TSX: TVE

CREATING SUSTAINABLE VALUE

January 2026 | **Investor Presentation**

tamarack valley ENERGY

Corporate and Operational Snapshot

The Largest Public Clearwater Producer

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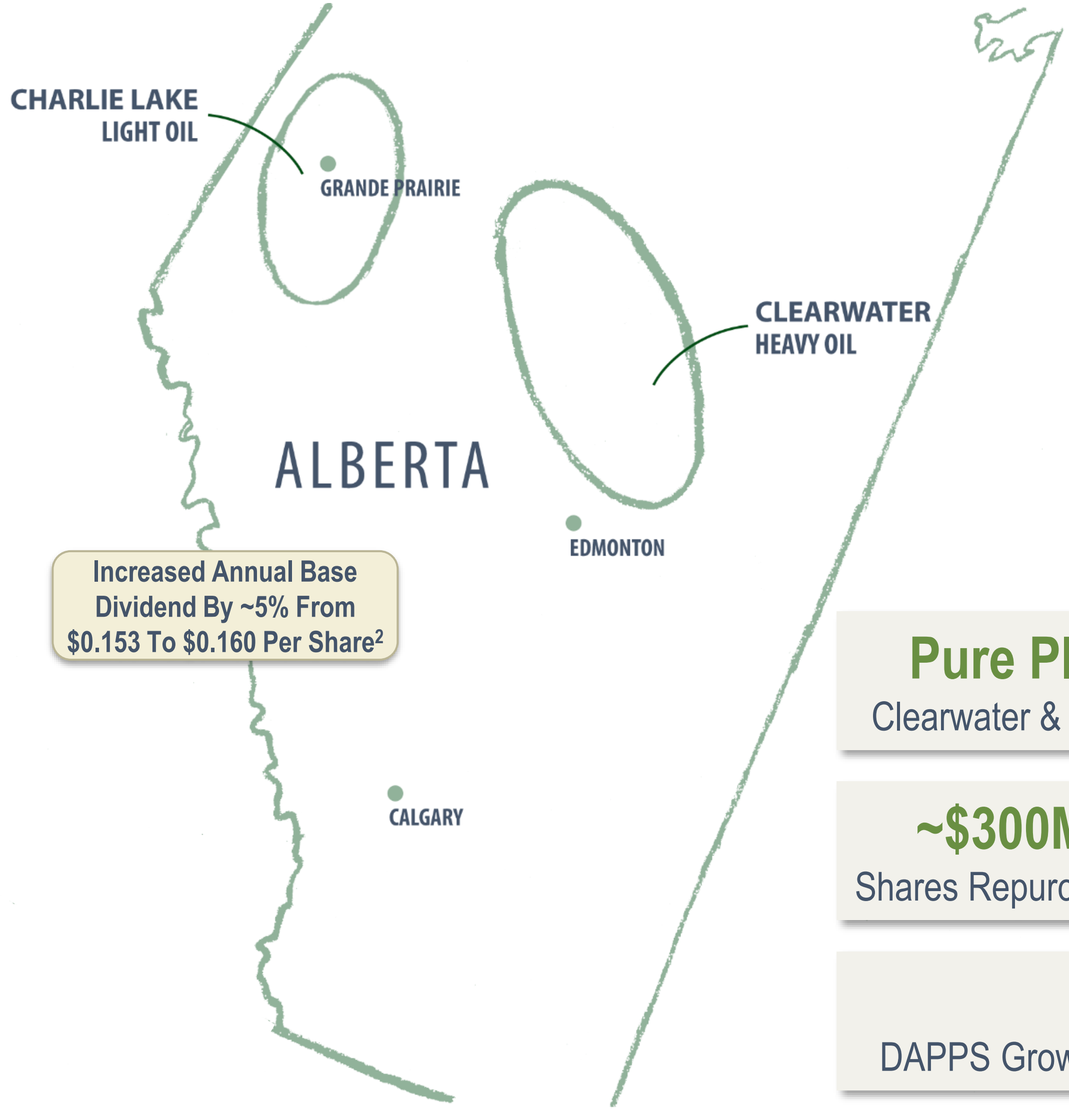
Corporate Overview		
Ticker Symbol		**TSX: TVE**
Shares Outstanding (Basic)[1]	*(MM)*	489
Share Price (Dec. 29, 2025)	*($/Sh.)*	*$8.08*
Market Capitalization	***($B)***	**$4.0**
Q3 2025 Net Debt	***($B)***	**$0.6**
Enterprise Value	***($B)***	**$4.6**
Annual Base Dividend[2]	*($/Sh.)*	$0.16
Annual Base Dividend Yield[2]	*(%)*	~2.0%
Q3 2025 Net Debt / LTM EBITDA	*(x)*	0.6x
2025 Current Guidance Highlights		
Production[3]	*(boe/d)*	67,000 – 69,000
Capital Expenditures[4]	*($MM)*	$400 – $420
2026 Guidance Highlights		
Production[3]	*(boe/d)*	69,000 – 71,000
Average Liquids Weighting	*(%)*	84% – 86%
Capital Expenditures[4]	*($MM)*	$390 – $410



Pure Play Oil Focus
Clearwater & Charlie Lake Producer

~$300MM | ~12.2%[5]
Shares Repurchased Since Dec. 2023

~21%
DAPPS Growth (Q3/25 vs. Q4/23)[6]

1) Share count as at the end of November 2025.
2) Based on the annual base dividend of $0.16 per share per the recent announcement on Oct 29, 2025, to increase the dividend starting Nov. 28, 2025 (record date), payable Dec. 15, 2025. Dividend yield uses Tamarack share price as at Dec. 29, 2025.
3) 2025E Production of 67,000 – 69,000 boe/d: 41,150 - 42,350 bbl/d heavy oil, 13,300 - 13,700 bbl/d light/medium oil, 2,300 - 2,360 bbl/d NGLs and 61,550 - 63,550 mcf/d natural gas.
3) (cont.) 2026E Production of 69,000 – 71,000 boe/d: 47,700 bbl/d heavy oil, 9,200 bbl/d light/medium oil, 2,600 bbl/d NGL and 63.0 MMcf/d natural gas.
4) Capital expenditures excluding ARO spending.
5) Based on shares outstanding Dec. 31, 2023, and repurchases up to and including Nov. 30, 2025.
6) Debt adjusted with a TVE share price of ~$7.50/Sh. DAPPS = debt adjusted production per share.

Differentiating Tamarack: Asset Scale & Economic Scope

Highly Economic Full-Cycle Returns = Growing Return of Capital

Top Tier Assets With Large OOIP

- >11 billion barrels of OOIP in the Clearwater[1]; current recovery <1% of OOIP
- Proven Clearwater waterflood driving incremental resource capture and duration

Low Production Declines & Trending Lower

- Unique ability to grow Clearwater production and reduce decline rates

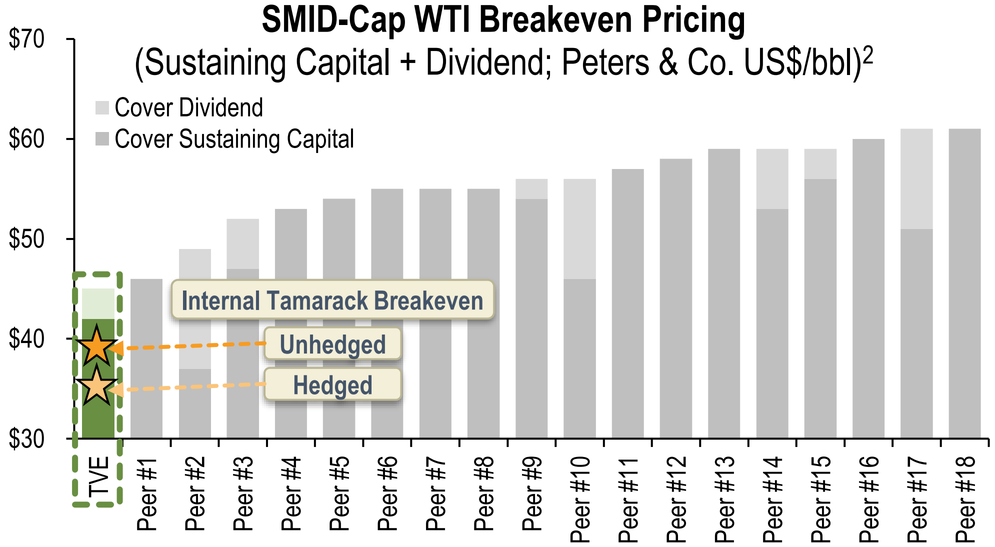
Low Sustaining Cost & Resilient Breakeven Price

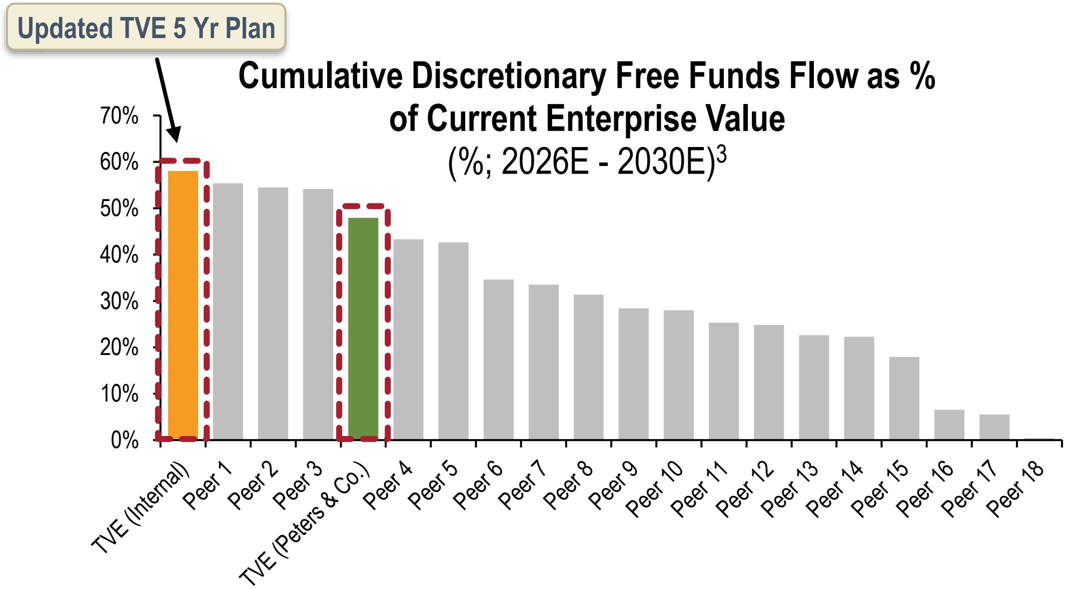
- Unhedged breakeven <US$40/bbl WTI covering maintenance capital + base dividend

Increasing Cash Return On Invested Capital

Capital Allocation Flexibility Allows For Optionality

- Focused on assets and capital allocation to generate the highest return ON capital, to allow the highest return OF capital





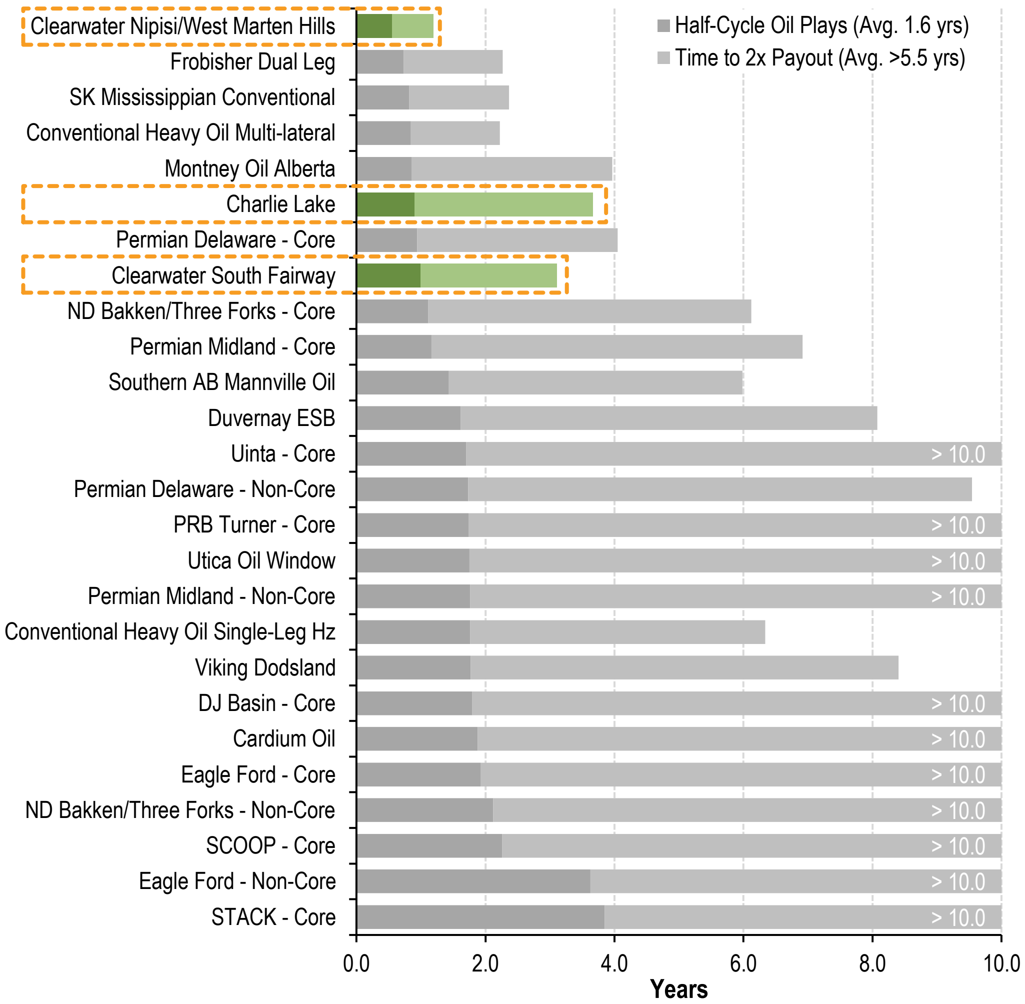
See Disclaimers – "Specified Financial Measures".

1) OOIP – original oil in place based on internal estimates; excludes Clearwater PrivateCo. lands.
2) Breakeven estimates per Peters & Co. Breakeven estimates are ranked by the total of sustaining capital + dividend (not 2026 capital program). Peer group includes ATH, BNE, BTE, CJ, GFR, HWX, IPCO, JOY, LCX, LTC, OBE, RBY, SCR, SGY, SOIL, VET, WCP, and YGR.
3) Forward estimates and capitalization per Peters & Co. on strip pricing as at Nov. 17, 2025. Cumulative discretionary funds flow from 2026E-2030E as a % of current enterprise value. Assumes companies spend at sustaining capital each year. Peer group is the same as footnote #2.

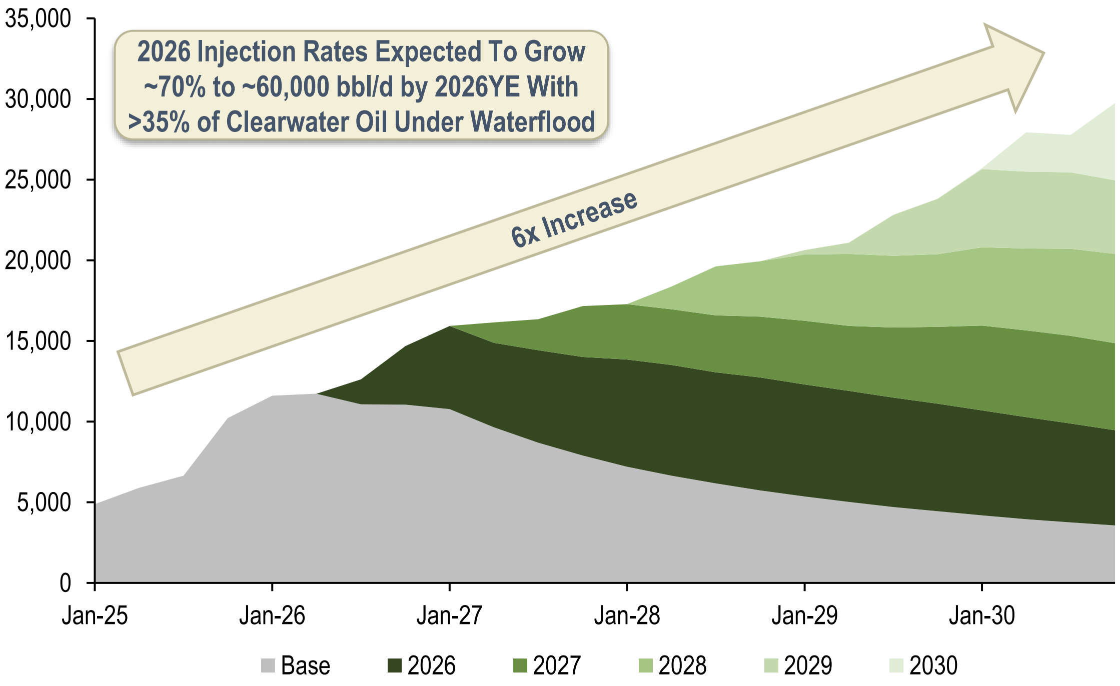
Top Tier Primary Assets and Proven Waterflood

Leverage Top Tier Primary Production To Establish Long-Term Low-Cost Waterflood

Primary Payout Periods (Years)[1]



Clearwater Oil Under Waterflood By Year (bbl/d)[2]



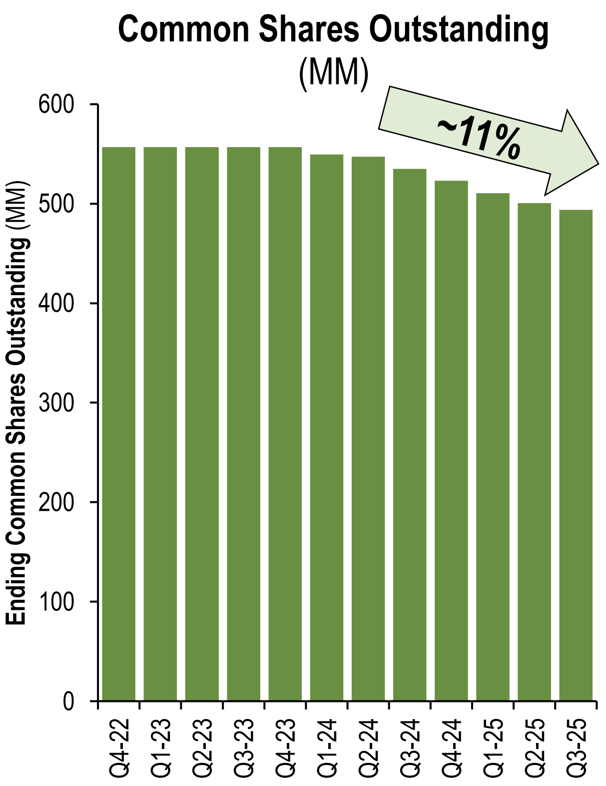
Tamarack Valley
Conventional Play Economics
Unconventional Resource Scale

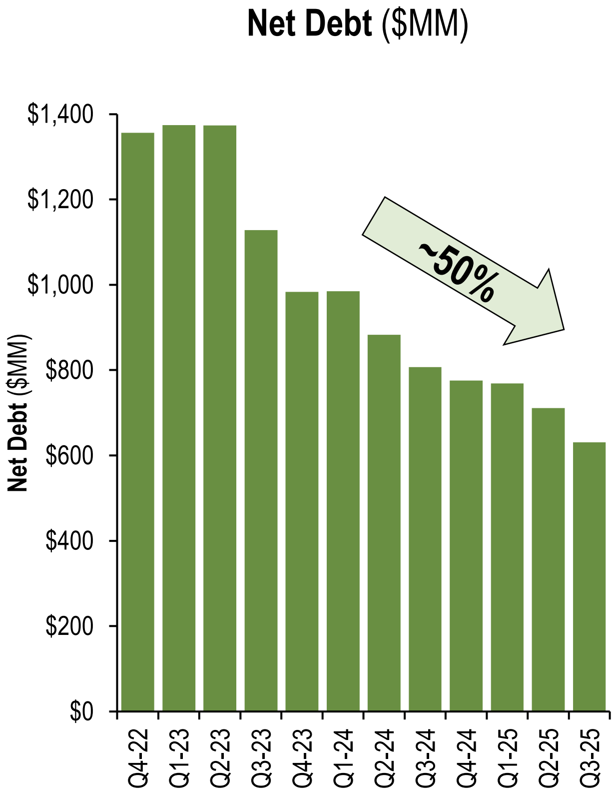
1) Source: Peters & Co. Limited estimates based on US$69.00/bbl WTI, US$13.37/bbl WCS Differential, US$4.25/bbl MSW Differential, US$3.60/Mcf NYMEX, $2.75 AECO, and 0.71 CAD/USD. Sorted by half-cycle payout.

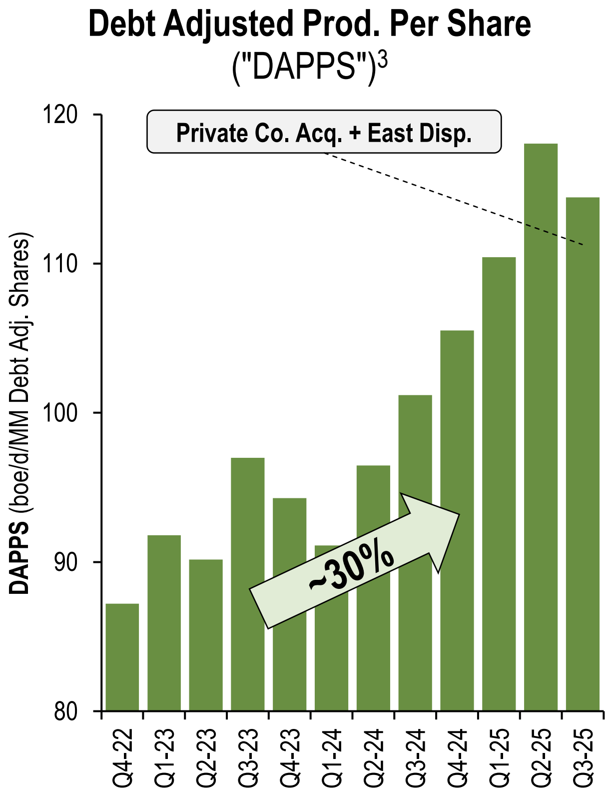
2) Baes on internal management estimates.

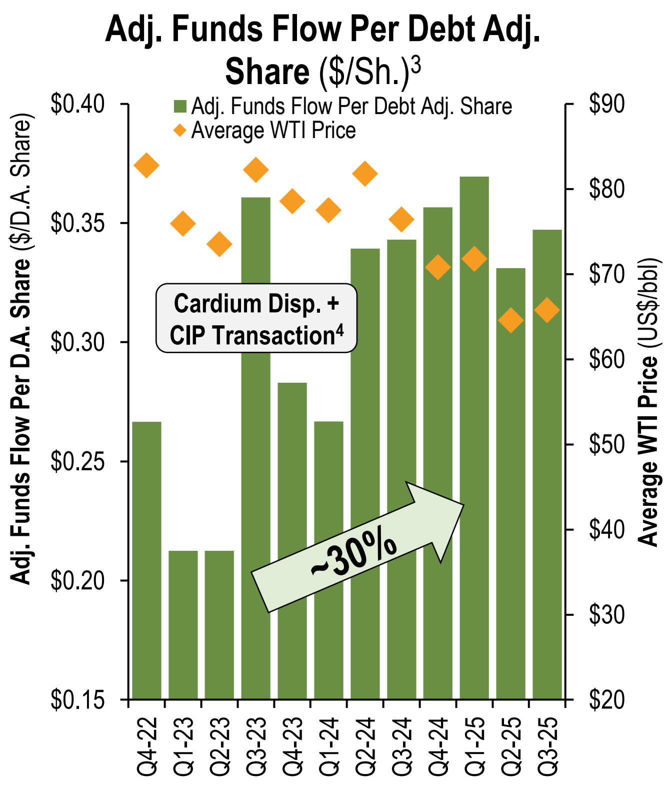
Demonstrated Per Share Value Creation

Compounding Success On A Per Share Basis









Repurchased ~11.4% of 2023YE Share Count (as at Q3/2025)[1]

Reduced Net Debt by ~$750 MM (~$1.50/Sh.) Since Deltastream Acquisition (Oct. 2022)[2]

~30% Debt Adj. Per Share Value Growth From Operational Outperformance, Long-Term Buybacks, and Debt Repayment

1) Change in share count from Dec. 31, 2023, to Sep. 30, 2025.
2) Net Debt Per Share = net debt at transaction close / share count for the most recent quarter. DSE acquisition closed Oct. 2022.
3) Debt adjusted using a Tamarack share price of $7.50/Sh. (was D.A. with $3.81/Sh. previously (2024A trading price)). Based on respective quarter ending basic shares outstanding and net debt.
4) Cardium assets were held for sale in Q3/23, sale closed in Q4/23.

2026 Capital Budget

2026 Corporate Guidance

More For Less: Growing Production With Less Capital And Returning More To Shareholders

2026 Budget Pricing	
WTI (US$/bbl)	$60.00
WTI / MSW Diff. (US$/bbl)	($4.00)
WTI / WCS Diff. (US$/bbl)	($12.75)
AECO ($/GJ)	$2.75
FX (US$/C$)	1.35

2026 Annual Guidance	Guidance
2026 Capital Budget[1] ($MM)	$390 – $410
Production	69,000 – 71,000
Average Oil & NGL %	84% – 86%
Expenses:	
Royalties (%)	19% – 21%
Wellhead Oil Price Diff[2] ($/bbl)	$1.00 – $1.50
Production Expense[3] ($/boe)	$6.85 – $7.15
Transport Expense ($/boe)	$4.00 – $4.50
G&A ($/boe)	$1.30 – $1.45
Interest[4] ($/boe)	$2.70 – $3.10
Income Tax (%)[5]	10% – 12%

Growing Production By ~3% (9% Adjusted For A&D) Year Over Year With Less Capital

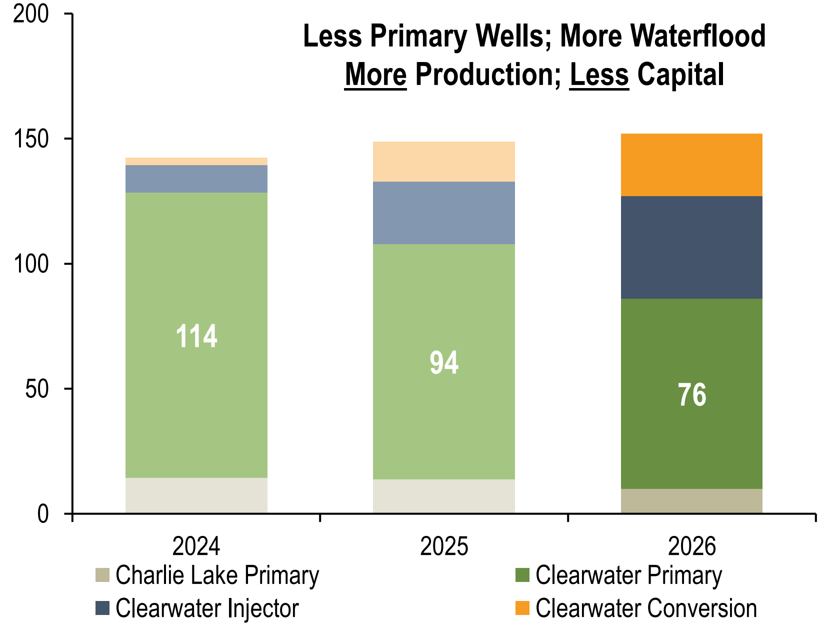
70% Of Capital Allocated To The Clearwater
Primary Development & Waterflood Expansion

Double Waterflood Investment to ~$100 MM
Clearwater Injection Expected To Grow By ~70%

Focused De-Risking
Greater Clearwater Fairway & Pelican Region

Accelerating Decline Mitigation And Lower Future Reinvestment Ratios Longer Term

2026 Net Well Activity



1) Excludes ARO capital.
2) Oil wellhead deductions for grade specific trading differential (ex CHV), blending requirements, quality differential, and pipeline tolls if TVE is not marketing (lease transactions).
3) Includes CIP fee for service and minimal carbon tax budgeted.
4) Includes CIP ToP capital fee.
5) Income tax expense measured as a % of B-Tax funds flow.

Accelerating Shareholder Returns

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Lower Debt, Higher Margins, Lower Declines = Higher Shareholder Returns

Deleveraging Framework (Complete)

	2023YE	2H/2024
Net Debt[1] ($MM) & *Net Debt / LTM EBITDA (x)*	$900MM – $1,100MM & *~1.0x Net Debt / EBITDA*	$500MM – $900MM & *~1.0x Net Debt / EBITDA*

Adjusted Funds Flow[1]

Free Funds Flow[1] Allocation

2023YE	2H/2024
60% Net Debt Reduction	40% Net Debt Reduction & Strategic Growth Capital Allocation
Up to 40% Base Dividend + Enhanced Returns	Up to 60% Base Dividend + Enhanced Returns

Capital Expenditures

Shift To More Flexible "Guiding Principals" for Shareholder Returns

Tamarack Evolution: Deleveraging & Asset Portfolio Transformation Complete

- Net debt reduced by ~$750 MM (~50%) since Deltastream acquisition (Oct. 2022)

Lower Decline
Less Capital
Less Cash Costs
=
Improved Breakeven

	2026E vs. 2023	
	2026E	**2023**
Base Decline	~22%	~35%
Sustaining Capital	Reduced by ~30%	
Operating Expense	Reduced by ~25%	
Breakeven WTI Maintenance + Dividend (unhedged)	**Reduced by ~US$8/bbl**	

2026 Guiding Principals:

Maximize Per Share Returns & Overall Value To Shareholders Across Commodity Cycles

- Lower prices: share buybacks and incremental waterflood focus
- Higher prices: focus on returns through more production growth

Ensuring Financial Resilience: Target ~1.0x Net Debt / EBITDA at US$50/bbl WTI

In 2026, Tamarack Is Allocating Additional Free Funds Flow To Share Buybacks

1) See Disclaimers – "Specified Financial Measures".

2026 Free Funds Flow Allocation

Low Breakeven Drives Flexibility & Increasing Returns To Shareholders

Production Growth & Disciplined Capital Allocation

~3% Annual Production Growth[1] (~9% Adjusted For A&D) | Focus on Buybacks To Augment Per Share Growth At Lower Prices

Strong Free Funds Flow Generation

>$250MM Annual Free Funds Flow[2,3] | Sustaining Capital Reinvestment Ratio of ~40% at US$60/bbl WTI

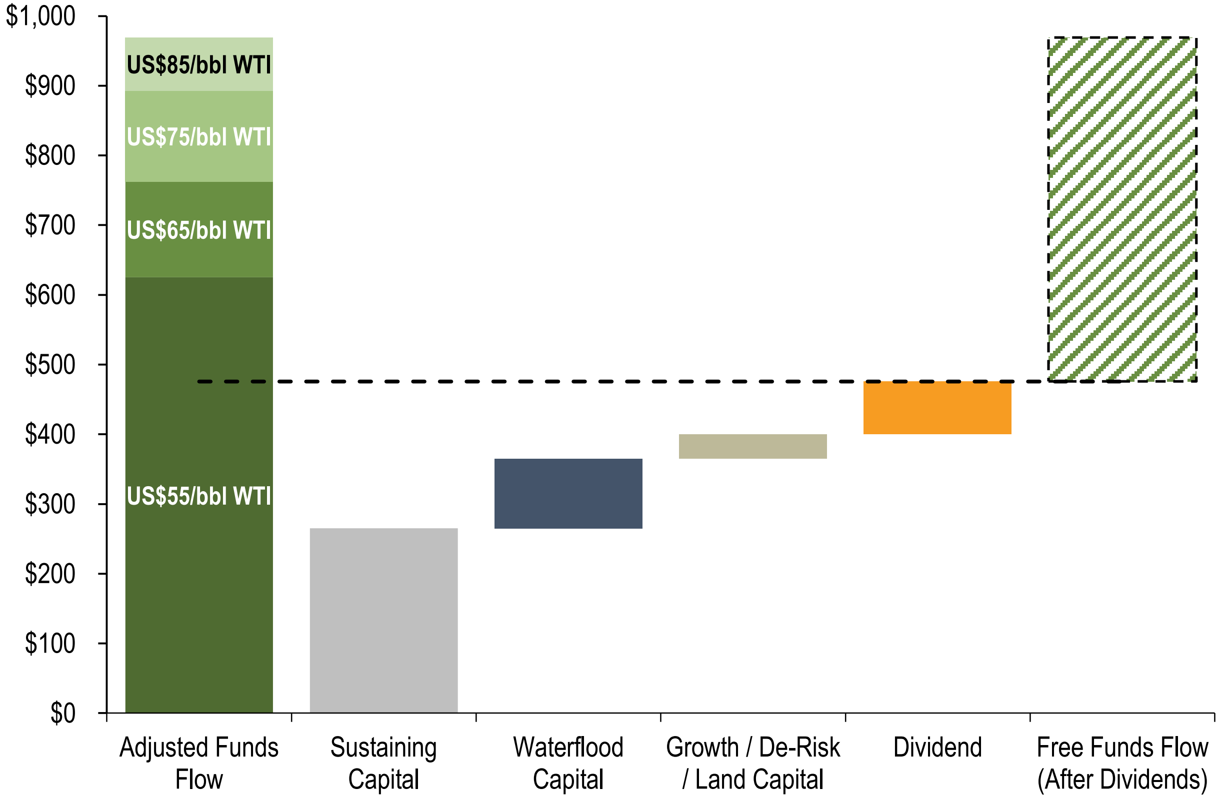
Financial Strength & Resiliency

2026E Corporate Sustaining Free Funds Flow Breakeven[2] of ~US$35/bbl (<US$40/bbl Unhedged) | Long Dated Laddered Credit Structure with Significant Liquidity and Low Debt/EBITDA Ratio[2]

Returns To Shareholders

Allocating Additional Free Funds Flow[2] To Share Buybacks

2026 Free Funds Flow Allocation ($MM)[4]



2026 Capital Program & Base Dividend Funded at <US$50/bbl WTI

1) Production growth measured as 2026E production at the midpoint of guidance relative to midpoint of 2025E annual production guidance.
2) See Disclaimers – "Specified Financial Measures".
3) Based on 2026 Budget pricing (flat US$60/bbl, US$(12.75)/bbl WCS differential to WTI, 1.35 US$/C$)
4) Sensitivity decks assume C$3.00/GJ AECO and 1.30 US$/C$; Oil differentials to WTI on US$55/US$65/US$75/US$85 price decks are as follows (US$/bbl): WCS differential to WTI: US$(12.75)/US$(13.25)/US$(13.50)/US$(14.00). MSW differential to WTI: US$(2.50)/US$(2.75)/US$(3.00)/US$(3.50).

5-Year Plan: Compounding Returns

Updated 5-Year Plan *(2026E-2030E)*

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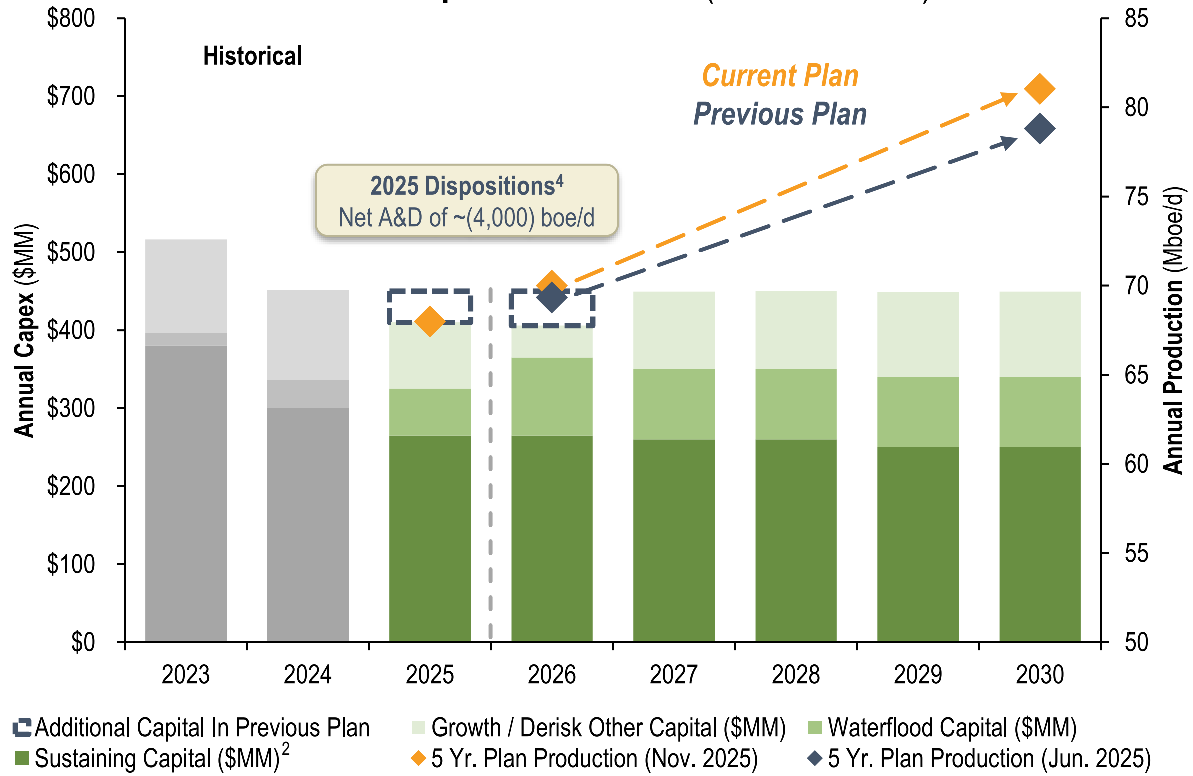
Achieving More High Margin Production with Less Capital

- 5-Year production growth CAGR of 3% - 5%[1]
- Annual reinvestment ratio: ~45% *(was ~50%)*[1,2,3]

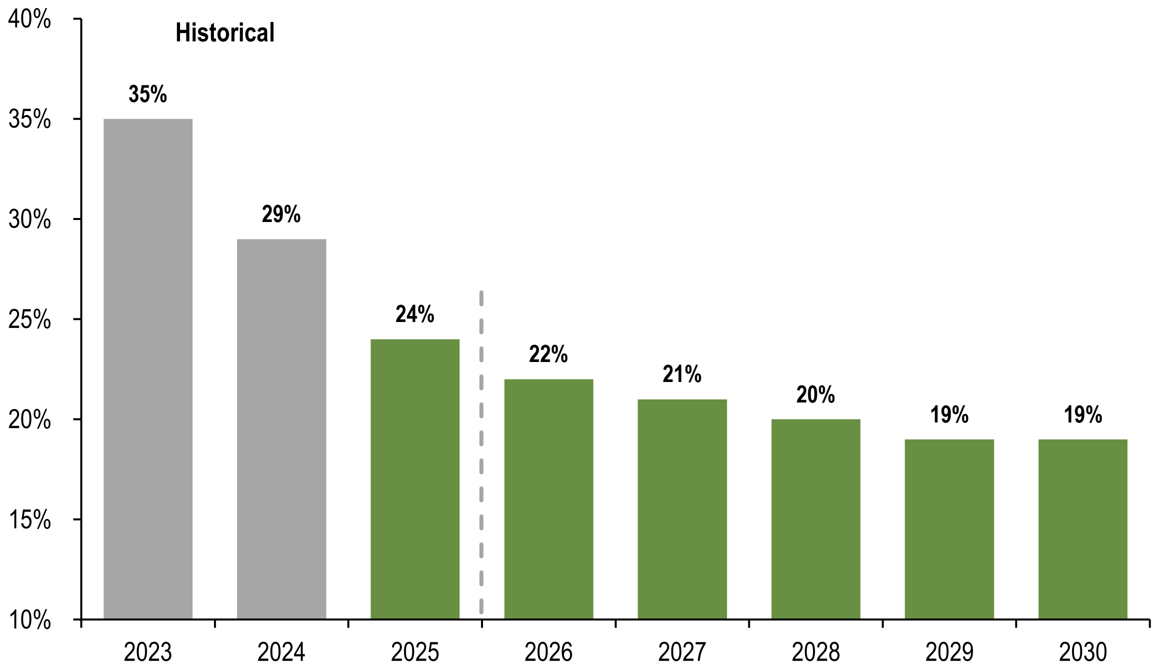
Shallowing Decline Rate Reduces Sustaining Capital[2], Improving Breakeven and Increasing Free Funds Flow[1]

- Waterflood mitigating declines YoY
- Reduced sustaining capital by ~30% since 2023

5 Yr. Plan Capex & Production ($MM & Mboe/d)



Annual Corporate Base Decline Rate (%)



1) See Disclaimers – "Specified Financial Measures". CAGR from 2026E-2030E.
2) Sustaining capital includes well drill, complete, equip and tie-in including infrastructure required to support development to hold production flat and minimum annual ARO spending. Reinvestment ratio = capex / adj. funds flow.
3) 2026E+ Pricing: US$75/bbl WTI price deck includes US($13.50) WCS differential, US($3.00) MSW differential, C$3.00/GJ AECO, and 1.30 C$/US$.
4) Production metrics cited for A&D are the production at the time of transaction close (i.e., not annualized amounts),

2026 Updated Base Plan vs. 2025 Investor Day Case

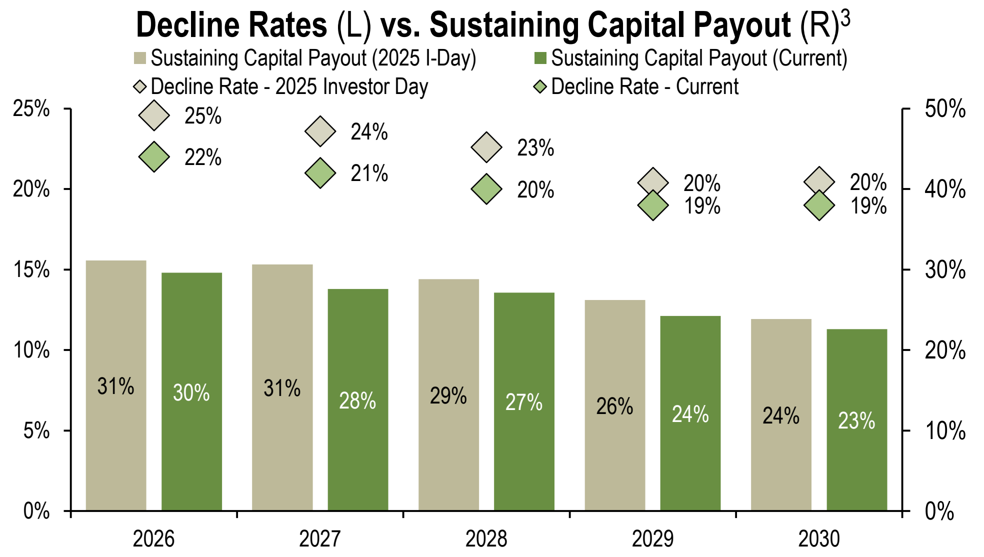
More Profitable Barrels For Less Capital Investment Throughout The Plan

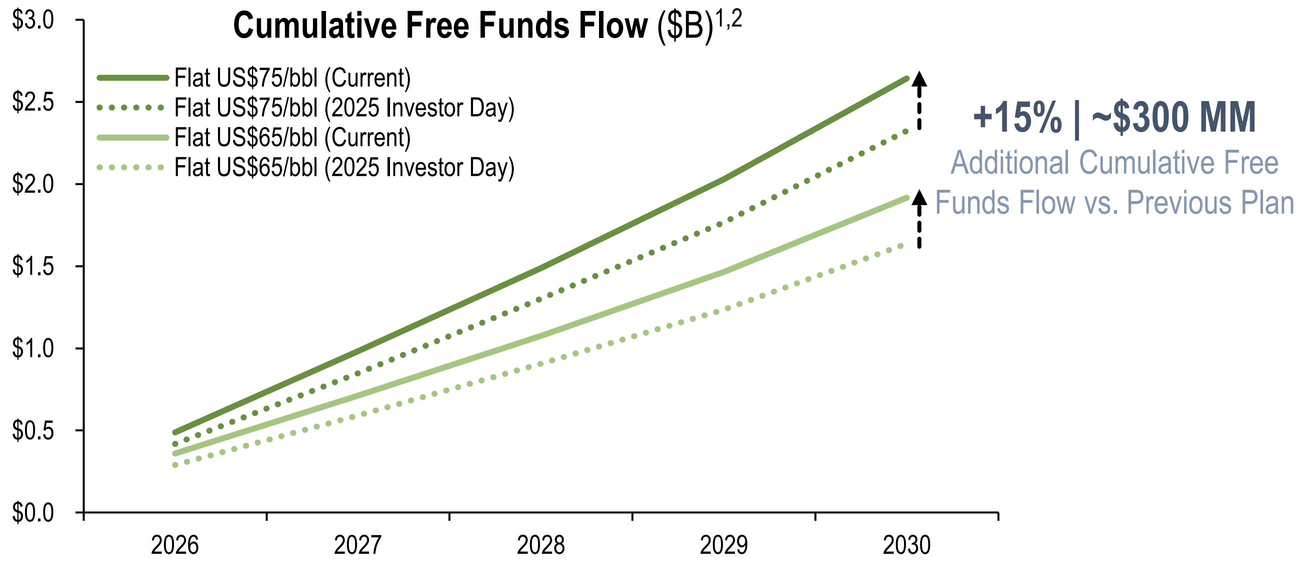
Decline Mitigation & Sustaining Capital Reduction

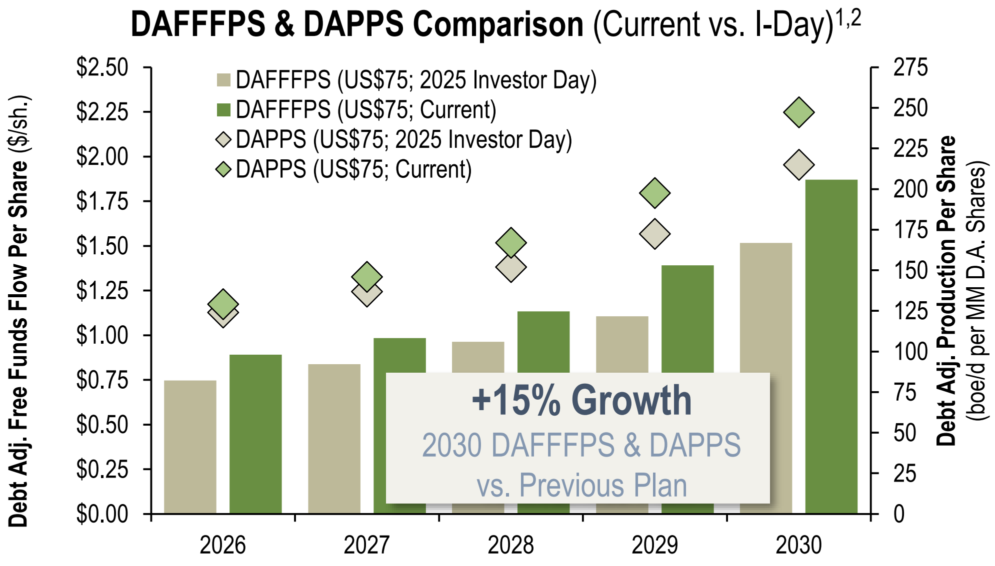
- Clearwater base outperformance
- Extended plateaus on high-graded Clearwater patterns
- Increased capital allocation toward waterflood development

Margin Enhancement

- Operational efficiencies driving overall lifting cost reductions
- High graded asset portfolio with recent A&D







1) Current and prior long term plan are both debt adjusted with a share price of $7.50/Sh. Assumes go-forward share buybacks are done at $7.50/Sh. in both 5 yr. plans.
2) Current plan assumes return of capital per current guiding principles. 2025 Investor Day assumes return of capital framework in place at the time.
3) 2026E+ Pricing: US$75/bbl WTI price deck includes US($13.50) WCS differential, US($3.00) MSW differential, C$3.00/GJ AECO, and 1.30 C$/US$.

Compounding Per Share Returns

Lower Sustaining Capital + Production Growth + Debt Reduction + Share Buybacks = Outsized Per Share Returns

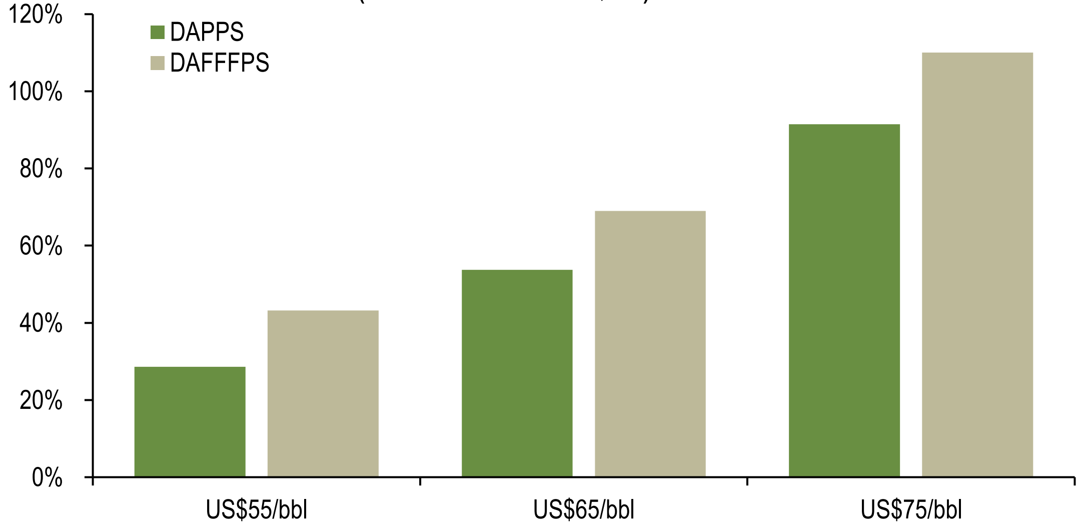
Total DAFFFPS & DAPPS Growth of ~100%[1,2,3] Over 5 Years (Flat US$75/bbl WTI)[4]

- Direct shareholder returns: 5% - 10%/Yr.[1]
- ~40% DAFFFPS growth at US$55/bbl WTI[1,2]

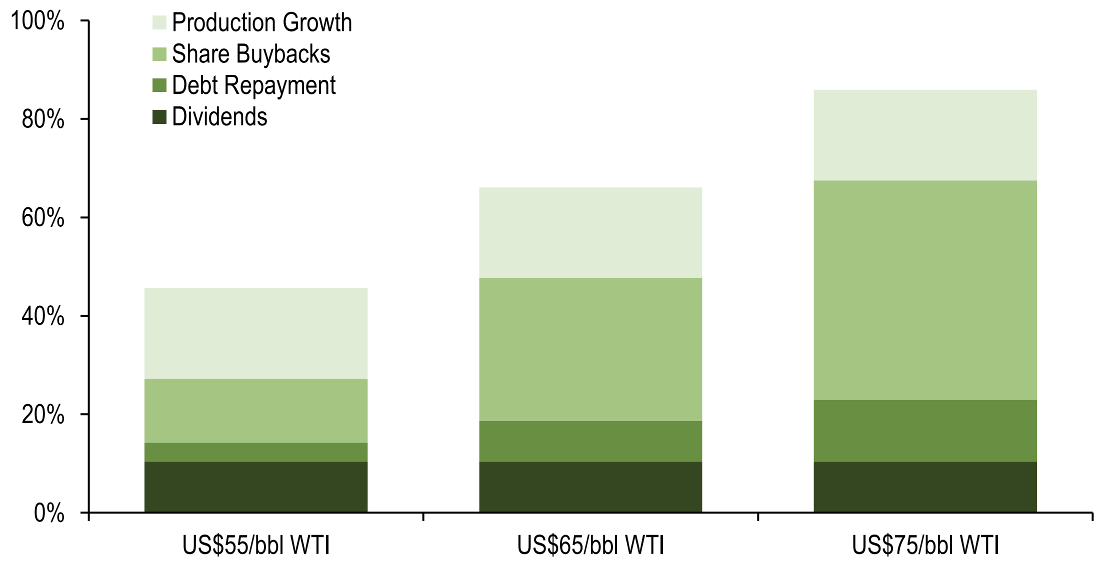
Cumulative Total Shareholder Return of ~80% Over 5 Years (Flat US$75/bbl WTI)[4]

- **TSR = Dividends + Buybacks + Debt Repayment + Production Growth**
- Base dividends ~$380 MM; repurchase >40% of 2025YE share count[4]

Cumulative ∆ In Debt Adj. Production Per Share & Debt Adj. Free Funds Flow Per Share
(2030E vs. 2026E; %)[1,2,3,4]



Cumulative 5 Year Total Shareholder Return
(2026E-2030E; %)[2,3,4]

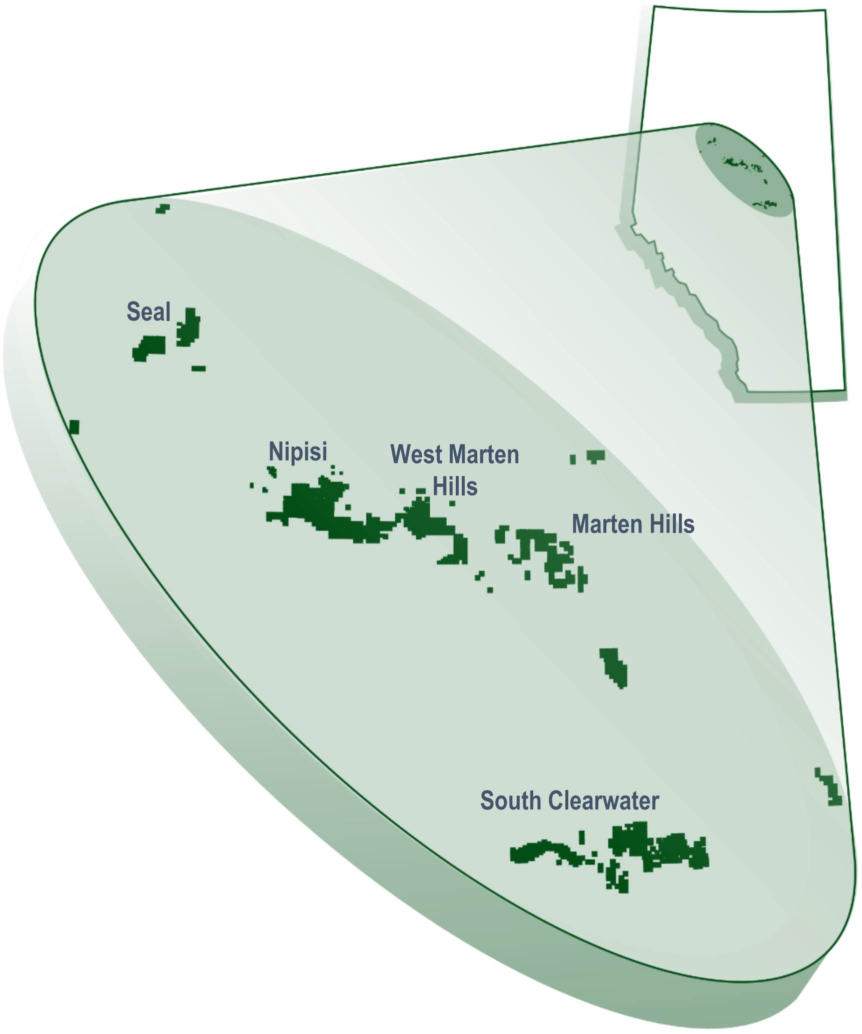


1) See Disclaimers – "Specified Financial Measures". Direct shareholder returns defined as dividend yield + % of prior year share count repurchased.
2) FFFPS and DAPPS growth from 2026E to 2030E in the 5-year plan. Free funds flow before base dividends and buybacks.
3) Debt adjusted using a Tamarack share price of $7.50, using average annual share counts and net debts. DAPPS/DAFFFPS growth uses 2026E as base.
4) Assumes annual dividend payout ($MM) is flat at ~$77MM. Returns for buybacks, debt repayment, and dividends based on changes or totals relative to 2025YE. Assumes shares repurchased at $7.50/Sh. Return from share buybacks is % of share count repurchased vs 2025YE. Return from debt repayment is debt repaid divided by current market capitalization. Assumes buybacks are not constrained by NCIB limits.

Asset Portfolio

Largest Public Clearwater Producer

Established Extensive Exposure Through The Heart of The Clearwater Fairway



Scale

- Extensive holdings across the Clearwater fairway; 808 net sections of land[1]
- >11 billion barrels of OOIP[2] in the Clearwater
- TPP reserve life index of ~9 years[3] & total resource size supports decades of additional development

Economics

- Stacked zone development & well design optimization drives capital efficiencies
- Multiple well payouts on primary recovery & waterflood provides additional payouts
- Pipeline connected to key oil terminals enhances market access to realize premium pricing

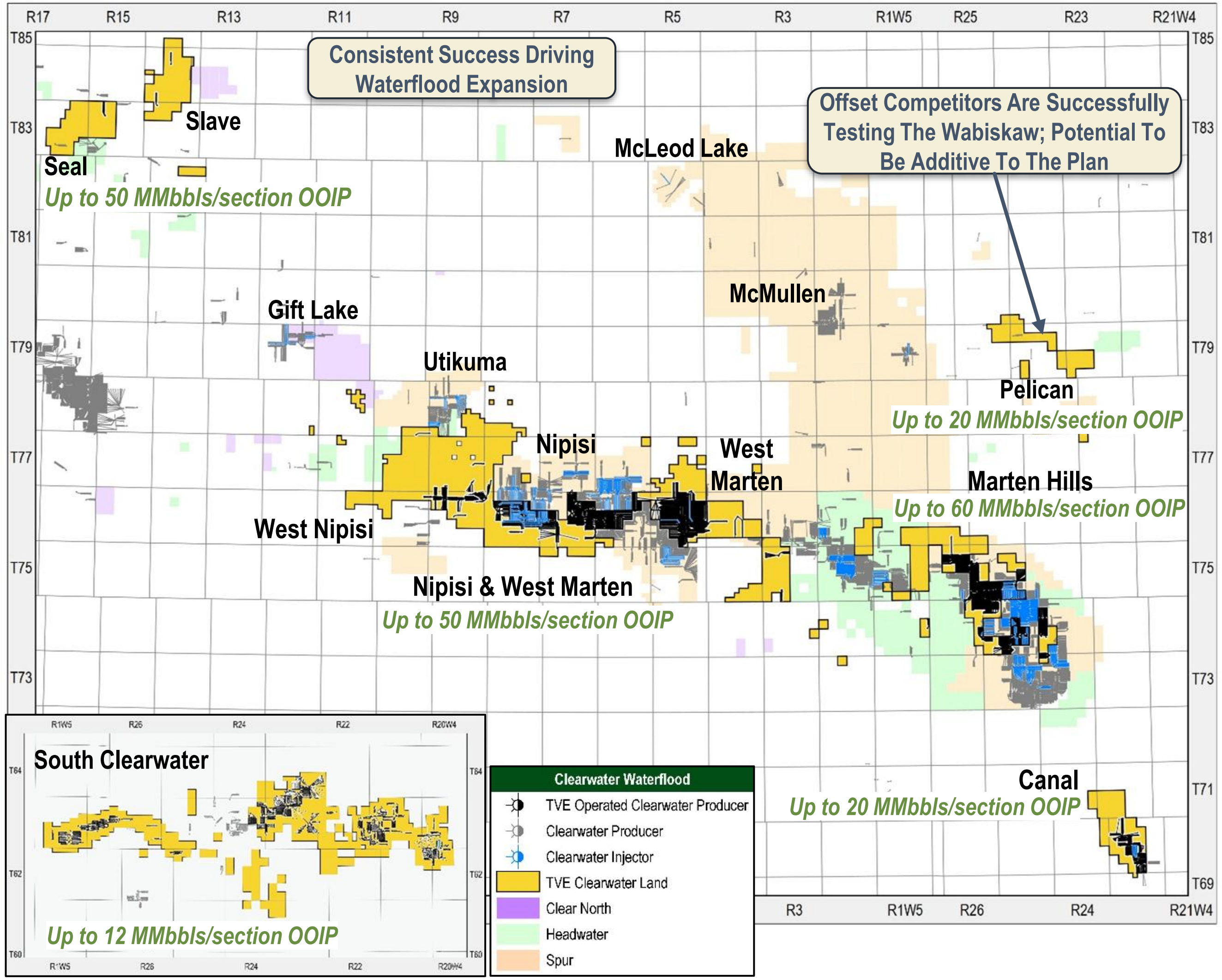
Duration

- Successful implementation of waterflood program increasing ultimate recoveries up to 3x primary recovery
- Significant asset duration driven by >2,000 drilling locations[4]

1) As at September 30, 2025.
2) OOIP – original oil in place based on internal estimates.
3) Based on 2024 Clearwater oil production of ~13.9 MMbbls.
4) Net primary locations as at 2024YE, see Disclaimers – "Drilling Locations" (excludes PrivateCo. locations).

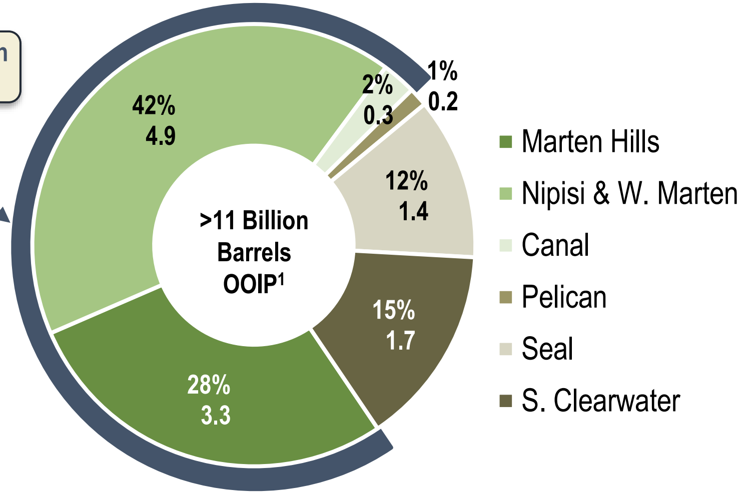
Clearwater Waterflood Expansion

Substantial Oil In Place and Proven Waterflood Drives Asset Duration

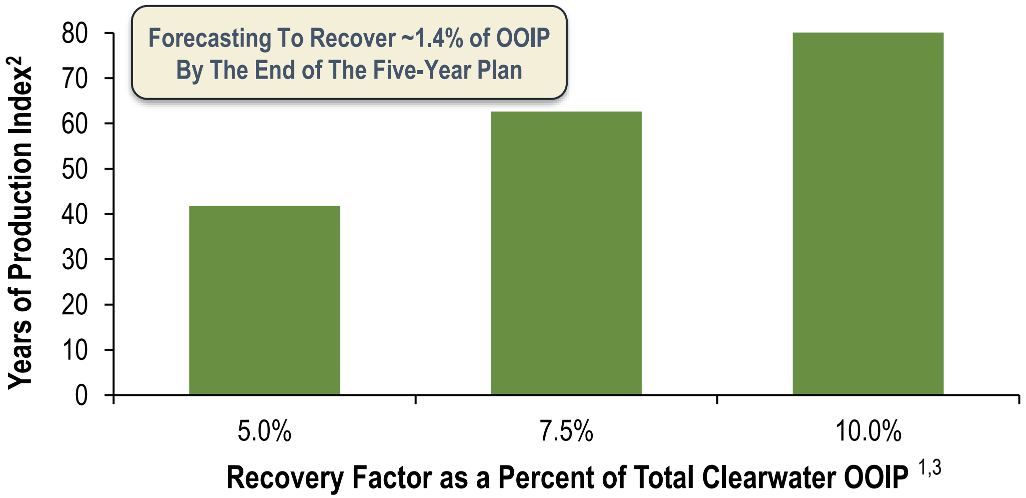


Clearwater OOIP by Area (Excludes PrivateCo.)[1]

~72% of OOIP[1] in Areas With Demonstrated Waterflood



Years of Production

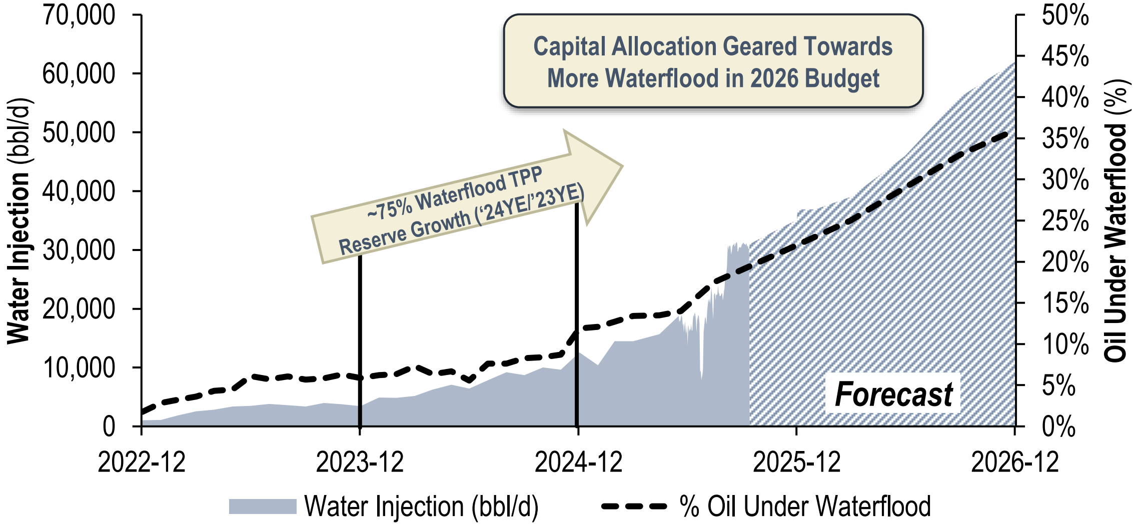


1) OOIP – original oil in place based on internal estimates, excluding PrivateCo. lands.
2) Years of Production Index is defined as recovered oil divided by 2024 oil production; based on internal management estimates.
3) Based on 2024 Clearwater oil production of ~14 MMbbls.

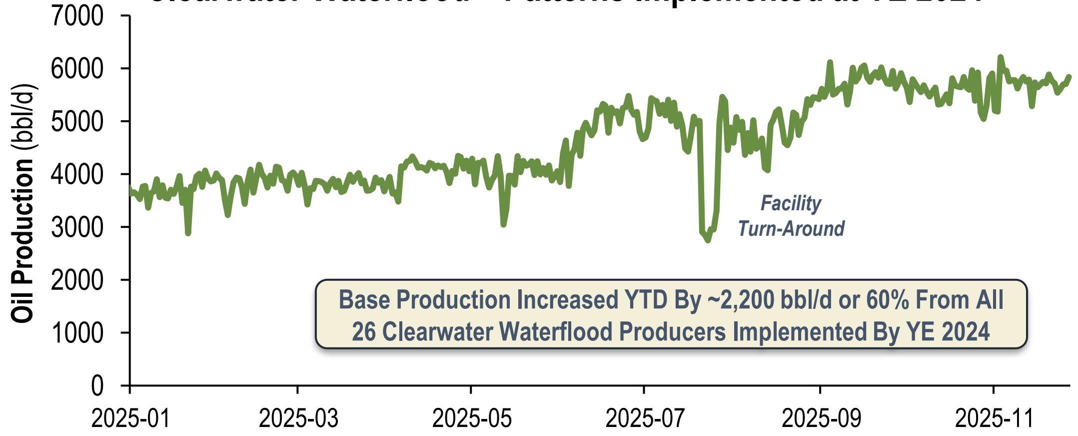
Clearwater Waterflood Progression

Advancing Secondary Recovery To Drive Incremental Resource Capture

Clearwater Injection & Production Under Waterflood



Clearwater Waterflood – Patterns Implemented at YE 2024



EUR's Up To 3x Primary Recovery

Demonstrated waterflood success across Clearwater fairway

Mitigating Decline

Reduces sustaining capital requirements

Demonstrated Repeatability

Positive waterflood responses across multiple sands, areas, and well designs

Superior Economics

Stacked multi-zone waterflood potential and large, contiguous resource result in economies of scale

>35% of Clearwater Production Under Waterflood by YE 2026

Waterflood Reserve Growth[1]

Performance Pointing Towards Further Technical Revisions

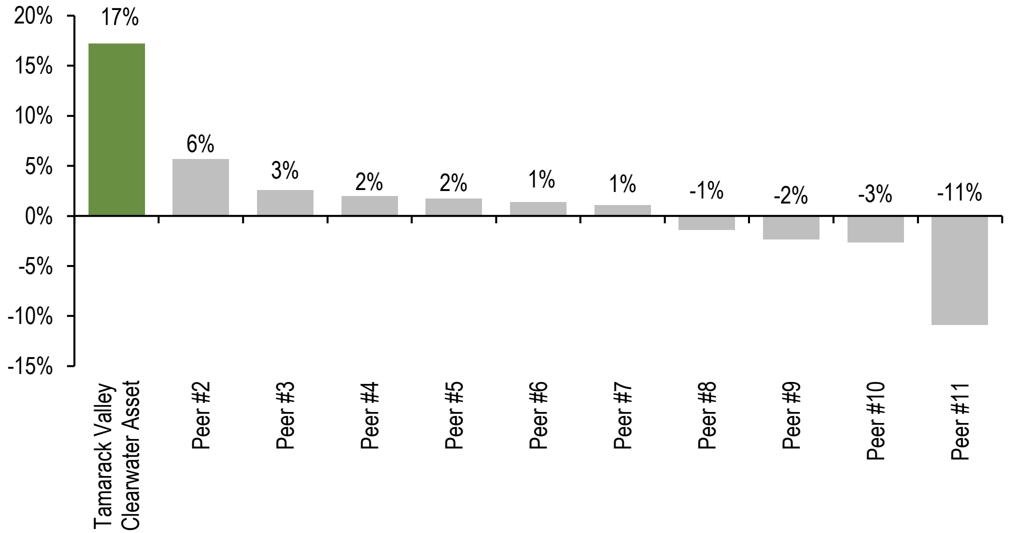
Clearwater Waterfloods Have Outperformed Reserve Forecasts

- Waterfloods achieving upward technical revisions as data matures and certainty grows

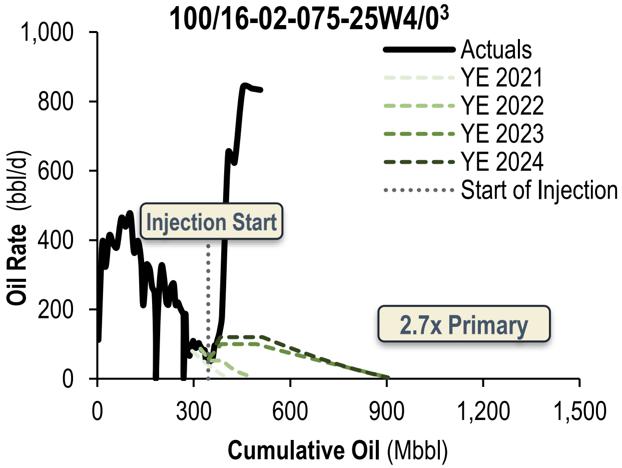
Waterflood Success Adds Tailwinds to Reserves

- Reserves added broadly every year the waterflood outperforms
- Clearwater Waterflood F&D <$6/boe on TPP basis in 2024

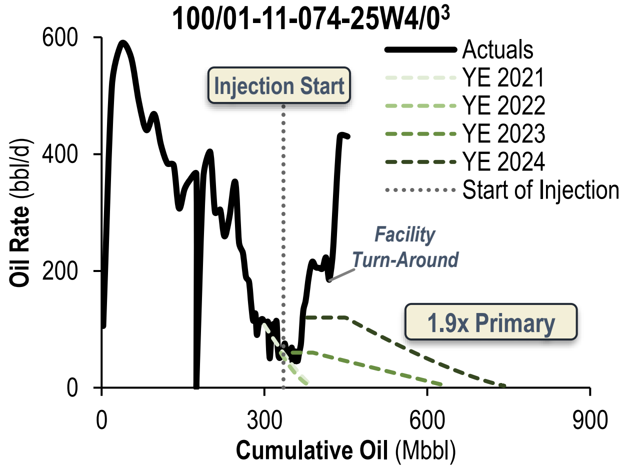
Total Proved Technical Revisions[2]
(as % of the reserves opening balance)



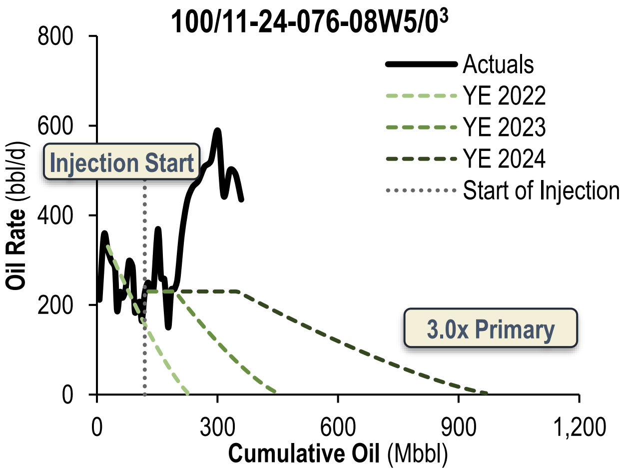
Marten Hills Stacked Pattern Pilot



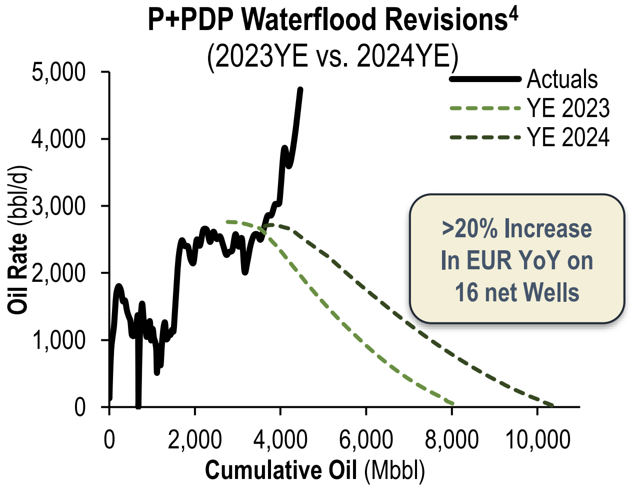
Marten Hills W Pattern Pilot



Nipisi Waterflood Pattern



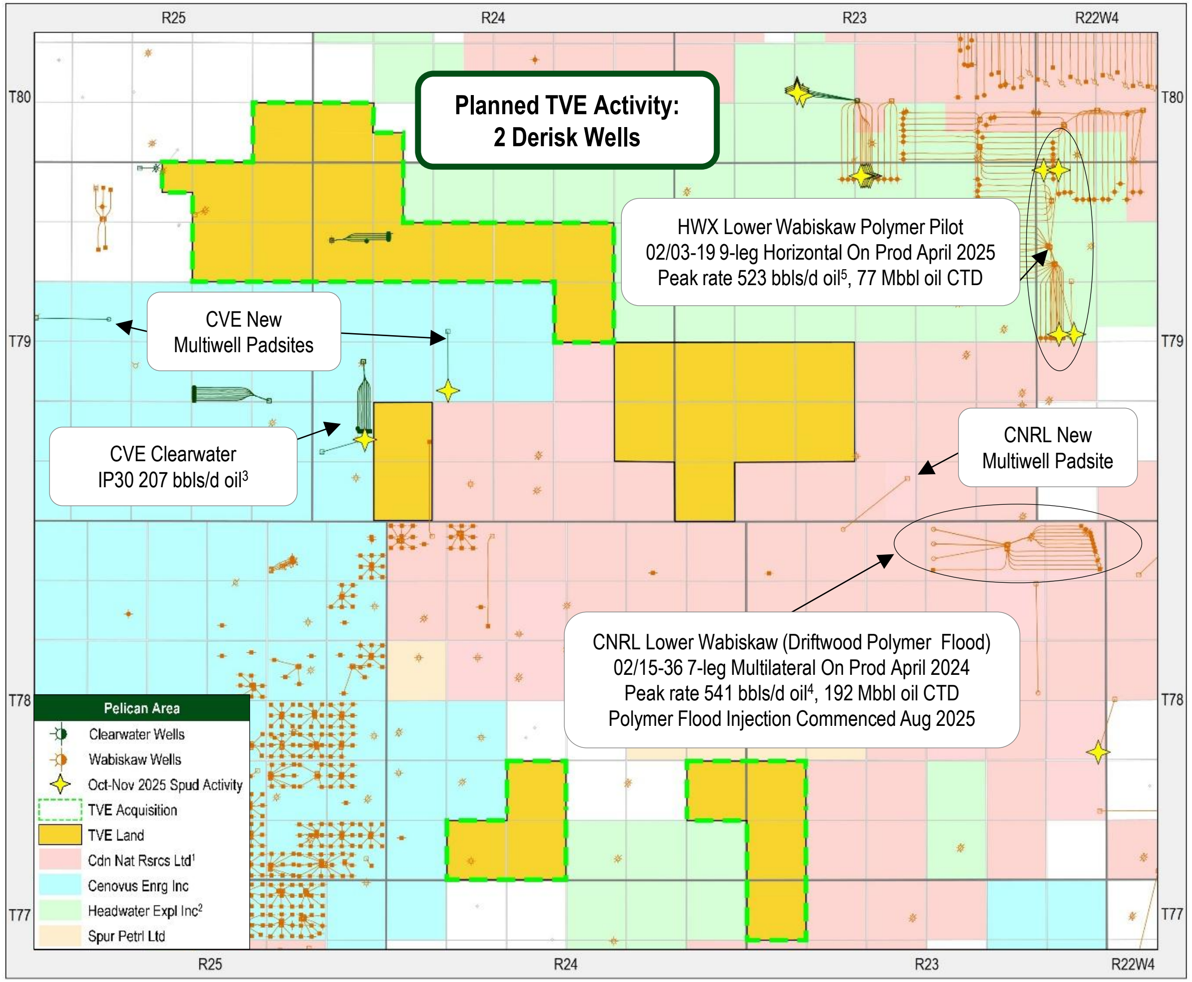
Nipisi & Marten Hills



F&D = Finding & Development Costs. See "Disclaimers – Oil & Gas Metrics".
1) See Disclaimers – "Reserves Disclosure".
2) Peer group includes AAV, ARX, ATH, BIR, CVE, KEC, KEL, MEG, NVA, TOU.
3) Based on TPP reserves for each respective year.
4) P+PDP revisions are technical revisions for producing wells under waterflood as at 2023YE.

Pelican: Future Growth Area

Derisking of Stacked Zone Potential; Upside to Updated 5-Yr Plan



Pelican

Land Position:

- ~32 gross sections (Oil Sands Tenure), including 21 sections acquired in Q4 2025

Stacked Development Upside:

- Lower / Middle Wabiskaw & Clearwater
- 630 MMbbl OOIP

Offsetting Activity:

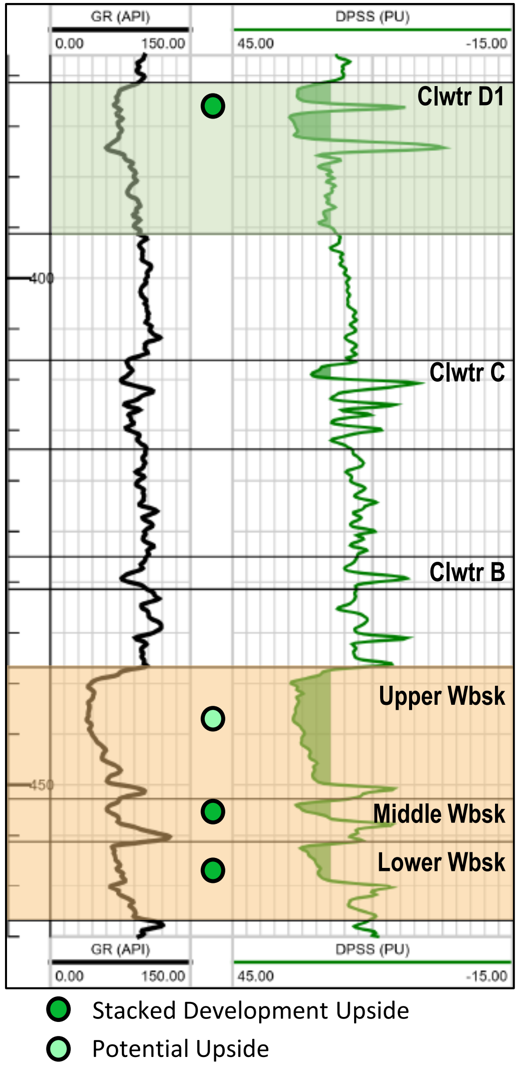
- Multiple operators with offsetting activity in both Clearwater and Wabiskaw zones

Secondary Recovery Schemes:

- Can increase recovery factors by 2-3x

Planned TVE Activity:

- Drill 2 derisk wells targeting Clearwater D1 and Middle/Lower Wabiskaw



1) Source: Canadian Natural Investor Open House Presentation, November 7, 2025.
2) Source: Headwater Exploration Inc. Corporate Presentation, October 2025.
3) Source: GeoScout August 2025 Producing Day Average Oil Rate.
4) Source: GeoScout Aug 2024 Producing Day Average Oil Rate.
5) Source: GeoScout June 2025 Producing Day Average Oil Rate.

Charlie Lake: Quick Cycle Times With High Rates Of Return

Scalable Light Oil Inventory

Inventory

- Top tier light oil reservoir continues to result in exceptional well performance
- Inventory supports 17,000 boe/d[1] for >10 years; multi-zone potential
- Extensive holdings across the Charlie Lake fairway; 236 net sections of land[2]

Economics

- Extended Reach Horizontal ("ERH") wells, multi-well pad development and stacked reservoir potential enhances capital efficiency
- Average breakeven costs of <$35/bbl WTI and first payout < 1 year
- Low-cost production additions and quick cycle times[3] result in high rates of return

Operational Reliability

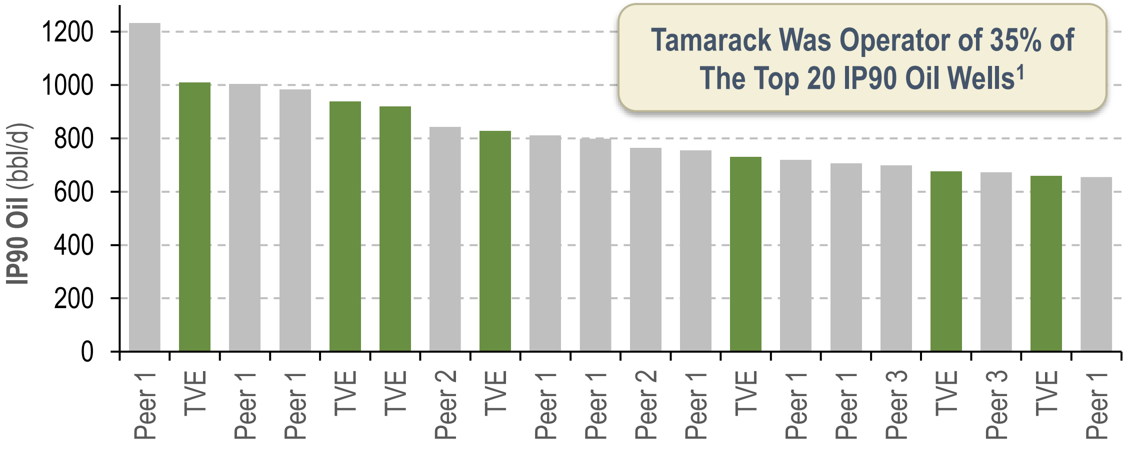
- Owned and operated infrastructure supports Wembley and Pipestone development
- Demonstrated enhanced reliability and improved operating expenses
- Infrastructure control provides ability to maximize initial rate potential

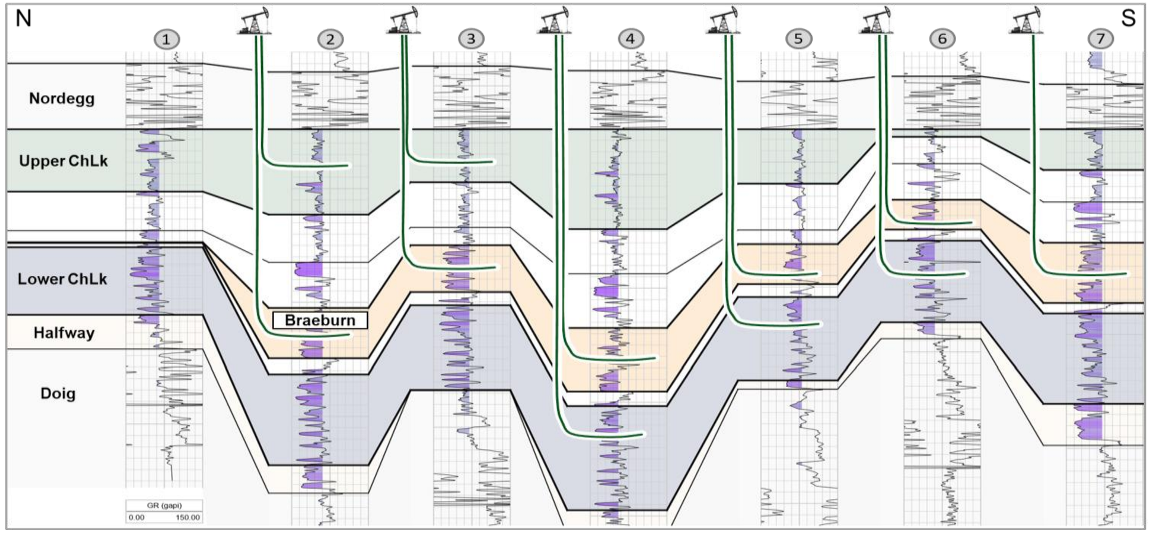
1) 17.0 Mboe/d comprised of approximately 9,100 bbl/d light and medium oil, 2,400 bbl/d NGL and 33.0 MMcf/d.
2) As at September 30, 2025.
3) Cycle times defined as pad rig release date to first oil, 2024 onstream average = 25 days.

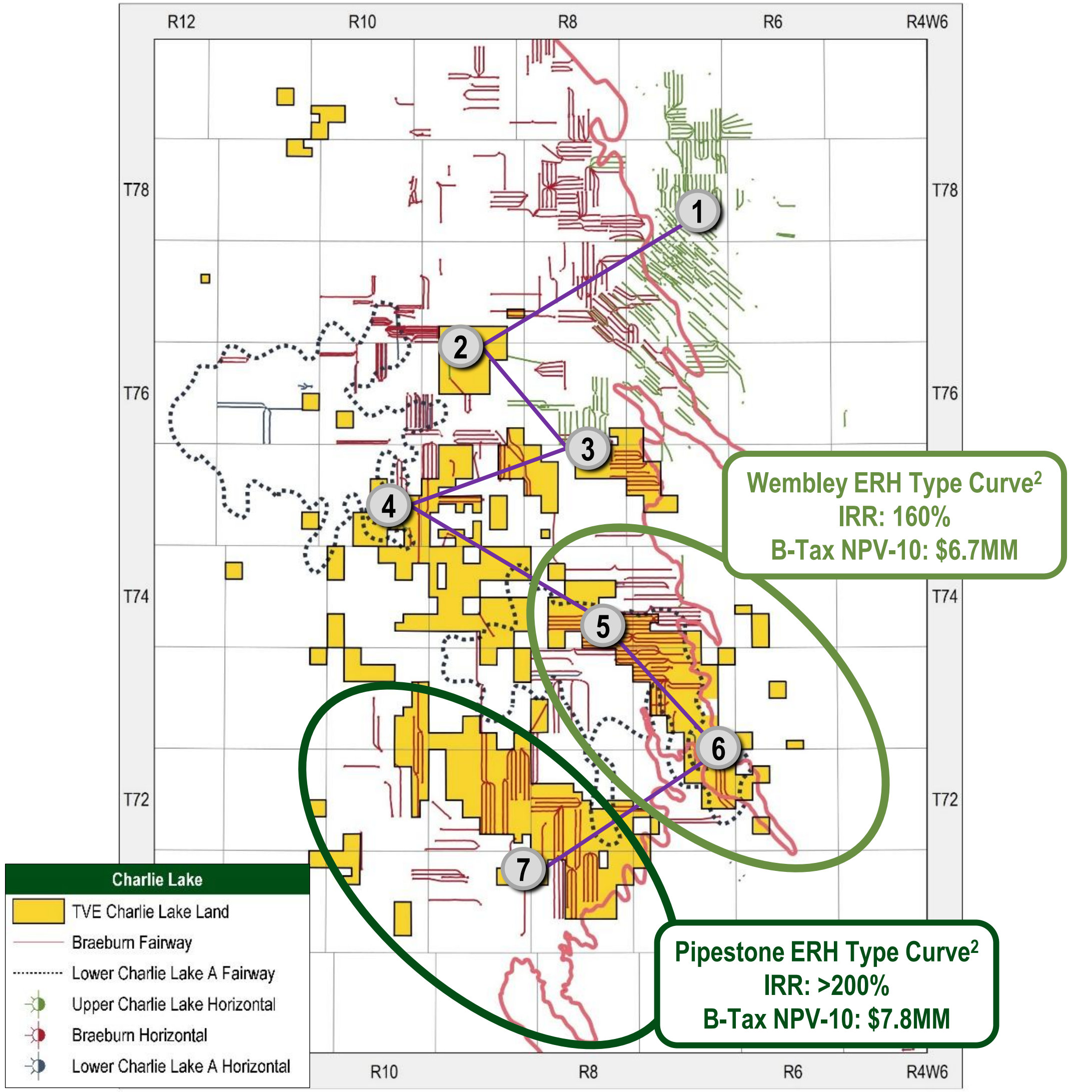
Charlie Lake: Superior Economics In The Heart of The Play

Well Design and Program Execution Driving Sustained Outperformance In Core Areas

Charlie Lake – 2024 & 2025 IP90 Oil Performance[1]







1) Source: GeoSCOUT, representing the peak three consecutive months for each Charlie Lake well brought on stream in 2024 and 2025, where at least 4 months of data is available.

2) Internal type curve, flat pricing assumes US$75/bbl WTI, US($3.00)/bbl Ed. Par / WTI Diff, CDN $3.00/GJ AECO and 1.30 C$/US$. Breakeven assumptions include 10% discount, 2% inflation.

Maximizing Long-Term Free Funds Flow[1] Per Share

Unprecedented Clearwater Waterflood Providing More For Less

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Asset Quality & Duration

- ✓ *>11 Bln bbls of OOIP[2] in the Clearwater*
- ✓ *Advancing EOR to drive incremental resource capture*

Proven Waterflood To Lower Declines

- ✓ *Unique Ability To Lower Declines & Grow Production*
- ✓ *Reducing sustaining capital requirements*

Compounding Returns to Shareholders

- ✓ **Commitment to Returns: Maximize Returns To Shareholders Across Commodity Cycles**
- ✓ **Leveraging Scale and Quality To Deliver Sustainable Long-Term Returns Per Share**
- ✓ **Financial Flexibility and Liquidity To Take Advantage of Strategic Opportunities and/or Growth**

Operational Execution

- ✓ *Premium netbacks, higher price realizations and lower cost structure*
- ✓ *<US$40/bbl Sustaining Breakeven (Unhedged)*

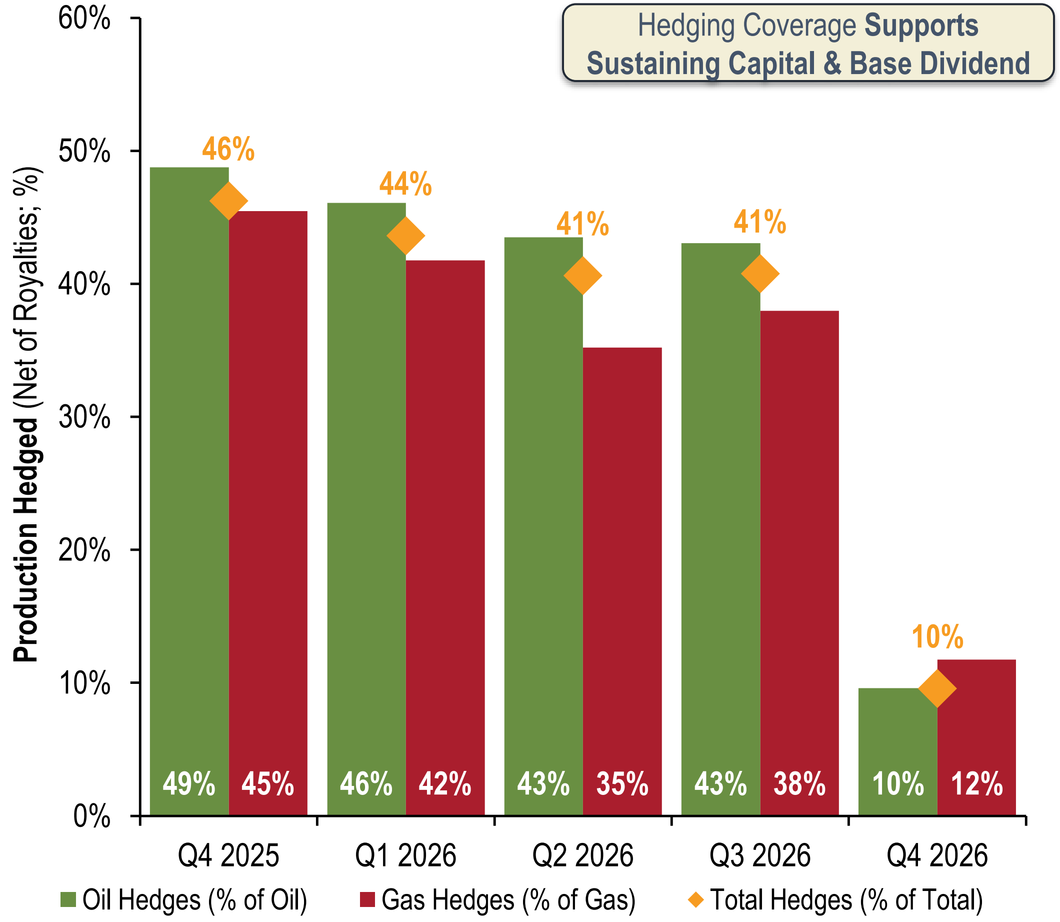
1) See Disclaimers – "Specified Financial Measures".
2) OOIP – original oil in place based on internal estimates. Excludes PrivateCo.

Appendix: Financial

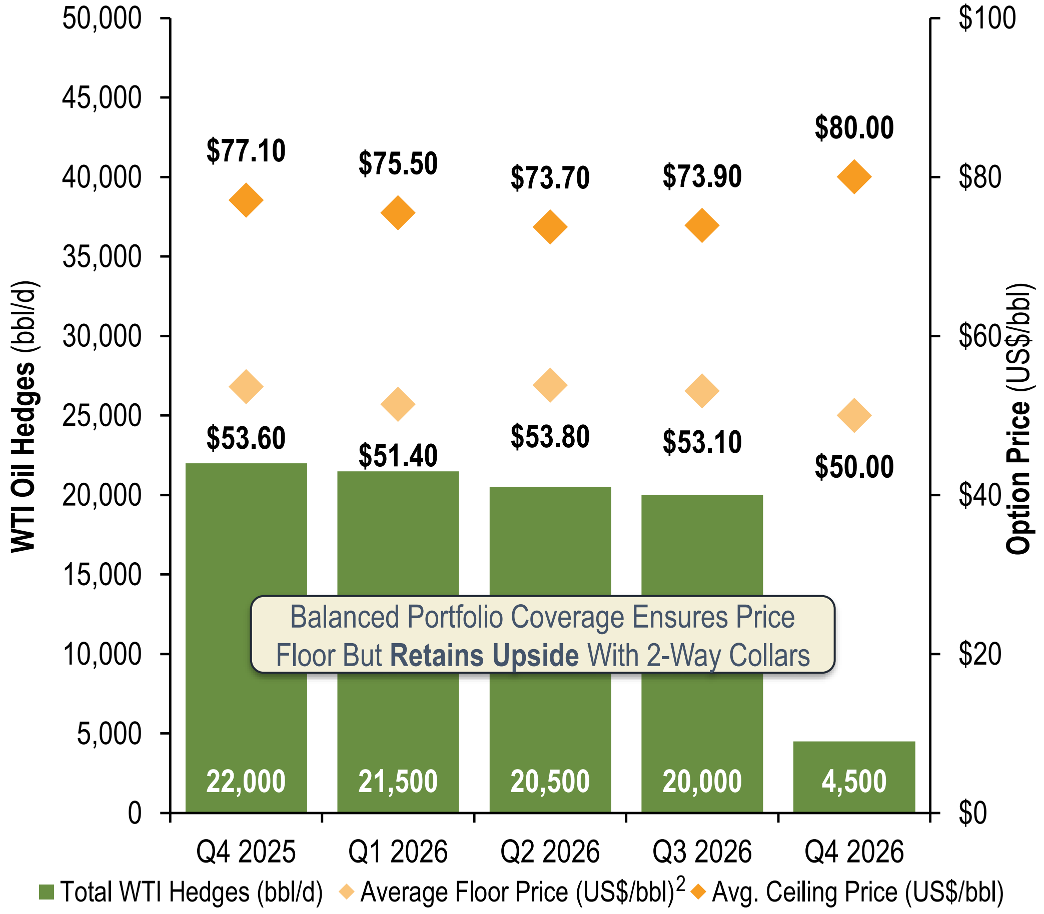
Risk Management[1]

Enhancing Certainty With Flexibility To Capture Upside Value

Percentage of Volume Hedged[1]



Weighted Average WTI Hedge Price[1]



1) Hedges in place as at Dec. 2, 2025. WTI hedge prices rounded to nearest $0.10/bbl. Percent hedged is net after royalties ("NAR").
2) Average floor price includes volume weighted average of puts from 2-way collar structures and fixed price hedges and excludes premiums.

Risk Management[1]

Enhancing Certainty With Flexibility To Capture Upside Value

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Oil Hedges	Units	Q4 2025	Q1 2026	Q2 2026	Q3 2026	Q4 2026
WTI Collars						
Volume	bbl/d	22,000	21,500	20,500	15,500	4,000
Avg. Floor Price	US$/bbl	$53.64	$51.40	$53.78	$54.03	$50.00
Avg. Ceiling Price	US$/bbl	$77.14	$75.53	$73.72	$73.89	$80.00
Avg. Premium	US$/bbl	$0.69	$0.52	$0.13	$0.44	$1.93
WTI Puts						
Volume	bbl/d	-	-	-	4,500	-
Avg. Put Price	US$/bbl	-	-	-	$50.00	-
Avg. Premium	US$/bbl	-	-	-	$2.78	-
WTI - WCS Basis Swaps						
Volume	bbl/d	16,000	17,500	-	-	-
Avg. Fixed Price	US$/bbl	($15.09)	($13.30)	-	-	-
WTI - MSW Basis Swaps						
Volume	bbl/d	5,000	3,500	3,500	3,500	3,500
Avg. Fixed Price	US$/bbl	($3.93)	($3.92)	($3.92)	($3.92)	($3.92)

Natural Gas Hedges	Units	Q4 2025	Q1 2026	Q2 2026	Q3 2026	Q4 2026
AECO 5A Swaps						
Volume	GJ/d	8,592	-	20,000	20,000	6,739
Avg. Fixed Price	C$/GJ	$2.69	-	$2.69	$2.69	$2.69
NYMEX-AECO 7A Basis Swaps						
Volume	MMBtu/d	7,459	11,250	-	-	-
Avg. Floor Price	US$/MMbtu	($1.46)	($1.46)	-	-	-
NYMEX Collars						
Volume	MMbtu/d	14,918	22,500	-	-	-
Avg. Floor Price	US$/MMbtu	$3.50	$3.50	-	-	-
Avg. Ceiling Price	US$/MMbtu	$5.20	$5.20	-	-	-

Gas Hedges For Winter & Summer Term (Nov. – March; Apr. – Oct.)

FX Hedges	Units	Q4 2025	Q1 2026	Q2 2026	Q3 2026	Q4 2026
US$/C$ Collars						
Notational	US$MM/Month	$5.0	$14.0	$14.0	$8.0	$8.0
Avg. Floor Price	US$/C$	1.336	1.343	1.343	1.351	1.351
Avg. Ceiling Price	US$/C$	1.394	1.396	1.396	1.395	1.395
US$/C$ Swaps						
Notational	US$MM/Month	$3.0	$7.0	$7.0	$5.0	$5.0
Avg. Fixed Price	US$/C$	1.348	1.363	1.363	1.371	1.371
US$/C$ Variable Collars[(2)]						
Notational	US$MM/Month	$31.5	$14.0	$14.0	$7.0	$7.0
Avg. Floor Price	US$/C$	1.342	1.349	1.349	1.353	1.353
Avg. Ceiling Price	US$/C$	1.402	1.420	1.420	1.426	1.426
Avg. Knock-In Price	US$/C$	1.372	1.388	1.388	1.390	1.390
US$/C$ Variable Collars (Ext. Option)[(3)]						
Notational	US$MM/Month	$3.0	-	-	-	-
Avg. Floor Price	US$/C$	1.350	-	-	-	-
Avg. Ceiling Price	US$/C$	1.442	-	-	-	-
Avg. Knock-In Price	US$/C$	1.387	-	-	-	-

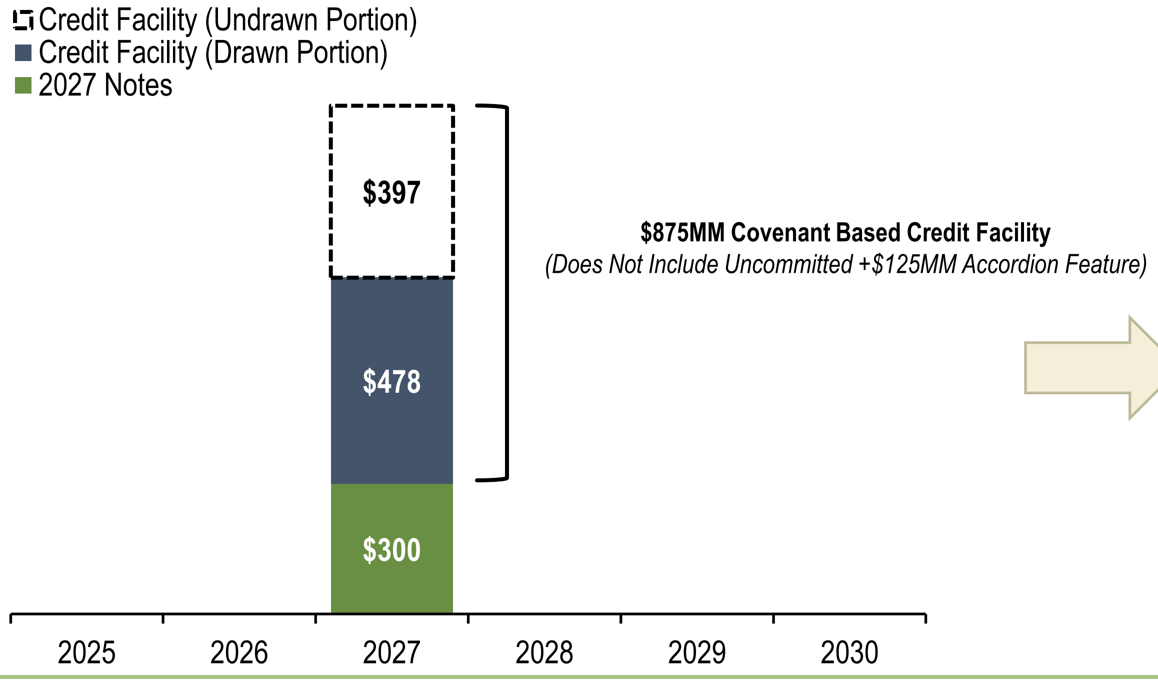
1) Hedges in place as at Dec. 2, 2025.
2) If the average rate for the month exceeds the call, Tamarack receives an average rate forward equivalent to the knockout rate.
3) Includes an extension option at the end of a collar, at the counterparty's option, for a predetermined term, notational value and swap rate. Extension contracts not included in this table.

Long Dated Laddered Credit Structure

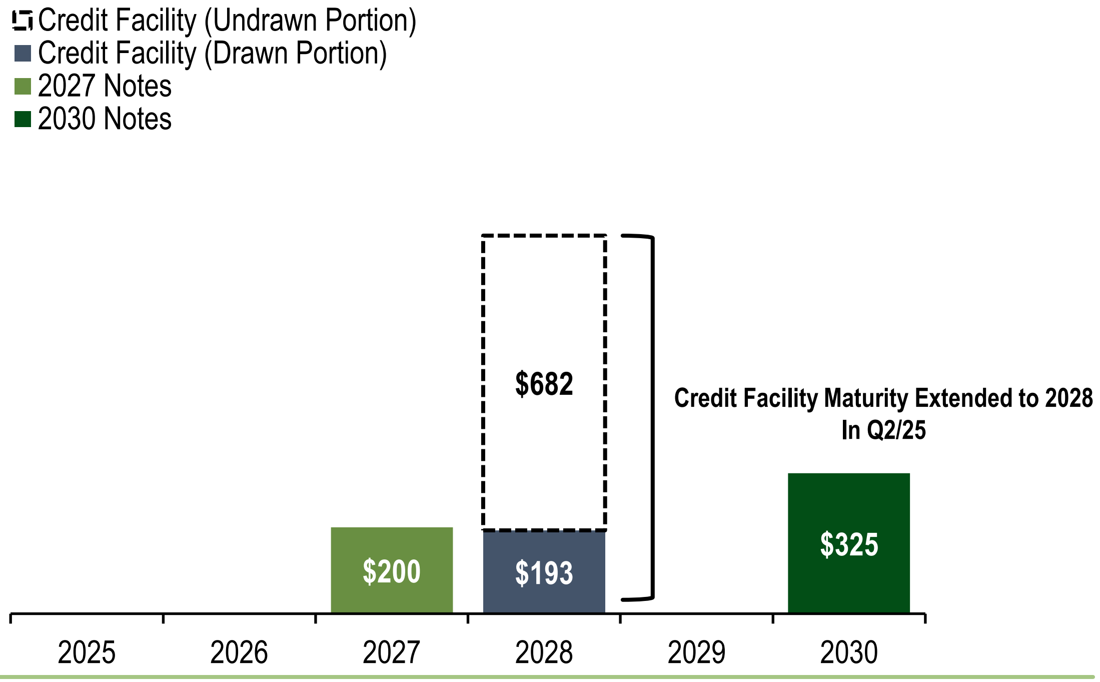
Robust Credit Profile With Significant Liquidity & Low Debt/EBITDA Ratios

- On Jun. 6, 2025, Tamarack's $875MM credit facility was amended primarily to extend the maturity date of the facility by one year to Apr. 30, 2028.
- On Jul. 25, 2025, Tamarack issued $325MM aggregate principal amount of 6.875% interest-bearing senior unsecured notes due July 2030
  - Net proceeds were utilized primarily to repay amounts outstanding under the Credit Facility and redeem $100MM of the 2027 Notes
- Sep. 30, 2025, Tamarack had net debt of ~$631MM (including assets held for sale; ~0.6x Nebt Debt/LTM EBITDA)[1]

Q1 2025 (Prior To Credit Facility Maturity Extension)



Q3 2025 (Excluding Proceeds From East Disposition)[2]



1) See disclaimers - "Specified Financial Measures"; LTM EBITDA – Last 12 months EBITDA.
2) Credit facility draw includes $3.7 MM of LCs.

Tailwinds For Canadian Heavy Producers

Tamarack Is In An Excellent Position to Capture Strong Netbacks Now & In The Future

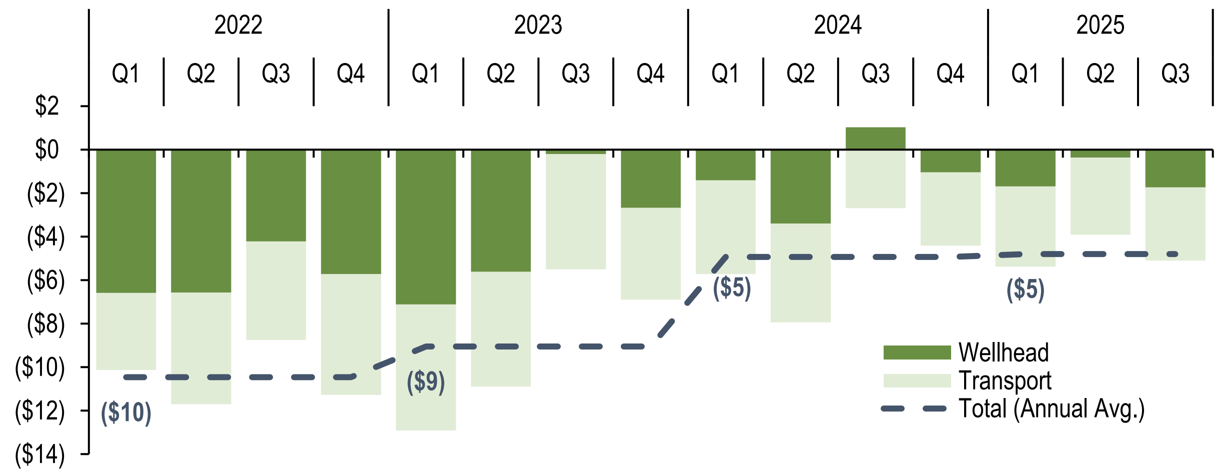
WCS Continues to Trade Exceptionally Strong Since the Start-Up of TMX (US$9 - US$14 / bbl since Jul. 2024); Expected to Stay Strong in Future Years:

- Additional trunkline plans from Alberta hubs to exceed producer development plans
- Increasing access to tidewater & global refining market
- Lack of alternative heavy feedstock for USGC refiners

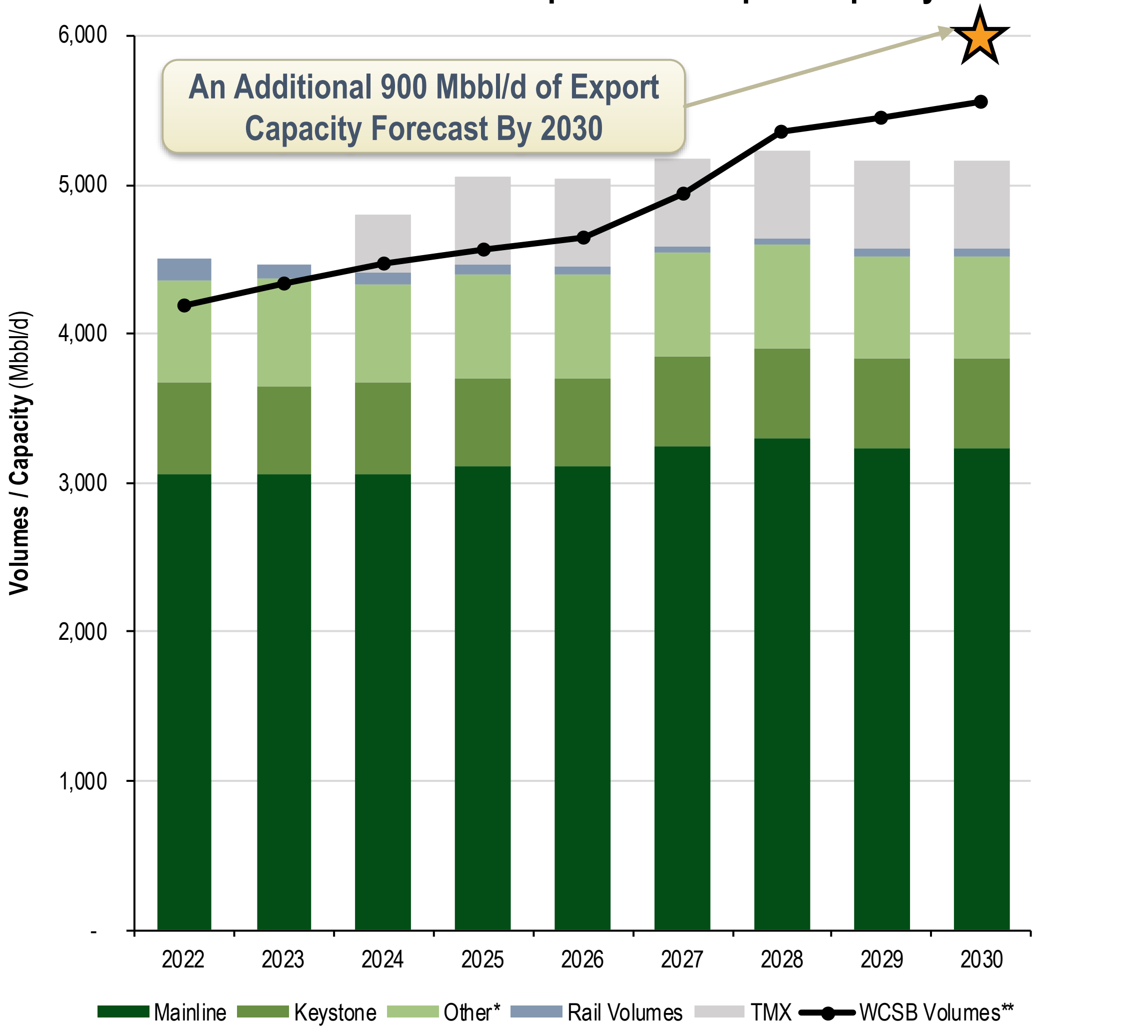
Tamarack Executed its Strategic Plan to Significantly Improve Heavy Oil Wellhead And Transportation Deductions:

- Pipe connections with long-term regional egress aligning with development plans
- Reducing blending & trucking requirements
- Selling premium product to market (Clearwater Heavy pricing)

Improving Heavy Oil Wellhead & Transport Costs ($/boe)



WCSB Crude Volumes vs. Operational Export Capacity

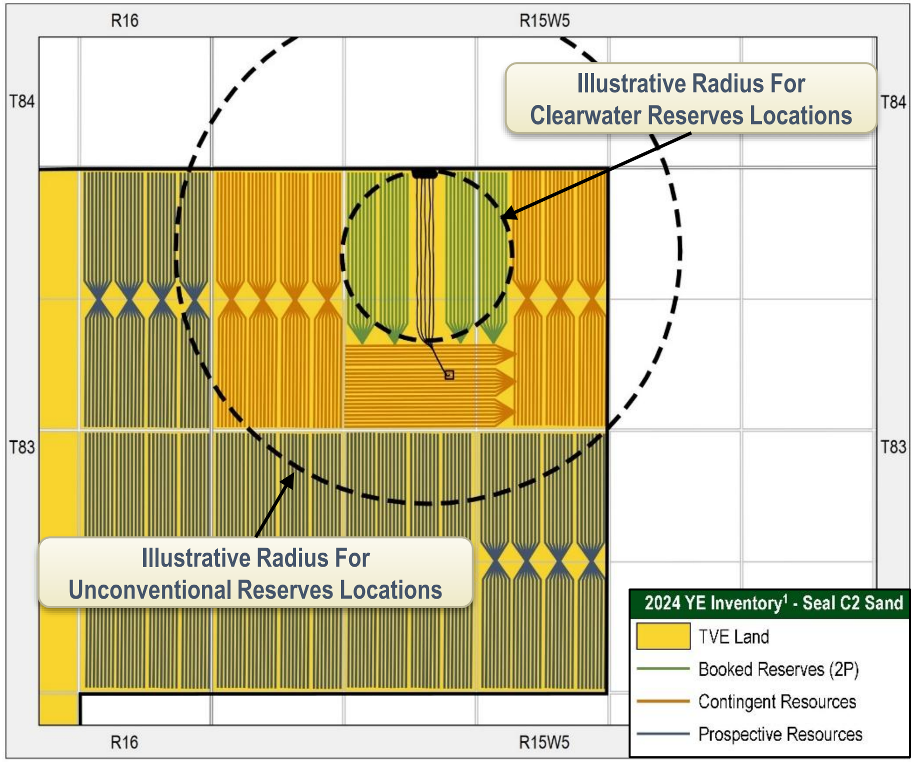


WCSB Crude Volumes vs. Export Capacity Sources: Peters & Co. Limited estimates, company reports, and government data.
Note: *Other includes Express, Rangeland and Trans Mountain pipelines.
**Volumes presented net of domestic WCSB refinery demand. TMX presented as half capacity in 2024 for illustrative purposes.

Appendix: Clearwater Assets

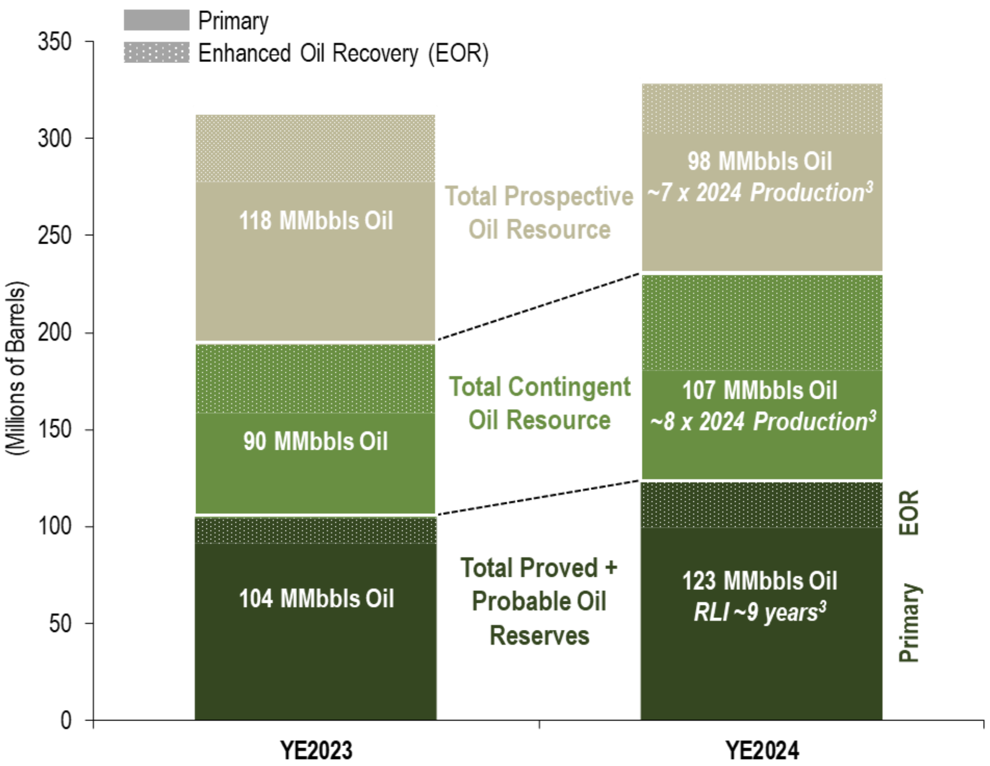
Clearwater Reserves and Resources

Successful Conversion of Resources to Reserves Reflected In Year-Over-Year Growth



- Much tighter radius for booking undeveloped reserves in conventional plays like the Clearwater and Charlie Lake relative to unconventional plays (i.e. Montney)
- Results in significant inventory with similar reservoir left to be classified as contingent or prospective resources

Clearwater Reserves & Resources YoY Growth[1,2]



- Successful promotion of resources through delineation of inventory and waterflood in 2024 resulted in 19% growth in Contingent Oil Resource and 18% growth in TPP Oil Reserves

1) Based on McDaniel & Associates Consultants Ltd. Resource Report effective December 31, 2023 and 2024. See Disclaimers – "Resource Disclosure".
2) Reserves, contingent resources, and prospective resources should not be combined without recognition of the significant differences in the criteria associated with their classification.
3) Based on 2024 Clearwater oil production of ~14 MMbbls.

Clearwater Economics: Primary Recovery

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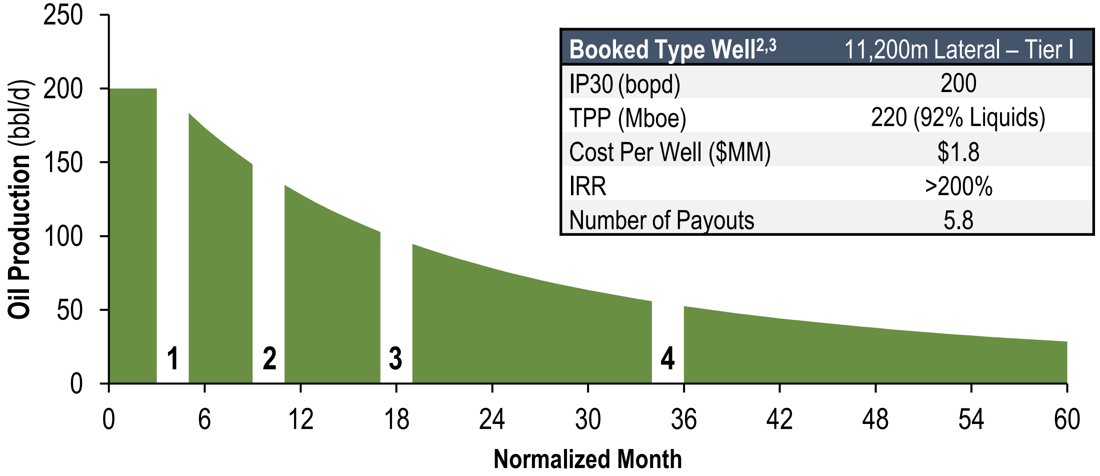
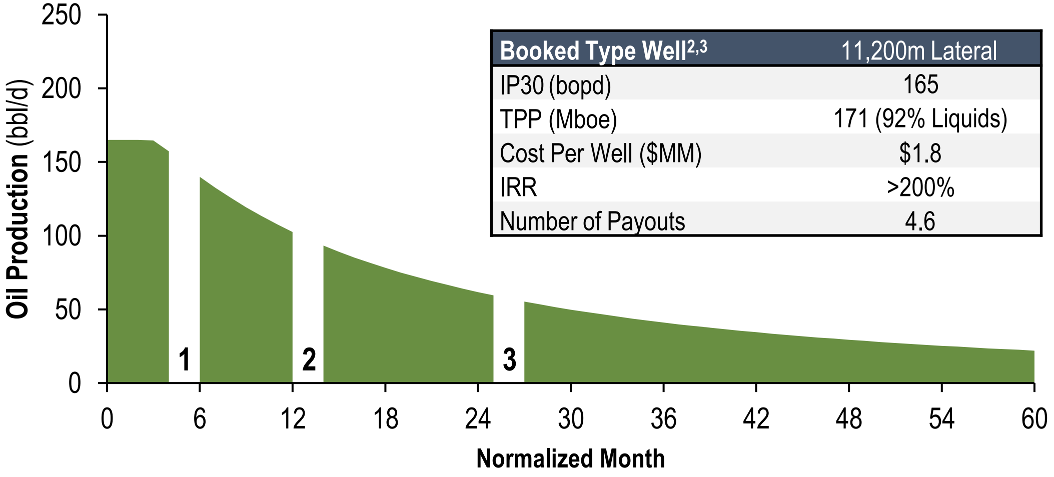
Multiple Payouts Compound Free Funds Flow[1] Growth

West Marten "B" Sand



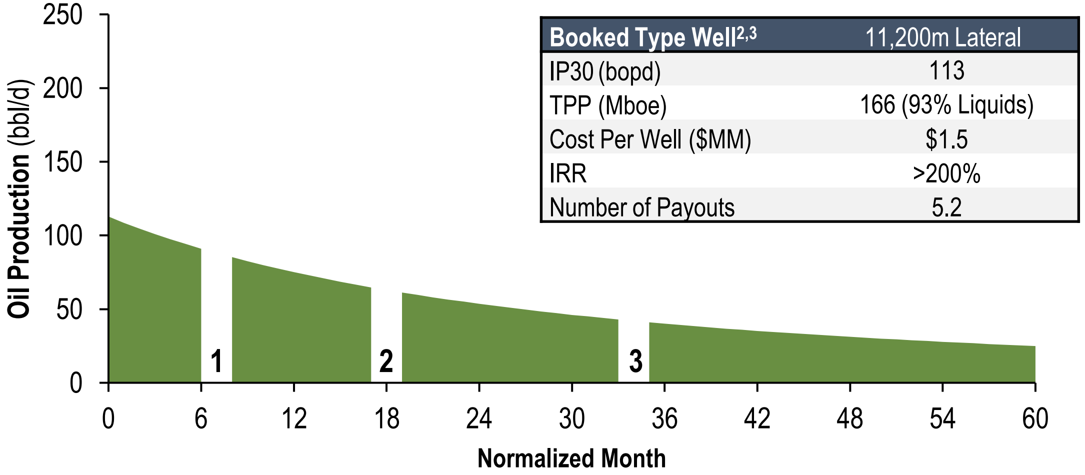
Booked Type Well[2,3]	11,200m Lateral – Tier I
IP30 (bopd)	200
TPP (Mboe)	220 (92% Liquids)
Cost Per Well ($MM)	$1.8
IRR	>200%
Number of Payouts	5.8

West Marten "C" Sand



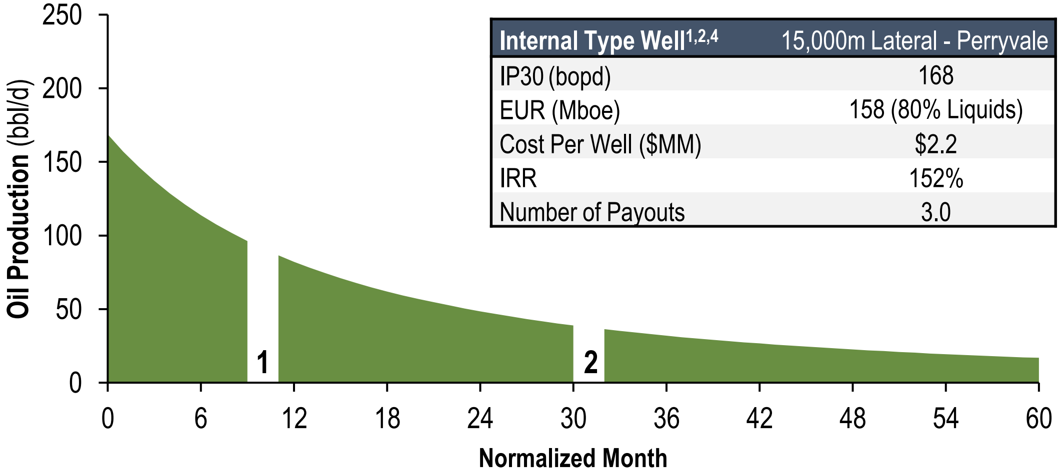
Booked Type Well[2,3]	11,200m Lateral
IP30 (bopd)	165
TPP (Mboe)	171 (92% Liquids)
Cost Per Well ($MM)	$1.8
IRR	>200%
Number of Payouts	4.6

Marten Hills "C" Sand



Booked Type Well[2,3]	11,200m Lateral
IP30 (bopd)	113
TPP (Mboe)	166 (93% Liquids)
Cost Per Well ($MM)	$1.5
IRR	>200%
Number of Payouts	5.2

South Clearwater Fan

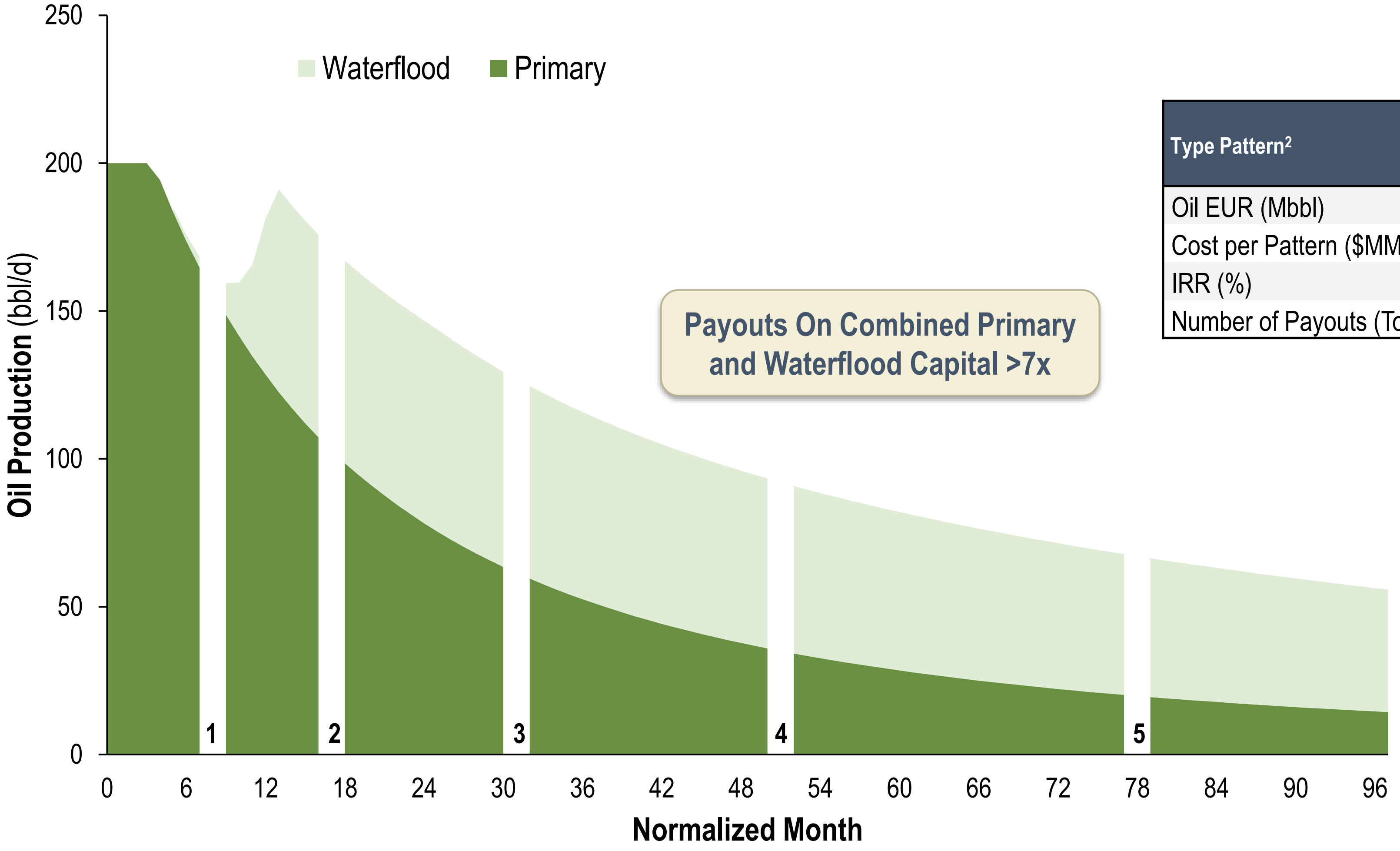


Internal Type Well[1,2,4]	15,000m Lateral - Perryvale
IP30 (bopd)	168
EUR (Mboe)	158 (80% Liquids)
Cost Per Well ($MM)	$2.2
IRR	152%
Number of Payouts	3.0

1) See Disclaimers – "Specified Financial Measures"; based on internal management estimates.
2) Flat pricing assumes US$75/bbl WTI, US($13.50)/bbl WCS Diff, CDN $3.00/GJ AECO and 1.30 C$/US$.
3) Based on McDaniel & Associates Consultants Ltd Reserves Report effective December 31, 2024.
4) Based on internal estimate using most recently available data.

Clearwater Waterflood – New Injector Drill Type Curve

Secondary Recovery Provides Additional Payouts & Reduces Long-Term Sustaining Capital



Waterflood Economics

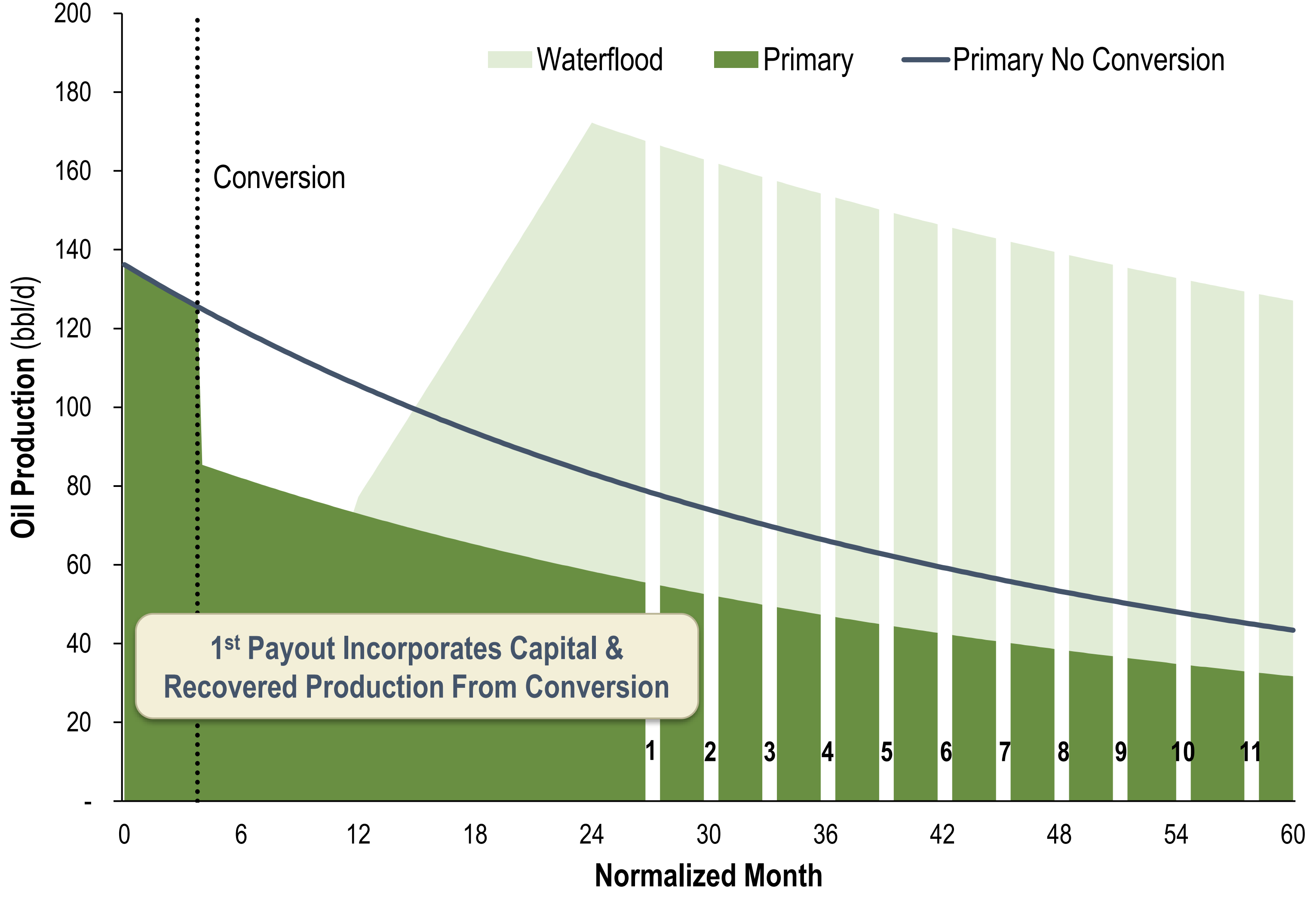
Type Pattern[2]	Primary[3] – West Marten "B" Sand Tier I	Waterflood Injector Wedge[4] – Internal Estimate	Total Project
Oil EUR (Mbbl)	205	308	513
Cost per Pattern ($MM)	$1.8	$1.2	$3.0
IRR (%)	>200%	100%	>200%
Number of Payouts (Total)	5.8	9.0	7.1

- **Early Success:** Waterflood has been successfully implemented broadly across the Clearwater
- **Asset Duration:** Mature patterns indicate up to 3x recovery compared to primary development
- **Free Funds Flow:** Significant free funds flow[1] generated from incremental payouts of waterflood capital

1) See Disclaimers – "Specified Financial Measures"; based on internal management estimates
2) Flat pricing assumes US$75/bbl WTI, US($13.50)/bbl WCS Diff, CDN $3.00/GJ AECO and 1.30 C$/US$.
3) Based on McDaniel & Associates Consultants Ltd Reserves Report effective December 31, 2024.
4) Waterflood incremental wedge based on internal estimates for a single leg injector drill with 2-mile lateral length achieving a total pattern oil recovery equal to 2.5x primary at an incremental capital cost of $1.2 MM.

Marten Hills Waterflood – Injector Conversion Typical Type Curve

Low-Cost Conversions Provide Substantial Returns



Waterflood Conversion Economics

Type Pattern[2]	Waterflood Wedge[1] – Internal Estimate
Incremental Oil EUR (Mbbl)	850
Conversion Cost ($MM)	$0.4
IRR (%)	>100%
Number of Payouts (Total)	>30

- Increased injection rates at Marten Hills have led to faster waterflood response and quicker payouts
- Conversions can payout in under two years followed by recurring payouts every 3-4 months due to stable production profile and low initial capital requirement
- Large OOIP and strong waterflood performance suggest over 10 payouts within 5 years of implementation, with ultimate recovery of 2.5x - 3.0x primary performance

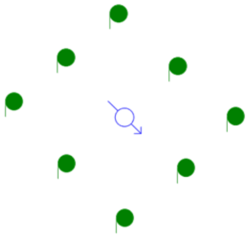
1) See Disclaimers – "Specified Financial Measures"; based on internal management estimates.
2) Flat pricing assumes US$75/bbl WTI, US($13.50)/bbl WCS basis, CDN $3.00/GJ AECO and 1.30 US$/C$.
3) Waterflood incremental wedge based on internal estimates for a single waterflood conversion achieving a total pattern oil recovery equal to 2.5x primary at an incremental capital cost of $0.4 MM.

Well Designs Reducing Water Velocity

Lateral Length Providing Extremely Low Flood Front Velocities

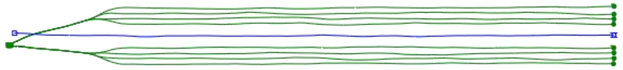
Conventional Vertical Injection Well

- 139.7mm casing
- 20m net pay



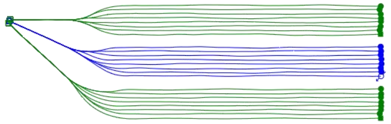
Clearwater Single-Leg Injector

- 159mm hole diameter
- 2 mile lateral length (3200m)

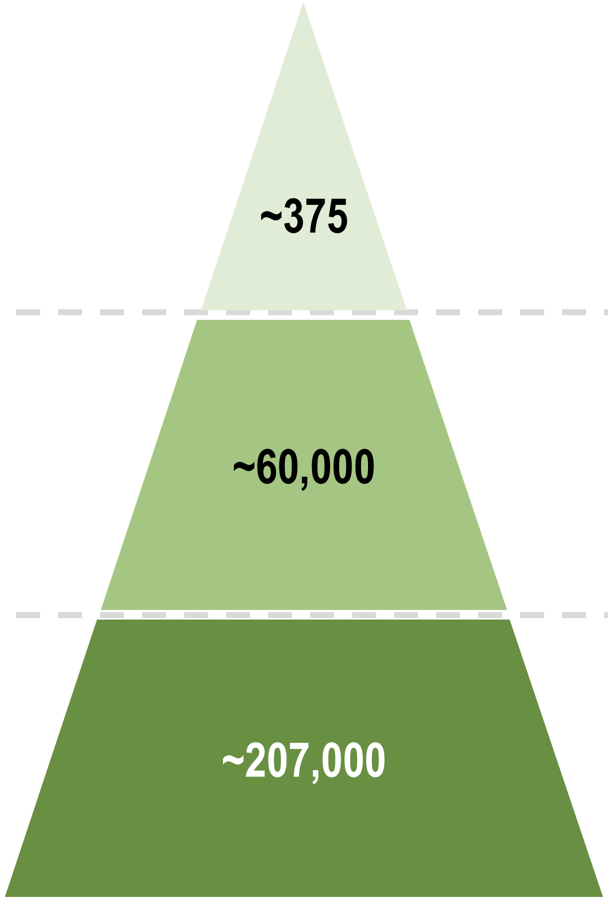


Clearwater Multilateral Injector

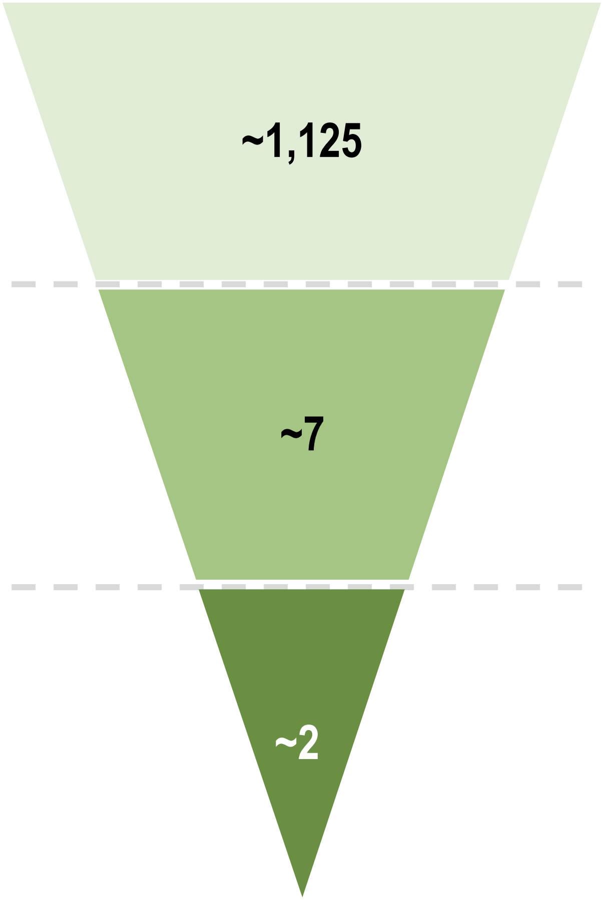
- 159mm hole diameter
- 8 leg Multilateral (~11,500m TLL)



Area[1] Open To Flow (m^2)



Water Velocity[1] at 1,000 bwpd Injection (cm/d)

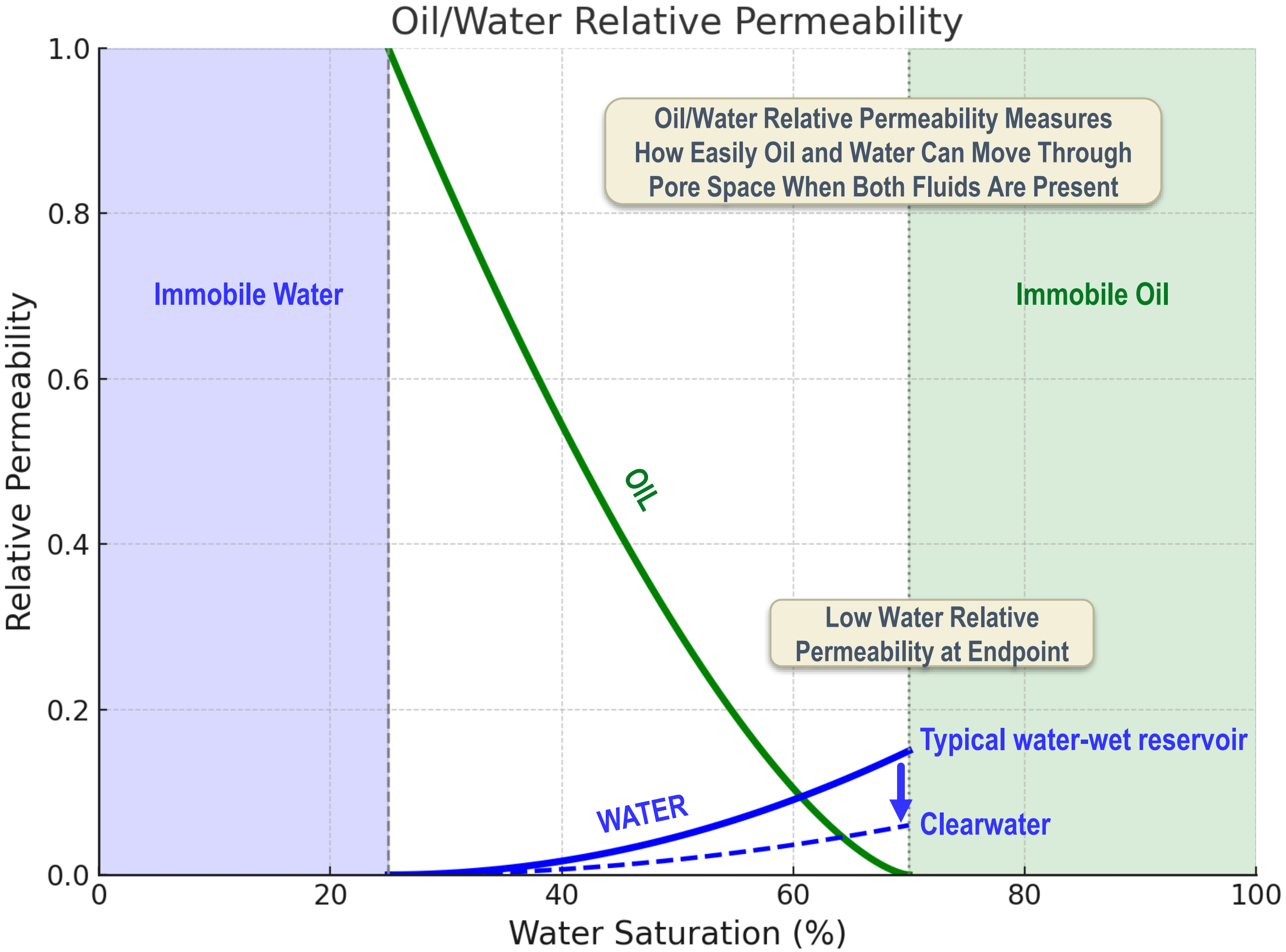


Horizontal and Multilateral Wells Provide Extremely Large Areas Open To Flow, Which Results In Extremely Low Fluid Velocities In The Reservoir

1) Area and Velocity calculated 3m from wellbore. Assumes Porosity = 25%; 15% of mobile fluid recovered in swept zone at breakthrough.

Clearwater Waterflood Relative Permeability

Low Relative Permeability to Water Driving Strong Conformance and Recovery



Clearwater Reservoirs Have Low Relative Permeability To Water at The Endpoint (Residual Oil Saturation)

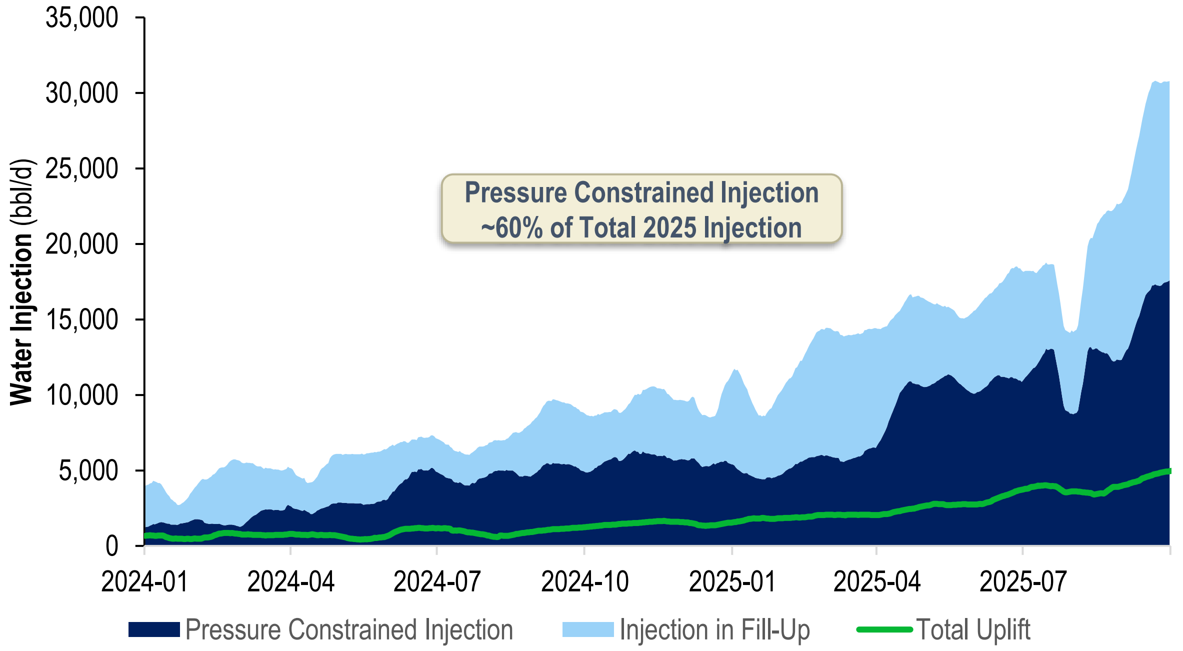
- Means that even after water invades a pore space, water does not flow easily
- Forces the water to find new paths through the reservoir, improving the sweep and pushing oil from unswept zones
- Reduces early channeling or fingering of water, helping displace more oil toward the producers
- Results in a more gradual rise in water cut, prolonging the period of high oil production rates

Low Relative Permeability to Water Ultimately Results in Increased Sweep Efficiency and Recovery

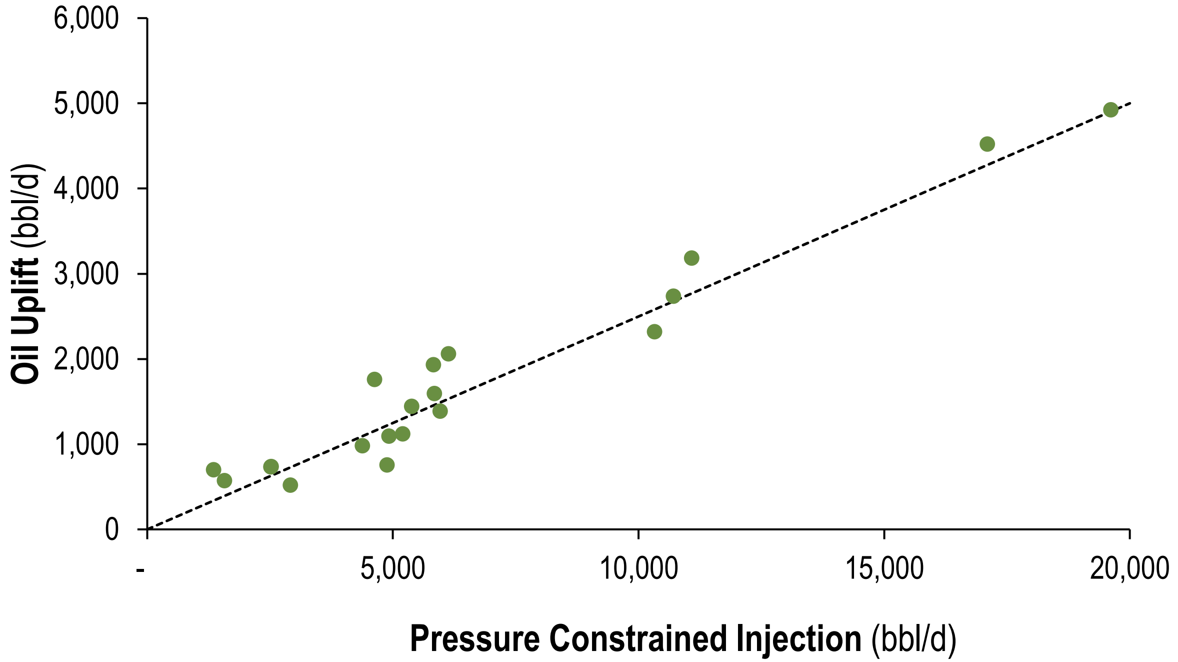
Injection Volume as a Leading Indicator

Correlation of Injection to Production Uplift

Water Injection and Oil Uplift



Oil Uplift vs. Pressure Constrained Injection



Pressure Regimes: Water Injection can be categorized according to pressure observed

- **Injection in Fill-up[2]**: Pre-response phase occurs prior to observing Injection Pressure
- **Pressure Constrained Injection[1]**: When injection pressure is observed, uplift follows shortly after

Strong Correlation

Pressure Constrained Injection Volume and Total Uplift Correlate to a ratio of ~4:1

1) Pressure constrained Injection equals total water injection into injectors with sustained or increasing injection pressure
2) Injection in Fill-Up equals total water injection less Pressure Constrained Injection

Repeatable Returns From the Flood

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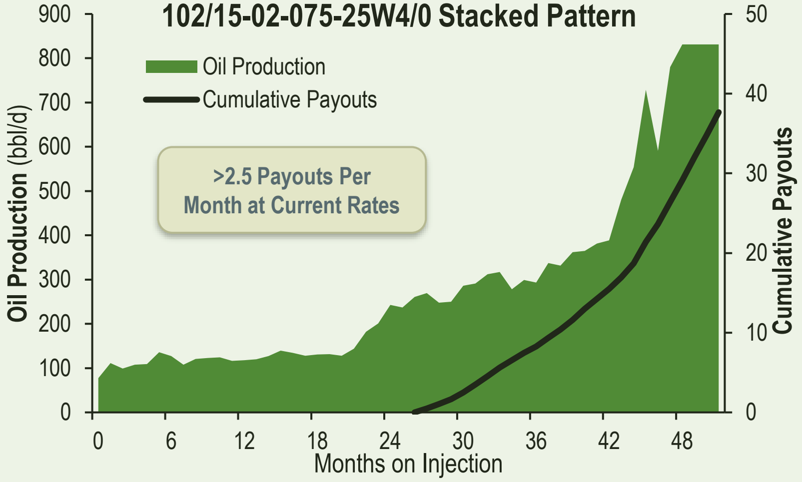
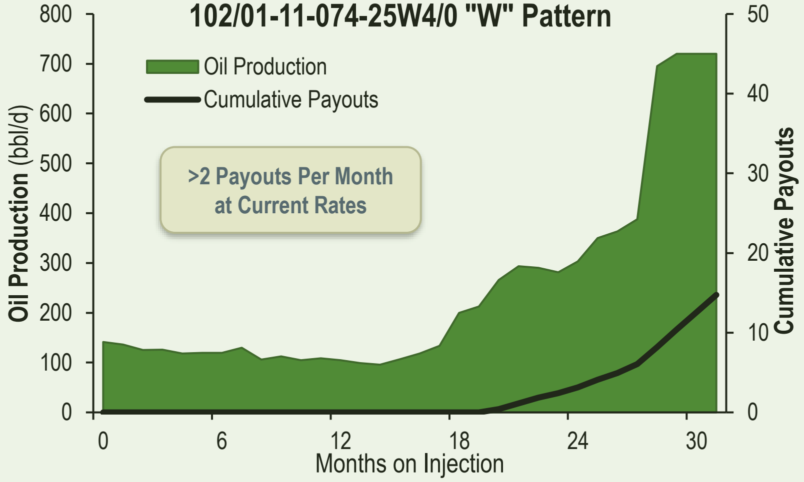
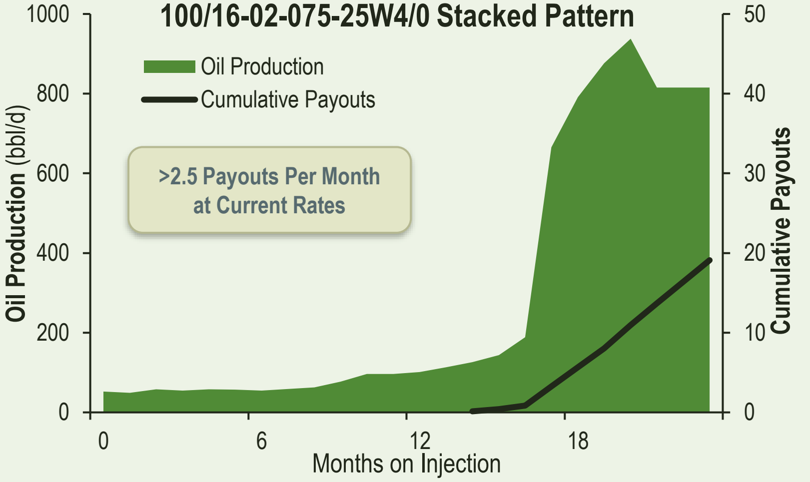
Demonstrated, Multi-Payout[1,2] Wells Across the Assets

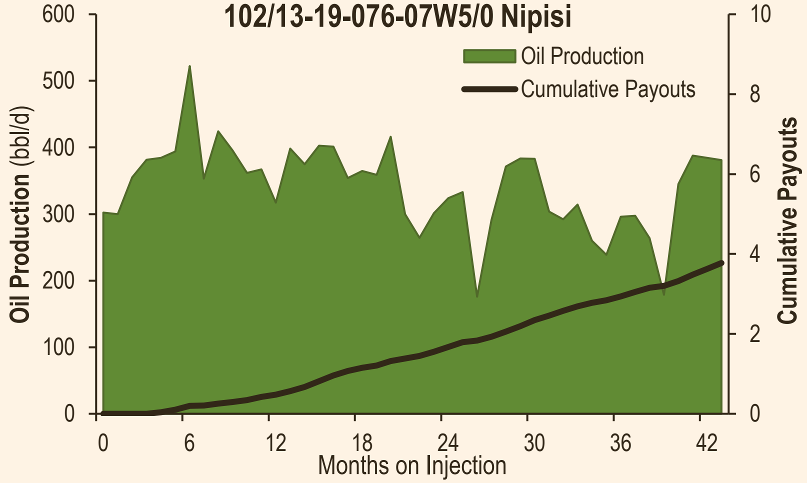
Primary Conversions

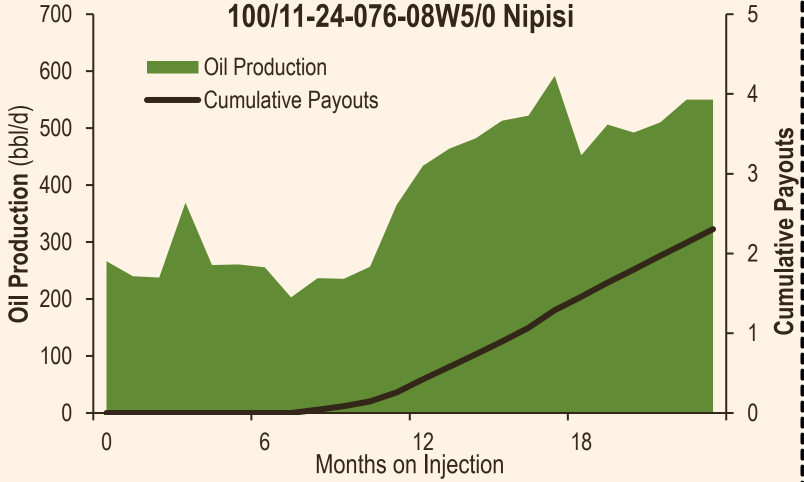






New Injectors





Multi-Payout Performance: Field examples confirm strong, repeatable payouts[1,2]

Marten Hills

- High post-response rates providing multiple payouts per month
- "W" pattern response now comparable to more-established Stacked Patterns

Nipisi

- With multiple payouts achieved, still producing at or near peak rates.

1) Payouts are calculated using historical received pricing and forward strip pricing (November 12, 2025) to the end of 2025
2) Payouts are calculated on the incremental oil from waterflood using half-cycle capital assumptions

Corporate Information

tamarack valley ENERGY

Executive

Brian Schmidt (Aakaikkitstakii)	Founder & Chief Executive Officer
Steve Buytels	President
Kevin Johnston	VP, Finance & Chief Financial Officer
Ben Stoodley	VP, Engineering
Lynne Chrumka	VP, Exploration
Scott Shimek	VP, Production & Operations
Rocky Baker	VP, Marketing & Commercial

Board of Directors

John Rooney [1, 3, 4]	Chairman of the Board
Brian Schmidt (Aakaikkitstaki)	Founder & Chief Executive Officer
Caralyn Bennett [2, 4]	Independent Director
Craig Bryksa	Independent Director
John Leach [1, 2]	Independent Director
Marnie Smith [1, 3]	Independent Director
Rene Amirault [4]	Independent Director
Robert Spitzer [2, 3]	Independent Director
Shannon Joseph[4]	Independent Director
Sony Gill	Corporate Secretary

Legal Counsel

Stikeman Elliott LLP

Banking Syndicate Co-Leads

National Bank of Canada
Royal Bank of Canada

Auditors

KPMG LLP

Independent Reserve Evaluators

GLJ Ltd.
McDaniel and Associates Consultants Ltd.

Head Office

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Calgary, AB T2P 1G1

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Investor Contact Information

Brian Schmidt	**Steve Buytels**	**Kevin Johnston**
Founder & Chief Executive Officer	President	VP, Finance & Chief Financial Officer

1) Member of Audit Committee of the Board of Directors.
2) Member of the Reserves Committee of the Board of Directors.
3) Member of the Governance & Compensation Committee of the Board of Directors.
4) Member of the Environment, Safety & Sustainability Committee.

Disclaimers

Forward Looking Statements: Certain information included in this presentation constitutes forward-looking information under applicable securities legislation. Forward-looking information typically contains statements with words such as “budget”, “guidance”, “outlook”, "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", "project" or similar words or variations (including negative and grammatical variations) suggesting future outcomes or statements regarding an outlook. Forward-looking information in this presentation may include, but is not limited to, statements about Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") as they relate to: Tamarack's corporate and waterflood strategy, objectives, plans, strength, focus and differentiators; the Company's plans to expand the Clearwater waterflood and the anticipated benefits and strategic rationale for such expansion, including materially flattening declines, increasing reserves and recovery, enhancing economics and multi-payout performance, lowering sustaining capital needs, reducing primary drilling requirements and ultimately extending asset duration while increasing free funds generation; expectations that given the ongoing improvement in the overall profitability of the business through a lower cost structure, lower reinvestment requirements and lower corporate breakeven oil price; the Company's updated five year plan, including with regard to sustaining capital, growth and waterflood investment and decline mitigation; the Company’s plan to achieve significant and profitable total shareholder return growth within 5 years;; Tamarack's capital program, budget and guidance for 2026 (including capital investments of $390 - $410 million and the allocation thereof, annual average production of 69,000 – 71,000 boe/day, average oil and natural gas weightings of 84% – 86%, royalty rates of 19% – 21%, corporate wellhead price differentials – oil of $1.00 – $1.50 per boe, net production expenses of $6.85 – $7.15 per boe, transportation expenses of $4.00 – $4.50 per boe, general and administrative expenses of $1.30 – $1.45 per boe, interest expense of $2.70 – $3.10 per boe and income taxes as a % of adjusted funds flow before tax of 10% – 12% and the Company remaining nimble and able to scale the 2026 capital program in either direction if commodity prices materially fluctuate during the year); Tamarack's return of capital framework, including debt repayment, dividends and share buybacks and the Company’s intention to increase return of capital as net debt declines and shift to more flexible capital allocation in 2026; generating significant free funds flow at a budgeted price of US$60 per bbl WTI, allowing the Company to continue delivering strong returns for investors through sustainable dividends, share buybacks and debt reduction; 2026 free funds flow forecasts and allocations; application of EOR and expectations in respect of waterflood development including the expectation of 2.5x to 3.0x primary recovery and outperforming reserve forecasts; expectations regarding improved field egress capacity; development opportunities and drilling locations; expectations regarding economics and payouts of the Company's wells; and risk management activities, including hedging positions and targets. Statements relating to "reserves", "recovery", "EUR", “contingent resources”, “prospective resources” and "OOIP" are also deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated and that the reserves and resources can be profitably produced in the future. Without limitation of the foregoing, future dividend payments, if any, and the level thereof, are uncertain, as the Company's dividend policy and the funds available for the payment of dividends from time to time is dependent upon, among other things, commodity prices, free funds flow, financial requirements for the Company's operations and the execution of its growth strategy, fluctuations in working capital and the timing and amount of capital expenditures, debt service requirements and other factors beyond the Company's control. Further, the ability of Tamarack to pay dividends, and the frequency thereof, will be subject to applicable laws (including the satisfaction of the solvency test contained in applicable corporate legislation) and contractual restrictions contained in the instruments governing its indebtedness, including its credit facility.

Forward-looking information is based on a number of factors and assumptions concerning Tamarack which have been used to develop such information, but which may prove to be incorrect. In addition to other factors and assumptions which may be identified in the presentation, assumptions have been made regarding and are implicit in, among other things: the business and waterflood plans of Tamarack; the success of future drilling, development, completion and injection activities; future strip prices; the performance of existing wells; the performance of new wells, including leveraging optimized well designs; the performance of EOR projects; the availability and performance of facilities and pipelines; the geological characteristics of Tamarack's properties; the successful application of drilling; completion and seismic technologies; the impact of inflation on costs; prevailing weather and break- up conditions and access to Tamarack's drilling locations; stable commodity prices, price volatility, price differentials and the actual prices received for the Company's products (including expectations concerning WCS differentials); royalty regimes and exchange rates; the application of regulatory and licensing requirements; the availability of capital, labour and services; the Company's ability to complete planned capital expenditures within budgeted cost estimates; Tamarack's ability to market its products successfully; and the creditworthiness of industry partners. Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used.

Although Tamarack believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because Tamarack can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature, they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to: risks relating to inclement and severe weather events and natural disasters, including fire, drought and flooding and corresponding effects, including in respect of safety, asset integrity, shutting in production, impact on production, delivering on 2026 guidance; risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration, production and waterflood, including breakthrough events; delays or changes in plans with respect to exploration, development projects, capital expenditures, or the implementation of the Company’s corporate strategy, objectives, strength, focus and five year plan; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses, including increased operating, labour, and capital costs due to inflationary pressures, volatility in the stock market and financial system; and health, safety and environmental risks); risks relating to reliance on third parties, including in respect of the Company’s use of third-party infrastructure at Charlie Lake; competition for skilled labour; incorrect assessments of the value of acquisitions or failure to realize the benefits of acquisitions and dispositions (including the Acquisition and the East Asset Disposition); constraints in the availability of services; commodity price and exchange rate fluctuations; the actions of OPEC and OPEC+ members; changes in legislation (including but not limited to tax laws, royalty regimes and environmental legislation); the risk that the U.S. and Canadian governments maintain tariffs, increase the rate or scope of tariffs, or impose new tariffs on the import of goods from one country to the other, including on oil and natural gas, (ii) the U.S. and/or Canada imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas, and (iii) the tariffs imposed by the U.S. on other countries and responses thereto could have a material adverse effect on the Canadian, U.S. and global economies, and by extension the Canadian oil and natural gas industry and the Company; changes to demand for Tamarack’s products; adverse weather or break-up conditions; uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects; capital expenditures; pandemics; impacts of conflicts in Eastern Europe and the Middle East. Production forecasts are directly impacted by commodity prices and the actual timing of Tamarack's capital expenditures. Actual results may vary materially from forecasts due to changes in interest rates, oil differentials, exchange rates and the timing of expenditures and production additions. These and other risks are set out in more detail in Tamarack's annual information form for the year ended December 31, 2024 (the "AIF") and Tamarack's management's discussion and analysis for the three and nine months ended September 30, 2025 (the "MD&A"). The Company's AIF and MD&A can be accessed on Tamarack's website at www.tamarackvalley.ca or under Tamarack's SEDAR+ profile at www.sedarplus.ca. Forward-looking information is based on current expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by management and described in the forward-looking information. The forward-looking information contained in this presentation is made as of the date hereof and management undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, unless required by applicable securities laws. The forward-looking information contained in this presentation is expressly qualified by this cautionary statement.

Disclaimers *(Oil and Gas Advisories)*

FOFI Disclosure: This presentation contains future-oriented financial information and financial outlook information (collectively, "FOFI") about Tamarack's five year plan (including expectations regarding annual capital, annual reinvestment ratio, direct shareholder returns, total DAFFFPS, DAPPS growth and cumulative total shareholder returns), the 2026 capital budget of $390 - %410 million, guidance and budget pricing and allocation, including prospective results of operations, production (including annual average production of 69,000 – 71,000 boe/day, average oil and natural gas weightings of 84% – 86% and production growth of 3%) and free funds flow, operating costs (including net production expenses in 2026 declining by up to 6% compared to the 2025 budget), expectations of having resources to support decades of additional development, the Company's return of capital framework, including generating sustainable long term growth in free funds flow, dividends and share buybacks, annual returns to shareholders, prospective results of operations and production, breakeven costs (including a <US$40/bbl free funds flow after dividends breakeven), timing of payout of wells and number of payouts, yield, CAGR, CROIC, IRR, EUR, debt, net debt, net debt reduction, debt targets and utilization, balance sheet strength, NPV-10%, TPP reserve life index of ~9 years, half-cycle returns, operating costs, expected royalties, transportation expenses, cost per well, G&A expenses, interest and taxes, decline rates, and capital structure and components thereof, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs and the assumptions outlined in the Non- IFRS measures section below. FOFI contained in this presentation was approved by management as of the date of this presentation and was provided for the purpose of providing further information about Tamarack's anticipated future business operations. Tamarack disclaims any intention or obligation to update or revise any FOFI contained in this presentation, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law. Readers are cautioned that the FOFI contained in this presentation should not be used for purposes other than for which it is disclosed herein. The material assumptions used by the Company in the development and assessment of its 2026 budget and guidance are disclosed in the Company's press release dated December 3, 2025. Changes in forecast commodity prices, differences in the timing and allocation of capital expenditures, and variances in average production estimates can have a significant impact on the key performance measures included in Tamarack's guidance. The Company's actual results may differ materially from these estimates.

Reserves Disclosure: All reserve references in this presentation are to gross reserves as at the effective date of the applicable evaluation. Gross reserves are Tamarack's total working interest reserves before the deduction of any royalties and without including any royalty interests of Tamarack. The recovery and reserve estimates of Tamarack's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein. The reserve estimates contained herein for 2024 YE were derived from reserves assessments and evaluations prepared by McDaniel & Associates Consultants Ltd. ("McDaniel") and GLJ Ltd. ("GLJ"), qualified independent reserves evaluators, each with an effective date of December 31, 2024 and preparation dates of January 20, 2025 (the "McDaniel Report") and January 10, 2025 (the "GLJ Report") respectively, prepared in accordance with National Instrument 51-101 ("NI 51-101") and the most recent publication of the Canadian Oil and Gas Evaluations Handbook (the "COGE Handbook"). Reserves estimates for prior years were evaluated by independent qualified evaluators with an effective date of December 31 for the applicable year unless otherwise stated. It should not be assumed that the present worth of estimated future cash flow presented herein represents the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of Tamarack's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

Resource Disclosure: This document contains information relating to estimates of heavy oil contingent and prospective resources of Tamarack (the "Resource Report") by McDaniel a qualified independent reserves evaluator, with an effective date of December 31, 2024, in accordance with the definitions, standards and procedures contained in NI 51-101 and COGEH. The contingent and prospective resources estimates of Tamarack's Clearwater heavy oil contingent resources provided herein are estimates only and there is no guarantee that the estimated prospective and contingent resources will be recovered. Actual resources may be greater than or less than the estimates provided herein and the differences may be material. Tamarack's Statement of Contingent and Prospective Resources dated February 12, 2025, which has been filed on the Company's SEDAR+ profile at www.sedarplus.ca, includes further disclosure of Tamarack's contingent and prospective resources, including the risks and uncertainties related thereto. Contingent resources are defined as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early project stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. Prospective resources are those quantities of bitumen estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates, assuming their discovery and development, and may be subclassified based on project maturity. Estimates of prospective resources have not been adjusted for risk based on the chance of discovery or the chance of development. Resources are classified according to degree of certainty associated with those estimates. In this presentation, "best estimate" classification is used which is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources identified as best estimate have a 50 percent probability that the actual quantities recovered will equal or exceed the estimate.

Short-Term Production Rates: References in this presentation to peak rates, peak monthly rates, initial production rates, average peak production rate for the 30 days after the well is brought onstream (IP30), average peak production rate for the 90 days after the well is brought onstream (IP90) and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long-term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production of Tamarack.

Analogous Information: In this presentation, the Company has provided certain information on the prospectivity and the production rate of wells on properties adjacent to the Company's acreage which is "analogous information" as defined by applicable securities laws. This analogous information is derived from publicly available information sources which the Company believes are predominantly independent in nature. Some of this data may not have been prepared by qualified reserves evaluators or auditors and the preparation of any estimates may not be in strict accordance with the COGE Handbook. Regardless, estimates by engineering and geotechnical practitioners may vary and the differences may be significant. The Company believes that the provision of this analogous information is relevant to the Company's activities and forecasting, given its property ownership in the area; however, readers are cautioned that there is no certainty that the forecasts provided herein based on analogous information will be accurate.

Type Curves: Certain type curves disclosure presented herein was internally estimated by the Company's management and represents estimates of the production decline and ultimate volumes expected to be recovered from wells over the life of the well. The type curves represent what management believes an average well will achieve, based on methodology that is analogous to wells with similar geological features. Individual wells may be higher or lower but over a larger number of wells, management expects the average to come out to the type curve. Over time type curves can and will change based on achieving more production history on older wells or more recent completion information on newer wells. Such type curves are useful in understanding management's assumptions of well performance in making investment decisions in relation to development drilling in such areas and for determining the success of the performance of development wells. However, internally prepared type curves do not reflect the type curves used by our independent qualified reserves evaluator in estimating Tamarack's reserves volumes and such type curves have not been assigned reserves or resources. The South Clearwater Fan type curve presented herein is an internally generated forecast prepared by the Company's management to illustrate expected well performance under its go-forward development plan. Due to limited empirical data for the Company's updated well design—including longer horizontal lengths and wider well spacing—the Company believes the internally derived curve is the most representative indicator of anticipated performance for future performance. The curve is based on engineering and geoscience interpretation, analogous data, and internal technical analysis. The Company's management has also prepared an internally generated waterflood incremental type curves to illustrate the potential production uplift associated with planned waterflood development. This curve is derived from reservoir simulation, waterflood modeling, and internal technical analysis of reservoir response, rather than historical reserves bookings, which may lag the most current understanding of waterflood performance. The curve is intended only to demonstrate possible incremental production attributable to waterflooding under the Company's planned injection design and operating assumptions. There is no certainty that Tamarack will ultimately recover such volumes from the wells it drills. Actual results may vary materially from both primary and waterflood incremental curve estimates.

Disclaimers *(Oil and Gas Advisories Cont.)*

BOE Disclosure: The term barrels of oil equivalent ("BOE") may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel of natural gas to barrels of oil equivalence is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All BOE conversions in the presentation are derived from converting gas to oil in the ratio mix of six thousand cubic feet of gas to one barrel of oil. Throughout this presentation, "crude oil" or "oil" refers to light, medium and heavy crude oil product types as defined by NI 51-101. References to "NGLs" throughout this presentation comprise pentane, butane, propane, and ethane, being all NGLs as defined by NI 51-101. References to "natural gas" throughout this presentation refers to conventional natural gas as defined by NI 51-101.

OOIP Disclosure: is that quantity of petroleum that is estimated to originally exist in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered. A portion of the OOIP is considered undiscovered and there is no certainty that any portion of such undiscovered resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of such undiscovered resources. With respect to the portion of the OOIP that is considered discovered resources, there is no certainty that it will be commercially viable to produce any portion of such discovered resources. A significant portion of the estimated volumes of OOIP will never be recovered. OOIP disclosed herein in respect of the Company's Clearwater assets by area and in aggregate was internally estimated by the Company's management. There is no certainty management's OOIP estimates were prepared in accordance with the COGE Handbook. The estimates may not be comparable to similar measures presented by other companies and therefore should not be used to make such comparisons.

Specified Financial Measures: This presentation includes various specified financial measures, including non-IFRS financial measures, non-IFRS financial ratios, capital management measures and supplementary financial measures as further described herein. These measures do not have a standardized meaning prescribed by International Financial Reporting Standards ("IFRS") and, therefore, may not be comparable with the calculation of similar measures by other companies. "Adjusted funds flow (capital management measure)" is defined as cash provided by operating activities excluding asset retirement obligation expenditures, transaction costs and changes in non-cash working capital. Asset retirement obligation expenditures and transactions costs from business combinations both result from the Company's capital budgeting and strategic planning processes, which first considers available adjusted funds flow. Asset retirement obligation expenditures vary from period to period depending on capital programs, government regulations and the maturity of the Company's operating areas. By also excluding changes in non-cash working capital from cash provided by operating activities, the adjusted funds flow measure provides a meaningful metric for Tamarack and others by establishing a clear link between the Company's cash flows, income statement and operating netbacks by isolating the impact of changes in the timing between accrual and cash settlement dates, which are often within management's control. Tamarack uses adjusted funds flow to assess the Company's financial performance and cash generated from operating activities. Adjusted funds flow per share is calculated using the same weighted average basic and diluted shares that are used in calculating income per share, which results in the measure being considered a supplemental financial measure. Adjusted funds flow can also be calculated on a per boe basis, which results in the measure being considered a supplemental financial measure. "Free funds flow (capital management measure)" is defined as adjusted funds flow less investments in oil and natural gas assets (excluding acquisitions and dispositions) and the settlement of asset retirement obligations. Management utilizes free funds flow to assess how much cash was generated in excess of the Company's capital investment and asset retirement programs within the same period, which can be utilized to reduce net debt, fund acquisitions or return capital.. "Free funds flow breakeven cost (capital management measure)" reflects the average minimum WTI price (US per bbl) received by Tamarack where adjusted funds flow net of the base dividend and sustaining capital requirements is approximately equivalent to zero, with sustained current hedged production levels and all other variables held constant. Management believes that free funds flow breakeven provides a useful measure to establish corporate financial sustainability. The calculation of Tamarack's free funds flow breakeven cost of US$35 per bbl was primarily determined by utilizing the budget assumptions included in the table on page 1 of this news release, other than for capital investments, which utilize the Company's sustaining capital requirements of $265.0 million under an assumed scaled-budget, break-even price scenario, and average royalty rates which would be expected to decline to 14% – 15% at WTI price of $35 per bbl. Other assumptions utilized by the Company to calculate the free funds flow breakeven cost includes annual dividends of $0.16 per share, hedging gains of $4.67 per boe and asset retirement obligation expenditures of $5.0 million. Sustaining capital is management's estimate of annual capital activities required to maintain production levels.. "Net debt (capital management measure)" is calculated as the sum of the Company's debt, government loans and other, cash, accounts receivable, prepaid expenses and deposits, cross-currency swap liability (asset), assets held for sale (net), accounts payable and accrued liabilities. Tamarack and others utilize net debt to assess liquidity and balance sheet strength by aggregating the select financial assets and financial liabilities on the Company's balance sheet.. "Market capitalization" is calculated as shares outstanding multiplied by the closing market price of the shares on the day referenced. "Enterprise value" (supplementary financial measure)" is calculated as market capitalization (shares outstanding multiplied by the closing market price of the shares on the day referenced) less net debt. "EBITDA (non-IFRS financial measure)" is calculated as consolidated net income (loss) before interest and financing expenses, income taxes, depletion, depreciation and amortization, adjusted for certain non-cash, extraordinary and non-recurring items primarily relating to unrealized gains and losses on financial instruments and impairment losses. The Company considers this metric as key measures that demonstrate the ability of the Company's continuing operations to generate the cash flow necessary to maintain production at current levels and fund future growth through capital investment and to service and repay debt. The most directly comparable IFRS measure to EBITDA is cash provided by operating activities. This measure is consistent with the EBITDA formula prescribed under the Company's Senior Credit Facility. "Blending expense" (non-IFRS financial measure) includes the cost of blending diluent purchased to reduce the viscosity of our heavy oil transported through pipelines to meet pipeline specifications. The blending expense represents the difference between the cost of purchasing and transporting the diluent and the realized price of the blended product sold. In the MD&A, blending expense is recognized as a reduction to heavy oil revenues, whereas blending expense is reported as an expense in the financial statements. This metric can also be calculated on a per boe basis, which results in them being considered a non- IFRS financial ratio. "Differential including transportation expense" (non-IFRS financial measure) is determined by comparing the Company's realized price to the published benchmark price, plus transportation expenses. The calculation of the Company's heavy oil differential including transportation expenses is presented in the "Petroleum and natural gas sales" section of the MD&A. "Net production expense" is calculated as production expenses less processing income. Tamarack generates processing income from third parties that utilize excess capacity at Tamarack's facilities. If Tamarack has excess capacity at one of its facilities, the Company will seek to process third-party volumes as a means of offsetting a portion of the facility costs. Accordingly, net production expenses allow Tamarack and others to assess the field and facility operating results by including the associated income generated from plant operations. The calculation of the Company's net production expenses is presented in the Non–GAAP financial measures and non-GAAP financial ratios section of the MD&A. The Company and others utilize these performance measures to assess the value of net revenue received by Tamarack for each barrel sold relative to the published market price during that period. These performance measures are presented on a per boe basis as a non-IFRS financial ratio. Please refer to the MD&A for additional information relating to specified financial measures including non-IFRS financial measures, non-IFRS financial ratios and capital management measures. The MD&A can be accessed either on Tamarack's website at www.tamarackvalley.ca or under the Company's SEDAR+ profile at www.sedarplus.ca.

Oil and Gas Metrics. This presentation contains metrics commonly used in the oil and natural gas industry, such as "NPV-10" (meaning the net present value (net of capex) of net income discounted at 10%), "EUR" (meaning estimated ultimate recovery, an approximation of the quantity of oil or gas that is potentially recoverable or has already been recovered from a reserve or well), "IRR" (meaning internal rate of return, a rate of return measure used to compare the profitability of an investment and represents the discount rate at which the net present value of costs equals the net present value of the benefits. The higher a project's IRR, the more desirable the project), "FDC" (meaning future development costs), "Finding and development costs" or "F&D costs" (calculated as the sum of field capital plus the change in FDC for the period divided by the change in reserves that are characterized as development for the period. The aggregate of the exploration and development costs incurred in the financial year and changes during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. Finding and development costs both including and excluding acquisitions and dispositions have been presented in this presentation because acquisitions and dispositions can have a significant impact on Tamarack's ongoing reserves replacements costs and excluding these amounts could result in an inaccurate portrayal of the Company's cost structure),"Recycle ratio" (measured by dividing the operating netback for the applicable period by F&D cost per boe for the year. The recycle ratio compares netback from existing reserves to the cost of finding new reserves and may not accurately indicate the investment success unless the replacement reserves are of equivalent quality as the produced reserves) and "CAGR" or "Compound annual growth rate" (representing the consistent rate at which an investment or business result would have grown had the investment or business result compounded at the same rate each year).

Disclaimers *(Oil and Gas Advisories Cont.)*

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

Third Party Information: Certain information contained in this presentation has been obtained from published sources prepared by independent industry analysts and third-party sources (including industry publications, surveys and forecasts). While such information is believed to be reliable for the purpose used herein, none of the directors, officers, owners, managers, partners, consultants, shareholders, employees, affiliates or representatives assumes any responsibility for the accuracy of such information. Some of the sources cited in this presentation have not consented to the inclusion of any data from their reports, nor has Tamarack sought their consent. The accuracy and completeness of the market, industry and economic data used throughout this presentation are not guaranteed and Tamarack makes no representation as to the accuracy of such information.

US Registration: This presentation is not an offer of the securities for sale in the United States. The securities have not been registered under the U.S. Securities Act of 1933, as amended, and may not be offered or sold in the United States absent registration or an exemption from registration. This presentation shall not constitute an offer to sell or the solicitation of an offer to buy nor shall there be any sale of the securities in any state in which such offer, solicitation or sale would be unlawful.

Drilling Locations: This presentation discloses Clearwater and Charlie Lake drilling locations in two categories: (i) booked locations; and (ii) unbooked locations. Booked locations are proved and probable locations derived from the McDaniel Report and the GLJ Report, each with an effective date of December 31, 2024, prepared in accordance with NI 51-101 and the most recent publication of the COGE Handbook. Unbooked locations do not have attributed reserves. The unbooked Charlie Lake locations do not have attributed resources, while the unbooked Clearwater locations do have attributed contingent or prospective resources based on the Resource Report. Of the Clearwater inventory of 2,071.2 net drilling locations identified herein, 401.2 net are proved or probable locations, and 1,670 net are unbooked locations. Of the Charlie lake inventory of 219.1 net drilling locations identified herein, 106.2 net are proved or probable locations, and 112.9 net are unbooked locations. Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company actually drills wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been de-risked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Abbreviations	
AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
bbls	barrels
bbls/d	barrels per day
boe/d	barrels of oil equivalent per day
bopd	barrels of oil per day
DAPPS	Debt adjusted production per share
EOR	Enhanced Oil Recovery
ERH	extended reach horizontal
EUR	estimated ultimate recovery
FFFPS	Free funds flow per share
FX	foreign exchange
GJ	gigajoule
IFRS	International Financial Reporting Standards as issued by the International Accounting Standards Board
IP30	average peak production rate for the 30 days after the well is brought onstream
IP90	average peak production rate for the 90 days after the well is brought onstream
KPI	key performance indicator
MMcf/d	million cubic feet per day
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
NAV	net asset value
OOIP	Original Oil In Place
P3	proved + probable + possible reserves
ROR	rate of return
ROY	remainder of the year
TLL	total lateral length
TTM	trailing twelve months
TPP	total proved plus probable reserves
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade