Corporate Presentation

March 2024

Advisories

- In the interest of providing information regarding Paramount Resources Ltd. ("Paramount", "PRL" or the "Company") and its future plans and operations, this presentation contains certain forward-looking information and statements. The projections, estimates and forecasts contained in such forward-looking information and statements necessarily involve a number of assumptions and are subject to both known and unknown risks and uncertainties that may cause the Company's actual performance and financial results in future periods to differ materially from these projections, estimates and forecasts. The Advisories Appendix attached hereto lists some of the material assumptions, risks and uncertainties that these projections, estimates and forecasts are based on and are subject to. Readers are encouraged to carefully review the Advisories Appendix.
- All dollar amounts in this presentation are expressed in Canadian dollars, unless otherwise noted.
- Reserves and production information are presented in accordance with Canadian standards.
- The Advisories Appendix attached hereto contains additional information concerning the oil and gas measures and terms, reserves data and non-GAAP financial measures and other specified financial measures contained in this presentation.
- The forward-looking information and statements contained in this presentation are made effective as of March 5, 2024, except the information contained herein respecting Paramount's five-year outlook which is effective November 1, 2023. Certain internally estimated play data contained in this presentation was prepared effective March 5, 2024. In each case, events or information subsequent to the applicable effective dates have not been incorporated.
- This presentation includes references to sales volumes of "natural gas", "condensate and oil", "NGLs", "other NGLs" and "Liquids". "Natural gas" refers to shale gas and conventional natural gas combined. "Condensate and oil" refers to condensate, light and medium crude oil, tight oil and heavy crude oil combined. "NGLs" refers to condensate and other NGLs combined. "Other NGLs" refers to ethane, propane and butane combined. "Liquids" refers to condensate and oil and other NGLs combined. Readers are referred to the Product Type Information section of the Advisories Appendix for more information about sales volumes by the specific product types of shale gas, conventional natural gas, NGLs, light and medium crude oil, tight oil and heavy crude oil.

Corporate Overview

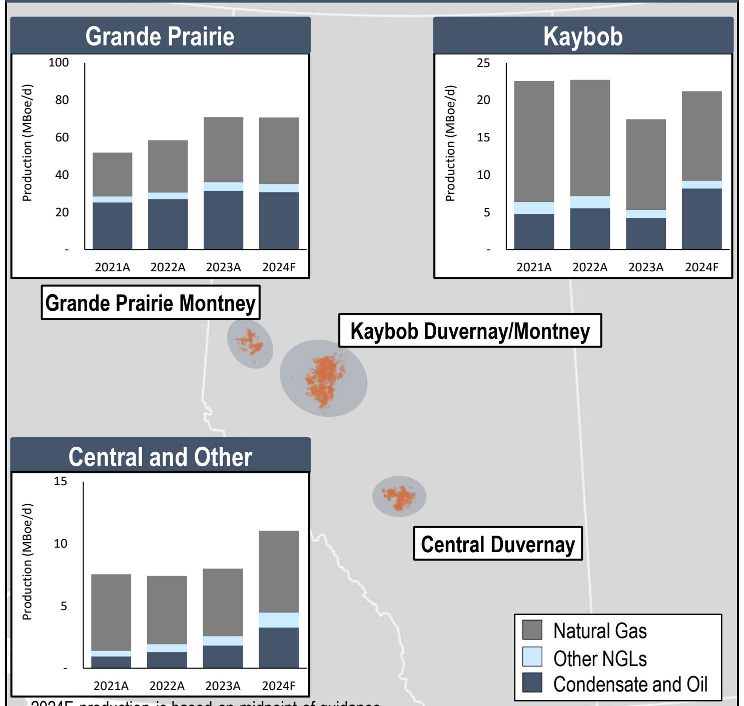
Paramount has significant land positions in the most liquids-rich areas of the prolific Montney and Duvernay resource plays

- Founded in 1976 (IPO'd in 1978)
- Significant insider ownership (~46%) (1)
- Total Proved Reserves: 415 MMBoe (49% liquids) (2)
  - NPV_{10} ~$4.5 Bn ($31.60 / basic share)
- Proved + Probable Reserves: 761 MMBoe (50% liquids) (2)
  - NPV_{10} ~$7.9 Bn ($55.04 / basic share)
- 4Q23 sales volumes: 101,348 Boe/d (46% liquids)

Market Snapshot (TSX-POU)	
Shares Outstanding (MM)	144.8
Market Capitalization ($MM) (3)	~$4,500
Bank Debt at Dec. 31, 2023 ($MM)	$0
Net Debt at Dec. 31, 2023 ($MM) (4)	~$60
Investments in Securities at Dec. 31, 2023 ($MM)	~$540
Monthly Dividend ($/share | Annualized Yield) (5)	$0.125 | 4.8%

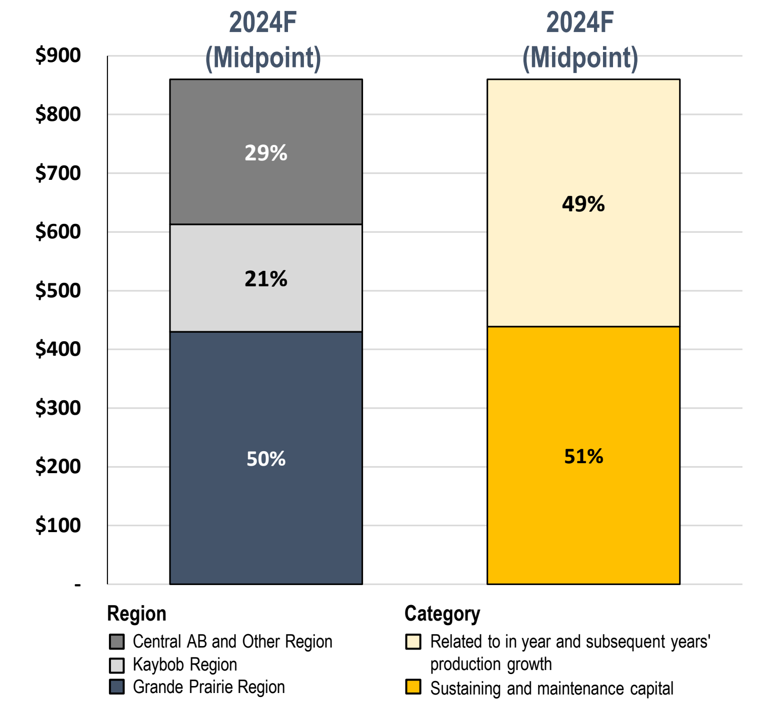
Guidance Summary (6)	2024F
Sales volumes (MBoe/d) (% Liquids)	100-106 (47%)
CapEx ($MM)	$830-$890 *(~50% to growth)*
ARO ($MM)	$40
Mid-point FCF ($MM) (7)	~$235
Annualized base dividend ($MM) (8)	~$215

Focus Areas

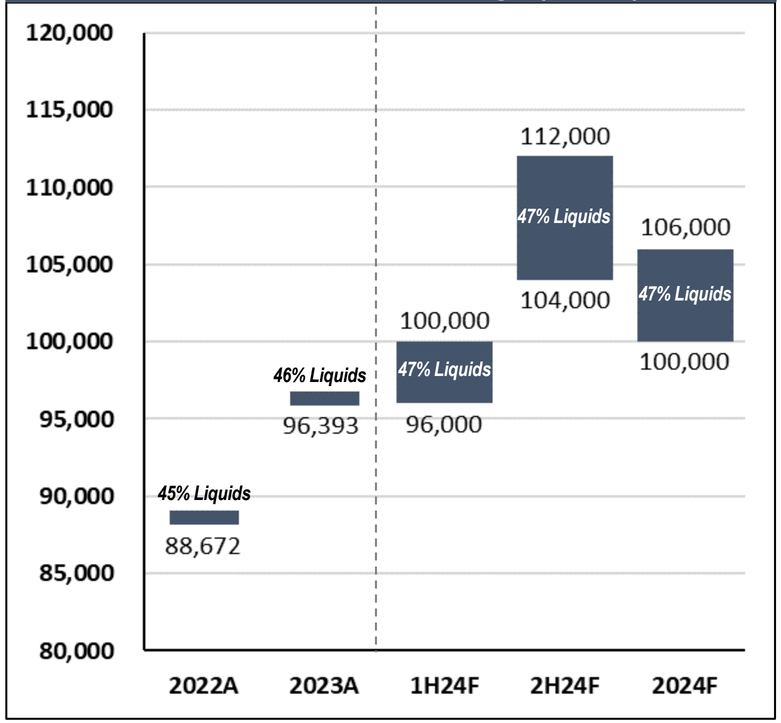


2024F production is based on midpoint of guidance

Capital Expenditure Outlook ($MM)



Production Outlook Range (Boe/d)



(1) Consists of class A common shares ("Common Shares") held by directors, officers and other insiders. (2) Gross reserves based upon an evaluation prepared by McDaniel & Associates Consultants Ltd. ("McDaniel") dated March 5, 2024 and effective December 31, 2023 (the "McDaniel Report"). "NPV10" refers to the before tax net present value of future net revenue of the applicable reserves, discounted at 10 percent, as estimated in the McDaniel Report. Such value does not represent fair market value. See Advisories Appendix – Reserves Data. (3) 144.8MM Common Shares at $31.36/share. (4) Net debt is a capital management measure used by Paramount. See Advisories Appendix – Specified Financial Measures (5) Annualized yield is obtained by dividing 12 months of the stated monthly dividend by a Common Share price of $31.36. (6) See Advisories Appendix – Forward Looking Information for a breakdown of the pricing, cost, expenditure and other assumptions for annual 2024 on which the estimates are based. (7) FCF means free cash flow. Free cash flow is a capital management measure used by Paramount. See Advisories Appendix – Specified Financial Measures. See "Advisories – Pricing Sensitivity" for additional information respecting the potential impact of changes to assumed pricing on forecast 2024 free cash flow.(8) Based on current monthly dividend of $0.125 per share and current shares outstanding.

Delivering on Free Cash Flow Priorities

With an undrawn $1.0 billion credit facility at year end, Paramount is well positioned to deliver on its FCF priorities

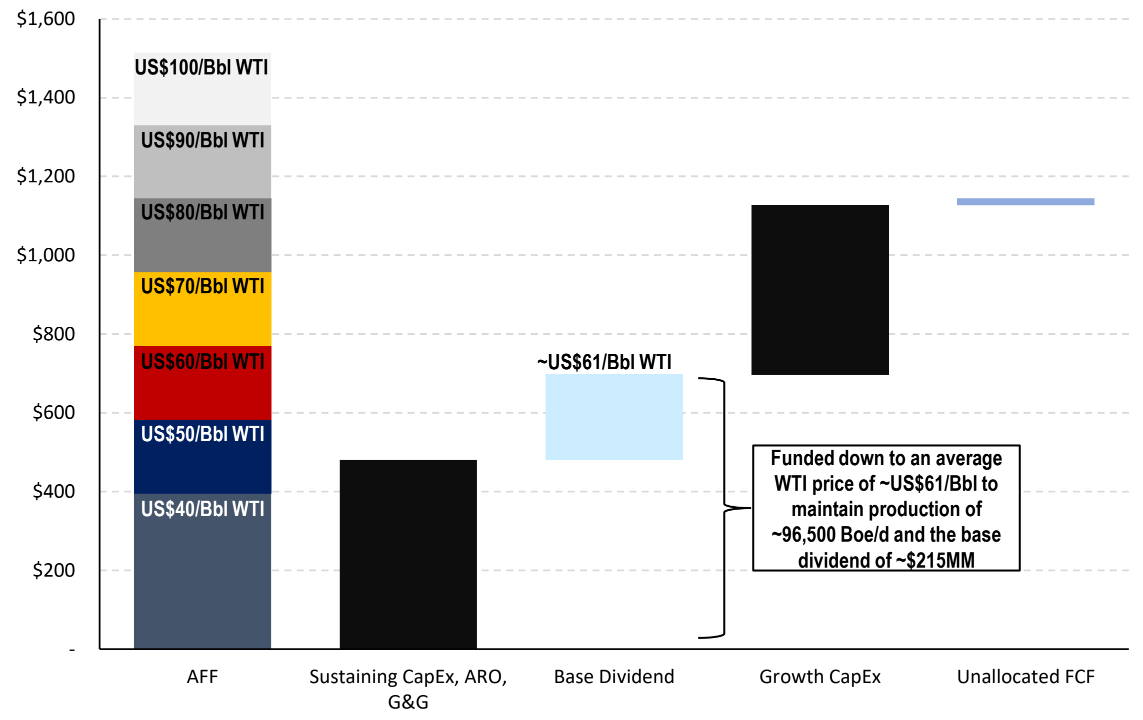
- Paramount's free cash flow priorities continue to be the maintenance of conservative leverage levels and the delivery of attractive shareholder returns through a combination of:
  - Dividends, including the flexibility for incremental returns through further special dividends
  - Investments in growth opportunities
  - Opportunistic share buybacks
- Cumulative $4.08/share (~$580MM) cash dividends from Jul. 2021 to Feb. 2024
  - Increased monthly base dividend four times since inception
  - Special cash dividend of $1.00/share in January 2023

Guidance (1)(2)

		2024F
Midpoint of Sales Volumes Guidance	*(MBoe/d)*	*103*
FCF Guidance	*($MM)*	~$235
Midpoint of CapEx Guidance	*($MM)*	~$860
ARO Guidance	*($MM)*	~$40
Geological & Geophysical Expense ("G&G")	*($MM)*	~$10
Illustrative Adjusted Funds Flow ("AFF")	*($MM)*	**~$1,145**

- Paramount's midpoint 2024 sustaining and maintenance capital program, abandonment and reclamation expenditures and regular monthly dividend would remain fully funded down to an average WTI price in 2024 of about US$61/Bbl (3)

Illustrative 2024 AFF Estimates ($MM) (1)(2)



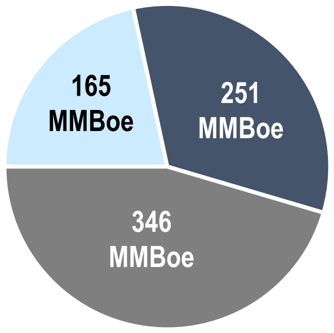
(1) Free cash flow and adjusted funds flow are capital management measures used by Paramount. See Advisories Appendix – Specified Financial Measures. **(2)** See Advisories Appendix – Forward Looking Information for a breakdown of the pricing, cost, expenditure and other assumptions on which the estimates are based. See "Advisories – Pricing Sensitivity" for additional information respecting the potential impact of changes to assumed pricing on forecast 2024 free cash flow. **(3)** Assuming no changes to the other forecast assumptions for 2024.

Reserves

Strong reserves replacement ratios, three-year average F&D and recycle ratios

2023 Reserves (1)

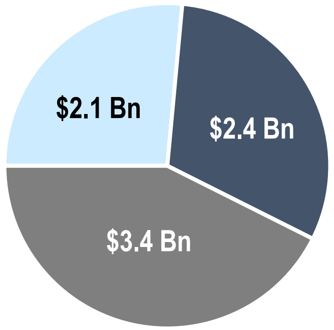
Volumes (MMBoe)



PDP	165 MMBoe
TP	415 MMBoe
P+P	761 MMBoe

PDP
PUD
Probable

Value ($Bn NPV_{10})



PDP	$2.1 Bn	($14.57/sh.)
TP	$4.5 Bn	($31.60/sh.)
P+P	$7.9 Bn	($55.04/sh.)

PDP
PUD
Probable

	2023 (2)				Three-Year Average (2)			
	F&D ($/Boe)		Recycle Ratio (x)		F&D ($/Boe)		Recycle Ratio (x)	
	Total	Grande Prairie	Total	Grande Prairie	Total	Grande Prairie	Total	Grande Prairie
PDP	$16.58	$10.08	1.6x	3.2x	$10.89	$8.93	3.0x	4.2x
TP	$16.96	$18.18	1.6x	1.7x	$12.39	$10.17	2.6x	3.7x
P+P	$12.52	$14.65	2.2x	2.2x	$10.57	$9.71	3.1x	3.9x

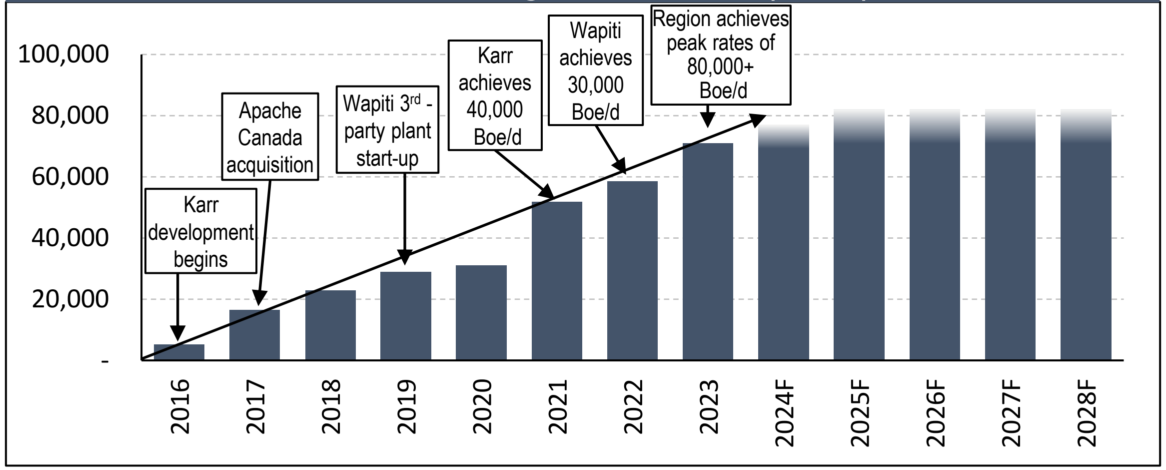
- In the Grande Prairie Region, where the majority of 2023 development activity occurred, PDP, TP and P+P reserves volumes were 14% higher, unchanged from 2022 and 9% higher, respectively
- The Company's reserves replacement ratios in 2023 were 1.4x for PDP reserves, 1.2x for TP reserves and 2.8x for P+P reserves (3)
- Paramount realized cash proceeds of $377MM in 2023 from property dispositions; these resulted in reductions to PDP, TP and P+P of 8 MMBoe, 36 MMBoe and 60 MMBoe, respectively

(1) Gross reserves evaluated by McDaniel as of December 31, 2023. "NPV10" refers to the before tax net present value of future net revenue of the applicable reserves, discounted at 10 percent as estimated by McDaniel. Net present values of future net revenue do not represent fair market value. "PDP" means proved developed producing. "TP" means total proved. "P+P" means total proved plus probable. "PUD" means proved undeveloped. See Advisories Appendix – Reserves Data. Per share amounts are calculated based on the number of Common Shares outstanding on December 31, 2023. **(2)** F&D costs and recycle ratio are non-GAAP ratios. Refer to "Specified Financial Measures" and "Oil and Gas Measures and Definitions" in the Advisories Appendix for more information on these measures and the related non-GAAP financial measure of F&D Capital. **(3)** See "Oil and Gas Measures and Definitions" in the Advisories Appendix of this document for a description of the calculation and use of reserves replacement ratio.

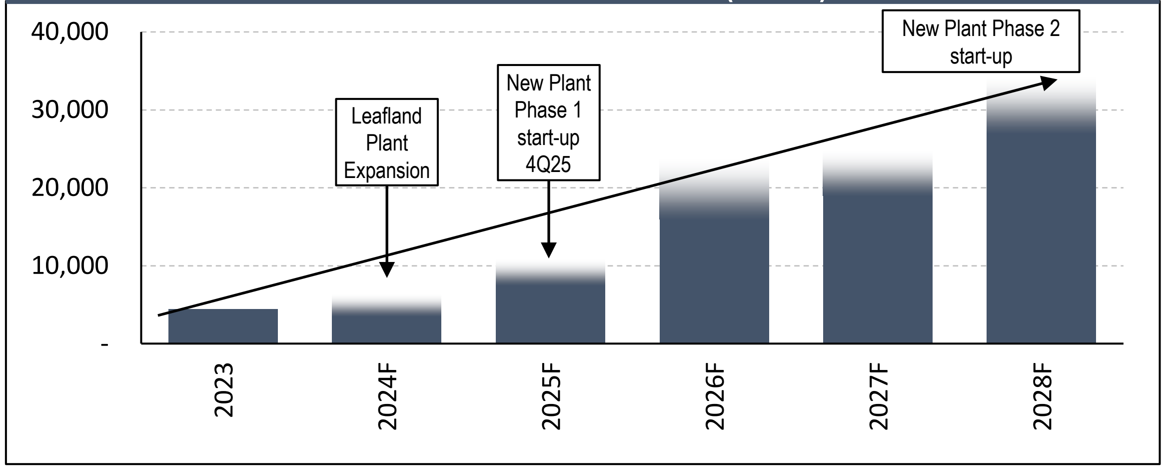
Building Sustainable Free Cash Flow for the Long-Term

A history of profitable asset development and production growth that drives material free cash flow generation

Grande Prairie Region Production (Boe/d) (1)



Willesden Green Production (Boe/d) (1)



- Paramount has a proven track record of assembling material positions in key resource plays and solving for plateau production levels that can be sustained for 15+ years
  - **Grande Prairie Region:** Began meaningful Karr drilling program in 2016 and added Wapiti through the 2017 acquisition of Apache Canada. Methodically grew production from near zero to peak rates over 80,000 Boe/d
  - **Willesden Green Duvernay:** Land position acquired over multiple years at a low-cost with current plans to grow production from over 4,000 Boe/d in 2023 to targeted full-field development plateau of over 50,000 Boe/d

Highlights of 5-Year Outlook (1)	
2028 Annual Average Sales Volumes	140,000 to 155,000 Boe/d
Midpoint Annual Capital Expenditures	$850 million to $1.0 billion
Midpoint Cumulative After-Tax Free Cash Flow (1)	**~$2.8 Bn (~$19.40/sh.)** (2)

- No cash tax in five-year outlook until 2027 (3)

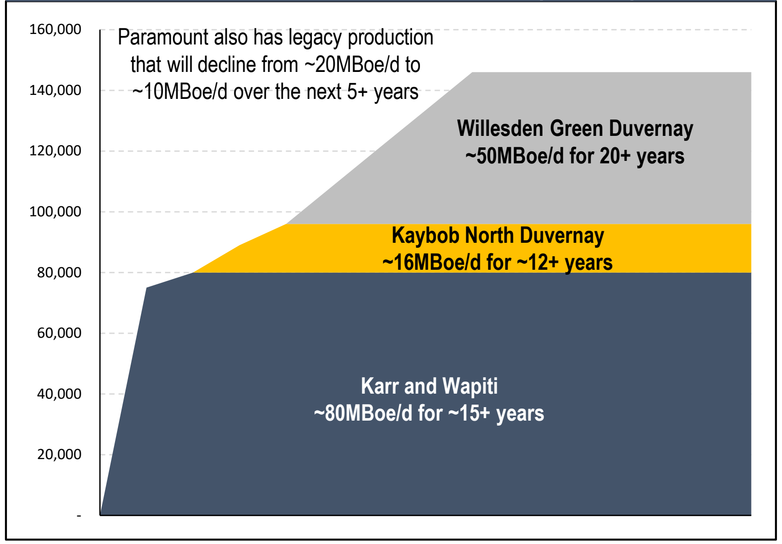
(1) The five-year outlook is based on preliminary planning and market conditions as of November 1, 2023 and is subject to change. The five-year outlook was prepared effective November 1, 2023 and has not been updated for events or information subsequent to that date. The stated anticipated cumulative free cash flow is based on the following assumptions: (i) the stated midpoint annual estimated capital expenditures; (ii) a compound annual production growth rate of 8% to 10% between 2023 and 2028; (iii) approximately $40 million in 2024 and thereafter approximately $45 million in average annual abandonment and reclamation costs, (iv) approximately $7 million in annual geological and geophysical expenses, (v) 2024 realized pricing of $56.40/Boe (US$80.00/Bbl WTI, US$3.50/MMBtu NYMEX, $2.84/GJ AECO) and thereafter commodity prices of US$75.00/Bbl WTI, US$4.00/MMBtu NYMEX and $3.55/GJ AECO, (vi) a 2024 $US/$CAD exchange rate of $0.735 and thereafter a $US/$CAD exchange rate of $0.740 and (vii) internal management estimates of future royalties, operating costs, transportation and NGLs processing costs and, beginning in 2027, cash taxes. **(2)** Based on 144.3MM outstanding Common Shares as at October 31, 2023. **(3)** See the Advisories Appendix – Forward-Looking Information for a description of certain of the key underlying assumptions.

Prudent Development of Inventory-Rich Opportunity Set

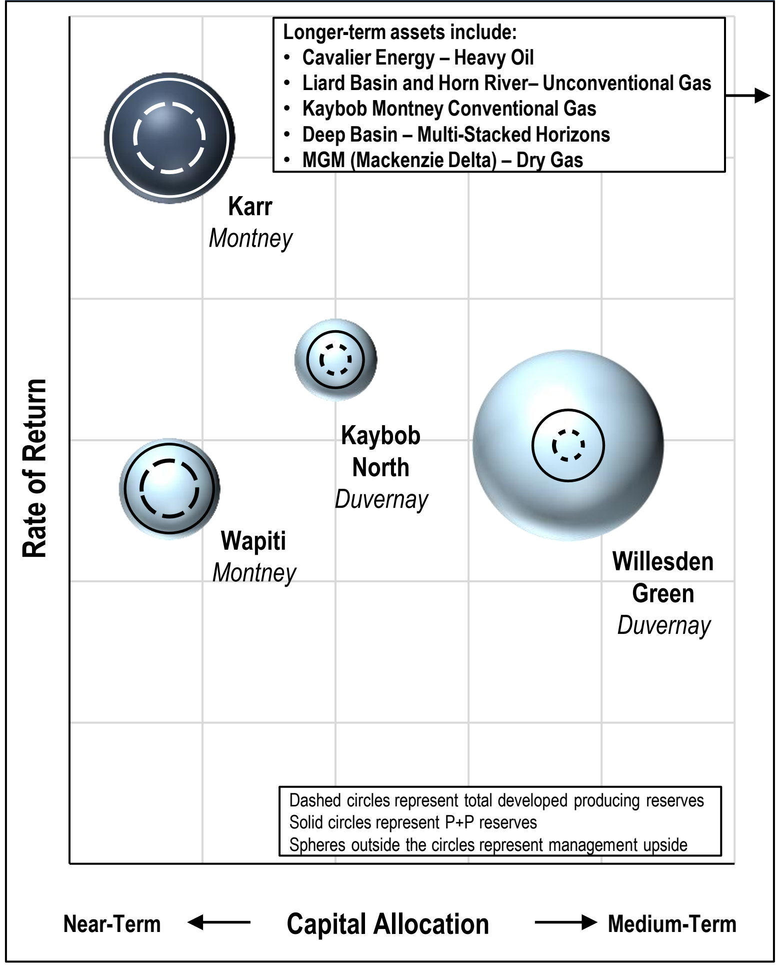
Paramount continues to allocate capital to its highest risk-adjusted return opportunities while maintaining balance sheet strength

- Significant inventory of opportunities across Paramount's land base at various stages in the development lifecycle
- Measured and focused approach to development
  - Targeting asset-level plateau production that can be sustained for 12 to 20+ years based on management estimates of full field development location count

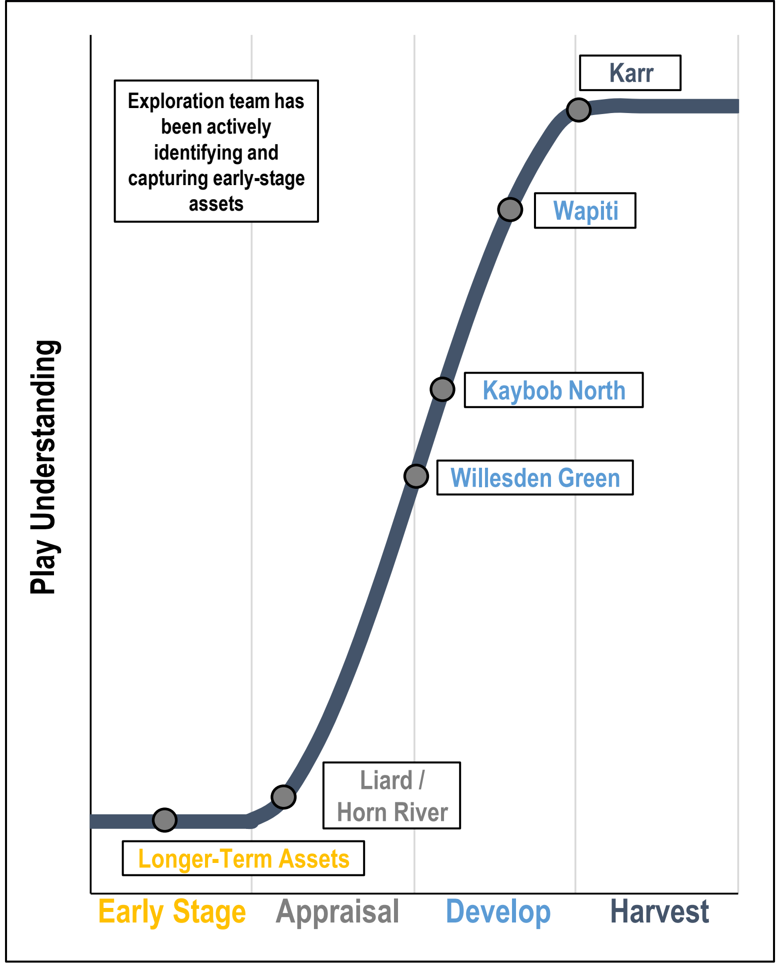
Potential Plateau Production (Boe/d) (1)



Significant Asset Optionality & Value (2)



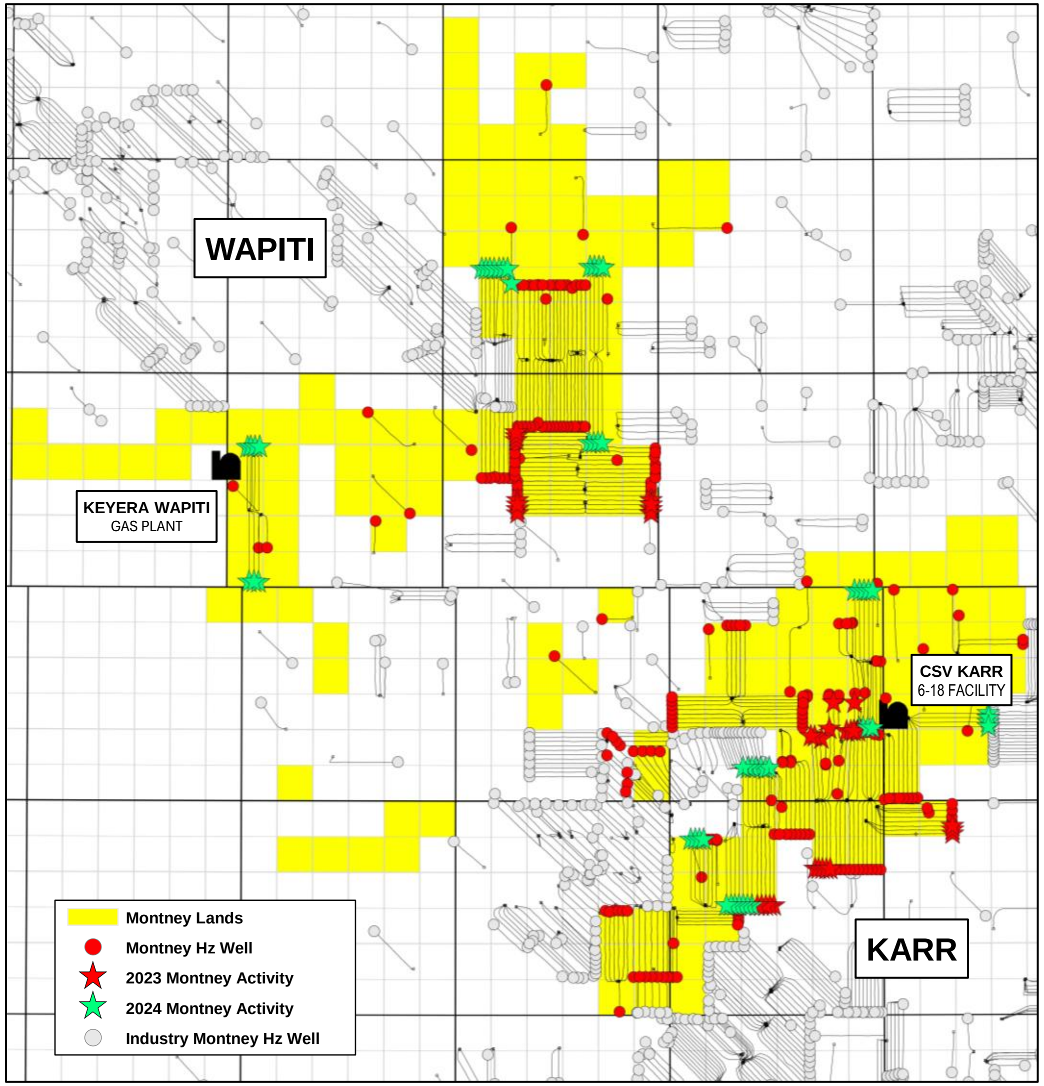
Stage of Development



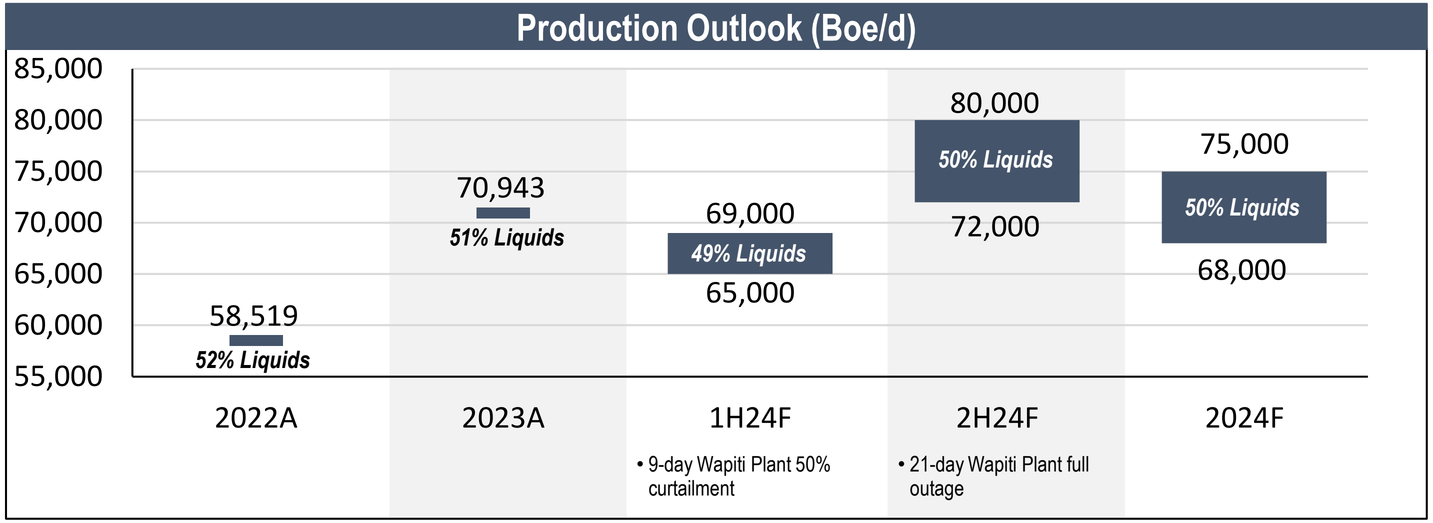
(1) Based on management estimates of play data and undeveloped drilling locations as described on pages 8, 9, 11, 13 and 14. See Advisories Appendix – Play Data and Undeveloped Locations. (2) Paramount's expectation of rate of return (as of March 5,2024) vs. the relative before tax net present value of future net revenue, discounted at 10 percent, of: (i) proved plus probable developed producing reserves as estimated by McDaniel in the McDaniel Report (dashed lines), (ii) proved plus probable reserves as estimated by McDaniel in the McDaniel Report (solid lines), and (iii) management undeveloped locations not assigned reserves, calculated, for illustrative purposes only, by assigning such locations a value equivalent to the average value by property assigned to undeveloped locations in the McDaniel Report (spheres outside the lines). The chart is provided solely to provide readers with information respecting management's views of the relative rates of return and potential values of its major properties. The illustrative value of management undeveloped locations should not be relied on as an estimate or evaluation of reserves or resources associated with the Company's properties. See Advisories Appendix – Reserves Data, Play Data and Undeveloped Locations.

Grande Prairie Region

Development of Paramount's flagship asset in 2024 is set to include the western portion of the Wapiti field



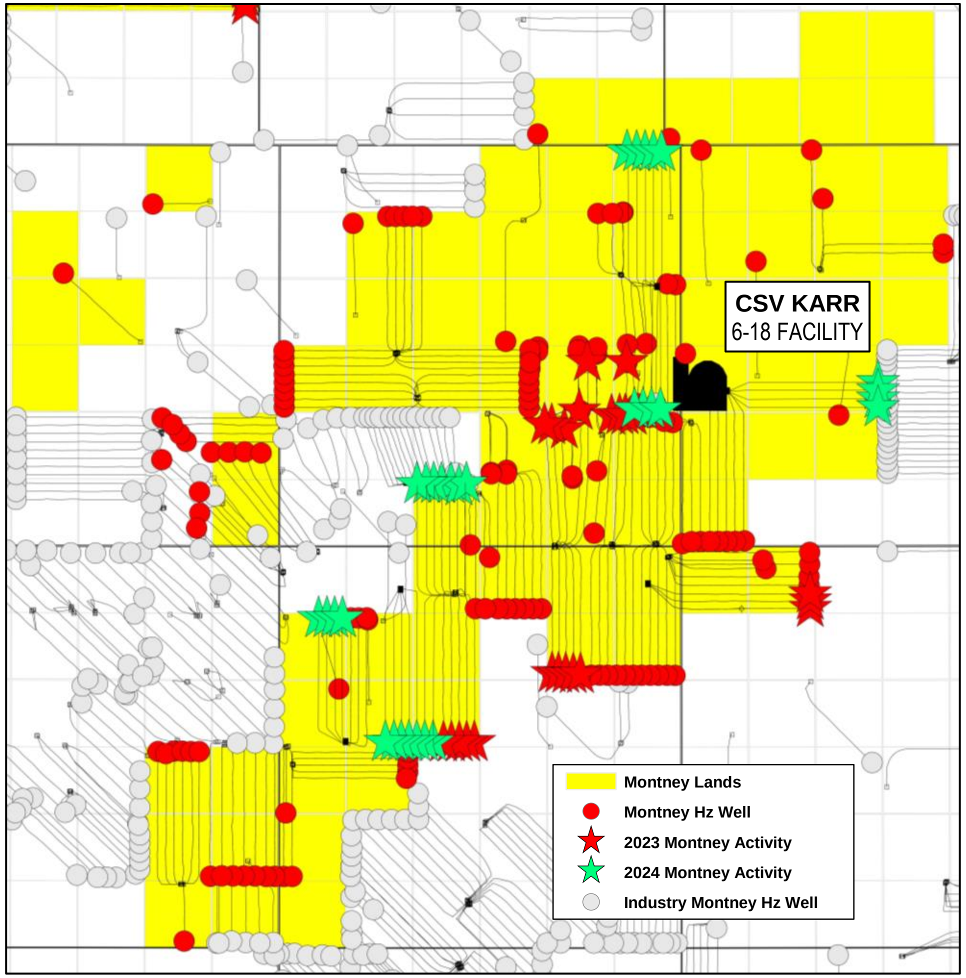
- Paramount holds approximately 109,000 net acres of Montney rights at Karr and Wapiti (1)
- Actively began development in 2016 with 185 wells brought onstream to December 31, 2023
- Eight pads were brought onstream in 2023 of which seven pads (consisting of 33 wells) have at least 30 days of production. (2) Gross 30-day peak production per well averaged 1,920 Boe/d (4.7 MMcf/d of shale gas and 1,133 Bbl/d of NGLs) with an average CGR of 240 Bbl/MMcf (3)
- Planned 2024 activities include 40 drills, 36 wells to be brought onstream and the commencement of an aggressive well optimization program aimed at increasing production from mature wells
- Plans include the commencement of development activities in the western portion of the Wapiti field where a new compressor node is being constructed
- Management high-graded undeveloped location count of 206 wells at Karr (middle Montney development only) and 235 wells at Wapiti (4)



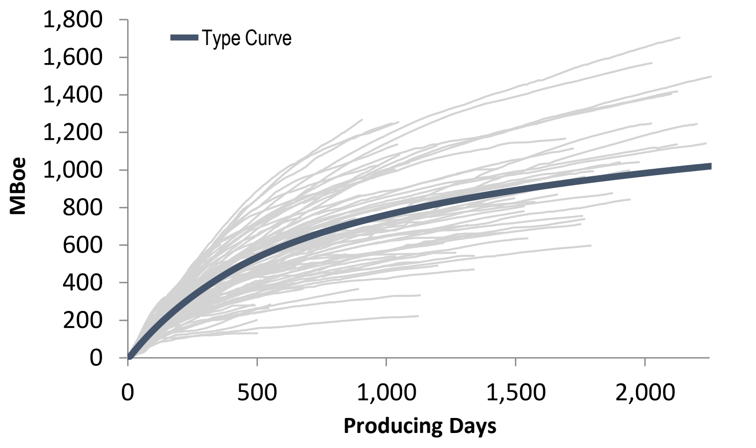
(1) As of December 31, 2023. **(2)** As of February 27, 2024. **(3)** 30-day peak production is the highest daily average production rate for each well, measured at the wellhead, over a rolling 30-day period, excluding days when the well did not produce. Weighted average natural gas sales volumes were approximately 10 percent lower and weighted average NGLs sales volumes were approximately 6 percent lower due to shrinkage. The production rates shown are 30-day peak rates over a short period of time and, therefore, are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. See "Oil and Gas Measures and Definitions" in the Advisories Appendix. **(4)** See Advisories Appendix – Undeveloped Locations, including for a description of undeveloped location assigned reserves in the McDaniel Report as at December 31, 2023.

Karr Activity and Production Performance

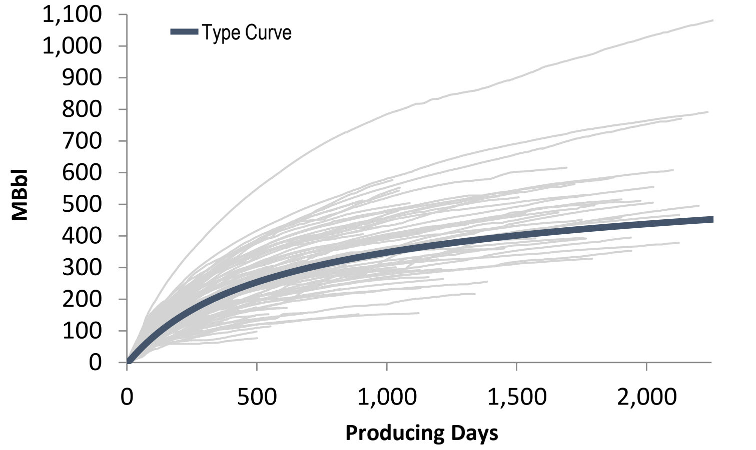
Paramount's Montney wells at Karr continue to perform strongly



Cumulative Boe (1)



Cumulative NGLs (1)



Play Data – 3,000m Avg. Lateral Length (2)

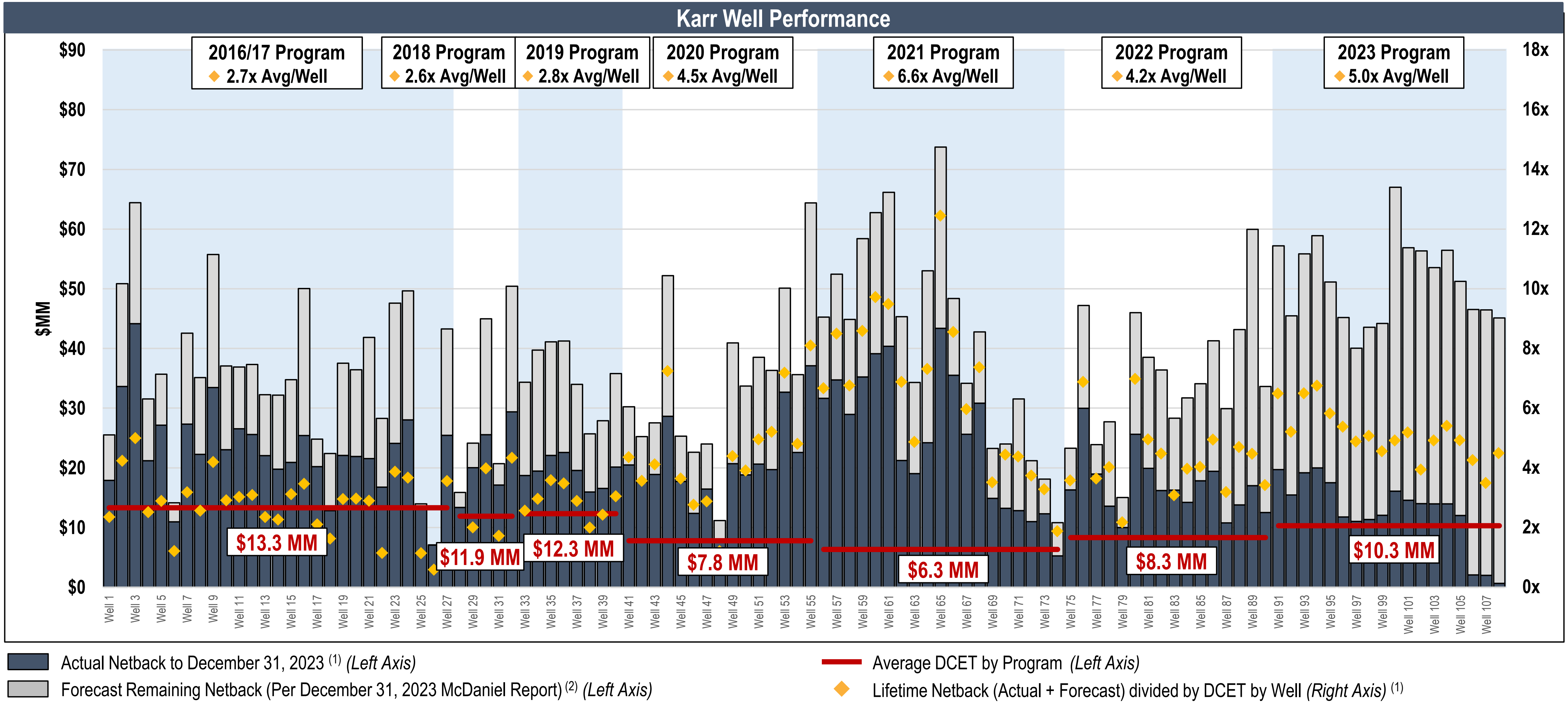
IP 365 *(Boe/d)*	1,200
IP 365 CGR *(Bbl/MMcf)*	181
Sales Volume *(MBoe)*	1,487
Average CGR *(Bbl/MMcf)*	134
Sales Gas *(Bcf)*	4.7
Sales Condensate *(MBbl)*	591
DCET *($MM)*	$9.1

- Highly productive, liquids-rich wells drive attractive half-cycle economics
- Estimated per well sales volumes of ~1.5 MMBoe
  - Implied capital efficiency of ~$7,600/Boe/d (3)
- Grande Prairie Region PDP F&D costs were $10.08/Boe (3.2x recycle ratio) in 2023 (3)
- Grande Prairie Region three-year average PDP F&D costs were $8.93/Boe (4.2x recycle ratio) (3)

(1) Production measured at the wellhead. Natural gas sales volumes were lower by approximately 10 percent and liquids sales volumes were lower by approximately 7 percent due to shrinkage. **(2)** Per well data based on management estimates and price deck. See Advisories Appendix – Play Data. **(3)** Implied capital efficiency is a supplementary financial measure. F&D costs and recycle ratio are non-GAAP ratios. Refer to "Specified Financial Measures", "Oil and Gas Measures and Definitions" and "Play Data" in the Advisories Appendix for more information on these measures.

Karr Performance

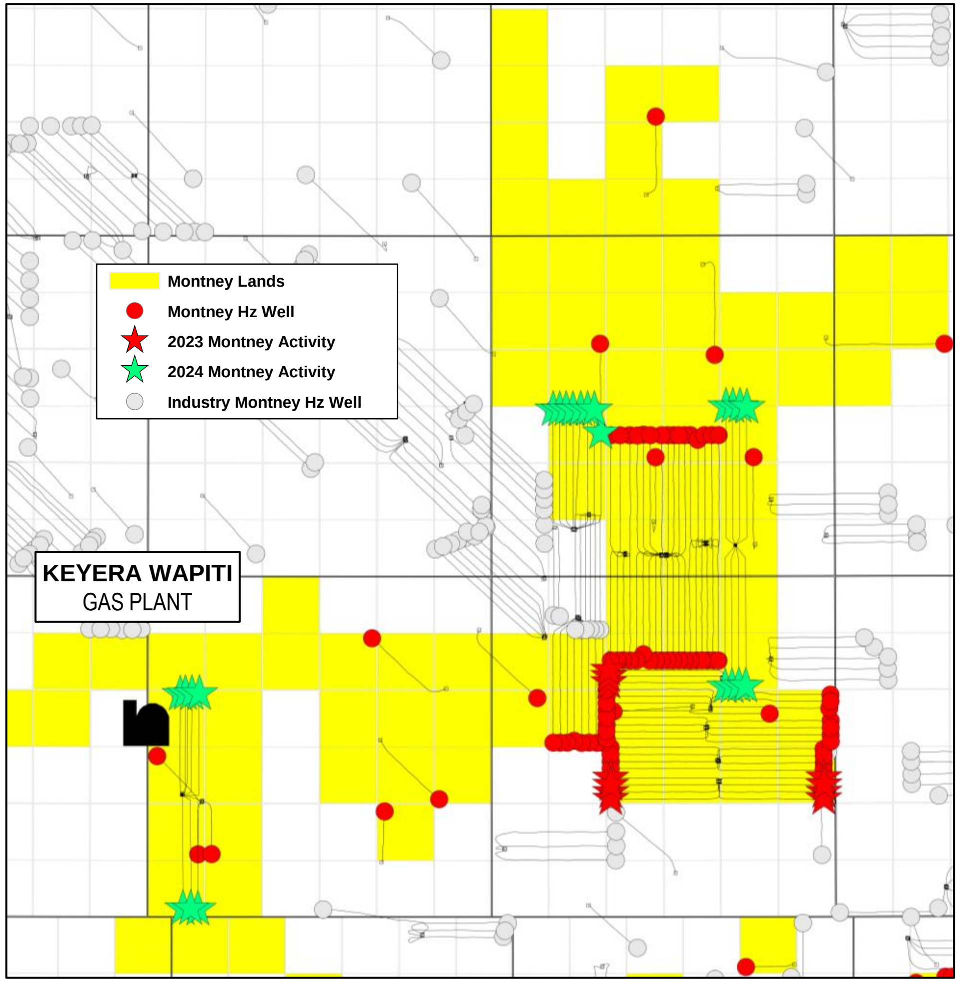
Wells exhibit strong returns and quick payouts



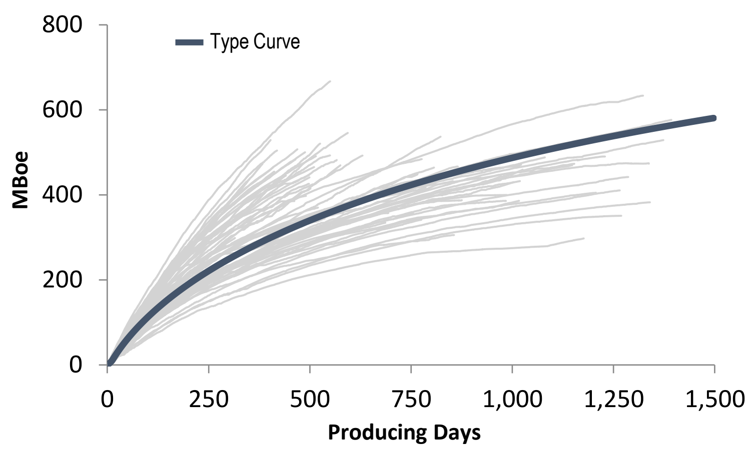
(1) Netback is a non-GAAP financial measure. Lifetime Netback divided by DCET by Well is a non-GAAP ratio. See Advisories Appendix – Specified Financial Measures. **(2)** See Advisories Appendix – Reserves Data. Amounts represent undiscounted forecast proved plus probable netback over the remaining life of each well as included in the McDaniel Report.

Wapiti Activity and Production Performance

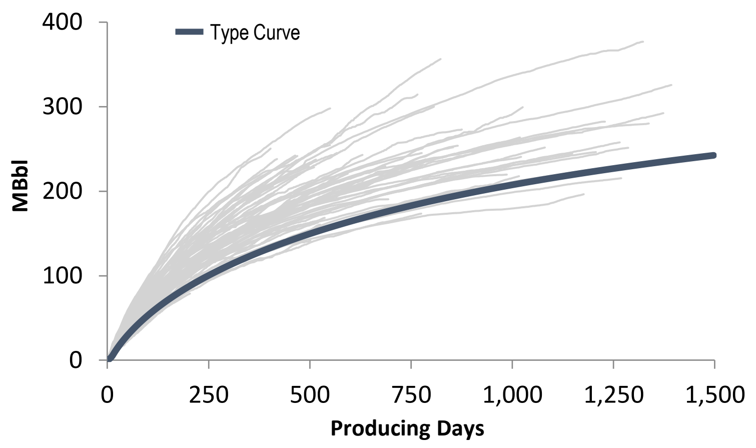
Paramount's 2024 plans include the commencement of development activities in the western portion of the Wapiti land base



Cumulative Boe [1]



Cumulative NGLs [1]



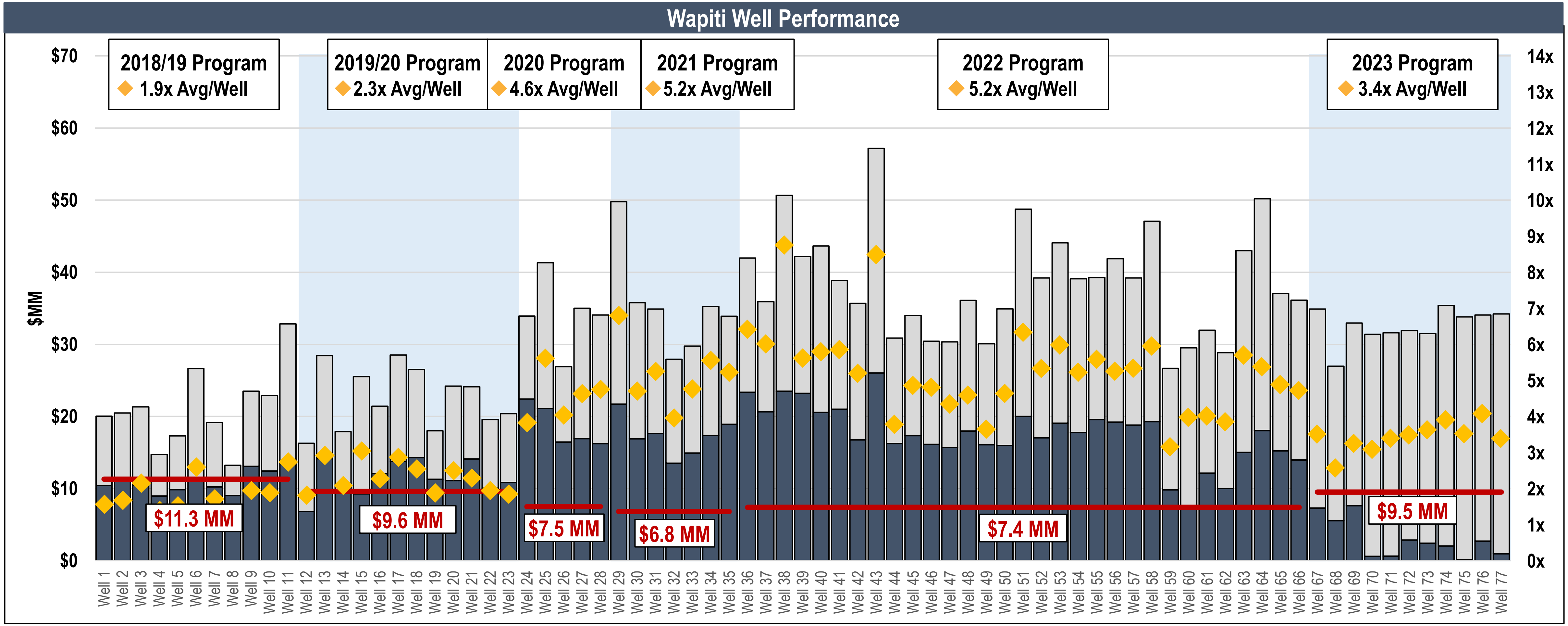
Play Data – 3,000m Avg. Lateral Length [2]	
IP 365 *(Boe/d)*	778
IP 365 CGR *(Bbl/MMcf)*	213
Sales Volume *(MBoe)*	1,043
Average CGR *(Bbl/MMcf)*	149
Sales Gas *(Bcf)*	3.6
Sales Condensate *(MBbl)*	393
DCET *($MM)*	$9.4

- Implied capital efficiency of ~$12,100/Boe/d [3]
- Grande Prairie Region PDP F&D costs were $10.08/Boe (3.2x recycle ratio) in 2023 [3]
- Grande Prairie Region three-year average PDP F&D costs were $8.93/Boe (4.2x recycle ratio) [3]

(1) Production measured at the wellhead. Natural gas sales volumes were lower by approximately 9 percent and liquids sales volumes were lower by approximately 2 percent due to shrinkage. **(2)** Per well data based on management estimates and price deck. See Advisories Appendix – Play Data. **(3)** Implied capital efficiency is a supplementary financial measure. Netback is a non-GAAP financial measure. F&D costs and recycle ratio are non-GAAP ratios. Refer to "Specified Financial Measures", "Oil and Gas Measures and Definitions" and "Play Data" in the Advisories Appendix for more information on these measures.

Wapiti Performance

Wapiti wells are generating strong returns on invested capital



Actual Netback to December 31, 2023 (1) *(Left Axis)*

Forecast Remaining Netback (Per December 31, 2023 McDaniel Report) (2) *(Left Axis)*

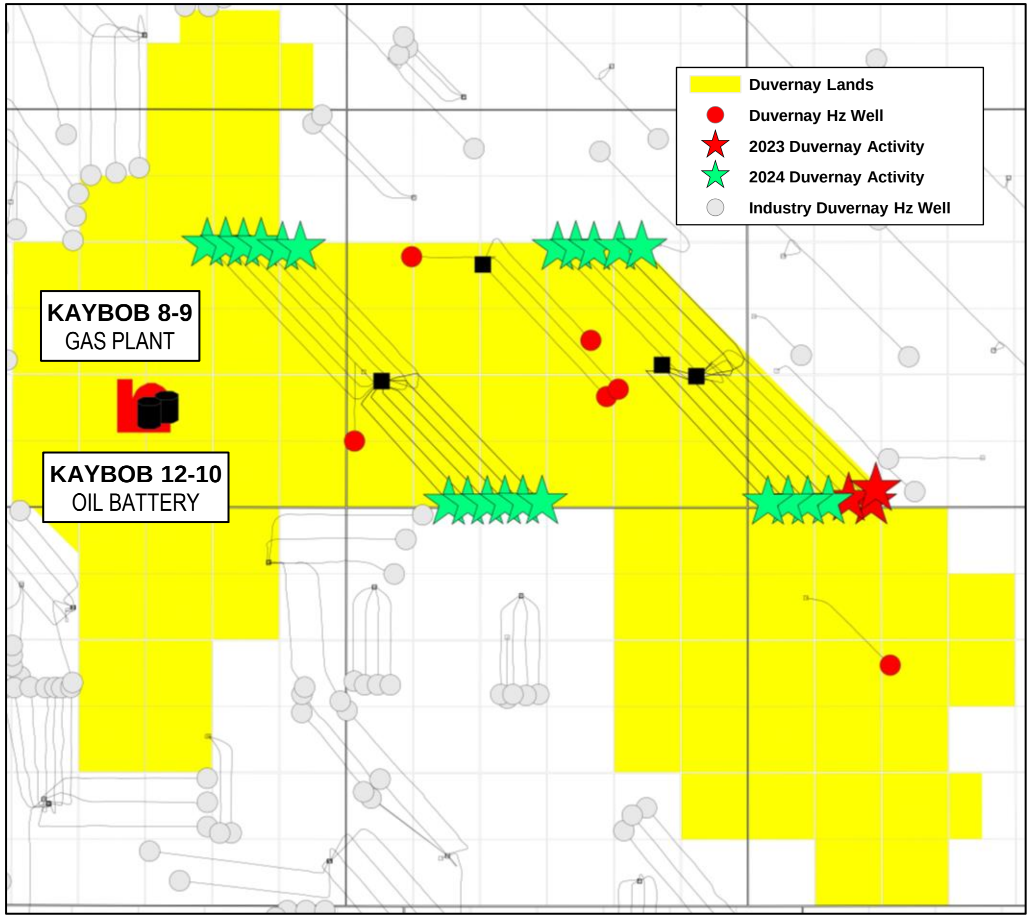
Average DCET by Program *(Left Axis)*

Lifetime Netback (Actual + Forecast) divided by DCET by Well *(Right Axis)* (1)

(1) Netback is a non-GAAP financial measure. Lifetime Netback divided by DCET by Well is a non-GAAP ratio. See Advisories Appendix – Specified Financial Measures. **(2)** See Advisories Appendix – Reserves Data. Amounts represent undiscounted forecast proved plus probable netback over the remaining life of each well as included in the McDaniel Report.

Kaybob North Duvernay Overview

Recent results have confirmed Paramount's decision to commence the active development of its Kaybob North Duvernay asset



- Six Duvernay wells from the 2023 development program were recently brought onstream and have exhibited strong initial production rates
- Paramount plans to grow production from 2,000 Boe/d in 2023 to as high as 14,000 Boe/d within its five-year outlook
- Better than expected results from the Company's Duvernay wells have contributed to an increase in annual forecast sales volume in the Kaybob Region
- 2024 plans include drilling 14 Duvernay wells and bringing onstream 17 Duvernay wells
- Paramount has ownership in strategic facilities and infrastructure including the 8-9 Gas Plant and 12-10 Oil Battery
- The Company owns and operates a crude oil terminal capable of capturing incremental value in price differentials with capacity to handle future growth

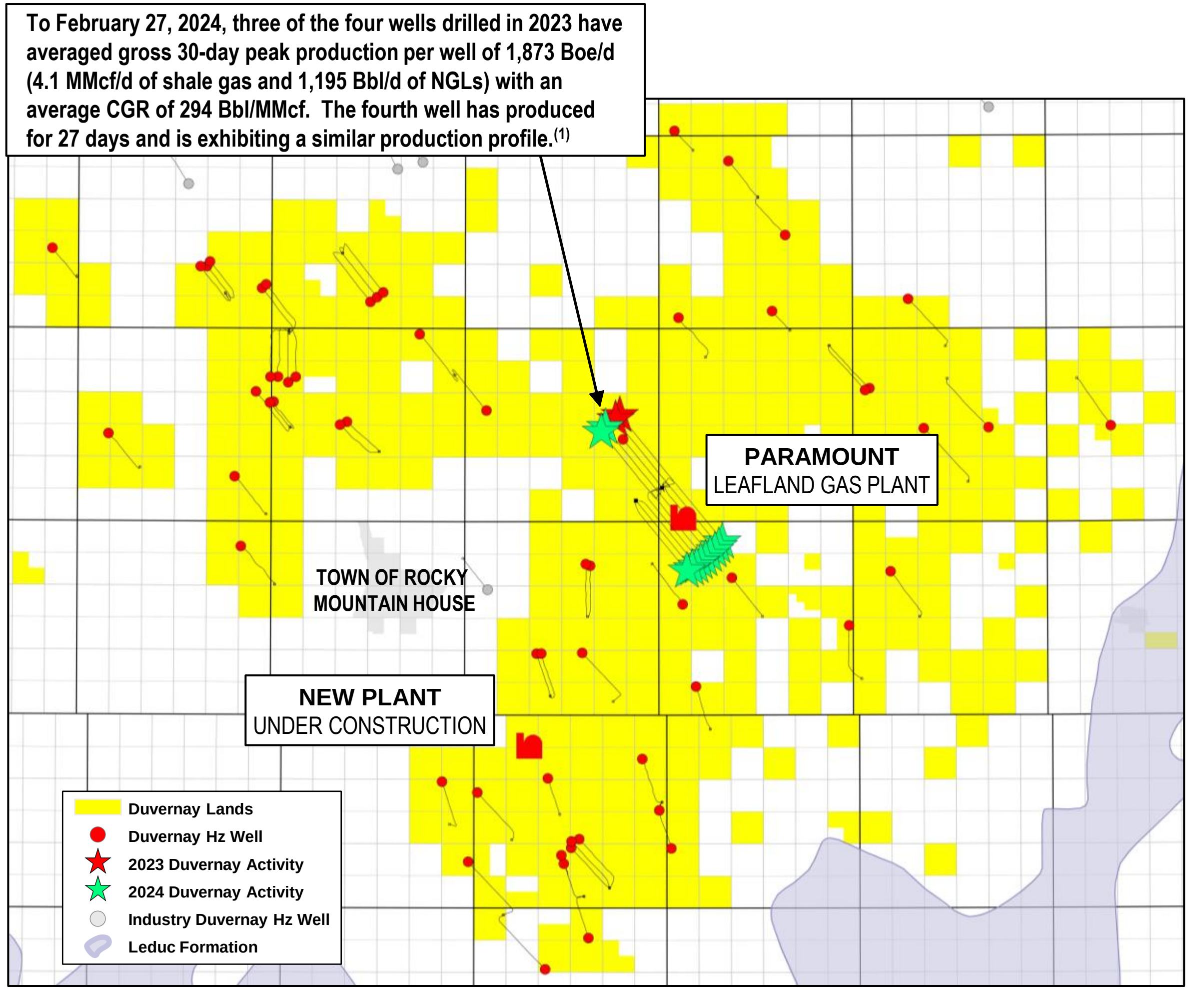
Play Data – 4,200m Avg. Lateral Length (1)	
IP 365 *(Boe/d)*	593
IP 365 CGR *(Bbl/MMcf)*	515
Sales Volume *(MBoe)*	881
Average CGR *(Bbl/MMcf)*	366
Sales Gas *(Bcf)*	1.6
Sales Condensate *(MBbl)*	575
DCET *($MM)*	$11.8

- Targeting plateau production of ~16,000 Boe/d
- 144 management high-graded locations based on ~320m inter-well spacing and lateral length of 4,200m (2)
- Implied capital efficiency of ~$19,900/Boe/d (3)

(1) Per well data based on management estimates and price deck. See Advisories Appendix – Play Data. **(2)** See Advisories Appendix – Undeveloped Locations, including for a description of undeveloped location assigned reserves in the McDaniel Report as at December 31, 2023. **(3)** Implied capital efficiency is a supplementary financial measure. Refer to "Specified Financial Measures" and "Play Data" in the Advisories Appendix for more information on this measure.

Willesden Green Duvernay Overview

Paramount is increasing development activities in its core Duvernay area



- The Leafland Plant liquids handling expansion was commissioned in December, under budget and approximately one month ahead of schedule
- Paramount's 2024 Willesden Green Duvernay plans include the drilling of 9 wells and the bringing onstream of 5 wells
- The Company has begun construction of its new processing facility
  - Ultimate capacity of 150 MMcf/d of raw gas and 30,000 Bbl/d of raw liquids handling
  - Expected to be built in three phases of 50 MMcf/d and 10,000 Bbl/d each
  - First phase expected to start-up in the fourth quarter of 2025
- Paramount controls approximately 249,000 net acres of contiguous land with over 700 internally estimated Duvernay drilling locations supporting targeted plateau production of over 50,000 Boe/d that can be sustained for over 20 years (2)

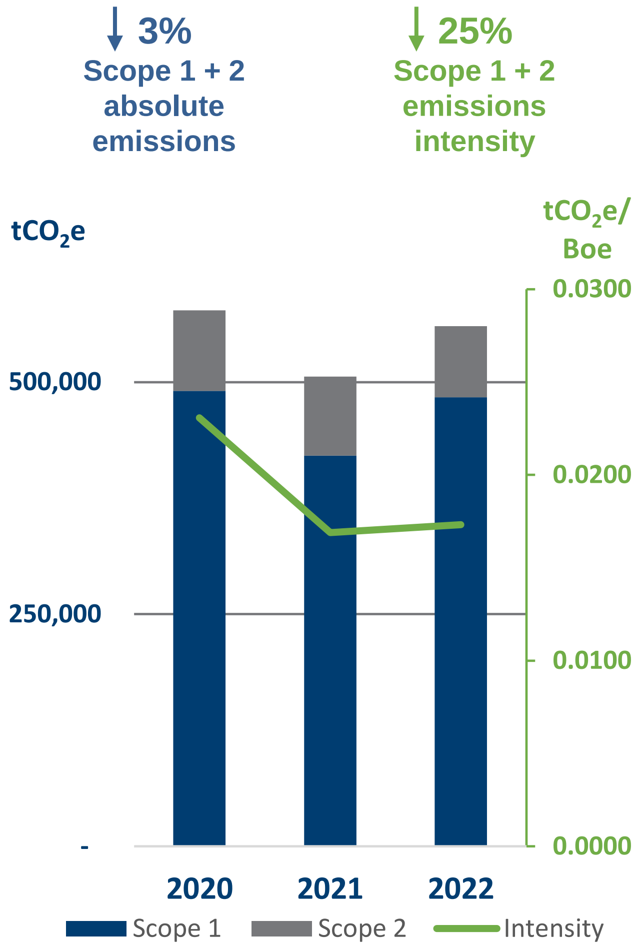
Play Data at 4,000m Avg. Lateral Length (3)	
IP 365 *(Boe/d)*	756
IP 365 CGR *(Bbl/MMcf)*	280
Sales Volume *(MBoe)*	1,221
Average CGR *(Bbl/MMcf)*	209
Sales Gas *(Bcf)*	2.7
Sales Condensate *(MBbl)*	575
DCET *($MM)*	$12.8

- Implied capital efficiency of ~$16,900/Boe/d (4)
  - The Company expects capital efficiencies to improve over time as it develops the play

(1) 30-day peak production is the highest daily average production rate for each well, measured at the wellhead, over a rolling 30-day period, excluding days when the well did not produce. Natural gas sales volumes were lower by approximately 8 percent and liquids sales volumes were lower by approximately 20 percent due to shrinkage. The production rates and volumes stated are over a short period of time and, therefore, are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. CGR means the condensate to gas ratio calculated by dividing wellhead NGLs volumes by wellhead natural gas volumes. See Advisories Appendix - Oil and Gas Measures and Definitions. **(2)** See Advisories Appendix – Undeveloped Locations, including for a description of undeveloped location assigned reserves in the McDaniel Report as at December 31, 2023. **(3)** Per well data based on management estimates and price deck. See Advisories Appendix – Play Data. **(4)** Implied capital efficiency is a supplementary financial measure. Refer to "Specified Financial Measures" and "Play Data" in the Advisories Appendix for more information on this measure.

Environmental, Social and Governance (“ESG”)

Paramount takes pride in responsibly delivering value to all stakeholders



Environmental

- Participated in the 2023 CDP Climate Change Survey and received a score of “B”
  - Global oil and gas sector averaged "B"
  - Global, all sectors averaged "C"
- Bi-fuel drilling rigs contributed to a ~62% reduction in per well diesel consumption since 2018
- Equipping new pads with instrument air where possible to minimize methane emissions
- Replaced 48 chemical pumps with solar, reducing an estimated 2,200 tCO_2e of emissions per year
- Proactively managing decommissioning and reclamation obligations; over 732 wells decommissioned and 1,040 hectares reclaimed since 2017

Social

- Fosters a safety conscious culture with written policies and procedures to protect the health and safety of those involved with and affected by our operations
- Supports a wide range of community and charitable organizations both financially and through volunteer hours
- Committed to creating and maintaining an environment that respects diverse traditions, heritages and experiences

Governance

- 75% independent board members; independent Lead Director
- All board committees fully independent
- Environmental, Health and Safety Committee of the Board of Directors and senior management provide oversight of ESG related matters
- 3 of 8 (37.5%) board members are women
- Minimum shareholding requirements for directors
- Officers and directors prohibited from hedging Paramount securities
- Loans to officers and directors prohibited
- Code of Ethics and Code of Business Conduct Policy
- Anonymous Whistleblower Policy and portal

Strategic and Long-Term Investments

Paramount holds strategic positions in a number of public and private entities

Summary of Investments & Other Assets

Investments in Public Companies (1)	~$420 million
Investments in Private Companies (2)	~$120 million
Drilling Rigs – Book Value (2)	~$80 million
Undeveloped Land	Not quantified
Total	**~$620 million +**

Other Long-Term Resources

Clearwater/Bluesky heavy oil

Horn River Basin unconventional natural gas

Liard Basin unconventional natural gas

Mackenzie Delta natural gas

Thermal oil

- Minimal ongoing holding costs, lease rental only
- Maintain flexibility to determine development timeline
- Prospective for future free cash flow through joint ventures, farm outs or dispositions

Fox Drilling

Wholly owned by Paramount

- Five triple-sized walking rigs
- One conventional triple-sized rig
- Used to drill the Company's Montney and Duvernay wells
- Bi-fuel capable, reducing costs and emissions compared to diesel

Cavalier Energy Inc.

Wholly owned by Paramount

- Cavalier Energy's lands are prospective for in-situ thermal oil recovery and cold flow heavy oil
- 1.30 million gross acres of land located primarily in the Athabasca and Peace River regions of Alberta
- 293,000 net acres with Clearwater and Bluesky potential

Sultran

Paramount holds a ~16% ownership

- Supply chain and logistics solutions for bulk commodities
- Wholly-owned BC terminal facilities (Pacific Coast Terminals Co. Ltd.)

Canadian Premium Sand Inc.

Paramount holds a ~18% ownership

- Planning to build the only ultra high-clarity patterned solar glass manufacturing facility in North America

Liard Basin

Besa River Shale Play

- Prospective feedstock for west coast LNG
- Paramount holds ~179,000 net acres

Horn River Basin

Muskwa Shale Play

- Prospective feedstock for west coast LNG
- Paramount holds ~19,000 net acres

Mackenzie Delta

- ~30,000 net acres

Central Mackenzie

- ~177,000 net acres

(1) Market value of public companies as at December 31, 2023 (includes ~37.3 million shares of NuVista Energy Ltd. @ $11.04/share). **(2)** Carrying value as at December 31, 2023. Investments in Private Companies include Sultran Ltd. and Westbrick Energy Ltd. For further details refer to Paramount's consolidated financial statements as at and for the year ended December 31, 2023.

Paramount Investment Attributes

Paramount offers a unique investment proposition

- 45+ year history of responsible energy development and environmental stewardship
- Extensive portfolio of liquids-rich resource plays in the Montney and Duvernay
- Proven track record of building large, contiguous land positions and developing them into material and sustainable free cash flow engines
- Risk adjusted returns-focused capital allocation strategy supported by rigorous full-cycle analysis
- Meaningful free cash flow outlook of ~$2.8 billion (1) (~$19.40 per basic share (2)) over the next five years
- No cash tax in five-year outlook until 2027 (3)
- Strong liquidity position with an undrawn $1.0 billion revolving credit facility at year end (May 2026 maturity)
- Stakeholder-aligned management and board with significant insider ownership
- Regular monthly dividend has been increased over six-fold to $0.125 per share through four increases
- Special cash dividend of $1.00/share paid in January 2023

(1) The five-year outlook is based on preliminary planning and current market conditions and is subject to change. The five-year outlook was prepared effective November 1, 2023 and has not been updated for events or information subsequent to that date. **(2)** Based on 144.2MM outstanding Common Shares as at December 31, 2023. **(3)** See the Advisories Appendix – Forward-Looking Information for a description of certain of the key underlying assumptions.

Appendix

Appendix

The following summarizes the performance of the wells in the Grande Prairie Region

	Activity Period	Well Count (#)	DCET Costs (1) ($MM)	Peak 30-Day (2) Total (Boe/d)	Peak 30-Day (2) Wellhead NGLs (Bbl/d)	Peak 30-Day (2) Wellhead Shale Gas (MMcf/d)	Peak 30-Day (2) CGR (4) (Bbl/MMcf)	Cumulative (3) Total (MBoe)	Cumulative (3) Wellhead NGLs (MBbl)	Cumulative (3) Wellhead Shale Gas (MMcf)	Cumulative (3) CGR (4) (Bbl/MMcf)	Days on Production
Karr (Avg. per well)												
	2023	18	$10.3	2,217	1,349	5.2	260	361	180	1,091	165	223
	2022	16	$8.3	1,602	864	4.4	195	430	189	1,445	131	516
	2021	19	$6.3	1,872	988	5.3	186	728	328	2,402	137	828
	2020	15	$7.8	1,548	907	3.8	236	676	324	2,118	153	1,132
	2019	8	$12.3	1,825	1,262	3.4	373	723	434	1,739	249	1,447
	2018	5	$11.9	1,760	1,051	4.3	247	836	437	2,397	182	1,455
	2016/2017	27	$13.3	1,969	1,171	4.8	245	977	478	2,994	160	1,819
Wapiti (Avg. per well)												
	2023	3	$10.1	1,188	730	2.7	267	172	97	455	212	205
	2022	31	$7.4	1,582	892	4.1	215	438	202	1,417	142	464
	2021	7	$6.8	1,292	794	3.0	266	396	229	1,005	227	753
	2020	5	$7.5	1,189	795	2.4	336	460	283	1,063	266	819
	2019/2020	12	$9.6	1,588	1,044	3.3	320	424	248	1,059	234	1,014
	2018/2019	11	$11.3	1,051	722	2.0	366	453	269	1,109	242	1,291

(1) DCET means all-in lease construction, drill, completion, equip and tie-in costs. **(2)** 30-day peak production is the highest daily average production rate for each well, measured at the wellhead, over a rolling 30-day period, excluding days when the well did not produce. Natural gas sales volumes were approximately 10 percent lower and NGLs sales volumes were approximately 7 percent lower due to shrinkage in Karr and natural gas sales volumes were approximately 9 percent lower and NGLs sales volumes were approximately 2 percent lower due to shrinkage in Wapiti. The production rates and volumes shown are 30-day peak rates over a short period of time and, therefore, are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. These wells were produced at restricted rates from time-to-time due to facility and gathering system constraints. See "Oil and Gas Measures and Definitions" in the Advisories Appendix. **(3)** Cumulative is the aggregate production measured at the wellhead to February 27, 2024. Natural gas sales volumes were approximately 10 percent lower and NGLs sales volumes were approximately 7 percent lower due to shrinkage in Karr and natural gas sales volumes were approximately 9 percent lower and NGLs sales volumes were approximately 2 percent lower due to shrinkage in Wapiti. These wells were produced at restricted rates from time-to-time due to facility and gathering system constraints. The production rates and volumes shown are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. **(4)** CGR means condensate to gas ratio calculated by dividing wellhead NGLs by wellhead natural gas volumes.

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Forward-Looking Information

Certain statements in this presentation constitute forward-looking information under applicable securities legislation. Forward-looking information typically contains statements with words such as "anticipate", "believe", "estimate", "will", "expect", "plan", "intend", "propose", or similar words suggesting future outcomes or an outlook.

Forward-looking information in this presentation includes, but is not limited to: (i) forecast sales volumes for 2024 and certain periods therein; (ii) planned capital expenditures in 2024 and the allocation thereof; (iii) planned abandonment and reclamation expenditures in 2024; (iv) forecast free cash flow in 2024; (v) the Company's free cash flow priorities; (vi) the potential payment of future dividends; (vii) anticipated geological and geophysical expenses; (viii) illustrative adjusted funds flow in 2024; (ix) planned future production at Grande Prairie, Kaybob North Duvernay and Willesden Green Duvernay; (x) the Company's five-year outlook for 2028 average annual sales volumes, capital expenditures and cumulative free cash flow; (xi) the statement that Paramount does not forecast cash tax in its five-year outlook until 2027; (xii) targeted potential plateau production rates and the years of production that may be supported by undeveloped locations at Karr and Wapiti, Kaybob North Duvernay and Willesden Green Duvernay; (xiii) anticipated legacy production declines; (xiv) potential rates of return or value for the Company's properties; (xv) planned exploration, development and production activities, including the expected timing of drilling, completing and bringing new wells on production and the expected timing of completion and capacity of planned facilities and infrastructure, including the new facility at Willesden Green; (xvi) expected Grande Prairie sales volumes in 2024; (xvii) the expected realization of capital cost efficiencies at Willesden Green Duvernay; (xviii) undeveloped drilling locations at various properties; (xix) play data, anticipated well performance and forecast netback for various properties; and (xx) general business strategies and objectives.

Statements relating to reserves are also deemed to be forward looking information, 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.

Such forward-looking information is based on a number of assumptions which may prove to be incorrect. Assumptions have been made with respect to the following matters, in addition to any other assumptions identified in this presentation or Paramount's continuous disclosure documents: (i) future commodity prices; (ii) the impact of international conflicts, including in Ukraine and the Middle East; (iii) royalty rates, taxes and capital, operating, general & administrative and other costs; (iv) foreign currency exchange rates, interest rates and the rate and impacts of inflation; (v) general business, economic and market conditions; (vi) the performance of wells and facilities; (vii) the availability to Paramount of the funds required for exploration, development and other operations and the meeting of commitments and financial obligations; (viii) the ability of Paramount to obtain equipment, materials, services and personnel in a timely manner and at expected and acceptable costs to carry out its activities; (ix) the ability of Paramount to secure adequate processing, transportation, fractionation, disposal and storage capacity on acceptable terms and the capacity and reliability of facilities; (x) the ability of Paramount to obtain the volumes of water required for completion activities; (xi) the ability of Paramount to market its production successfully; (xii) the ability of Paramount and its industry partners to obtain drilling success (including in respect of anticipated sales volumes, reserves additions, product yields and product recoveries) and operational improvements, efficiencies and results consistent with expectations; (xiii) the timely receipt of required governmental and regulatory approvals; (xiv) the application of regulatory requirements respecting abandonment and reclamation; and (xv) anticipated timelines and budgets being met in respect of: (a) drilling programs and other operations, including well completions and tie-ins, (b) the construction, commissioning and start-up of new and expanded third-party and Company facilities, including the new natural gas processing facility at Willesden Green, and (c) facility turnarounds and maintenance.

In addition to the above, forecast 2024 free cash flow is based on (i) the midpoint of stated capital expenditures and sales volumes, (ii) $40 million in abandonment and reclamation costs, (iii) $10 million in geological and geophysical expenses, (iv) realized pricing of $56.90/Boe (US$80/Bbl WTI, US$3.50/MMBtu NYMEX, $2.84/GJ AECO), (v) a $US/$CAD exchange rate of $0.735, (vi) royalties of $8.35/Boe, (vii) operating costs of $12.90/Boe and (vii) transportation and NGLs processing costs of $3.85/Boe.

With respect to the statement that there is no cash tax in the five-year outlook until 2027, taxable income varies depending on total income and expenses and estimates as to the timing of paying cash tax are sensitive to assumptions regarding commodity prices, production, cash from operating activities, capital spending levels, the allocation of free cash flow and acquisition and disposition transactions. Changes in these factors could result in the Company paying income taxes earlier or later than expected.

Although Paramount believes that the expectations reflected in such forward-looking information are reasonable based on the information available at the time of the preparation of this presentation, undue reliance should not be placed on the forward-looking information as Paramount can give no assurance that such expectations will prove to be correct. Forward-looking information is based on current expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by Paramount and described in the forward-looking information. These risks and uncertainties include and/or relate (but are not limited) to: (i) the risks set out in the Company's Management's & Discussion and Analysis for the year ended December 31, 2023; (ii) fluctuations in commodity prices; (iii) changes in capital spending plans and planned exploration and development activities; (iv) the potential for changes to the Company's five-year outlook for capital expenditures, cumulative free cash flow and sales volumes; (v) changes in foreign currency exchange rates, interest rates and the rate of inflation; (vi) the uncertainty of estimates and projections relating to future production, product yields (including condensate to natural gas ratios), revenue, free cash flow, reserves additions, product recoveries, royalty rates, taxes and costs and expenses; (vii) the ability to secure adequate processing, transportation, fractionation, disposal and storage capacity on acceptable terms; (viii) operational risks in exploring for, developing, producing and transporting natural gas and liquids, including the risk of spills, leaks or blowouts; (ix) the ability to obtain equipment, materials, services and personnel in a timely manner and at expected and acceptable costs, including the potential effects of inflation and supply chain disruptions; (x) potential disruptions, delays or unexpected technical or other difficulties in designing, developing, expanding or operating new, expanded or existing facilities, including third-party facilities and the new natural gas processing facility at Willesden Green; (xi) processing, transportation, fractionation, disposal and storage outages, disruptions and constraints; (xii) potential limitations on access to the volumes of water required for completion activities due to drought, conditions of low river flow, government restrictions or other factors; (xiii) risks and uncertainties involving the geology of oil and gas deposits; (xiv) the uncertainty of reserves estimates; (xv) general business, economic and market conditions; (xvi) the ability to generate sufficient cash from operating activities to fund, or to otherwise finance, planned exploration, development and operational activities and meet current and future commitments and obligations (including processing, transportation, fractionation and similar commitments and obligations); (xvii) changes in, or in the interpretation of, laws, regulations or policies (including environmental laws); (xviii) the ability to obtain required governmental or regulatory approvals in a timely manner, and to obtain and maintain leases and licenses, including those required for the new natural gas processing facility at Willesden Green; (xix) the effects of weather and other factors including wildlife and environmental restrictions which affect field operations and access; (xx) uncertainties as to the timing and cost of future abandonment and reclamation obligations and potential liabilities for environmental damage and contamination; (xxi) uncertainties regarding Indigenous claims and in maintaining relationships with local populations and other stakeholders; (xxii) the outcome of existing and potential lawsuits, regulatory actions, audits and assessments; and (xxiii) other risks and uncertainties described elsewhere in this document and in Paramount's other filings with Canadian securities authorities. The foregoing list of risks is not exhaustive. For more information relating to risks, see the section titled "Risk Factors" in Paramount's annual information form for the year ended December 31, 2023, which is available on SEDAR+ at www.sedarplus.ca or on the Company's website at www.paramountres.com.

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In addition, there are risks that may result in the Company changing, suspending or discontinuing its monthly dividend program, including changes to its free cash flow, operating results, capital requirements, financial position, market conditions or corporate strategy and the need to comply with requirements under debt agreements and applicable laws respecting the declaration and payment of dividends. There are no assurances as to the declaration and payment of any future dividends or the amount or timing of any such dividends

Certain forward-looking information in this presentation, including forecast free cash flow in 2024 and future periods, may also constitute a "financial outlook" within the meaning of applicable securities laws. A financial outlook involves statements about Paramount's prospective financial performance or position and is based on and subject to the assumptions and risk factors described above in respect of forward-looking information generally as well as any other specific assumptions and risk factors in relation to such financial outlook noted in this presentation. Such assumptions are based on management's assessment of the relevant information currently available and any financial outlook included in this presentation is provided for the purpose of helping readers understand Paramount's current expectations and plans for the future. Readers are cautioned that reliance on any financial outlook may not be appropriate for other purposes or in other circumstances and that the risk factors described above or other factors may cause actual results to differ materially from any financial outlook.

The forward-looking information and statements contained in this presentation are made effective as of March 5, 2024, except the information contained herein respecting Paramount's five-year outlook which is effective November 1, 2023. The internally estimated play data information for Karr, Wapiti, Kaybob North Duvernay and Willesden Green contained at pages 9, 11, 13 and 14 in this presentation has been prepared effective March 5, 2024. In each case, events or information subsequent to the applicable effective dates have not been incorporated. Except as required by applicable securities law, Paramount undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Specified Financial Measures

Non-GAAP Financial Measures

Netback and F&D capital are non-GAAP financial measures. These measures are not standardized measures under IFRS and might not be comparable to similar financial measures presented by other issuers. These measures should not be considered in isolation or construed as alternatives to their most directly comparable measure used in the Company's primary financial statements or other measures of financial performance calculated in accordance with IFRS.

Netback equals petroleum and natural gas sales (the most directly comparable measure disclosed in the Company's primary financial statements) plus sales of commodities purchased less royalties, operating expense, transportation and NGLs processing expenses and commodities purchased. Sales of commodities purchased and commodities purchased are treated as corporate items and not allocated to individual regions or properties. Netback is used by investors and management to compare the performance of the Company's producing assets between periods.

Total Company netbacks for the applicable periods are summarized below:

	Three Months ended December 31				Year Ended			
	2023		2022		**2023**		2022	
Netback	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)
Petroleum and natural gas sales	**470.5**	***50.46***	597.7	*66.72*	**1,798.5**	***51.12***	2,252.4	*69.60*
Royalties	**(68.9)**	***(7.39)***	(84.4)	*(9.43)*	**(254.3)**	***(7.23)***	(335.3)	*(10.36)*
Operating expense	**(126.4)**	***(13.56)***	(119.2)	*(13.31)*	**(453.8)**	***(12.90)***	(407.1)	*(12.58)*
Transportation and NGLs processing	**(33.2)**	***(3.56)***	(27.2)	*(3.03)*	**(134.4)**	***(3.82)***	(123.7)	*(3.82)*
Sales of commodities purchased (1)	**50.2**	***5.38***	102.7	*11.47*	**255.1**	***7.25***	272.0	*8.41*
Commodities purchased (1)	**(47.4)**	***(5.08)***	(100.4)	*(11.21)*	**(250.2)**	***(7.11)***	(267.0)	*(8.25)*
	244.8	**26.25**	369.2	41.21	**960.9**	**27.31**	1,391.3	43.00

Grande Prairie Region netbacks for the applicable periods are summarized below:

	Three Months ended December 31				Year Ended			
	2023		2022		**2023**		2022	
Netback	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)
Petroleum and natural gas sales	**367.4**	***54.81***	436.4	*73.62*	**1,446.1**	***55.85***	1,651.8	*77.33*
Royalties	**(56.8)**	***(8.47)***	(66.4)	*(11.21)*	**(217.5)**	***(8.40)***	(261.2)	*(12.23)*
Operating expense	**(84.1)**	***(12.54)***	(69.9)	*(11.80)*	**(297.8)**	***(11.50)***	(247.6)	*(11.59)*
Transportation and NGLs processing	**(26.0)**	***(3.88)***	(22.1)	*(3.70)*	**(107.5)**	***(4.16)***	(93.1)	*(4.36)*
	200.5	***29.92***	278.0	*46.91*	**823.3**	***31.79***	1,049.9	*49.15*

Karr netbacks for the applicable periods are summarized below:

	Three Months ended December 31				Year Ended			
	2023		2022		**2023**		2022	
Netback	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)
Petroleum and natural gas sales	**248.5**	***54.21***	239.3	*71.84*	**872.8**	***54.54***	985.0	*74.86*
Royalties	**(35.9)**	***(7.83)***	(42.7)	*(12.83)*	**(120.8)**	***(7.55)***	(190.2)	*(14.46)*
Operating expense	**(50.7)**	***(11.07)***	(38.5)	*(11.55)*	**(174.5)**	***(10.90)***	(149.3)	*(11.35)*
Transportation and NGLs processing	**(20.9)**	***(4.55)***	(11.5)	*(3.43)*	**(73.1)**	***(4.57)***	(58.4)	*(4.43)*
	141.0	***30.76***	146.6	*44.03*	**504.4**	***31.52***	587.1	*44.62*

Wapiti netbacks for the applicable periods are summarized below:

	Three Months ended December 31				Year Ended			
	2023		2022		**2023**		2022	
Netback	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)
Petroleum and natural gas sales	**118.9**	***56.11***	197.1	*75.90*	**573.3**	***57.96***	666.8	*81.30*
Royalties	**(20.9)**	***(9.85)***	(23.7)	*(9.13)*	**(96.7)**	***(9.77)***	(71.0)	*(8.65)*
Operating expense	**(33.4)**	***(15.74)***	(31.4)	*(12.11)*	**(123.4)**	***(12.47)***	(98.3)	*(11.99)*
Transportation and NGLs processing	**(5.1)**	***(2.41)***	(10.6)	*(4.05)*	**(34.3)**	***(3.48)***	(34.7)	*(4.24)*
	59.5	***28.11***	131.4	*50.61*	**318.9**	***32.24***	462.8	*56.42*

(1) Sales of commodities purchased and commodities purchased are treated as corporate items and not allocated to individual regions or properties.

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F&D capital is a measure used in determining F&D costs and is comprised of capital expenditures (the most directly comparable measure disclosed in the Company's primary financial statements) for the applicable year, excluding certain expenditures described herein, plus the change from the prior year in estimated future development capital included in the applicable reserves evaluation prepared by McDaniel. Capital expenditures related to Fox Drilling and corporate capital expenditures are excluded in all periods where F&D capital has been calculated. Capital expenditures related to Cavalier Energy are excluded in all periods were F&D capital has been calculated prior to 2023 as no reserves were attributed to the properties of Cavalier Energy prior to 2023. F&D capital is used by management and investors, in calculating F&D costs, to represent the amount of capital invested in oil and gas exploration and development projects to generate reserves additions. Set out below is the calculation of F&D capital for the years ended December 31, 2023, 2022 and 2021. Columns may not add due to rounding.

($ millions)	Total Company			
Proved Developed Producing	**2023**	2022	2021	3-year Total
Capital expenditures	**732**	655	275	1,662
Fox Drilling, Cavalier Energy (2022 and 2021) and corporate	**(34)**	(69)	(6)	(109)
Change in estimated future development capital	**94**	(10)	(11)	73
F&D Capital – PDP	**792**	577	257	1,626
Total Proved	**2023**	2022	2021	3-year Total
Capital expenditures	**732**	655	275	1,662
Fox Drilling, Cavalier Energy (2022 and 2021) and corporate	**(34)**	(69)	(6)	(109)
Change in estimated future development capital	**1**	1,249	221	1,471
F&D Capital – TP	**700**	1,835	490	3,025
Proved Plus Probable	**2023**	2022	2021	3-year Total
Capital expenditures	**732**	655	275	1,662
Fox Drilling, Cavalier Energy (2022 and 2021) and corporate	**(34)**	(69)	(6)	(109)
Change in estimated future development capital	**516**	1,176	(93)	1,599
F&D Capital – P+P	**1,214**	1,762	176	3,152

($ millions)	Grande Prairie Region			
Proved Developed Producing	**2023**	2022	2021	3-year Total
Capital expenditures	**380**	453	229	1,062
Change in estimated future development capital	**20**	(20)	(22)	(22)
F&D Capital – PDP	**401**	433	207	1,041
Total Proved	**2023**	2022	2021	3-year Total
Capital expenditures	**380**	453	229	1,062
Change in estimated future development capital	**101**	447	(182)	366
F&D Capital – TP	**481**	901	47	1,429
Proved Plus Probable	**2023**	2022	2021	3-year Total
Capital expenditures	**380**	453	229	1,062
Change in estimated future development capital	**643**	297	(197)	743
F&D Capital – P+P	**1,024**	750	31	1,805

Non-GAAP Ratios

F&D costs, recycle ratio, lifetime netback divided by DCET by well and netback presented on $/Boe or $/Mcf basis are non-GAAP ratios as they each have a non-GAAP financial measure as a component. These measures are not standardized measures under IFRS and might not be comparable to similar financial measures presented by other issuers. These measures should not be considered in isolation or construed as alternatives to their most directly comparable measure disclosed in the Company's primary financial statements or other measures of financial performance calculated in accordance with IFRS.

F&D costs are calculated by dividing: (i) F&D capital (a non-GAAP financial measure) for the applicable reserves category and period; by (ii) the net changes to reserves in such reserves category from the prior period from extensions/improved recovery, technical revisions and economic factors, expressed in Boe. F&D costs are a measure commonly used by management and investors to assess the relationship between capital invested in oil and gas exploration and development projects and reserve additions. The three-year average F&D costs contained in this presentation were calculated by dividing total F&D capital over the period by the aggregate reserves additions in the period. Readers should refer to the information under the heading "Reserves and Other Oil and Gas Information – Reserves Information – Reserves Reconciliation" in the Company's annual information forms for the years ended December 31, 2023, 2022 and 2021, which are available on www.sedarplus.ca or at www.paramountres.com, for a description of the net changes to reserves in each reserves category from the prior year. See "Oil and Gas Definitions and Measures" in the Advisories Appendix for more information about this measure.

Recycle ratio is calculated by dividing the netback (a non-GAAP financial measure) per Boe for the period by the F&D costs for the period. Recycle ratio is used by investors and management to compare the cost of adding reserves to the netback realized from production. See "Oil and Gas Definitions and Measures" in the Advisories Appendix for more information about this measure.

Set out below are the applicable F&D costs and recycle ratios for 2023, 2022 and 2021.

	Total Company					
	F&D ($/Boe)			Recycle Ratio (x)		
	2023	2022	2021	2023	2022	2021
Proved Developed Producing	**$16.58**	$9.58	$6.22	**1.6x**	4.5x	4.3x
Total Proved	**$16.96**	$14.11	6.72	**1.6x**	3.0x	4.0x
Proved plus Probable	**$12.52**	$14.87	2.12	**2.2x**	2.9x	12.6x

	Grande Prairie					
	F&D ($/Boe)			Recycle Ratio (x)		
	2023	2022	2021	2023	2022	2021
Proved Developed Producing	**$10.08**	$9.61	$6.53	**3.2x**	5.1x	5.1x
Total Proved	**$18.18**	$9.95	$1.99	**1.7x**	4.9x	16.8x
Proved plus Probable	**$14.65**	$11.82	$0.59	**2.2x**	4.2x	56.2x

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Lifetime netback divided by DCET by well is calculated by dividing the actual netback (a non-GAAP financial measure) for a well to December 31, 2023 plus the forecast total proved plus probable netback over the remaining life of each well as estimated in the McDaniel Report by the DCET costs for the well. This measure is used by investors and management to assess the relationship of netback from a well to the DCET costs for the well.

Netback on a $/Boe is calculated by dividing netback (a non-GAAP financial measure) for the applicable period by the total sales volumes during the period in Boe. This measure is used by investors and management to assess netback on a unit of sales volumes basis.

Capital Management Measures

Adjusted funds flow, net debt and free cash flow are capital management measures that Paramount utilizes in managing its capital structure. These measures are not standardized measures and therefore may not be comparable with the calculation of similar measures by other entities. Refer to Note 18 – Capital Structure in the consolidated financial statements of Paramount as at and for the year ended December 31, 2023 for: (i) a description of the composition and use of these measures, and (ii) reconciliations of adjusted funds flow and free cash flow to cash from operating activities, the most directly comparable measure disclosed in the Company's primary financial statements, for the years ended December 31, 2023 and 2022.

Supplementary Financial Measures

Implied capital efficiency is a supplementary financial measure. See "Play Data“ in this Advisories Appendix for a description of the calculation of implied capital efficiency.

Oil and Gas Measures and Definitions

Natural Gas		Liquids		Oil Equivalent	
GJ	Gigajoules	Bbl	Barrels	Boe	Barrels of oil equivalent
GJ/d	Gigajoules per day	Bbl/d	Barrels per day	Mboe	Thousands of barrels of oil equivalent
Mcf	Thousands of cubic feet	MBbl	Thousands of barrels	MMBoe	Millions of barrels of oil equivalent
MMcf	Millions of cubic feet	NGLs	Natural Gas Liquids	Boe/d	Barrels of oil equivalent per day
MMcf/d	Millions of cubic feet per day	Condensate	Pentane and heavier hydrocarbons		
AECO	AECO-C reference price	WTI	West Texas Intermediate		

This document contains disclosures expressed as "Boe", "$/Boe", "MBoe", "MMBoe" and "Boe/d". Natural gas equivalency volumes have been derived using the ratio of six thousand cubic feet of natural gas to one barrel of oil when converting natural gas to Boe. Equivalency measures may be misleading, particularly if used in isolation. A conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. For the year ended December 31, 2023, the value ratio between crude oil and natural gas was approximately 36:1. This value ratio is significantly different from the energy equivalency ratio of 6:1. Using a 6:1 ratio would be misleading as an indication of value.

This document contains metrics commonly used in the oil and natural gas industry. Each of these metrics is determined by the Company as set out below or elsewhere in this document. The metrics are F&D costs, recycle ratio, reserves replacement ratio and CGR. These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies. As such, they should not be used to make comparisons. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare the Company's performance over time; however, such measures are not reliable indicators of the Company's future performance and future performance may not compare to the performance in previous periods and therefore should not be unduly relied upon.

Refer to the "Specified Financial Measures" section of this Advisories Appendix for a description of the calculation and use of F&D costs and recycle ratio. Reserves replacement ratio is calculated by dividing: (i) the net changes in reserves from the prior year in the applicable category from technical revisions, economic factors and extensions/improved recovery, by (ii) the aggregate production during the year. Reserves replacement ratio is a measure commonly used by management and investors to assess the rate at which reserves depleted by production are being replaced. CGR means condensate to gas ratio and, except as noted in this Advisories Appendix under "Play Data“, is calculated by dividing raw wellhead liquids volumes by raw wellhead natural gas volumes. CGR is a measure commonly used by management and investors to assess the relative liquids production from a well.

All information in this presentation respecting acres of land held is effective as of December 31, 2023 unless otherwise stated.

Additional information respecting the Company's oil and gas properties and operations is provided in the Company's annual information form for the year ended December 31, 2023 which is available on SEDAR+ at www.sedarplus.ca or on the Company's website at www.paramountres.com.

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Pricing Sensitivity

The below table reflects forecast 2024 free cash flow under the revised 2024 guidance and, for illustrative comparison, two alternative pricing scenarios:

	Revised 2024 Guidance	Alternative Scenario 1	Alternative Scenario 2
WTI	US$80.00/Bbl	US$77.50/Bbl	US$75.00/Bbl
NYMEX	US$3.50/MMBtu	US$3.00/MMBtu	US$2.40/MMBtu
AECO	$2.84/GJ	$2.37/GJ	$1.90/GJ
2024 Free Cash Flow	$235 million	$135 million	$25 million

Forecast 2024 free cash flow is forward-looking information. See "Forward-looking Information" in these Advisories.

Product Type Information

This presentation includes references to forecast sales volumes of "liquids". "Liquids" refers to light and medium crude oil, tight oil, heavy crude oil, condensate and ethane, propane and butane ("Other NGLs") combined. Below is further information respecting the composition of sales volumes or forecast sales volumes for applicable periods.

The Company forecasts that 2024 annual sales volumes will average between 100,000 Boe/d and 106,000 Boe/d (53% shale gas and conventional natural gas combined, 41% condensate, light and medium crude oil, tight oil and heavy crude oil combined and 6% Other NGLs). First half 2024 sales volumes are expected to average between 96,000 Boe/d and 100,000 Boe/d (53% shale gas and conventional natural gas combined, 41% condensate, light and medium crude oil, tight oil and heavy crude oil combined and 6% Other NGLs). Second half 2024 sales volumes are expected to average between 104,000 Boe/d and 112,000 Boe/d (53% shale gas and conventional natural gas combined, 41% condensate, light and medium crude oil, tight oil and heavy crude oil combined and 6% Other NGLs).

See "Product Type Information" at page 37 of the Company's Management's Discussion and Analysis for the year ended December 31, 2023 for a description of historical average sales volumes by the specific product types of shale gas, conventional natural gas, NGLs, light and medium crude oil, tight oil and heavy crude oil.`

Reserves Data

Reserves data set forth in this presentation is based upon an evaluation of the Company's reserves prepared by McDaniel & Associates Consultants Ltd. ("McDaniel") dated March 5, 2024 and effective December 31, 2023 (the "McDaniel Report"). The reserves referenced in this document are gross reserves. The price forecast used in the McDaniel Report is an average of the January 1, 2024 price forecasts for McDaniel and GLJ Petroleum Consultants Ltd. and the December 31, 2023 price forecast of Sproule Associates Ltd. The estimates of reserves contained in the McDaniel Report and referenced in this document are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates contained in the McDaniel Report and referenced in this document. There is no assurance that the forecast prices and costs assumptions used in the McDaniel Report will be attained, and variances could be material. Estimated future net revenue does not represent fair market value. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. Readers should refer to the Company's annual information form for the year ended December 31, 2023, which is available on SEDAR+ at www.sedarplus.ca or at www.paramountres.com, for a complete description of the McDaniel Report (including reserves by the specific product types of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil) and the material assumptions, limitations and risk factors pertaining thereto.

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Play Data

The internally estimated play data information for Karr, Wapiti, Kaybob North Duvernay and Willesden Green contained at pages 9, 11, 13 and 14 in this presentation has been prepared effective March 5, 2024 by internal qualified reserves evaluators from Paramount in accordance with COGEH and using commodity prices of US$80.00/Bbl WTI, $3.00/MMBtu AECO and an exchange rate of US$0.735 for one Canadian dollar for 2024 and US$75.00/Bbl WTI, $3.75/MMBtu AECO and an exchange rate of US$0.740 for one Canadian dollar for 2025 and beyond. The play data has been prepared excluding certain wells with significant deviation in completion, lateral length and depletion or infrastructure constraints. The play data contains no adjustments or assumptions respecting unscheduled potential future facility and transportation constraints or outages. Underlying forecast economics are half-cycle economics and include only the cost to drill, complete, tie-in and equip wells. The forecasts do not take into account certain other capital costs, including those required to construct central processing facilities, regional gathering facilities, condensate stabilization facilities and other infrastructure and costs related to water disposal and wellbore optimization. Sales and production volumes presented in the play data have been estimated on the basis of an equal likelihood that actual volumes recovered will be greater or less than those estimated.

The metrics and terms "CGR", "IP 365", "IP 365 CGR", "Sales Volumes", "Average CGR", "Sales Gas Volume", "Sales Condensate", "Implied Capital Efficiency" and "DCET" are used in presenting play data. "CGR" means condensate to gas ratio and, in the context of play data, is calculated by dividing sales condensate volumes by sales natural gas volumes. "IP 365" means the estimated average daily sales volumes of production over the initial 365 calendar days of production. "IP 365 CGR" means the estimated average CGR over the initial 365 calendar days of production. "Sales Volume" means the estimated aggregate potential sales volumes of production. "Average CGR" means the estimated average CGR over the life of the well. "Sales Gas Volume" means the estimated aggregate potential sales volumes of natural gas. "Sales Condensate" means the estimated aggregate potential sales volumes of condensate. "Implied Capital Efficiency" is calculated by dividing IP365 by DCET. "DCET" means estimated drilling, completion, equip and tie-in costs.

The play data contained in this presentation has been included for the purposes of informing readers as to certain assumptions and estimates relied on by management of Paramount as of the date of preparation for capital budgeting and forecasting purposes. The play data represents an estimate only respecting undeveloped locations in 2024 development plans, is subject to revision and may not be applicable to all undeveloped locations. Play data should not be relied on as an estimate or evaluation of reserves or resources associated with the Company's properties and readers are referred to the McDaniel Report and to the Company's annual information form for the year ended December 31, 2023, which is available on SEDAR+ at www.sedarplus.ca or at www.paramountres.com, for reserves information respecting the Company.

Undeveloped Locations

This presentation contains information respecting Paramount's internal estimate of future potential undeveloped locations at various properties. The future potential undeveloped location information contained in this presentation represents gross locations and was prepared March 5, 2024 and effective December 31, 2023 by internal qualified reserves evaluators from Paramount. The undeveloped locations referred to in this presentation were determined by Paramount's internal evaluators based on, among other matters, their assessment of available reservoir, geological and technical information, the economic thresholds necessary for development and potential future development plans. There is no certainty that the Company will drill any of the identified future potential undeveloped locations and there is no certainty that such locations will result in additional reserves or production. The locations on which the Company will actually drill wells, including the number and timing thereof will be dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil, NGLs and natural gas prices, costs, actual drilling results, additional reservoir, geological and technical information that is obtained and other factors. While certain of the estimated undeveloped locations have been de-risked by drilling existing wells in relative close proximity to such locations, many of the locations are further away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty as to whether wells will be drilled in such locations, and if wells are drilled in such locations there is more uncertainty that such wells will result in additional oil and natural gas reserves or production. This below table references the future potential undeveloped locations assigned reserves in the McDaniel Report solely to provide the reader with additional information concerning internally estimated future potential undeveloped locations as compared to locations assigned reserves in the McDaniel Report. The comparability of internally estimated future potential undeveloped locations to locations assigned in the McDaniel Report is limited due to differing assumptions and differing effective dates. There is no guarantee that any internally estimated future potential development location will be included and assigned reserves in any future reserves report prepared for the Company. The table below sets out Paramount's internal estimate of future potential undeveloped locations for each applicable property as at December 31, 2023 and the number of undeveloped locations that were assigned reserves in the McDaniel Report as at December 31, 2023.

	Karr (Middle Montney)	Wapiti	Kaybob North Duvernay	Willesden Green Duvernay
Referenced Undeveloped Locations	206	235	144	705
Locations Assigned Reserves in the McDaniel Report	156	167	60	86

Paramount Resources Ltd.
4700 – 888 3rd Street S.W.
Calgary, Alberta Canada
T2P 5C5
Telephone: 403.290.3600
www.paramountres.com