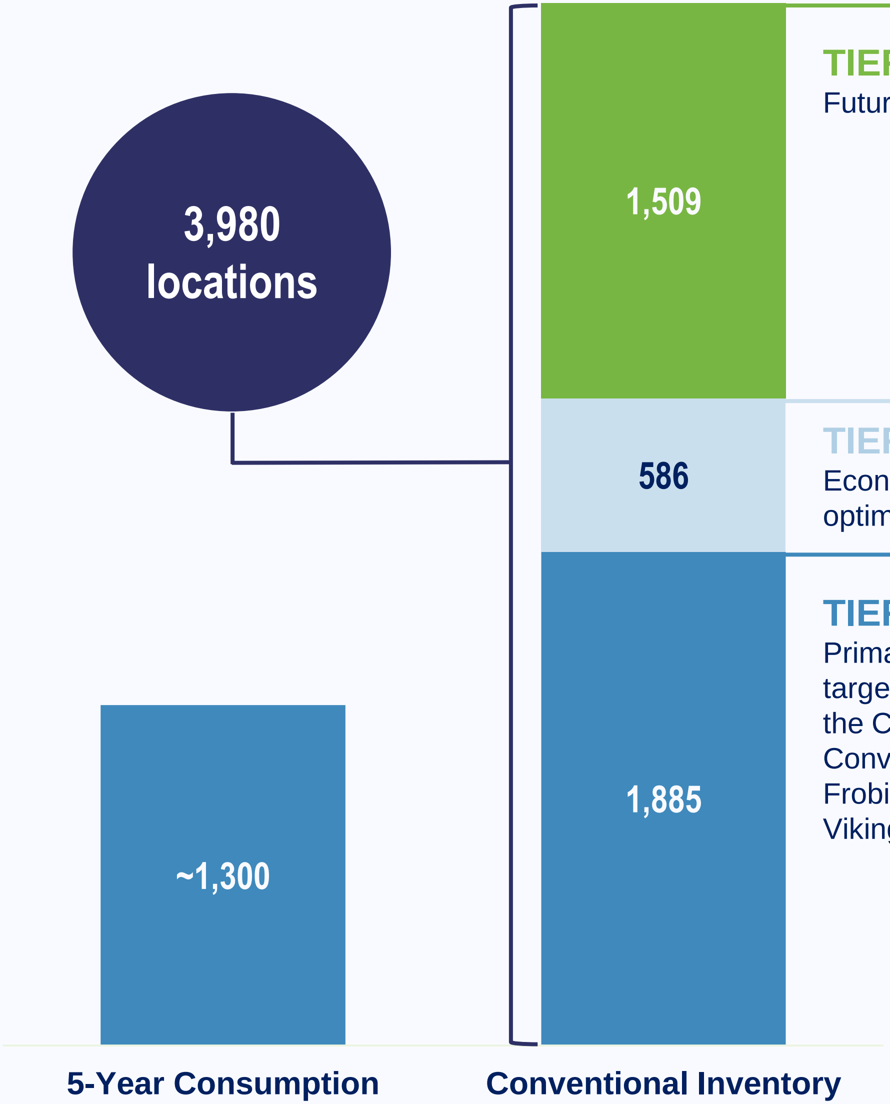
History of Strong Execution and Optimization of Acquired Assets

WHITECAP RESOURCES INC

CONVENTIONAL INVENTORY

Well defined and derisked inventory with optimization upside

5 Year Plan consumes < 33% of Inventory



TIER 3
Future upside locations

TIER 2
Economic development with optimization opportunities

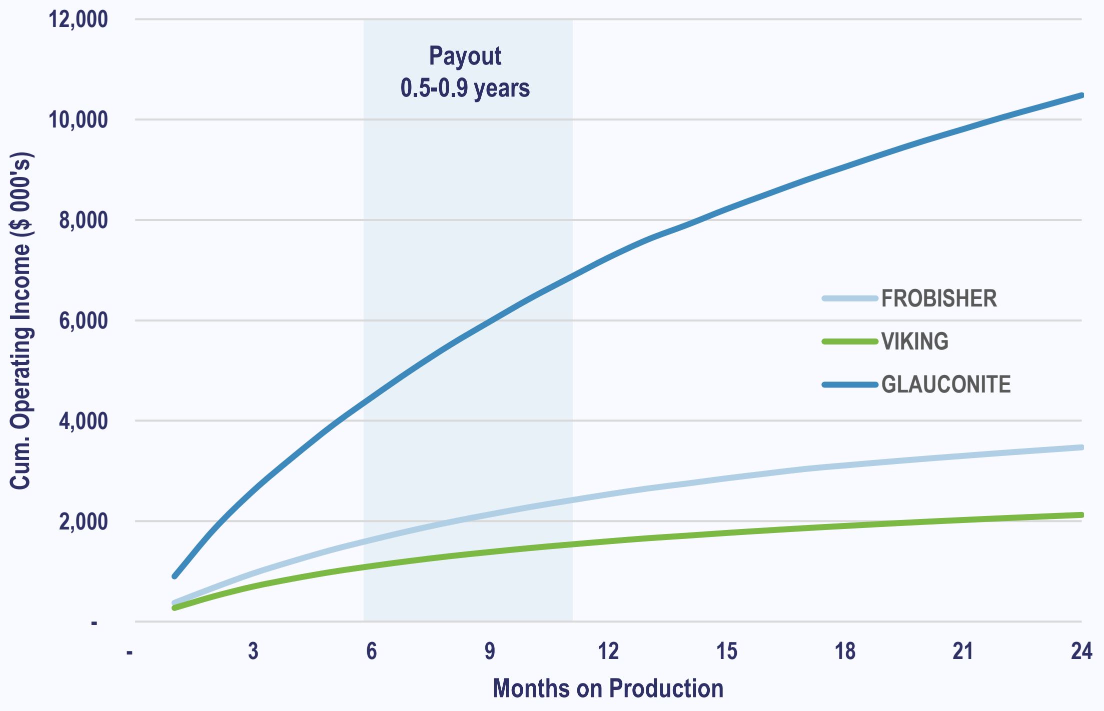
AVERAGE PAYOUT
= 1.4 Years

TIER 1
Primary development targeting light oil assets in the Cardium, Charlie Lake, Conventional Montney, Frobisher, Glauconite and Viking Formations

AVERAGE PAYOUT
= 0.8 Years

US$75/bbl WTI, $3.00/GJ AECO, $1.37 USD/CAD

A REPEATABLE, HIGH-QUALITY INVENTORY



		FROBISHER	VIKING	GLAUCONITE
DCE&T Costs	($mm)	**$1.60**	**$1.30**	**$7.20**
P+P Reserves	(mboe)	**93** (95% Liquids)	**51** (73% Liquids)	**864** (48% Liquids)
IP90	(boe/d)	**142** (95% Liquids)	**114** (79% Liquids)	**756** (57% Liquids)
Payout	(years)	**0.5**	**0.7**	**0.9**
P/I	(x)	**1.9**	**1.1**	**1.3**
IRR	(%)	**>200%**	**>200%**	**128%**
NPV (10% disc.)	($mm)	**$3.00**	**$1.40**	**$9.70**

Assumptions: US $75/bbl WTI, $3.00/GJ AECO, 1.37 USD/CAD

5 YEAR PLAN

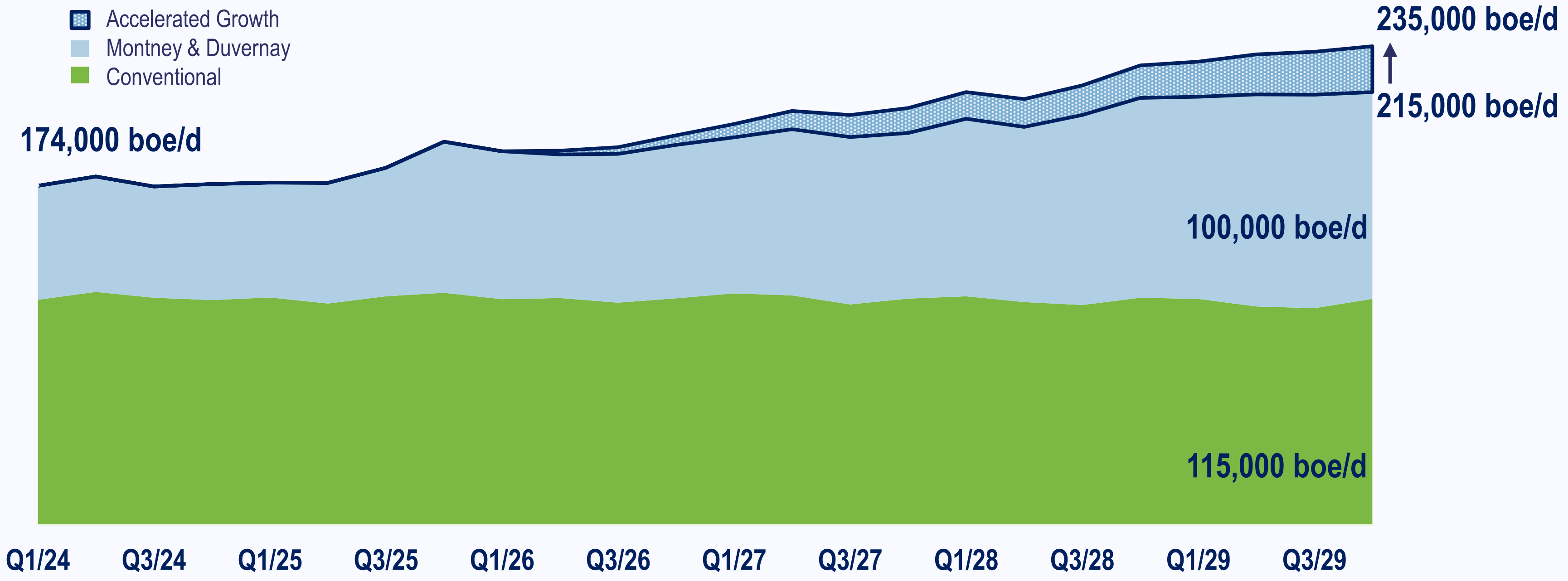
5 YEAR PLAN

5% Average Annual Growth Rate to 215,000 boe/d

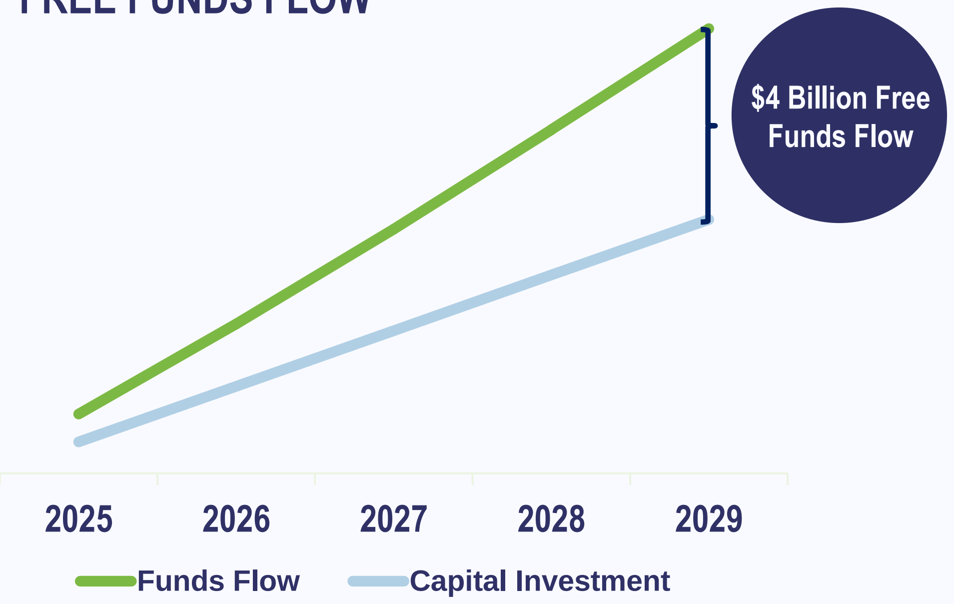
$10 Billion Funds Flow

$6 Billion Capital Investment

$4 Billion Free Funds Flow



FREE FUNDS FLOW

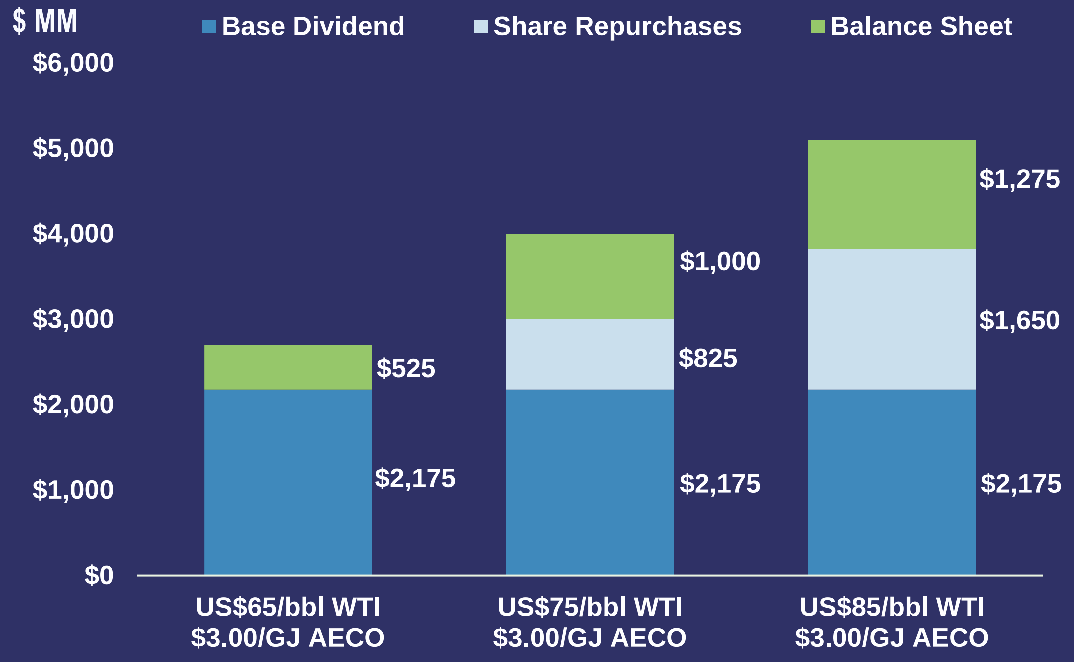


NET DEBT

Refer to Slide Notes and Advisories

US$75/bbl WTI, $3.00/GJ AECO, $1.37 USD/CAD

5 YEAR
FREE FUNDS FLOW PROFILE



$4 Billion of Free Funds Flow

$3 Billion of Returns to Shareholders

$1 Billion of Debt Repayment

UPSIDE POTENTIAL TO THE 5 YEAR PLAN

Over $800 million in incremental free funds flow

CAPITAL EFFICIENCY IMPROVEMENTS

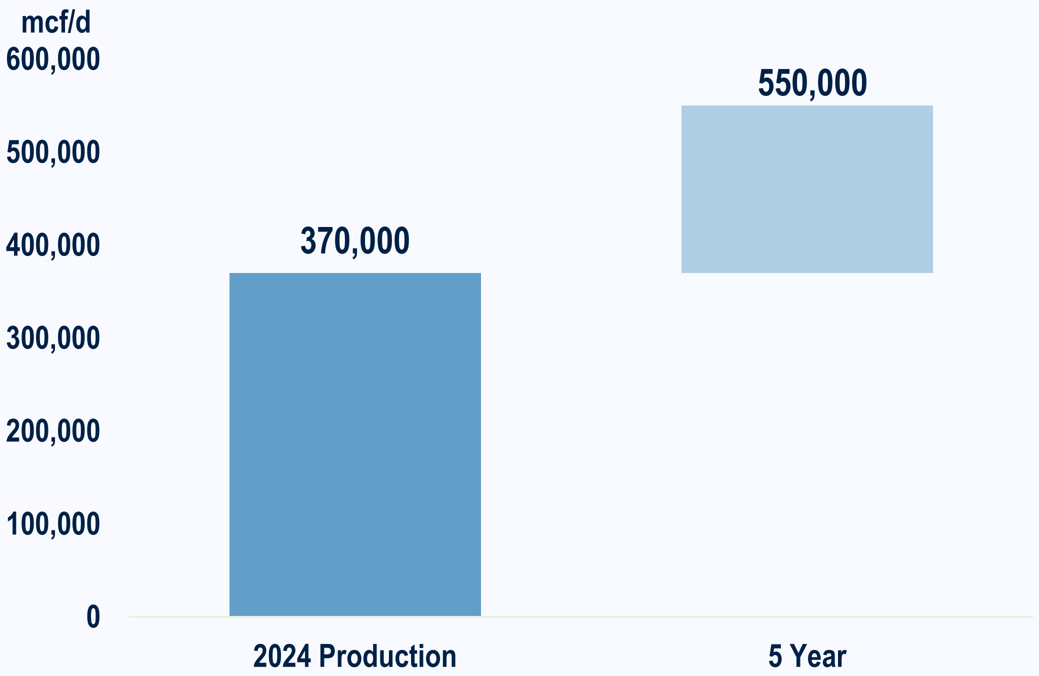
- Well Design (spacing, benching, lateral lengths, etc.)
- Development Optimization
- Focus on cost control & efficient planning

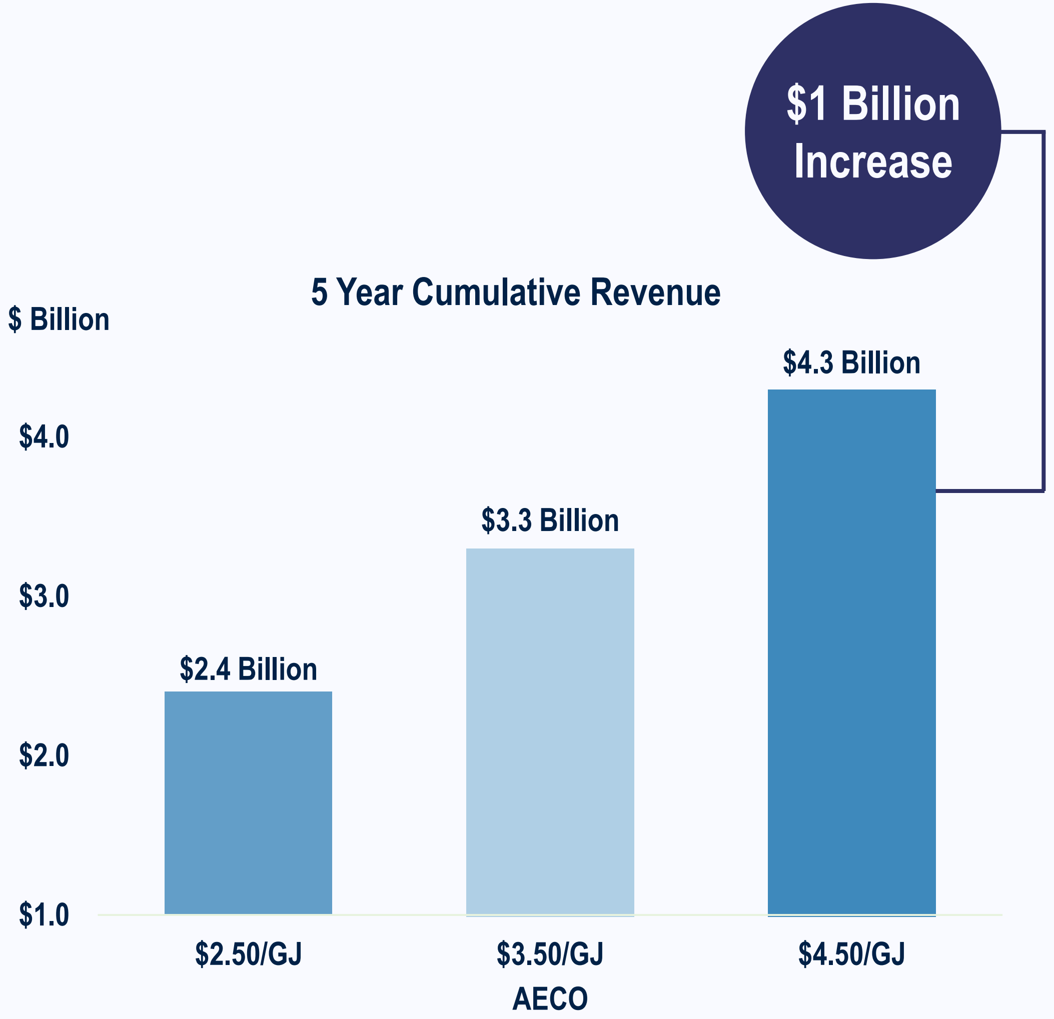
OPERATING COST REDUCTIONS

- Utilizing technological advancements
- Focus on cost control and take advantage of scale

Refer to Slide Notes and Advisories

NATURAL GAS OPTIONALITY





Timing capital projects into long-term takeaway capacity

Significant future cash flow upside

Refer to Slide Notes and Advisories

MARKETING

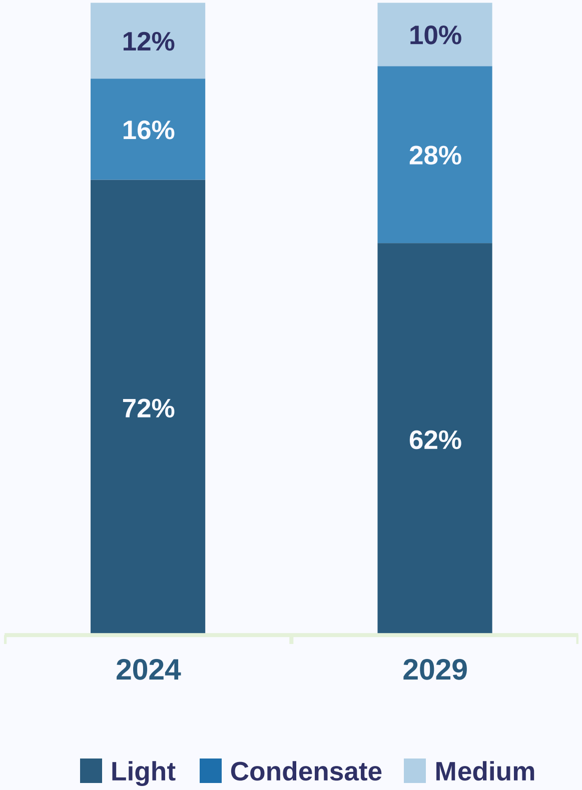
CRUDE OIL MARKETING

HIGH NETBACK
Majority light oil pricing drives strong operating netbacks of $40/boe

PIPELINE ACCESS
Our advantaged locations and firm service agreements ensure reliable pipeline egress for our entire production portfolio

TRANSMOUNTAIN EXPANSION
Additional pipeline egress out of the basin has improved differentials on all grades of crude oil

CRUDE OIL FINANCIAL EXPOSURE



Refer to Slide Notes and Advisories

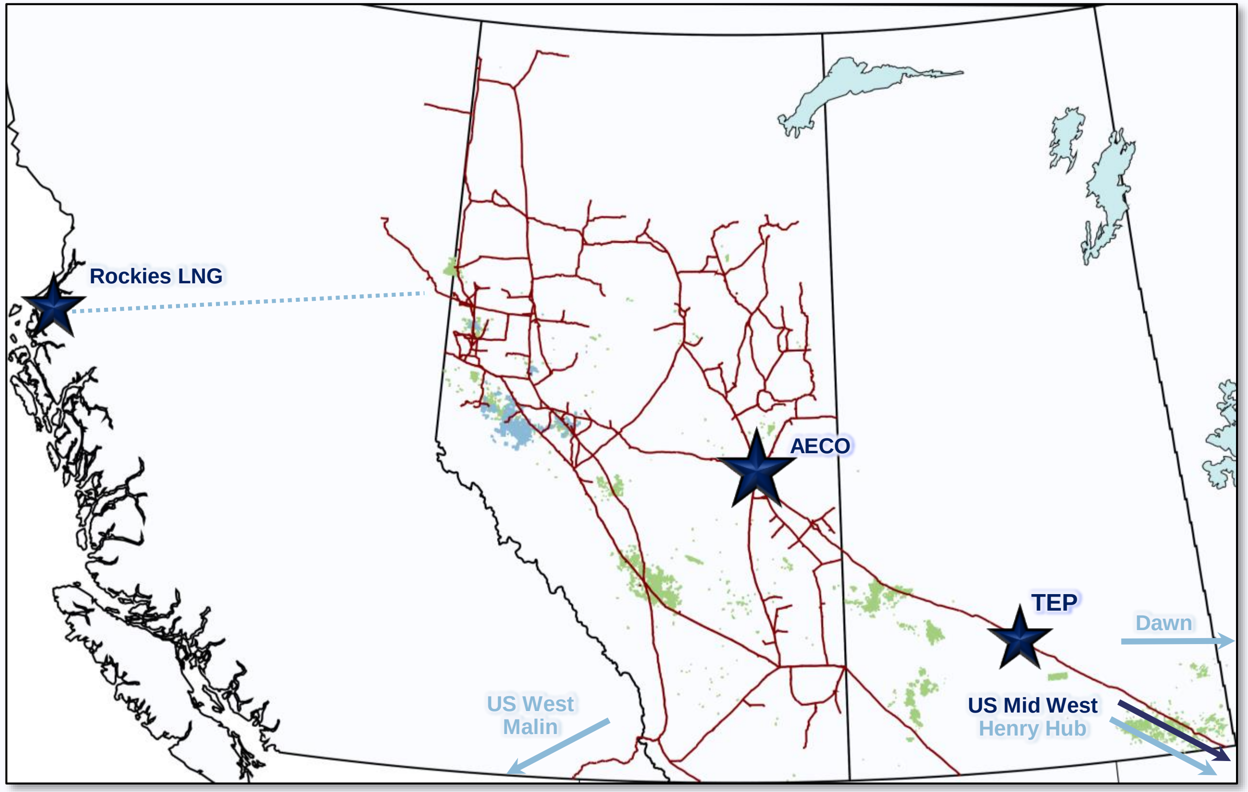
NATURAL GAS AND NGL MARKETING

MARKET ACCESS
Established term transportation agreements and leveraged dual-connected facilities

DIVERSIFICATION
Future focus on price diversification across North America and globally through LNG exposure

GLOBAL LNG
Partnered in the 1.7 Bcf/d Ksi Lisims LNG project

NGL FRACTIONATION
Fractionation secured for our 5+ year growth plans in a bottlenecked market



NATURAL GAS FINANCIAL EXPOSURE

Refer to Slide Notes and Advisories

SUSTAINABILITY

CARBON CAPTURE, UTILIZATION, & STORAGE EXPERTISE

Leader in CO_2 Sequestration

We safely store ~2 MT/year

Weyburn Project	
To date	*41 MT*
Annual Rate	*~2 MT/year*
Total Storage Capacity	*115 MT*
Remaining Injection Life	*35+ Years*

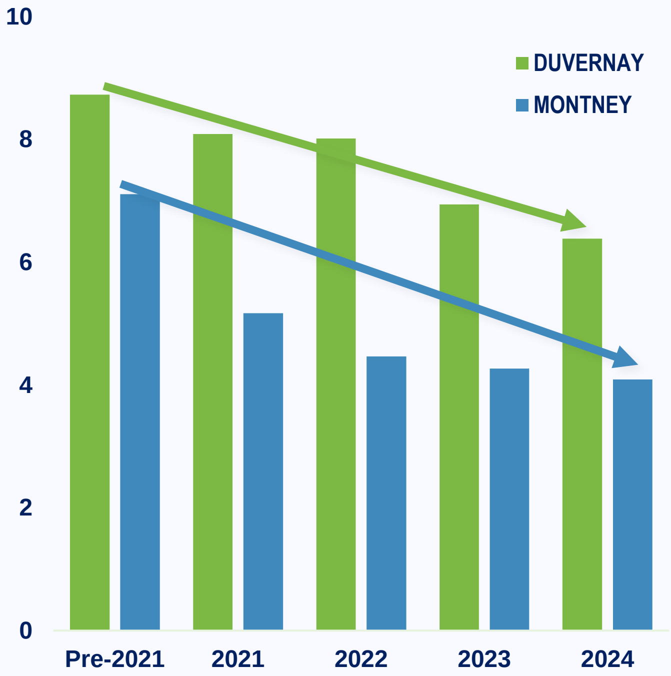
Future Projects

Carbon Hub	Sequestration Opportunity
Saskatchewan	*~4 MT/year*
Lamont	*~3 MT/year*
Rolling Hills	*~3 MT/year*
Central Alberta	*~1.5 MT/year*
Total	***~11.5 MT/year***

Refer to Slide Notes and Advisories

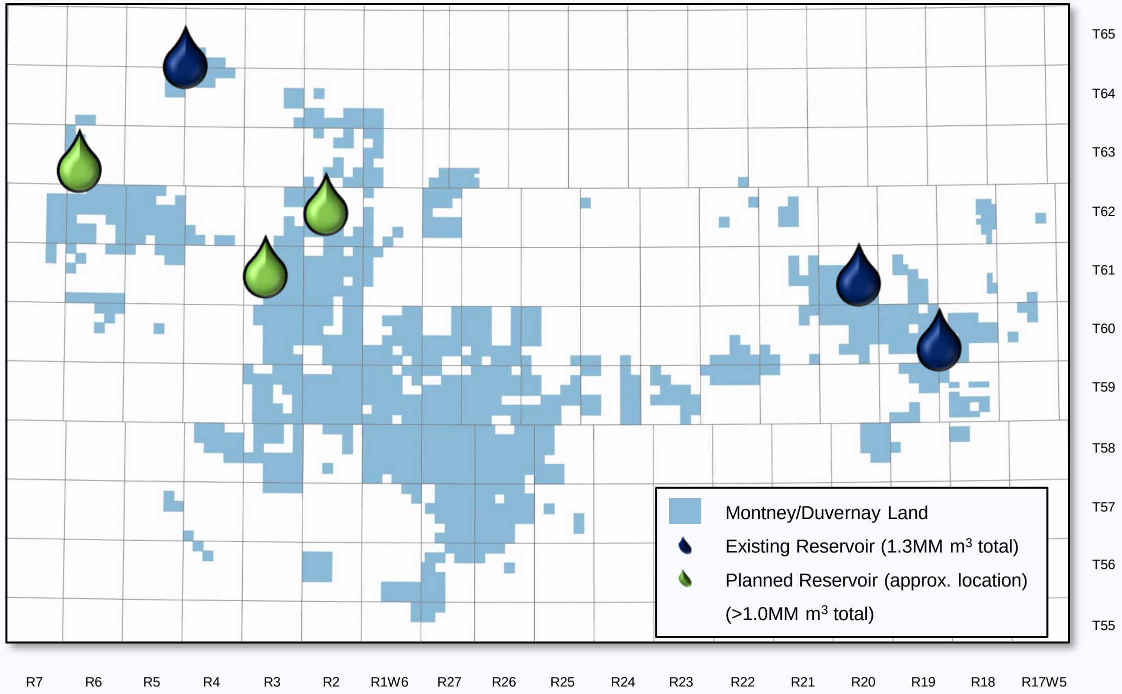
REDUCING OUR WATER USAGE AND SECURING AVAILABILITY

MONTNEY AND DUVERNAY WATER INTENSITY (m^3/tonne)



-27%
Duvernay Water Usage vs pre-2021

-42%
Montney Water Usage vs pre-2021



Refer to Slide Notes and Advisories

WHITECAP RESOURCES INC

TSX: WCP

www.wcap.ca

InvestorRelations@wcap.ca

December 16, 2024

SLIDE NOTES

Slide 2
1. Market capitalization calculated based on current shares outstanding as at September 30, 2024, and 7.5 million share awards outstanding.
2. Market Capitalization and Enterprise value are supplementary financial measures. See *Specified Financial Measures* in the Advisories.
3. Enterprise value calculated based on fully diluted common shares outstanding as at September 30, 2024, a share price of $9.75 and pro forma net debt of $1 billion.
4. Net debt is pro forma the closing of the PGI transaction as announced on July 2, 2024.
5. Net debt is a capital management measure. See *Specified Financial Measures* in the Advisories.
6. The debt used in the Debt to EBITDA calculation includes bank indebtedness, letters of credit, and dividends declared in accordance with the Company's credit agreements.
7. The EBITDA used in the Debt to EBITDA calculation is adjusted for non-cash items, transaction costs and extraordinary and non-recurring items such as material acquisitions or dispositions in accordance with the Company's credit agreements.
8. Expenditures on property, plant and equipment also referred to as "Capital Expenditures" or "Capital Spending" or "Capital Investments".
9. See *Oil and Gas Advisory* in the Advisories for additional information on production.
10. Funds flow is a capital management measure. See *Specified Financial Measures* in the Advisories.

Slide 3
1. See *Oil and Gas Advisory* in the Advisories for additional information on production.
2. Production per share is calculated based on the weighted average diluted shares outstanding in the period.

Slide 5
1. Funds flow is a capital management measure. See *Specified Financial Measures* in the Advisories.
2. Expenditures on property, plant and equipment also referred to as "Capital Expenditures" or "Capital Spending" or "Capital Investments".
3. Production per share is calculated based on the weighted average diluted shares outstanding in the period.
4. See *Oil and Gas Advisory* in the Advisories for additional information on production.
5. Maintenance capital is a non-GAAP financial measure. See *Specified Financial Measures* in the Advisories.

Slide 8
1. The debt used in the Debt to EBITDA calculation includes bank indebtedness, letters of credit, and dividends declared in accordance with the Company's credit agreements.
2. The EBITDA used in the Debt to EBITDA calculation is adjusted for non-cash items, transaction costs and extraordinary and non-recurring items such as material acquisitions or dispositions in accordance with the Company's credit agreements.

Slide 9
1. Funds flow is a capital management measure. See *Specified Financial Measures* in the Advisories.
2. See *Oil and Gas Advisory* in the Advisories for additional information on production.
3. Reserves for 2010-2023 are based on McDaniel & Associates Consultants Ltd.'s ("McDaniel") reserves evaluation reports effective December 31 of the respective year in accordance with NI 51-101 and the COGE Handbook.
4. For production and TPP reserves, the constituent product types and their respective quantities may be found in the Annual Information Form for the respective year, copies of which may be accessed through the Company's profile on the SEDAR+ website (www.sedarplus.ca).
5. CAGR is the compound annual growth rate representing the measure of annual growth over multiple time periods.
6. TPP is defined as total proven plus probable reserves.

Slide 10
1. NCIB refers to our normal course issuer bid.
2. Total dividends per share and cumulative dividends plus NCIB are based on the weighted average basic shares in the year the dividend was paid or shares repurchased.

Slide 11
1. The debt used in the Debt to EBITDA calculation includes bank indebtedness, letters of credit, and dividends declared in accordance with the Company's credit agreement.
2. The EBITDA used in the Debt to EBITDA calculation is adjusted for non-cash items, transaction costs and extraordinary and non-recurring items such as material acquisitions or dispositions in accordance with the Company's credit agreement.

Slide 12
1. Net debt is a capital management measure. See *Specified Financial Measures* in the Advisories.
2. Pro forma net debt incorporates the closing of the Pembina Gas Infrastructure ("PGI") transaction, as announced on July 2, 2024, which is pending final regulatory approval.
3. The debt used in the Debt to EBITDA calculation and Debt to Capitalization calculation includes bank indebtedness, letters of credit, and dividends declared in accordance with the Company's credit agreements.
4. The EBITDA used in the Debt to EBITDA calculation is adjusted for non-cash items, transaction costs and extraordinary and non-recurring items such as material acquisitions or dispositions in accordance with the Company's credit agreements.

SLIDE NOTES

Slide 13
1. Hedge positions current to December 15, 2024.
Note:
(i) Prices reported are the weighted average prices for the period.
(ii) Percent of net royalty volumes hedged are based on Whitecap average production of 175,500 boe/d for Q4/24, 178,000 boe/d for 2025 and 187,000 boe/d for 2026

2. Full hedge positions by product are:

WTI Crude Oil	Term	Volume (bbls/d)	Bought Put Price (C$/bbl) (i)	Sold Call Price (C$/bbl) (i)	Swap Price (C$/bbl) (i)
Collar	2024 Oct – Dec	5,000	82.00	116.98	
Swap	2024 Oct – Dec	9,000			106.20
Swap	2025 Jan – Jun	8,000			104.39
Swap	2025 Jan – Dec	19,000			101.77
Swap	2025 Jul – Dec	1,000			100.05
Swap	2026 Jan – Dec	20,000			91.52

Natural Gas	Term	Volume (GJ/d)	Bought Put Price (C$/GJ) (i)	Sold Call Price (C$/GJ) (i)	Swap Price (C$/GJ) (i)
Collar	2026 Jan – Dec	68,500	2.25	3.52	
Swap	2024 Oct – Dec	37,000			3.16
Swap	2024 Oct	25,000			2.56
Swap	2024 Nov – 2025 Mar	10,000			3.58
Swap	2025 Jan – Dec	105,000			3.34
Swap	2026 Jan – Dec	30,000			3.58

Slide 15
1. "Operating Netback" is a non-GAAP financial measure. See *Specified Financial Measures* in the Advisories.

Slide 16
1. Production forecasts are calculated using the first year (IP365) production additions of each identified drilling location (booked and unbooked), a 5% corporate growth rate and a corporate decline rate of 24% increasing to 32%.
2. Potential upside represents prospective drilling locations contingent on the success of current and upcoming pilot projects. These drilling locations are not yet included in our Total Inventory.
3. See *Oil and Gas Advisory* in the Advisories for additional information on production and drilling locations.

Slide 17
1. Gross acreage and locations depicted.
2. See *Oil and Gas Advisory* in the Advisories for additional information on production and drilling locations.

Slide 18
1. See *Oil and Gas Advisory* in the Advisories for additional information on production and drilling locations.

Slide 19
1. Gross locations depicted.
2. See *Oil and Gas Advisory* in the Advisories for additional information on drilling locations.
3. Tier 1 is defined as 1.2 year payout and less. Tier 2 is defined as 1.2 - 1.5 year payout.

Slide 20
1. See *Oil and Gas Advisory* in the Advisories for additional information on payout, production, profit to investment, and reserves.
2. See *Specified Financial Measures* in the Advisories for additional information on NPV.
3. "Operating Netback" is also referred to as "Operating Income". "Operating Netback" is a non-GAAP financial measure. See *Specified Financial Measures* in the Advisories.
4. See *Production, Initial Production Rates & Product Type Information* in the Advisories.

Slide 21
1. See *Oil and Gas Advisory* in the Advisories for additional information on production and drilling locations.
2. Gross locations depicted.

Slide 22
1. See *Oil and Gas Advisory* in the Advisories for additional information on drilling locations.

Slide 23
1. The closing of the Pembina Gas Infrastructure ("PGI") transaction, as announced on July 2, 2024, is pending final regulatory approval.

Slide 24
1. The closing of the Pembina Gas Infrastructure ("PGI") transaction, as announced on July 2, 2024, is pending final regulatory approval.
2. EBITDA is a non-GAAP financial measure. See *Specified Financial Measures* in the Advisories.
3. Funds flow is a capital management measure. See *Specified Financial Measures* in the Advisories.
4. Operational and financial synergies based on future values discounted using a 10% discount rate.
5. EBITDA impact reflects working interest dispositions and synergies from the PGI partnership.
6. Funds flow impact includes working interest dispositions, synergies from the PGI partnership and interest/tax adjustments.
7. Per boe figures are supplementary financial measures. See *Specified Financial Measures* in the Advisories.
8. Per boe figures are based on average production of 178,000 boe/d for 2025 and average production of 195,000 boe/d for average 2025-2029.
9. 2025-2029 commodity prices of US$75/bbl WTI, $3.00/GJ AECO, $1.37 USD/CAD.

SLIDE NOTES

Slide 25
1. Gross acreage and locations depicted.
2. "Free Funds Flow" is also referred to as "Free Cash Flow". Free funds flow is a non-GAAP financial measure. See *Specified Financial Measures* in the Advisories.

Slide 26
1. Gross locations depicted.
2. See *Oil and Gas Advisory* in the Advisories for additional information on drilling locations and payout.
3. Tier 1 is defined as 1.2 year payout and less. Tier 2 is defined as 1.2 - 1.5 year payout.

Slide 27
1. See *Oil and Gas Advisory* in the Advisories for additional information on payout, production, profit to investment, and reserves.
2. See *Specified Financial Measures* in the Advisories for additional information on NPV.
3. "Operating Netback" is also referred to as "Operating Income". "Operating Netback" is a non-GAAP financial measure. See *Specified Financial Measures* in the Advisories.
4. See *Production, Initial Production Rates & Product Type Information* in the Advisories.

Slide 29
1. Funds flow is based on US$75/bbl WTI and $3.00/GJ AECO.
2. Funds flow is a capital management measure. See *Specified Financial Measures* in the Advisories.
3. Free funds flow is a non-GAAP financial measure. See *Specified Financial Measures* in the Advisories.
4. Expenditures on property, plant and equipment also referred to as "Capital Expenditures" or "Capital Spending" or "Capital Investments" .
5. See *Oil and Gas Advisory* in the Advisories for additional information on production.
6. Pro forma net debt incorporates the closing of the Pembina Gas Infrastructure ("PGI") transaction, as announced on July 2, 2024, which is pending final regulatory approval.
7. The debt used in the Debt to EBITDA calculation includes bank indebtedness, letters of credit, and dividends declared in accordance with the Company's credit agreements.
8. The EBITDA used in the Debt to EBITDA calculation is adjusted for non-cash items, transaction costs and extraordinary and non-recurring items such as material acquisitions or dispositions in accordance with the Company's credit agreements.

Slide 30
1. Free funds flow is a non-GAAP financial measure. See *Specified Financial Measures* in the Advisories.

Slide 31
1. Free funds flow is a non-GAAP financial measure. See *Specified Financial Measures* in the Advisories.

Slide 32
1. See *Oil and Gas Advisory* in the Advisories for additional information on production.

Slide 34
1. "Operating Netback per boe" is a non-GAAP financial measure. See *Specified Financial Measures* in the Advisories.
2. Forecasted current operating netback provided.
3. Crude oil financial exposure based on forecasted volumes.

Slide 35
1. Natural gas financial exposure based on forecasted volumes.

Slide 37
1. CO_2 emissions and storage are based on gross operated numbers. Whitecap has a 65.3% operated working interest in the Weyburn Unit, 100% working interest in the Saskatchewan Carbon Hub, 20% working interest in the Lamont Hub, and 50% working interest in each of the Rolling Hills and Central Alberta Hubs.
2. Potential capacity includes unit extensions at Weyburn that may or may not be currently owned.
3. The identified sequestration opportunity at each of the future carbon hubs is based on reported emissions data from counterparties that Whitecap or its partners have had direct contact with (including having signed MOUs) regarding future sequestration opportunities. Whitecap provides no assurance that the total emissions values will be captured by each counterparty or they will be sequestered through a Whitecap owned carbon hub.

Slide 38
1. Water intensity is defined as the total water pumped, divided by the total proppant pumped per well.
2. Includes prior operators.

ADVISORIES

Special Note Regarding Forward-Looking Statements and Forward-Looking Information

This presentation 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, position and our value creation its components. In particular, and without limiting the generality of the foregoing, this presentation contains forward-looking information with respect to: our 2024 production guidance; our 2025 production, capital, funds flow and free funds flow guidance; our forecast for pro forma net debt upon closing of the PGI transaction; our belief that maintenance capital plus the base dividend will be fully funded at US$50/bbl and $2.00/GJ; the allocation of our 2025 budget between and among our unconventional and conventional assets; our plans for a specific number of wells at Montney and Duvernay for 2024; our belief that the 15-07 gas processing facility will be full by the second half of 2025; our forecast to maintain the 05-09 battery at capacity; our forecast for the start-up of our 04-13 battery in late 2026/early 2027; our plans for a specific number of wells at Alberta, Western Saskatchewan, Eastern Saskatchewan and Weyburn for 2025; our belief that the Glauconite monobore drilling design will reduce well costs; our belief that longer laterals in Western Saskatchewan will improve capital efficiencies; our CAGR per share projections with respect to funds flow and production; our belief that our balanced portfolio reduces risk and maximizes returns; our forecast for 10%-15% annual growth in the Montney and Duvernay; our belief that we have area optionality supported by new infrastructure in the Montney and Duvernay; our belief that high condensate production and pad drilling efficiencies will result in top tier economics; our belief that significant growth on our Montney and Duvernay assets will lower our cost structure and enhance future profitability; our belief that an approximate 20% base decline will lower our maintenance capital requirements for our conventional assets; forecasted operating netback and the benefits to be derived therefrom; our belief that we have advantaged locations and that our firm transportation contracts will provide reliable downstream accessibility; our forecasts for 2024, 5 year, 10 year, total inventory and potential upside production potential; our belief that we have significant upside beyond TPP value in the Montney and Duvernay; our beliefs regarding our growth potential, including the areas of growth focus in the near, medium and long term; the production profile of our Montney and Duvernay wells from 2024-2029, and the allocation by area thereof; the number of Montney and Duvernay wells to be drilled from 2024-2029, and the allocation by area thereof; the number of drilling locations and the breakdown by Montney and Duvernay and conventional assets and location type; our belief that we have decades of top tier inventory in the Montney and Duvernay to support growth; the amount of Montney and Duvernay inventory we consume in our 5 year plan; our forecasted average payout of our tier 1 and 2 Montney and Duvernay inventory; our forecast type curve parameters and economics; the expected timing of our infrastructure buildout at Lator; the number of future drilling locations identified at Lator; our belief that we can target multiple benches to enhance acreage recovery and productivity at Lator; our belief that we have over 25 years of stay-flat inventory at phase 1 capacity at Lator; our belief that we can increase facility capacity to 85,000 boe/d through an eventual second phase at Lator; our forecast production profile at Lator; the number of future drilling locations identified at Resthaven; our belief that we can enhance economic returns at Resthaven by capturing efficiencies and optimization from development on current focus areas; the capacity, liquids content, cost (including funding source) and timing of future infrastructure in the Montney and Duvernay; our belief that we will develop third-party partnerships to fund future strategic projects while retaining operatorship; our forecast for the impact that the partial infrastructure monetization will have on our 2025 and 2025-2029 EBITDA and funds flow; our forecast for gross and after tax proceeds of the partial infrastructure monetization; our belief that enhanced processing, transportation, fractionation and marketing fees from PGI strategic partnership and lower interest expense will result in minimal funds flow impact; our belief that our conventional assets are the foundation that supports our long-term sustainability; our belief that our conventional assets can generate significant free cash flow; the number of drilling locations on our conventional acreage; our belief that our conventional inventory is well defined and is derisked with optimization upside potential; the amount of conventional inventory we consume in our 5 year plan; our forecasted average payout of our tier 1 and 2 conventional inventory; our total forecast annual growth rate, production, capital investment, funds flow and free funds flow from 2025 to 2029; the allocation of cumulative free funds flow over 2025-2029 to shareholder returns and the balance sheet, including at the commodity prices shown; the breakdown of 2025-2029 production between the Montney/Duvernay and our conventional assets; our beliefs regarding the upside potential to our 5 year plan; our plans for capital efficiency improvements and operating cost reductions; our calculation of incremental funds flow realized upon capital efficiency improvements and operating cost reductions; our forecast natural gas production and 5 year cumulative revenue; our plans to time our capital projects into long-term takeaway capacity; our belief that natural gas growth provides significant cash flow upside; our target range for percentage hedged; our belief that our advantaged locations and firm service agreements ensure reliable pipeline egress for our entire portfolio; our 2024 and 2029 crude oil financial exposure; our focus on price diversification across North America and globally through LNG exposure; our belief that we have fractionation secured for our 5 year growth plans; our 2025 and target natural gas financial exposure; our forecast for total CO_2 storage capacity and remaining injection life at the Weyburn Project; our belief that we are a leader in CO_2 sequestration; and the size of sequestration opportunity at each of our Saskatchewan, Lamont, Rolling Hills and Central Alberta Carbon Hubs.

Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas and NGLs reserves and in projecting future rates of production and the timing of capital expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates.

The forward-looking information is based on certain key expectations and assumptions made by our management, including: that the disposition to PGI will occur on the terms and timing anticipated by the Company; that we will continue to conduct our operations in a manner consistent with past operations except as specifically noted herein (and for greater certainty, except with respect to the proposed disposition to PGI, 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

ADVISORIES

Special Note Regarding Forward-Looking Statements and Forward-Looking Information (*continued*)

forecast 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 timing and costs of pipeline, storage and facility construction and expansion; the state of the economy and the exploration and production business; results of operations; 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, droughts or extreme hot or cold temperatures; the commodity pricing and exchange rate forecasts 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.

In addition, this presentation contains various assumptions regarding future commodity prices, exchange rates, capital expenditures, net debt levels, free cash flow levels and other matters that are located proximate to the aforementioned forward-looking information.

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 our disposition to PGI does not close on the terms and/or on the timetable currently anticipated or at all; 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 2024 and 2025-2029 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, 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 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 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; 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, 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, 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 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, 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 presentation 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 our Company profile on the SEDAR+ website (www.sedarplus.ca).

These forward-looking statements are made as of the date of this presentation 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 presentation contains future-oriented financial information and financial outlook information (collectively, "FOFI") about our forecast 2025 capital expenditures, including the allocation to our unconventional and conventional assets and certain details thereof; our forecast for net debt of approximately $1 billion (0.5 times Debt to EBITDA) upon close of the PGI transaction; the impact that the partial infrastructure monetization will have on our 2025 and 2025-2029 EBITDA and funds flow; our forecast for after tax proceeds from the partial infrastructure monetization; our 2025-2029 cumulative free funds flow and return of capital sensitivity at US$65/bbl WTI, US$75/bbl WTI and US$85/bbl WTI; our forecast pro forma net debt; our 2025-2029 cumulative free funds flow and the allocation to returns to shareholders and our balance sheet; our forecast for the cost of the Lator Phase 1 and Phase 2 facilities; our forecast for incremental free funds flow provided by 10% capital efficiency improvements and 5% operating cost reductions; our 2025 forecast capital spending split by Montney/Duvernay and conventional and certain details thereof; the single well economics of certain assets including drill, complete, equip and tie-in costs and NPV (10%) all of which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth in the above slides.

ADVISORIES

Special Note Regarding Forward-Looking Statements and Forward-Looking Information (*continued*)

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 presentation was made as of the date of this presentation 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 presentation should not be used for purposes other than for which it is disclosed herein.

Additionally, readers are advised that historical results, growth, acquisitions and dispositions described in this presentation may not be reflective of future results, growth, acquisitions and dispositions with respect to Whitecap.

The assumptions used for the 2025 forecast funds flow netbacks ($/boe) used on slides 2, 5, 9, & 24 and for the 2025-2029 forecast funds flow netbacks ($/boe) on slides 29 & 30 of this presentation are as follows (based on the mid-point where applicable). All other references to current, 2025 and/or 2025-2029 (5 Year Plan) forecast funds flow in this presentation utilize the same underlying assumptions/forecasts with the following being impacted by the various commodity price scenarios contemplated throughout this presentation: petroleum and natural gas revenues, realized hedging gains/losses, royalties and cash taxes.

	2025	2025-2029
WTI (US$/bbl)	$70.00	$75.00
AECO (C$/GJ)	$2.50	$3.00
Petroleum and natural gas revenues	$55.51	$57.00 - $60.00
Tariffs	($0.50)	($0.50)
Processing income	$0.75	$0.75
Realized hedging gains	$1.34	$0.00
Royalties	($8.80)	($9.00) - ($10.50)
Operating expenses	($14.00)	($13.50) - ($14.50)
Transportation expenses	($2.10)	($2.00) - ($2.20)
General and administrative expenses	($1.00)	($1.00)
Interest and financing expenses	($1.00)	($0.00) - ($1.00)
Cash settled share awards	($0.50) - ($0.60)	($0.25) - ($0.50)
Cash taxes	($3.00) – ($4.00)	($3.50) – ($4.50)
Decommissioning liabilities	($0.65)	($0.50) - ($0.75)

Oil and Gas Advisory

Reserves and Net Present Value

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

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

Barrel of Oil Equivalency

"Boe" means barrel of oil equivalent. All boe conversions in this presentation 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.

This presentation contains metrics commonly used in the oil and natural gas industry which have been prepared by management, such as "DCE&T Cost", "IRR", "operating netback", "payout", and "profit to investment ratio". These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons.

"DCE&T Cost" includes all direct, on-lease costs of a typical well under pad development, including drill, completion, equip and tie-in and excludes ancillary costs such as lease construction, area trunk lines and processing facilities, water infrastructure and later-life artificial lift, that are carried separately on a case by case basis.

"IRR" is the discount rate that is applied to the forecasted operating income of a well such that it equates to the DCE&T Costs of a well.

"Payout" or "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.

"Profit to investment ratio" is calculated by dividing the NPV of a well by the individual well cost. NPV is a supplementary financial measure. Management uses profit to investment ratio to make capital allocation decisions.

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

ADVISORIES

Type Curve

This presentation references certain type curves and well economics. Such type curves and well economics are useful in understanding management's assumptions of well performance in making investment decisions in relation to development drilling in certain areas and for determining the success of the performance of wells; however, such type curves and well economics are not necessarily determinative of the production rates and performance of existing and future wells and such type curves do not reflect the type curves used by Whitecap's independent qualified reserves evaluator in estimating Whitecap's reserves volumes. The type curves can differ as a result of varying horizontal well length, stage count and stage spacing. The type curves represent the average type curves expected.

Drilling Locations

This presentation 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's reserves evaluation effective December 31, 2023 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.

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.

The following table provides a breakdown of the current Whitecap gross (net) drilling locations included in this presentation:

Gross (Net)	Total Drilling Inventory	Proved Locations	Probable Locations	Unbooked Locations
Conventional	3,980 (3,406)	1,318 (1,148)	201 (169)	2,461 (2,089)
Montney & Duvernay	2,462 (2,213)	262 (226)	118 (102)	2,082 (1,885)
Lator (midpoint)	375 (369)	46 (46)	46 (46)	283 (277)
Resthaven	1,000 (1,000)	3 (3)	1 (1)	996 (996)

Production, Initial Production Rates & Product Type Information

References to petroleum, crude oil , natural gas liquids ("NGLs"), natural gas and average daily production in this presentation 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 natural gas liquids ("NGLs") product type. The Company has disclosed condensate as combined with crude oil and separately from other natural gas liquids since the price of condensate as compared to other natural gas liquids 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 presentation to initial production rates (IP(90), IP(365)) 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 production disclosed in this presentation consist 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:

	Light and Medium Oil (bbls/d)	Tight Oil / Condensate (bbls/d)	NGLs (bbls/d)	Shale Gas (Mcf/d)	Conventional Natural Gas (Mcf/d)	Total (boe/d)
2024	75,200	17,000	20,200	221,300	148,300	174,000
2025	73,000	19,000	20,000	241,000	155,000	178,000

ADVISORIES

Specified Financial Measures

This presentation 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.

"EBITDA" is a non-GAAP financial measure. The most directly comparable financial measure that is disclosed in our financial statements is net income. EBITDA is calculated as earnings before interest, taxes, depreciation and amortization, and is adjusted for non-cash items, transaction costs and extraordinary and non-recurring items such as material acquisitions or dispositions. Management uses EBITDA to compare principal business activities across historical periods to future financial forecasts and in assessment of our historical and future financial leverage. Whitecap's EBITDA for the year ended December 31, 2023 was $2.0 billion.

"Enterprise value" is a supplementary financial measure and is calculated as market capitalization plus net debt. Management believes that enterprise value provides a useful measure of the market value of Whitecap's debt and equity.

"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, 2024 which is incorporated herein by reference, and available on SEDAR+ at www.sedarplus.ca.

"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. 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, 2024 which is incorporated herein by reference, and available on SEDAR+ at www.sedarplus.ca.

"Maintenance capital" is a non-GAAP financial measure calculated as the required annual expenditures on PP&E to keep production flat. Management believes that maintenance capital provides a useful measure of the required cash outflow that would maintain the same level of potential earnings.

"Market capitalization" is a supplementary financial measure and is calculated as period end share price multiplied by the number of shares outstanding at the end of the period. Management believes that market capitalization provides a useful measure of the market value of Whitecap's equity.

"Net Debt" is a capital management measure that management considers to be key to assessing the Company's liquidity. Refer to Note (2) in the "Summary of Quarterly Results" section of our management's discussion and analysis for the three and nine months ended September 30, 2024 which is incorporated herein by reference, and available on SEDAR+ at www.sedarplus.ca.

"NPV" (10% discount rate) is a supplementary financial measure comprised of the before tax NPV for TPP reserves, discounted at 10%, as determined in accordance with NI 51-101.

"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, 2024, which is incorporated herein by reference, and available on SEDAR+ at www.sedarplus.ca.

"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.

"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.

See the related sections in our management's discussion and analysis for the three and nine months ended September 30, 2024, which is incorporated herein by reference, and available on SEDAR+ at www.sedarplus.ca for free funds flow, net debt and operating netback reconciliation tables.

Per Share Amounts

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

RESEARCH COVERAGE

- ATB Capital Markets
- BMO Capital Markets
- Canaccord Genuity
- CIBC World Markets
- Desjardins Capital Markets
- Haywood Securities
- Jefferies
- National Bank Financial
- Peters & Co.
- Raymond James
- RBC Capital Markets
- Scotiabank Global
- TD Securities