Corporate Presentation

August 2023

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 August 1, 2023, except the information contained herein respecting Paramount's five-year outlook which is effective March 6, 2023. Certain internally estimated play data contained in this presentation was prepared effective July 31, 2023. 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

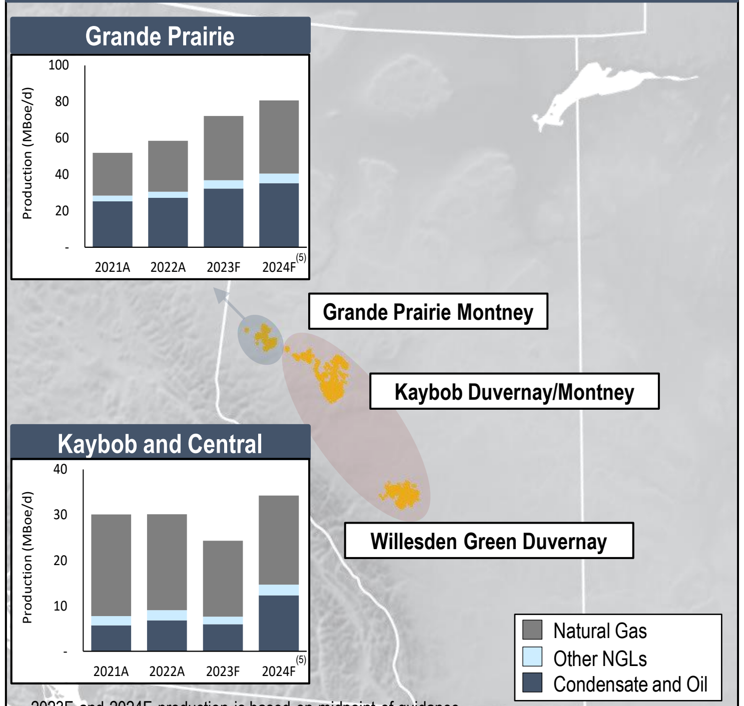
Paramount has significant land positions in the most liquids-rich areas of the prolific Montney and Duvernay resource plays

- Founded in 1976 (IPO'd in 1978)
- Significant insider ownership (~47%) [(1)]
- Total Proved Reserves: 445 MMBoe (49% liquids) [(2)]
  - NPV_{10} ~$5.8 Bn ($41.18 / basic share)
- Proved + Probable Reserves: 759 MMBoe (50% liquids) [(2)]
  - NPV_{10} ~$9.1 Bn ($64.52 / basic share)
- 2Q23 Production: 88,243 Boe/d (45% liquids)

Market Snapshot (TSX-POU)	
Shares Outstanding (MM)	143.5
Market Capitalization ($MM) [(3)]	~$4,600
Bank Debt at June 30, 2023 ($MM)	$0
Cash and Cash Equivalents at June 30, 2023 ($MM)	~$38.6
Investments in Securities at June. 30, 2023 ($MM)	~$490
Monthly Dividend ($/share | Annualized Yield) [(4)]	$0.125 | 4.7%

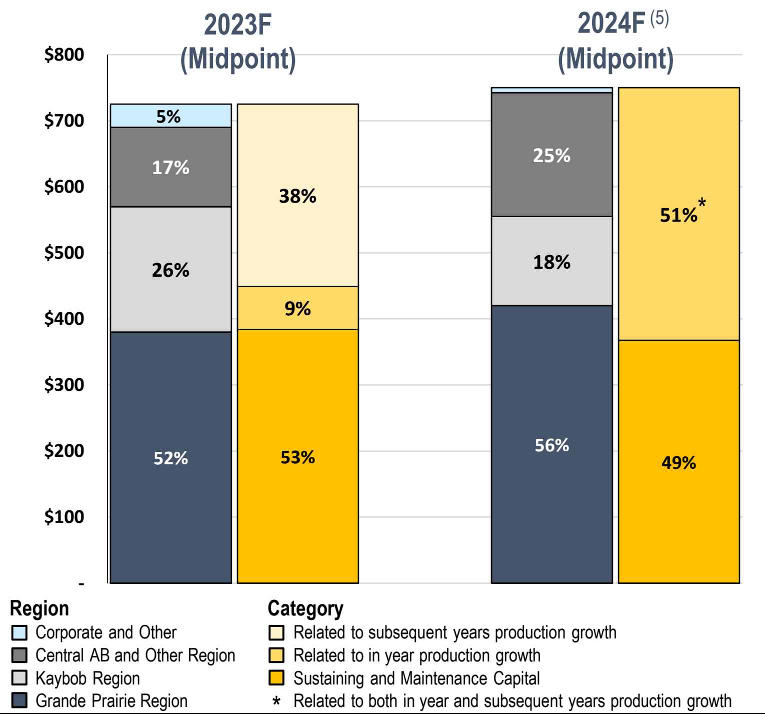
Guidance Summary	2023F	2024F [(5)]
Sales volumes (MBoe/d) (% Liquids)	95-98 (46%)	110-120 (48%)
CapEx ($MM)	$700-$750 *(~50% to growth)*	$700-$800 *(~50% to growth)*
ARO ($MM)	$55	$40
Mid-point FCF ($MM) [(6)]	~$185	~$445
Annualized base dividend ($MM) [(7)]	~$215	~$215

Focus Areas

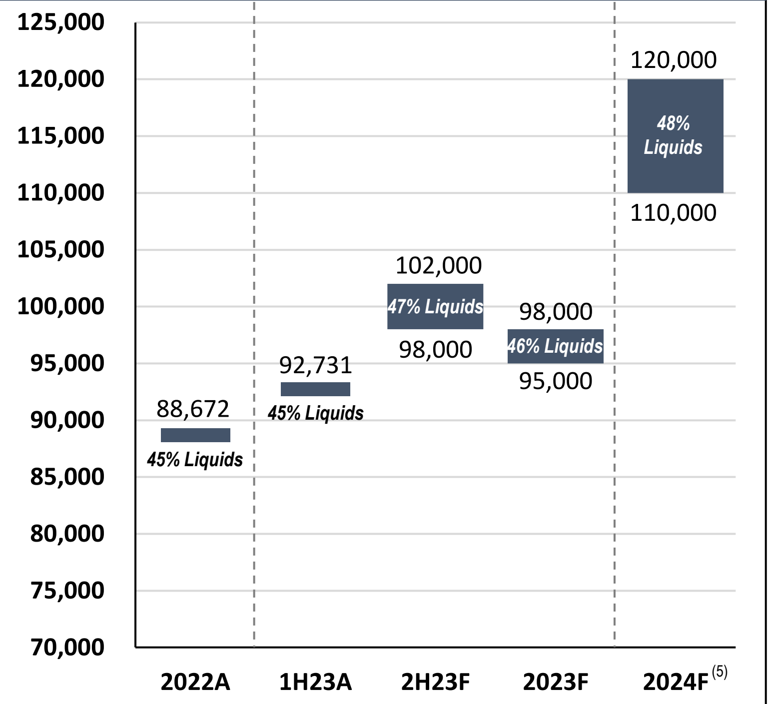


2023F and 2024F production is based on midpoint of guidance

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 6, 2023 and effective December 31, 2022 (the "McDaniel Report"). "NPV10" refers to the 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) 143.5MM Common Shares at $31.87/share. (4) Annualized yield is obtained by dividing 12 months of the stated monthly dividend by a Common Share price of $31.87. (5) 2024 amounts are current expectations based on preliminary planning and current market conditions and are subject to change. (6) FCF means free cash flow. Free cash flow is a capital management measure used by Paramount. See Advisories Appendix – Specified Financial Measures. (7) 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 quarter end, Paramount is well positioned to deliver on its FCF priorities

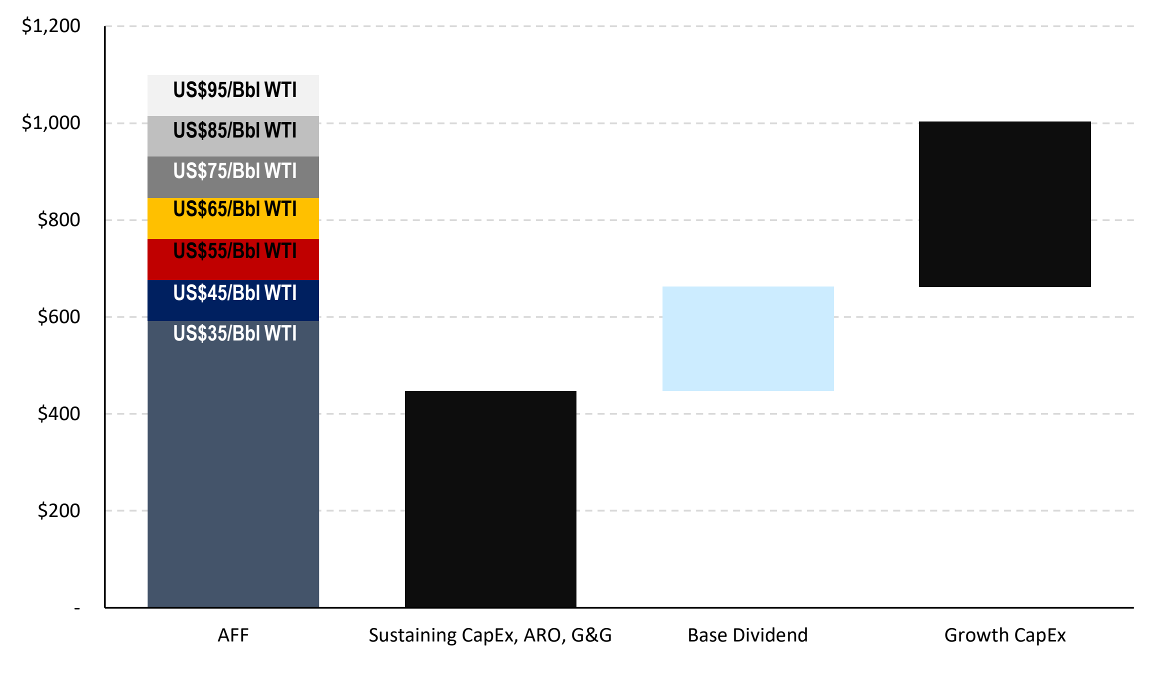
- Paramount's free cash flow priorities continue to be the maintenance of conservative leverage levels and the delivery of attractive shareholder returns through a combination of:
  - Dividends, including the flexibility for incremental returns through further special dividends
  - Investments in growth opportunities
  - Opportunistic share buybacks
- Cumulative $3.21/share (~$456MM) cash dividends from Jul. 2021 to Jul. 2023
  - Increased monthly base dividend four times since inception
  - Special cash dividend of $1.00/share in January 2023

Guidance (1)(2)

		2023F	2024F
Midpoint of Sales Volumes Guidance	*(MBoe/d)*	*96.5*	*115*
FCF Guidance	*($MM)*	~$185	~$445
Midpoint of CapEx Guidance	*($MM)*	~$725	~$750
ARO Guidance	*($MM)*	~$55	~$40
Geological & Geophysical Expense ("G&G")	*($MM)*	~$7	~$7
Illustrative Adjusted Funds Flow ("AFF")	*($MM)*	**~$970**	**~$1,240**

- Capacity available under the Company's $1.0 billion senior secured credit facility (undrawn at quarter end) to fund any portion of the 2023 growth capital not funded from AFF, if required
- In 2024, preliminary midpoint CapEx, ARO, G&G and regular monthly dividend fully funded from AFF with an estimated excess of ~$230 million

Illustrative 2023 AFF Estimates ($MM) (1)(2)



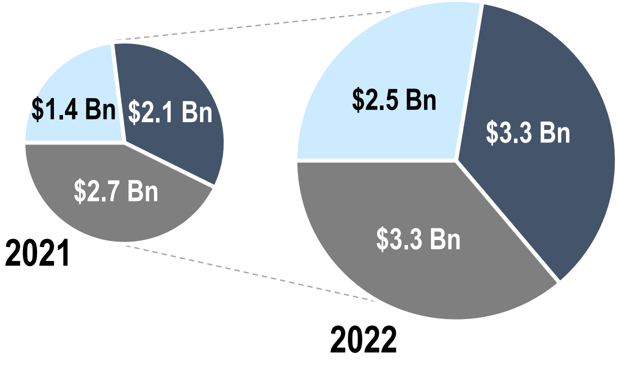
(1) See Advisories Appendix – Forward Looking Information for a breakdown of the pricing, cost, expenditure and other assumptions for the last two quarters of 2023 and annual 2024 on which the estimates are based. 2024 amounts are current expectations based on preliminary planning and current market conditions and are subject to change. **(2)** Free cash flow and adjusted funds flow are capital management measures used by Paramount. See Advisories Appendix – Specified Financial Measures.

Reserves

Strong recycle ratios that generate material free cash flows

Reserves Growth[1]

Value ($Bn NPV$_{10}$)

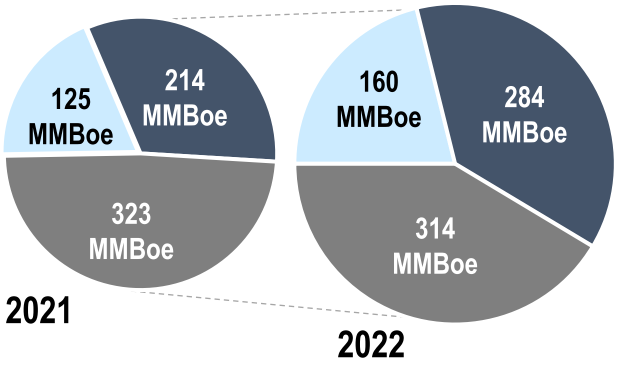


PDP	$2.5 Bn ($17.82/sh.) (+75%)
TP	$5.8 Bn ($41.18/sh.) (+62%)
P+P	$9.1 Bn ($64.52/sh.) (+46%)

Percentages represent year-over-year growth

PDP
PUD
Probable

Volumes (MMBoe)



PDP	160 MMBoe (+28%)
TP	445 MMBoe (+31%)
P+P	759 MMBoe (+15%)

Percentages represent year-over-year growth

PDP
PUD
Probable

	2022 [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	$9.58	$9.61	4.5x	5.1x	$8.13	$8.44	3.4x	4.1x
TP	$14.11	$9.95	3.0x	4.9x	$7.72	$3.73	3.5x	9.4x
P+P	$14.87	$11.82	2.9x	4.2x	$4.42	nmf [3]	6.5x	nmf [3]

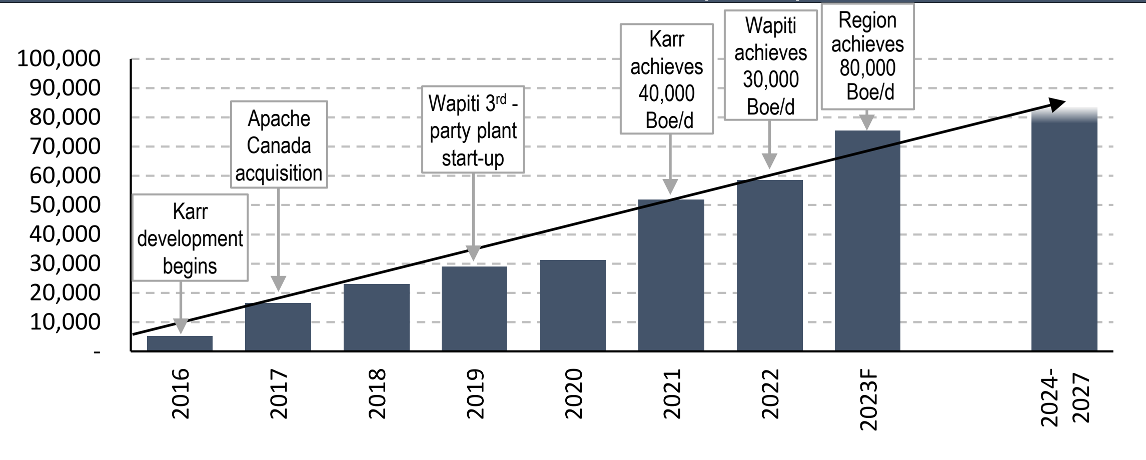
- In Grande Prairie, where the majority of 2022 development activity occurred, PDP, TP and P+P reserves volumes were up 33%, 35% and 10%, respectively
- With the significant reserves additions in 2022, the Company's reserves replacement ratios were 1.9x for PDP reserves, 4.0x for TP reserves and 3.7x for P+P reserves. [4]
- Significant factors leading to the increase in 2022 P+P reserves:
  - acceleration of development plans in the Grande Prairie Region to a higher combined production plateau
  - the advancement of the Willesden Green Duvernay development
  - further advancement of the Kaybob North Duvernay development, including increased well density

(1) Gross reserves evaluated by McDaniel as of December 31, 2022 and December 31, 2021. "NPV10" refers to the 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 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 March 6, 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)** Three-year average Grande Prairie F&D cost and recycle ratios are not meaningful since F&D capital (including change in future development cost) is negative. **(4)** 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.

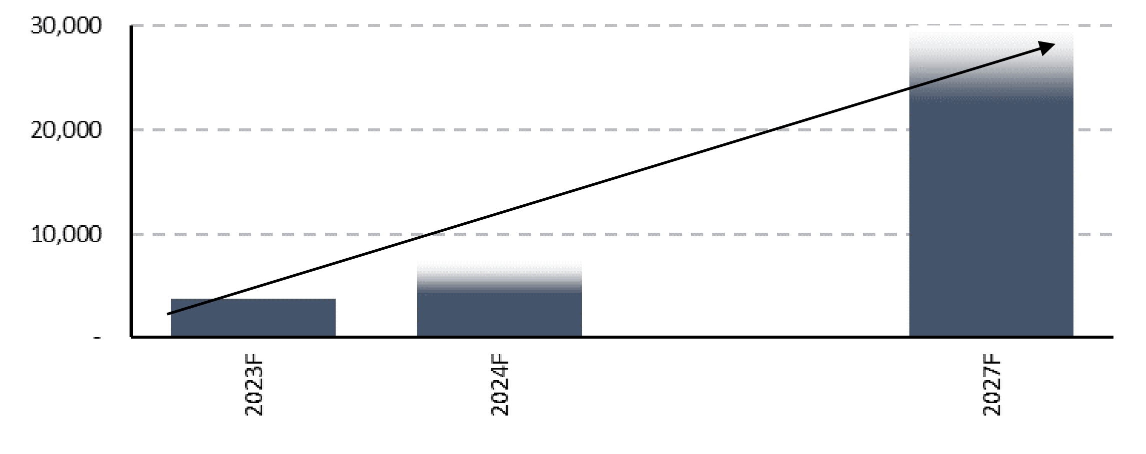
Building Sustainable Free Cash Flow for the Long-Term

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

Grande Prairie 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:** 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:** Current land position acquired over multiple years at a low-cost with current plans to grow production from ~3,750 Boe/d in 2023 to targeted full-field development plateau of over 50,000 Boe/d

Highlights of 5-Year Outlook (1)	
2027 Annual Average Sales Volumes	135,000 to 145,000 Boe/d
Annual Capital Expenditures	$700 to $800 million
Midpoint Cumulative After-Tax Free Cash Flow (1)	**~$3.1 Bn (~$22/sh.) (2)**

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

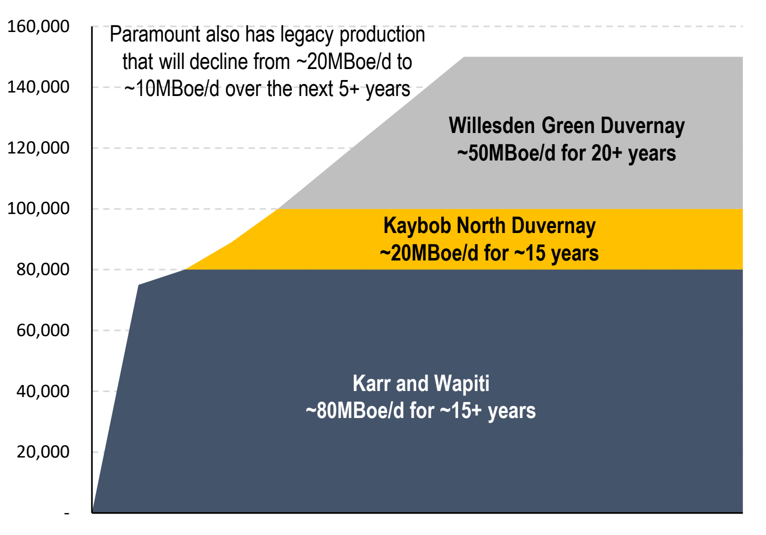
(1) The five-year outlook is based on preliminary planning and market conditions. The five-year outlook was prepared effective March 6, 2023 and does not incorporate subsequent changes or events, including changes to development plans made subsequent to such date. The stated anticipated cumulative free cash flow is based on the following assumptions: (i) the stated annual capital expenditures and assumed production growth resulting in the stated 2027 annual average sales volumes; (ii) approximately $55 million in 2023 and $40 million thereafter in average annual abandonment and reclamation costs, (iii) approximately $7 million in annual geological and geophysical expenses, (iv) 2023 realized pricing of $55.20/Boe (US$80.00/Bbl WTI, US$3.50/MMBtu NYMEX, $3.08/GJ AECO) and thereafter commodity prices of US$75.00/Bbl WTI, US$3.50/MMBtu NYMEX and $3.08/GJ AECO, (v) a $US/$CAD exchange rate of $0.755 and (vi) internal management estimates of future royalties, operating costs, transportation and NGLs processing costs and, beginning in 2027, cash taxes. **(2)** Based on 142.9 million outstanding Common Shares as at March 6, 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

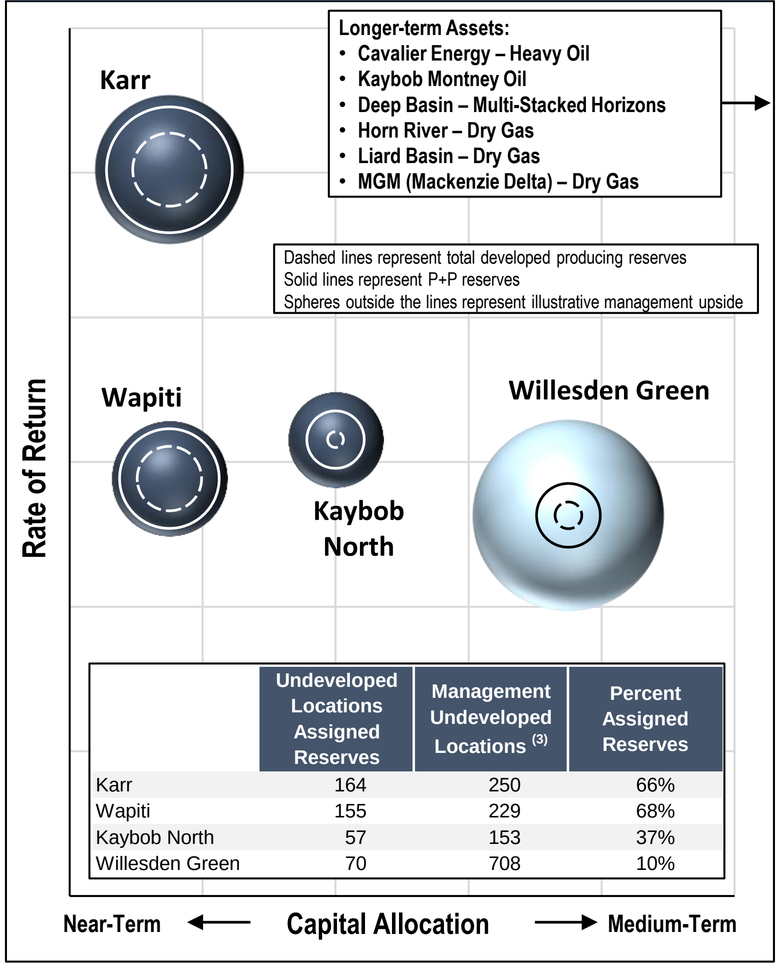
Paramount continues to allocate capital to its highest risk-adjusted return opportunities while maintaining balance sheet strength

- 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 15 to 20 years based on management estimates of full field development location count

Potential Plateau Production (Boe/d) (1)

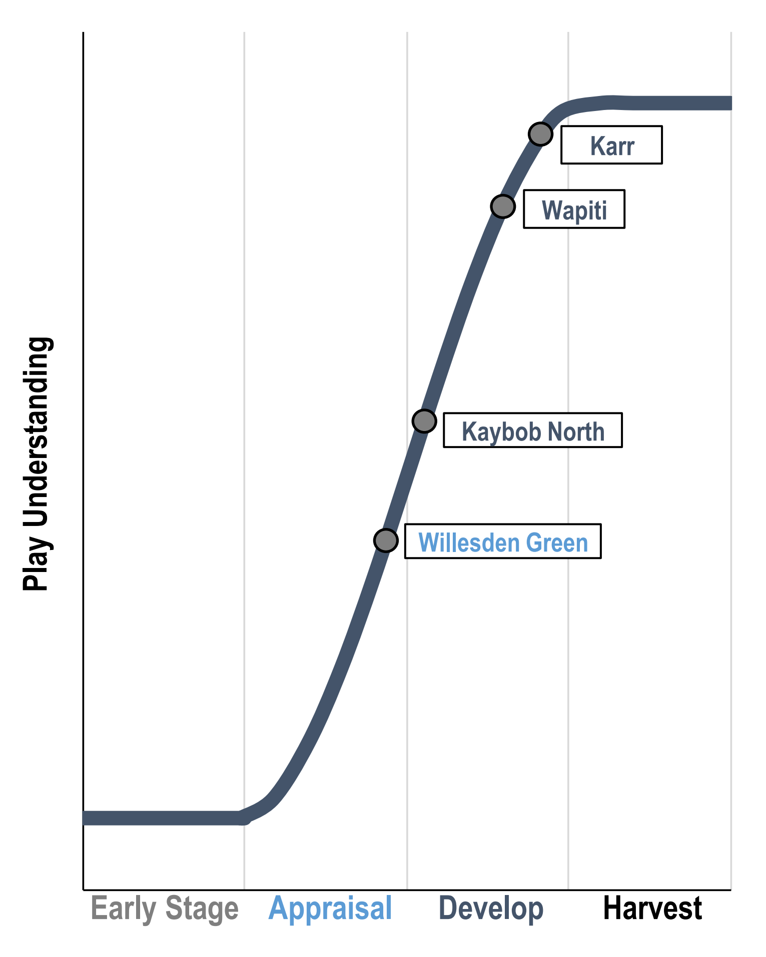


Significant Asset Optionality & Value (2)



	Undeveloped Locations Assigned Reserves	Management Undeveloped Locations (3)	Percent Assigned Reserves
Karr	164	250	66%
Wapiti	155	229	68%
Kaybob North	57	153	37%
Willesden Green	70	708	10%

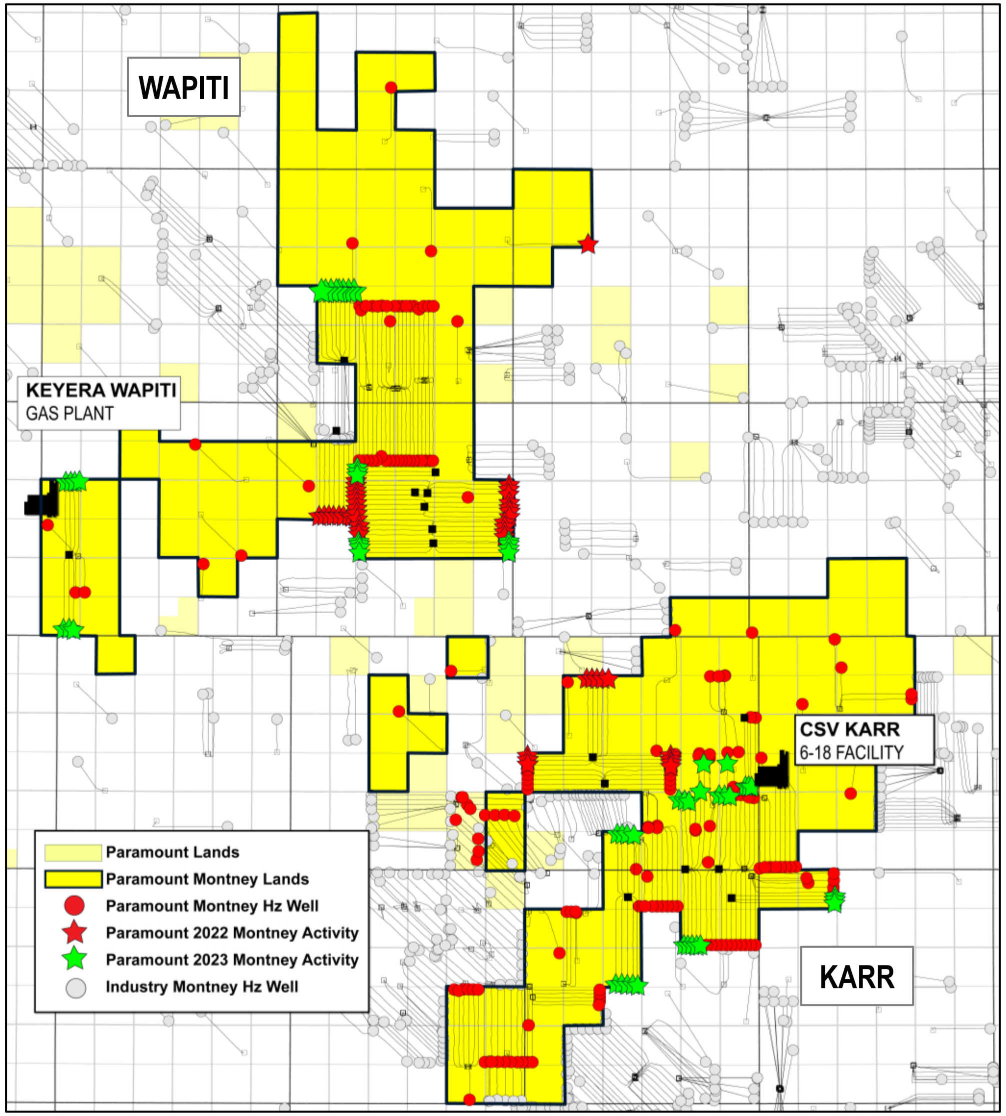
Stage of Development



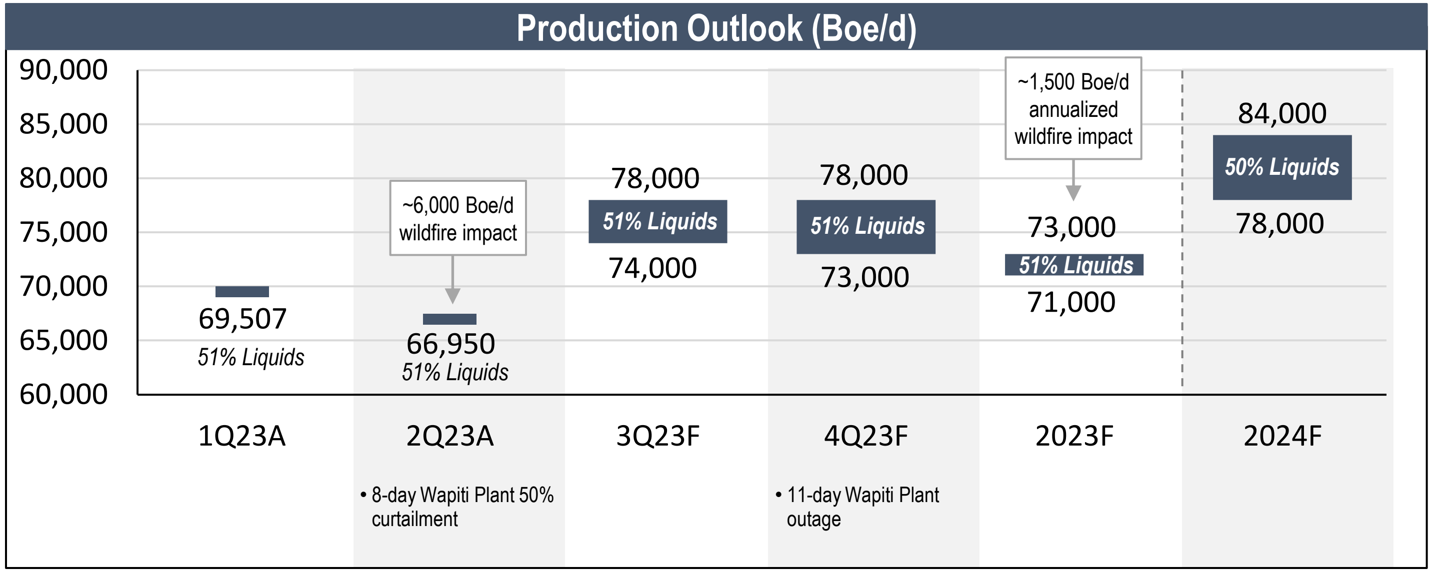
(1) Based on management estimates of play data and undeveloped drilling locations as described on pages 8, 9, 11, 13 and 14. See Advisories Appendix – Play Data and Undeveloped Locations. **(2)** Paramount's expectation of rate of return (as of July 31, 2023) vs. the relative net present value of future 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

Production from Paramount's Montney assets at Karr and Wapiti in Q2/23 exceeded 80,000 Boe/d on multiple days



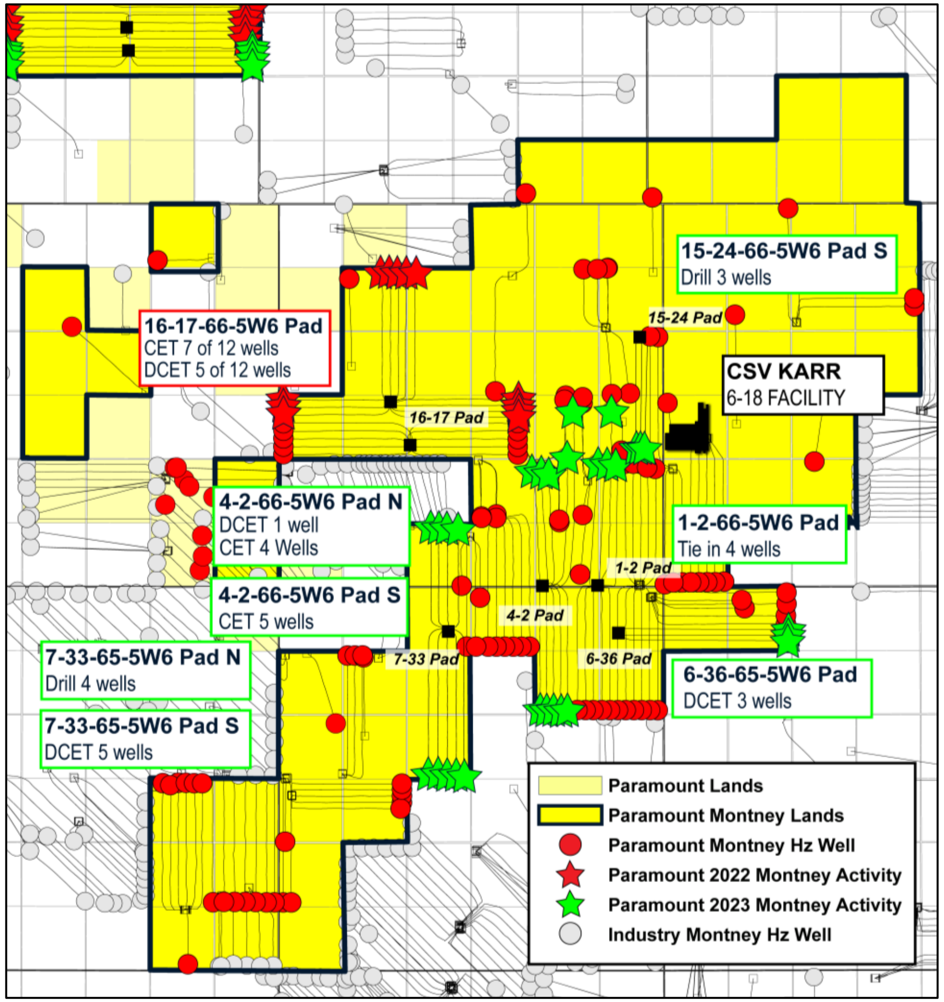
- Paramount holds approximately 101,000 net acres of Montney rights at Karr and Wapiti (1)
- Actively began development in 2016 with 166 wells brought onstream to the end of June 2023
- 2023 activities include 36 drills, 35 wells to be brought onstream
- Infrastructure debottlenecking project completed in 2023
- Liquids volumes at Paramount's southern-most Wapiti pads have proven to be similar to those exhibited by earlier Wapiti wells; however, gas rates are proving to be considerably higher
- Management high-graded undeveloped location count of 250 wells at Karr (middle Montney development) and 229 wells at Wapiti
  - ~66% assigned reserves at Karr and 68% assigned reserves at Wapiti at Dec. 31, 2022 (2)



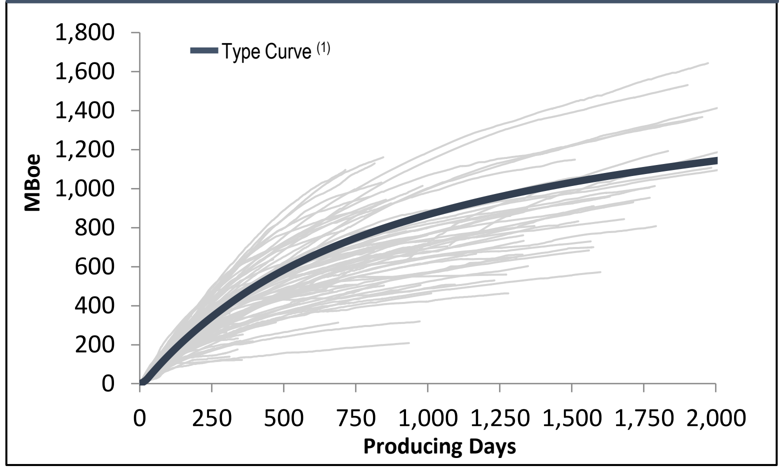
(1) As of December 31, 2022. (2) See Advisories Appendix – Undeveloped Locations.

Karr Activity and Production Performance

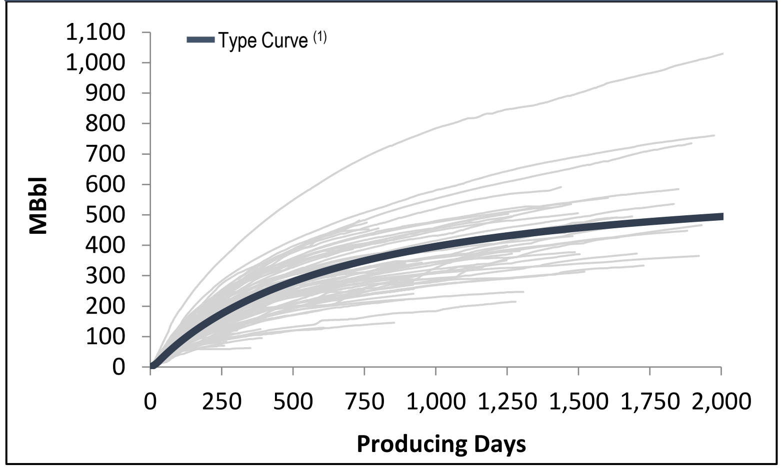
Paramount's Montney wells at Karr continue to perform strongly



Cumulative Boe – Karr Wells



Cumulative NGLs – Karr Wells



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

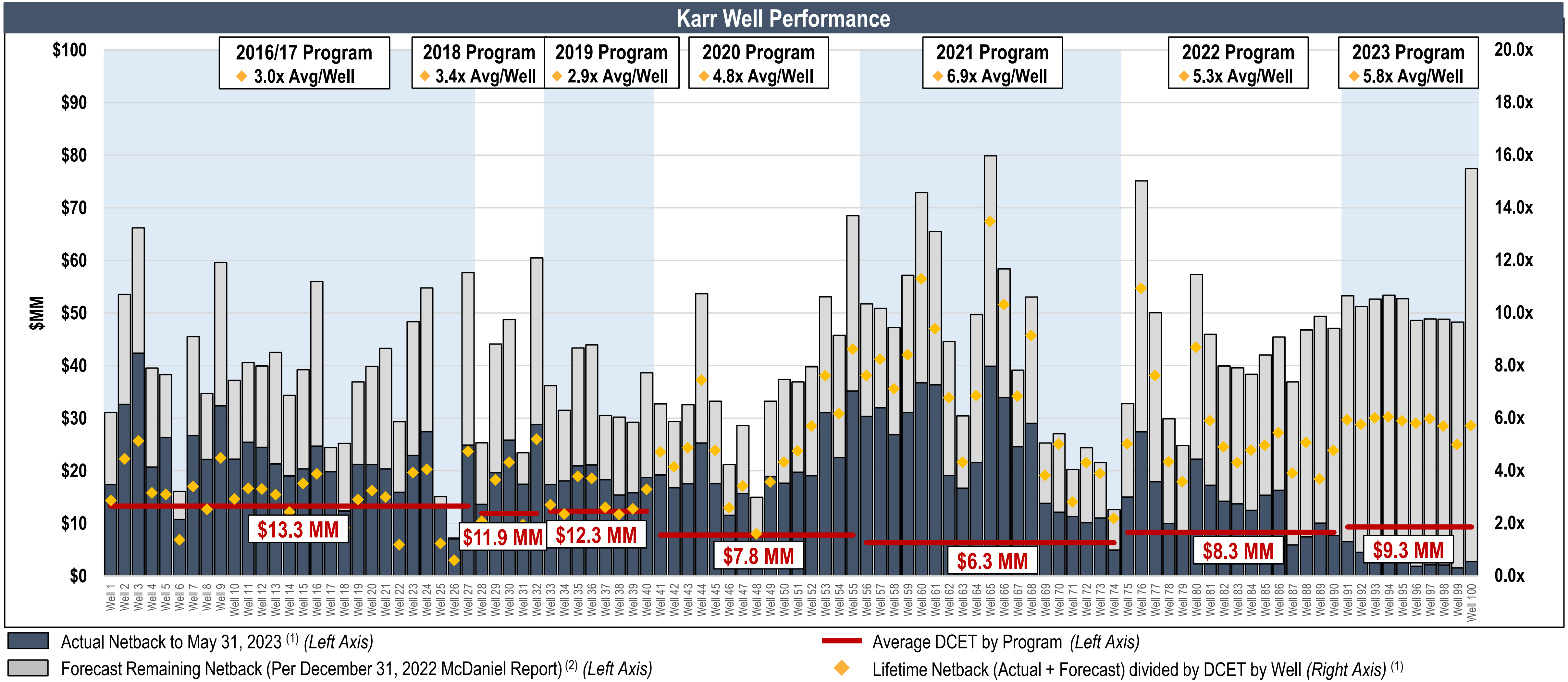
IP 365 *(Boe/d)*	1,255
IP 365 CGR *(Bbl/MMcf)*	189
Sales Volume *(MBoe)*	1,632
Average CGR *(Bbl/MMcf)*	117
Sales Gas Volume *(Bcf)*	5.4
Sales Condensate *(MBbl)*	590
DCET *($MM)*	$9.2

- Highly productive liquids-rich wells drive attractive half-cycle economics
- Estimated per well sales volumes of ~1.6 MMBoe
  - Implied capital efficiency of ~$7,300/Boe/d (3)
- Grande Prairie PDP F&D costs were $9.61/Boe in 2022 (3)
  - Results in a recycle ratio of 4.6x when using Karr's 2022 netback of $44.62/Boe (3)

(1) Production measured at the wellhead. Natural gas sales volumes were lower by approximately 11 percent and liquids sales volumes were lower by approximately 6 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

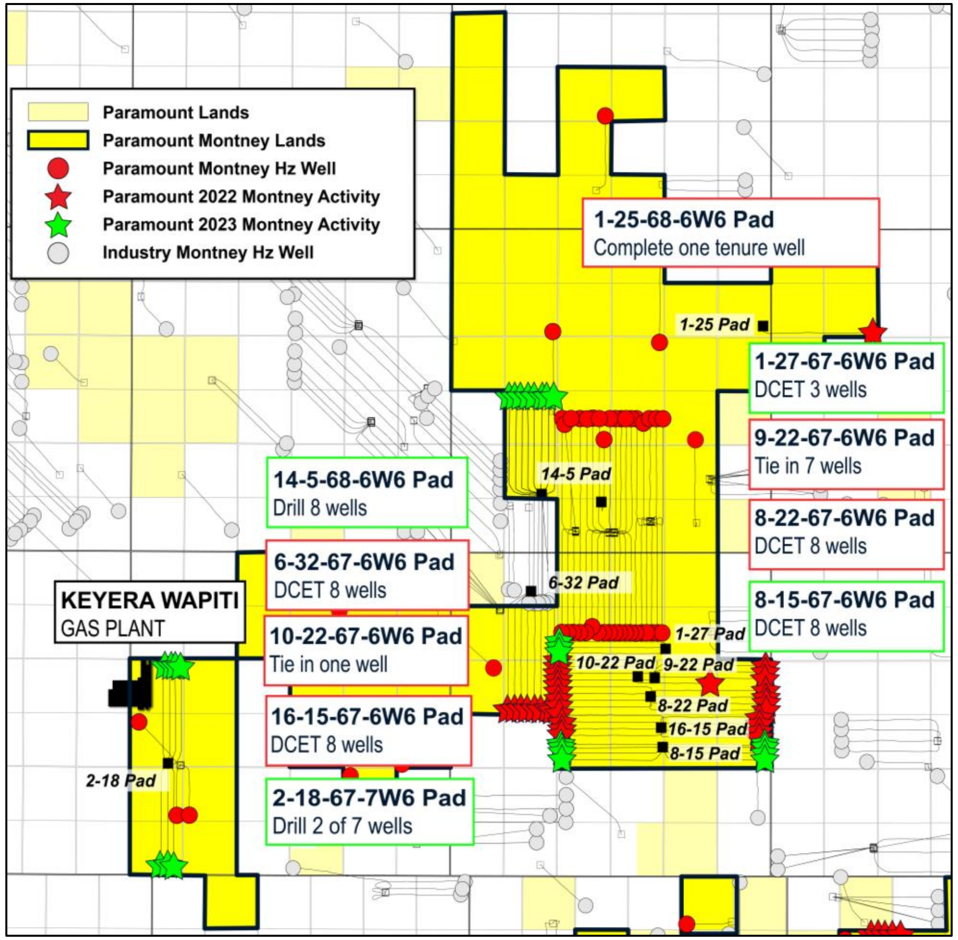
Wells exhibit strong returns and quick payouts



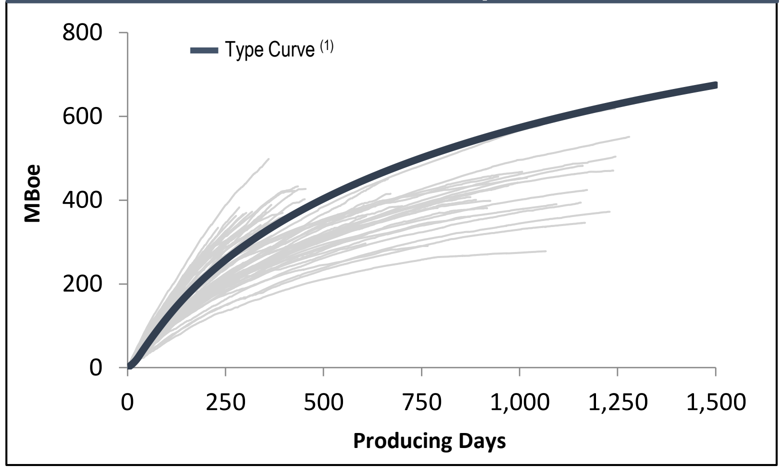
(1) Netback is a non-GAAP financial measure. Lifetime Netback divided by DCET by Well is a non-GAAP ratio. See Advisories Appendix – Specified Financial Measures. **(2)** See Advisories Appendix – Reserves Data. Amounts represent undiscounted forecast proved plus probable netback over the remaining life of each well as included in the McDaniel Report less actual netback between January 1, 2023 and May 31, 2023.

Wapiti Activity and Production Performance

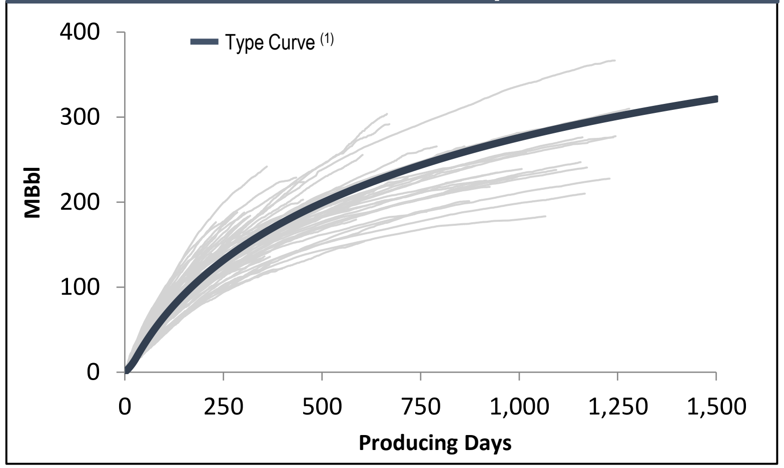
Recent pads exhibiting higher total production while maintaining already strong liquids volumes



Cumulative Boe – Wapiti Wells



Cumulative NGLs – Wapiti Wells



Play Data – 3,000m Avg. Lateral Length [2]

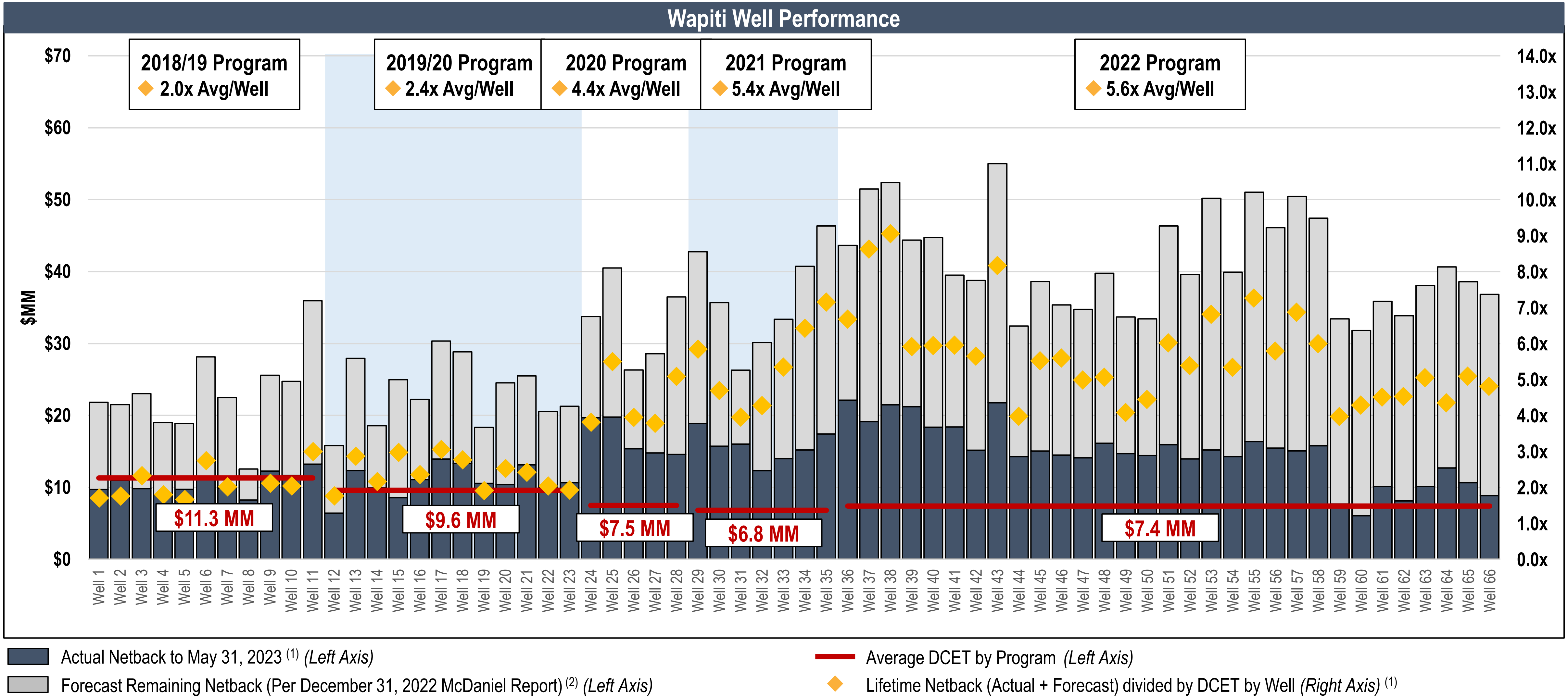
IP 365 *(Boe/d)*	901
IP 365 CGR *(Bbl/MMcf)*	186
Sales Volume *(MBoe)*	1,056
Average CGR *(Bbl/MMcf)*	164
Sales Gas Volume *(Bcf)*	3.1
Sales Condensate *(MBbl)*	491
DCET *($MM)*	$9.0

- Implied capital efficiency of ~$9,950/Boe/d [3]
- Grande Prairie PDP F&D costs were $9.61/Boe in 2022 [3]
  - Results in a recycle ratio of 5.9x when using Wapiti's 2022 netback of $56.42/Boe [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

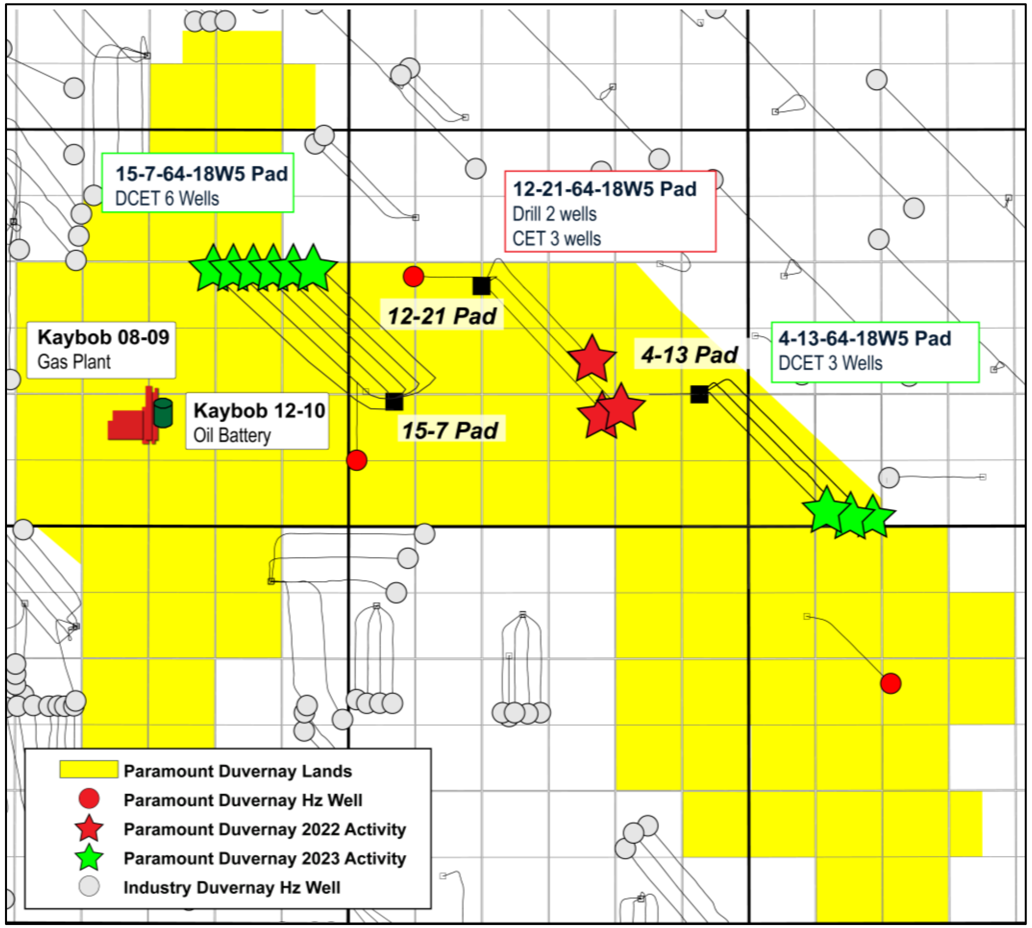
Wapiti wells are generating strong returns on invested capital



(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 less actual netback between January 1, 2023 and May 31, 2023.

Kaybob North Duvernay Overview

The Kaybob North Duvernay play will contribute to the next material wedge of production growth over the coming years



- Three wells were recently brought onstream and six wells are to be drilled and completed in 2023
  - The three-well 4-13 pad was recently brought onstream and includes the longest well drilled in the Company's history by total measured depth
    - Initial production results significantly exceeding expectations
  - Drilling of the six-well 15-7 pad commenced in the second quarter; all wells are expected to be brought onstream in the first quarter of 2024
- 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

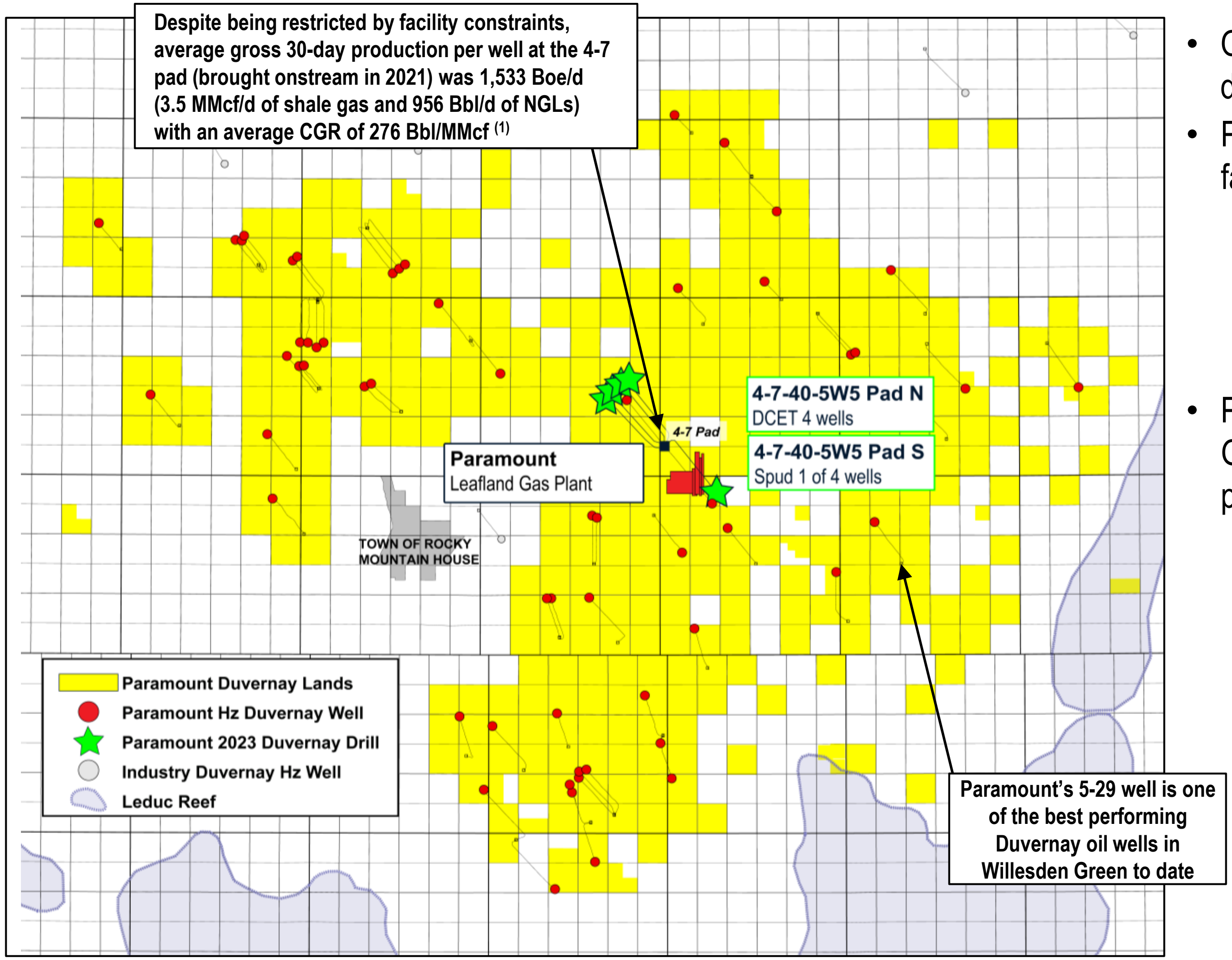
Play Data – 4,200m Avg. Lateral Length (1)	
IP 365 *(Boe/d)*	599
IP 365 CGR *(Bbl/MMcf)*	550
Sales Volume *(MBoe)*	912
Average CGR *(Bbl/MMcf)*	398
Sales Gas Volume *(Bcf)*	1.5
Sales Condensate *(MBbl)*	606
DCET *($MM)*	$12.0

- Targeting plateau production of ~20,000 Boe/d
- 153 full field development locations (37% assigned reserves as at December 31, 2022) based on ~320m inter-well spacing and lateral length of 4,200m (2)
- Implied capital efficiency of ~$20,000/Boe/d (3)
- Paramount expects to realize capital cost efficiencies in the Kaybob North Duvernay as more wells are drilled

(1) Per well data based on management estimates and price deck. See Advisories Appendix – Play Data. **(2)** See Advisories Appendix – Undeveloped Locations. **(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 recently consolidated ~240,000 net acre core Duvernay area



- One four-well pad is planned for 2023 with a second four-well pad set to commence drilling late in the fourth quarter
- Planning for the second phase of development is ongoing including a 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 be onstream in late 2025
  - Advancing commercial arrangements for sales volumes egress
- Paramount controls approximately 240,000 net acres of contiguous land at Willesden Green 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)

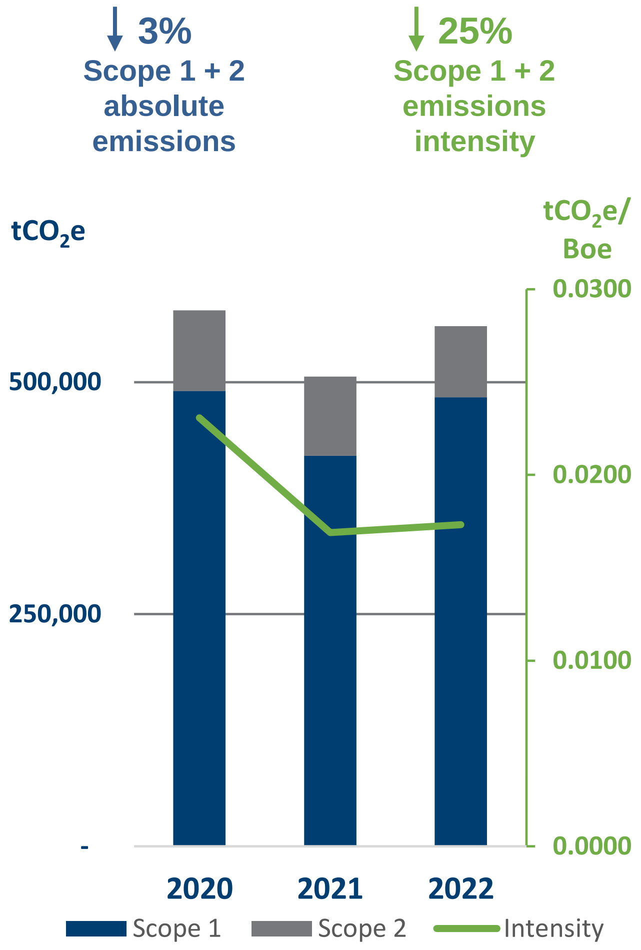
Play Data at 4,000m Avg. Lateral Length (3)	
IP 365 *(Boe/d)*	760
IP 365 CGR *(Bbl/MMcf)*	270
Sales Volume *(MBoe)*	1,240
Average CGR *(Bbl/MMcf)*	202
Sales Gas Volume *(Bcf)*	2.9
Sales Condensate *(MBbl)*	591
DCET *($MM)*	$12.9

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

(1) Production measured at the wellhead. Natural gas sales volumes were lower by approximately 10 percent and liquids sales volumes were lower by approximately 15 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. **(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 prides itself in delivering value to all stakeholders in a responsible manner



Environmental

- Participated in the 2022 CDP Climate Change Survey and received a score of "B"
  - Global oil and gas sector averaged "C"
  - 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
- Recently replaced 26 chemical pumps with solar as part of a pilot program, reducing vented emissions
- Proactively managing decommissioning and reclamation obligations; over 650 wells decommissioned and 740 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]	~$410 million
Investments in Private Companies [2]	~$80 million
Drilling Rigs – Book Value [2]	~$70 million
Undeveloped Land	Not quantified
Total	**~$560 million**

Other Long-Term Resources

Clearwater heavy oil

Horn River Basin natural gas

Liard Basin 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

- Four triple-sized walking rigs
- One conventional triple-sized rig
- Constructing new super-spec walking rig for use in Paramount's 2023 drilling program

Cavalier Energy Inc.

Wholly owned by Paramount

- Cavalier Energy's lands are prospective for in-situ thermal oil recovery and cold flow heavy oil
- 1.357 million gross acres of land located primarily in the Athabasca and Peace River regions of Alberta
- 276,000 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 ~16% 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 ~86,000 net acres

Horn River Basin

Muskwa Shale Play

- Prospective feedstock for west coast LNG
- Paramount holds ~35,000 (19,000 net) acres

Mackenzie Delta

- ~182,000 (30,000 net) acres

Central Mackenzie

- 301,000 (177,000 net) acres

(1) Market value of public companies as at June 30, 2023 (includes ~37.3 million shares of NuVista Energy Ltd. @ $10.62/share). **(2)** Carrying value as at June 30, 2023. Investments in Private Companies include the Company's investments in Sultran and Westbrick Energy Ltd. For further details refer to Paramount's interim consolidated financial statements as at and for the three and six months ended June 30, 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 profile of ~$3.1 billion (1) (~$22 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 financial covenant based revolving credit facility at quarter 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 market conditions. The five-year outlook was prepared effective March 6, 2023 and does not incorporate subsequent changes or events, including changes to development plans made subsequent to such date. **(2)** Based on 142.9 million outstanding Common Shares as at March 6, 2023. (3) See the Advisories Appendix – Forward-Looking Information for a description of certain of the key underlying assumptions.

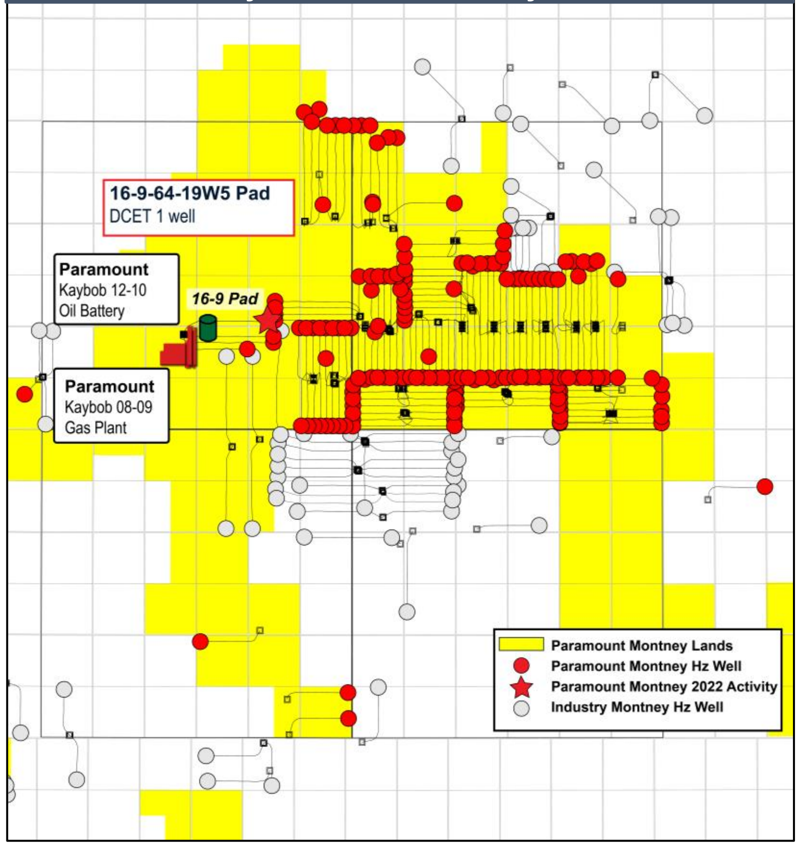
Appendix

Other Montney Assets at Kaybob

Despite limited capital being currently deployed, assets have significant running room for future development

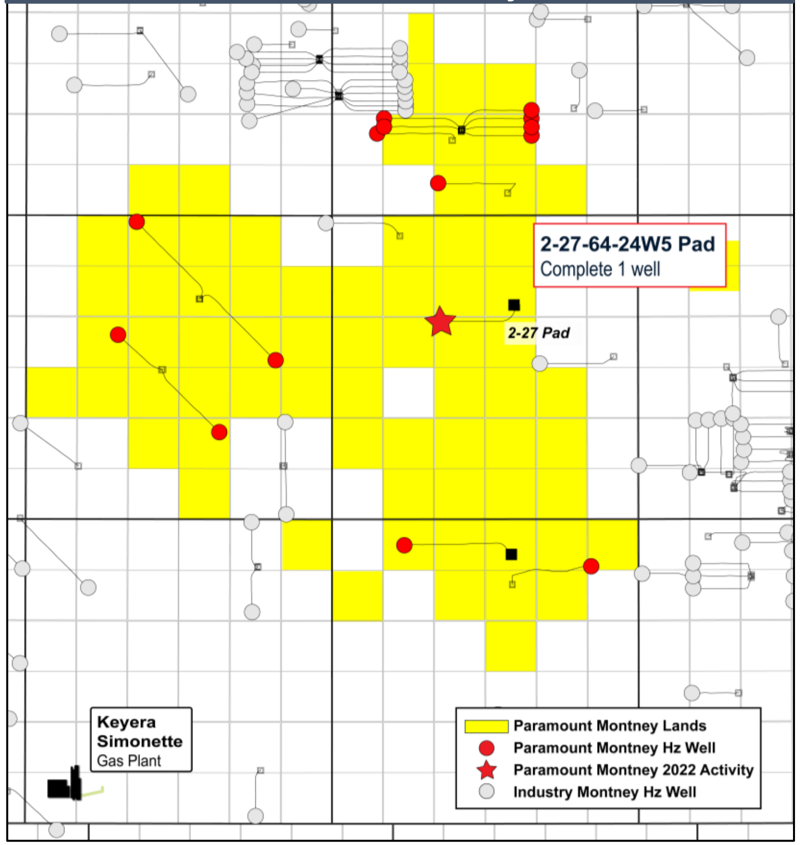
- 26 full field development locations (no locations assigned reserves as at December 31, 2022) (1)

Kaybob North Montney Oil



- 99 full field development locations (no locations assigned reserves as at December 31, 2022) (1)

Ante Creek Montney Oil



(1) See Advisories Appendix – Undeveloped Locations.

Appendix

The following summarizes the performance of the wells at Karr

	DCET Costs ($MM)	Peak 30-Day [1] Total (Boe/d)	Peak 30-Day [1] Wellhead NGLs (Bbl/d)	Peak 30-Day [1] Wellhead Shale Gas (MMcf/d)	Peak 30-Day [1] CGR [3] (Bbl/MMcf)	Cumulative [2] Total (MBoe)	Cumulative [2] Wellhead NGLs (MBbl)	Cumulative [2] Wellhead Shale Gas (MMcf)	Cumulative [2] CGR [3] (Bbl/MMcf)	Days on Production
2023 Wells										
10 wells (Avg. per well)	$9.3	2,078	1,174	5.4	217	175	95	478	200	97
2022 Wells										
16 wells (Avg. per well)	$8.3	1,602	864	4.4	195	319	147	1,029	143	321
2021 Wells										
19 wells (Avg. per well)	$6.3	1,872	988	5.3	186	652	294	2,152	137	647
2020 Wells										
15 wells (Avg. per well)	$7.8	1,548	907	3.8	236	632	306	1,954	157	944
2019 Wells										
8 wells (Avg. per well)	$12.3	1,825	1,262	3.4	373	688	415	1,636	254	1,284
2018 Wells										
5 wells (Avg. per well)	$11.9	1,760	1,051	4.3	247	826	432	2,367	182	1,343
2016/2017 Wells										
27 wells (Avg. per well)	$13.3	1,969	1,171	4.8	245	940	462	2,868	161	1,663

**Paramount is a single stream reporter, and as such, all public production data represents recombined gas.*

(1) Peak 30-Day is the highest daily average production rate over a 30-day consecutive period for each well, measured at the wellhead. Natural gas sales volumes were approximately 11 percent lower and NGLs sales volumes were approximately 6 percent lower due to shrinkage. Excludes days when the wells did not produce. 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. **(2)** Cumulative is the aggregate production measured at the wellhead to July 25, 2023. Natural gas sales volumes were approximately 11 percent lower and NGLs sales volumes were approximately 6 percent lower due to shrinkage. 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. **(3)** CGR means condensate to gas ratio calculated by dividing wellhead NGLs by wellhead natural gas volumes.

Appendix

The following summarizes the performance of the wells at Wapiti

	DCET Costs	Peak 30-Day [1]				Cumulative [2]				Days on Production
	DCET Costs *($MM)*	Total *(Boe/d)*	Wellhead NGLs *(Bbl/d)*	Wellhead Shale Gas *(MMcf/d)*	CGR [3] *(Bbl/MMcf)*	Total *(MBoe)*	Wellhead NGLs *(MBbl)*	Wellhead Shale Gas *(MMcf)*	CGR [3] *(Bbl/MMcf)*	
2022 Wells										
31 wells (Avg. per well)	$7.4	1,582	892	4.1	215	340	162	1,066	152	316
2021 Wells										
7 wells (Avg. per well)	$6.8	1,292	794	3.0	266	349	203	874	232	586
2020 Wells										
5 wells (Avg. per well)	$7.5	1,189	795	2.4	336	406	251	931	269	673
2019/2020 Wells										
12 wells (Avg. per well)	$9.6	1,588	1,044	3.3	320	404	234	1,020	230	905
2018/2019 Wells										
11 wells (Avg. per well)	$11.3	1,051	722	2.0	366	439	259	1,080	240	1,187

**Paramount is a single stream reporter, and as such, all public production data represents recombined gas.*

(1) Peak 30-Day is the highest daily average production rate over a 30-day consecutive period for each well, measured at the wellhead. Natural gas sales volumes were approximately 9 percent lower and NGLs sales volumes were approximately 2 percent lower due to shrinkage. Excludes days when the wells did not produce. 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. **(2)** Cumulative is the aggregate production measured at the wellhead to July 25, 2023. Natural gas sales volumes were approximately 9 percent lower and NGLs sales volumes were approximately 2 percent lower due to shrinkage. 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. **(3)** 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 in 2023 and certain periods therein; (ii) planned capital expenditures in 2023; (iii) forecast free cash flow in 2023; (iv) preliminary 2024 sales volumes, capital expenditures and free cash flow guidance; (v) the anticipated allocation of capital expenditures; (vi) planned 2023 and preliminary expected 2024 abandonment and reclamation expenditures; (vii) the Company's free cash flow priorities; (viii) the potential payment of future dividends; (ix) illustrative adjusted funds flow in 2023 and 2024; (x) anticipated geological and geophysical expenses; (xi) the statement that the Company will, if required, utilize available capacity under the Company's $1.0 billion senior secured credit facility to fund any portion of the 2023 growth capital not funded from adjusted funds flow; (xii) the statement that, based on forecast assumptions, the Company's total preliminary midpoint 2024 capital program, abandonment and reclamation expenditures, geological and geophysical expenses and regular monthly dividend would be fully funded from adjusted funds flow with an estimated excess of approximately $230 million; (xiii) planned production growth at Grande Prairie and Willesden Green Duvernay; (xiv) the Company's five-year outlook for 2027 average annual sales volumes, capital expenditures and cumulative free cash flow; (xv) the statement that there is no cash tax in the five-year outlook until 2027; (xvi) 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; (xvii) potential rates of return or value for the Company's properties; (xviii) undeveloped drilling locations at various properties; (xix) play data, anticipated well performance and forecast netback for various properties; (xx) planned exploration, development and production activities, including the expected timing of 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; (xxi) the expectation that Kaybob North Duvernay will contribute to the next wedge of production growth; and (xxii) 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 the Russian invasion of the Ukraine; (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 required capital to fund its exploration, development and other operations and meet its 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 and storage capacity on acceptable terms and the capacity and reliability of facilities; (x) the ability of Paramount to market its production successfully; (xi) the ability of Paramount and its industry partners to obtain drilling success (including in respect of anticipated production volumes, reserves additions, product yields and resource recoveries) and operational improvements, efficiencies and results consistent with expectations; (xii) the timely receipt of required governmental and regulatory approvals, including approvals required for the expansion and construction of facilities at Willesden Green; (xiii) the application of regulatory requirements respecting abandonment and reclamation and; and (xiv) anticipated timelines and budgets being met in respect of drilling programs and other operations (including well completions and tie-ins, the construction, commissioning and start-up of new and expanded facilities, including facilities at Willesden Green, and facility turnarounds and maintenance).

In addition to the above: (a) forecast 2023 free cash flow is based on (i) the midpoint of stated capital expenditures and annual sales volumes, (ii) $55 million in abandonment and reclamation costs, (iii) $7 million in geological and geophysical expenses, (iv) realized pricing of $53.55/Boe (US$77.48/Bbl WTI, US$3.14/MMBtu NYMEX, $3.11/GJ AECO), (v) a $US/$CAD exchange rate of $0.749, (vi) royalties of $7.90/Boe, (vii) operating costs of $12.60/Boe and (vii) transportation and NGLs processing costs of $4.00/Boe. Assumed pricing of US$80.00/Bbl WTI, US$3.50/MMBtu NYMEX and $3.08/GJ AECO and an assumed $US/$CAD exchange rate of $0.755 for the remaining two quarters of 2023 is unchanged from previous guidance provided on May 3, 2023 but the stated amounts have been adjusted to incorporate actual results for the first two quarters of 2023; and (b) estimated 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) $7 million in geological and geophysical expenses, (iv) realized pricing of $53.60/Boe (US$75.00/Bbl WTI, US$3.50/MMBtu NYMEX, $3.08/GJ AECO), (v) a $US/$CAD exchange rate of $0.755, (vi) royalties of $8.10/Boe, (vii) operating costs of $11.20/Boe and (vii) transportation and NGLs processing costs of $3.60/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 three and six months ended June 30, 2023; (ii) fluctuations in commodity prices; (iii) changes in capital spending plans and planned exploration and development activities; (iv) the potential for changes to preliminary 2024 sales volumes, capital expenditure and free cash flow guidance prior to finalization; (v) the potential for changes to the Company's five-year outlook for 2027 average annual sales volumes, capital expenditures and cumulative free cash flow; (vi) changes in foreign currency exchange rates, interest rates and the rate of inflation; (vii) the uncertainty of estimates and projections relating to future production, revenue, free cash flow, reserves additions, product yields (including condensate to natural gas ratios), resources recoveries, well performance, royalty rates, taxes and costs and expenses; (viii) the ability to secure adequate processing, transportation, fractionation, and storage capacity on acceptable terms; (ix) operational risks in exploring for, developing, producing and transporting natural gas and liquids, including the risk of spills, leaks or blowouts; (x) 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; (xi) potential disruptions, delays or unexpected technical or other difficulties in designing, developing, expanding or operating new, expanded or existing facilities (including third-party facilities); (xii) processing, pipeline, and fractionation infrastructure outages, disruptions and constraints; (xiii) risks and uncertainties that may result in changes to the planned expansion and construction of facilities at Willesden Green, including the potential for changes to facility design or the timelines for construction prior to finalization or the failure to obtain required governmental and regulatory approvals; (xiv) risks and uncertainties involving the geology of oil and gas deposits; (xv) the uncertainty of reserves estimates; (xvi) general business, economic and market conditions; (xvii) 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); (xviii) changes in, or in the interpretation of, laws, regulations or policies (including environmental laws); (xix) the ability to obtain required governmental or regulatory approvals in a timely manner, and to obtain and maintain leases and licenses; (xx) the effects of weather and other factors including wildlife and environmental restrictions which affect field operations and access; (xxi) uncertainties as to the timing and cost of future abandonment and reclamation obligations and potential liabilities for environmental damage and contamination; (xxii) uncertainties regarding Indigenous claims and in maintaining relationships with local populations and other stakeholders; (xxiii) the outcome of existing and potential lawsuits, insurance claims, regulatory actions, audits and assessments and; and (xxiv) 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, 2022, which is available on SEDAR at www.sedar.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 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 2023 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 August 1, 2023, except the information contained herein respecting Paramount's five-year outlook which is effective March 6, 2023. The internally estimated play data information for Karr, Wapiti, Kaybob North Duvernay and Willesden Green contained at pages 8, 9, 11, 13 and 14 in this presentation has been prepared effective July 31, 2023. 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 expense 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 June 30				Year Ended			
	2023		2022		**2022**		2021	
Netback	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)
Petroleum and natural gas sales	**374.4**	***46.63***	536.2	*76.22*	**2,252.4**	***69.60***	1,383.6	*46.23*
Royalties	**(41.2)**	***(5.12)***	(85.2)	*(12.11)*	**(335.3)**	***(10.36)***	(127.0)	*(4.24)*
Operating expense	**(104.6)**	***(13.03)***	(88.7)	*(12.61)*	**(407.1)**	***(12.58)***	(340.4)	*(11.37)*
Transportation and NGLs processing	**(33.6)**	***(4.19)***	(30.8)	*(4.37)*	**(123.7)**	***(3.82)***	(114.5)	*(3.83)*
Sales of commodities purchased [1]	**47.7**	***5.94***	42.7	*6.06*	**272.0**	***8.41***	75.5	*2.52*
Commodities purchased [1]	**(49.3)**	***(6.15)***	(41.1)	*(5.84)*	**(267.0)**	***(8.25)***	(76.1)	*(2.54)*
	193.4	**24.08**	333.1	47.35	**1,391.3**	**43.00**	801.1	26.77

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

	Three Months ended June 30				Year Ended			
	2023		2022		**2022**		2021	
Netback	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)
Petroleum and natural gas sales	**315.8**	***51.83***	379.9	*85.65*	**1,651.8**	***77.33***	1,006.1	*53.14*
Royalties	**(39.3)**	***(6.45)***	(62.9)	*(14.17)*	**(261.2)**	***(12.23)***	(87.2)	*(4.61)*
Operating expense	**(70.7)**	***(11.61)***	(55.9)	*(12.61)*	**(247.6)**	***(11.59)***	(205.3)	*(10.84)*
Transportation and NGLs processing	**(27.2)**	***(4.47)***	(22.1)	*(4.99)*	**(93.1)**	***(4.36)***	(82.9)	*(4.37)*
	178.6	***29.30***	239.0	*53.88*	**1,049.9**	***49.15***	630.7	*33.32*

Karr netbacks for the applicable periods are summarized below:

	Three Months ended June 30				Year Ended			
	2023		2022		**2022**		2021	
Netback	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)
Petroleum and natural gas sales	**202.4**	***50.34***	233.9	*82.14*	**985.0**	***74.86***	725.4	*51.78*
Royalties	**(21.5)**	***(5.35)***	(45.8)	*(16.09)*	**(190.2)**	***(14.46)***	(74.5)	*(5.32)*
Operating expense	**(44.4)**	***(11.04)***	(36.0)	*(12.65)*	**(149.3)**	***(11.35)***	(134.1)	*(9.57)*
Transportation and NGLs processing	**(18.4)**	***(4.57)***	(15.2)	*(5.34)*	**(58.4)**	***(4.43)***	(59.7)	*(4.26)*
	118.1	***29.38***	136.9	*48.06*	**587.1**	***44.62***	457.1	*32.63*

Wapiti netbacks for the applicable periods are summarized below:

	Three Months ended June 30				Year Ended			
	2023		2022		**2022**		2021	
Netback	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)
Petroleum and natural gas sales	**113.4**	***54.72***	146.0	*91.94*	**666.8**	***81.30***	280.7	*57.03*
Royalties	**(17.8)**	***(8.58)***	(17.1)	*(10.72)*	**(71.0)**	***(8.65)***	(12.7)	*(2.58)*
Operating expense	**(26.3)**	***(12.72)***	(19.9)	*(12.56)*	**(98.3)**	***(11.99)***	(71.2)	*(14.46)*
Transportation and NGLs processing	**(8.8)**	***(4.28)***	(6.9)	*(4.35)*	**(34.7)**	***(4.24)***	(23.2)	*(4.73)*
	60.5	***29.14***	102.1	*64.31*	**462.8**	***56.42***	173.6	*35.26*

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

Advisories

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 year, excluding expenditures related to Fox Drilling and Cavalier Energy and corporate capital expenditures, plus the change from the prior year in estimated future development capital included in the applicable reserves evaluation prepared by McDaniel. 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, 2022, 2021 and 2020. Columns may not add due to rounding.

($ millions)	Total Company			
Proved Developed Producing	**2022**	2021	2020	3-year Total
Capital expenditures	655	275	221	1,151
Fox Drilling, Cavalier Energy and corporate	(69)	(6)	(2)	(77)
Change in estimated future development capital	(10)	(11)	54	34
F&D Capital – PDP	577	257	273	1,107
Total Proved	**2022**	2021	2020	3-year Total
Capital expenditures	655	275	221	1,151
Fox Drilling, Cavalier Energy and corporate	(69)	(6)	(2)	(77)
Change in estimated future development capital	1,249	221	(962)	509
F&D Capital – TP	1,835	490	(743)	1,582
Proved Plus Probable	**2022**	2021	2020	3-year Total
Capital expenditures	655	275	221	1,151
Fox Drilling, Cavalier Energy and corporate	(69)	(6)	(2)	(77)
Change in estimated future development capital	1,176	(93)	(1,196)	(112)
F&D Capital – P+P	1,762	176	(977)	961

($ millions)	Grande Prairie Region			
Proved Developed Producing	**2022**	2021	2020	3-year Total
Capital expenditures	453	229	197	879
Change in estimated future development capital	(20)	(22)	(4)	(45)
F&D Capital – PDP	433	207	193	833
Total Proved	**2022**	2021	2020	3-year Total
Capital expenditures	453	229	197	879
Change in estimated future development capital	447	(182)	(736)	(470)
F&D Capital – TP	901	47	(539)	409
Proved Plus Probable	**2022**	2021	2020	3-year Total
Capital expenditures	453	229	197	879
Change in estimated future development capital	297	(197)	(1,106)	(1,007)
F&D Capital – P+P	750	31	(909)	(128)

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 Reconciliation" in the Company's annual information forms for the years ended December 31, 2022, 2021 and 2020, which are available on www.sedar.com 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 2022, 2021 and 2020.

	Total Company					
	F&D ($/Boe)			Recycle Ratio (x)		
	2022	2021	2020	2022	2021	2020
Proved Developed Producing	$9.58	$6.22	$7.90	4.5x	4.3x	1.0x
Total Proved	$14.11	$6.72	na	3.0x	4.0x	na
Proved plus Probable	$14.87	$2.12	na	2.9x	12.6x	na

	Grande Prairie					
	F&D ($/Boe)			Recycle Ratio (x)		
	2022	2021	2020	2022	2021	2020
Proved Developed Producing	$9.61	$6.53	$8.79	5.1x	5.1x	1.3x
Total Proved	$9.95	$1.99	na	4.9x	16.8x	na
Proved plus Probable	$11.82	$0.59	na	4.2x	56.2x	na

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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 May 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 production during the period in Boe. This measure is used by investors and management to assess netback on a unit of production basis.

Capital Management Measures

Adjusted funds flow 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 15 – Capital Structure in the interim consolidated financial statements of Paramount as at and for the three and six months ended June 30, 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 three and six months ended June 30, 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	
GJ	Gigajoules
GJ/d	Gigajoules per day
Mcf	Thousands of cubic feet
MMcf	Millions of cubic feet
MMcf/d	Millions of cubic feet per day
AECO	AECO-C reference price

Liquids	
Bbl	Barrels
Bbl/d	Barrels per day
MBbl	Thousands of barrels
NGLs	Natural Gas Liquids
Condensate	Pentane and heavier hydrocarbons
WTI	West Texas Intermediate

Oil Equivalent	
Boe	Barrels of oil equivalent
Mboe	Thousands of barrels of oil equivalent
MMBoe	Millions of barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day

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 three months ended June 30, 2023, the value ratio between crude oil and natural gas was approximately 31:1. 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, 2022 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, 2022 which is available on SEDAR at www.sedar.com.

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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 2023 annual sales volumes will average between 95,000 Boe/d and 98,000 Boe/d (54% shale gas and conventional natural gas combined, 40% condensate, light and medium crude oil, tight oil and heavy crude oil combined and 6% other NGLs). Second half 2023 sales volumes are expected to average between 98,000 Boe/d and 102,000 Boe/d (53% shale gas and conventional natural gas combined, 40% condensate, light and medium crude oil, tight oil and heavy crude oil combined and 7% other NGLs).

The Company's preliminary 2024 guidance provides for annual sales volumes that will average between 110,000 Boe/d and 120,000 Boe/d (52% shale gas and conventional natural gas combined, 41% condensate, light and medium crude oil, tight oil and heavy crude oil combined and 7% other NGLs).

See "Product Type Information" at page 28 of the Company's Management's Discussion and Analysis for the three and six months ended June 30, 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 6, 2023 and effective December 31, 2022 (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, 2023 price forecasts for McDaniel and GLJ Petroleum Consultants Ltd. and the December 31, 2022 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. The reserves referenced in this document include reserves associated with the Kaybob Smoky and Kaybob South Duvernay properties that were subsequently disposed of in January 2023. Readers should refer to the Company's annual information form for the year ended December 31, 2022, which is available on SEDAR at www.sedar.com 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. The annual information form also contains a description of the reserves associated with the Kaybob Smoky and Kaybob South Duvernay properties in the section titled "Reserves and Other Oil and Gas Information - Impact of Kaybob Disposition".

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Play Data

The internally estimated play data information for Karr, Wapiti, Kaybob North Duvernay and Willesden Green contained at pages 8, 9, 11, 13 and 14 in this presentation has been prepared effective July 31, 2023 by internal qualified reserves evaluators from Paramount in accordance with COGEH and using commodity prices of US$80.00/Bbl WTI, $3.25/MMBtu AECO and an exchange rate of US$0.755 for one Canadian dollar for the last six months of 2023 and US$75.00/Bbl WTI, $3.25/MMBtu AECO and an exchange rate of US$0.755 for one Canadian dollar for 2024 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 current 2023 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, 2022, which is available on SEDAR at www.sedar.com 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 effective December 31, 2022 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 presentation references the percentage of future potential undeveloped locations assigned reserves in the McDaniel Report solely to provide the reader with additional information concerning the proportion of 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. 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, for the referenced gross undeveloped locations of each applicable property, the number of locations that were assigned reserves in the McDaniel Report.

	Karr (Middle Montney)	Wapiti	Kaybob North Duvernay	Kaybob North Montney Oil	Ante Creek Montney Oil	Willesden Green Duvernay
Referenced Undeveloped Locations	250	229	153	26	99	708
Locations Assigned Reserves in the McDaniel Report	164	155	57	0	0	70

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