March 20, 2024

Investor Day

CRESCENT POINT

Bringing Energy To Our World - The Right Way

Land Acknowledgement

Crescent Point respectfully acknowledges our head office and our field operations are situated within the traditional territories of diverse Indigenous peoples of Treaty 4, Treaty 6, Treaty 7, and Treaty 8 and the Métis Nation. We recognize and honour the many First Nations, Métis and Inuit people who have stewarded these lands for centuries.

We are committed to advancing reconciliation and engaging with Indigenous communities in a respectful and collaborative manner.

Agenda

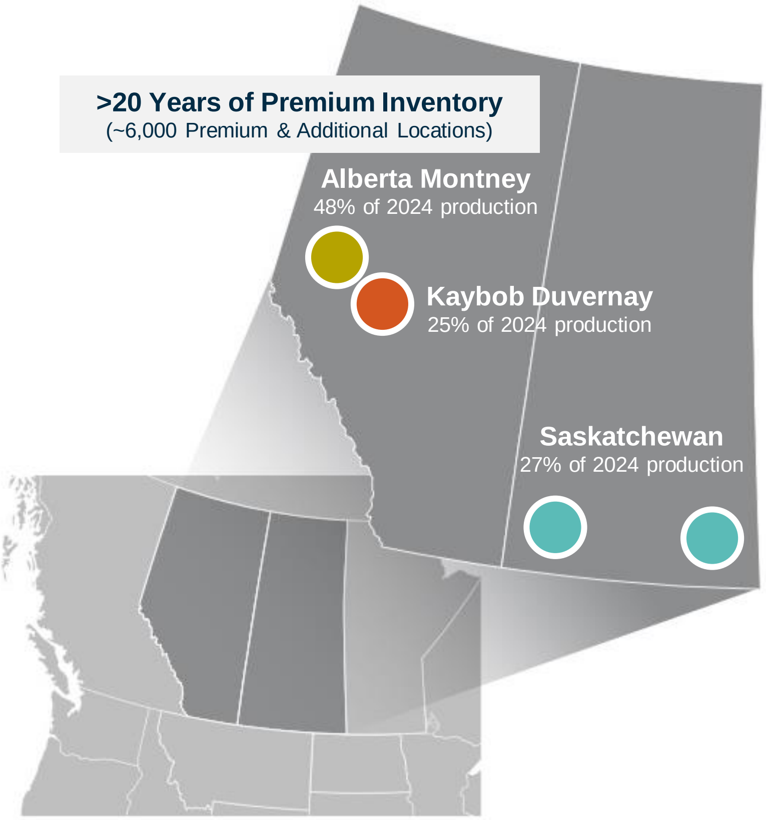
- **Introduction** – Shelly Witwer, SVP Business Development
- **Alberta Montney Geology** – Mike Blair, VP Geosciences
- **Alberta Montney Operations** – Katie Anne MacInnis, VP Engineering
- **Market Access and Alberta Montney Infrastructure** – Justin Foraie, VP Operations & Marketing
- **Kaybob Duvernay Update** – Justin Foraie, VP Operations & Marketing
- **Saskatchewan Update** – Ryan Gritzfeldt, COO
- **Corporate Portfolio and Outlook** – Ken Lamont, CFO
- **Strategy and Closing Remarks** – Craig Bryksa, President & CEO
- **Q&A**

Crescent Point at a Glance

Capital Markets Summary	
Shares Outstanding	620 million
Market Capitalization	$6.4 billion
Net Debt	$3.7 billion
Enterprise Value	$10.1 billion

2024 Outlook	
Annual Average Production	198,000 - 206,000 boe/d (~65% Liquids)
Development Capital Expenditures	$1.4 - $1.5 billion
Excess Cash Flow (US$75 WTI)	$830 million
YE D/CF (US$75 WTI)	1.2x

Return of Capital	
Quarterly Base Dividend	$0.115/share (4.4% Annual Yield)
Total Return of Capital (Dividends & Share Repurchases)	60% (% of Excess Cash Flow)



D/CF, enterprise value, net debt, excess cash flow, base dividends and total return of capital are specified financial measures - refer to Specified Financial Measures. Capital markets data as at March 13, 2024. Net debt as at December 31, 2023. Total inventory based on YE 2023 locations, less locations related to the disposition of Swan Hills and Turner Valley assets. 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 based on mid-cycle pricing. D/CF refers to YE 2024 net debt / funds flow. 2024 excess cash flow and YE D/CF assume an average price of ~US$75/bbl WTI and ~$2.30/Mcf AECO for the full year.

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

~10% EXCF/share CAGR over 5-year plan (~15% including share repurchases)

+

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

Plan to increase percentage of capital returned over time

+

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

Expect to reduce net debt by >50% over 5-year plan

Net debt reduction assumes US$70/bbl WTI flat and an average price of $3.35/mcf AECO from 2024-2028.

Benefits of a Balanced Portfolio of Short-Cycle & Long-Cycle Assets

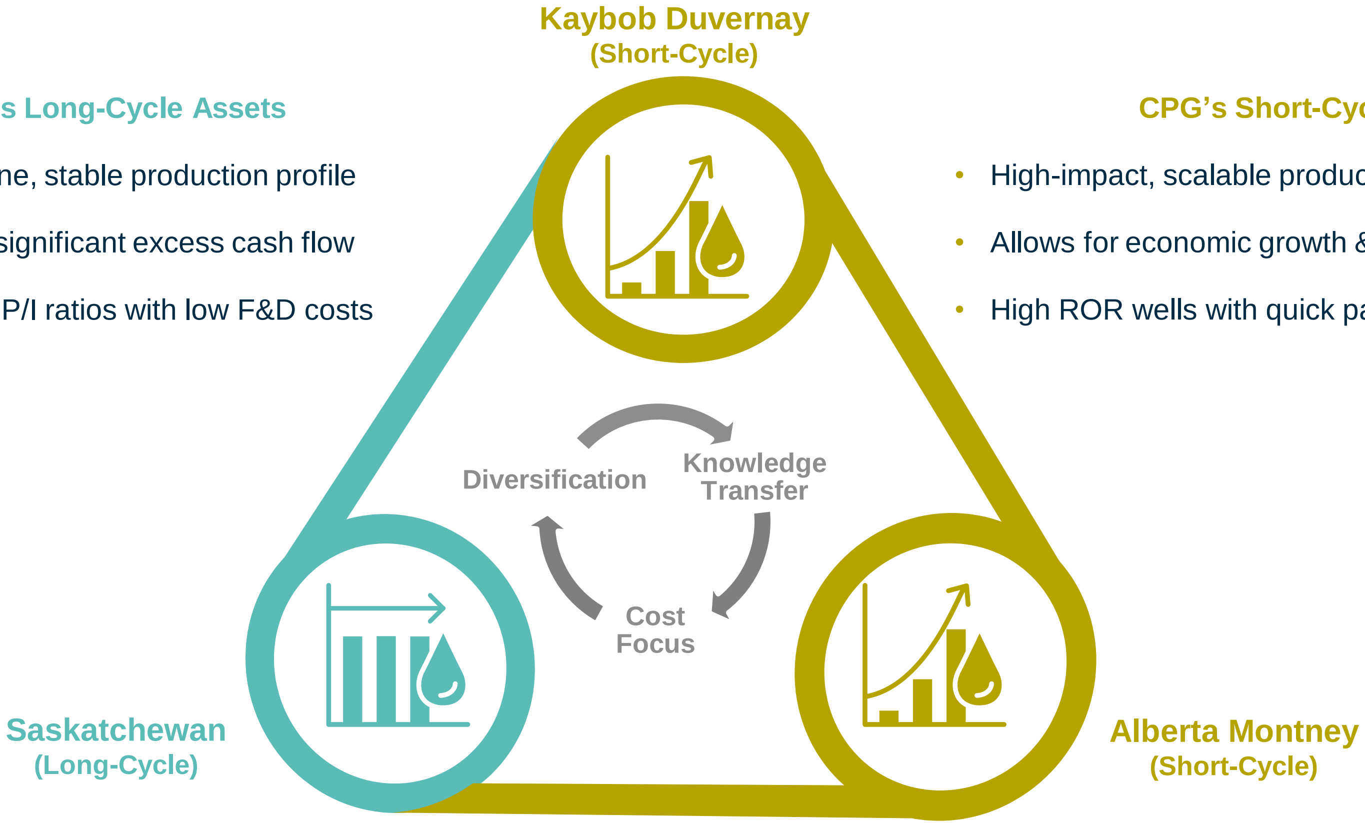
Delivers sustainable significant excess cash flow generation and returns-based per-share growth

CPG's Long-Cycle Assets

- Low-decline, stable production profile
- Provides significant excess cash flow
- Attractive P/I ratios with low F&D costs

CPG's Short-Cycle Assets

- High-impact, scalable production
- Allows for economic growth & excess cash flow
- High ROR wells with quick payback periods



F&D: finding and development. P/I: profit investment ratio.

Portfolio Transformation

CPG has transformed its portfolio and is set to deliver long-term returns for shareholders

Accomplishments Since 2018

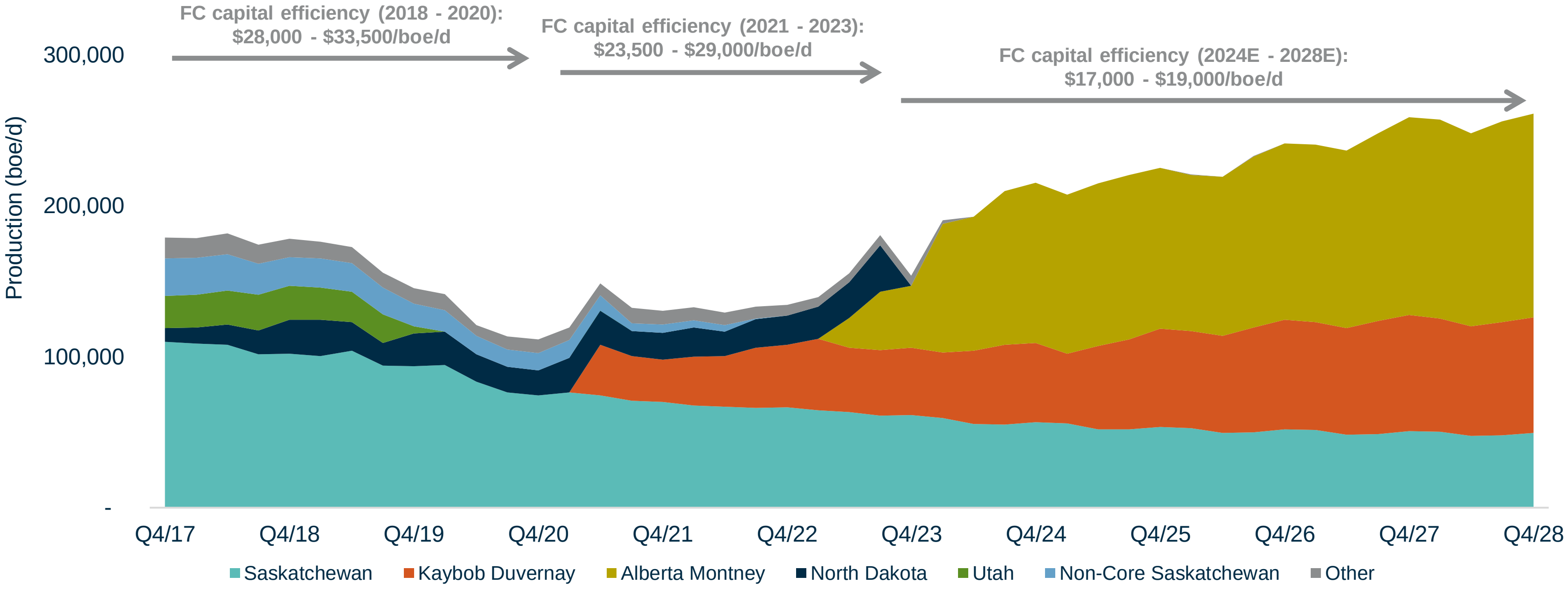
- ✓ **Created high-quality, multi-basin portfolio** of assets
- ✓ **Increased sustainability** with premium inventory >20 years
- ✓ **Returned >$1.5B of capital** to shareholders
- ✓ **Reduced ARO and Scope 1** tCO2e/boe by ~60%

Priorities (2024 - 2028)

Operational Execution: organic EXCF/share CAGR of 10% (15% incl. repurchases)

Balance Sheet Strength: reduce net debt by >50%

Increase Return of Capital: return ~60% of EXCF and plan to increase further



All figures are approximates. Full cycle (FC) capital efficiency numbers include drilling, completions, tie-in, equipment and facilities capital.
Saskatchewan includes core areas of Viewfield, Shaunavon (including Battrum) and Flat Lake. 2024 - 2028 assumes US$70/bbl WTI flat and average price of $3.35/mcf AECO. ARO: asset retirement obligations.

Strategic Priorities

Operational Execution

- Execute long-term plan to deliver **organic per-share growth**
- **Enhance corporate returns** through operational efficiencies and productivity improvements
- Maintain **capital discipline** to ensure targets are met on or under budget

Balance Sheet Strength

- Allocating **~40% of excess cash flow to the balance sheet**
- **Maintain disciplined hedging program** to provide downside protection against commodity prices
- Evaluate **additional non-core dispositions** to further enhance balance sheet strength

Increasing Return of Capital

- **Target base dividend increases** as the business continues to grow on a per-share basis
- **Prioritize share buybacks** as a tool of choice for additional return of capital
- **Increase return of capital beyond 60% of excess cash flow** over time as balance sheet strengthens further

2024 Investor Day Key Highlights

Alberta Montney

High-quality position in the Volatile Oil window achieving industry-leading results to-date

✓ Significant resource in place across multiple benches
✓ Identified opportunities to enhance returns
✓ Provides organic growth and excess cash flow with infrastructure already in place

Kaybob Duvernay

Delivering high-returns and consistent results across the land base

✓ Continue to deliver strong results from modified well design and step-out program
✓ Enhanced returns through improved efficiencies and EURs
✓ Provides organic growth and excess cash flow with infrastructure already in place

Crescent Point

>20 years of premium inventory set to deliver top decile returns

✓ Cumulative excess cash flow of $3.8B - $5.6B in 5-year plan, organic production growth of 30% and unbooked upside
✓ Saskatchewan assets complements portfolio providing stable, low-decline production and significant excess cash flow
✓ Strong track record of operational execution and continuous improvement

Cumulative excess cash flow between 2024E-2028E based on forecast of US$65-US$75/bbl WTI and $3.35/mcf AECO. EURs: estimated ultimate recoveries. Top decile returns ranking based on average total return yield percentage (see slide 69).

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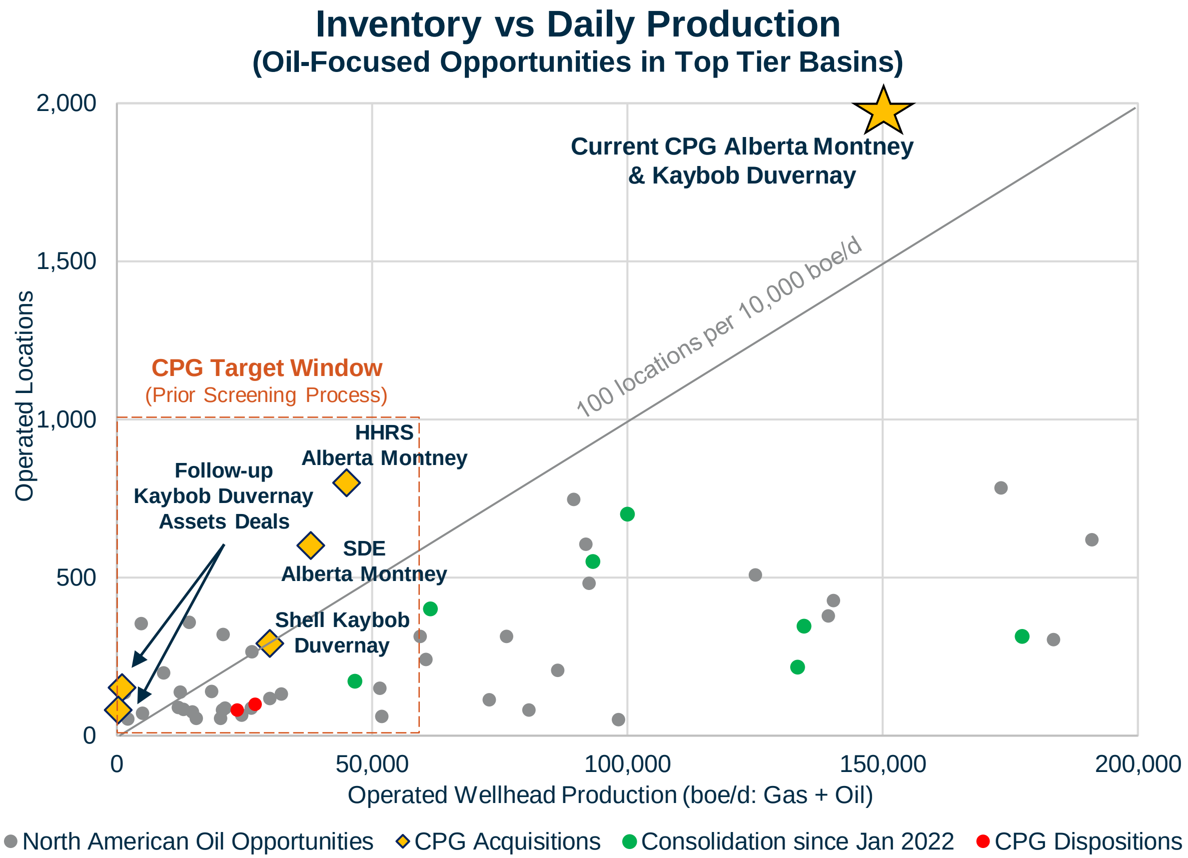
Inventory Screening & Ranking for CPG's Portfolio Transformation

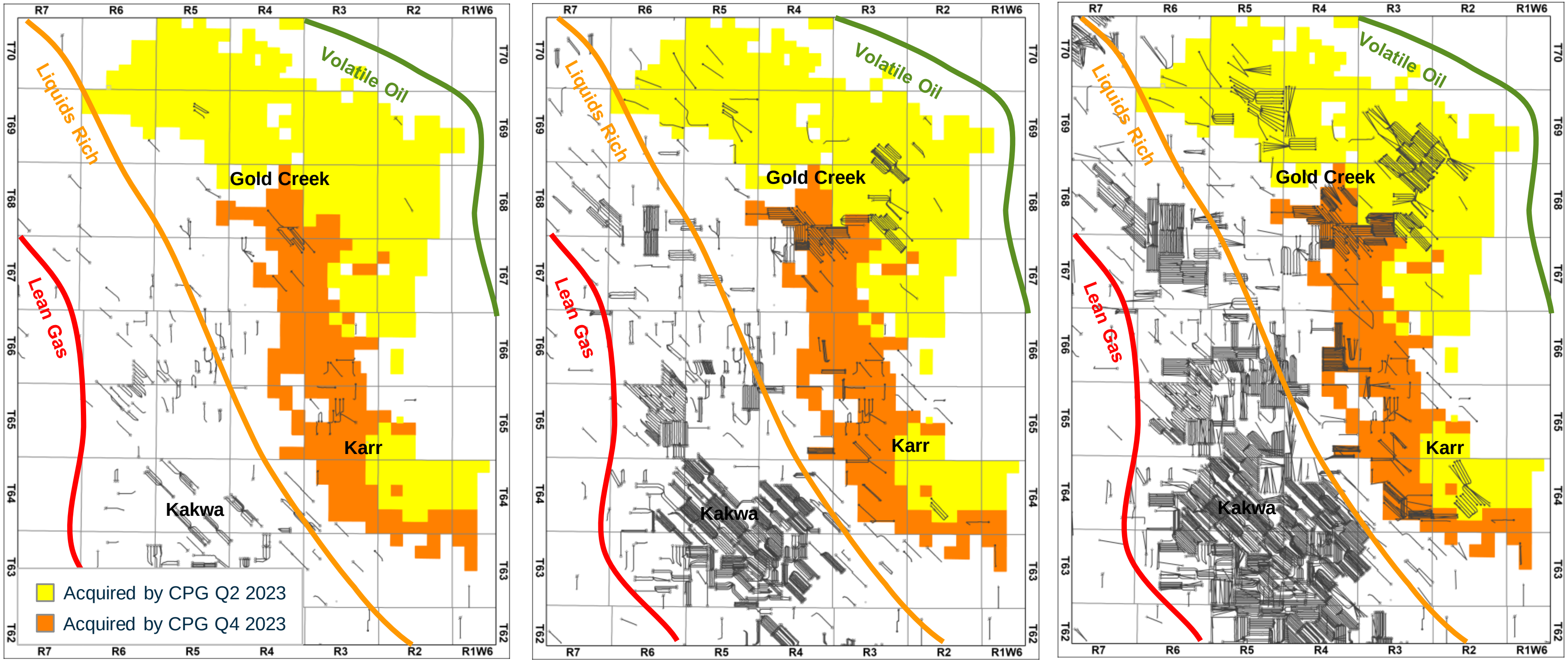
- Focused on **top tier oil-weighted plays** with **high-quality rock**
- **Screened opportunities with a high ratio of inventory versus daily production** as part of strategy to enhance long-term sustainability
- Analysis **provided confidence to execute on strategic acquisitions** of highest-quality assets and **dispositions** of non-core assets
- **CPG now stands out with abundant oil** and **Liquids-Rich inventory** in the Alberta Montney and Kaybob Duvernay, further complemented by its low-decline, long-cycle assets in Saskatchewan



SDE: Spartan Delta Corp. (Montney assets acquired by CPG Q2 2023). HHRS: Hammerhead Energy Inc. (acquired by CPG Q4 2023). CPG dispositions refers to the sale of non-conventional assets since 2018.

Alberta Montney: Kakwa, Gold Creek & Karr Horizontal Well Development

Development over time has moved from Liquids-Rich to Volatile Oil window with significant inventory remaining

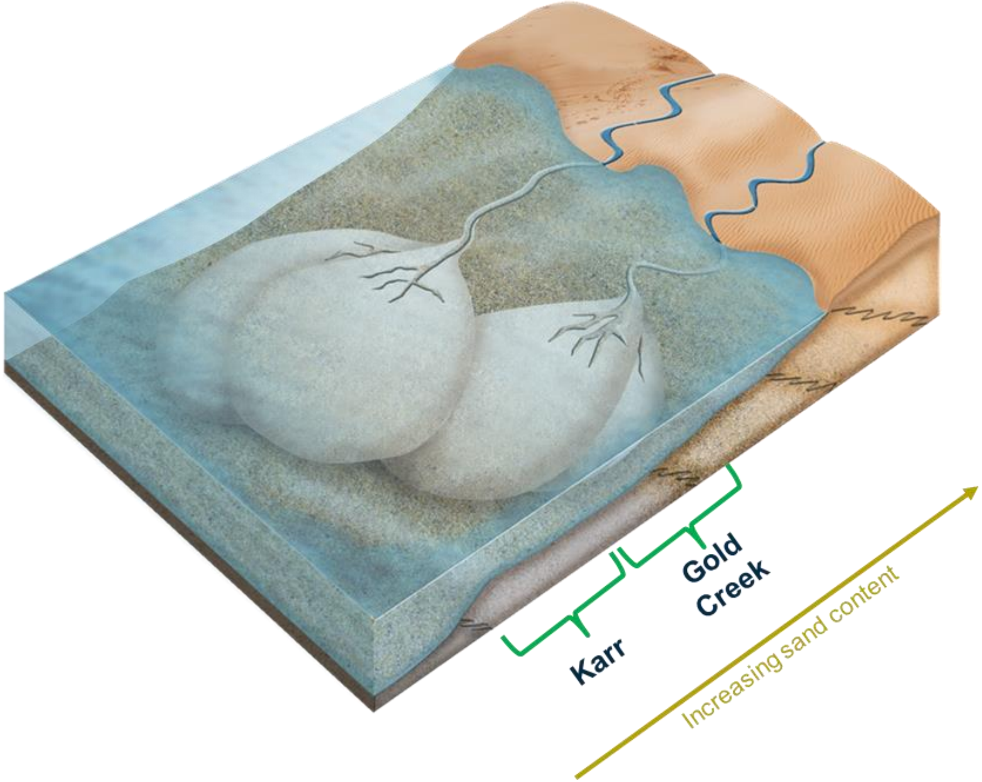


Prior to 2015 | **Prior to 2020** | **Present Day**

Gold Creek & Karr Montney Depositional Environment

Depositionally unique with attractive porosity and permeability with significant OOIP

- **Montney turbidite deposits** – thin alternating layers of silts and fine sand transported out into deeper water
- Turbidites continually deposit over time, shifting laterally and eventually form 150 - 200m thick beds of silts, sands and shale
- The sand content increases toward the shoreline in the NE direction



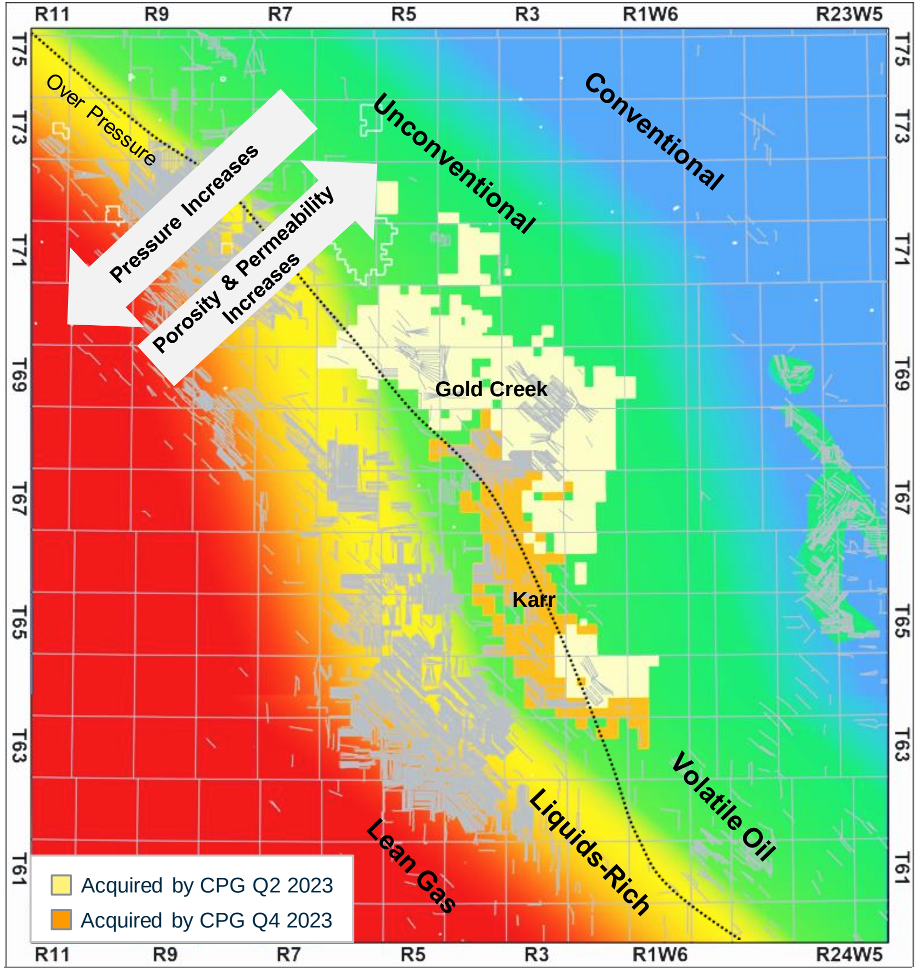
OOIP: original oil in place.

Volatile Oil Window

- CPG's land base within the Alberta Montney is **situated entirely in the Volatile Oil window** *(~40 degree API oil)*

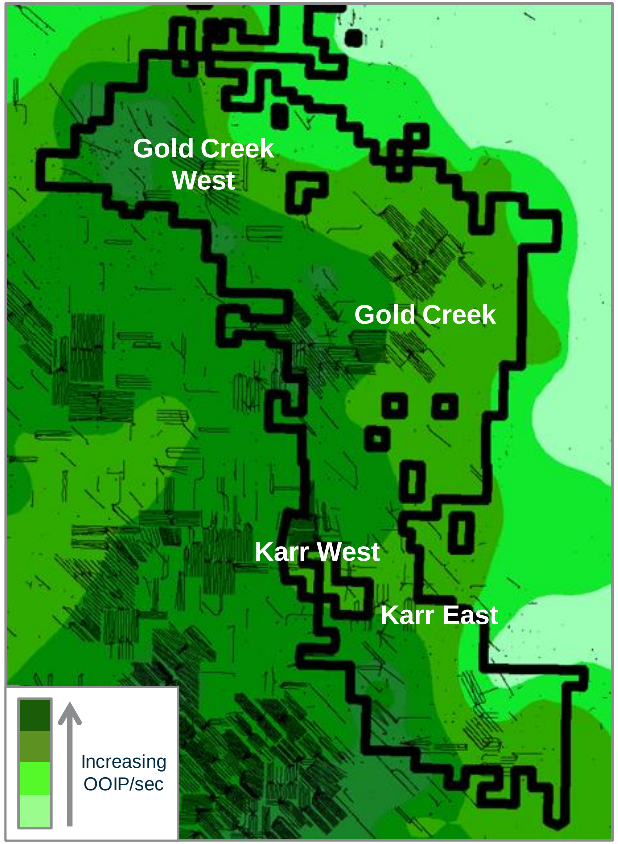
- **Gold Creek and Karr depositionally unique** as porosity and permeability increase to the NE while pressure increases to the SW
  - Gold Creek (normal pressured)
  - Karr (slightly over pressured)

- **This variation in porosity and permeability allows for oil to flow at very economic rates even in a normal pressure gradient**



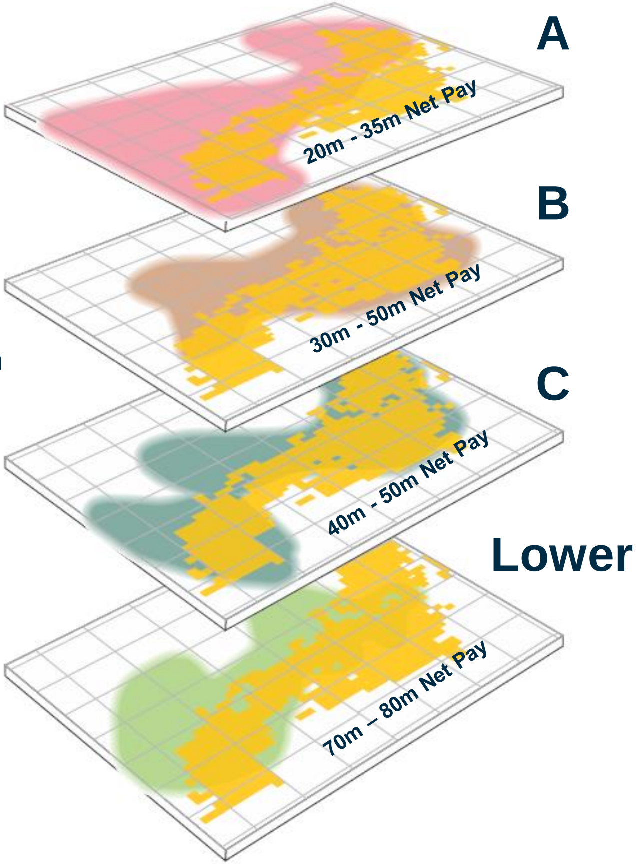
API: American Petroleum Institute gravity.

Gold Creek & Karr: Significant Resource In Place



- **Net Pay across CPG's land base**
  - Karr West: **~200m Net Pay**
  - Gold Creek West: **~200m Net Pay**
  - Karr East: **~180m Net Pay**
  - Gold Creek: **~170m Net Pay**
- Net Pay and OOIP by layer **influences development strategy** and well design
  - Optimal landing zone
  - Well spacing
  - Number of potential benches
- Significant resource also highlights the **opportunity for development of additional Lower Montney** bench

Montney Stack



OOIP: original oil in place.

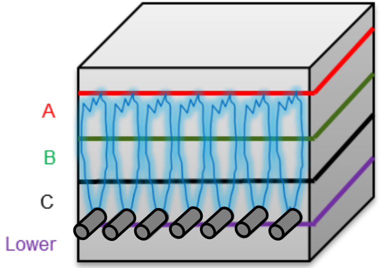
Development Strategy: One Bench vs Multi-Bench in Middle Montney

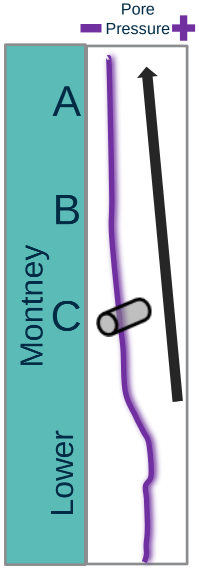
CPG development plan based on in-depth technical analysis factoring in OOIP, pore pressure and landing zone

One Bench Development

Gold Creek West, Gold Creek, Karr East

- Normally pressured, depths <2,600m
- Improved porosity and permeability
- Landing zone base of Middle Montney
- Pore pressure decreases upward, regardless of geologic variability, allowing the frac to grow upward to the Top Montney

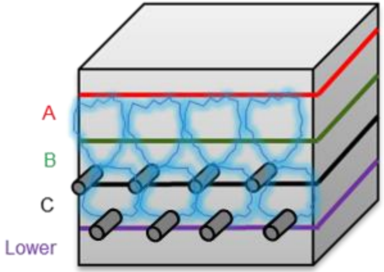


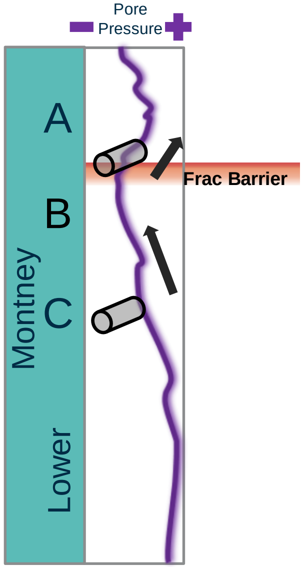


Multi-Bench Development

Karr West

- Highest OOIP area
- Over pressured, depths >2,600m
- Higher oil saturation
- Pore pressure increases in higher porosity zones, limiting vertical frac growth and supporting multi-bench development



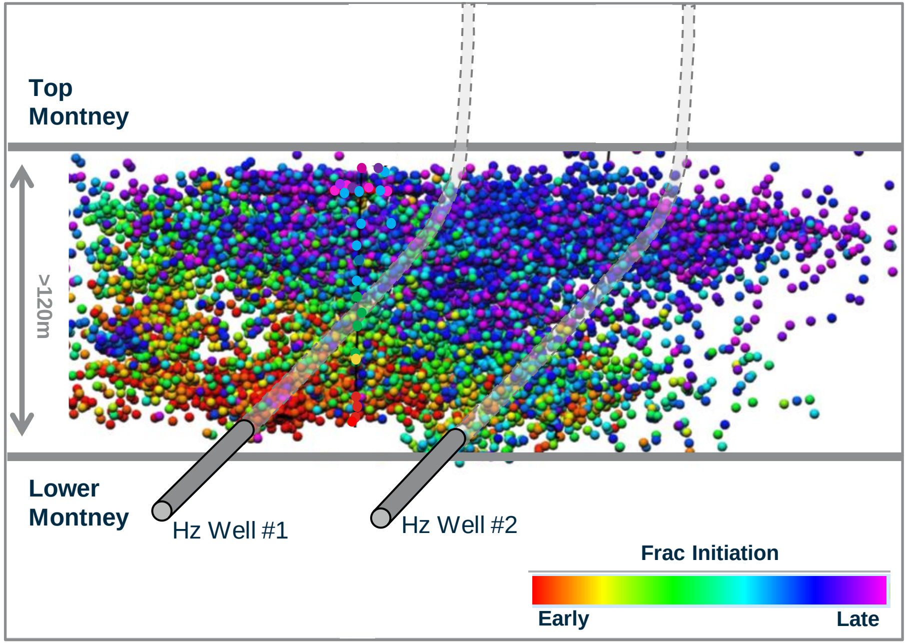


OOIP: original oil in place.

Gold Creek Microseismic Data Analysis

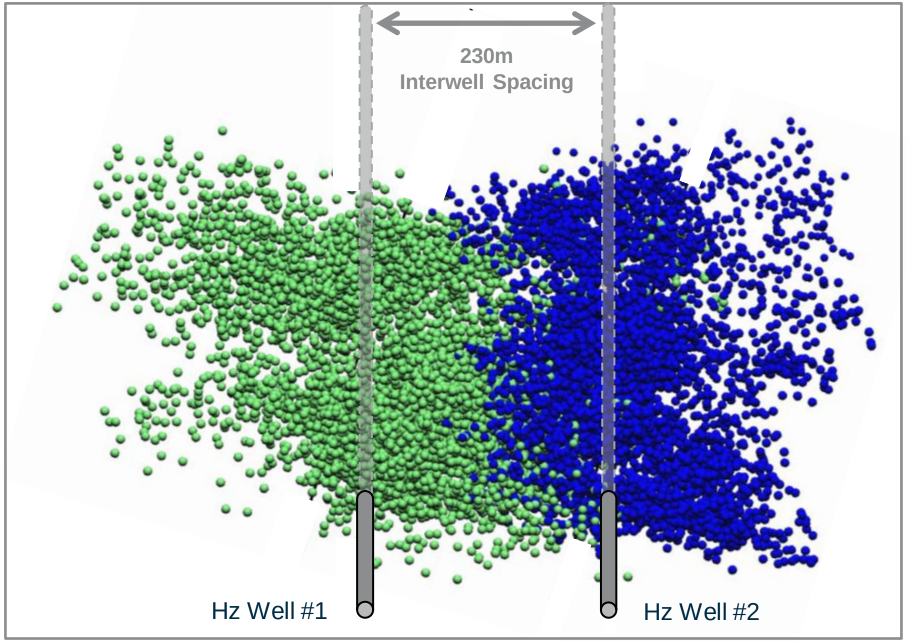
Elevator Fracs - uniform frac growth from Lower Montney to Top Montney with minimal interference laterally

Side View of Two Horizontal Wells



Two adjacent horizontal wells showing upward frac growth in a uniform manner

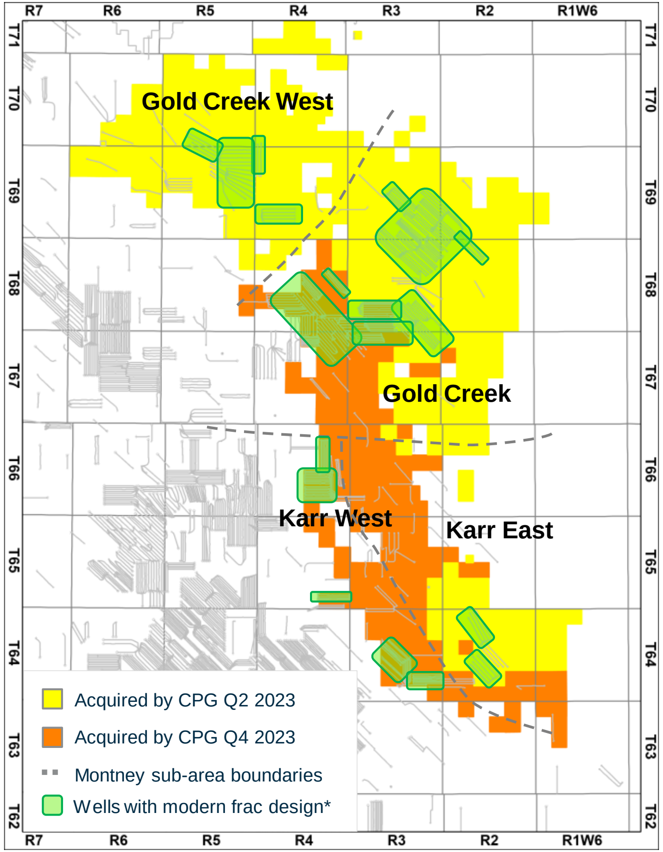
Top View of Two Horizontal Wells



Two adjacent horizontal wells showing frac containment laterally

Identified Opportunities to Create Value

Opportunity for down spacing, optimizing wells per section & potential development of additional Montney bench



Gold Creek

- Apply CPG's 7 wells/section, single bench development to lands most recently acquired to the SW where pressure and OOIP are higher

Gold Creek West

- Strong results to-date confirm significant OOIP
- Optimize well design for cost efficiencies (i.e. plug & perf vs. sleeves) and test down spacing to 7 wells/section

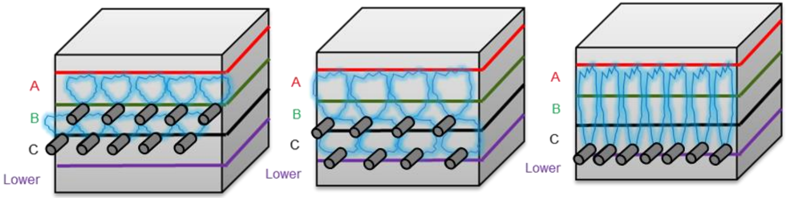
Karr West

- Highest OOIP area in land base and situated in over pressured window
- Moving to CPG's optimized 8 wells/section, multi-bench development with opportunity for additional Lower Montney development

Karr East

- Highest oil weighting area in land base
- Test down spacing to 7 wells/section

Gold Creek / Karr West (Prior Operator) | Karr West (CPG Optimization) | Gold Creek / Karr East (CPG Existing 'Elevator Frac')



10 - 11 wells/section
Cross-Link Gel Fracs
1.5-2.5 T/m Tonnage

8 wells/section
Slickwater Fracs
3 T/m Tonnage

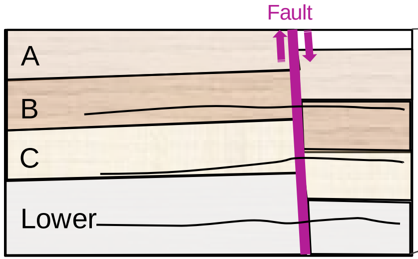
5 - 7 wells/section
Slickwater Fracs
3 T/m Tonnage

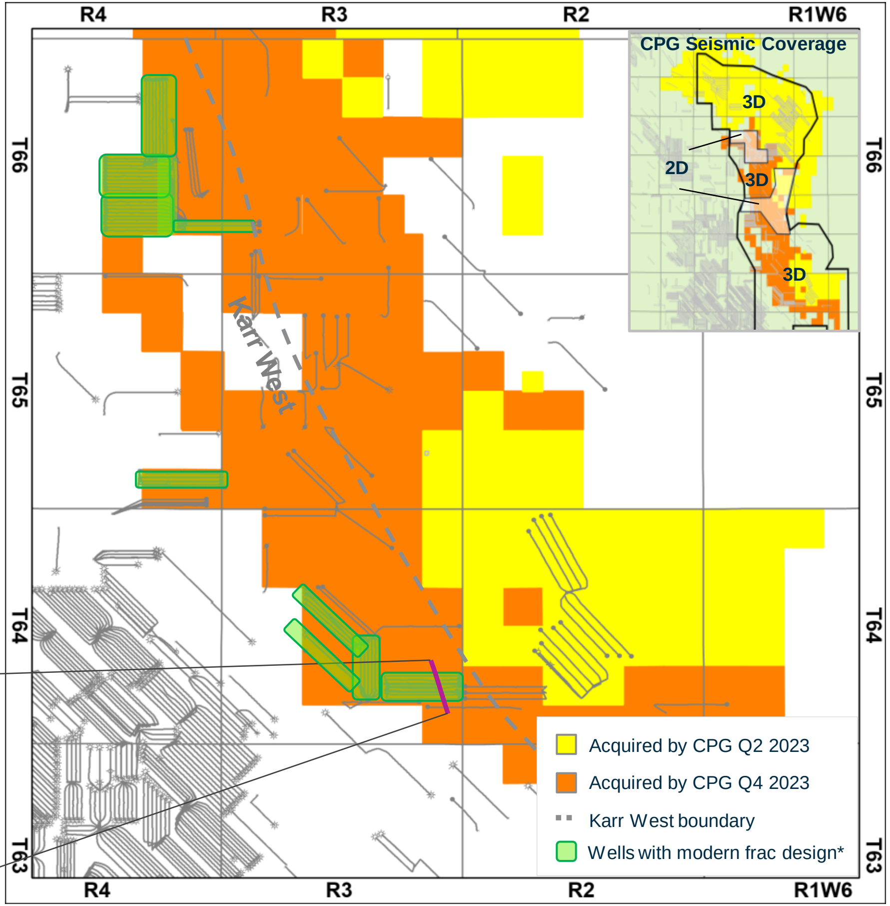
*Spacing and well design not optimized on lands acquired in Q4 2023. OOIP: original oil in place.

Karr West Opportunity

- Highest OOIP area with Net Pay of ~200m
- **Economics from previously drilled wells are impressive despite sub-optimal landing zones, completions and well spacing**, with an identified opportunity to enhance returns
- Prior operator's recent 5-11 pad in late 2023 also illustrated a missed opportunity and a case encountering a known localized fault
  - Resulted in three well bores being truncated, impacting effective lateral length and potential EURs
  - Avoidable with proper planning and seismic data
- **CPG has access to extensive seismic data across its Montney land base**, which has been incorporated into its long-term development plans

Prior Operator
5-11 Pad Cross-Section View





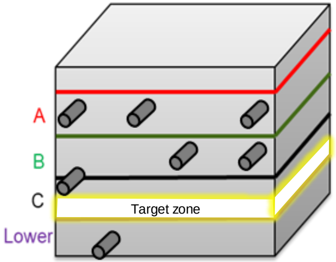
*Spacing and well design not optimized. EURs: estimated ultimate recoveries.

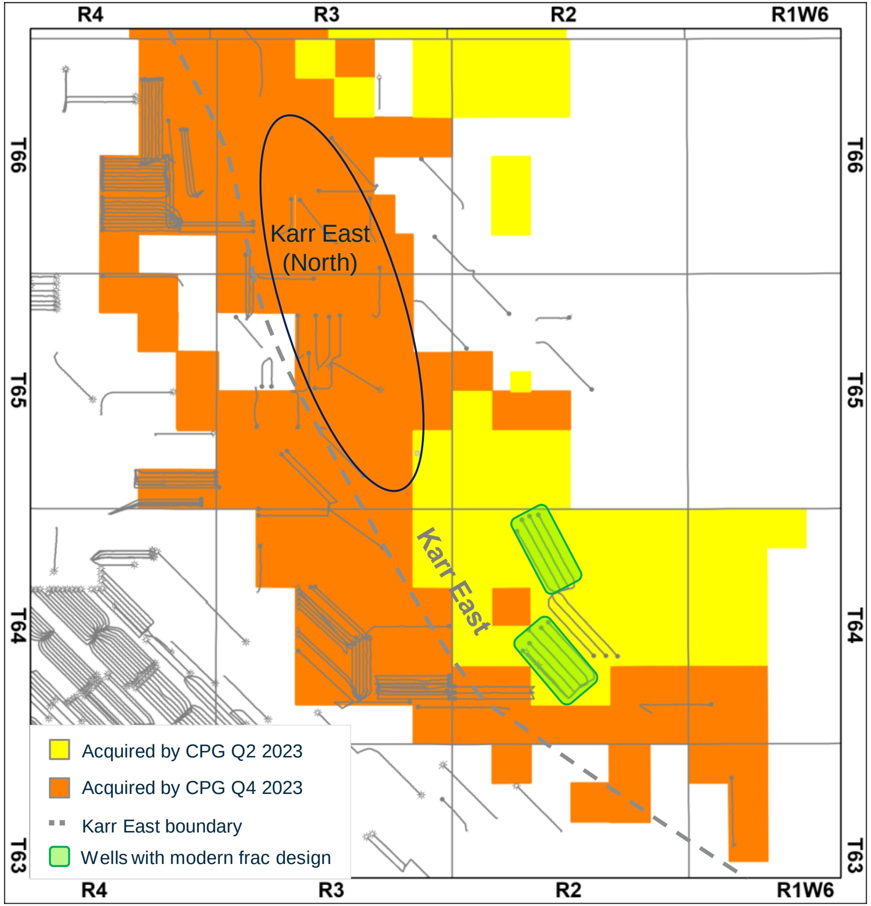
Karr East Opportunity

- Highest oil weighting area with Net Pay of ~180m
- **Two pads have been completed in the south utilizing an optimal well design** (landing zones and modern style fracs) and have yielded **impressive results to-date**
  - Avg. Peak 30-day rate: ~820 boe/d (>80% liquids)
  - Avg. EURs: ~900 Mboe (~80% liquids)
- **Development in the northern portion of Karr East took place prior to 2017** primarily through single wells that were landed out of zone and with outdated fracs. These wells are still expected to generate average EURs of ~500 Mboe
  - Opportunity to enhance returns based on CPG's design

	Prior Operator	CPG Design
Lateral Length	<1,700 m	2,800 m
Frac Tonnage	1 T/m	3 T/m
Fluid Intensity	2 m^3/m	15 m^3/m
Stage Spacing	140 m	50 m
EURs	~500 Mboe	>750 Mboe

Prior Development in Karr East (North) Outside of Target Landing Zone

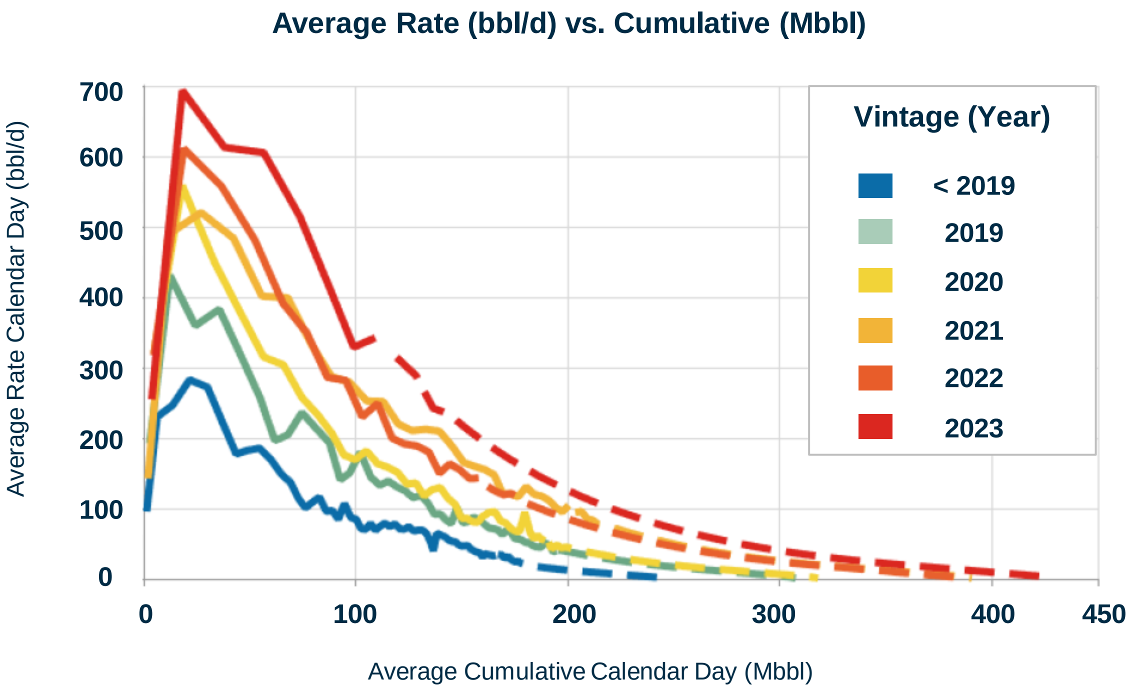




OOIP: original oil in place. Estimated ultimate recoveries (EURs) based on an average of type well assigned by independent reserves evaluator McDaniel as at December 31, 2023.

EUR Progression in Volatile Oil Window

Results continue to improve within CPG's Montney Volatile Oil window



EUR: estimate ultimate recovery. Source: McDaniel. Cumulative and rate figures includes oil, condensate, C5+.

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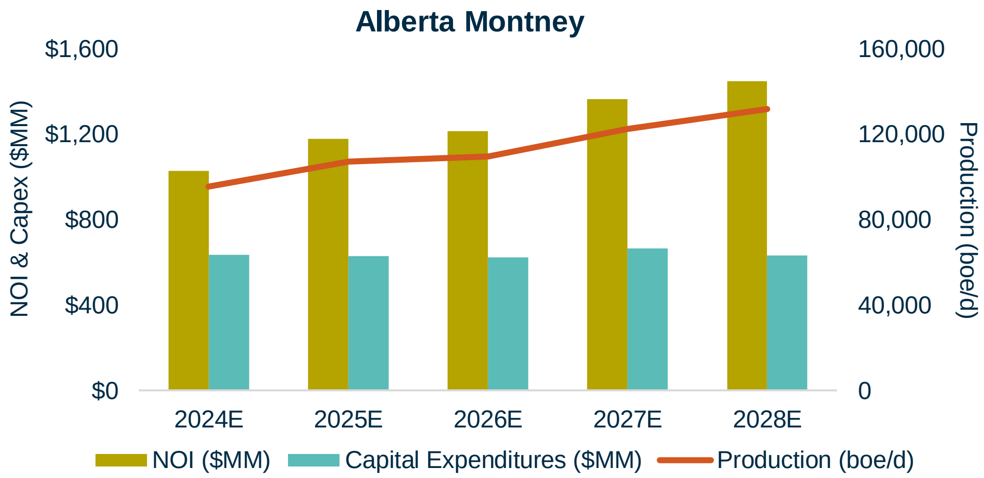
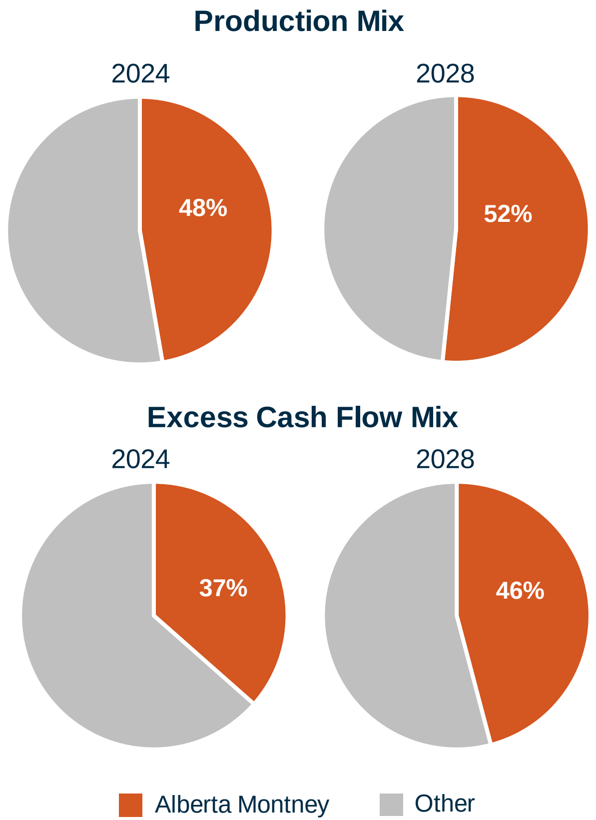
Alberta Montney 5-Year Outlook (2024 – 2028)

Production CAGR of ~10% through 2028 in addition to generating significant excess cash flow growth





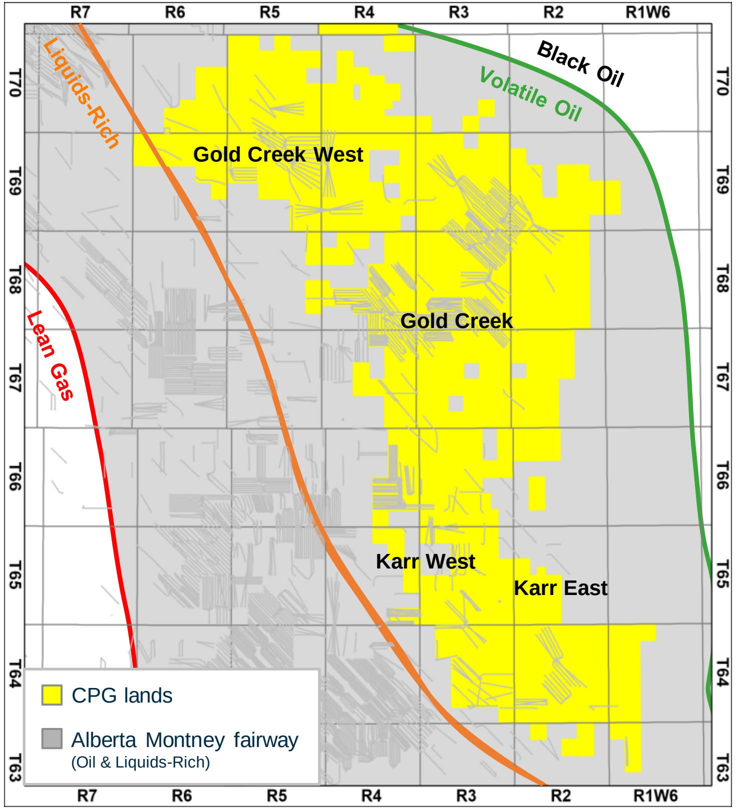
(US$70 WTI)	2024E	2028E
Production (boe/d)	96,000	132,000
Capital Expenditures ($MM)	$635	$630
Net Operating Income (NOI) ($MM)	$1,030	$1,450
Asset Level Excess Cash Flow ($MM)	$395	$820
Net Drill Count (Rig Count)	>60 (3)	>60 (3)

All figures are approximates. Asset level excess cash flow is net operating income less capex. 2024 - 2028 assumes US$70/bbl WTI flat and average price of $3.35/mcf AECO.

Alberta Montney Reservoir Regions & Economics

>1,400 premium locations in the Volatile Oil window

Gold Creek West	
IP30 (boe/d)	1,250
(% Liquids)	(65%)
EUR (mboe)	790
(% Liquids)	(55%)
Cost Per Well ($MM)	$9.5
NPV10% ($MM)	$8.0
Payout (Months)	12
IRR%	100%
Net Locations	310



Gold Creek	
IP30 (boe/d)	1,300
(% Liquids)	(55%)
EUR (mboe)	1,150
(% Liquids)	(45%)
Cost Per Well ($MM)	$9.0
NPV10% ($MM)	$9.5
Payout (Months)	10
IRR%	110%
Net Locations	560

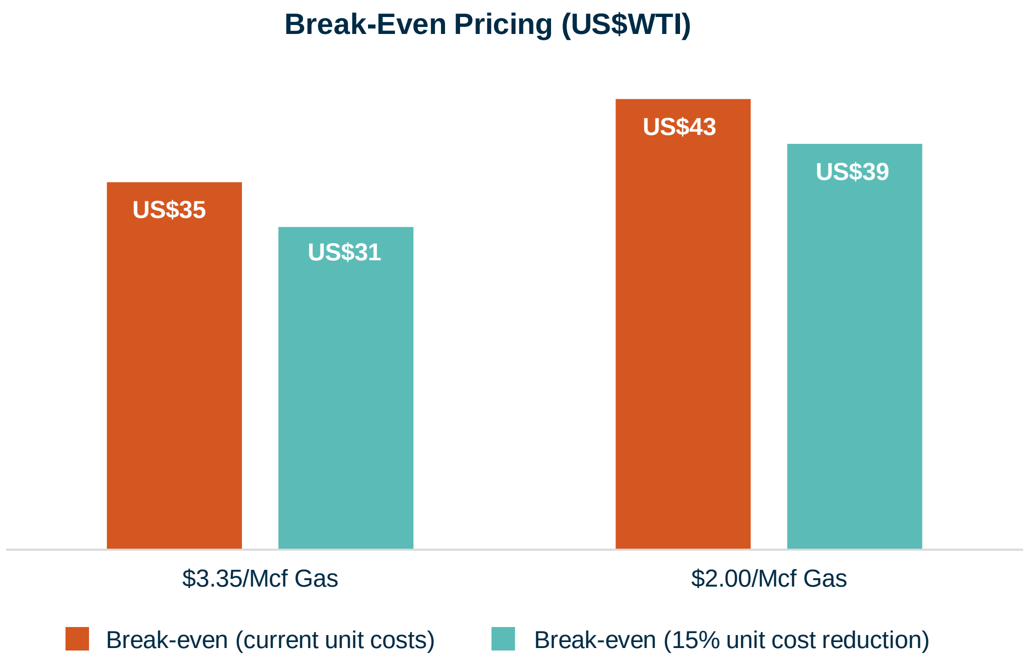
Karr West	
IP30 (boe/d)	1,330
(% Liquids)	(65%)
EUR (mboe)	1,050
(% Liquids)	(50%)
Cost Per Well ($MM)	$10.0
NPV10% ($MM)	$12.0
Payout (Months)	9
IRR%	115%
Net Locations	170

Karr East	
IP30 (boe/d)	700 – 1,075
(% Liquids)	(55% – 80%)
EUR (mboe)	750 – 820
(% Liquids)	(50% – 70%)
Cost Per Well ($MM)	$9.5 – $10.5
NPV10% ($MM)	$7.5 – $13.0
Payout (Months)	10 – 13
IRR%	65% – 110%
Net Locations	390

All figures are approximates. Estimated ultimate recoveries (EURs) based on an average of booked proved plus probable (2P) type well assigned by independent reserves evaluator McDaniel as at December 31, 2023.
Economics as at US$70/bbl WTI and $3.35/mcf AECO, with payouts calculated from initial on stream date. Inventory of approximately 1,430 net premium locations includes 383 booked proved plus probable (2P) locations as at December 31, 2023.

Alberta Montney Break-Even Economics & Sensitivity to Gas Prices

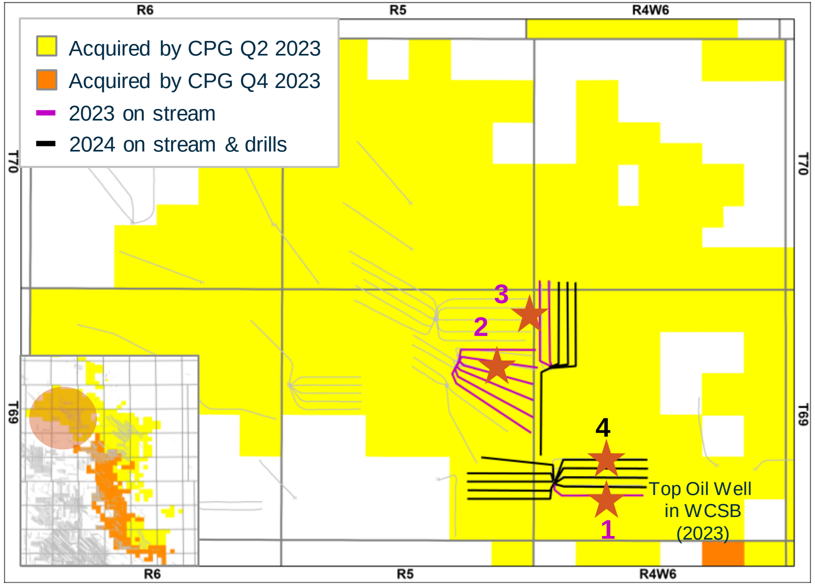
Alberta Montney inventory provides attractive economics given location within the Volatile Oil window

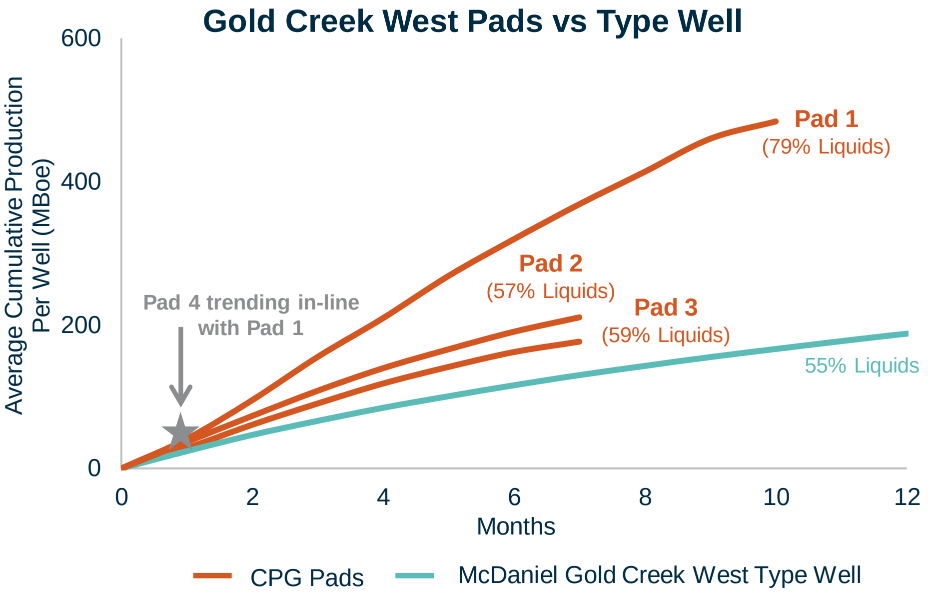


All figures are approximates. Break-even is based on BT NPV10%. Economics based on proved plus probable (2P) booked type wells assigned by independent reserves evaluator McDaniel as at December 31, 2023. Gas price sensitivity (AECO).

Gold Creek West: Superior Performance from Single Bench Development

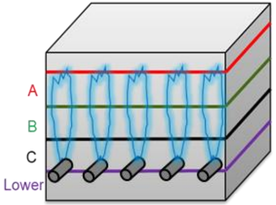
Recent Gold Creek West results exceeding booked type well expectations





Well Results

Pad (On stream)	Peak 30-Day Rate (boe/d)	% Liquids
1 (Q1 2023)	1,990	84%
2 (Q2 2023)	1,355	75%
3 (Q3 2023)	1,165	68%
4 (Q1 2024)	1,900 (20 days)	>80%



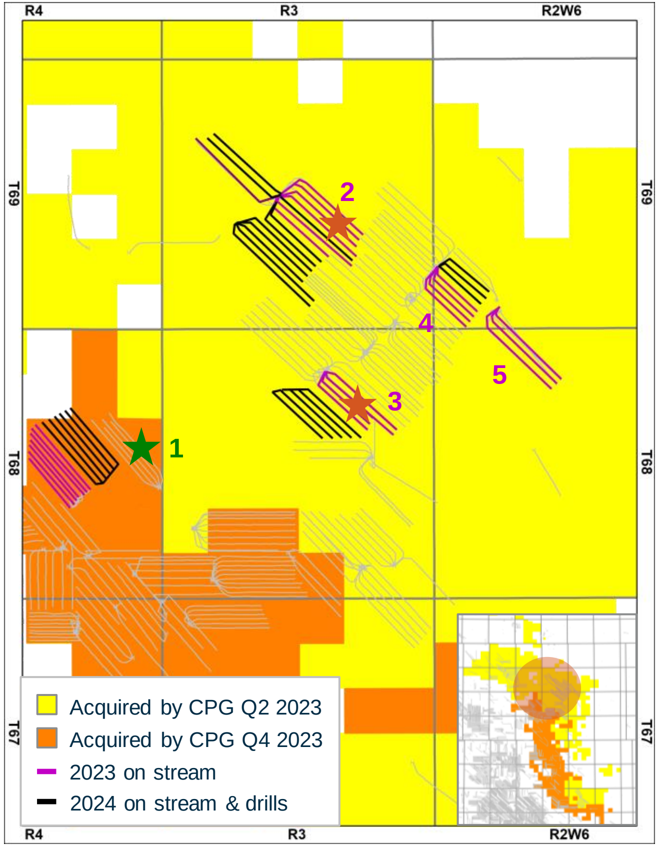
CPG's Gold Creek West had the top 2023 oil and liquids well in the WSCB, which has recently been offset by a 4-well pad that is currently producing at similar rates

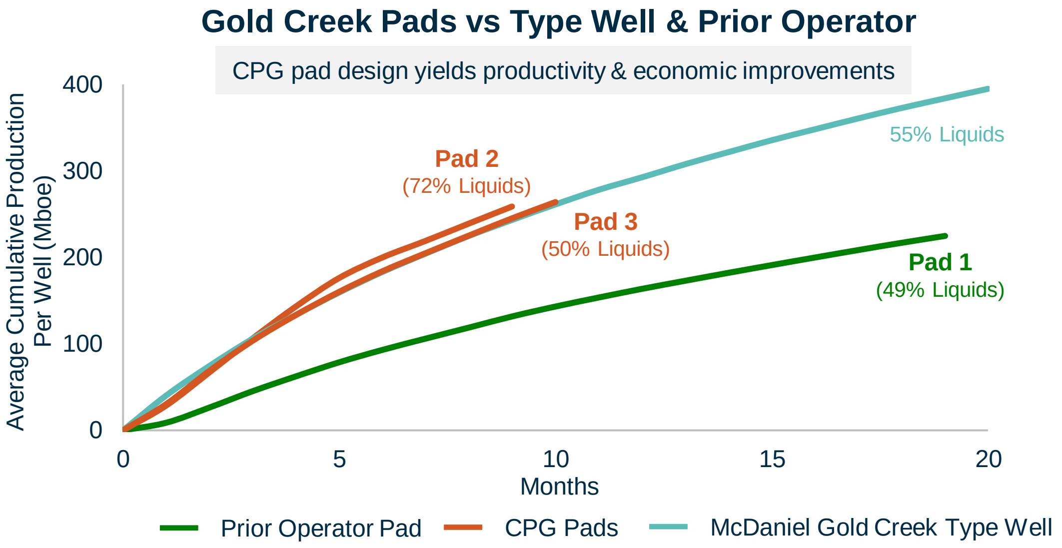
Strong results in in this area drove an increase in booked type well at YE 2023

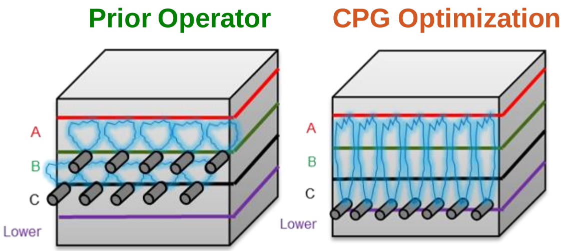
Production plot normalized to 3,000m. WCSB Top oil well in Alberta in 2023 based on rig release over the last 12 month ending December 2023.
Pad liquids percentage for cumulative production based on performance to-date. Type well liquids based on cumulative estimated ultimate recovery (EUR) to date.

Gold Creek: Enhanced Performance through Optimized Development

Pads developed in single bench with wider spacing and larger completions yielding higher production and returns







Well Results

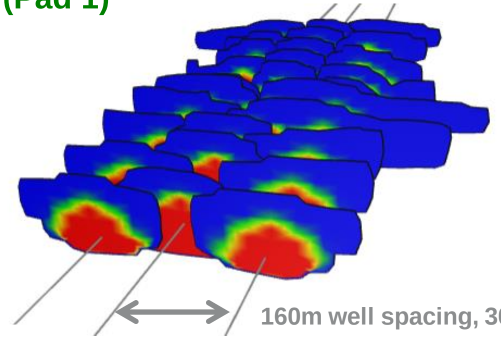
Pad (On stream)	Peak 30-Day Rate (boe/d)	% Liquids
1 (Prior Operator)	545	52%
2 (Q2 / Q4 2023)	1,340	71%
3 (Q2 2023)	1,120	53%
4 (2022 / 2023)	1,245	56%
5 (Q4 2023)	1,265	41%

Production plot normalized to 3,000m. Pad liquids percentage for cumulative production based on performance to-date. Type well liquids based on cumulative estimated ultimate recovery (EUR) to date.

Gold Creek: Data Analysis Supports Optimized Development Plan

Wider-spaced, single bench pads with larger fracs yield productivity and economic improvements

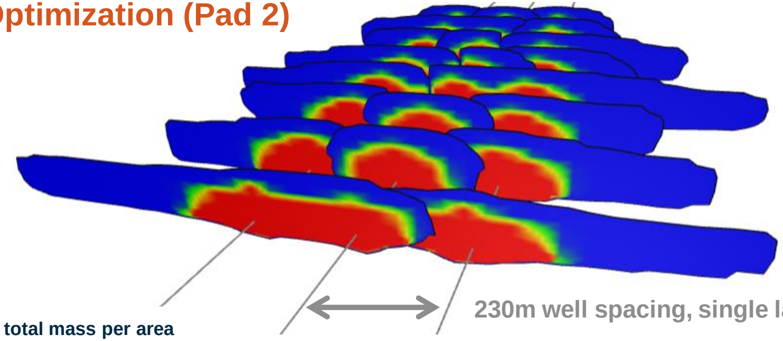
Prior Operator (Pad 1)



160m well spacing, 30m vertical spacing

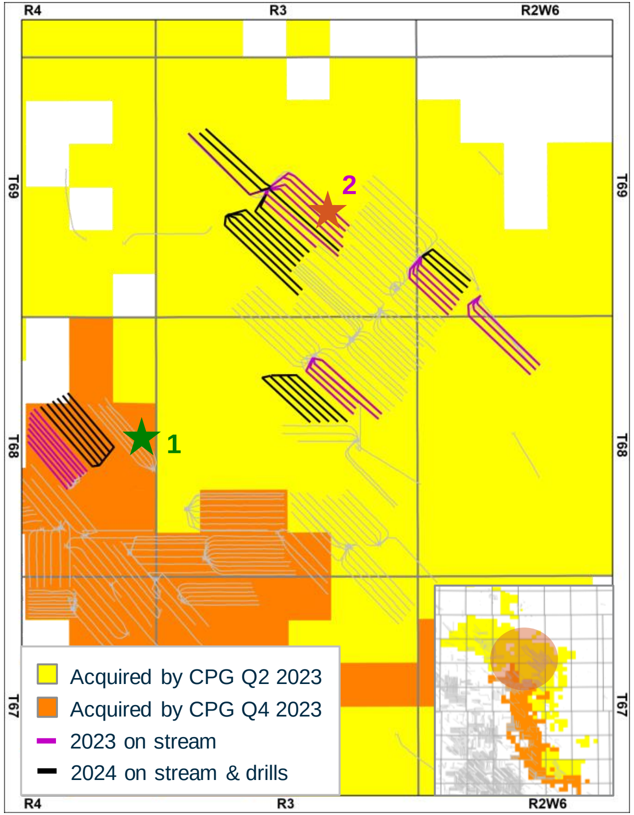
Proppant total mass per area

CPG Optimization (Pad 2)



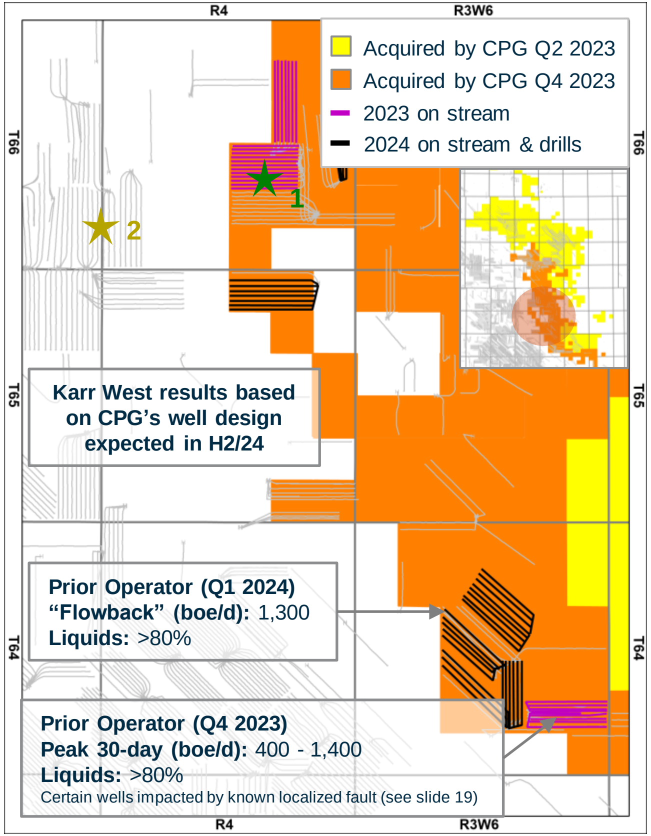
230m well spacing, single landing zone

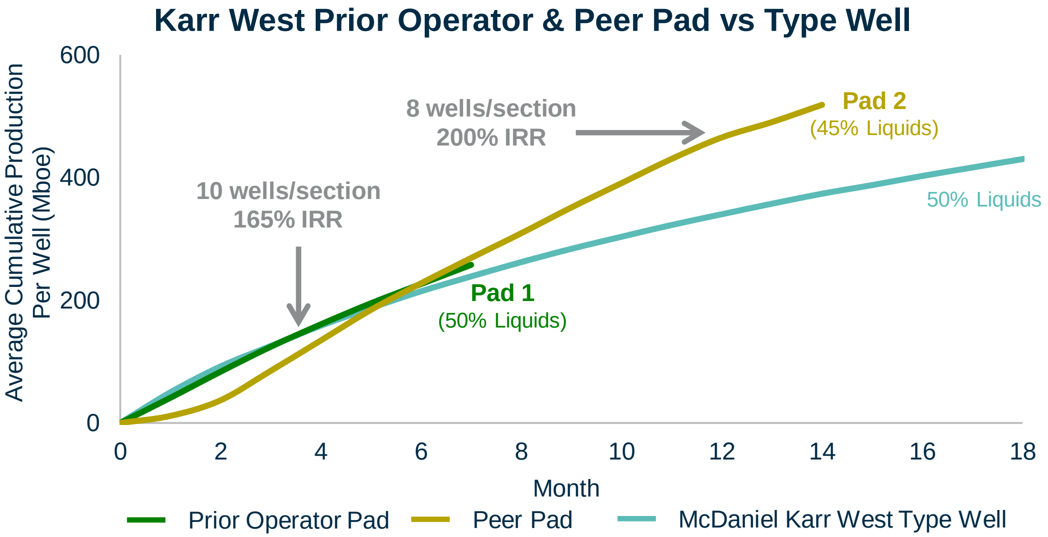
Proppant total mass per area

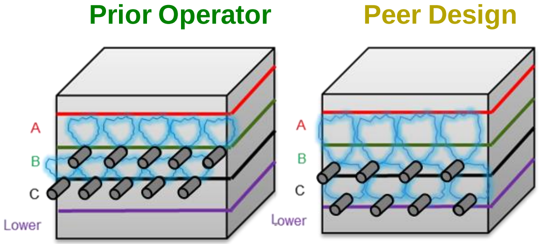


Karr West: Significant Opportunity with Higher OOIP & Pressure

Currently drilling in the area based on CPG modified well design, with results expected in H2 2024







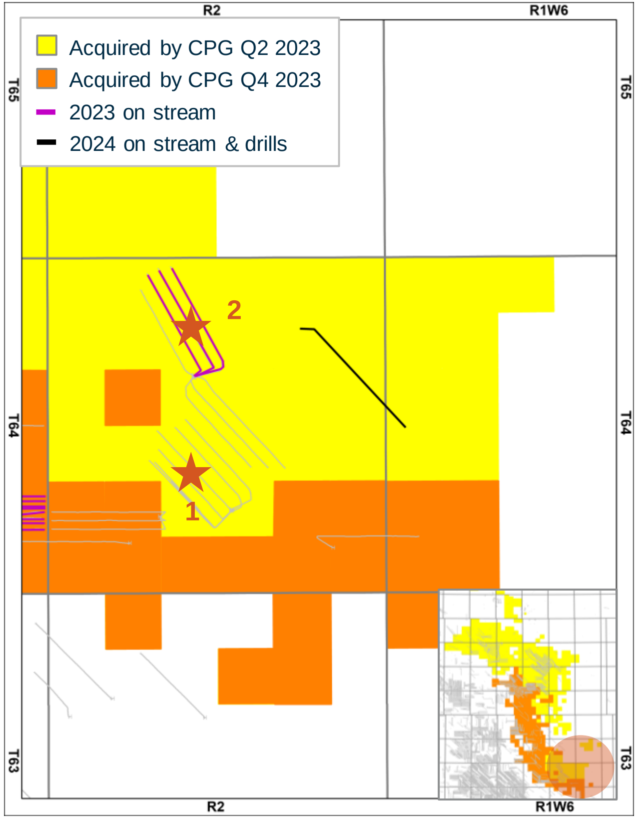
Increased OOIP and pressure in Karr West resulting in highly economic type wells. Opportunity to further improve economics by optimizing the number of wells per section

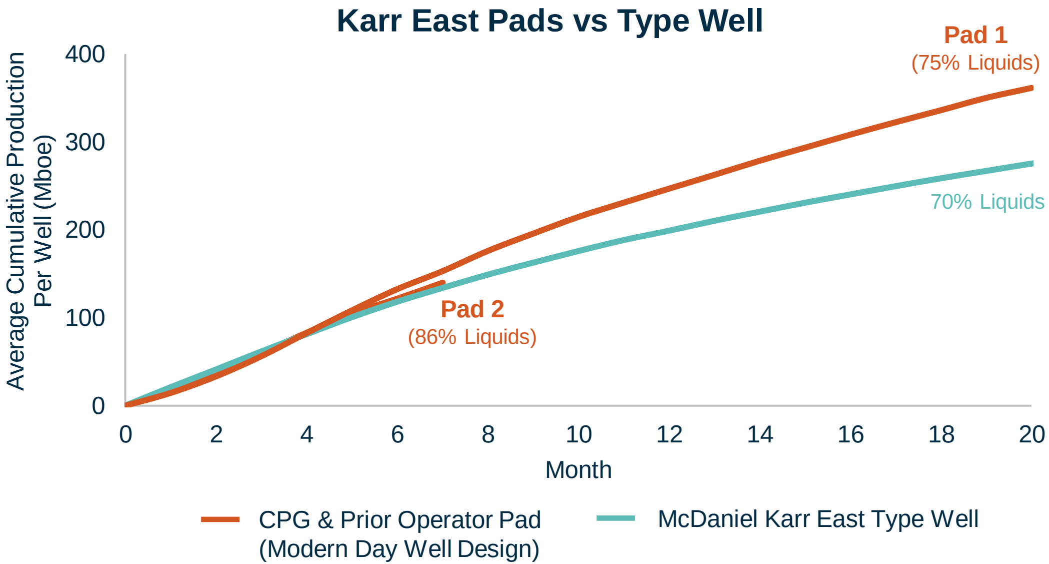
OOIP: original oil in place. Pad liquids percentage for cumulative production based on performance to-date. Type well liquids based on cumulative estimated ultimate recovery (EUR) to date. Peer cumulative boe based on public data.

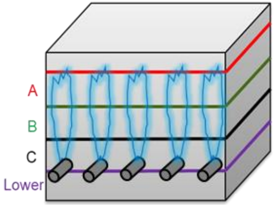
CRESCENT POINT | CORPORATE PRESENTATION

Karr East: Strong Results To-Date with High-Liquids Weighted Production

Highest liquids weighting wells across CPG's Montney with new wells performing in-line or above type well







Well Results

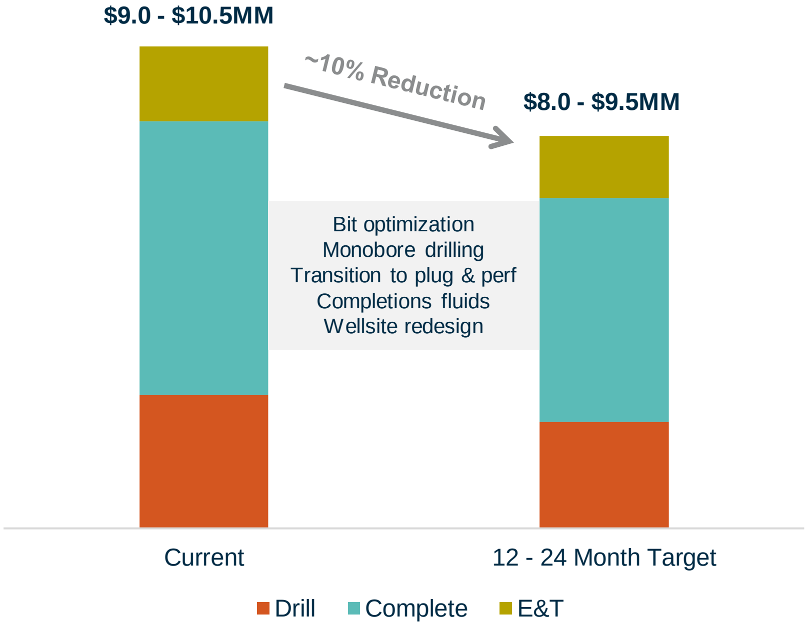
Pad (On stream)	Peak 30-Day Rate (boe/d)	% Liquids
1 (2018 / 2019 / 2021)	860	80%
2 (Q3 2023)	775	85%

Production plot normalized to 3,000m.
Pad 1 includes a well brought on stream in Q2 2018, Q2 2019 and 3 wells in Q2 2021. Pad liquids percentage for cumulative production based on performance to-date. Type well liquids based on cumulative estimated ultimate recovery (EUR) to date.

Alberta Montney Cost Saving Opportunities & Corporate Synergies

Further synergies expected from recent Alberta Montney consolidation, including cost of capital improvement

Average Well Costs ($MM)



Corporate Costs (2024E vs. 2022)

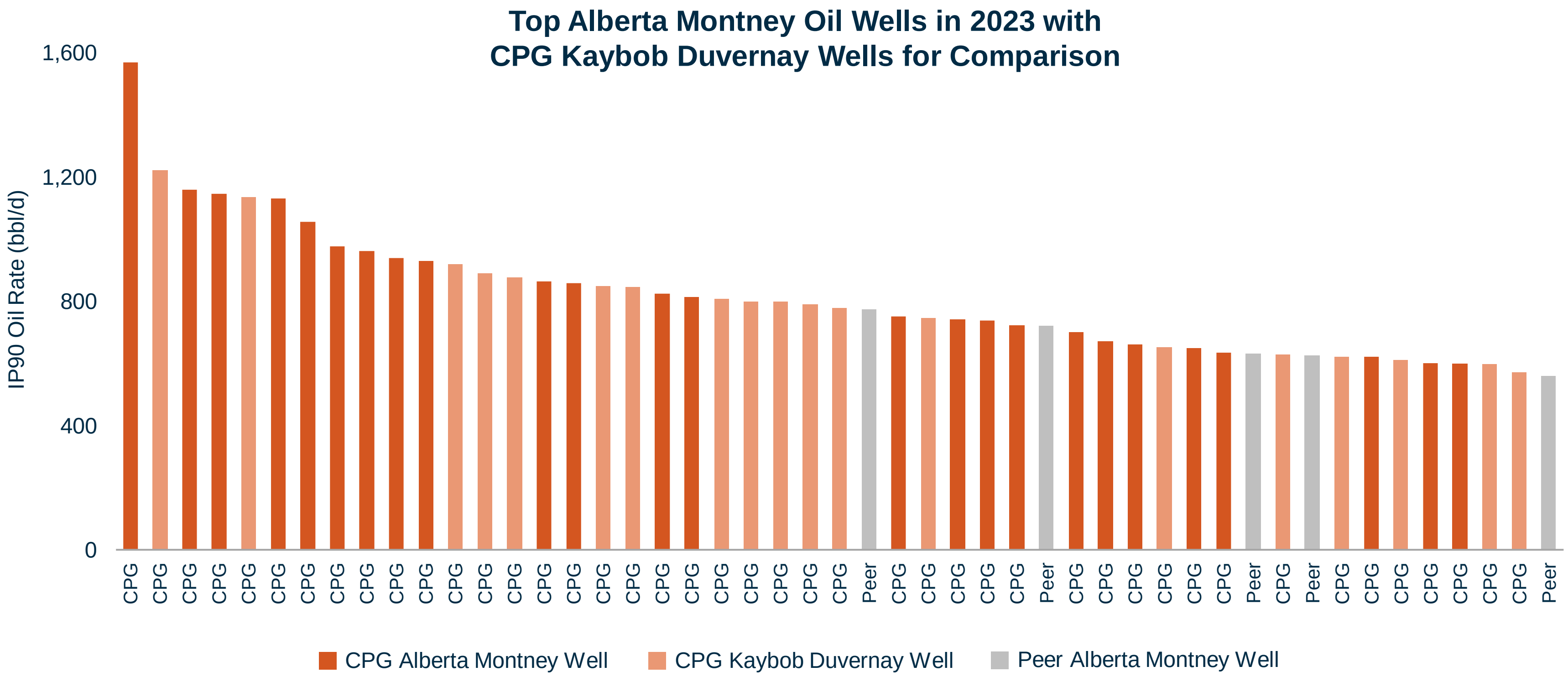
Opex per boe	↓ 10%
Royalties %	↓ 20%
G&A per boe	↓ 25%
Capital Efficiency	↓ 25%

Addition of Alberta Montney assets, net of dispositions, has improved our cost structure given organizational infrastructure that was already in place

All figures are approximates. Average well costs based on 3,000m lateral length. 2024 corporate costs based on mid-point of guidance range. E&T: equip and tie-in.
G&A per boe excludes share based compensation. Capital efficiency numbers are full-cycle and include drilling, completions, tie-in, equipment and facilities capital.

Results Highlight Returns & Scalability of CPG's Alberta Montney

Industry-leading Alberta Montney results complemented by high-return Kaybob Duvernay assets



Source: Top Alberta Montney wells based on Peters & Co. Limited research February 7, 2024.
CPG Kaybob Duvernay 2023 well results based on internal data for comparison purposes. Industry peer Kaybob Duvernay results not included due to limited public information.

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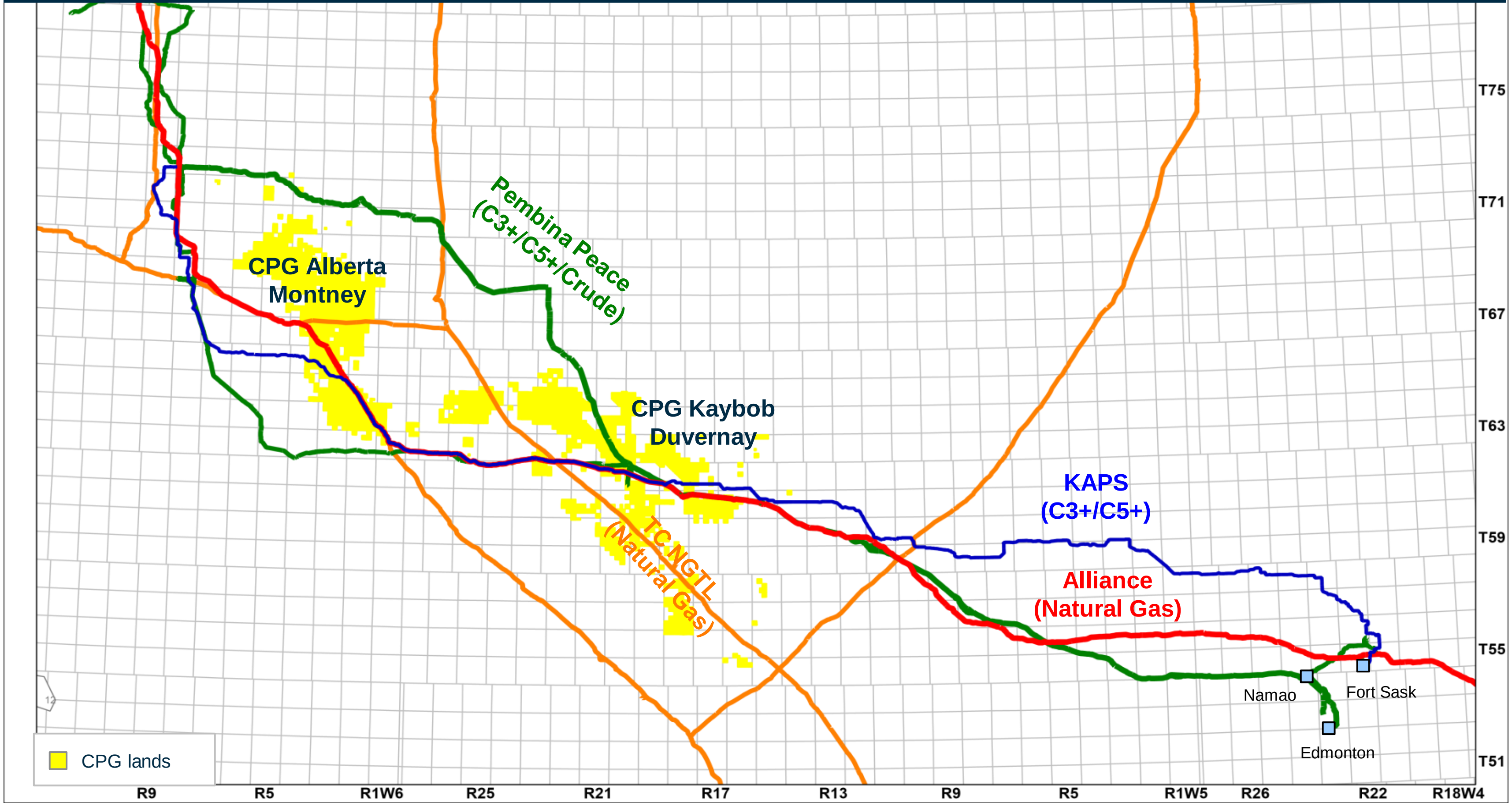
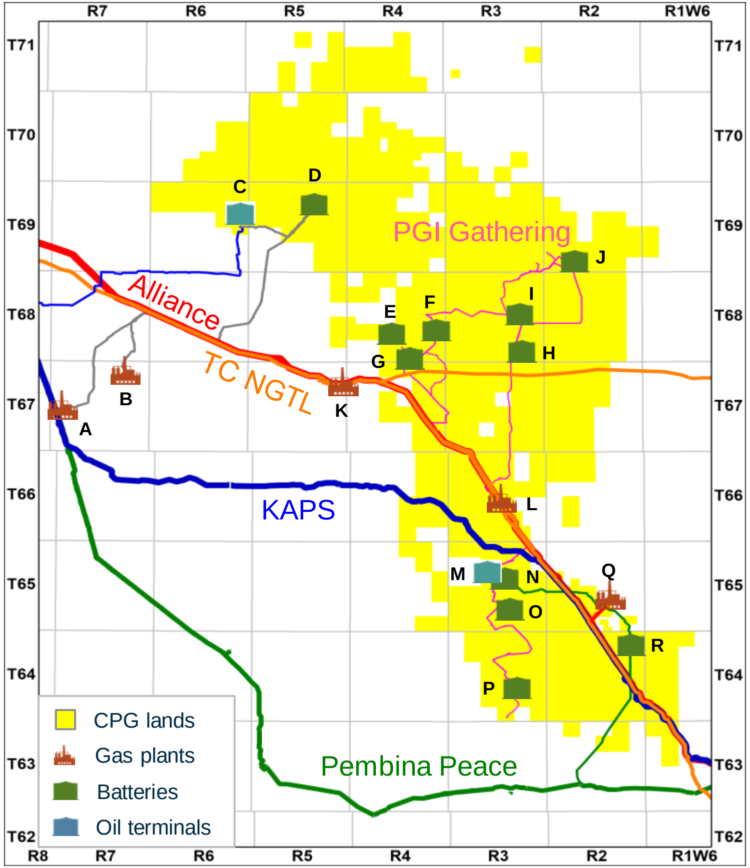
Well Positioned For Product Egress

Kaybob Duvernay and Alberta Montney are well connected to all major product pipelines



Alberta Montney Area Infrastructure Provides Ample Connectivity

~10% of development capital expenditures directed to facility capital in 10-year development plan

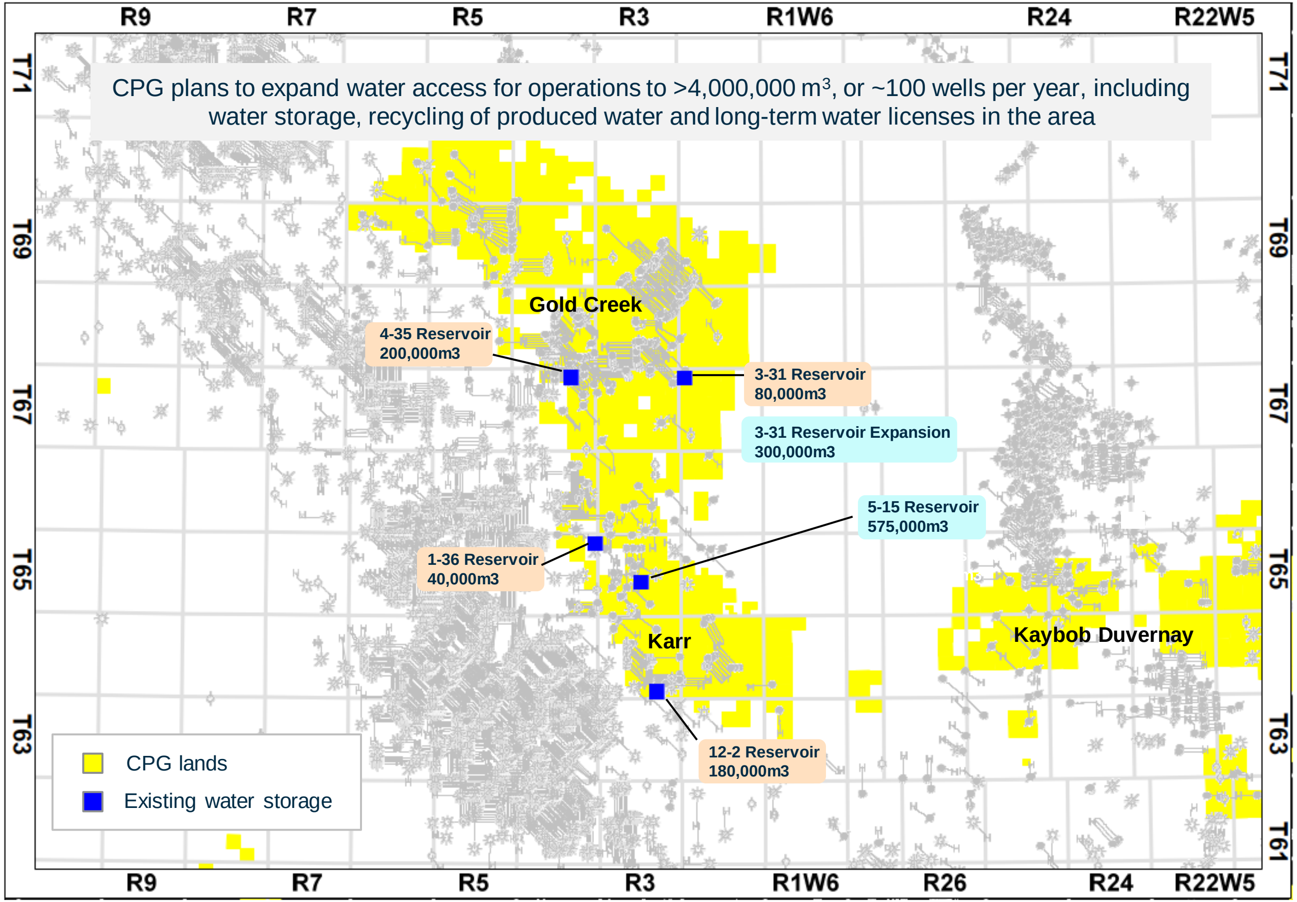


- Access to major liquids pipelines from all major processing facilities
- Primary gas plants connected to Nova Gas Transmission Line (NGTL) system, Alliance Pipeline or both
- Firm transportation service held to support long-term plans for liquids and gas
- >1.1 Bcf/d of third-party gas plant capacity in the area (~75% utilized)
- Majority of CPG's gas volumes directed to PGI Patterson Creek (~60% utilized)

Major Facilities	
A	14-18 Keyera Wapiti Gas Plant
B	07-35 PGI Wapiti Gas Plant
C	15-13 R360 South Wapiti
D	03-26 CPG Battery
E	03-10 CPG Battery
F	11-12 CPG Battery
G	09-03 CPG Battery
H	11-02 PGI Battery
I	02-23 PGI Battery
J	11-05 PGI Battery
K	13-26 CNRL Gold Creek
L	11-21 PGI Patterson Creek
M	01-28 Pembina Oil Terminal
N	10-21 CPG Battery
O	01-16 CPG Battery
P	01-15 CPG Battery
Q	10-10 CNRL Karr Creek
R	05-35 PGI Battery

CPG Alberta Montney: Water Infrastructure

CPG owned frac water infrastructure growing to ~1.3 million m^3 of storage



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

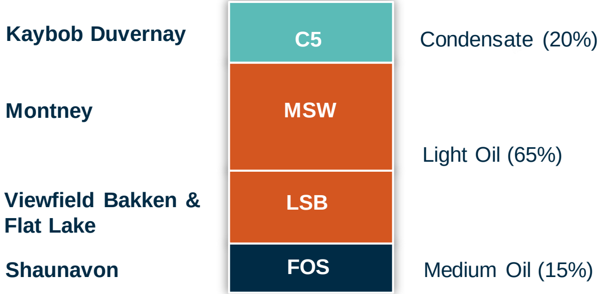
Saskatchewan (Viewfield Bakken, Flat Lake & Shaunavon)

- 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)

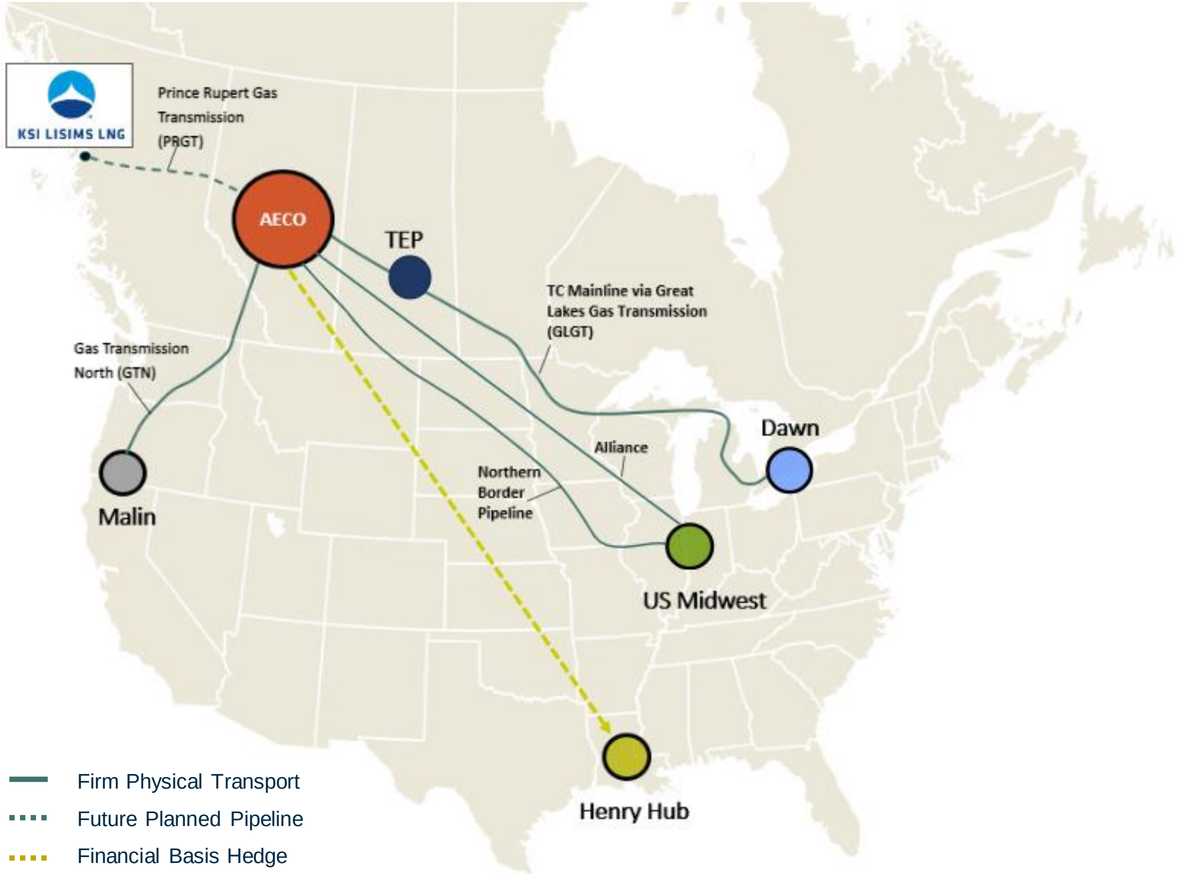
- Receives premium pricing to AECO, with exposure to NYMEX, Chicago, Dawn and Malin & Stanfield pricing
- Exposure to international natural gas pricing through future Ksi Lisims LNG project

2024E Oil & Condensate Production Breakdown by Stream

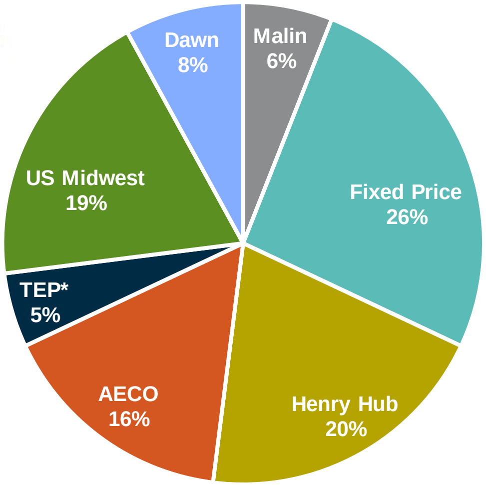


Liquids and gas percentages are based on 2024 production. WCS: Western Canadian select. FOS: Fosterton, LSB: Light Sour Blend, C5: condensate. MSW: Mixed Sweet Blend.

Majority of Natural Gas Diversified Away from Alberta



Diversification Through 2025



TEP – Saskatchewan hub trades at a premium to AECO – current contract year premium ~$0.50/GJ.

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Takeaways from CPG's 2023 Kaybob Duvernay Analyst Day

Kaybob Duvernay is a high-return, condensate-rich play that provides growth & excess cash flow generation

- ✓ Kaybob Duvernay play has evolved over the years with enhanced EURs and more consistent results
- ✓ CPG is strategically positioned in the geological "sweet spot" of the Kaybob fairway
- ✓ Strong industry results offsetting CPG's undeveloped land position
- ✓ Major infrastructure and market access already in place

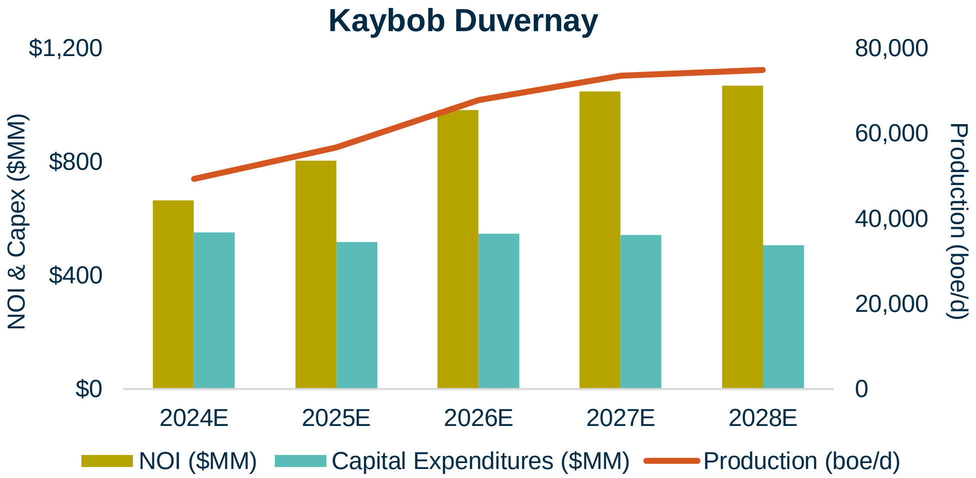
CPG's operational excellence has enhanced overall returns in the play with industry-leading results

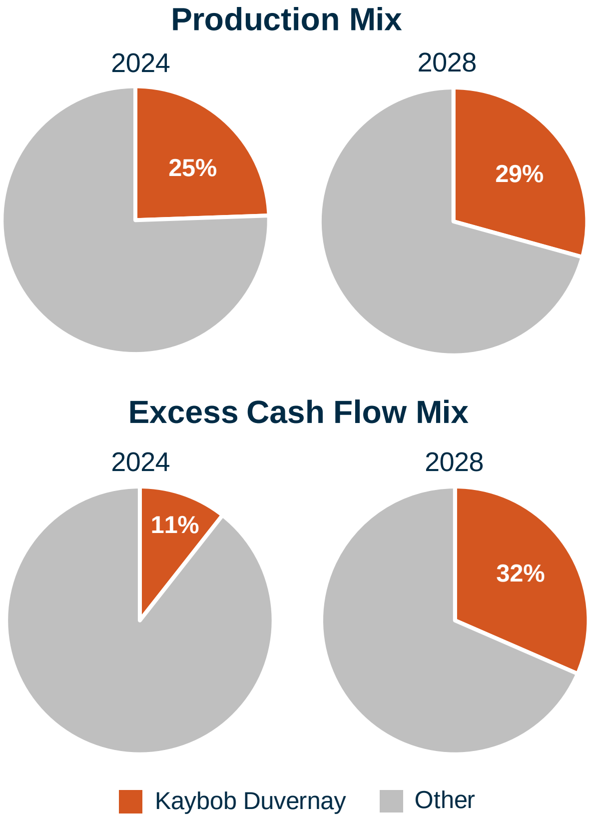
- ✓ CPG is a premier operator in the play
- ✓ Realized cost efficiencies and improved well productivity
- ✓ Strong NAV per share growth from Kaybob Duvernay
- ✓ Inaccurate public data was not reflecting the actual liquids-rich nature of the production

NAV: Net asset value. EURs: estimated ultimate recoveries.

Kaybob Duvernay 5-Year Outlook (2024 – 2028)

Production CAGR of ~10% through 2028 in addition to generating significant excess cash flow growth





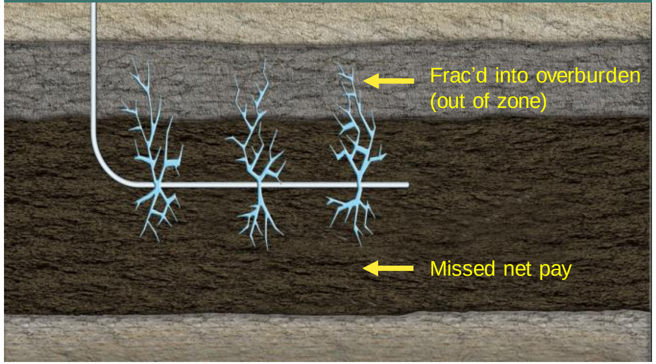
(US$70 WTI)	2024E	2028E
Production (boe/d)	50,000	75,000
Capital Expenditures (Capex) ($MM)	$550	$505
Net Operating Income (NOI) ($MM)	$665	$1,070
Asset Level Excess Cash Flow ($MM)	$115	$565
Net Drill Count (Rig Count)	>40 (2)	>40 (2)

All figures are approximates. Asset level excess cash flow is net operating income less capex. 2024 - 2028 assumes US$70/bbl WTI flat and average price of $3.35/mcf AECO.

Identified & Capitalized on Opportunity to Optimize Well Design

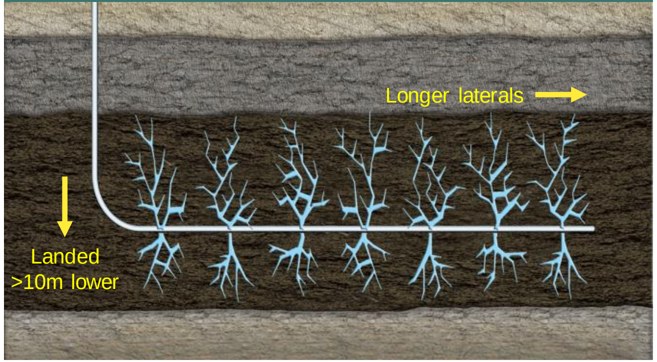
Lowered landing zone helps to contain hydraulic fractures and target additional higher quality rock

Prior Operator Landing Zone



Lowered landing zone in thick uniform geology to optimize frac and ultimately have more stimulated rock/well

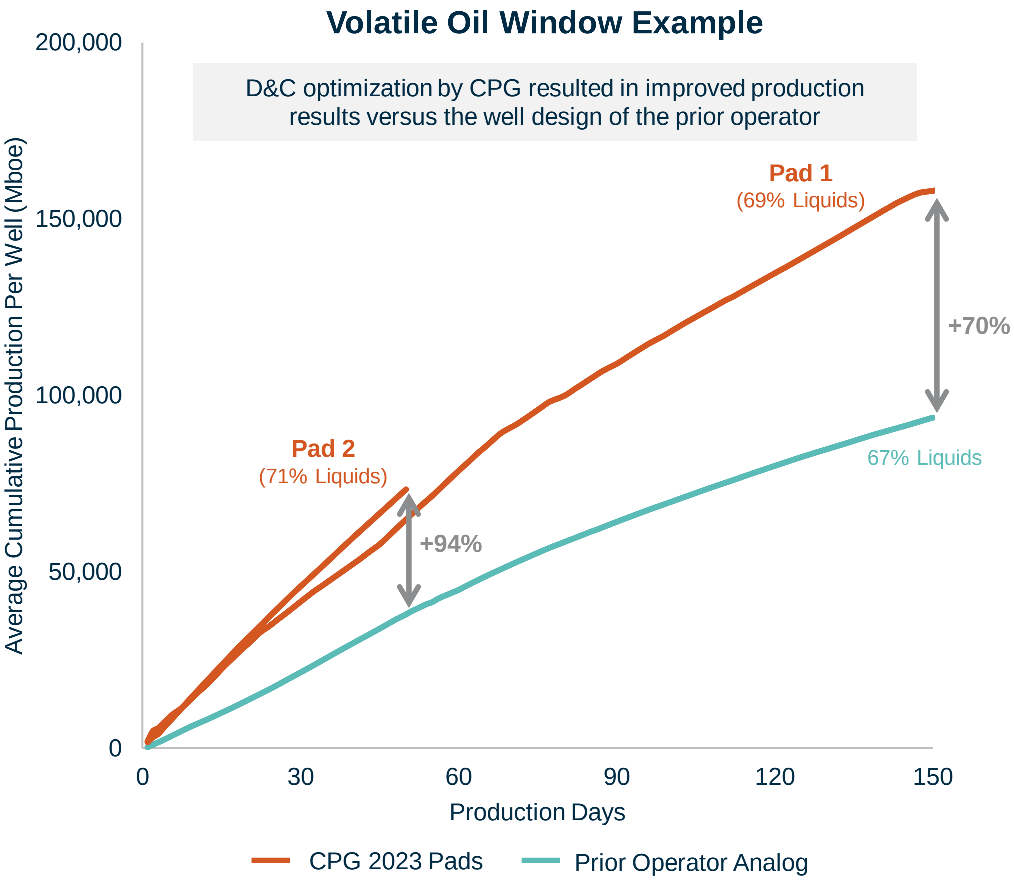
CPG Landing Zone

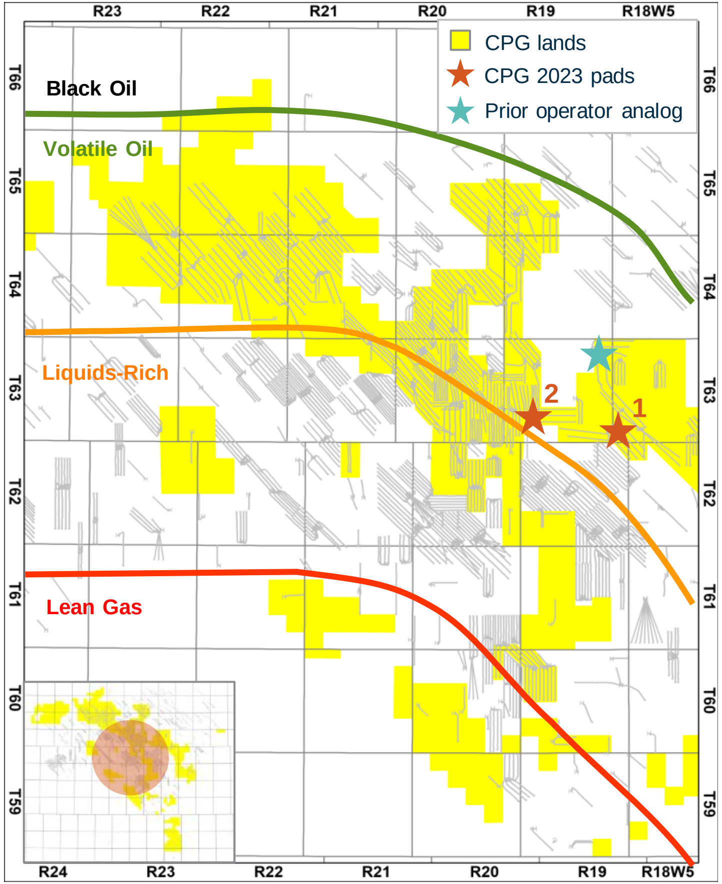


Stimulation Design	Prior to Q2 2021	Q1 2024	
Completions Cycle Time	5 days/well	4 days/well	Consistent maximum pumping efficiency and removal of initial perf run with new toe port design
Sand Loading	2.5 T/m	3.0 T/m	Increase in stimulated rock volume
Fluid Loading	12 m^3/m	17m^3/m	Increase in fracture complexity and reservoir drainage
Stage Spacing	80m	70m	Better frac efficiency and contact with the reservoir
Cluster Spacing	13m	8m	Better near-wellbore reservoir contact
Perforation Design	6x3	9x2	

CRESCENT POINT | CORPORATE PRESENTATION

Enhanced Performance vs. Prior Operator: 2023 Pads



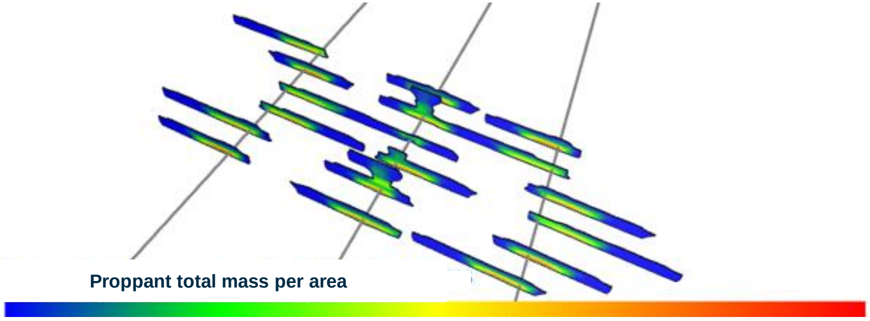


CPG newer drilling and completions (D&C) design example normalized to 2-mile lateral length.

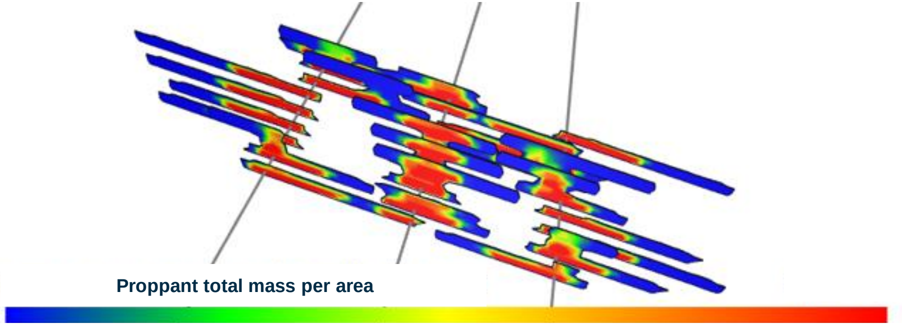
2023 Stimulation Optimization vs. Prior Operator

Increasing frac stimulation through higher sand and fluid loading in addition to tighter stage spacing

Prior Operator Analog



CPG Pads

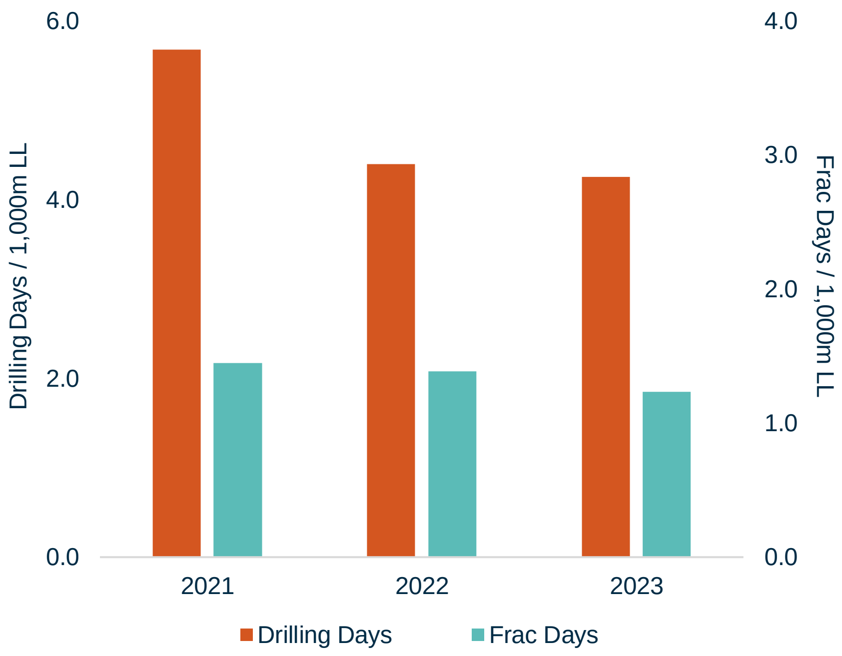


Stimulation Design	Prior Operator	CPG Pads	
Lateral Length	~2,900m	~3,300m ⬆	Increase in stimulated rock volume
Landing Depth From Top Duvernay	13m	26m ⬆	
Sand Loading	2.0 T/m	3.0 T/m ⬆	Increase in stimulated rock volume
Fluid Loading	11 m^3/m	17 m^3/m ⬆	Increase in fracture complexity and reservoir drainage
Stage Spacing	90m	70m ⬇	Better frac efficiency and contact with the reservoir
Cluster Spacing	14m	8m	Better near-wellbore reservoir contact, consistent hole sizing and optimal orientation
Perforation Design	6x3	9x2	
Perforation Phasing	120°	0°	

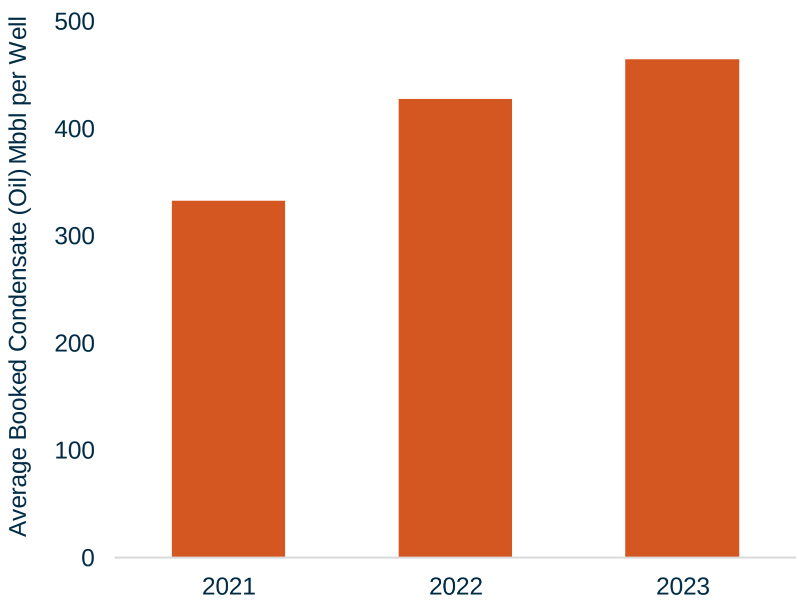
Operational Execution Driving Results

Enhancing asset level returns through improved efficiencies and EURs, including the benefit of longer lateral wells

Reducing Drilling & Frac Days



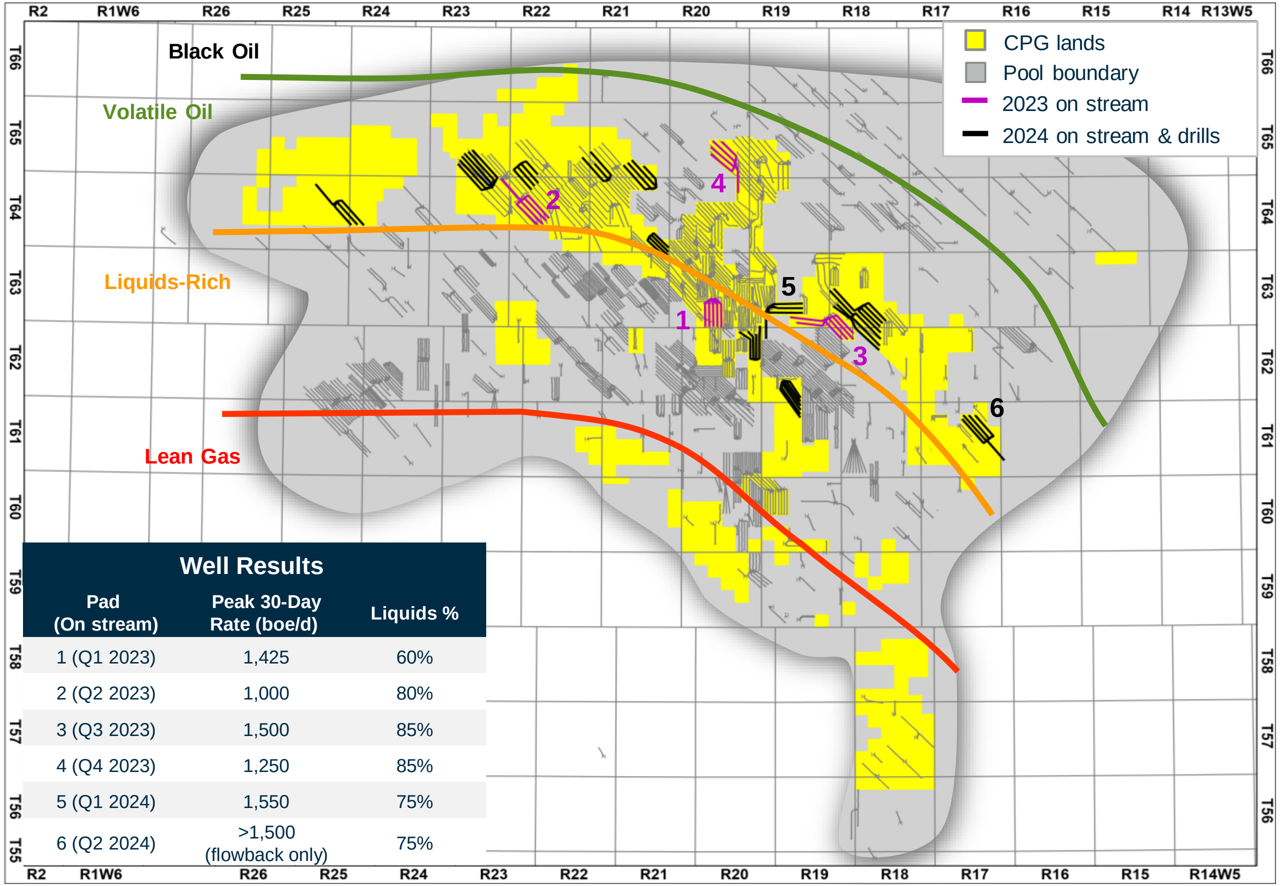
Increasing Condensate (Oil) EUR Per Well



LL: lateral length.
Booked estimated ultimate recoveries (EURs) as per independent evaluator McDaniel & Associates Consultants Ltd. (McDaniel) as of year end 2023. Figures represent an average of wells based on year of rig release.

Kaybob Duvernay On Stream & Drills (2023 - 2024)

Strong results to-date across land base; 10-year plan primarily focused in Volatile Oil and Liquids-Rich windows



Well Results

Pad (On stream)	Peak 30-Day Rate (boe/d)	Liquids %
1 (Q1 2023)	1,425	60%
2 (Q2 2023)	1,000	80%
3 (Q3 2023)	1,500	85%
4 (Q4 2023)	1,250	85%
5 (Q1 2024)	1,550	75%
6 (Q2 2024)	>1,500 (flowback only)	75%

Volatile Oil	
IP30 (boe/d) (% Liquids)	700 – 1,000 (>70%)
EUR (mboe) (% Liquids)	700 – 1,000 (>60%)
Cost Per Well ($MM)	$10.5
NPV10% ($MM)	$13.5
Payout (Months)	9
IRR%	100%
Net Locations	225

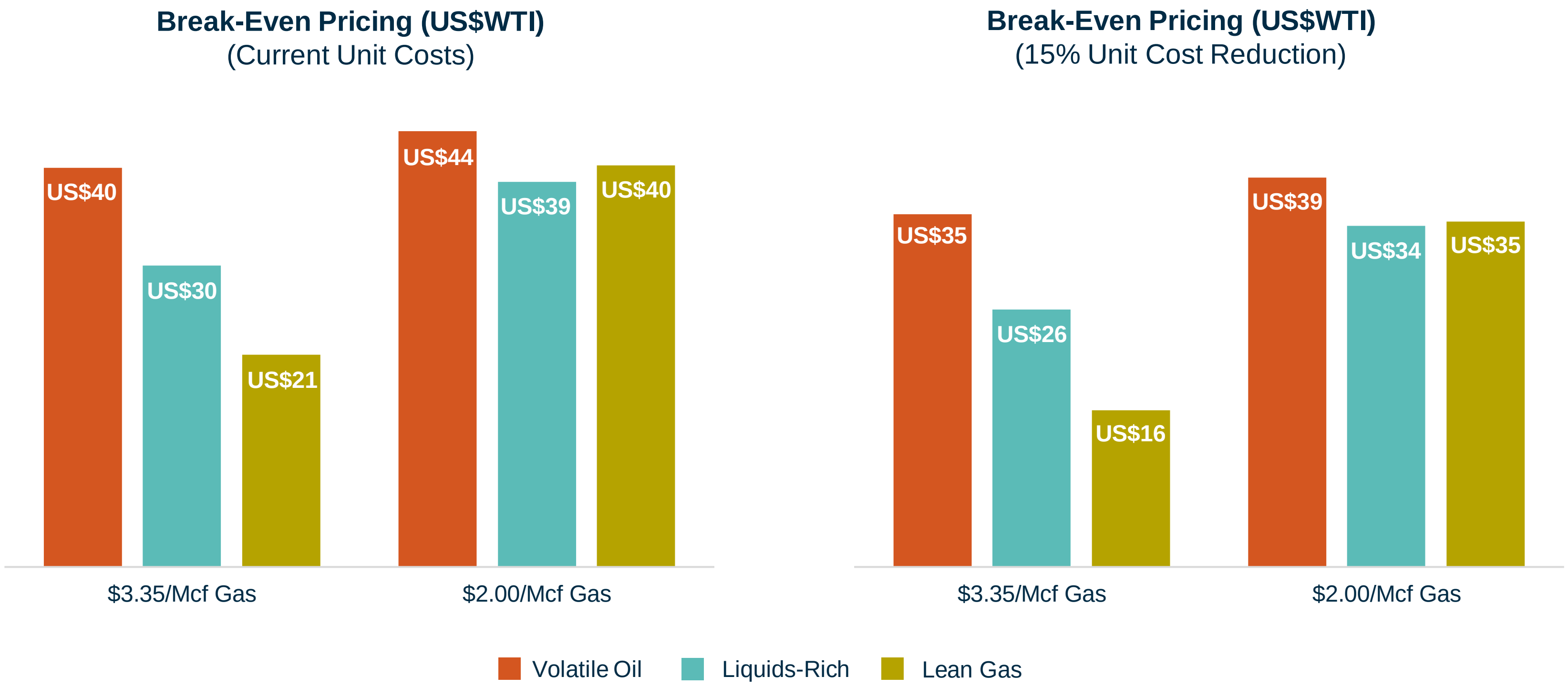
Liquids-Rich	
IP30 (boe/d) (% Liquids)	1,000 – 1,500 (35% – 70%)
EUR (mboe) (% Liquids)	1,000 – 1,500 (35% – 60%)
Cost Per Well ($MM)	$11.0
NPV10% ($MM)	$17.5
Payout (Months)	8
IRR%	130%
Net Locations	140

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)	$10.0
Payout (Months)	14
IRR%	60%
Net Locations	160

NPV10 and payout as at US$70/bbl WTI and $3.35/mcf AECO, assuming the mid-point of estimated ultimate recovery (EUR) ranges as assigned by independent reserves evaluator McDaniel as at December 31, 2023. Payouts are calculated from the initial on stream date. Internally identified inventory of 525 net locations includes 213 net booked proved plus probable (2P) locations as at December 31, 2023.

Kaybob Duvernay Break-Even Economics & Sensitivity to Gas Prices

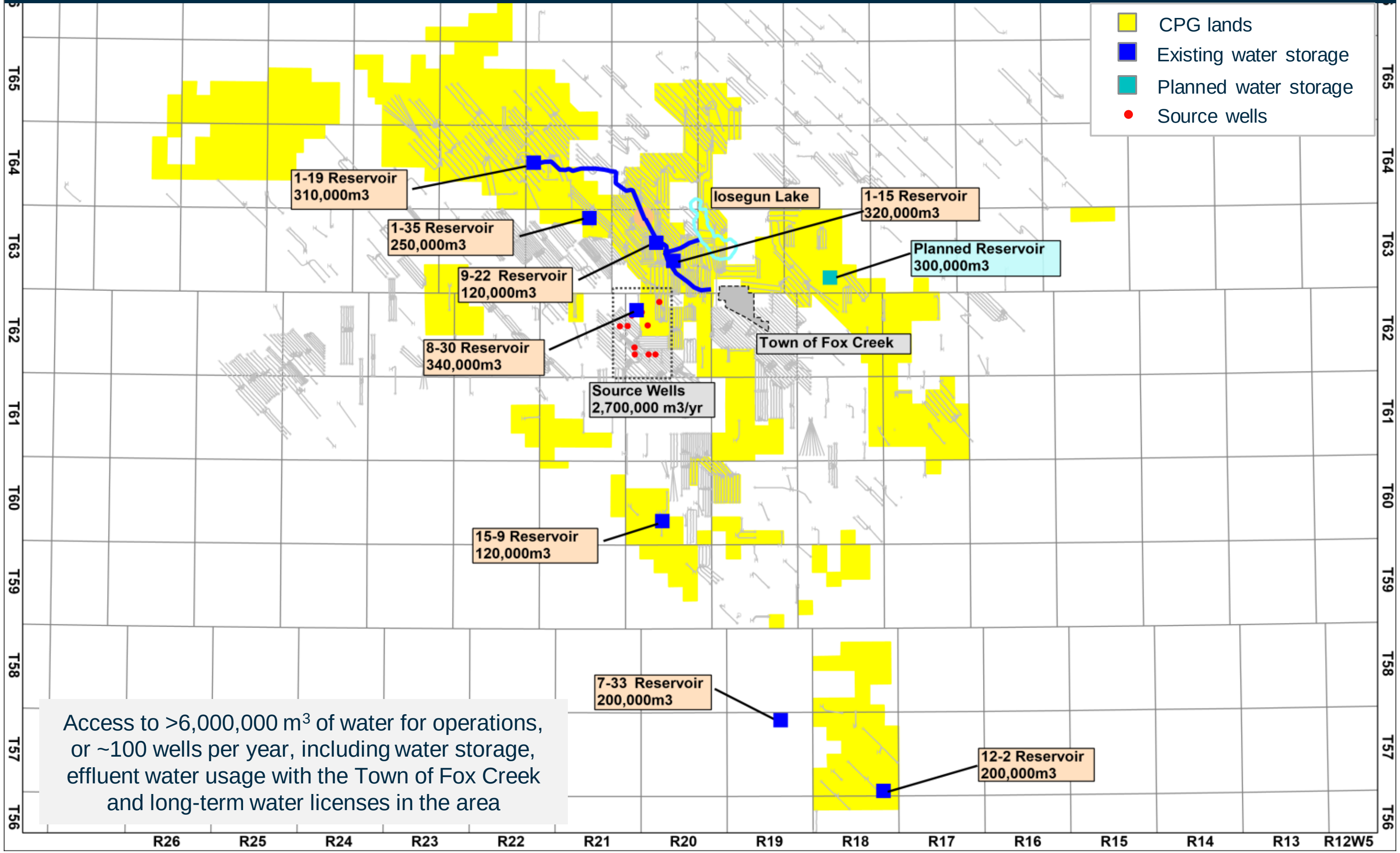
Attractive economics with ~70% of inventory situated in Volatile Oil and Liquids-Rich windows



All figures are approximates. Break-even is based on BT NPV10%. Economics based on proved plus probable (2P) booked type wells assigned by independent reserves evaluator McDaniel as at December 31, 2023. Gas price sensitivity (AECO).

CPG Kaybob Duvernay: Water Infrastructure

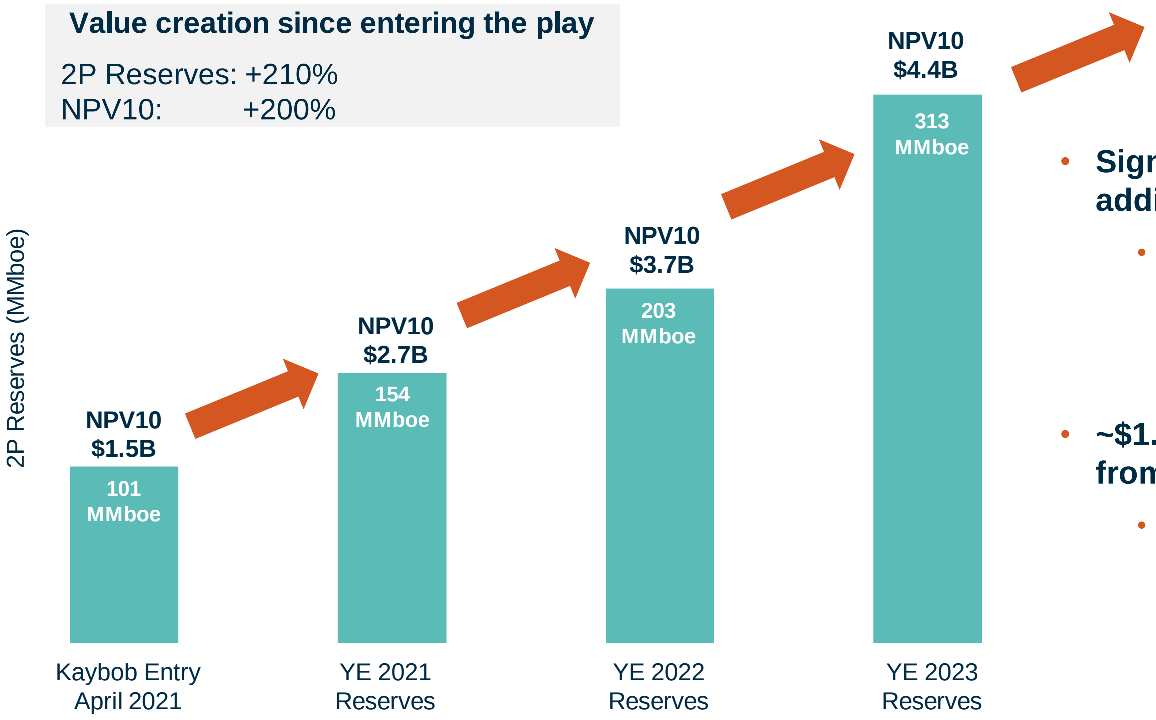
CPG has significant water storage across the field of >1.8 million m³ already in place



Access to >6,000,000 m^3 of water for operations, or ~100 wells per year, including water storage, effluent water usage with the Town of Fox Creek and long-term water licenses in the area

Kaybob Duvernay Continues to Create Significant Shareholder Value

Created value through organic reserves additions, realized efficiencies & opportunistic acquisitions



- **Significant value in 2P reserves and additional upside in unbooked locations**
  - ~60% of premium inventory remains unbooked providing opportunity for future reserves additions and NAV growth
- **~$1.35B of cumulative asset level excess CF from Kaybob Duvernay by YE 2024**
  - Pays off CPG's total acquisition cost of ~$1.35B since entering the play in early 2021

NPV10 values based on independent engineers reserves and price forecasts. YE 2023 reserves include 213 net booked proved plus probable (2P) locations as assigned by independent reserves evaluator McDaniel as at December 31, 2023. Cumulative asset level excess cash flow is net operating income less capital expenditures and assumes US$75/bbl WTI and $2.30/Mcf AECO for full year 2024.

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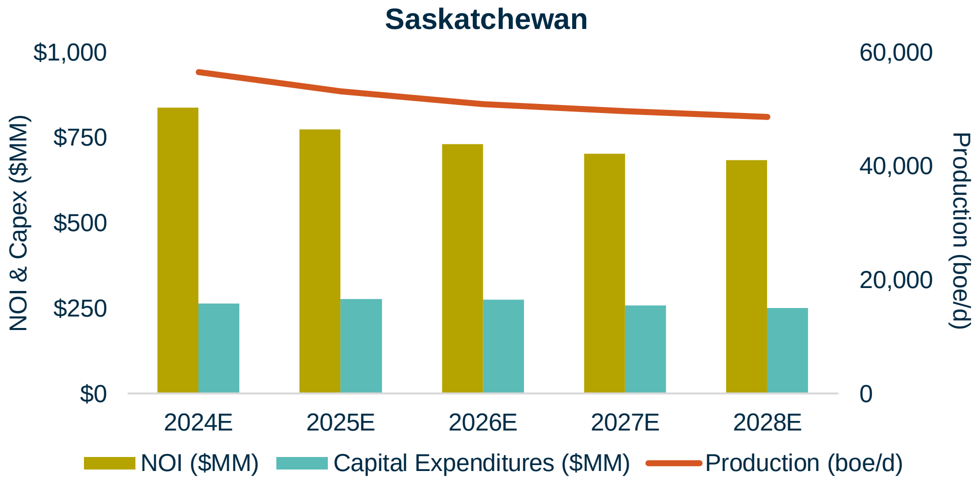
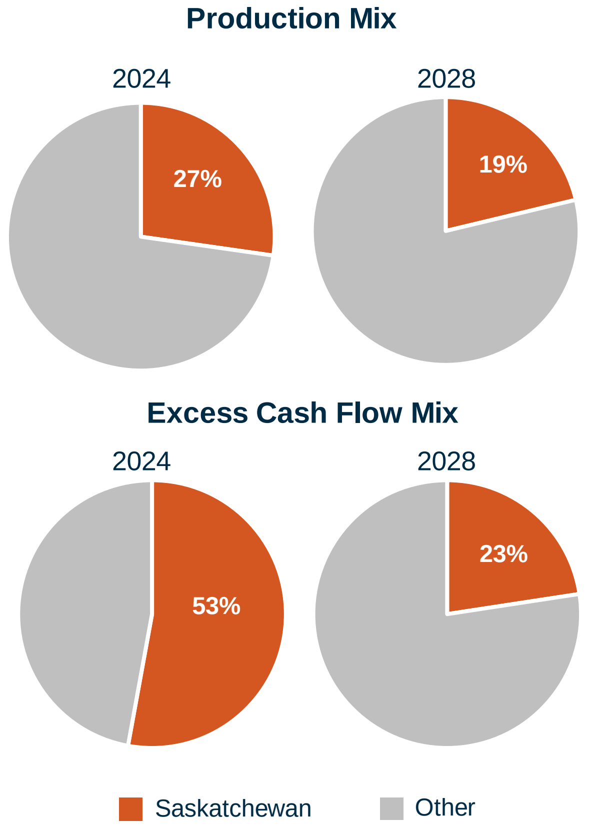
Saskatchewan 5-Year Outlook (2024 – 2028)

Generates significant excess cash flow allowing for reinvestment into growth assets and shareholder returns



(US$70 WTI)	2024E	2028E
Production (boe/d)	56,000	49,000
Capital Expenditures ($MM)	$265	$250
Net Operating Income (NOI) ($MM)	$840	$685
Asset Level Excess Cash Flow ($MM)	$575	$435
Net Drill Count (Rig Count)	>85 (3)	>85 (3)

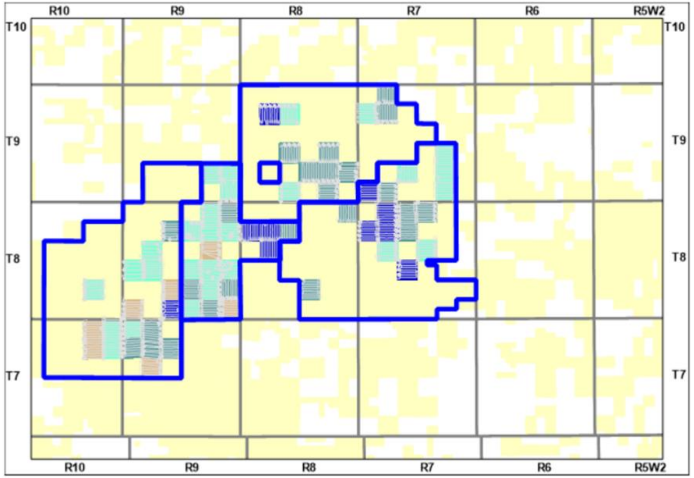


All figures are approximates. Asset level excess cash flow is net operating income less capex.
2024 - 2028 assumes US$70/bbl WTI flat and average price of $3.35/mcf AECO. Saskatchewan includes core areas of Viewfield, Shaunavon (including Battrum) and Flat Lake.

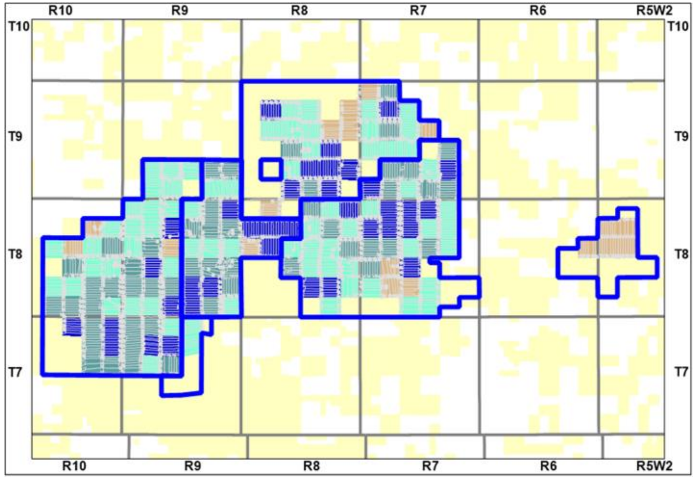
Viewfield Bakken Cumulative VRR Progression & Waterflood Expansion

Disciplined commitment to decline mitigation programs to enhance long-term sustainability

2018



2023



- Unit Boundary
- 1-10% Cum. VRR
- 11-40% Cum. VRR
- 41-70% Cum. VRR
- 71-100% Cum. VRR

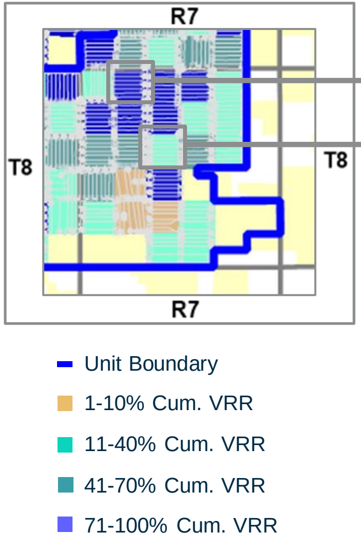
$$\textit{Voidage Replacement Ratio (VRR)} = \frac{\textit{Volume of water injected}}{\textit{Volumes of production}}$$

Two-thirds cumulative voidage replacement typically required for effective waterflood response

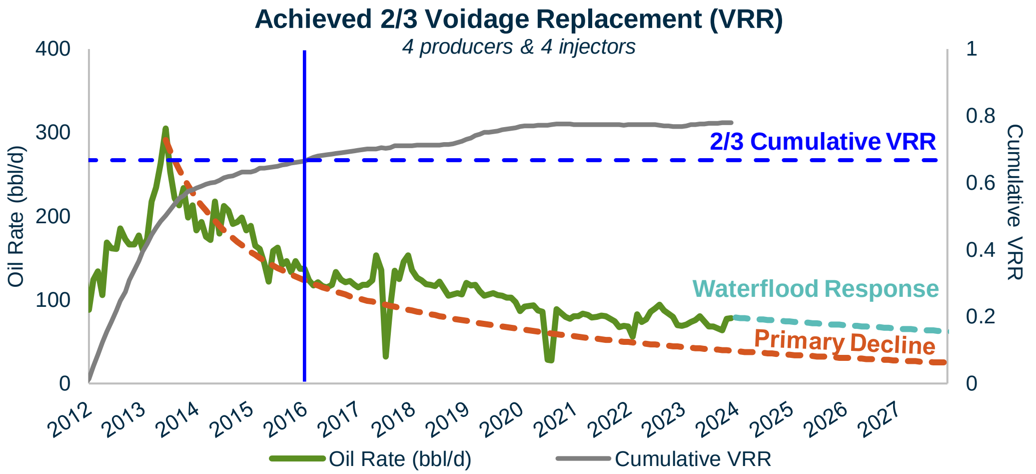
	2018	2023
Cumulative Injector Conversions Completed	215	570
Waterflood Influenced Sections	69	174
Waterflood Affected Production (bbl/d)	4,600 (5-10% decline rate)	8,300 (5-10% decline rate)
Cumulative VRR (4 Core Units)	0.13	0.32
Cumulative Waterflood Capital Spent ($MM)	$170	$267

All figures are approximates.

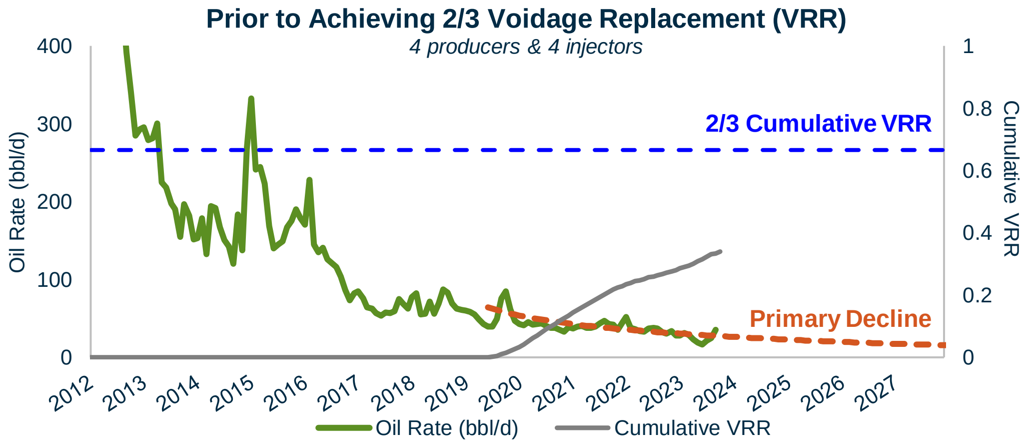
Viewfield Bakken Waterflood Response: Effect of Cumulative VRR



Effective Waterflood Response

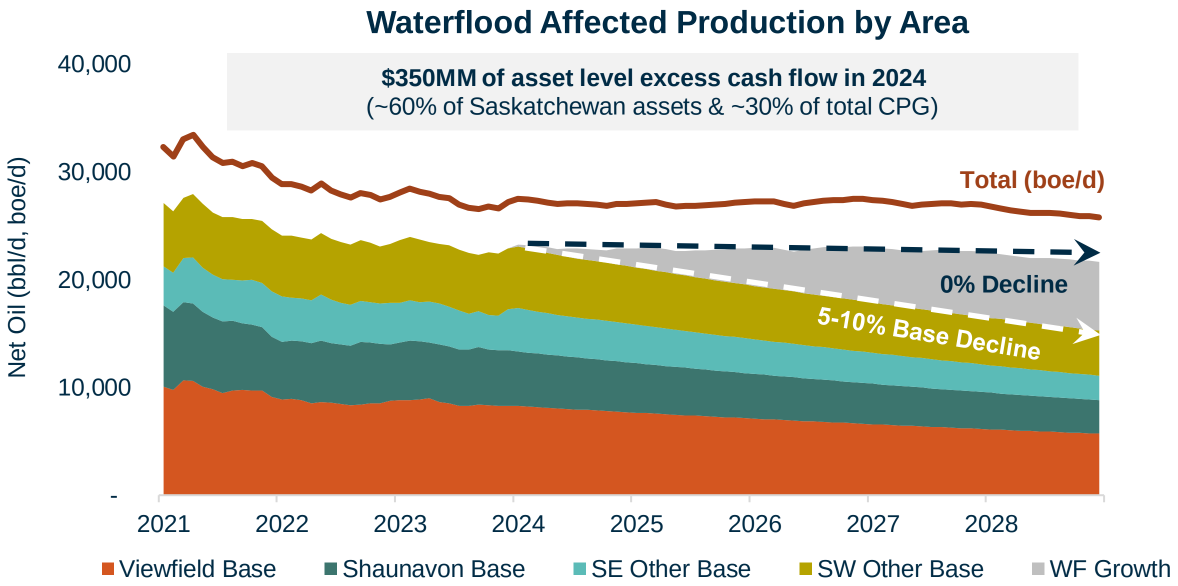


Awaiting Waterflood Response



Saskatchewan Waterflood Assets: Production & Free Cash Flow

20% of corporate oil production currently under waterflood

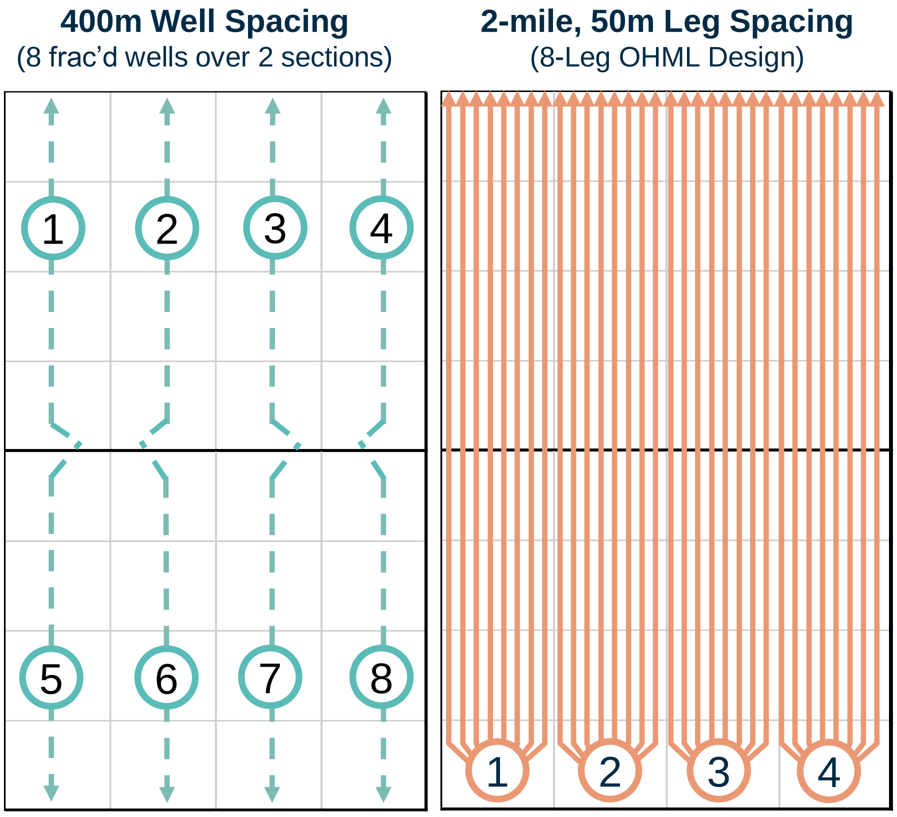


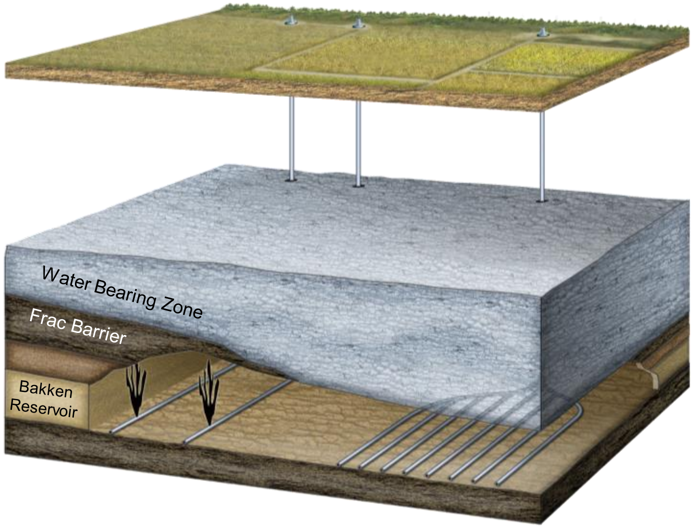
- **5% - 10% base decline rate** on production under waterflood
- 5-year plan waterflood production at **0% decline**, which requires ~$50MM / year of capital expenditures (<5% corporate total)
- **>15% of corporate 2P reserves under waterflood** as at YE 2023 (~$5/boe F&D for reserves booked to date)
- **Economics support long-term sustainability** with P/I ratios of ~4.0 - 5.0

2P: proved plus probable. F&D: finding and development. P/I: profit investment ratio.
2024 asset level excess cash flow is net operating income (NOI) less capex and assumes ~US$70/bbl WTI and ~$2.30/Mcf AECO for the full-year. Economics assume US$70/bbl WTI and $3.35/mcf AECO.

OHML Has Unlocked Value & Extended Drilling Inventory

Unlocks access to thinner, productive pay in the reservoir without the costs associated with fracs and liners





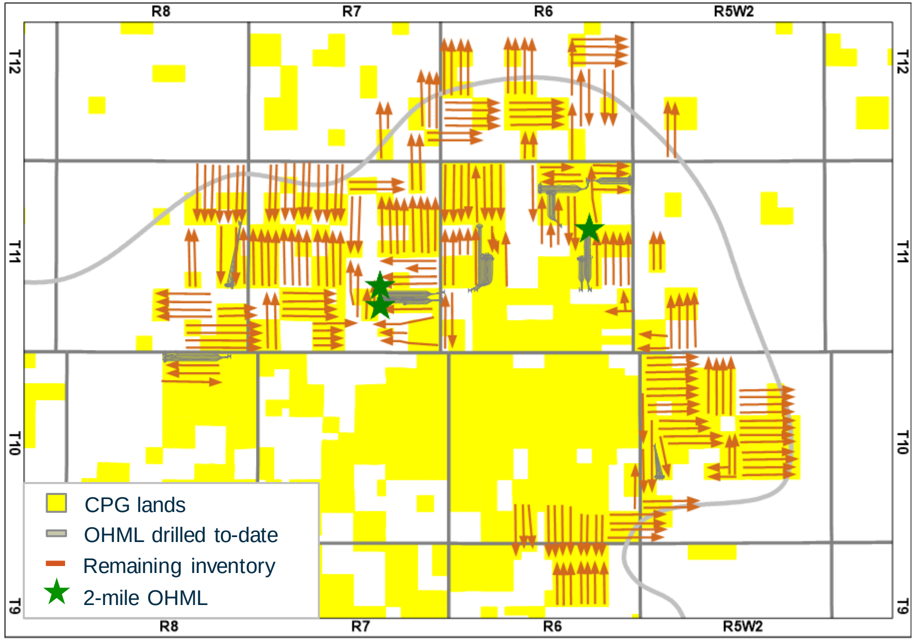
Well Type	Wells Per Two Sections	Capital ($MM)	NPV10 ($MM)	IRR (%)	Payout (months)	EUR (Mbbl)
Frac'd	8	14	3	31	24	360
OHML	4	12	12	87	13	600

OHML economics do not take into account any volumetric drilling incentives expected to be announced as part of upcoming Saskatchewan provincial budget

EUR: estimated ultimate recovery.
Economics assume US$70/bbl WTI and $3.35/mcf AECO. Open hole multi-lateral (OHML) economics based on booked proved plus probable (2P) type wells as assigned by independent reserves evaluator McDaniel as at December 31, 2023.

OHML Development Offers Premium Inventory Extension in SE Saskatchewan

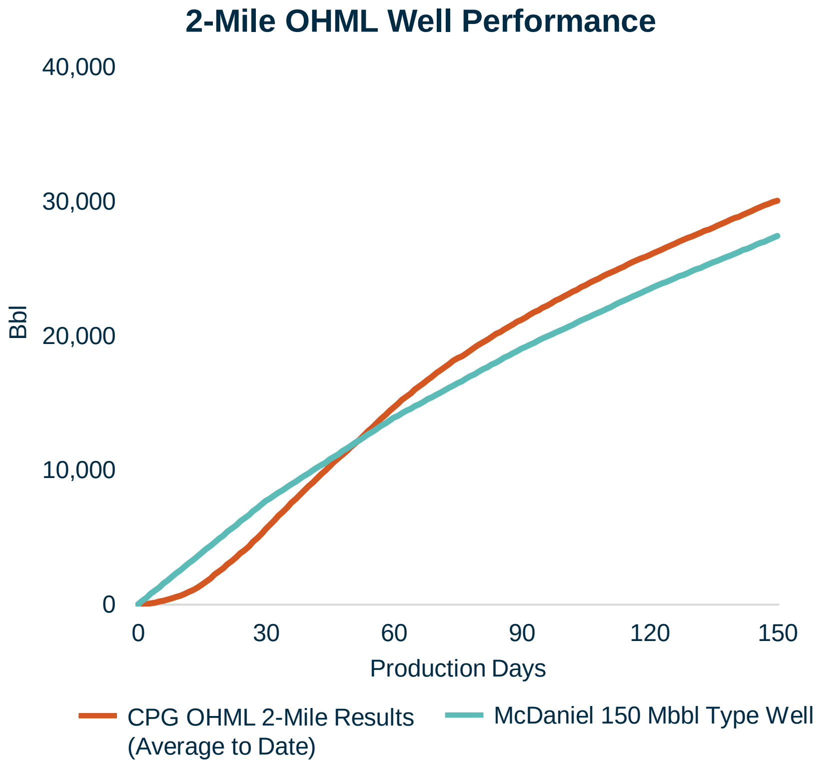
OHML technology preserves capital discipline and unlocks additional high-netback production



2024 OHML budget is ~$20MM (drilling 7 net locations)

Only 12 of ~130 net internally identified locations drilled to-date

~75% of locations remain unbooked at YE 2023, allowing for future reserves growth



OHML: open hole multi-lateral. Booked proved plus probable (2P) locations as assigned by independent reserves evaluator McDaniel as at December 31, 2023.

Agenda

- **Introduction** – Shelly Witwer, SVP Business Development
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- **Q&A**

Highly Economic Long-Term Plan

>20 years of premium inventory supports a highly economic development plan

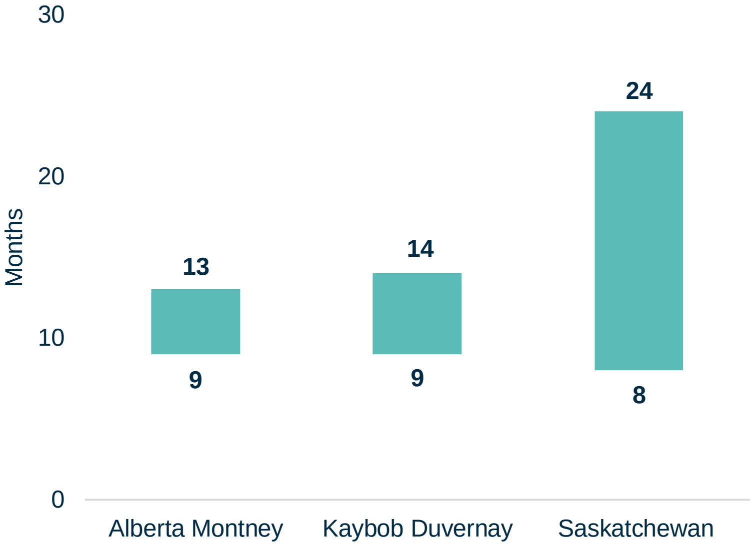
Corporate Inventory vs 10-Year Plan

Additional locations that will be drilled at higher commodity prices or with additional improvements in costs or EURs

Established, delineated and well-defined locations in major operating areas with an estimated payback period of less than two years at mid-cycle pricing

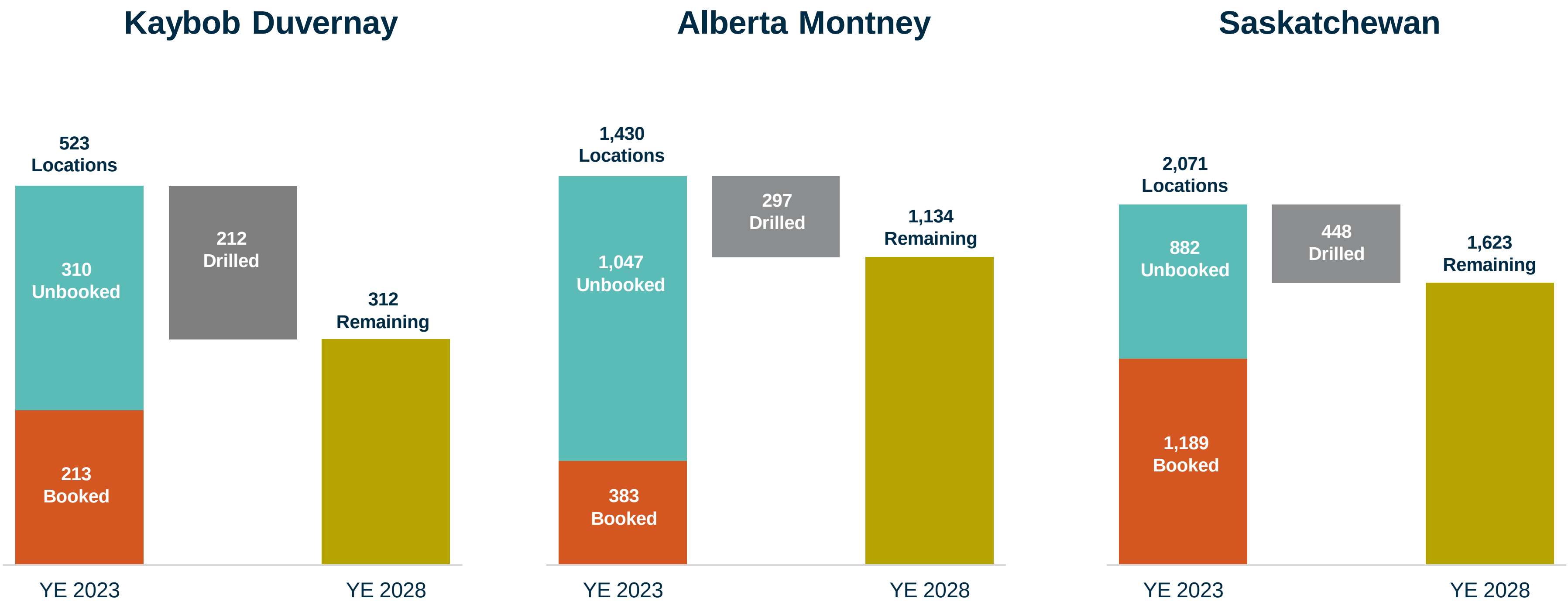
Economics of Premium Locations

(Well Payout – US$70 WTI & $3.35 AECO)



Inventory locations presented above are net and include 1,786 booked proved plus probable (2P) locations, as derived from the Company's internal reserves evaluation in accordance with NI 51-101 and the COGE Handbook. Booked 2P locations exclude non-core assets sold in Q1 2024. Payouts are calculated from the initial on stream date. EURs: estimated ultimate recoveries.
Economics of unbooked locations as part of premium inventory are based on booked type well expectations.

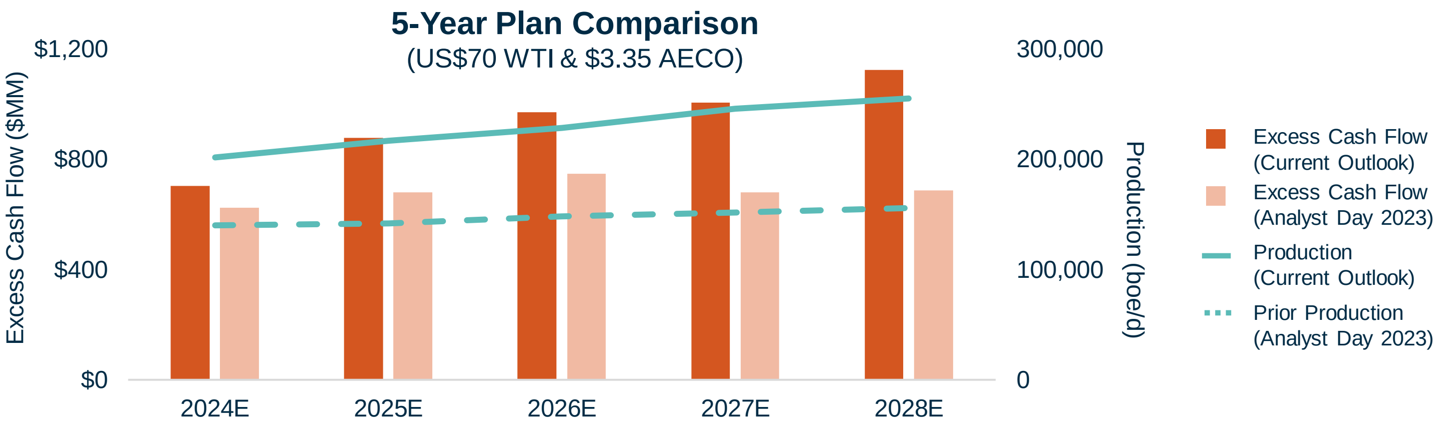
Premium Locations by Major Operating Area & 5-Year Development Plan



Figures above are approximates. Booked locations are proved and probable locations (2P), as derived from the Company's internal reserves evaluation in accordance with NI51-101 and the COGE Handbook.

Enhanced 5-Year Plan

Over the past year CPG has significantly enhanced its excess cash flow per-share and long-term sustainability



Key Metrics Comparison in 5-Year Plans (2024E – 2028E)	Current Outlook	Analyst Day 2023
Production in 2028 (CAGR)	260,000 boe/d (+6%)	155,000 boe/d (+3%)
Excess Cash Flow per Share CAGR (incl. repurchases)	10% (15%)	2% (8%)
Cumulative Excess Cash Flow	$4.7B or $7.52/sh	$3.4B or $6.57/sh
Premium Inventory Life (Period Start)	>20 years	12 years
Net Debt / Funds Flow (Period End)	0.6x	-0.1x
Reinvestment Ratio (Period End)	53%	59%
Decline Rate (Period End)	<30%	26%

Comparison of 2024 to 2028 outlook versus the plan presented at the March 2023 Analyst Day, which did not include the Alberta Montney acquisitions or certain non-core dispositions

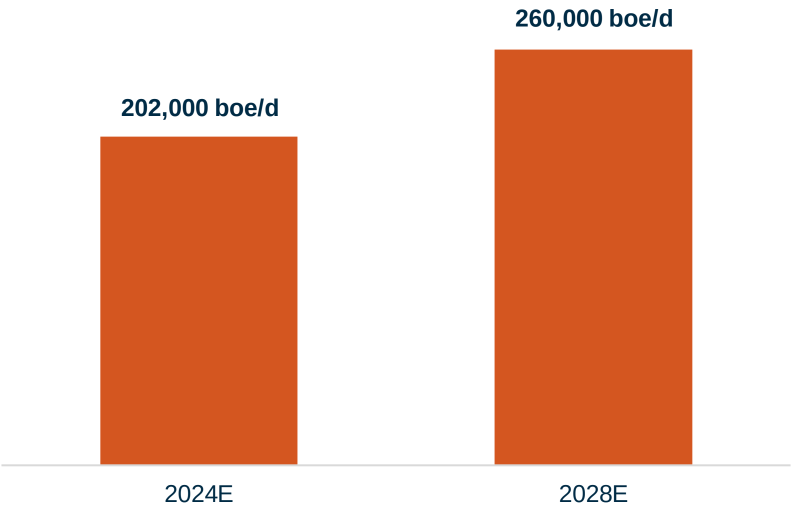
All figures are approximates. Reinvestment ratio is defined as development capital expenditures as a % of cash flow. The comparison of five-year outlooks are both based on the period starting 2024 and ending in 2028.
Reinvestment ratio and excess cash flow per share – diluted are specified financial measures – refer to Specified Financial Measures section. Outlook is derived by utilizing, among other assumptions, historical production performance.
Excess cash flow per share CAGR including share repurchases assumes EV/DACF kept unchanged over 5-year plan for repurchases. Forecasts beyond 2024 have not been finalized and are subject to a variety of factors including prior year's results.

Execution of 5-Year Plan

Strong track record of operational execution and continuous improvement

Organic Growth Plan

(~30% production growth through 2028)



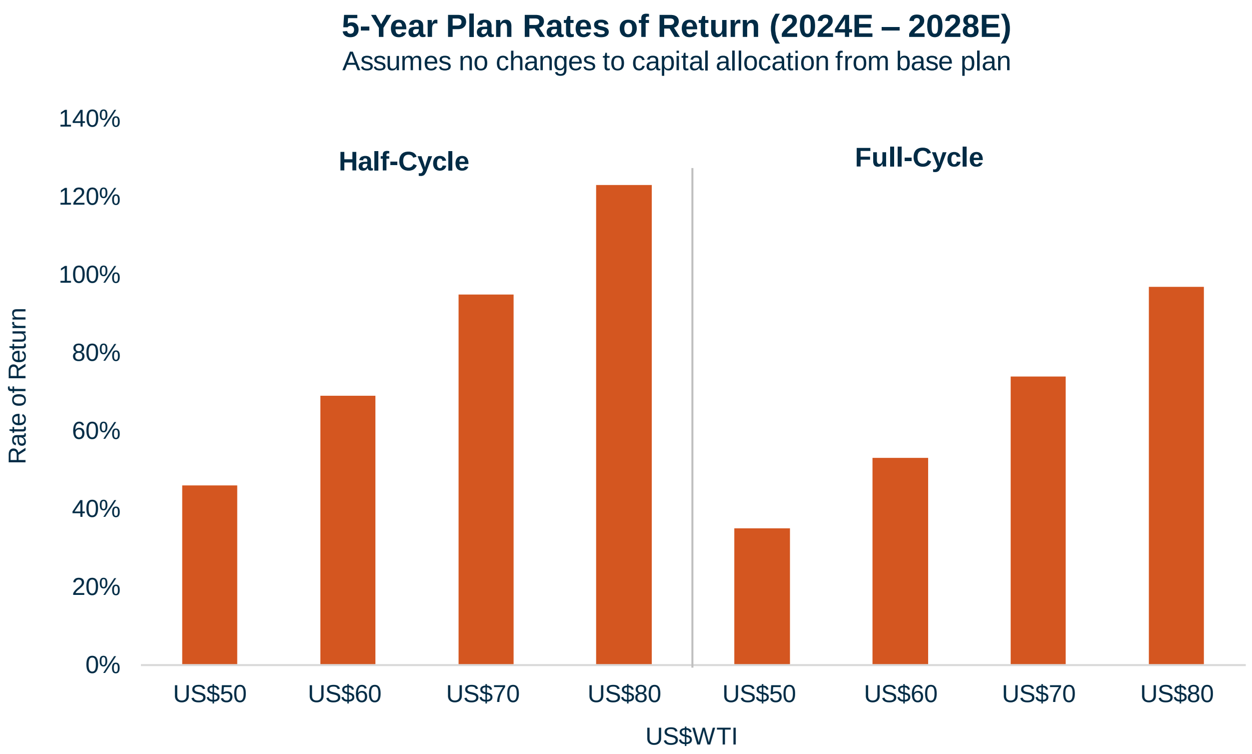
Key Factors in 5-Year Plan

- ✓ 5-year drilling program accounts for only ~25% of total premium inventory and ~55% of booked 2P inventory at YE 2023
- ✓ Consistent rig activity throughout 5-year plan
- ✓ Conservative type well forecasts relative to recent production results
- ✓ Forecasts do not assume any benefit from cost improvements
- ✓ Secured market egress for future liquids and gas production with no major infrastructure required to be built
- ✓ Strong industry delineation around undeveloped land base

Booked 2P locations exclude those related to non-core assets sold after December 31, 2023.

5-Year Plan Rates of Return

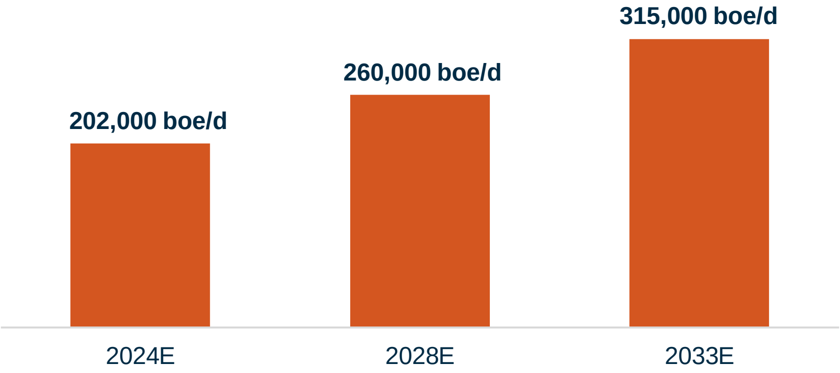
Attractive returns based on depth of premium inventory



Forecasts beyond 2024 have not been finalized and are subject to a variety of factors including prior year's results.

5 & 10-Year Outlook (2024 – 2033)

5-year plan generates $3.8B - $5.6B of cumulative excess cash flow, which more than doubles in 10-year plan



Average per Year (US$70 WTI & $3.35 AECO)	2024 - 2028	2024 - 2033
Avg. Capital Expenditures ($B)	~$1.45	~$1.50
Reinvestment Ratio (Period End)	53%	52%
Net Debt / Funds Flow (Period End)	0.6x	-0.2x
Decline Rate (%)	<30%	<30%
Cumulative Excess Cash Flow ($B)	$4.7	$10.8
Premium Inventory Remaining (Period End)	15 years	10 years

5-Year Plan
(2024 - 2028)

$3.8B - $5.6B
of cumulative after-tax **excess cash flow**
or
$6.12 - $8.96 per share
(US$65 – US$75 WTI)

10-Year Plan
(2024 - 2033)

$8.9B - $12.9B
of cumulative after-tax **excess cash flow**
or
$14.21 - $20.63 per share
(US$65 – US$75 WTI)

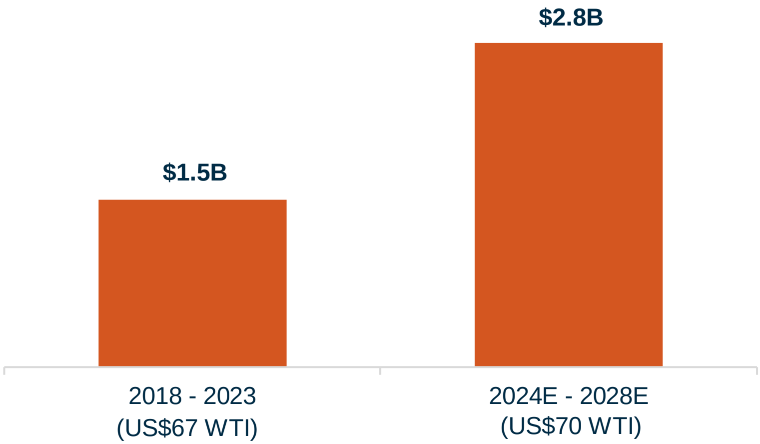
All figures are approximates. Capital expenditures refers to development capital expenditures. Reinvestment ratio is defined as development capital expenditures as a % of cash flow.
Budgets and forecast beyond 2024 have not been finalized and are subject to a variety of factors including prior year's results. Cumulative excess cash flow per-share - diluted based on current shares outstanding.

Increasing Return of Capital to Shareholders

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

Total Return of Capital
(Includes Dividends & Share Repurchases)

Improved excess cash flow and return of capital profile through operational execution and strategic A&D



Return of Capital Framework

Funds Flow

(-) Development Capital Expenditures & Additional Items

Excess Cash Flow

↓

Current Return of Capital Outlook ~60%

(Dividends & Share Repurchases)

- Target base dividend increases as the business continues to grow on a per-share basis
- Increase return of capital allocation beyond 60% of excess cash flow as the balance sheet strengthens further
- Plan to prioritize share buybacks as the tool of choice for additional return of capital beyond base dividends

Total return of capital assumes current framework of returning ~60% of excess cash flow to shareholders.
Additional items include capitalized administration, reclamation activities, payments on lease liability and other items, excluding net acquisitions and dispositions.

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Corporate Strategy Focused on Delivering Long-Term Value

Strategy

Our **actions, goals and vision** are **guided by** our **corporate strategy**

*“**Deliver lasting market-leading value to our stakeholders** as a **trusted, ethical, and environmentally responsible** source for energy. We will **maintain a resilient, balanced and sustainable portfolio**, and apply our agile, diverse, learning mindset to optimize all aspects of our business”*

Foundation Of Our Strategy

Purpose led company with core convictions driving

Why we do what we do

What we believe in

How we behave

Strategy Support

Process driven with component strategies in place

People

Portfolio

Stakeholders & ESG

Finance

Digital

Communications

Deliver Long-Term Value

Key Components Driving Our Strategic Vision

Size and Scale

- Enterprise Value
- Production and Liquids %
- Short-Cycle and Long-Cycle Portfolio

Sustainability

- Premium Inventory Life
- Decline Rate
- Reinvestment Ratio

Returns

- Corporate Returns (ROACE)
- Excess Cash Flow and Return of Capital
- Disciplined Growth

Balance Sheet

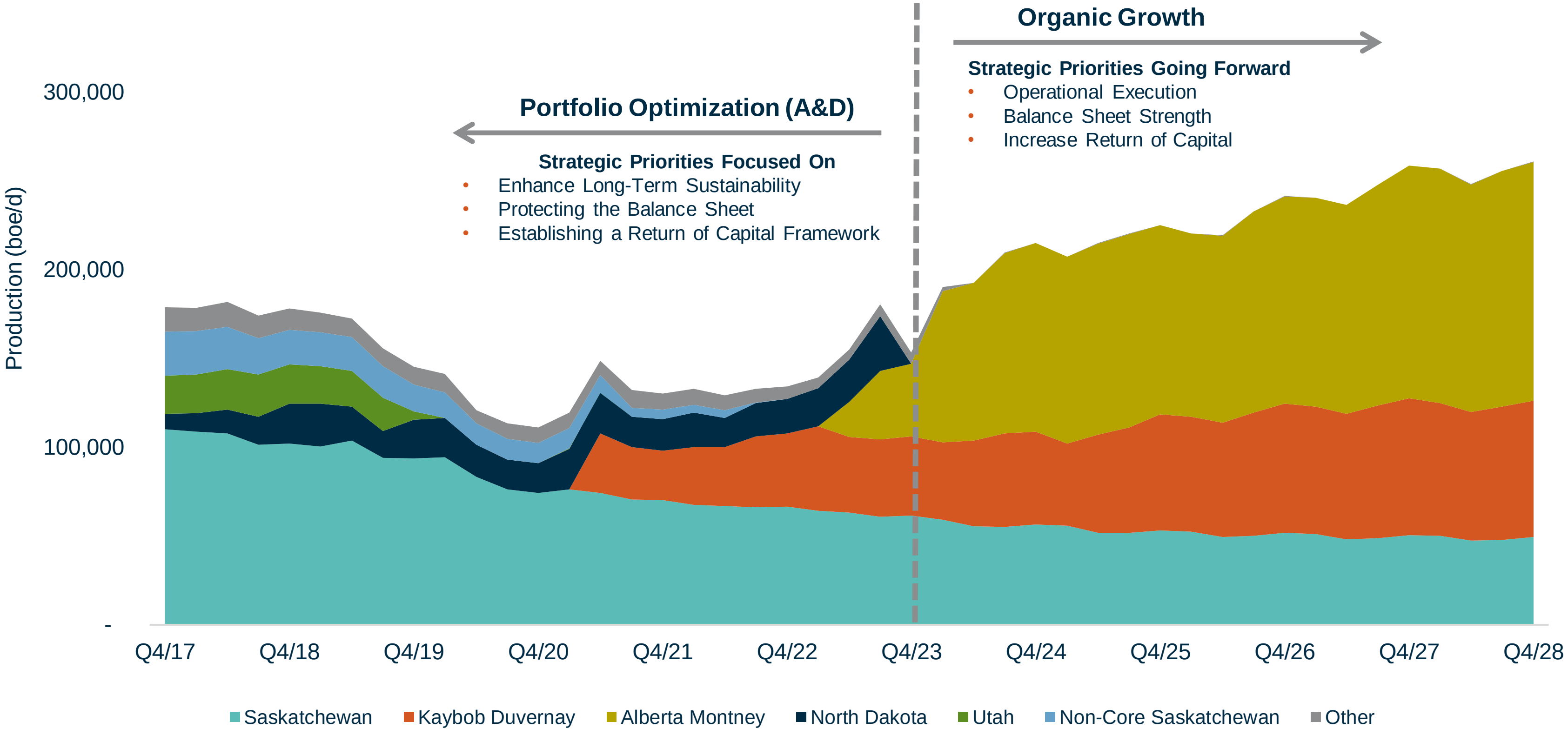
- Debt / EBITDA
- Investment Grade Rating

Commitment to ESG

Reinvestment ratio is total capital expenditures as a percentage of adjusted funds flow from operations.

Strategy in Action: Portfolio Transformation

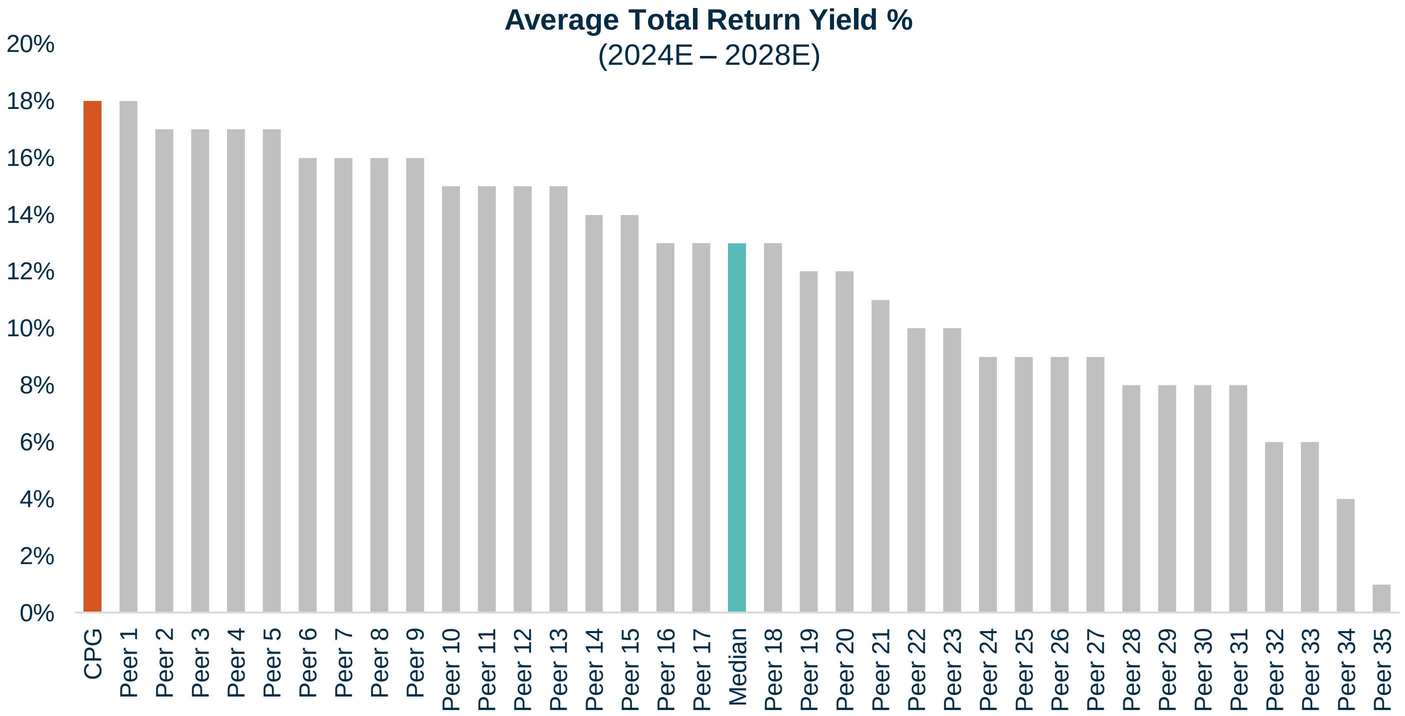
Key asset criteria focused on returns, scalability, excess cash flow generation and market access



Saskatchewan includes core areas of Viewfield, Shaunavon (including Battrum) and Flat Lake.

5-Year Plan: Strong Total Return Proposition (Excess Cash Flow + Growth)

Compelling compound returns for shareholders through dividends, buybacks, per-share growth and debt reduction



Peers AAV, APA (US), AR (US), ARX, ATH, BIR, BTE, CJ, CNQ, CR, CTRA (US), CVE, DVN (US), EOG (US), EQT (US), FANG (US), HWX, IMO, KEC, KEL, MEG, NVA, OBE, OVV, PEY, POU, PXD (US), SCR, SDE, SGY, SU, TOU, TVE, VET, WCP.
Source: Peters & Co. Limited research March 4, 2024. Total return is calculated as the sum of dividend yield + buyback yield, year-over-year production growth and remaining excess cash flow yield (or change in net debt).

New Corporate Name

Signals transformation and alignment with our strategy and purpose statement

Crescent Point → veren

Truth and Energy

'ver' = truth (derived from the latin word veritas)

'en' = reference to energy

Bringing Energy To Our World – The Right Way

New ticker symbol and website effective following upcoming AGM

Summary and Q&A

Alberta Montney

High-quality position situated entirely in the Volatile Oil window achieving industry-leading results to-date

- ✓ Significant resource in place with multiple opportunities to enhance returns

Kaybob Duvernay

Delivering consistent results, high-returns and combination of growth and excess cash flow generation

- ✓ Continued success on modified well design centered around optimizing landing zone and completions

Corporate Outlook

Transformed into a highly strategic company with >20 years of premium inventory generating top decile returns

- ✓ 5-year cumulative excess CF of $3.8B - $5.6B driven by balanced portfolio of short-cycle assets in Alberta and long-cycle assets in Saskatchewan

Cumulative excess cash flow from 2024-2028 based on forecast of US$65 - US$75/bbl WTI and $3.35/Mcf AECO.

Appendix

Capital Markets Summary & Guidance

Capital Markets Summary
CPG (TSX and NYSE)

Share Price (March 13, 2024)	C$10.39 / US$7.73
Shares Outstanding	620 million
Avg. Daily Trading Volume	10.4 million
Annual Dividend Yield	4.4%
Market Capitalization	$6.4 billion
Net Debt	$3.7 billion
Enterprise Value	$10.1 billion

Dividend yield based on first quarter 2024 base dividend of $0.115/share. Net debt as at December 31, 2023.

2024 Guidance

Annual Avg. Production (mboe/d)(1)	198 - 206
Capital Expenditures	
Development Capital Expenditures ($MM)	$1,400 - $1,500
Capitalized Administration ($MM)	$40
Total ($MM) (2)	$1,440 - $1,540
Other Information	
Reclamation Activities ($MM) (3)	$40
Capital Lease Payments ($MM)	$20
Annual Operating Expenses ($/boe)	$12.75 - $13.75
Royalties	10.00% - 11.00%

1) The total annual average production (boe/d) is comprised of approximately 65% Oil, Condensate & NGLs and 35% Natural Gas
2) Land expenditures and net property acquisitions and dispositions are not included. Development capital expenditures is allocated as follows: approximately 90% drilling & development and 10% facilities & seismic
3) Reflects Crescent Point's portion of its expected total budget

Return of Capital Outlook

Quarterly Base Dividend	$0.115/share
Total Return of Capital (Dividends & Share Repurchases)	60% (% of Excess Cash Flow)

Total return of capital is based on a framework that targets to return to shareholders 60% of excess cash flow on an annual basis

2024 Funds Flow Sensitivities

US$1/bbl Change in WTI	~$30 million
$0.25/mcf Change in Benchmark Gas Prices	~$20 million
$0.01 Change in CAD/USD FX	~$25 million

Sensitivities are based on pricing change for the remainder of the year.

Major Operating Area Economics

Area	IP30 boe/d (Liquids %)	EUR Mboe (Liquids %)	Cost Per Well (C$MM)	US$70 WTI & $3.35 AECO IRR%	US$70 WTI & $3.35 AECO Payout (Months)
Alberta Montney (Volatile Oil)					
Gold Creek West	1,250 (65%)	790 (55%)	$9.5	100%	12
Gold Creek	1,300 (55%)	1,150 (45%)	$9.0	110%	10
Karr East	700 - 1,075 (55 - 80%)	750 - 820 (50 - 70%)	$9.5 - $10.5	65 - 110%	10 - 13
Karr West	1,330 (65%)	1,050 (50%)	$10.0	115%	9
Kaybob Duvernay					
Volatile Oil	700 - 1,000 (>70%)	700 - 1,000 (>60%)	$10.5	100%	9
Liquids-Rich	1,000 - 1,500 (35 - 70%)	1,000 - 1,500 (35 – 60%)	$11.0	130%	8
Lean Gas	>1,500 (<35%)	1,500 - 2,000 (<35%)	$11.5	60%	14
Viewfield Bakken	150 - 250 (>90%)	80 - 150 (>90%)	$1.7 - $3.0	50 - 85%	12 - 20
Shaunavon	100 - 150 (>90%)	70 - 100 (>90%)	$1.9	40 - 75%	12 - 24
Flat Lake - Torquay	200 - 300 (>90%)	100 - 150 (>90%)	$2.7 - $3.4	50 - 90%	12 - 24
SK Conventional	80 - 130 (>90%)	70 - 150 (>90%)	$1.5	65 - 150%	8 - 20

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

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.

Conversions & Disclosures

- Production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by companies in the United States

- We incorporate additional information with respect to production and reserves which is either not required to be included or prohibited under rules of the SEC and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes (before deduction of Crown and other royalties), however, we also follow the United States practice of separately reporting these volumes on a net basis (after the deduction of royalties and similar payments). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves, whereas, the SEC rules require that a trailing 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-month for each month within the 12-month period to the end of the reporting period, and uninflated (constant) costs be utilized. The SEC permits, but does not require, the disclosure of reserves based on forecast prices and costs

Conversions
Tonnes per metre (T/M) x 670 = pounds per foot (lbs/foot)
Cubic metre (M^3) x 6.3 = barrels
Cubic metre per metre (M^3/M) = 80.5 gallons per foot
MegaPascal (MPa) x 145 = pounds per square inch (psi)
Metres (M) = 3.28 feet

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”, “2024E”, or “2028E”) and includes: more than 20 years of premium inventory set to deliver top decile returns; organic growth expectations; ~6,000 Premium & Additional Locations; expected proportions of 2024 production by area; 2024 outlook including, but not limited to, annual average production and portion of liquids production, development capital expenditures, excess cash flow (at the commodity prices specified) and leverage ratio (at the commodity prices specified); return of capital including, but not limited to, quarterly base dividend, dividend yield, total return of capital and percentage of excess cash flow returned; sustainable long-term returns driven by high-quality multi-basin portfolio and disciplined capital allocation; disciplined per-share growth; ~10% EXCF/share CAGR over 5-year plan (~15% including share repurchases); Plan to grow base dividend over time, in-line with business; Plan to increase percentage of capital returned over time; Long-term leverage target of <1.0x at low commodity prices; Disciplined hedging strategy; Expect to reduce net debt by >50% over 5-year plan; Benefits of a Balanced Portfolio of Short-Cycle & Long-Cycle Assets; expected characteristics of long and short cycle assets; priorities from 2024-2028, including but not limited to operations execution, balance sheet strength and increased return of capital; 2024E-2028E capital efficiencies; expected proportions of 2024-2028 production by area; strategic priorities; organic per share growth; Allocating ~40% of excess cash flow to the balance sheet; benefits of hedging program; additional non-core dispositions and expected benefits; increasing return of capital; base dividend increases; prioritizing share buybacks; timing for Karr West results; Increase return of capital beyond 60% of excess cash flow over time; Cumulative excess cash flow of $3.8B - $5.6B in 5-year plan at the pricing specified herein; organic production growth of 30% and unbooked upside; key takeaways from 2024 Investor Day; expectations of the Alberta Montney and Kaybob Duvernay, including but not limited to resources, EURs, and enhanced returns; expectations of Saskatchewan assets; Kaybob Duvernay 5-Year Outlook (2024 – 2028), including, but not limited to, production CAGR, excess cash flow growth, NOI and Capex, production, net drill count, production mix and excess cash flow mix; Kaybob Duvernay drilling locations, EUR, NPV10%, cost per well, IRR% and payout; Kaybob Duvernay Break-Even Economics & Sensitivity to Gas Prices, including, but not limited to, break even pricing at current unit costs and unit costs at a 15% cost reduction; planned Kaybob Duvernay water storage and expectation of water usage and availability; ~60% of Kaybob Duvernay inventory remains unbooked as at YE 2023 allowing for future reserves additions and NAV growth; ~1.3B of cumulative excess cash flow expected by YE 2024 from the Kaybob Duvernay; time to payoff Kaybob Duvernay acquisition cost; development plans for the Alberta Montney; opportunity for development of the Lower Montney bench; Identified opportunities to create value and opportunities to enhance returns in the Alberta Montney; Karr East average EURs; Alberta Montney 5-Year Outlook (2024 – 2028), including, but not limited to, production CAGR, excess cash flow growth, NOI and Capex, production, net drill count, production mix and excess cash flow mix; Alberta Montney drilling locations, EUR, NPV10%, cost per well, IRR% and payout; Alberta Montney Break-Even Economics & Sensitivity to Gas Prices, including, but not limited to, break even pricing at current unit costs and unit costs at a 15% cost reduction; enhanced Gold Creek performance; Planned Gold Creek on stream and drills; benefits of wider-spaced, single bench pads; timing for Karr West results; 2024 Karr East on stream and drills; Alberta Montney cost saving opportunities and synergies; average well costs target; 2024E improvements in corporate costs; Returns and scalability of CPG’s Alberta Montney; percentage of development capital expenditures directed to facility capital in 10-year development plan; Montney infrastructure provides ample connectivity; OOIP in the Alberta Montney; opportunities to creates value in the Montney; CPG plans to expand water access for operations; strong market access; marketing optionality; future Ksi Lisims LNG project; 2024E condensate production breakdown by stream; gas diversification through 2025; Saskatchewan volumetric drilling incentives; Saskatchewan 5-Year Outlook (2024 – 2028), including, but not limited to NOI and capex, production, net drill count, production mix and excess cash flow mix; predicted oil rate and cumulative VRR; portion of 2024 excess cash flow attributable to waterflood; base decline rate on production under waterflood; long term sustainability of waterflood; net waterflood oil in total and by area and expected decline rates; benefits of OHML, including, but not limited to, preserving capital discipline and adding additional high-netback production; wells per two sections, capital, NPV10, IRR, Payout and EUR; 2024 OHML budget and drilling plans; internally identified OHML locations; OHML well performance; highly economic long-term plan; additional and premium locations in the current development plan and requirements for development of additional locations; well payout timing of premium locations; premium locations by major operating area and 5-year development plan, with numbers planned to be drilled and remaining in 2028; 5-year plan excess cash flow and production; key metrics in 5-year plan, including, but not limited to: production and CAGR, excess cash flow per share CAGR, cumulative excess cash flow, premium inventory life; leverage ratio; reinvestment ratio and decline rate; attractive returns based on depth of premium inventory; 5-year plan rate of return (half-cycle ROR and full-cycle ROR); 10-year plan, including but not limited to cumulative after-tax excess cash flow and cumulative after-tax excess cash flow per share at the commodity prices specified; average per year metrics over the 5 and 10 year plans, at the commodity prices specified, including, but not limited to: average capital expenditures, reinvestment ratio, net debt/funds flow, decline ratio, cumulative excess cash flow and premium inventory remaining; plan to increase percentage allocation of excess cash flow over time as the balance sheet strengthens further; return of capital framework and components thereof; total return of capital from 2024E to 2028E at the commodity prices specified; base dividend increases; increasing return of capital allocation; strengthening balance sheet; plan to prioritize share buybacks as the tool of choice for additional return of capital beyond base dividends; strong total returns; average total return yield over 2024E to 2028E; compelling compound returns for shareholders through dividends, buybacks, per-share growth and debt reduction; corporate strategy focused on delivering long-term value and components; organic growth and strategic priorities forward; production by area to 2028; organic growth plan, 2024E and 2028E production guidance; ~30% production growth through 2028; key factor in 5-year plan, including, but not limited to: percentages of total premium inventory and booked 2P inventory at YE2023 used, rig activity, type well forecast and production results, cost improvements; market egress and infrastructure requirements; Alberta Montney resources in place; Kaybob Duvernay returns and growth and excess cashflow generation; significant unbooked upside; 2024 guidance, including, but not limited to annual average production, capital expenditures (including development capital expenditures and capitalized administration) and other information as part of the 2024 guidance; return of capital outlook including total return of capital, dividends and share repurchases and funds flow sensitivities; dividend expectations; major operating area economics including, but not limited to EUR, cost per well, IRR% and payout at the pricing assumptions stated; returns based capital allocation framework & excess cash flow priorities 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 of reserves 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, 2023, which is accessible at www.sedarplus.com. 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, 2023 under "Risk Factors“ and our Management’s Discussion and Analysis for the year ended December 31, 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, 2023, under the headings "Capital Expenditures", "Liquidity and Capital Resources", "Critical Accounting Estimates", "Risk Factors", "Changes in Accounting Policies" and "Guidance“. 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 or impediments in business operations or delivery of services due to pipeline restrictions, rail blockades, outbreaks or pandemics; 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 drought, water availability, wildfires, 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; 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 2024 guidance in respect of capital expenditures and average annual production, 2024E – 2028E capital efficiencies and total return of capital; 5-year plan rates of return; 5-year plan and outlook, and 10-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 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.

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").

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”, “excess cash flow per share – diluted”, “base dividends”, “total return of capital”, “reinvestment ratio”, “enterprise value”, “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.

For the year ended December 31, 2023, adjusted funds flow and excess cash flow were $2,339.1 million and $981.6 million, respectively. The most directly comparable financial measure for funds flow/adjusted funds flow and excess cash flow disclosed in the Company’s financial statements is cash flow from operating activities, which, for the year ended December 31, 2023, was $2,195.7 million. For the year ended December 31, 2023, base dividends were $219.4 million. The most directly comparable financial measure for base dividends disclosed in the Company’s financial statements is dividends declared, which for the year ended December 31, 2023 was $211.9 million. As at December 31, 2023, net debt was $3,738.1 million. The most directly comparable financial measure for net debt disclosed in the Company’s financial statements is long-term debt, which at December 31 2023, was $3,556.3 million. 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. Reinvestment ratio is a supplementary financial measure and is calculated as development capital expenditures divided by adjusted funds flow. Enterprise value is a supplementary financial measure and is calculated as market capitalization plus net debt. Excess cash flow per share – diluted is a non-GAAP ratio and is calculated as excess cash flow divided by the number of weighted average diluted shares outstanding. Excess cash flow per share presents a measure of financial performance to assess the ability of the Company to finance dividends, potential share repurchases, debt repayments and returns-based growth. Excess cash flow per share – diluted for the year ended December 31, 2023 was $1.79 . Net debt /funds flow, is a non-GAAP ratio and is calculated by dividing net debt by annualized quarterly funds flow. Net debt / funds flow as at December 31, 2023 was 1.6x. Excess cash flow for 2024 to 2028 and net debt / funds flow for 2024 to 2028 are forward-looking non-GAAP measures, and are calculated consistently with the measures disclosed in the Company’s MD&A. Refer to the Specified Financial Measures section of the Company’s MD&A for the period ended December 31, 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 year ended December 31, 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 & 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 “CAGR”, “payout”, “IRR”, “decline rate” “replacement rate”, "F&D costs", “FDC”, "FD&A", “NAV”, and “reinvestment 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. CAGR, or the compound annual growth rate of an investment or other unit of value, is the average annual amount it grows over a period of years assuming its reinvested during the period. 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. IRR is a discount rate that makes the net present value (NPV) of all cash flows equal to zero in a discounted cash flow analysis. 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. F&D costs, including change in FDC, and FD&A costs have been presented in this presentation because they provide a useful measure of capital efficiency. F&D costs and FD&A costs, including land, facility and seismic expenditures and excluding change in FDC have also been presented in this presentation because they provide a useful measure of capital efficiency. Net asset value (NAV) is a snapshot in time as at year-end and is based on the Company's reserves evaluated using the independent evaluators forecast for future prices, costs and foreign exchange rates.. NAV is an estimate of the value of the Company’s net assets. Replacement rate is the amount of oil added to the Company’s 2P reserves, divided by production. It is a measure of the ability of the Company to sustain production levels. Finding and development (F&D) costs are calculated by dividing the development capital expenditures by the applicable reserves additions. F&D costs can include or exclude changes to future development capital costs. Finding, development and acquisition costs (FD&A) are equivalent to F&D costs plus the costs of acquiring and disposing particular assets. Future development capital (FDC) reflects the best estimate of the cost required to bring undeveloped proved and probable reserves on production. Changes in FDC can result from acquisition and disposition activities, development plans or changes in capital efficiencies due to inflation or reductions in service costs and/or improvements to drilling and completion methods. Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Proved reserves are reserves estimated to have a high degree of certainty of recoverability. Probable reserves are less certain to be recoverable than proved reserves and possible reserves are less certain than probable reserves.

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 & Drilling Data

All reserves data for CPG contained in this presentation, and effective for the year ended 2023, is contained in the Corporation's AIF for the year ended, December 31, 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.

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.

Kaybob Duvernay Peak 30-Day Rate by Product Type			
Pad (on Stream)	Condensate	NGL	Shale Gas
1 (Q1 2023)	43%	18%	39%
2 (Q2 2023)	73%	8%	19%
3 (Q3 2023)	70%	13%	17%
4 (Q4 2023)	81%	5%	14%
5 (Q1 2024)	62%	12%	26%
6 (Q2 2024)	61%	13%	27%

Gold Creek West Peak 30-Day Rate by Product Type			
Pad (on Stream)	Light & Medium Crude Oil	NGL	Shale Gas
1 (Q1 2023)	81%	3%	16%
2 (Q2 2023)	71%	4%	25%
3 (Q3 2023)	63%	5%	32%
4 (Q1 2024)	85%	2%	13%

Karr East Peak 30-Day Rates by Product Type			
Pad (on Stream)	Light & Medium Crude Oil	NGL	Shale Gas
1 (Q2 2021)	76%	4%	20%
2 (Q3 2023)	82%	3%	15%

Gold Creek Peak 30-Day Rate by Product Type			
Pad (On stream)	Light & Medium Crude Oil	NGL	Shale Gas
1 (Prior Operator)	42%	10%	48%
2 (Q2 / Q4 2023)	65%	6%	29%
3 (2022 / 2023)	42%	11%	47%
4 (2022 / 2023)	47%	9%	44%
5 (Q4 2023)	31%	12%	57%

Reserves & Drilling Data

Initial production is for a limited time frame only (30 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. ("McDaniel") in addition to unbooked future drilling locations as identified by Crescent Point. References to McDaniel type wells are to proved plus probable (2P) booked type wells assigned by independent reserves evaluator McDaniel as at December 31, 2023.

The peak 30-day rates for the 20 wells brought on stream in the Kaybob Duvernay in 2023 ranging consisted of average product types of 74% condensate, 9% NGLs and 17% shale gas within the Volatile Oil window and 43% condensate, 18% NGLs and 39% shale gas within the Liquids-Rich window.

The average peak 30-day rates for the 25 wells brought on stream in the Alberta Montney since initial entry into the play in second quarter 2023 generated the following average product types: 72% light and medium crude oil, 4% NGL and 24% shale gas per well in Gold Creek West; 52% light and medium crude oil, 9% NGL and 39% shale gas per well in Gold Creek and 82% light and medium crude oil, 3% NGL and 15% shale gas per well in Karr East.

Prior Operator Karr West pad Q4 2023 and Q1 2024 production consisted of 80% light and medium crude oil, 3% NGL and 17% shale gas and 84% light and medium crude oil, 3% NGL and 13% shale gas, respectively.

This presentation discloses: (I) in the Kaybob Duvernay, (A) Volatile Oil region, ~225 potential internally identified net drilling locations, of which 146 are proved plus probable locations, as assigned in the company's year end 2023 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 77 are unbooked locations; (B) Liquids-Rich region ~140 potential internally identified net drilling locations, of which 42 are proved plus probable locations, as assigned in the company's year end 2023 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 100 are unbooked locations; and (C) Lean Gas region ~160 potential internally identified net drilling locations, of which 25 are proved plus probable locations, as assigned in the company's year end 2023 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 133 are unbooked locations; and (II) in the Alberta Montney, (A) Gold Creek West region, 310 potential internally identified net drilling locations, of which 37 are proved plus probable locations as assigned in the company's year end 2023 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 273 are unbooked locations; (B) Gold Creek region 560 potential internally identified net drilling locations, of which 123 are proved plus probable locations, as assigned in the company's year end 2023 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 436 are unbooked locations; (C) Karr West region 170 potential internally identified net drilling locations, of which 115 are proved locations, as assigned in the company's year end 2023 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 55 are unbooked locations; and (D) Karr East region 390 potential internally identified net drilling locations, of which 109 are proved plus probable locations, as assigned in the company's year end 2023 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, and an incremental 282 are unbooked locations.

This presentation also discloses ~6,000 locations in corporate inventory of which of which 1,887 are proved plus probable locations, as assigned in the company's year end 2023 independent reserves evaluation in accordance with NI 51-101 and the COGE Handbook, with the remainder unbooked.

Reserves & Drilling Data

Years of corporate inventory figures include proved and probable locations, as derived from the independently evaluated (by McDaniel & Associates Consultants Ltd.) Reserves Report for CPG 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 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' 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.