*All information contained in this presentation assumes the successful acquisition of Hammerhead Energy Inc. ("HHRS") and reflects the closing of the Company's $500 million bought deal financing on November 10, 2023 and the use of proceeds thereunder. Please see our presentation titled " Corporate Presentation – November 2023" on our website crescentpointenergy.com for a summary of our current operations and our forward looking plans without HHRS.*

**November 2023**

# Corporate Presentation
## (Pro Forma Closing Hammerhead Acquisition)

**CRESCENT POINT**

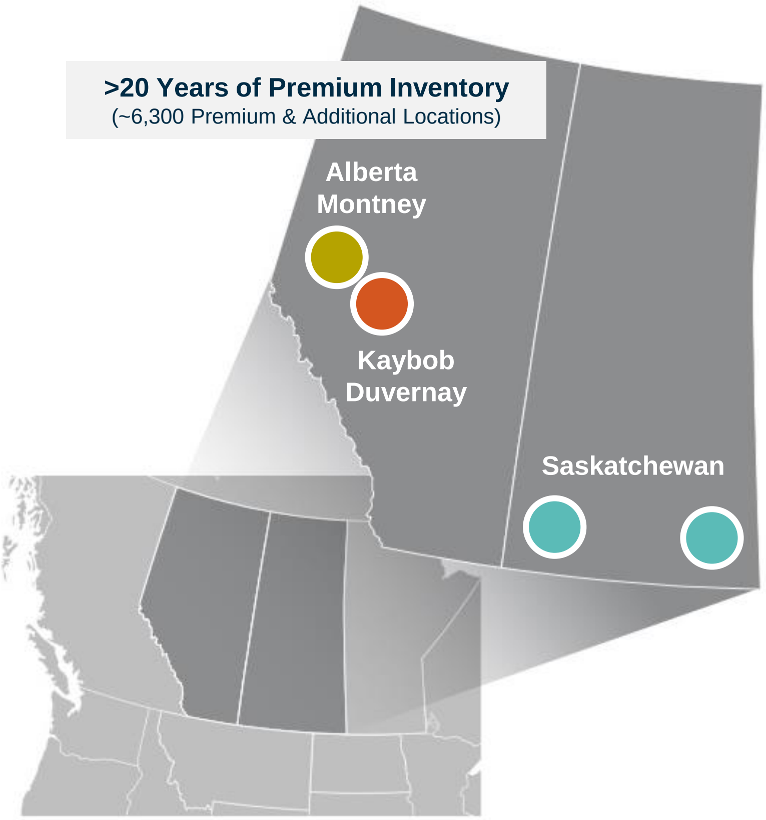
*Bringing Energy To Our World - The Right Way*

# Crescent Point At A Glance

| Capital Markets Summary | Prior | Pro Forma |
|---|---|---|
| **Shares Outstanding** | 525.1 million | 625.3 million |
| **Market Capitalization** | $5.2 billion | $6.2 billion |
| **Net Debt** | $2.2 billion | $3.7 billion |
| **Enterprise Value** | $7.4 billion | $9.9 billion |

| 2024 Preliminary Outlook | |
|---|---|
| **Annual Average Production** | 200,000 - 208,000 boe/d (~65% Liquids) |
| **Development Capital Expenditures** | $1.45 - $1.55 billion |
| **Excess Cash Flow** (US$75 - US$80 WTI) | $1.0 -1.2 billion |
| **YE D/CF** (US$75 - US$80 WTI) | 1.1x - 1.2x |

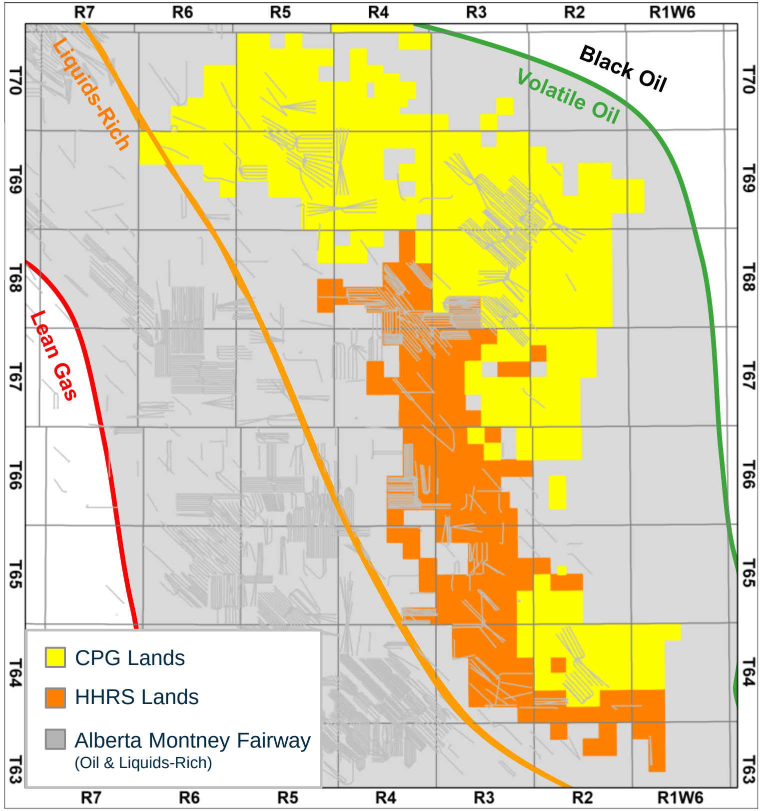
| Return of Capital | |
|---|---|
| **Quarterly Base Dividend** (Expected to be declared in Q1 2024) | $0.115/share (4.7% Yield) |
| **Total Return of Capital** (Base dividend, share repurchases & special dividend) | ~60% (% of Excess Cash Flow) |




Dividend yield based on first quarter 2024 base dividend of $0.115/share, which is subject to Board approval upon the successful closing of the Alberta Montney acquisition of Hammerhead Energy Inc. ("HHRS") (the "Transaction") and market conditions. Pro forma capital markets data as at November 7, 2023 pro forma Alberta Montney Transaction and bought deal offering which closed on November 10, 2023. Prior net debt as at September 30, 2023 net debt pro forma North Dakota disposition which closed subsequent to the quarter. Prior market capitalization and enterprise value are based on November 7, 2023 share price and October 24, 2023 share count. Total inventory based on YE 2022 locations and includes locations acquired in Kaybob Duvernay and Alberta Montney in 2023, less locations included in disposition of North Dakota assets which closed in Q4 2023. Premium inventory is based on management's estimates of established, delineated and well-defined locations with an estimated payback period of less than two years. D/CF refers to YE 2024 net debt / funds flow.

# Portfolio Transformation with Strategic Alberta Montney Consolidation

**Alberta Montney & Kaybob Duvernay focused company with complimentary long-cycle Saskatchewan assets**




*On a pro forma basis, the transaction is…*

## Highly Strategic

- ✓ **Enhances sustainability** with corporate premium drilling inventory estimated to exceed 20 years
- ✓ Ownership of **significant infrastructure** with secured **market access** in place for future scalability

## Significantly Accretive

- ✓ Expected to result in **>15% per share accretion** to excess cash flow and return of capital, on average, over the company's 5-year plan
- ✓ Planning to **increase the base dividend** by 15% to $0.46/share (annualized)

## Increases Size & Scale

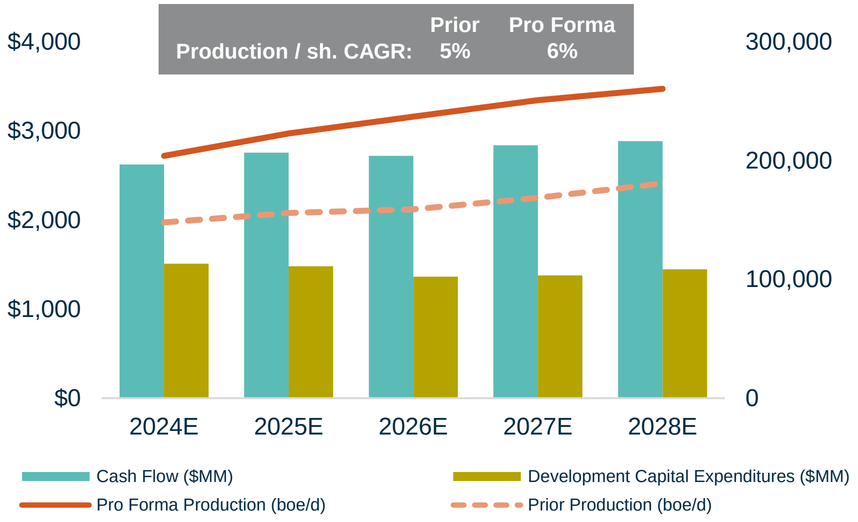
- ✓ **Largest owner of land** in the volatile oil fairway with ~350,000 net acres in the Alberta Montney, providing significant operational synergies
- ✓ Become 7th largest Canadian E&P by production volume (~65% oil & liquids)

Subject to the closing of the Transaction, market conditions and the approval of CPG's Board of Directors, CPG intends to increase its dividend, the declaration of which is anticipated to be in early 2024. >15% accretion estimate is an average of the expected annual accretion within the corporation's 5-year plan starting in 2024, assuming flat pricing of US$75/bbl WTI and $3.50/mcf AECO during such 5-year period. CPG would become the seventh largest company by production volume, when comparing the current production of Canadian domiciled companies operating in the Western Canadian Sedimentary Basin to the pro forma production of CPG post-closing the Transaction.

# Transaction is Accretive to 5-Year Plan

## Pro Forma 5-Year Plan: Disciplined Growth

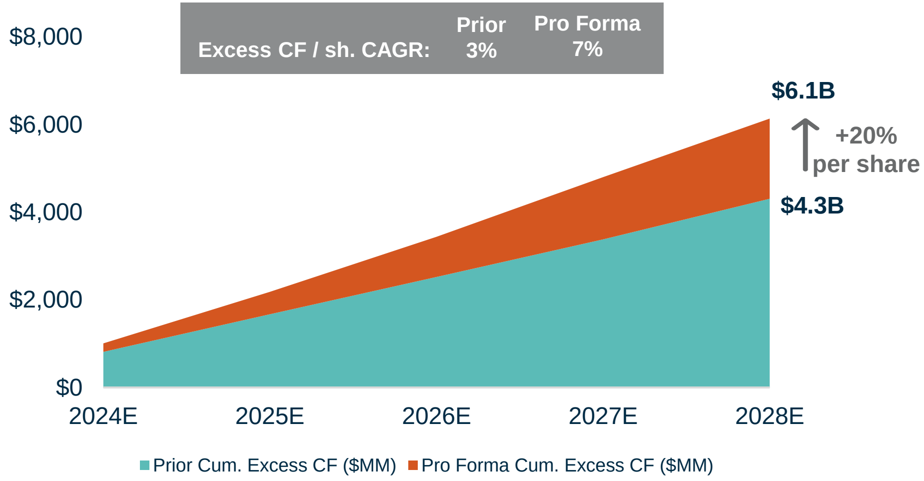
(US$75 WTI & $3.50 AECO)




- Production from acquired assets is expected to grow from ~56,000 boe/d in 2024 to ~80,000 boe/d in 2026 and stay flat for the remainder of the 5-Year plan
- 5-year expected cumulative asset level FCF (NOI-Capex) of $2.6B (~5-year payback on purchase price)

## Pro Forma 5-Year Plan: Significant After-Tax Excess Cash Flow

(US$75 WTI & $3.50 AECO)

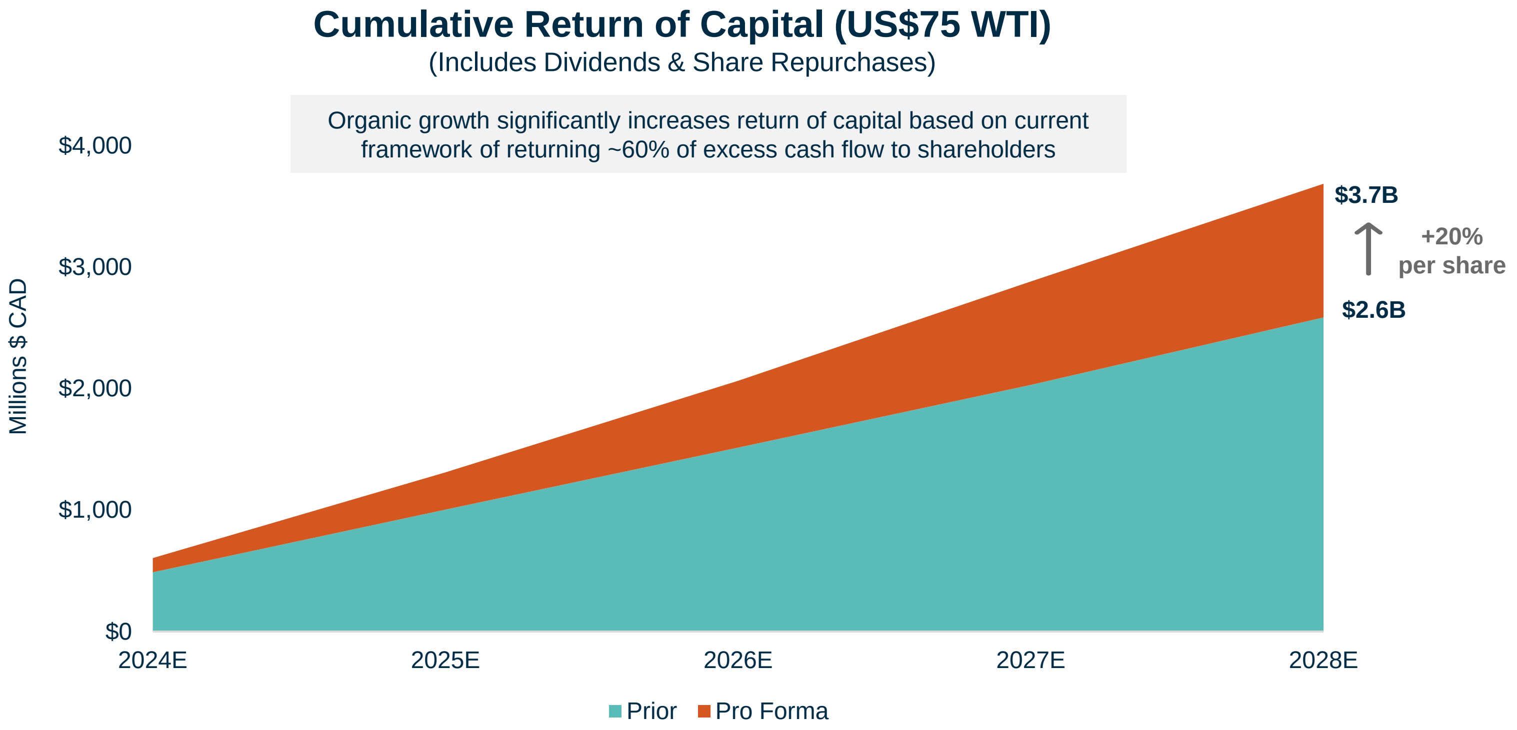



| Key Metrics | 2024E | 2028E |
|---|---|---|
| **Annual Avg. Production (boe/d)** | 204,000 | **260,000** |
| **Development Capital Expenditures** | $1.5B | **$1.4B** |
| **Reinvestment Ratio** | 57% | **50%** |
| **Year-End Leverage Ratio (D/CF)** | 1.1x | **0.4x** |
| **Base Decline Rate** | 30% | **27%** |

All figures are approximates. Per share amounts do not include any assumption of future share repurchases.
Outlook is derived by utilizing, among other assumptions, historical production performance. Reinvestment ratio is defined as development capital expenditures as a % of cash flow. Assumes AECO of $3.50/Mcf in 2024-2028. Forecasts beyond 2023 have not been finalized and are subject to a variety of factors including prior year's results. NOI: net operating income. 2024 key metrics based on the mid-point of preliminary guidance.

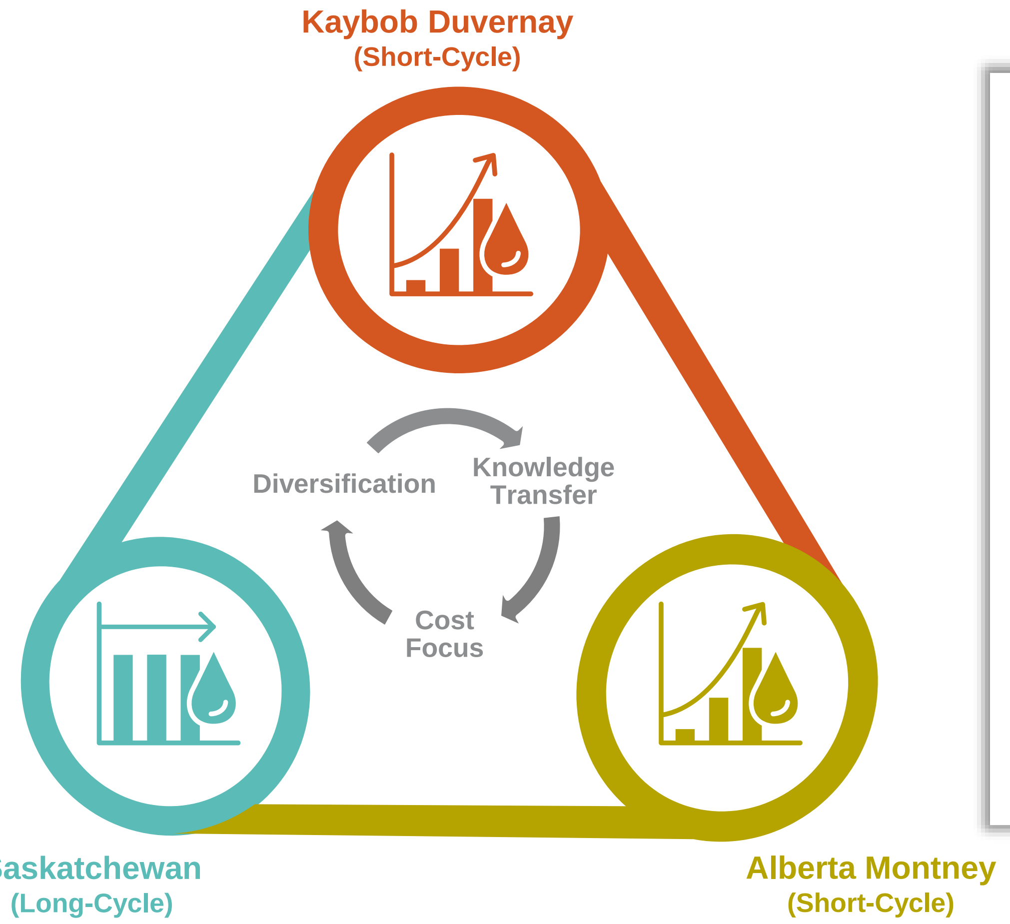
# Increasing Return of Capital to Shareholders

**Plan to increase percentage allocation of excess cash flow over time as the balance sheet strengthens further**




All figures are estimates.
Cumulative return of capital assumes a quarterly base dividend of $0.115/share which is subject to Board approval upon the successful closing of the Transaction and market conditions. Assumes $3.50/mcf AECO for 2024-2028.

# On Strategy & Bolsters Short-Cyle Assets within the Portfolio




## Alberta Montney Consolidation Adds:

- ✓ **+105,000 net acres** with Montney rights
- ✓ **+800 premium** net drilling locations
- ✓ **+56,000 boe/d growing to** an estimated **80,000 boe/d** in 5-year plan
- ✓ **Significant infrastructure** & **long-term market access** contracts
- ✓ **$1.3B of tax pools**

**Builds on operational execution** achieved to-date in the area

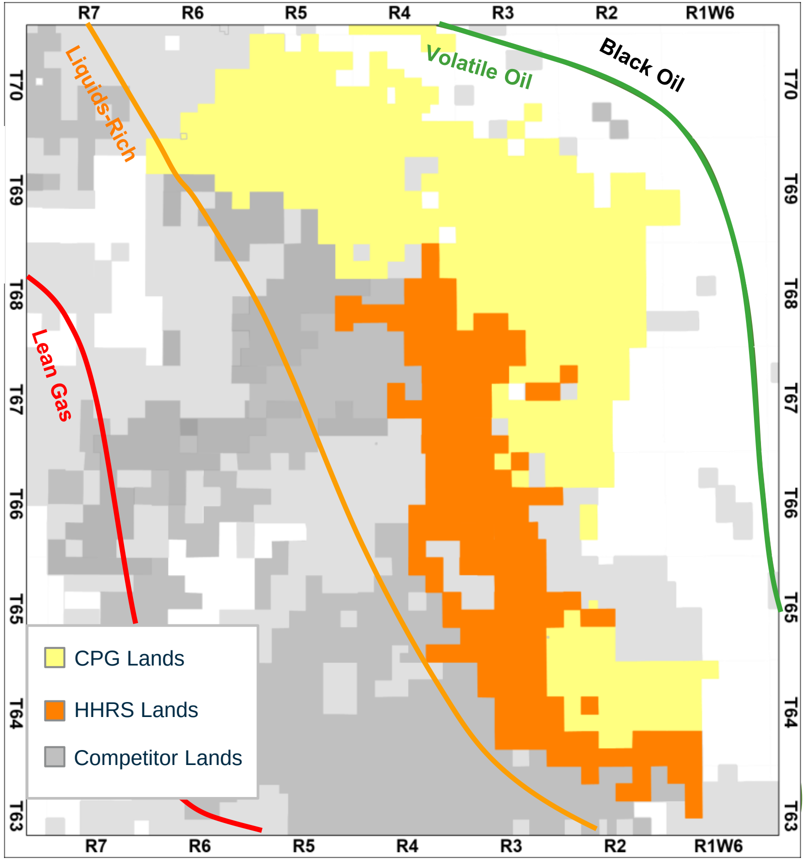
56,000 boe/d is the Company's expected production from the acquired assets in 2024E.

# Contiguous & Adjacent to Existing Montney Land with Operational Synergies

- Establishes **dominant and controlling land position** in the Alberta Montney volatile oil fairway
  - Acquired lands are Crown with a high average working interest rate, primarily 100%, and limited expiry concerns
- **Attractive reservoir characteristics** with significant net pay, similar to CPG's existing Gold Creek, and higher than normal pressure
- Expected to generate **significant financial and operational synergies** in the near-term through lower G&A and capital costs
  - Focused on realizing additional value by optimizing the number of wells drilled per section, D&C design, sharing of infrastructure, pad development continuity and supply chain management

## Alberta Montney Metrics

| | Hammerhead | Pro Forma CPG |
|---|---|---|
| **2024E Production (boe/d)**<br>% Oil & Liquids | 56,000<br>50% | 94,000<br>50% |
| **Net Acres** | 105,000 | 350,000 |
| **Phase Window** | Volatile Oil | Volatile Oil |
| **Premium Drilling Locations**<br>% Booked | 800<br>30% | 1,400<br>30% |

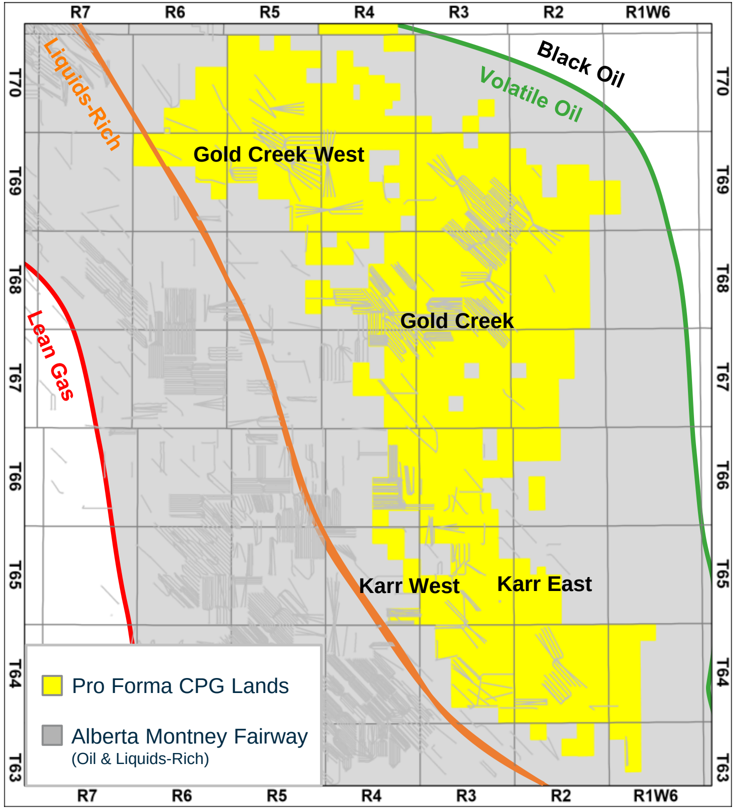



All figures are estimates and approximates. G&A: general and administrative. 2024E production for HHRS assets reflects CPG's management's estimates based on the assets' production profile and CPG's expected development capital spend on the assets of ~$400MM in 2024. Premium drilling locations include 415 net booked locations for pro forma CPG Alberta Montney, including 252 net booked locations for the acquired assets as assigned by the independent evaluator McDaniel & Associates ("McDaniel") as of November 1, 2023 and 163 net booked locations for CPG's existing assets as assigned by McDaniel as of December 31, 2022.

# Alberta Montney Reservoir Regions & Economics (Booked Type Wells)

## 1,400 premium locations in the Volatile Oil window

| Gold Creek West | |
|---|---|
| IP30 (boe/d)<br>(% Liquids) | 1,025<br>(58%) |
| EUR (mboe)<br>(% Liquids) | 710<br>(54%) |
| Cost Per Well ($MM) | $9.0 |
| NPV10% ($MM) | $9.0 |
| Payout (Months) | 10 |
| IRR% | 125% |
| Net Locations | 300 |




| Gold Creek | |
|---|---|
| IP30 (boe/d)<br>(% Liquids) | 950 – 1,300<br>(50% – 55%) |
| EUR (mboe)<br>(% Liquids) | 750 – 1,150<br>(40% – 45%) |
| Cost Per Well ($MM) | $6.0 – $9.0 |
| NPV10% ($MM) | $8.5 – $10.5 |
| Payout (Months) | 9 – 10 |
| IRR% | 140% – 145% |
| Net Locations | 445 |

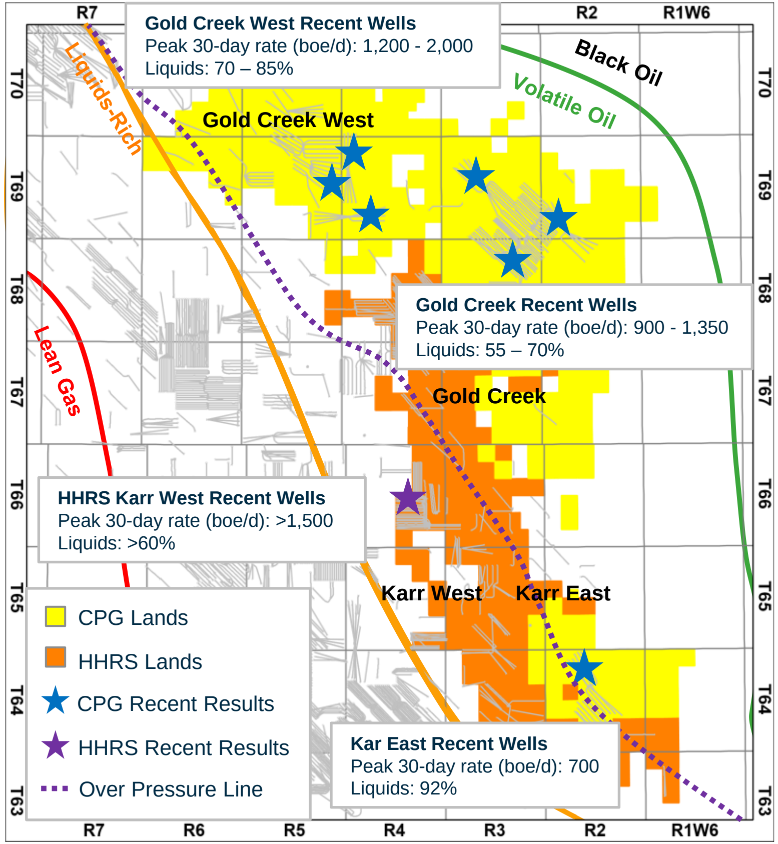
| Karr West | |
|---|---|
| IP30 (boe/d)<br>(% Liquids) | 1,330<br>(65%) |
| EUR (mboe)<br>(% Liquids) | 1,050<br>(50%) |
| Cost Per Well ($MM) | $10.0 |
| NPV10% ($MM) | $14.0 |
| Payout (Months) | 10 |
| IRR% | 140% |
| Net Locations | 180 |

| Karr East | |
|---|---|
| IP30 (boe/d)<br>(% Liquids) | 700 – 1,080<br>(55% – 80%) |
| EUR (mboe)<br>(% Liquids) | 750 – 850<br>(50% – 75%) |
| Cost Per Well ($MM) | $9.5 – $11.0 |
| NPV10% ($MM) | $8.5 – $17.5 |
| Payout (Months) | 8 – 15 |
| IRR% | 75% – 175% |
| Net Locations | 485 |

All figures are approximates. Estimated ultimate recoveries (EURs) based on an average of type wells in McDaniel's evaluation reports for CPG (Decmeber 31, 2022) and HHRS (November 1, 2023).
Economics as at US$75/bbl WTI and $3.50/mcf AECO, with payouts calculated from initial onstream date. Inventory of approximately 1,400 net premium locations includes 415 booked Proved plus Probable (2P) locations.

# Alberta Montney Results & Development Plan

**Focused on efficient development of resource by optimizing landing zone and number of wells drilled per section**



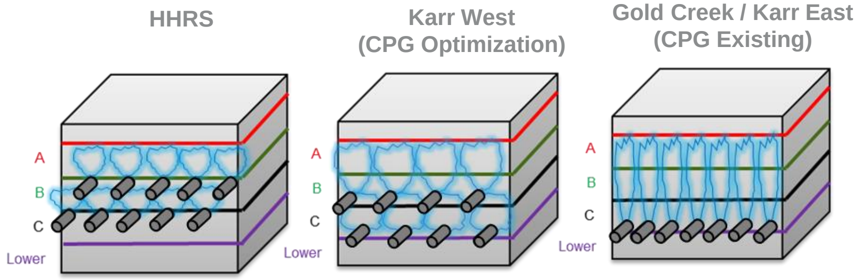

All figures are approximates.

## CPG's Existing Montney Development Plan:

- CPG **optimized well design by landing lower in middle Montney formation** and deploying a **larger frac** to enhance EURs across multiple benches
- Ability to execute 'elevator fracs' based on consistent pressure gradients
- Currently drilling 5-7 wells per section

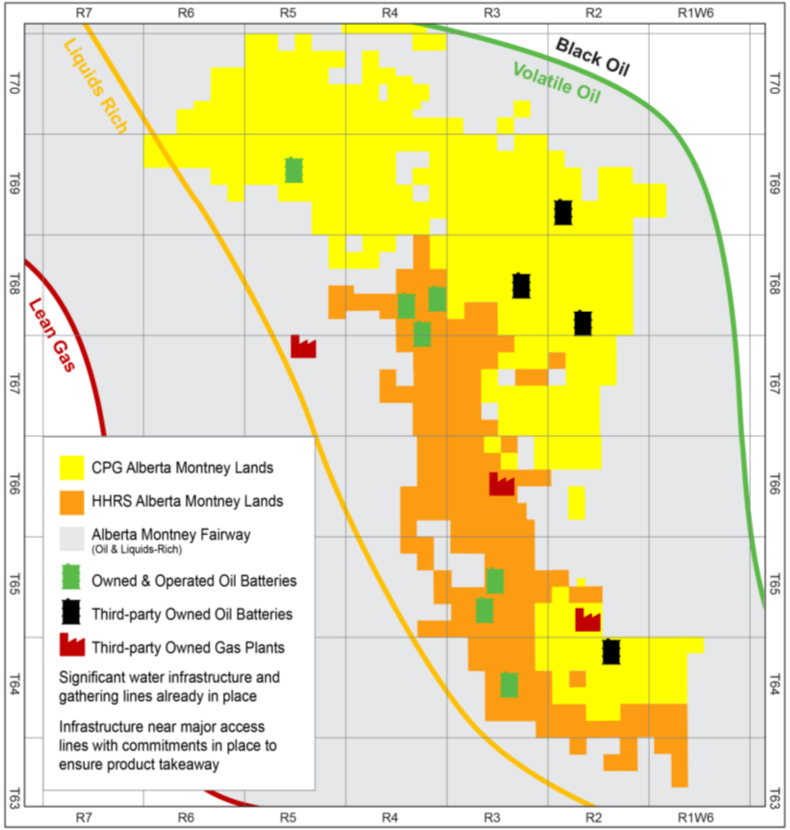
## Development Plan For Acquired Assets:

- **Opportunity to enhance well design and reduce wells drilled per section** (HHRS currently drills 10-11 wells per section across its land base)
- In Gold Creek & Karr East (both normally pressured lands), CPG plans to drill up to 7 wells per section across one bench with a larger frac design
- In Karr West (slightly over pressured lands), CPG plans to drill 8 wells per section across two benches with an optimized frac design



# Transaction Adds Significant Alberta Montney Infrastructure & Market Access

**Infrastructure supports significant potential for Alberta Montney production growth**



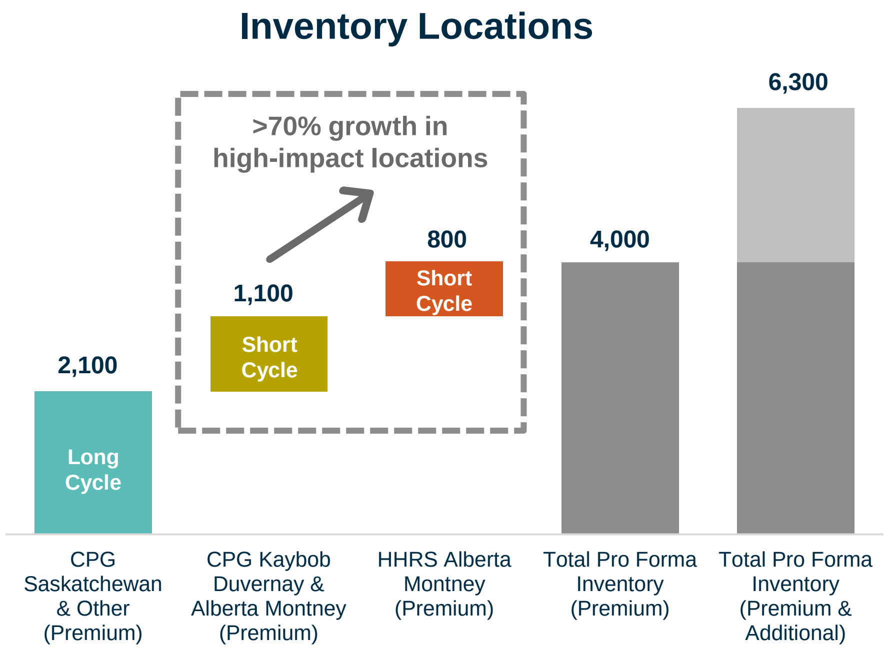

## Key Infrastructure Ownership

- ✓ Benefitting from ~$500MM of previous infrastructure investment by HHRS, including:
  - ✓ Six oil batteries & compression facilities with sales capacity of >80,000 boe/d, which CPG expects to grow production to within its 5-year plan
  - ✓ Gathering lines to all key plants & access lines for product takeaway
  - ✓ Major water infrastructure, including ~25 water disposal wells
- ✓ Access to third party gas processing with significant unutilized capacity
- ✓ Strategic marketing and transportation agreements in place to support future production growth

$500MM reflects HHRS's estimate of its cumulative capital investment on infrastructure since its inception in 2009 to its expected spend by year-end 2023. The sixth battery is expected to be operational in December 2023.

# Deep Inventory of Premium Drilling Locations

**Acquisition expected to increase total premium drilling inventory to >20 years, supporting long-term sustainability**



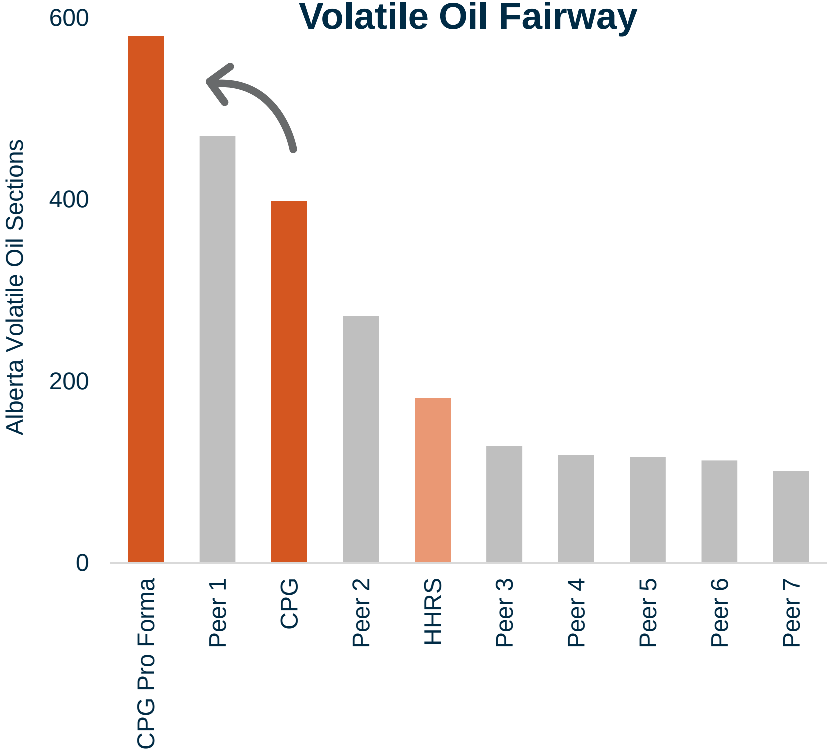

- 4,000 high-return premium locations (pro forma) across Alberta Montney, Kaybob Duvernay and Saskatchewan
- Depth of premium inventory across portfolio provides flexibility in capital allocation program and operations
- 2,300 locations in addition to premium inventory that can be drilled at higher commodity prices or with improvements in costs or EUR

All figures are estimates.
Estimated ultimate recoverable (EUR) reflects the amount of oil and gas expected to be economically recovered from a well, reservoir, or field by the end of its producing life. Pro forma inventory locations presented above are net and include 252 booked Proved plus Probable (2P) locations for the announced Transaction as of November 1, 2023, 163 net booked locations for CPG's existing Montney assets as estimated by McDaniel as of December 31, 2022,and 1,487 CPG booked 2P locations from the Company's McDaniel reserves evaluation as at YE 2022 in accordance with NI 51-101 and the COGE Handbook.

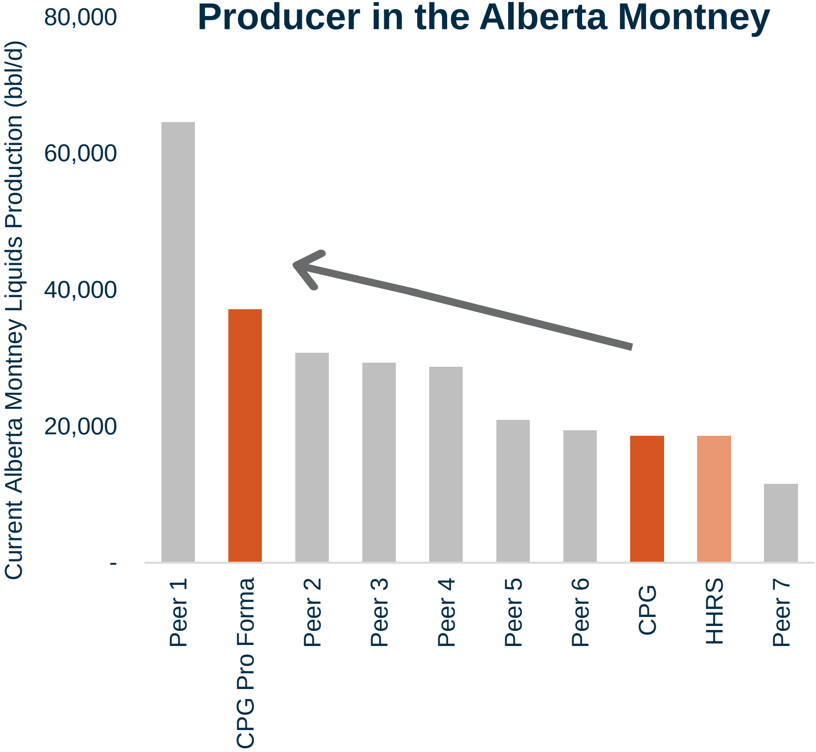
# Increased Scale

**Creates 7th largest E&P in Canada by production volume and is expected to improve cost of capital**

## Largest Position in the Alberta Montney Volatile Oil Fairway



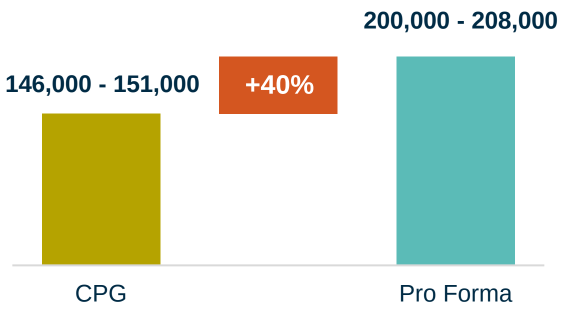

## Creates 2nd Largest Oil & Liquids Producer in the Alberta Montney



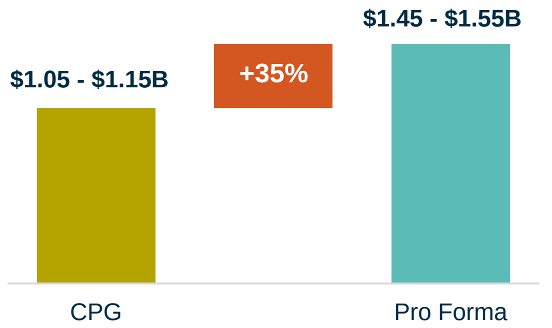

Alberta volatile oil sections source: BMO Capital Markets, geoSCOUT, GeoEdges, Canadian Discovery, company and public disclosure.
Alberta volatile oil sections peers: AAV, BIR, CNQ, KEL, LGN, OVV, SCR. Alberta Montney liquids production peers: ARX, CNQ, NVA, OVV, POU, SCR, WCP. CPG would become the seventh largest company by production volume, when comparing the current production of Canadian domiciled companies operating in the Western Canadian Sedimentary Basin to the pro forma production of CPG post-closing the Transaction.

# Preliminary 2024 Budget

## 2024 Production (boe/d)




## 2024 Development Capital Expenditures




Revised preliminary **2024E production estimate to 200,000 - 208,000 boe/d** (65% oil & liquids) based on **development capital expenditures of $1.45 - $1.55B**, including ~$400MM for the acquired assets

2024E preliminary budget is expected to **generate $1.0 - $1.2B excess cash flow** with a leverage ratio of 1.1 - 1.2x D/CF by YE 2024 (US$75 - US$80 WTI)

**~80% of 2024 budget expected to be allocated to Alberta Montney and Kaybob Duvernay** with remaining capital allocated to long-cycle assets in Saskatchewan

All figures are estimates. D/CF is equivalent to net debt to adjusted funds flow.
YE 2024 D/CF is based on 2024E production of 145,000 – 151,000 boe/d from CPG's existing assets and production of 56,000 boe/d from the acquired assets, US$75 – US$80/bbl WTI and $3.50/mcf AECO.

# Strategic Priorities

## Operational Execution

- Continue to **enhance asset level returns** through efficiencies and productivity improvements
- **Execute organic growth plan** while generating **significant operational synergies** from the announced Transaction

## Balance Sheet Strength

- 1.1 - 1.2x D/CF at YE 2024 (US$75 - US$80 WTI) and established a **near-term target of ~1.0x** (mid-cycle pricing)
- Allocating **~40% of excess cash flow to balance sheet** with a third of 2024 production currently hedged at attractive pricing

## Increasing Return of Capital

- **Increasing base dividend ~15%,** while continuing to return ~60% of excess cash flow to shareholders
- As balance sheet strengthens further, CPG plans to **increase its return of capital allocation**

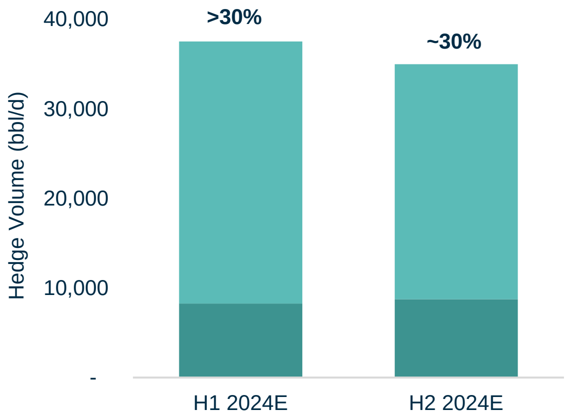
All figures are estimates. D/CF is equivalent to net debt to adjusted funds flow. YE 2024 D/CF is based on 2024E production of 145,000 – 151,000 boe/d from CPG's existing assets and production of 56,000 boe/d from the acquired assets, US$75 – US$80/bbl WTI and $3.50/mcf AECO. Subject to the closing of the Transaction, market conditions and the approval of CPG's Board of Directors, CPG intends to increase its dividend; the declaration of which is anticipated to be in early 2024.

# Hedging Summary

**Plan to remain disciplined in our approach to layering on additional protection in the context of commodity prices**

## Oil & Liquids Hedging

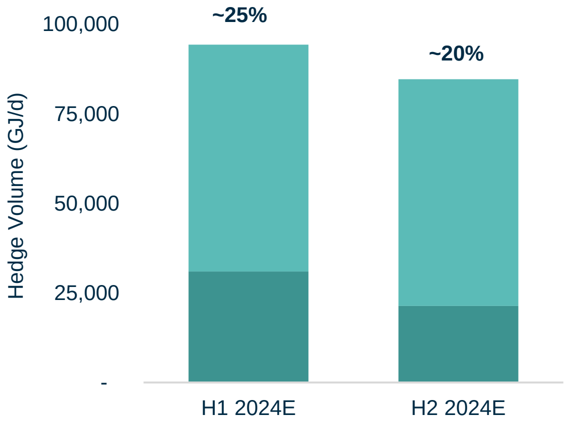
Oil & liquids hedges extend through Q4 2024




| | H1 2024E | H2 2024E |
|---|---|---|
| **Swap (C$)** | $110.41 | $105.80 |
| **Collar Floor (C$)** | $97.42 | $97.91 |
| **Collar Ceiling (C$)** | $115.49 | $113.86 |

## Gas Hedging

Gas hedges extend through 2025



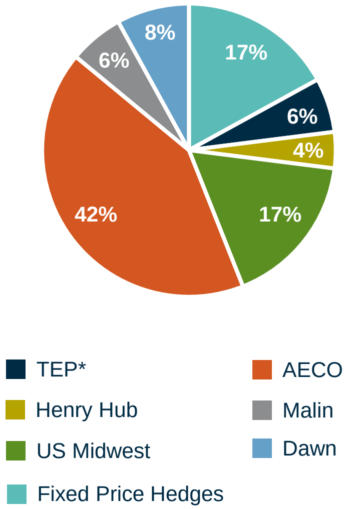

| | H1 2024E | H2 2024E |
|---|---|---|
| **Swap (C$)** | $3.47 | $3.12 |
| **Collar Floor (C$)** | $4.07 | $4.06 |
| **Collar Ceiling (C$)** | $5.46 | $5.44 |

Collars Swaps

## Gas Diversification

Through 2025

Plan to reduce AECO exposure to a third




Hedged volumes as at November 6, 2023, including CPG and HHRS hedges.
Hedged production is a percentage of volume net of royalty interest. *TEP – Saskatchewan hub trades at a premium to AECO – current contract year premium ~$0.50/GJ.

# Transaction Financing & Metrics

| | |
|---|---|
| **Purchase Price** | ~$2.55B (cash & shares), including ~$455MM in assumed net debt |
| **Equity to HHRS Shareholders** | ~$548MM of CPG common shares |
| **Equity Offering** | ~$500MM gross proceeds |
| **Debt Funding** | New three-year term loan totaling $750MM & existing credit facilities |

## Transaction Metrics

**3.4x net operating income**

**$45,500 per flowing boe**

**$16.93/boe of 2P reserves**
(including FDC)

**2P recycle ratio of 2.2x**
(including FDC)

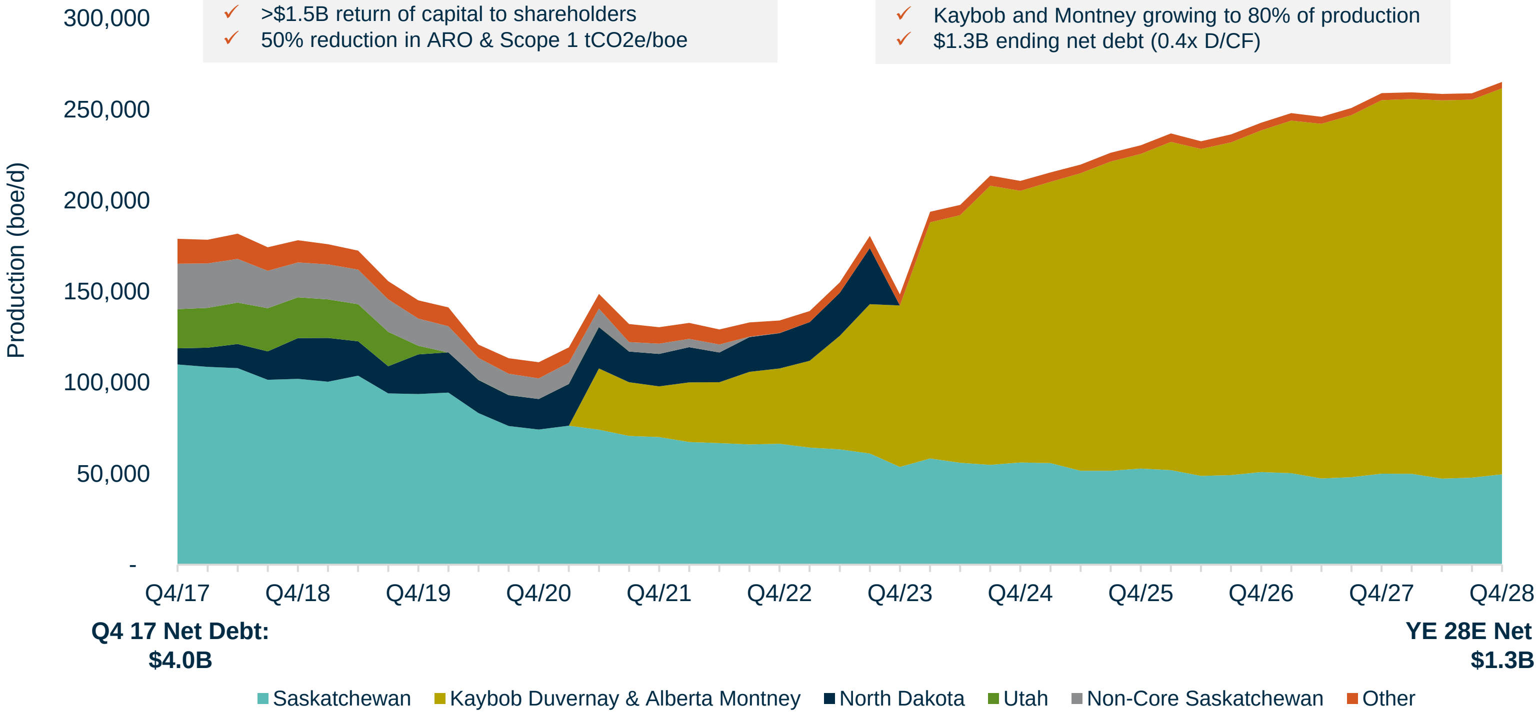
Transaction metrics reflect: 3.4x - purchase price divided by net operating income reflecting asset level cash flow from the Transaction assuming US$80/bbl WTI, $3.50/mcf AECO and 2024E production of ~56,000 boe/d; $45,500 per flowing boe - purchase price divided by 2024E production of ~56,000 boe/d; $16.93/boe - purchase price plus $2.7B of undiscounted future development capital (FDC) divided by Proved plus Probable (2P) reserves of 308.7 MMBoe as assigned by independent evaluator McDaniel as of November 1, 2023; 2.2x recycle ratio - net operating income, per boe, reflecting asset level cash flow from the acquired assets assuming US$80/bbl WTI, $3.50/mcf AECO and 2024E production of ~56,000 boe/d divided by $16.93/boe of 2P reserves

# Successful Transformation & Execution

**Delivering shareholder value through the responsible development of our assets**

**Accomplishments**
- ✓ >20 years of premium inventory
- ✓ >$5.0B directed to the balance sheet
- ✓ >$1.5B return of capital to shareholders
- ✓ 50% reduction in ARO & Scope 1 tCO2e/boe

**Outlook (2024 – 2028)**
- ✓ 7% excess cash flow per share CAGR
- ✓ $6.1B of cumulative excess cash flow
- ✓ Kaybob and Montney growing to 80% of production
- ✓ $1.3B ending net debt (0.4x D/CF)




**Q4 17 Net Debt: $4.0B**

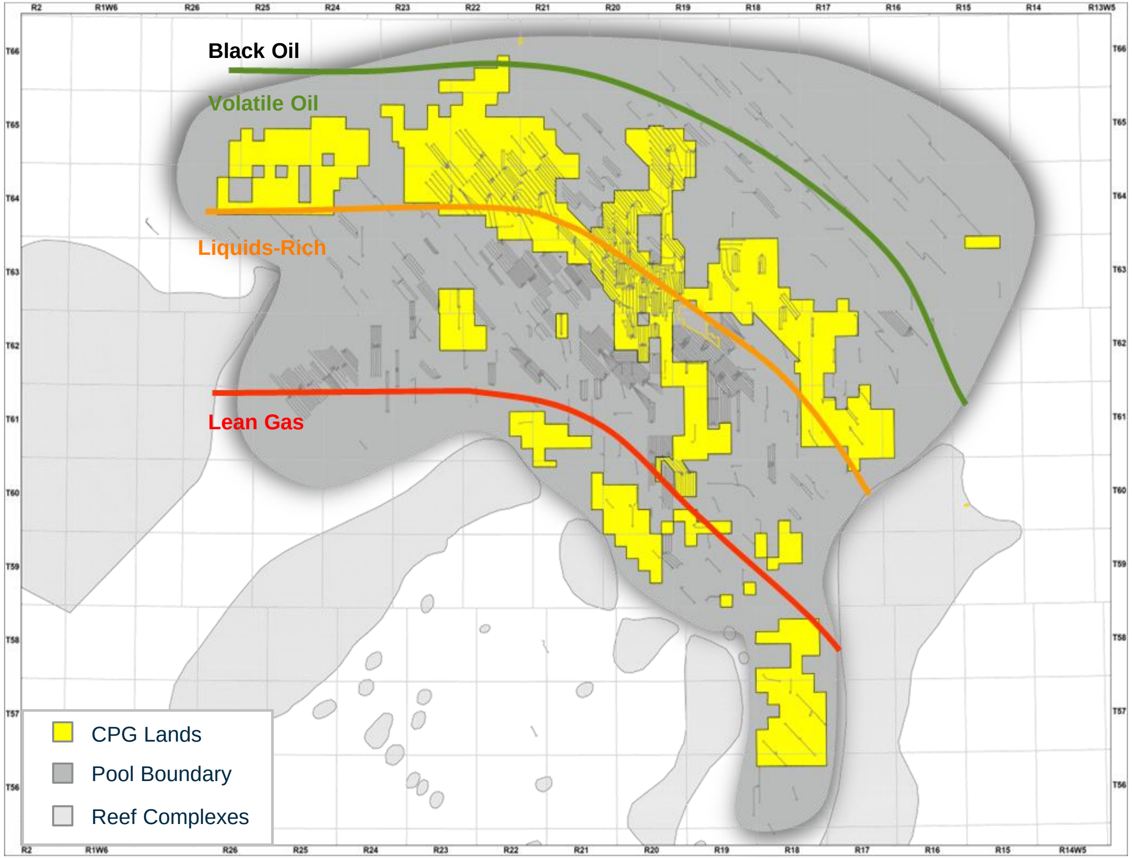
**YE 28E Net Debt: $1.3B**

All figures are approximates. YE 2028 net debt assumes US$75 WTI and $3.50 AECO.
Saskatchewan includes core areas of Viewfield, Shaunavon (including Battrum) and Flat Lake. Other includes North AB and South AB.

# Other Assets
## (Kaybob Duvernay & Saskatchewan)

# Kaybob Duvernay Reservoir Regions & Economics (Booked Type Wells)

## 500 premium locations primarily in the Volatile Oil and Liquids-Rich windows




| Volatile Oil | |
|---|---|
| IP30 (boe/d) (% Liquids) | 700 – 1,000 (>75%) |
| EUR (mboe) (% Liquids) | 700 – 1,000 (>65%) |
| Cost Per Well ($MM) | $10.5 |
| NPV10% ($MM) | $18.0 |
| Payout (Months) | 7 |
| IRR% | 140% |
| Net Locations | 225 |

| Liquids-Rich | |
|---|---|
| IP30 (boe/d) (% Liquids) | 1,000 – 1,500 (35% – 75%) |
| EUR (mboe) (% Liquids) | 1,000 – 1,500 (35% – 65%) |
| Cost Per Well ($MM) | $11.0 |
| NPV10% ($MM) | $20.0 |
| Payout (Months) | 6 |
| IRR% | 160% |
| Net Locations | 125 |

| Lean Gas | |
|---|---|
| IP30 (boe/d) (% Liquids) | >1,500 (<35%) |
| EUR (mboe) (% Liquids) | 1,500 – 2,000 (<35%) |
| Cost Per Well ($MM) | $11.5 |
| NPV10% ($MM) | $12.0 |
| Payout (Months) | 12 |
| IRR% | 75% |
| Net Locations | 150 |

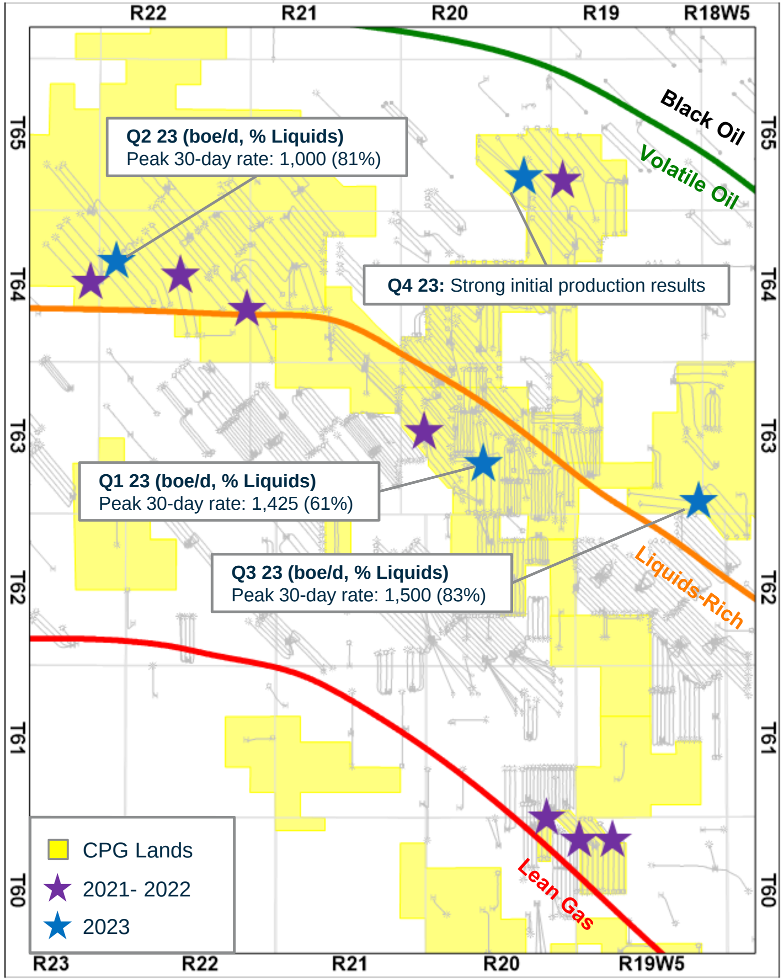
NPV10 and payout as at US$75/bbl WTI and $3.50/mcf AECO, assuming the mid-point of estimated ultimate recovery (EUR) ranges. Payouts are calculated from the initial onstream date.
Internally identified inventory of 500 net locations includes 126 booked 2P locations as assigned by McDaniel.

# Kaybob Duvernay Results

- **Track record of realizing cost efficiencies and improving well productivity** since initial entry into the play in Q2 2021
  - Initial rates in-line or ahead of average type well (higher liquids)
  - Optimized drilling and completion approach resulting in improved results vs. prior operator
  - Quickly reduced drilling days upon entering the play given experience in large multi-well pad programs

- **Deep premium inventory** of ~500 net locations, primarily in the Volatile Oil and Liquids-Rich windows
  - **Only 25% of locations are currently booked**
  - Opportunity for down-spacing and further step-out delineation

- Production of ~48,000 boe/d in 2024
  - **Expected to grow ~50% by 2028 (~10% CAGR)**



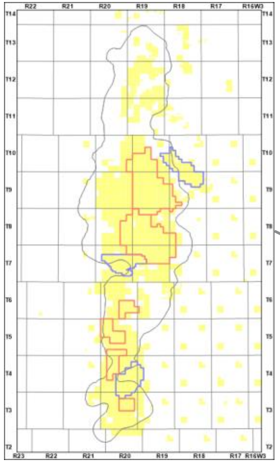

All figures are approximates.

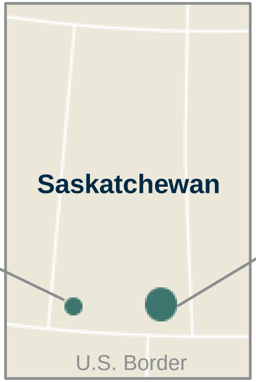
# Saskatchewan

**Long-cycle assets: low decline, stable production and significant excess cash flow generation**

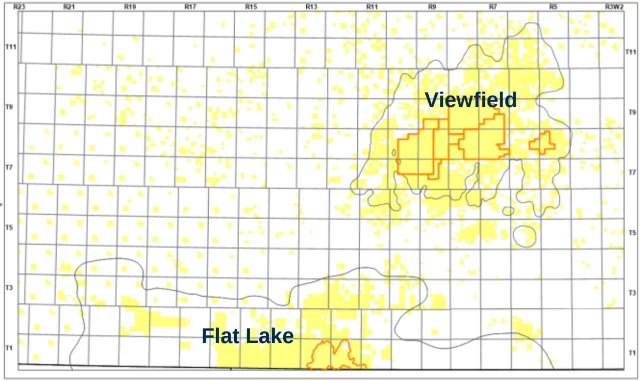
- **Stable production base** with **low decline rate** (~15%) and **significant excess cash flow**
- **Oil and liquids assets** resulting in **highest operating netbacks in the portfolio**
- **Significant oil in place** allows for enhanced oil recovery
- **Relative market access advantage**, positioned close to U.S. egress
- **Additional upside** through further advancement of decline mitigation projects, step-out drilling and new D&C technologies

**SW Saskatchewan**






**SE Saskatchewan**




- Pool Boundary
- Waterflood Unit Boundaries
- Polymer flood boundary

# Saskatchewan: Decline Mitigation & OHML Innovation

**Strong excess cash flow generation bolstered by enhanced oil recovery and new technology implementation**

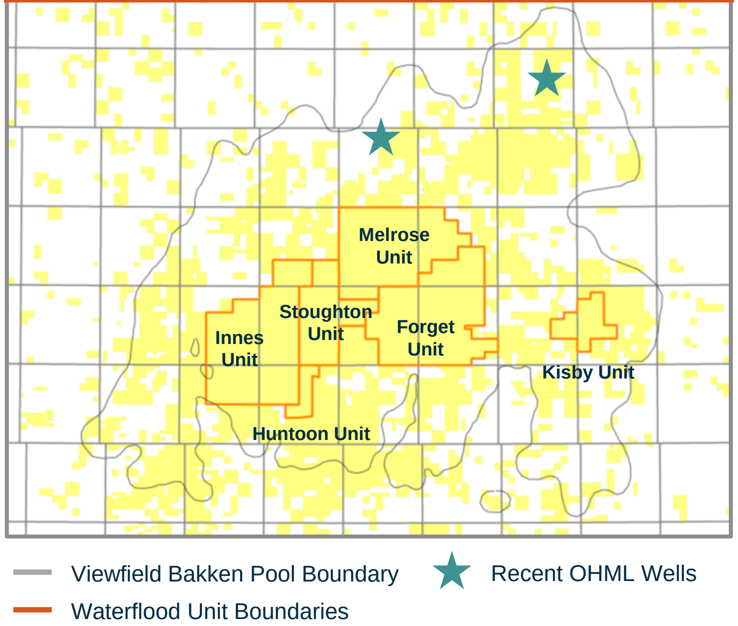
## Decline Mitigation

- Low decline rate as a result of commitment to decline mitigation projects, including waterflood and polymer floods
  - Enhances EURs
  - Low F&D costs with attractive long-term economics
- Total injector conversions across Saskatchewan expected to be ~50% complete by YE 2023 with opportunity for additional conversions

## Open-Hole Multi-Laterals (OHML)

- Improving returns by applying new OHML drilling in Viewfield
  - Recently brought on stream two OHML wells (8-legs) with a strong average peak 30-day rate of ~300 bbl/d per well (100% light crude oil)
  - Enhances EURs, economics and capital efficiencies
  - Has delivered organic inventory additions with the potential to implement the technology in other areas within the asset portfolio

**Viewfield Waterflood & OHML**




OHML: open hole multi-lateral. F&D: finding and development. EUR: estimated ultimate recoveries.

# Appendix

# Pro Forma Capital Markets Summary & Guidance

## Capital Markets Summary

| CPG (TSX and NYSE) | Prior | Po Forma |
|---|---|---|
| Share Price | C$9.86 / US$7.17 | C$9.86 / US$7.17 |
| Shares Outstanding | 525.1 million | 625.5 million |
| Avg. Daily Trading Volume | 8.3 million | 8.5 million |
| Dividend Yield | 3.6% | 4.7% |
| Market Capitalization | $5.2 billion | $6.2 billion |
| Net Debt | $2.2 billion | $3.7 billion |
| Enterprise Value | $7.4 billion | $9.9 billion |

Prior dividend yield is based on quarterly base dividend of $0.10/share and pro forma dividend yield based on first quarter 2024 base dividend of $0.115/share, which is subject to Board approval upon the successful closing of the Alberta Montney Transaction and market conditions. Pro forma capital markets data as at November 7, 2023 pro forma Alberta Montney Transaction and bought deal offering which closed on November 10, 2023. Prior net debt as at September 30, 2023 net debt pro forma the close of the North Dakota disposition which closed subsequent to the quarter. Prior market capitalization and enterprise value are based on November 7, 2023 share price and October 24, 2023 share count.

## 2024 Preliminary Guidance

| | Prior | Pro Forma |
|---|---|---|
| Annual Avg. Production (mboe/d)[(1)] | 145 - 151 | 200 – 208 |
| Capital Expenditures | | |
| Development Capital Expenditures ($MM) | $1,050 - $1,150 | $1,450 - $1,550 |
| Capitalized Administration ($MM) | $40 | $40 |
| Total ($MM) [(2)] | $1,090 - $1,190 | $1,490 - $1,590 |

1) The revised annual average production (boe/d) is comprised of ~65% Oil, Condensate & NGLs and ~35% Natural Gas. Assumes production of 56,000 boe/d (50% oil and liquids) for the assets acquired as part of the Transaction
2) Land expenditures and net property acquisitions and dispositions are not included. Revised development capital expenditures are allocated as follows: ~90% drilling & development and ~10% facilities & seismic

## Return of Capital Outlook

| | |
|---|---|
| Quarterly Base Dividend<br>(Expected to be declared in Q1 2024) | $0.115/share<br>(4.7% Yield) |
| Total Return of Capital<br>(Base dividend, share repurchases & special dividend) | ~60%<br>(% of Excess Cash Flow) |

The planned quarterly base dividend increase to $0.115 per share is subject to approval from the Board of Directors, the successful closing of the Transaction and market conditions. This dividend increase is expected to be effective in connection with the first quarter 2024 dividend. Total return of capital is based on a framework that targets to return to shareholders approximately 60% of excess cash flow

## 2024 Funds Flow Sensitivities

| | |
|---|---|
| US$1/bbl Change in WTI | ~$60 million |
| $0.25/mcf Change in AECO | ~$35 million |
| $0.01 Change in CAD/USD FX | ~$50 million |

# How CPG Executes Its Strategy

**Sustainable long-term returns driven by high-quality multi-basin portfolio and disciplined capital allocation**

## Disciplined Per-Share Growth

- Balanced portfolio of long and short-cycle assets
- Disciplined capital allocation framework
- Enhancing value through culture of operational excellence

+

## Significant Return of Capital

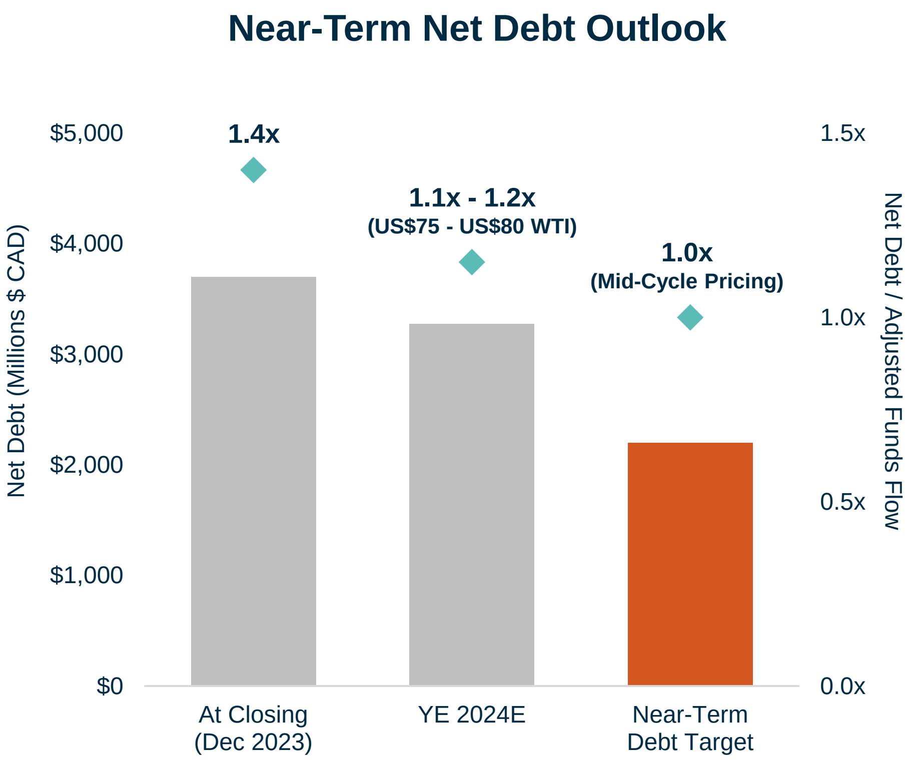
- Currently returning ~60% of excess cash flow
- High-netback assets generating significant excess cash flow
- Plan to grow base dividend over time, in-line with business

+

## Balance Sheet Strength

- Long-term leverage target of <1.0x at low commodity prices
- Track record of significant debt reduction and asset dispositions
- Disciplined hedging strategy

# Balance Sheet & Financial Flexibility




- Directing ~40% of excess cash flow to net debt reduction
- Will continue to hedge a portion of production to protect against balance sheet (currently hedged ~30% of oil & liquids and ~25% of gas production for 2024)
- Long-term target leverage ratio of <1.0x in a low commodity price environment

# Enhanced Return of Capital Profile

## Return of Capital Framework

**Funds Flow**

(-) Development Capital Expenditures*

**Excess Cash Flow**

↓

**Current Return of Capital Outlook ~60%**

(Base Dividends, Share Repurchases & Special Dividends)

## Tools Utilized for Return of Capital

### Base Dividends

Base dividend is not subject to this framework and is assessed within our capital allocation framework that targets dividend sustainability at lower commodity prices, allows for flexibility in the capital allocation process and dividend growth over time

### Share Repurchases

Takes into account the intrinsic value of the business, assuming mid-cycle commodity prices (NCIB currently in place to repurchase up to 10% of public float)

### Special Dividends

Used in combination with share repurchases to ensure Crescent Point fulfills its return of capital commitment to shareholders, or in greater proportion when share repurchases are no longer accretive

*Development capital expenditures includes additional items (capitalized administration, reclamation activities, payments on lease liability and other items, excluding net acquisitions and dispositions).

# Portfolio of High-Netback Assets

| Metric (US$75 – US$80 WTI) | Alberta Montney | Kaybob Duvernay | Saskatchewan (Viewfield Bakken, Shaunavon & Flat Lake) |
|---|---|---|---|
| Average Production (boe/d) | 94,000 | 48,000 | 56,000 |
| % Liquids | 50% | 60% | 95% |
| Royalty (%) | 11% | 9% | 11% |
| Operating Expenses ($/boe) | $10.00 | $7.50 | $22.50 |
| Operating Netback ($/boe) | $34.00 - $36.00 | $43.00 - $46.00 | $47.00 - $52.00 |
| Base Decline Rate | Mid-30% | Low-30% | ~15% |
| Premium Locations (Net) | ~1,400 | ~500 | ~2,000 |

Shaunavon includes Battrum. All figures are approximates and are based on preliminary 2024 guidance and US$75 – US$80/bbl WTI and $3.50/mcf AECO. Base decline rate is dependent on pad timing. Operating netback is a specified financial measure - refer to the Specified Financial Measures section. Inventory based on YE 2022 locations and includes locations acquired in Kaybob Duvernay and Alberta Montney in 2023.

# Returns Based Capital Allocation Framework & Excess Cash Flow Priorities

## ASSET LEVEL

### Base Plan

- Risk Adjusted Returns and Value Added (Well & Project Level)

### Long-Term

- Decline Mitigation
- Step-out Drilling
- Land Expiries
- Other Projects

### Environmental

- ARO
- Emissions Reduction
- Asset Integrity
- Spill Prevention

## CORPORATE LEVEL

**Funds Flow**
(Maximize with a cost discipline)

↓

**Maintenance Capital**
(Total spending in context of balance sheet and returns)

↓

**Balance Sheet / Base Dividend**

↓

**Follow-on decisions compete for capital based on expected returns and long-term corporate objectives**

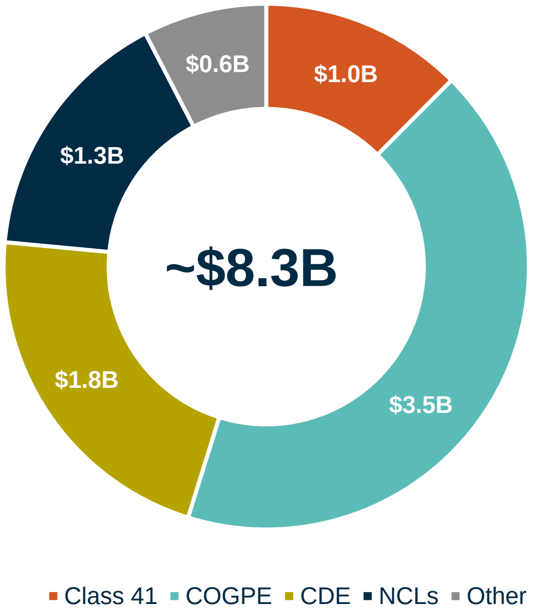
**Additional Debt Reduction** • **Additional Return of Capital** • **Organic Growth** • **M&A / Enhance Portfolio** • **Long-Term & Other**

ARO: Asset Retirement Obligations. Funds Flow is Adjusted Funds Flow.

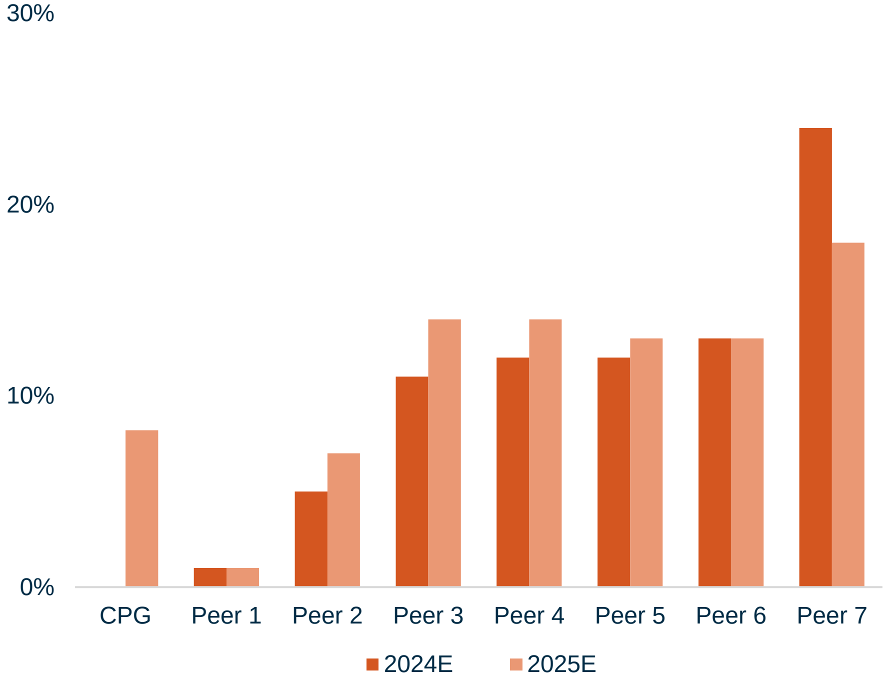
# Significant Tax Pools Enhance Excess Cash Flow

**Alberta Montney transaction provides CPG with an estimated $1.3B of tax pools**

## Canadian Tax Pools




## Cash Tax as % of Before Tax Cash Flow




CDN Peer List: ARX, BTE, ERF, NVA, TOU, VET, WCP. Canadian consolidated tax pools as at September 30, 2023 pro forma Alberta Montney transaction.
Other pools include CCA and CEE. CPG has US$1.8B of U.S. tax pools. CPG cash tax based on internal estimates, assuming closing of the Transaction and Peters & Co. Equity Research pricing.
Peer Cash Tax: Peters & Co. Equity Research (October 23, 2023; 2024 strip of US$81.79/bbl WTI & CAD/USD FX of $0.73, 2025 strip of US$76.35/bbl WTI & CAD/USD FX of $0.73).

# Strong Market Access

## Liquids (65% of Production)

### Alberta (Kaybob Duvernay & Montney)

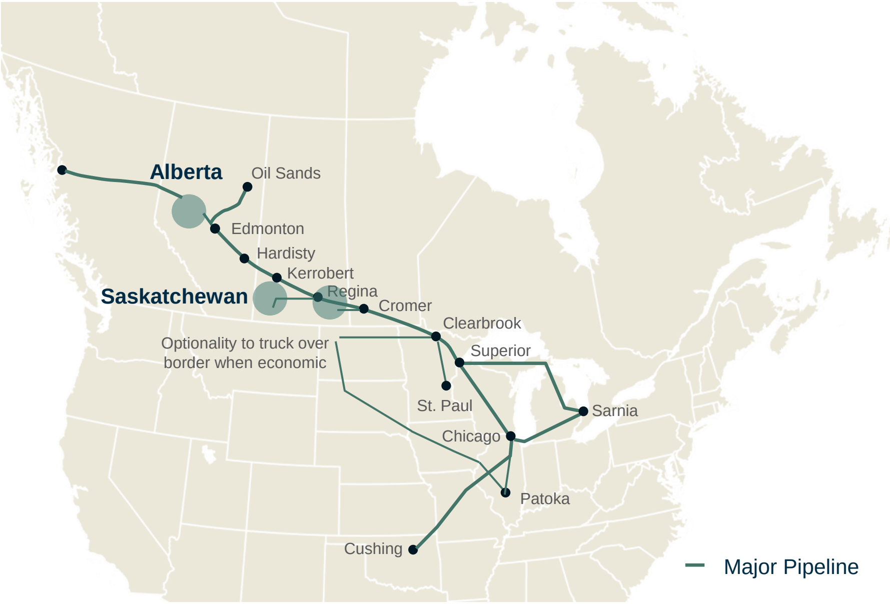
- MSW and C5 currently trade at a slight discount to WTI, with C5 benefitting from a strong expected demand outlook
- C5 has optionality to be sold as is for oil sands or as light oil

### Saskatchewan (Viewfield Bakken, Flat Lake & Shaunavon)

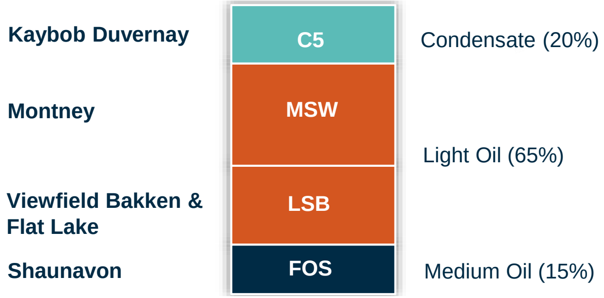
- LSB (SE Sask.) currently trades at a slight discount to WTI and FOS (SW Sask.) receives premium to WCS
- Below major apportionment points and close to U.S. border providing additional marketing optionality

## Gas (35% of Production)

- Receives premium pricing to AECO, with exposure to NYMEX, Chicago, Dawn and Malin & Stanfield pricing




### 2024E Oil & Condensate Production Breakdown by Stream




WCS: Western Canadian select. FOS: Fosterton, LSB: Light Sour Blend, C5: condensate. MSW: Mixed Sweet Blend.

# Major Operating Area Economics

| | | | | US$75 WTI & $3.50 AECO | |
|---|---|---|---|---|---|
| **Area** | **IP30 boe/d (Liquids %)** | **EUR Mboe (Liquids %)** | **Cost Per Well (C$MM)** | **IRR%** | **Payout (Months)** |
| **Alberta Montney** (Volatile Oil) | | | | | |
| Gold Creek West | 1,025 (58%) | 710 (54%) | $9.0 | 125% | 10 |
| Gold Creek | 950 - 1,300 (50 - 55%) | 750 - 1,150 (40 - 45%) | $6.0 - $9.0 | 140 - 145% | 9 - 10 |
| Karr East | 700 - 1,080 (55 - 80%) | 750 - 850 (50 - 75%) | $9.5 - $11.0 | 75 - 175% | 8 - 15 |
| Karr West | 1,330 (65%) | 1,050 (50%) | $10.0 | 140% | 10 |
| **Kaybob Duvernay** | | | | | |
| Volatile Oil | 700 - 1,000 (>75%) | 700 - 1,000 (>65%) | $10.5 | 140% | 7 |
| Liquids-Rich | 1,000 - 1,500 (35 - 75%) | 1,000 - 1,500 (35 – 65%) | $11.0 | 160% | 6 |
| Lean Gas | >1,500 (<35%) | 1,500 - 2,000 (<35%) | $11.5 | 75% | 12 |
| **Viewfield Bakken** | 95 - 200 (>90%) | 60 - 160 (>90%) | $1.7 - $2.2 | 55 - 125% | 9 - 16 |
| **Shaunavon** | 60 - 90 (>90%) | 60 - 115 (>90%) | $1.9 | 40 - 100% | 11 - 22 |
| **Flat Lake - Torquay** | 105 - 140 (>90%) | 105 - 140 (>90%) | $3.4 | 50 - 100% | 10 - 17 |
| **SK Conventional** | 80 - 130 (>90%) | 70 - 250 (>90%) | $1.5 | 65 - 175% | 6 - 18 |

All figures are approximates. See advisories. Payouts are calculated from the initial onstream date.

# ESG Highlights

**Released fifth annual Sustainability Report highlighting significant progress in ESG performance**

## Environmental

**On track to meet new Scope 1+2 emissions intensity target** of 0.020 $tCO_2e$/boe by 2030

**Safely decommissioned 240 wells** on track to achieve 30% inactive well reduction target ahead of 2031

**Commitment to environmental stewardship** with dedicated funding of 3-5% of maintenance capital budget

## Social

**Achieved safest year on record** driven by strong safety culture and active engagement with contractors

**$2.2MM of funding committed** supporting 450 local organizations

Enhanced **Indigenous engagement** with new targets for executive, staff, and Board awareness training

## Governance

Enhanced Board diversity, maintaining **gender diversity target of 30%**

Executive & staff **compensation linked to ESG performance**

**Ensuring strong ESG oversight** with updated Board Committee mandates

# Board of Directors

### Barbara Munroe

**Chair of the Board**

More than 30 years of legal experience and industry diversification. Former EVP with WestJet Airlines.

### Craig Bryksa 3

**President & Chief Executive Officer**

Over 20 years of oil and gas experience, including over 15 years at Crescent Point in several senior management roles.

### James E. Craddock 2 4 5

Over 30 years of upstream exploration and production experience. Former Chairman and CEO of Rosetta Resources.

### John P. Dielwart 3 5

Over 40 years of experience in the oil and gas sector. Founding member of ARC Resources.

### Mindy Wight 1 4

Tax and financial professional with over 15 years of experience. CEO for the Nch'kay Development Organization.

### Mike Jackson 1 2

More than 30 years in corporate and investment banking holding several senior management roles with Scotiabank.

### Jennifer F. Koury 2 4

Extensive business leadership and governance background. Former executive with BHP Billiton and Enerplus.

### Francois Langlois 1 3 5

More than 35 years of domestic and international oil and gas experience. Former SVP, Exploration and Production with Suncor.

### Myron M. Stadnyk 1 3 4

Over 35 years of business, industry, leadership and governance experience. Former President and CEO of ARC Resources.

| 1 Audit Committee | 2 CG & Nominating Committee | 3 ES&S Committee | 4 HR & Compensation Committee | 5 Reserves Committee |
|---|---|---|---|---|
| Financial risk management | Board renewal | Stakeholder engagement | Corporate culture | Operational excellence |
| Cybersecurity | Diversity | Environment | Compensation alignment | |
| Financial information | Governance | Safe operations | Employee engagement | |

CG: Corporate Governance. ES&S: Environmental, Safety & Sustainability.

# Forward Looking Information



This presentation contains "forward-looking statements" within the meaning of applicable securities legislation, such as section 27A of the Securities Act of 1933 and section 21E of the Securities Exchange Act of 1934, including estimates of future production, cash flows and reserves, business plans for drilling and exploration, the estimated amounts and timing of capital expenditures, the assumptions upon which estimates are based and related sensitivity analyses, and other expectations, beliefs, plans, objectives, assumptions or statements about future events or performance (often, but not always, using words or phrases such as "expects" or "does not expect", "is expected", "2023E", or "2024E") and includes: the business and financial prospects and opportunities of Crescent Point; 2024 preliminary outlook and 2024 preliminary outlook assuming the successful completion of the Company's acquisition (the "Acquisition") of Hammerhead Energy Inc. ("HHRS"), including, but not limited to annual average production and portion of production that is liquids, development capital expenditures, excess cash flow (at US$75-$80 WTI) and YE D/CF (at US$75-$80 WTI), enterprise value, and return of capital framework including, but not limited to, quarterly base dividend and total return of capital (as a percentage of excess cash flow); inventory including years of premium inventory and premium and additional locations; the Acquisition, including the characteristics, value drivers and anticipated benefits (including expected enhancement to sustainability of the Company's drilling inventory and the capital allocation flexibility that provides to the Company, the ownership of infrastructure, expected increase to share accretion resulting from Acquisition; an expected increase in the Company's dividend; the expectation that Crescent Point will become the 7th largest exploration and production business in Canada and largest land owner in the volatile window in the Alberta Montney as a result of the Acquisition; HHRS' expected contribution to Crescent Point's cashflow, development capital expenditures and production over the Company's pro forma 5-year plan; the Company's pro forma 5-year plan (including expected production per share CAGR, excess cash flow per share, and cumulative excess cash flow); key metrics expected under Crescent Point's pro forma 5-year plan (production, capital expenditures, reinvestment ratio, year end leverage ratio and decline rate); the tax pools associated with the Acquisition; expected financial and operational synergies through lower G&A and capital costs; opportunity to enhance well design and reduce wells drilled per section; pro forma metrics as a result of the Acquisition, including increases to 2024E production, net acres and premium drilling locations; anticipated qualities and characteristics of HHRS' assets and business, including production, marketing and transporting agreement supporting future Crescent Point production growth; and the integration of such assets into Crescent Point's current business; future drilling plans on the acquired assets; the Company's expected allocation of 2024 capital to Alberta and to Saskatchewan; Crescent Point's strategic priorities, including enhancing asset level returns, executing organic growth plans, discounted cash flow, excess cash flow allocation, expected base dividend increase and plans to increase the dividend after completing the Acquisition; Crescent Point's hedging plans; return of capital expectations and how the Acquisition is expected to accelerate return of capital under the pro forma 5-year plan; how the Acquisition is expected to be financed and the key metrics associated with the Acquisition; sustainable long-term returns driven by high-quality multi-basin portfolio and disciplined capital allocation; disciplined per-share growth; disciplined capital allocation framework; enhancing value through culture of operational excellence; significant return of capital; Returning approximately 60% of excess cash flow to shareholders; high-netback assets generating significant excess cash flow; plans to grow base dividend over time, in-line with business; balance sheet strength; long-term leverage target of <1.0x at low commodity prices; disciplined hedging strategy; generating $1.0 to$1.02 billion of excess cash flow per year in 2023 and 2024 (US$75-$80/bbl WTI); focused on enhancing outlook for shareholders through productivity improvements, cost efficiencies, identifying new drilling locations; tools used for return of capital framework; generating strong excess cash flow; strategic combination of short and long cycle assets generates sustainable shareholder returns; preliminary 2024 budget and components and expected levels thereof as well as components of excess cash flow and uses thereof; characteristics of the Company's pro forma Kaybob Duvernay and Alberta Montney assets, including but not limited to: high returns, scalability, quick payouts, long-term scalable growth and excess cash flow generation, ~1,900 premium locations, expected returns, sufficient infrastructure and market access and additional upside; Kaybob Duvernay drilling locations, EUR, NPV10%, cost per well, IRR% and payout; opportunities for down-spacing and further step-out delineation; deep premium inventory Kaybob inventory of ~500 net locations, primarily in the Volatile Oil and Liquids-Rich windows; only 25% of Kaybob locations are currently booked; opportunity for down-spacing and further step-out delineation in the Kaybob Duvernay; expected 2024 Kaybob Duvernay production and expected production growth levels in the Kaybob Duvernay by 2028; Montney CAGR by 2028; characteristics of Saskatchewan assets, including, but not limited to: market access, additional upside, low decline, stable production and significant excess cash flow generation; benefits of decline mitigation projects; water injector conversion plans; benefits of OHML; anticipated net debt at closing of the Acquisition; Crescent Point's preliminary and preliminary pro forma 2024 guidance, including, but not limited to annual average production, capital expenditures (including development capital expenditures and capitalized administration; return of capital outlook including base dividend and additional return of capital; and funds flow sensitivities); how Crescent Point expects to drive sustainable long term returns; expected pro forma 2024 and near term net debt outlook (including anticipated net debt and liquidity upon closing of the Acquisition and at year and 2024 based on strip pricing); Crescent Point's near-term and long-term debt targets and leverage ratios); the Company's plans to direct approximately 40% of excess cash flow to net debt reduction; the Company's hedging plans; the key metrics associated with the Company's pro forma Alberta Montney Assets, its Kaybob Duvernay assets and its Saskatchewan assets; the Company's pro forma tax pools and how they are expected to enhance excess cash flow; gas diversification; commodity pricing stream characteristics, discounts and premiums; strong market access; and major operating area economics pro forma the Acquisition, including, but not limited to EUR, cost per well, IRR% and payout; target to reduce Scope 1 & 2 emissions intensity to 0.02 tCO2e/boe by 2030; on track to achieve 30% reduction in inactive well inventory by 2031; commitment to environmental stewardship with dedicated funding of 3-5% of maintenance capital budget; Indigenous awareness training for executive, staff and Board; and Board gender diversity target of 30%; and other assumptions inherent in management's expectations in respect of the forward-looking statements identified herein.

There are numerous uncertainties inherent in estimating crude oil, natural gas and NGL reserves and the future cash flow attributed to such reserves. The reserves and associated cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating expenses, all of which may vary materially. Actual reserve values may be greater than or less than the estimates provided herein. Also, estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates and future net revenue for all properties because of aggregation. Information relating to "reserves" is deemed to be forward-looking information, as it involves the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and that the reserves described can be profitably produced in the future. All required reserve information for the Company is contained in its Annual Information Form for the year ended December 31, 2022 and in our material change reports dated April 6, 2023 and September 1, 2023, which are accessible at www.sedarplus.com. Reserve information related to HHRS is based on management's estimates based on the assets' production profile and expected development capital and a reserve report prepared by McDaniel with respect to the HHRS assets. With respect to disclosure contained herein regarding resources other than reserves, there is uncertainty that it will be commercially viable to produce any portion of the resources and there is significant uncertainty regarding the ultimate recoverability of such resources. All forward-looking statements are based on Crescent Point's beliefs and assumptions based on information available at the time the assumption was made. Crescent Point believes that the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this report should not be unduly relied upon. By their nature, such forward-looking statements are subject to a number of risks, uncertainties and assumptions, which could cause actual results or other expectations to differ materially from those anticipated, expressed or implied by such statements, including those material risks discussed in the Company's Annual Information Form for the year ended December 31, 2022 under "Risk Factors" and our Management's Discussion and Analysis for the year ended December 31, 2022, under the headings "Risk Factors" and "Forward-Looking Information" and for the quarter ended September 30, 2023, under the headings "Risk Factors" and "Forward-Looking Information". The material assumptions are disclosed in the Management's Discussion and Analysis for the year ended December 31, 2022, under the headings "Capital Expenditures", "Liquidity and Capital Resources", "Critical Accounting Estimates", "Risk Factors", "Changes in Accounting Policies" and "Guidance" and in the Management's Discussion and Analysis for the quarter ended September 30, 2023, under the headings "Overview", "Commodity Derivatives", "Liquidity and Capital Resources", "Guidance", "Royalties" and "Operating Expenses". In addition, risk factors include: financial risk of marketing reserves at an acceptable price given market conditions; volatility in market prices for oil and natural gas, decisions or actions of OPEC and non-OPEC countries in respect of supplies of oil and gas; delays in business operations or delivery of services due to pipeline restrictions, rail blockades, outbreaks and; uncertainty regarding the benefits and costs of acquisitions and dispositions; the risk of carrying out operations with minimal environmental impact; industry conditions including changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; uncertainties associated with estimating oil and natural gas reserves; risks and uncertainties related to oil and gas interests and operations on Indigenous lands; economic risk of finding and producing reserves at a reasonable cost; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; incorrect assessments of the value and likelihood of acquisitions and dispositions, and exploration and development programs; unexpected geological, technical, drilling, construction, processing and transportation problems; the impact of severe weather events and climate change; availability of insurance; fluctuations in foreign exchange and interest rates; stock market volatility; general economic, market and business conditions, including uncertainty in the demand for oil and gas and economic activity in general as a result of the COVID-19 pandemic; changes in interest rates and inflation; uncertainties associated with regulatory approvals; geopolitical conflicts, including the impacts of the war in Ukraine and the Middle East; uncertainty of government policy changes; uncertainties associated with credit facilities and counterparty credit risk; cybersecurity risks; changes in income tax laws, tax laws, crown royalty rates and incentive programs relating to the oil and gas industry; the wide-ranging impacts of the COVID-19 pandemic, including on demand, health and supply chain; and other factors, many of which are outside the control of the Company. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Crescent Point's future course of action depends on management's assessment of all information available at the relevant time. In addition, with respect to forward-looking information contained in this presentation, assumptions have been made regarding, among other things: future crude oil and natural gas prices; future interests rates and currency exchange rates; future cost escalation under different pricing scenarios; the corporation's future production levels; the applicability of technologies for recovery and production of the corporation's reserves and improvements therein; the recoverability of the corporation's reserves; Crescent Point's ability to market its production at acceptable prices; future capital expenditures; future cash flows from production meeting the expectations stated in this presentation; future sources of funding for the corporation's capital program; the corporation's future debt levels; geological and engineering estimates in respect of the corporation's reserves; the geography of the areas in which the corporation is conducting exploration and development activities; the impact of competition on the corporation; the corporation's ability to obtain financing on acceptable terms. These assumptions, risks and uncertainties could cause actual results or other expectations to differ materially from those anticipated, expressed or implied by such statements. The impact of any one assumption, risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent. Except as required by law, Crescent Point assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change. Certain information contained herein has been prepared by third-party sources. Included in this presentation are Crescent Point's pro forma 5-year outlook and 2024 guidance in respect of capital expenditures and average annual production and pro forma 5-year plan and outlook based on various assumptions as to production levels, commodity prices and other assumptions and are provided for illustration only and are based on budgets and forecasts that have not been finalized and are subject to a variety of contingencies including prior years' results. The Company's return of capital framework is based on certain facts, expectations and assumptions that may change and, therefore, this framework may be amended as circumstances necessitate or require. To the extent such estimates constitute a "financial outlook" or "future oriented financial information" in this presentation, as defined by applicable securities legislation, such information has been approved by management of Crescent Point. Such financial outlook or future oriented financial information is provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes.

# Advisories

## EXTERNAL, MARKET AND INDUSTRY DATA

Where this Presentation quotes any market and industry data and other statistical information from any external source, it should not be interpreted that the Company has adopted or endorsed such information or statistics as being accurate. The Company has obtained market and industry data and other statistical information presented in this Presentation from a certain third-party information. Such third-party publications and reports generally state that the information contained therein has been obtained from sources believed to be reliable. Although the Company believes these publications and reports to be reliable, it has not independently verified the data or other statistical information contained therein, nor has it ascertained the underlying economic or other assumptions relied upon by these sources, accordingly, no representation or warranty, express or implied, is made as to, and no reliance should be placed on, the fairness, accuracy, completeness or correctness of this information or any other information or opinions contained herein, for any purpose whatsoever. The Company has no intention and undertakes no obligation to update or revise any such information or data, whether as a result of new information, future events or otherwise, except as required by law.

All information related to HHRS, including in respect of Crescent Point and HHRS operating as a combined company, has been derived from the public filings of HHRS and/or information provided to Crescent Point by HHRS and/or the McDaniel report prepared in respect of HHRS' assets, and neither Crescent Point nor any of its advisors has independently verified such information. As a result, such information may be inaccurate or incomplete, and no representation is made by any such party as to the accuracy or completeness of such information.

## PRESENTATION OF FINANCIAL INFORMATION

The financial information of Crescent Point referred to in this Presentation is reported in Canadian dollars and has been derived from audited and unaudited historical financial statements of Crescent Point that were prepared in compliance with International Financial Reporting Standard ("IFRS"). The financial information of HHRS referred to in this Presentation has been derived from audited and unaudited historical financial statements of HHRS that were prepared in accordance with accounting principles generally accepted in the United States ("U.S. GAAP"). The recognition, measurement and disclosure requirements of U.S. GAAP differ from IFRS.

The unaudited pro forma financial information referred to in this Presentation has been prepared by management of Crescent Point and is derived from, and should be read in conjunction with; (i) the unaudited condensed consolidated financial statements of Crescent Point as at and for the three and nine months ended September 30, 2023, (ii) the audited consolidated financial statements of Crescent Point for the year ended December 31, 2022, (iii) the unaudited financial statements of HHRS as at and for the three and nine months ended September 30, 2023, and (iv) the audited financial statements of HHRS as at and for the year ended December 31, 2022. The pro forma financial information referred to in this Presentation was prepared utilizing accounting policies that are consistent with those disclosed in the unaudited consolidated financial statements of Crescent Point as at and for the three and nine months ended September 30, 2023, and the audited consolidated financial statements for the year ended December 31, 2022 and was prepared in accordance with recognition and measurement principles of IFRS. Crescent Point has not independently verified the financial statements of HHRS that were used to prepare the pro forma financial information included in this Presentation and the pro forma financial information included in this Presentation is not intended to be indicative of the results that would actually have occurred, or the results expected in future periods, had the events reflected in this Presentation occurred on the dates indicated. The pro forma financial information contained in this Presentation is included for informational purposes only and undue reliance should not be placed on such pro forma financial information.

The disclosure contained in this Presentation, including the pro forma financial information included herein, is based on a number of assumptions including that the Company will enter into a new term loan to fund the purchase price of the Acquisition. Management considers the pro forma financial information contained in this Presentation to reflect its long term financing plans for the Acquisition and that such information helps readers better understand how management views the Acquisition and its potential impacts on the Company and better allows readers to assess potential impacts of the Acquisition.

## NOTE TO READER REGARDING DISCLOSURE

In addition to obtaining all necessary Board approvals, the Company's long-established Disclosure Committee's mandate is to review and confirm the accuracy of the data and information contained in the documents, including this presentation, Crescent Point uses to communicate to the public. This review and confirmation process is formally completed prior to any such disclosure being released. This Committee is comprised of senior representatives (including officers) from each of the following departments: accounting and finance; engineering and operations (including drilling and completions, environment, health and safety and regulatory); exploration and geosciences; investor relations; land; legal; ESG; marketing and reserves.
This presentation contains "forward-looking statements" within the meaning of applicable securities legislation, such as section 27A of the Securities Act of 1933 and section 21E of the Securities Exchange Act of 1934, including estimates of future production, cash flows and reserves, business plans for drilling and exploration, the estimated amounts and timing of capital expenditures, the assumptions upon which estimates are based and related sensitivity analyses, and other expectations, beliefs, plans, objectives, assumptions or statements about future events or performance. Please see the "Forward-Looking Statements" section of this presentation for additional details regarding such statements.

# Definitions / Specified Financial Measures

Throughout this presentation the Company uses the terms “funds flow” (equivalent to “adjusted funds flow”), “excess cash flow”, “base dividends”, “total return of capital”, “operating netback”, “net debt” and “net debt / funds flow” (equivalent to net debt to adjusted funds flow from operations and to leverage ratio), which are specified financial measures under National Instrument 52-112 Non-GAAP and Other Financial Measures Disclosure. Specified financial measures do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities.

The most directly comparable financial measure for adjusted funds flow andexcess cash flow disclosed in the Company’s financial statements is cash flow from operating activities, which, for the three months ended September 30, 2023, was $648.9 million. The most directly comparable financial measure for net debt disclosed in the Company’s financial statements is long-term debt, which for the period ended September 30, 2023, was $2.95 billion. The most directly comparable financial measure for base dividends disclosed in the Company’s financial statements is dividends declared, which for the three months ended September 30, 2023 was $71.7 million. For the quarter ended September 30, 2023, operating netback, adjusted funds flow, excess cash flow, net debt and base dividends were $47.14/boe, $687.1 million, $321.6 million, $2.88 billion, $53.0 million, respectively.

Operating netback is a non-GAAP ratio and is calculated as total operating netback divided by total production. Operating netback is a common metric used in the oil and gas industry and is used to measure operating results on a per boe basis.

Total return of capital is a supplementary financial measure and is comprised of base dividends, special dividends and share repurchases, adjusted for the timing of special dividend payments.

Enterprise value is a supplementary financial measure and is calculated as market capitalization plus net debt.

Excess cash flow for 2023 to 2028 and 2024 net debt / funds flow are forward-looking non-GAAP measure. Refer to the Specified Financial Measures section of the Company’s MD&A for the period ended September 30, 2023.

# Definitions / Specified Financial Measures

For an explanation of the composition of adjusted funds flow, excess cash flow, net debt and net debt / funds flow, base dividends and how they provide useful information to an investor and quantitative reconciliations to the applicable GAAP measures, see the Company's MD&A available online for the quarter ended September 30, 2023 at www.sedarplus.com, or EDGAR at www.sec.gov and on our website at www.crescentpointenergy.com. The section of the MD&A entitled "Specified Financial Measures" is incorporated herein by reference. There are no significant differences in the calculations between historical and forward-looking specified financial measures.

Management believes the presentation of the specified financial measures above provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis. This information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS.

# Reserves and Drilling Data

Where applicable, a barrels of oil equivalent ("boe") conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent (6Mcf:1bbl) has been used based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of the 6:1 conversion ratio, utilizing the 6:1 conversion ratio may be misleading as an indication of value.

This presentation contains metrics commonly used in the oil and natural gas industry, including “payout”, "decline rate“ and “recycle ratio”. These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies and, therefore, should not be used to make such comparisons. Readers are cautioned as to the reliability of oil and gas metrics used in this presentation. Management uses these oil and gas metrics for its own performance measurements and to provide investors with measures to compare the Company’s performance over time; however, such measures are not reliable indicators of the Company’s future performance, which may not compare to the Company’s performance in previous periods, and therefore should not be unduly relied upon. Payout is the point at which all costs associated with leasing, exploring, drilling and operating have been recovered from the production of a well. It is an indication of profitability. Decline rate is the reduction in the rate of production from one period to the next. This rate is usually expressed on an annual basis. Management uses decline rate to assess future productivity of the Company’s assets. Recycle ratio is a profitability ratio that measures the profitability per boe (operation netback) to the cost of finding that boe (finding and development cost).

The reserve data provided in this presentation presents only a portion of the disclosure required under National Instrument 51-101. This presentation references more than 20 years of premium locations in corporate inventory, which amounts include booked and unbooked locations. Unbooked future drilling locations are not associated with any reserves or contingent resources and have been identified by the Company and have not been audited by independent qualified reserves evaluators. Expected well performance comes from analyzing historical well productivity within the geographic area outlined on the respective slides. The expected well is an average of our future planned inventory.

Certain terms used herein but not defined are defined in National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (“NI 51-101”), CSA Staff Notice 51-324 – Revised Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities (“CSA Staff Notice 51-324”) and/or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101, CSA Staff Notice 51-324 and the COGE Handbook, as the case may be.

# Reserves and Drilling Data

All reserves data for CPG contained in this presentation, and effective for the year ended 2022, is contained in the Corporation's AIF for the year ended, December 31, 2022 and in our material change reports dated April 6, 2023 and September 1, 2023, available on SEDAR+ (the "Reserves Report") and prepared in accordance with the standards contained in NI 51-101 and the COGE Handbook that were in effect at the relevant time. All reserves data for the acquired assets contained in this presentation, and effective as of November 1, 2023, is based on a reserve report prepared by McDaniel, and are referenced in our press release dated November 6, 2023, available on SEDAR+, and will be contained in a material change report to be filed on SEDAR+ on or before November 16, 2024 and prepared in accordance with the standards contained in NI 5-101 and the COGE Handbook that we in effect at the relevant time. There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only. In general, estimates of economically recoverable crude oil, natural gas and NGL reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For these reasons, estimates of the economically recoverable crude oil, NGL and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

| IP30 Production Results from Kaybob Duvernay Wells by Product Type | | | |
|---|---|---|---|
| On Prod | Condensate | NGL | Shale Gas |
| Q1 23 | 51% | 15% | 34% |
| Q2 23 | 73% | 8% | 19% |
| Q3 23 | 66% | 11% | 23% |

| Peak 30-day Production from Kaybob Duvernay Wells by Product Type | | | |
|---|---|---|---|
| On Prod | Condensate | NGL | Shale Gas |
| Q1 23 | 43% | 18% | 39% |
| Q2 23 | 73% | 8% | 19% |
| Q1 23 | 70% | 13% | 17% |

| IP90 Production Results from Kaybob Duvernay Wells by Product Type | | | |
|---|---|---|---|
| On Prod | Condensate | NGL | Shale Gas |
| Q1 23 | 44% | 18% | 38% |
| Q2 23 | 70% | 9% | 21% |
| Q3 23 | N/A | N/A | N/A |

| IP30 Production Results from Alberta Montney Wells by Product Type | | | |
|---|---|---|---|
| On Prod | Light Crude Oil | NGL | Shale Gas |
| Q1 23 | 87% | 2% | 11% |
| Q2 23 | 82% | 3% | 15% |
| Q2 23 | 50% | 9% | 41% |
| Q2 23 | 75% | 3% | 22% |
| Q3 23 | 69% | 4% | 27% |
| Q3 23 | 90% | 2% | 8% |
| Q3 23 | 63% | 7% | 30% |

| Peak 30-day Production from Alberta Montney Wells by Product Type | | | |
|---|---|---|---|
| On Prod | Light Crude Oil | NGL | Shale Gas |
| Q1 23 | 81% | 3% | 16% |
| Q2 23 | 64% | 7% | 29% |
| Q2 23 | 42% | 11% | 47% |
| Q2 23 | 71% | 4% | 25% |
| Q3 23 | 63% | 5% | 32% |
| Q3 23 | 90% | 2% | 8% |
| Q3 23 | 63% | 7% | 30% |

| IP90 Production Results from Alberta Montney Wells by Product Type | | | |
|---|---|---|---|
| On Prod | Light Crude Oil | NGL | Shale Gas |
| Q1 23 | 84% | 2% | 14% |
| Q2 23 | 71% | 6% | 23% |
| Q2 23 | 43% | 11% | 46% |
| Q2 23 | 60% | 6% | 34% |
| Q3 23 | 58% | 6% | 36% |
| Q3 23 | N/A | N/A | N/A |
| Q3 23 | N/A | N/A | N/A |

| Peak 30-day Production from HHRS Alberta Montney Wells by Product Type | | | |
|---|---|---|---|
| On Prod | Light Crude Oil | NGL | Shale Gas |
| Q3 23 | 57% | 9% | 34% |

# Reserves and Drilling Data

Initial production is for a limited time frame only (30, or 90 days) and may not be indicative of future performance. Peak IP30 refers the 30 consecutive days with the highest production rates since a pad has come on production and may not be indicative of future performance. For additional product type information for our major operating areas, refers to our Reserves Report.

Type wells, EUR and IP30 are based on the expected results from Crescent Point's premium drilling inventory, in accordance with the COGE handbook. These drilling locations include Proved plus Probable undeveloped reserves as evaluated by McDaniel & Associates Consultants Ltd. in addition to unbooked future drilling locations as identified by Crescent Point.

This presentation discloses: (I) in the Kaybob Duvernay, (A) Volatile Oil region, 225 potential internally identified net drilling locations, of which 104 are Proved plus Probable locations, as derived from the Company's internal reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 121 are unbooked locations; (B) Liquids-Rich region 125 potential internally identified net drilling locations, of which 17 are Proved plus Probable locations, as derived from the Company's internal reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 108 are unbooked locations; and (C) Lean Gas region 150 potential internally identified net drilling locations, of which 5 are Proved plus Probable locations, as derived from the Company's internal reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 145 are unbooked locations; (II) ~6,300 locations in corporate inventory of which of which 1,487 are Proved plus Probable locations, as derived from the Company's internal reserves evaluation in accordance with NI 51-101 and the COGE Handbook, 252 are Proved plus Probable locations for the announced Transaction as of November 1, 2023, and 163 Proved plus Probable locations for CPG's existing Montney assets as estimated by McDaniel as of December 31, 2022, with the remainder unbooked; and (III) ~1,400 net drilling locations associated with the Alberta Montney, of which 415 are booked as Proved plus Probable and 985 are not booked at year-end 2022.

This presentation also discloses: ~2,000 Saskatchewan Premium Locations, of which 1,246 are Proved plus Probable locations, as derived from the Company's internal reserves evaluation in accordance with NI 51-101 and the COGE Handbook; and an incremental 762 are unbooked locations.

# Reserves and Drilling Data

Years of corporate inventory figures include proved and probable locations, as derived from the independently evaluated (by McDaniel & Associates Consultants Ltd.) Reserves Reports for CPG and HHRS in accordance with NI 51-101 and the COGE Handbook, and additional internally identified net drilling locations. Company's ability to drill and develop new locations and the drilling locations on which the Company actually drills wells depends on a number of uncertainties and factors, including, but not limited to, the availability of capital, equipment and personnel, oil and natural gas prices, costs, inclement weather, seasonal restrictions, drilling results, additional geological, geophysical and reservoir information that is obtained, production rate recovery, gathering system and transportation constraints, the net price received for commodities produced, regulatory approvals and regulatory changes.  As a result of these uncertainties, there can be no assurance that the potential future drilling locations that the Company has identified will ever be drilled and, if drilled, that such locations will result in additional crude oil, natural gas or NGLs produced. As such, the pro forma Company's actual drilling activities may differ materially from those presently identified, which could adversely affect the company's business. The estimates for 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 recovery and reserve estimates of the Company's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered.

NI 51-101 includes condensate within the natural gas liquids (NGLs) product type. The Company has disclosed condensate as combined with crude oil and separately from other natural gas liquids in this presentation since the price of condensate as compared to other natural gas liquids is currently significantly higher and the Company believes that this crude oil and condensate presentation provides a more accurate description of its operations and results.

### Notice to US Readers

The oil and natural gas reserves contained in this presentation have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects of United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") generally permits oil and gas issuers, in their filings with the SEC, to disclose only proved reserves (as defined in SEC rules), but permits the optional disclosure of "probable reserves" and "possible reserves" (each as defined in SEC rules). Canadian securities laws require oil and gas issuers, in their filings with Canadian securities regulators, to disclose not only proved reserves (which are defined differently from the SEC rules) but also probable reserves and permits optional disclosure of "possible reserves", each as defined in NI 51-101. Accordingly, "proved reserves", "probable reserves" and "possible reserves" disclosed in this presentation may not be comparable to US standards, and in this presentation, Crescent Point has disclosed reserves designated as "proved plus probable reserves". Probable reserves are higher-risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves. "Possible reserves" are higher risk than "probable reserves" and are generally believed to be less likely to be accurately estimated or recovered than "probable reserves". In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalties and similar payments. The SEC rules require reserves and production to be presented using net volumes, after deduction of applicable royalties and similar payments. Moreover, Crescent Point has determined and disclosed estimated future net revenue from its and HHRS' reserves using forecast prices and costs, whereas the SEC rules require that reserves be estimated using a 12-month average price, calculated as the arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period.  Consequently, Crescent Point's reserve estimates and production volumes in this presentation may not be comparable to those made by companies using United States reporting and disclosure standards. Further, the SEC rules are based on unescalated costs and forecasts. All amounts in the presentation are stated in Canadian dollars unless otherwise specified.

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