TSX: TVE

2025 Investor Day

June 2025 | Compounding Success

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2025 Investor Day Agenda

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Introduction & Overview – Compounding Success
Brian Schmidt (AAKAIKKITSTAKII), President & CEO

Updated Corporate 5-Year Plan – Growing Return of Capital:
Steve Buytels, Chief Financial Officer

Charlie Lake – Stacked Resource & Ongoing Innovation:
Scott Shimek, VP Production Operations

Clearwater – Zeroing In On a Unique Asset:
Ben Stoodley, VP Engineering and Lynne Chrumka, VP Exploration

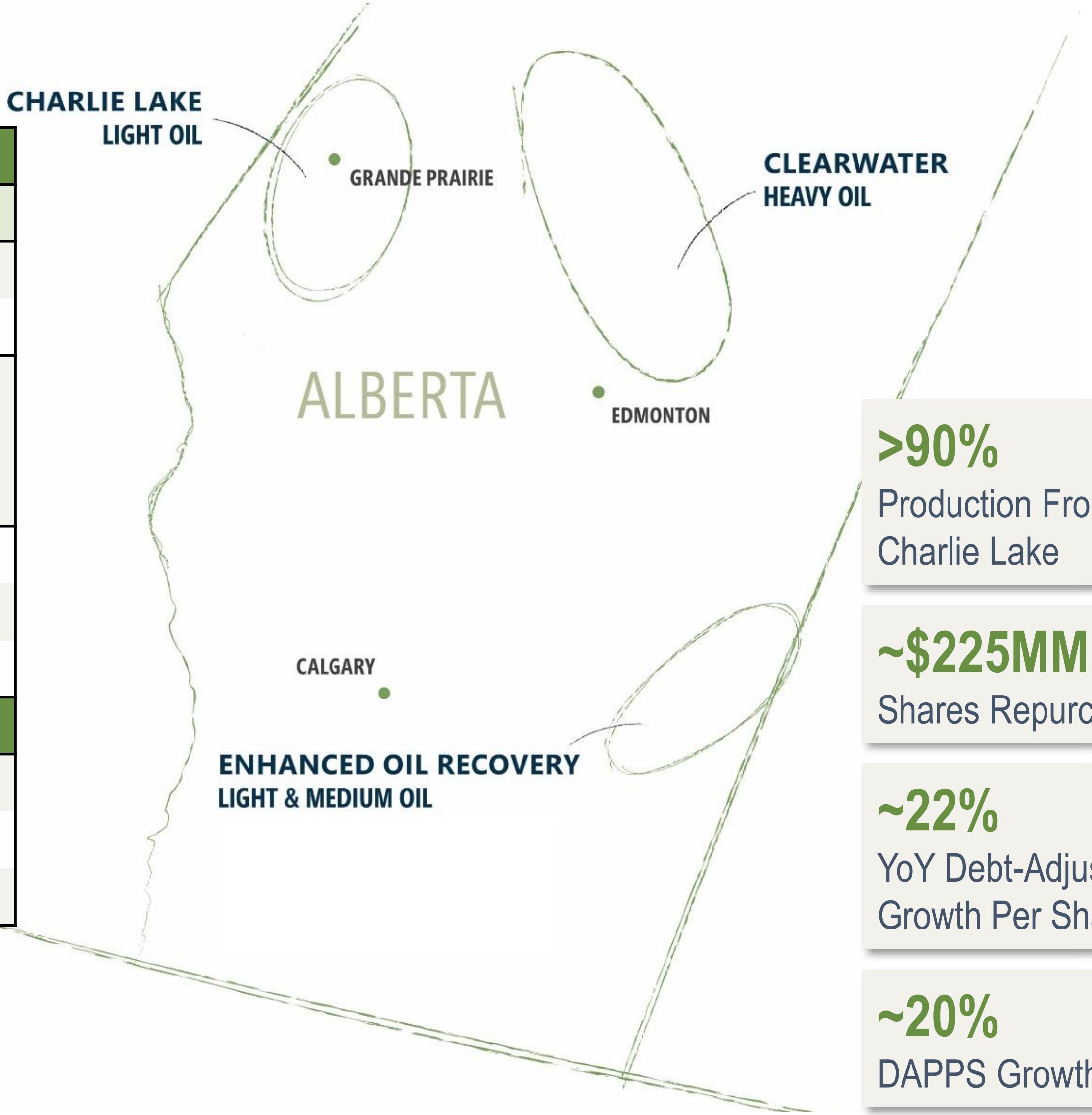
Marketing – The Heavy Oil Advantage:
Rocky Baker, VP Marketing

Returns to Shareholders & Closing Remarks:
Kevin Johnston, VP Finance and Brian Schmidt (AAKAIKKITSTAKII)

Corporate and Operational Snapshot

The Largest Public Clearwater Producer

Corporate Overview		
Ticker Symbol		**TSX: TVE**
Shares Outstanding (Basic)[1]	*(MM)*	502
Share Price (June 20th, 2025)[1]	*($/Sh.)*	*$5.03*
Market Capitalization[1]	***($B)***	**$2.5**
Q1 2025 Net Debt	***($B)***	**$0.8**
Enterprise Value	***($B)***	**$3.3**
Annual Base Dividend[1]	*($/Sh.)*	$0.153
Annual Base Dividend Yield[1]	*(%)*	~3.0%
Q1 2025 Net Debt / LTM EBITDA	*(x)*	0.7x
2025 Guidance Highlights		
Production[2]	*(boe/d)*	65,000 – 67,000
Average Liquids Weighting	*(%)*	83% – 85%
Capital Expenditures[3]	*($MM)*	$430 – $450



>90%
Production From Clearwater and Charlie Lake

~$225MM | ~9.8%[4]
Shares Repurchased Since Dec. 2023

~22%
YoY Debt-Adjusted PDP Reserve Growth Per Share (24YE vs. 23YE)

~20%
DAPPS Growth (Q1/25 vs. Q4/23)[5]

1) Share count as at the end of May 2025. Share price and dividend yield uses Tamarack share price as at June 20, 2025.
2) Production of 65,000 – 67,000 boe/d: 39,150-40,350 bbl/d heavy oil, 13,300-13,700 bbl/d light and medium oil, 2,300-2,360 bbl/d NGLs and 61,550-63,550 mcf/d natural gas.
3) Capital expenditures excluding ARO spending.
4) Based on shares outstanding January 1, 2024 and repurchases up to and including May 31, 2025.
5) Debt adjusted with a TVE share price of ~$3.81/Sh. (2024A average trading price); DAPPS = Debt adjust production per share.

Why Tamarack?

Highly Economic Full-Cycle Returns = Growing Return of Capital

Top Tier Assets With Large OOIP

- >11 Bln bbls of OOIP in the Clearwater[1]
- 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

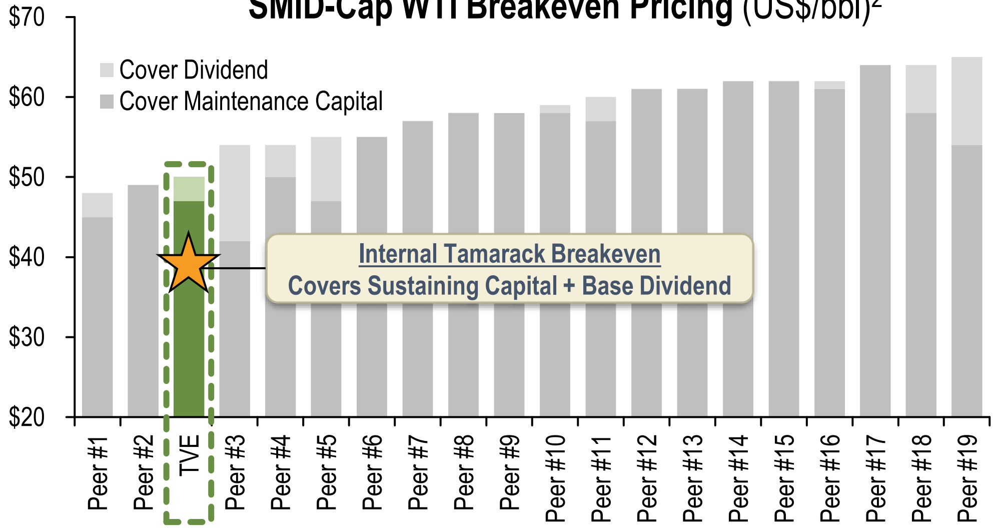
- Breakeven <US$40/bbl WTI covering maintenance capital + base dividend

Increasing Cash Return On Invested Capital

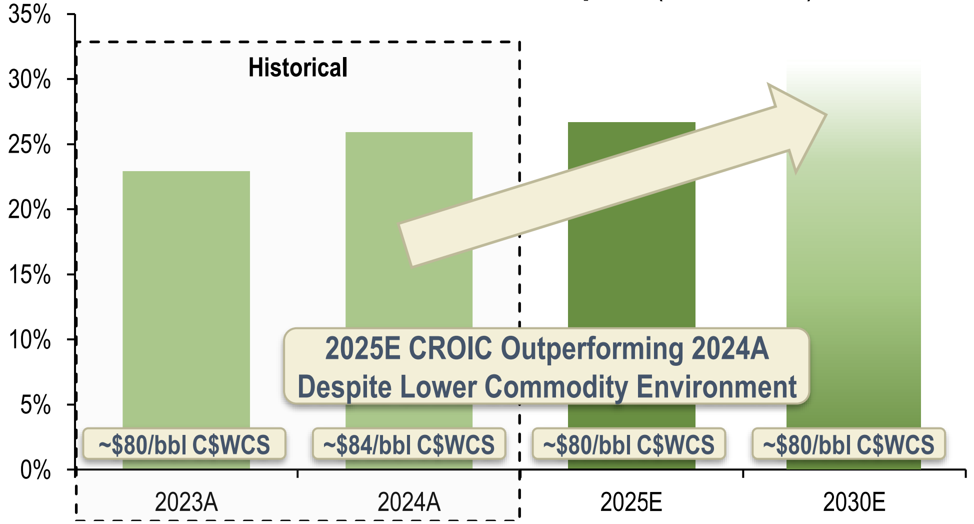
Capital Allocation Flexibility Allows For Optionality

- Focused on assets and capital allocation to generate the highest return <u>on</u> capital, to allow the highest return <u>of</u> capital

SMID-Cap WTI Breakeven Pricing (US$/bbl)[2]



Cash Return On Invested Capital (CROIC; %)[3]



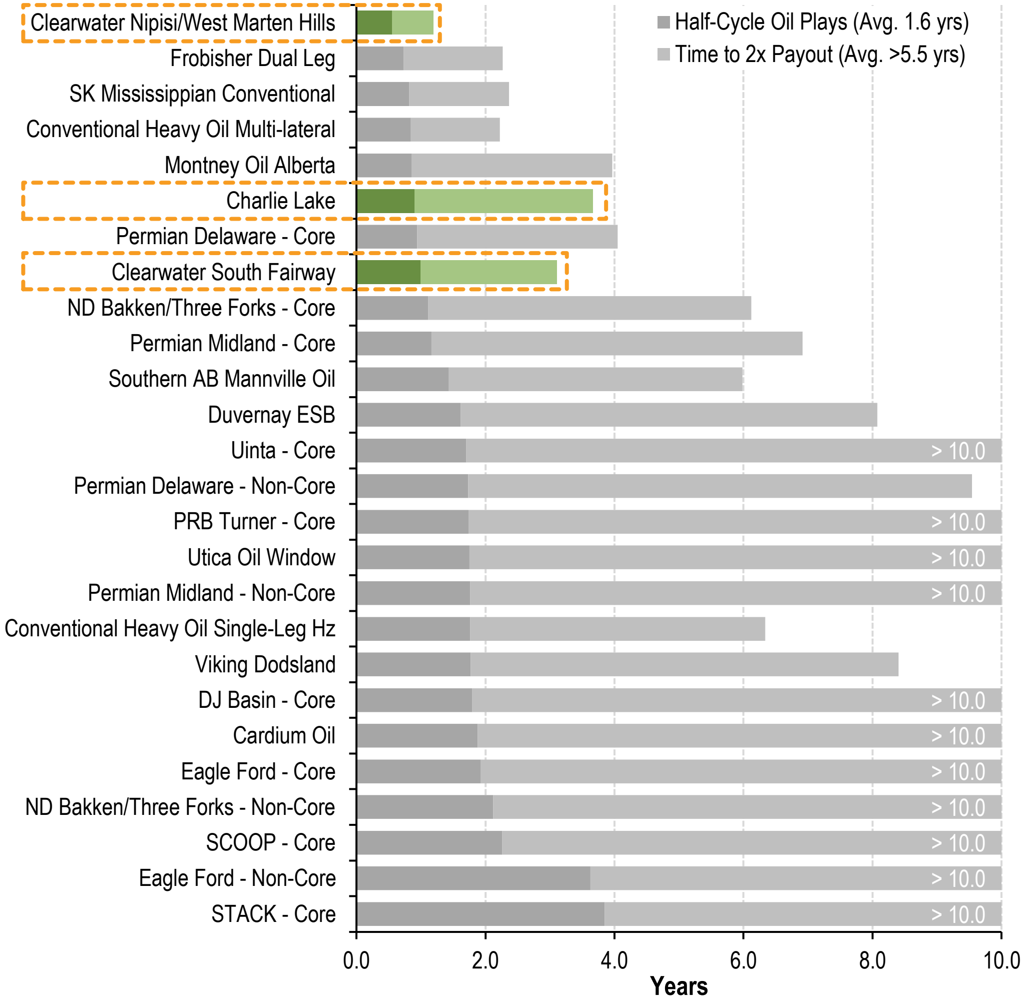
See Disclaimers – "Specified Financial Measures".

1) OOIP – original oil in place based on internal estimates.
2) Breakeven estimates per Peters & Co.
Peer group includes ATH, BNE, BTE, CJ, GFR, HWX, IPCO, JOY, KEC, LCX, LTC, MEG, OBE, SCR, SGY, SOIL, VET, WCP, and YGR.
3) Cash Return On Invested Capital ("CROIC") calculated as EBITDA divided by the net carrying value of oil and natural gas assets on the balance sheet (including E&E assets). Forward estimates at US$75/bbl WTI, US$(13.50) WCS basis, US$(3.00) MSW basis, and 1.30 US$/C$. Includes settled pricing to May 2025. Net carrying value of assets assumes $425 MM/yr. of DD&A.

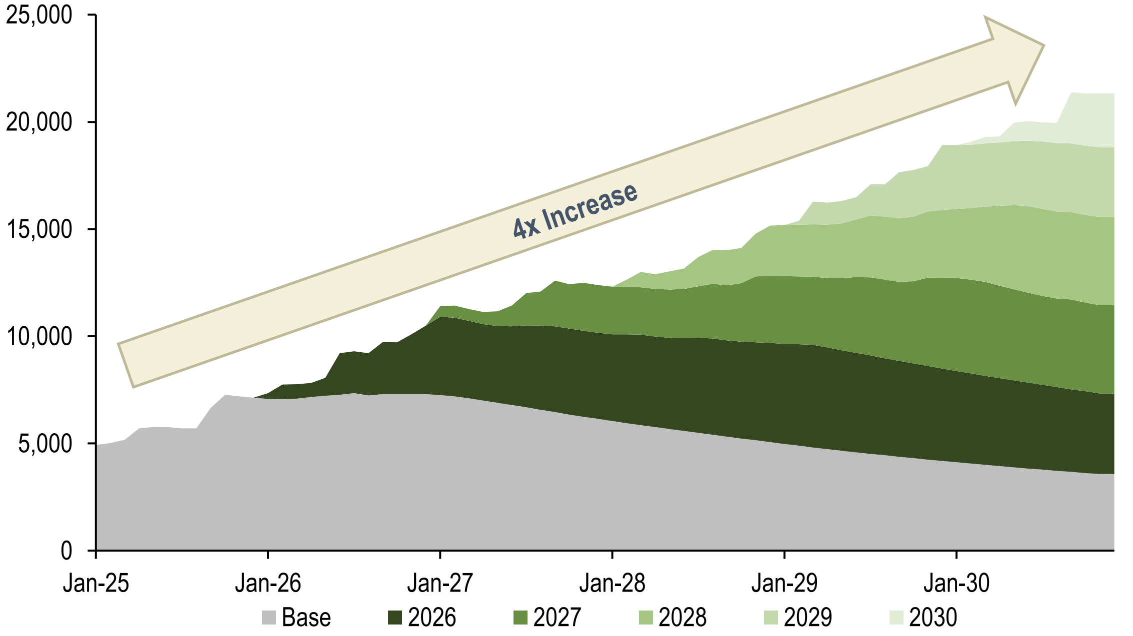
Top Tier Primary Assets and Proven Waterflood

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

Primary Payout Periods (Years)



Clearwater Oil Under Waterflood By Year (bbl/d)



Tamarack Valley
Conventional Play Economics
Unconventional Resource Scale

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

2025 vs. 2024 Investor Day Case *(2025E-2029E)*

More Profitable Barrels Driving Outsized Returns To Shareholders

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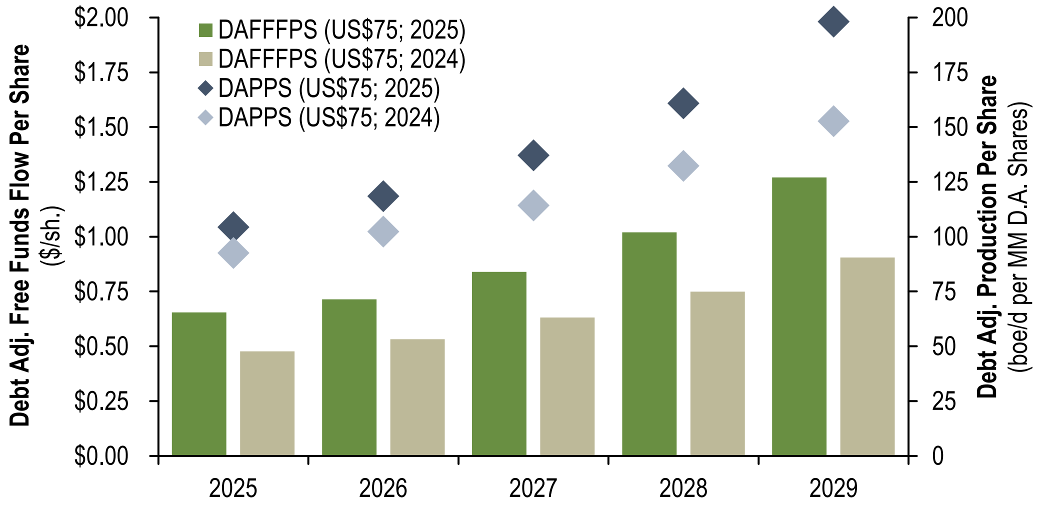
Year-Over-Year Improvements:

- Additional Clearwater inventory; optimized well designs
- Broadened application of waterflood; secondary recovery of 2.0x to > 3.0x, increased from 2.0x previously
- Clearwater base production outperformance and cost improvements
- Charlie Lake inventory improvement through strategic rationalization

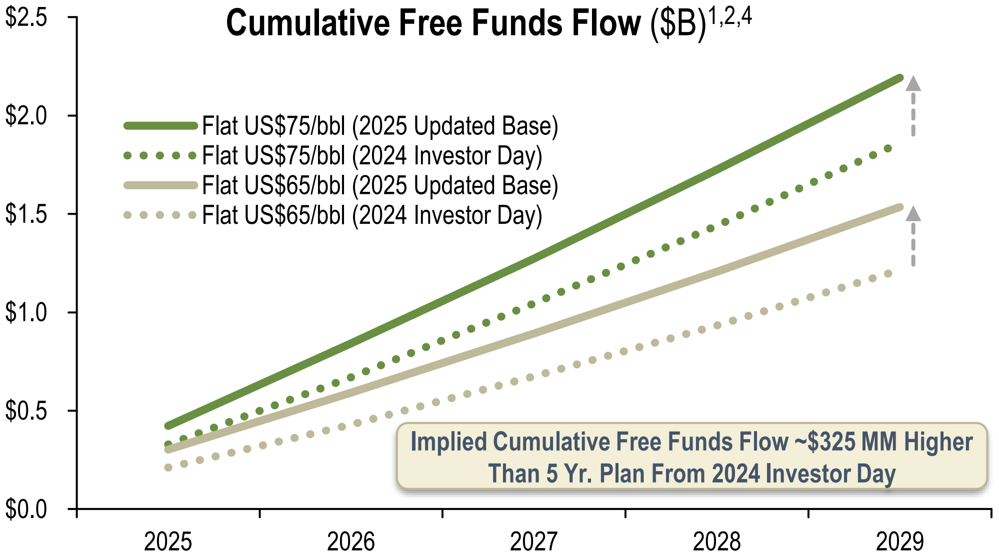
DAFFFPS & DAPPS Comparison (2025 vs. 2024)[1,2,4]



Key 5-Year Plan Metric Comparison YoY (US$75/bbl WTI)			
Metric	**2024 Investor Day *(2025-2029)***	**2025 Investor Day *(2025-2029)***	**∆**
Avg. Production (2025E-2029E)	**~67.5 Mboe/d**	**~70.0 Mboe/d**	***~4%***
Annual Capital	**$450MM**	**$450MM**	**-**
Annual Reinvestment:[1]	**~50% - 60%**	**~50%**	***<10%***
Annual Free Funds Flow:[1,2,]	**$325 - $425MM**	**$375 - $450MM**	***~$50MM***
Annual Direct Returns to Shareholders:[3]	**10% - 15%**	**10% - 15%**	**-**
Achieved Debt Target:	**2029 (Incl. Enhanced Returns)**	**2027 (Incl. Enhanced Returns)**	**~2 Yrs. Earlier**

Direct Shareholder Returns Unchanged From 2024 Despite Higher Tamarack Share Price In 2025 5 Yr. Plan

Cumulative Free Funds Flow ($B)[1,2,4]



1) See Disclaimers – "Specified Financial Measures".
2) Free funds flow is adjusted funds flow less capital expenditures & ARO.
3) Direct returns to shareholders defined as annual base dividend yield + share buybacks (as % of the previous YE share count). Assumes $4.75/Sh.
4) Debt adjusted with a share price of $4.75/Sh. Assumes share buyback price of $4.75/Sh. in both 5 yr. plans. DAFFFS = Debt adjust free funds flow per share; DAPPS = Debt adjust production per share.

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

Focused Clearwater Growth With Charlie Lake Light Oil Development

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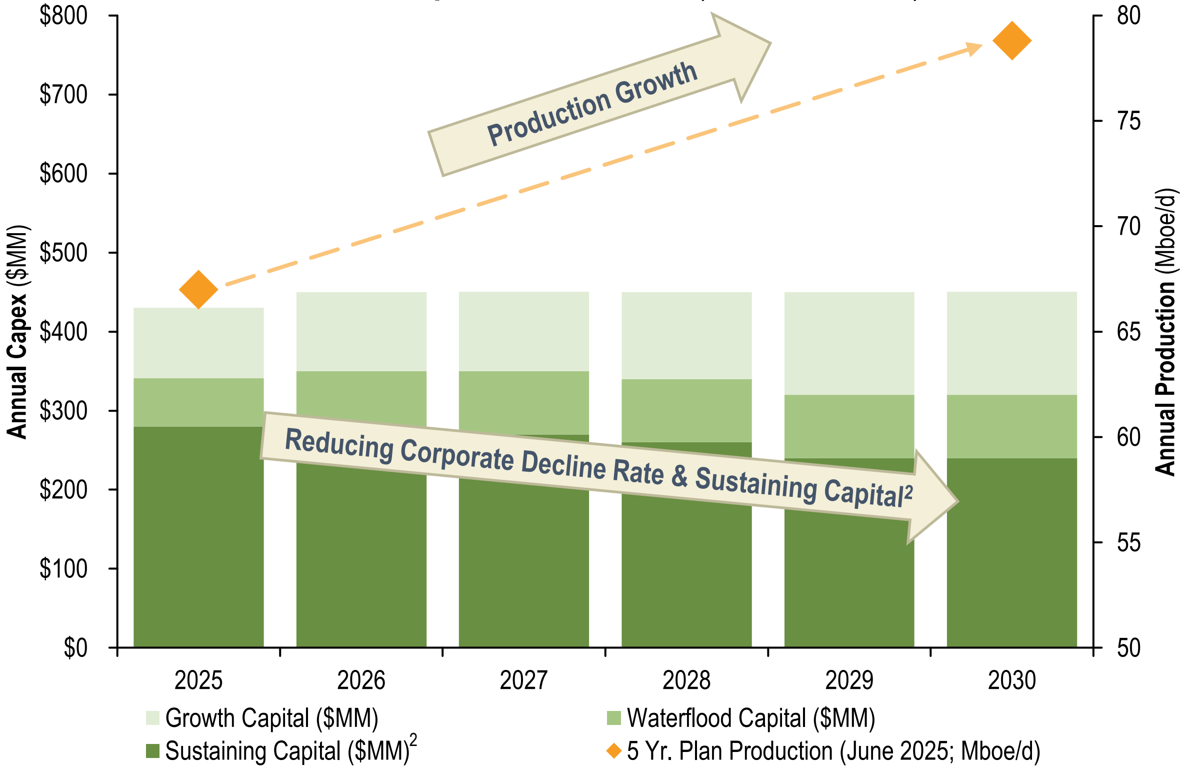
5-Year Production Growth CAGR of 3% - 5%[1]

- Annual capital: ~$450MM
- Annual reinvestment ratio: ~50%[1,3]
- Direct shareholder returns: ~10% - 15%[3,4]

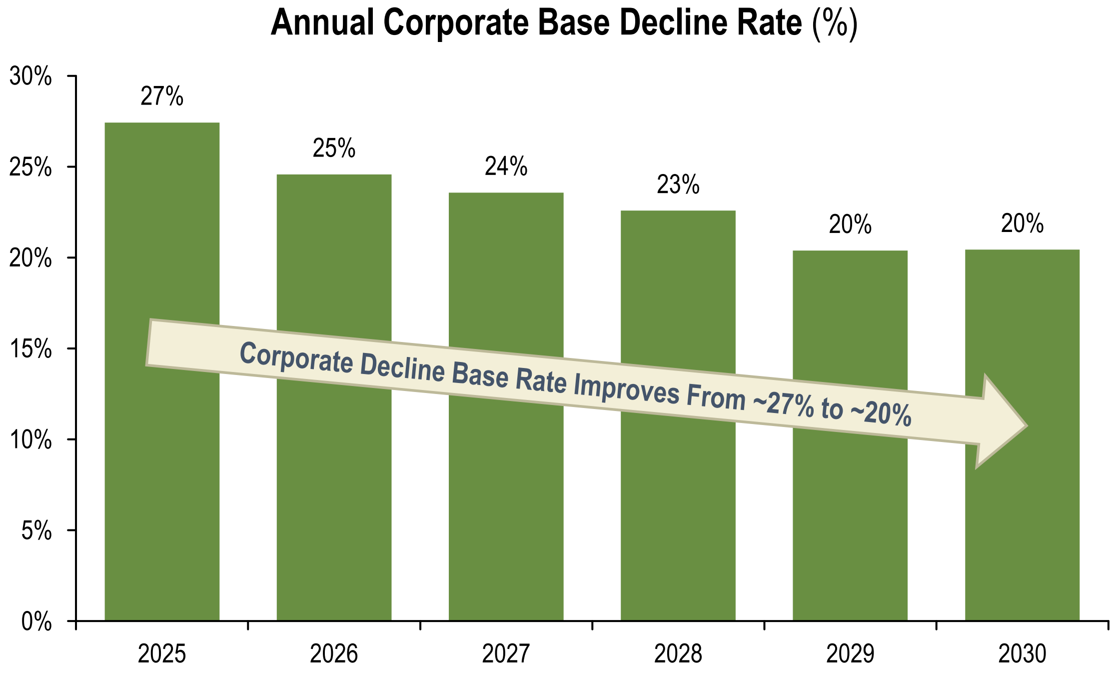
5 Yr. Plan Capex & Production ($MM & Mboe/d)



Shallowing Decline Rate Reduces Sustaining Capital[2], Increasing Free Funds Flow[1] For Debt Repayment, Returns, And Growth Optionality

- Debt target ($500MM) accelerated to 2027[3] optionality for additional:
  - Growth in the plan;
  - Clearwater waterflood: further mitigate declines & sustainable capital[2]

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.
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) Direct returns to shareholders defined as annual base dividend yield + share buybacks (as % of the previous YE share count). Assumes shares repurchased at $4.75/Sh.

Compounding Per Share Returns

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

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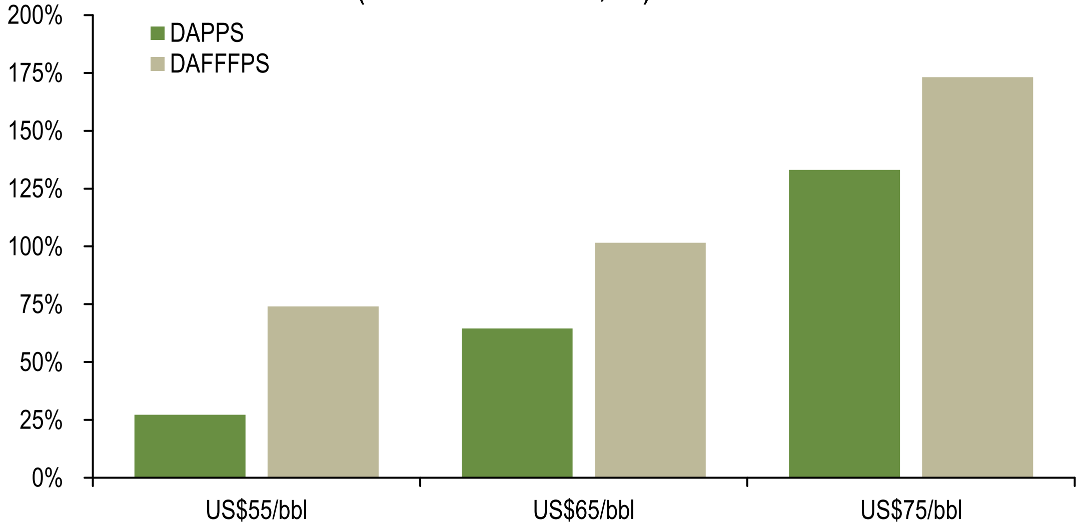
Total DAFFFPS & DAPPS Growth of >100%[1,2,3] Over 5 Years (Flat US$75/bbl WTI)[4]

- Debt adjusted free funds flow per share outpaces debt adjusted production per share through the 5-year plan
  - Lower decline, sustaining capital, net debt, and share count

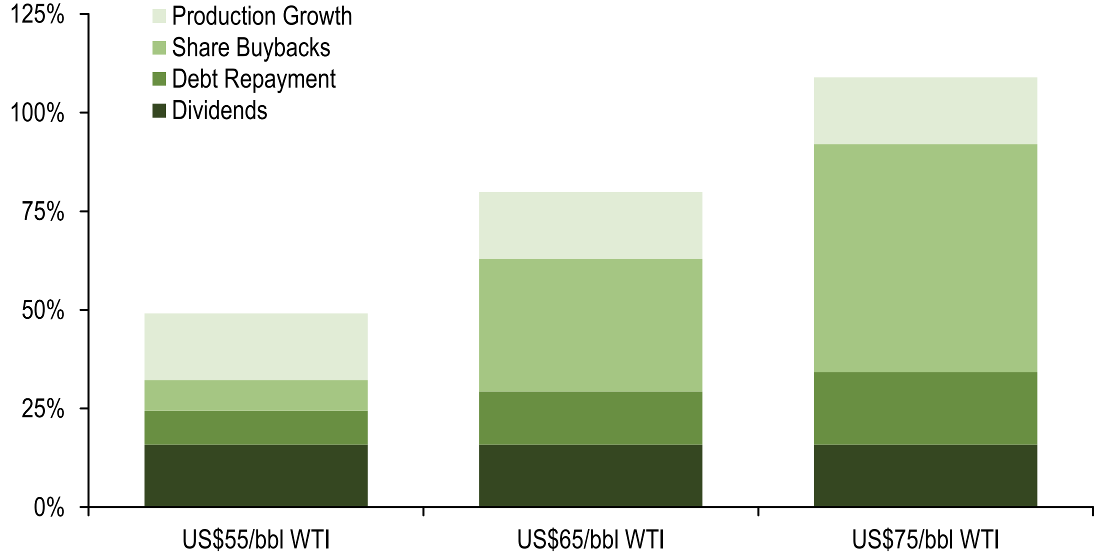
Cumulative △ In Debt Adj. Production Per Share & Debt Adj. Free Funds Flow Per Share
(2030E vs. 2026E; %)[1,2,3,4]



Cumulative Total Shareholder Return of >100% Over 5 Years (Flat US$75/bbl WTI)[4]

- *TSR = Dividends + Buybacks + Debt Repayment + Production Growth*
- Base dividends ~$400MM; repurchase ~50% of 2025YE share count[4]

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



1) See Disclaimers – "Specified Financial Measures".
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 $4.75, using average annual share counts and net debts. DAPPS/DAFFFPS growth uses 2026E as base.
4) Assumes annual dividend payout ($MM) is flat at ~$80MM. Returns for buybacks, debt repayment, and dividends are based on changes or totals relative to 2025YE. Assumes shares repurchased at $4.75/Sh. Return from share buybacks is % of share count repurchased vs 2025YE. Return from debt repayment is debt repaid divided by current market capitalization.

Charlie Lake – Stacked Resource & Ongoing Innovation

Charlie Lake Steady Growth and Reliable Performance

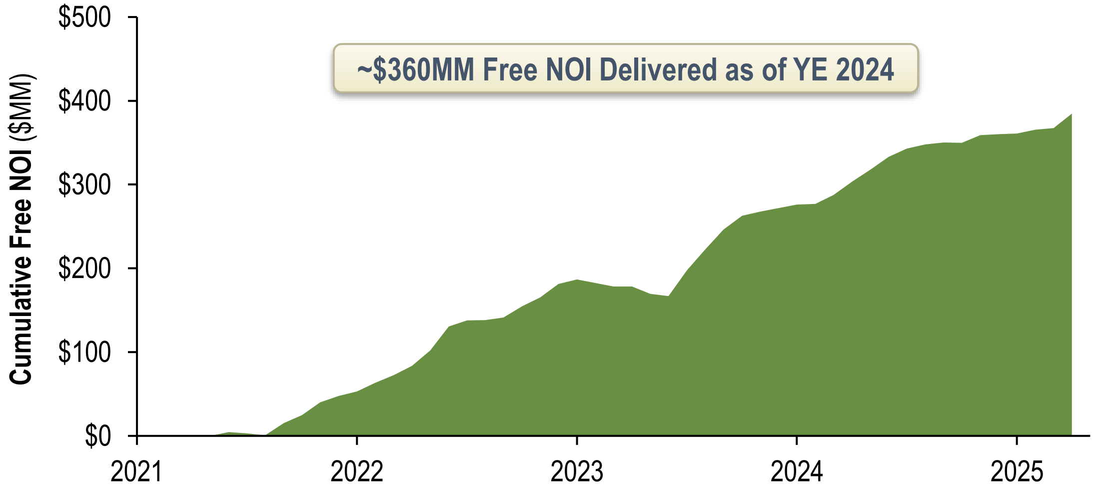
Largest Charlie Lake Oil Producer Generating Superior Economics

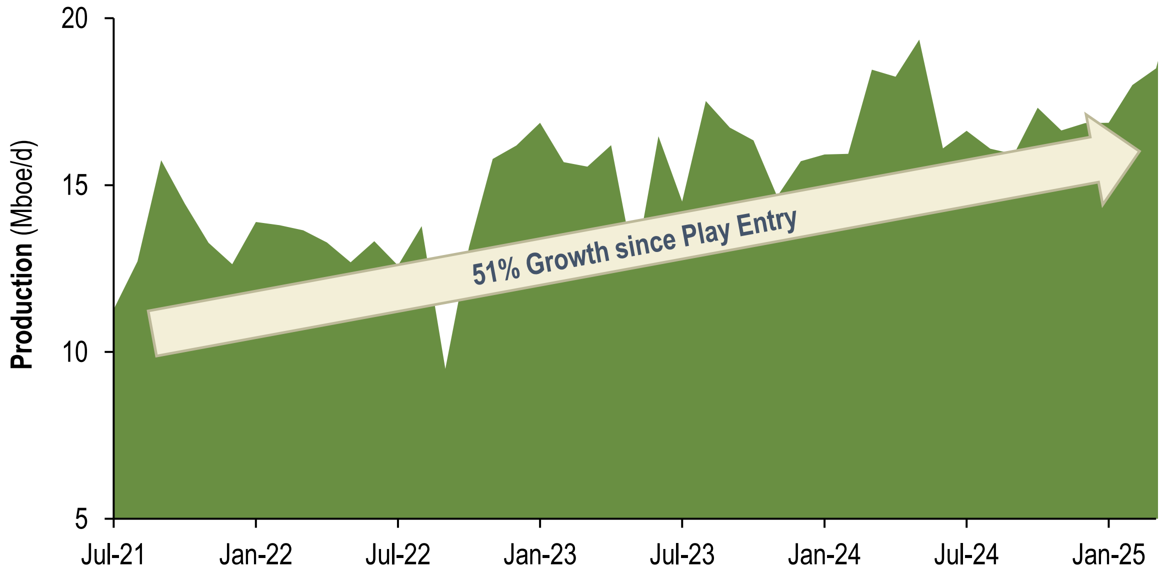
Growth & Performance

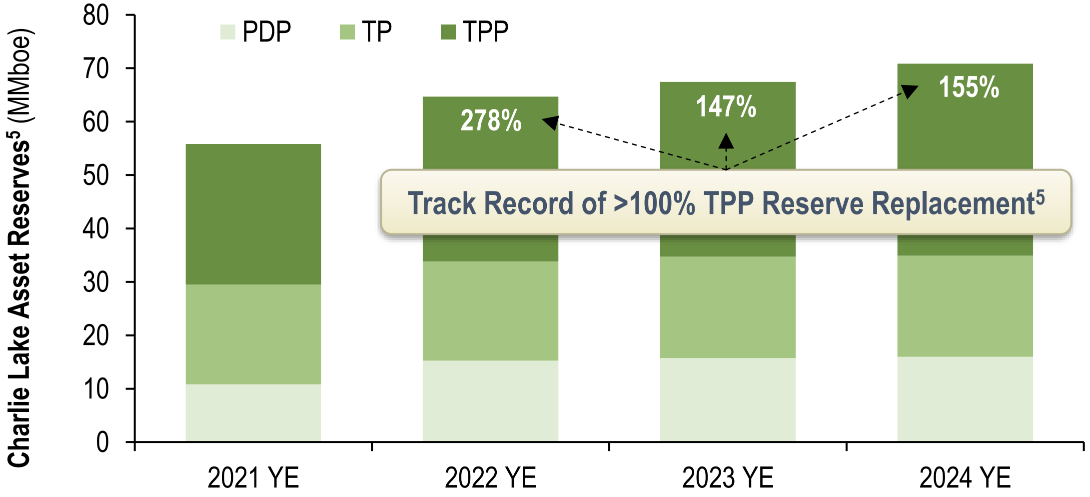
- **Production Up 51%:** 11,800 boe/d[1] (Apr. 2021) to 17,780 boe/d[2] (Q1/25)
- **46% Sustaining Reinvestment Ratio in 2024:** $96MM sustaining capital[3], $113MM of free net operating income (NOI)

Reserves Recognition & Value

- **TPP Reserves Up 77%:** 40.1 MMboe[4] (Apr. 2021) to 70.9 MMboe[5] (2024 YE)
- **Substantial Reserves Value at YE 2024:** $451MM[6] TP and $1,032MM[6] TPP



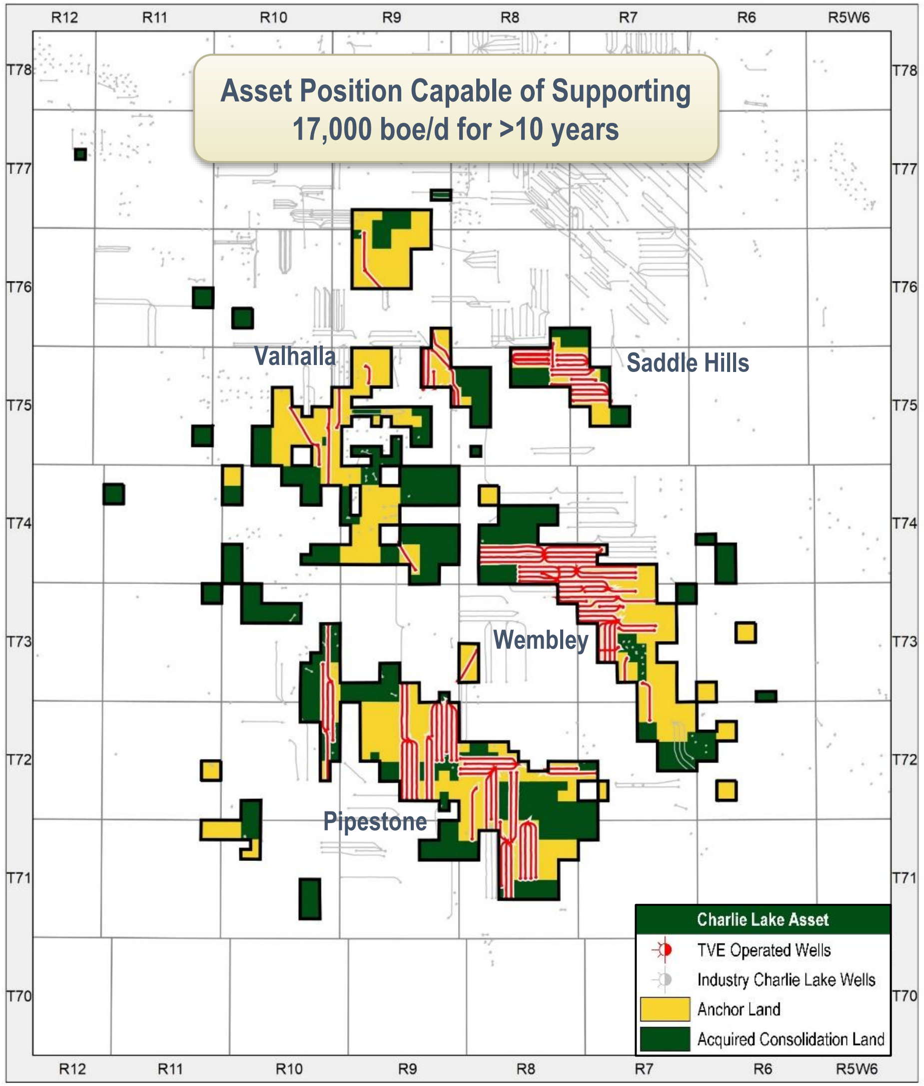




1) 11,800 boe/d comprised of approximately 6,500 bbl/d of light and medium oil, 1,900 bbl/d of NGLs, and 20.4 MMcf/d of natural gas.
2) 17,780 boe/d comprised of approximately 9,600 bbl/d light and medium oil, 2,640 bbl/d NGLs, and 33.2 MMcf/d natural gas.
3) Sustaining capital defined as pad, drilling, completions, and equip capital spend (excludes facilities, geophysical, land, and acquisition capital).
4) 40.1 MMboe of TPP reserves comprised of 71% liquids and 29% natural gas, per Apr. 2021 press release.
5) See Disclaimers – "Reserves Disclosure", %'s shown represent TPP reserve replacement for full years under TVE ownership.
6) Value is a reference to NPV-10% = Net Present Value, discounted at 10%, see Disclaimers – "Reserves Disclosure" for additional information.

Charlie Lake Growth Opportunity

Increased Inventory and Infrastructure Capacity Provides Optionality

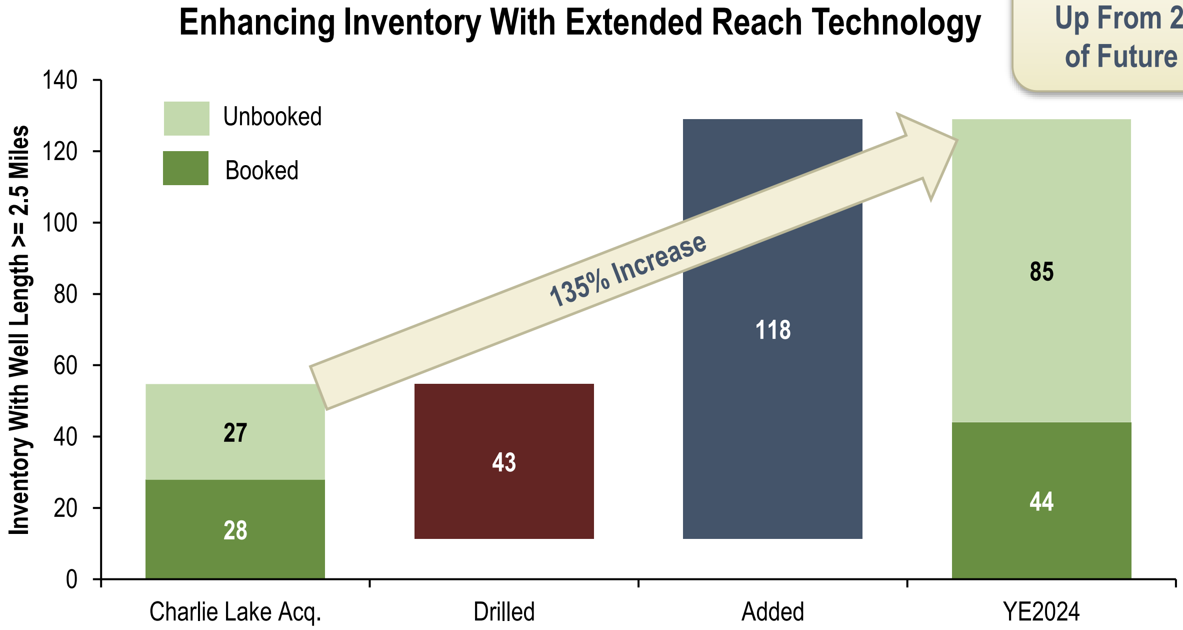


Anchor, Build, and Optimize

- Processing capacity expanded by 4x to facilitate growth of the play and enhance reliability
- Acquired 70 net sections of strategic land to strengthen and grow drilling inventory

Inventory (≥ 2.5-mile wells) – Up 135%

- 55 locations (Apr 2021) to 129 locations[1] (YE 2024)



1) Net primary drilling locations as at 2024YE, see Disclaimers – "Drilling Locations" for additional information.

Charlie Lake Stacked Resource and Ongoing Innovation

Multiple Zones Contributing to >10 Years of Inventory Provides Opportunity

Top Tier Reservoir

- Dominant position in the sweet spot of the fairway
- High oil weighted production (50% - 70%)
- Light oil (35 – 42° API gravity)

Multiple Zones to Pursue

Charlie Lake

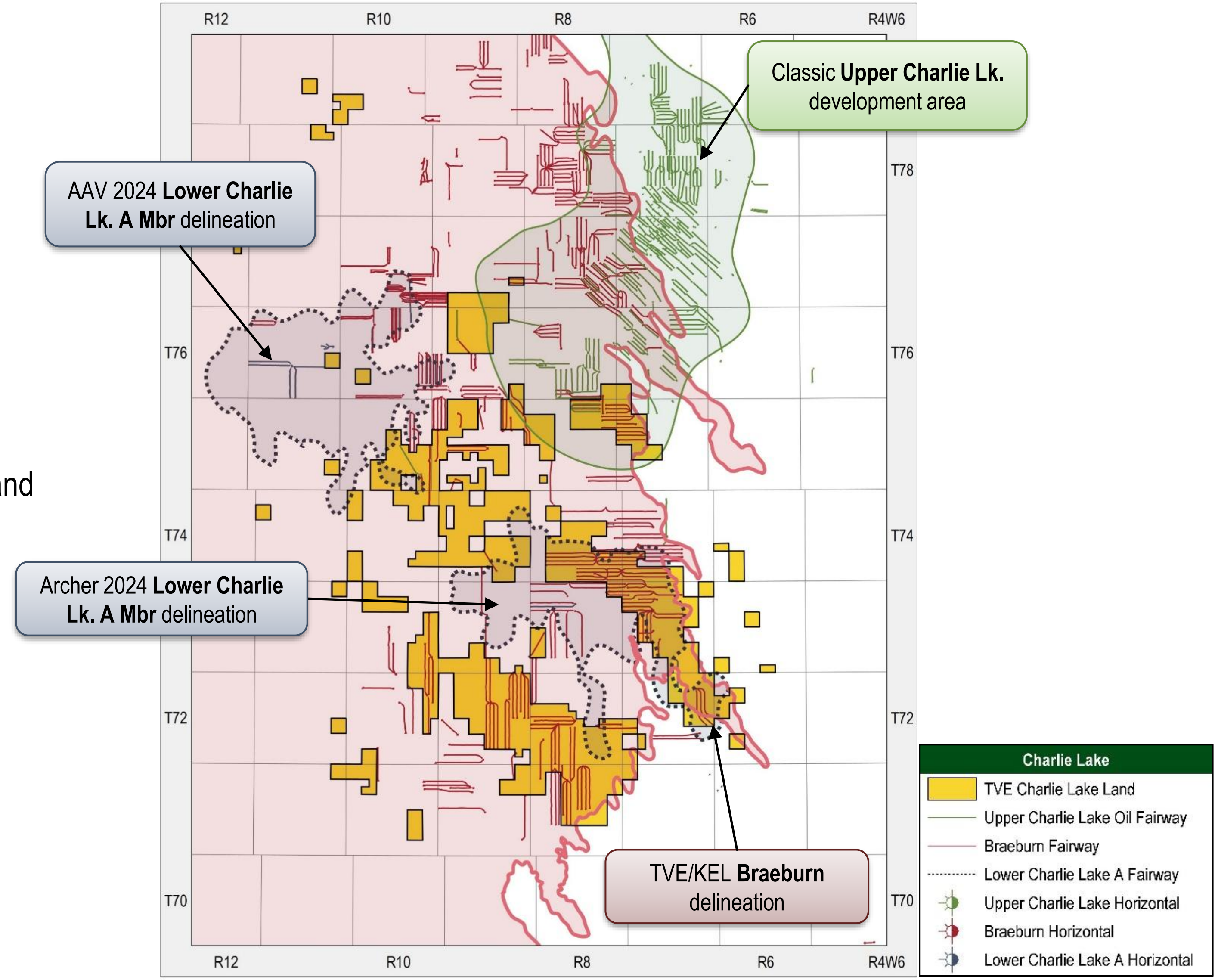
- Upper Charlie Lake extends south onto Tamarack lands
- Lower Charlie Lake Braeburn members extend across the fairway and continues to deliver exceptional results as Tamarack's main target
- Lower Charlie Lake A members are actively being delineated

Other Horizons

- Several additional targets available that will benefit from half cycle development metrics due to existing infrastructure footprint

Optimized Well Placement & Completions

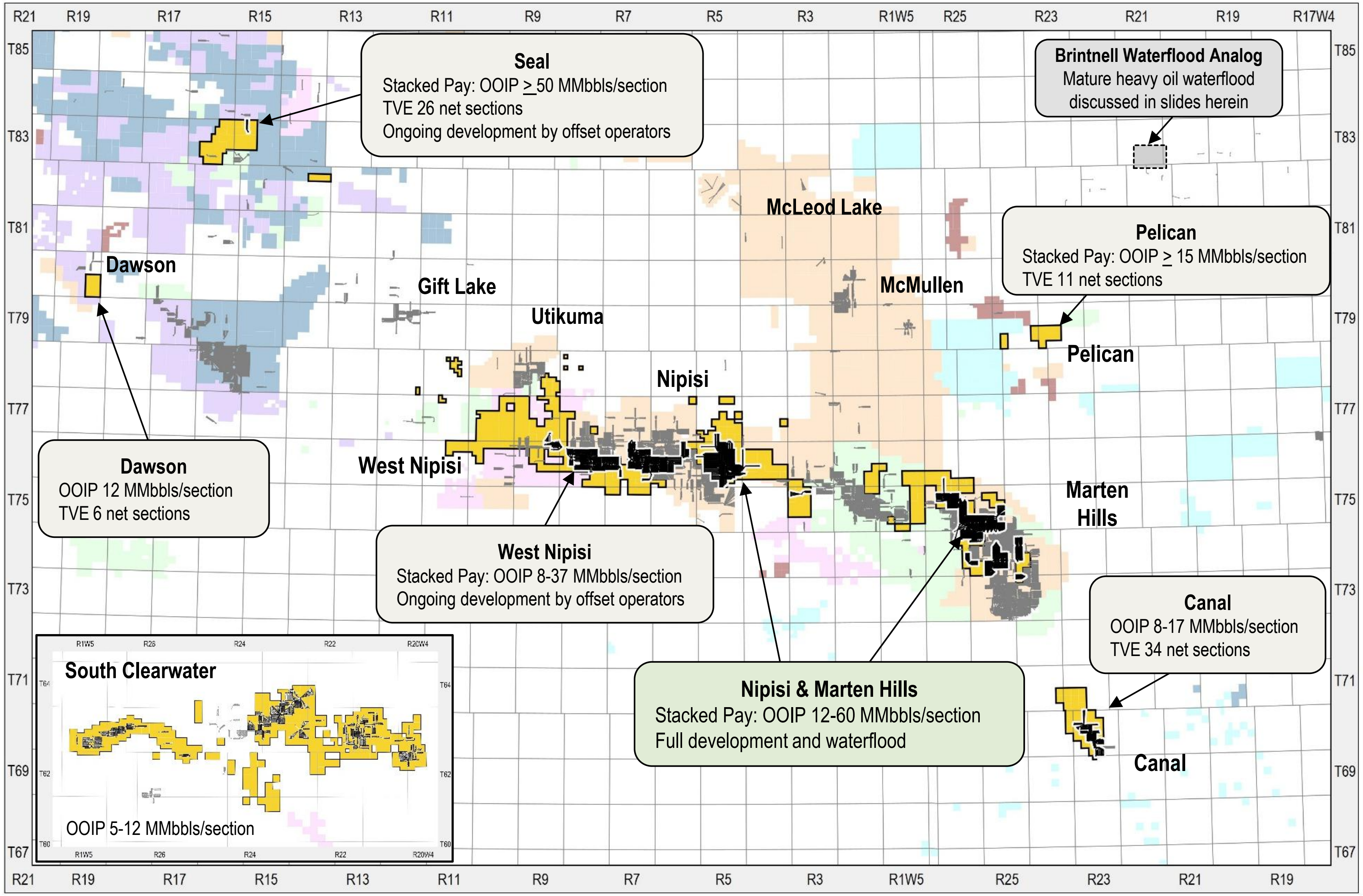
- Drilling extended reach horizontals to improve capital efficiencies
- Maximizing resource capture



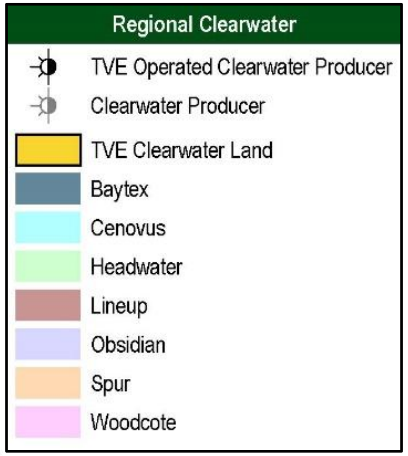
Clearwater – Zeroing In On a Unique Asset

Clearwater Expansive Resource

Largest Public Clearwater Producer With >11 Billion Barrels of OOIP[1]



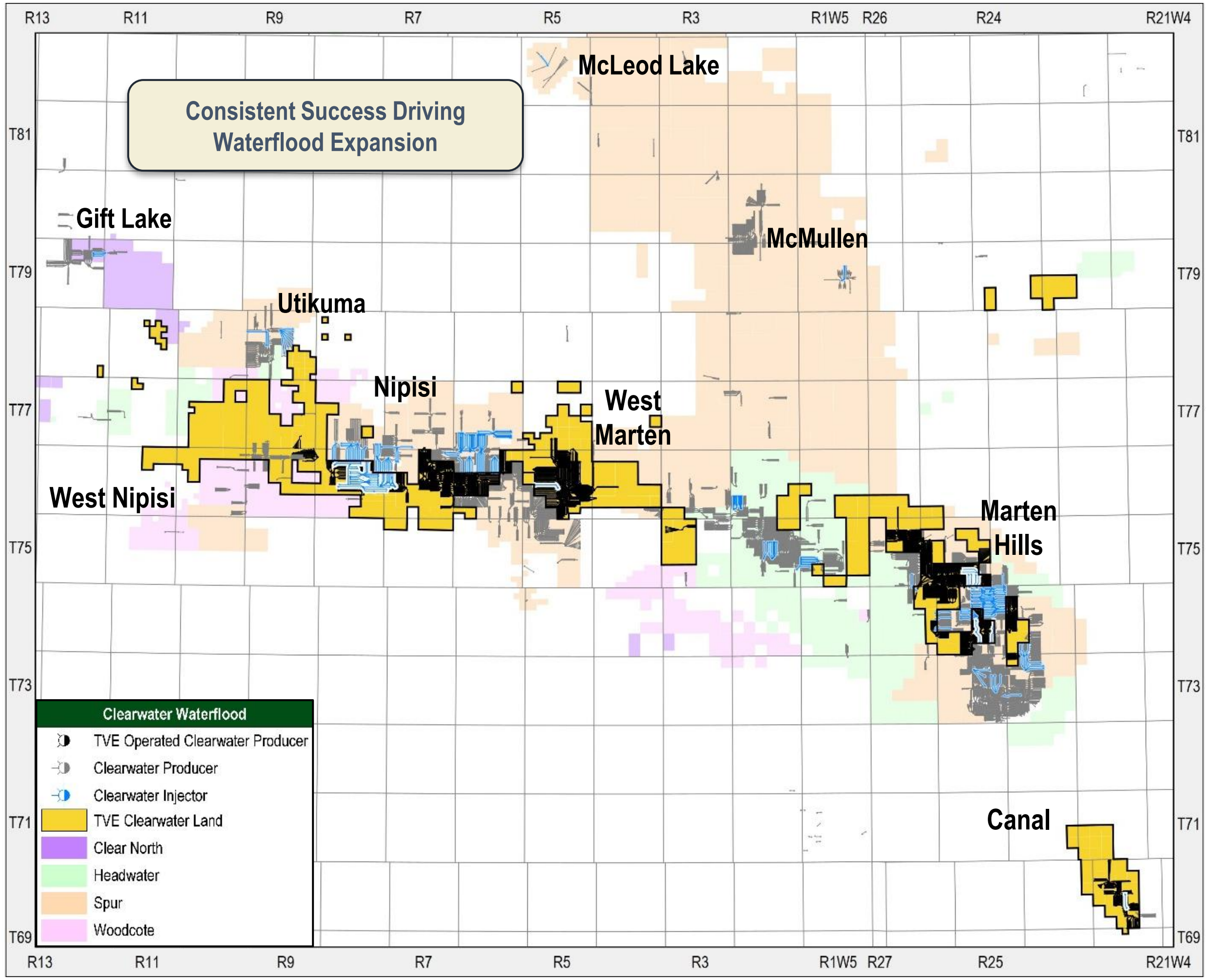
- **Expansive Resource:** >11 billion barrels of OOIP estimated on Tamarack lands[1]
- **Continued Growth:** Land additions, pool extensions and delineation of new targets contributing to growth of asset duration
- **Stacked Development:** Multi-zone development enhances operational and capital efficiency



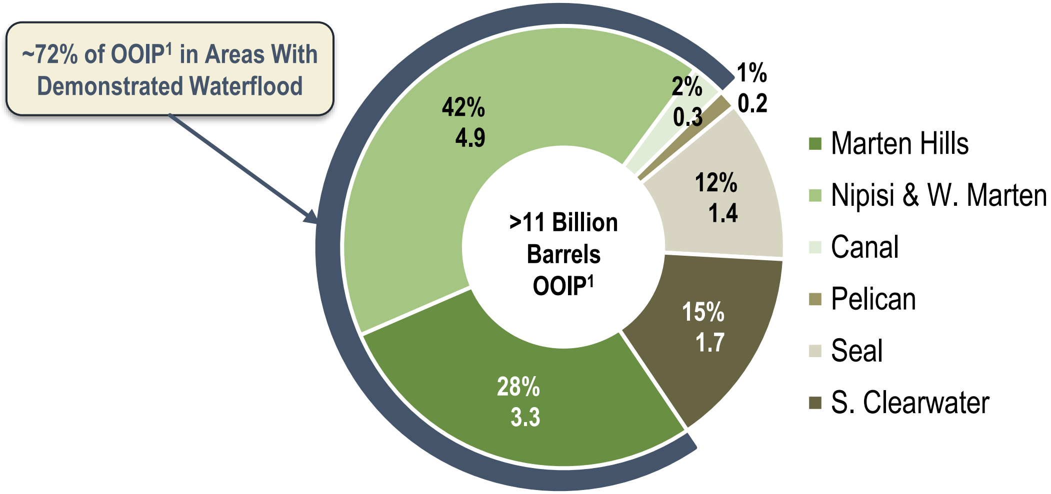
1) OOIP – original oil in place based on internal estimates.

Clearwater Waterflood Expansion

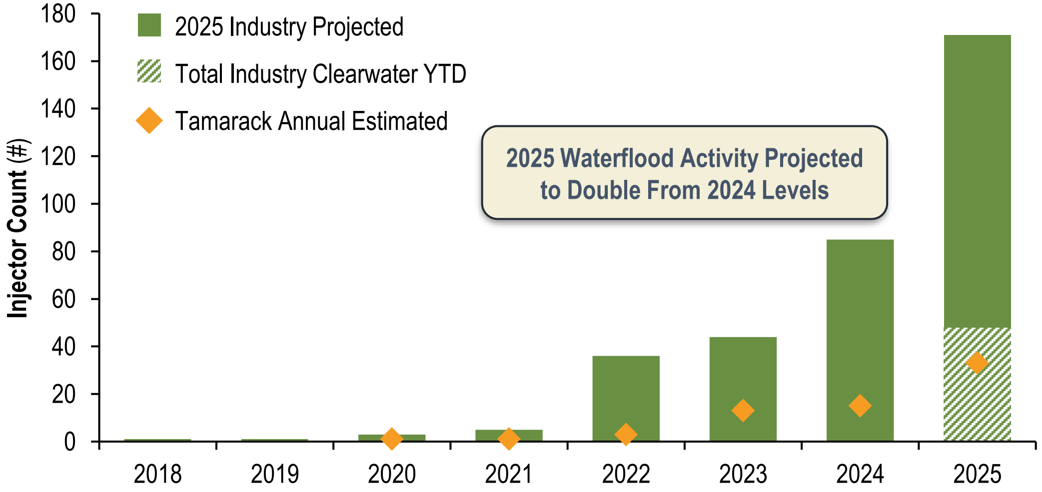
Activity Expansion Following Consistent Success



Clearwater OOIP by Area[1]



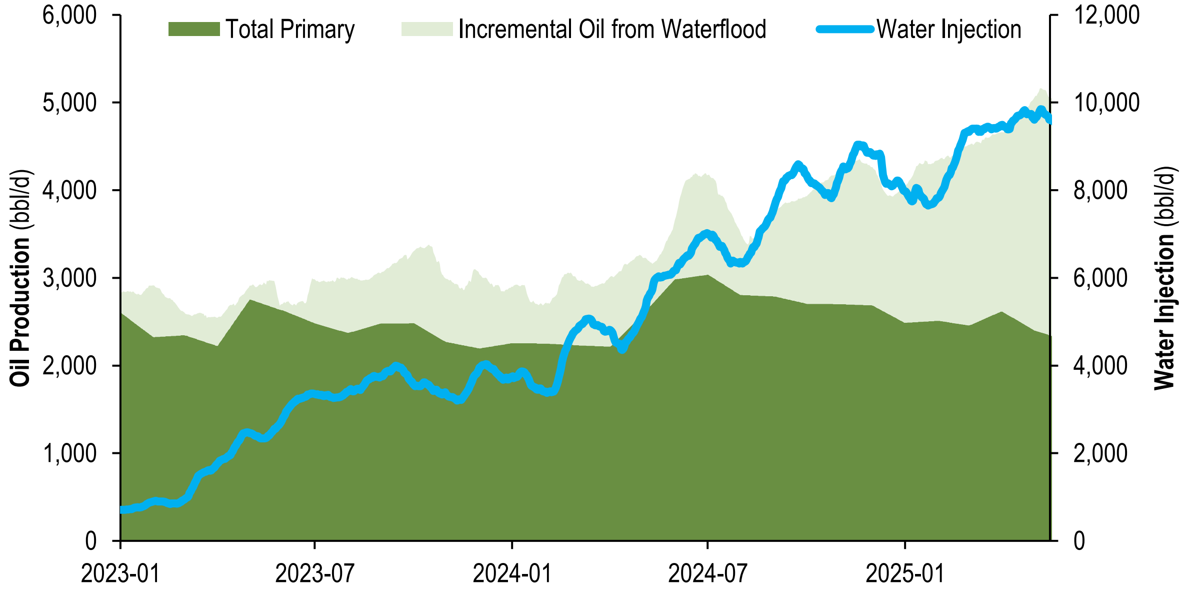
Industry Clearwater Injector Count by Year [2,3]

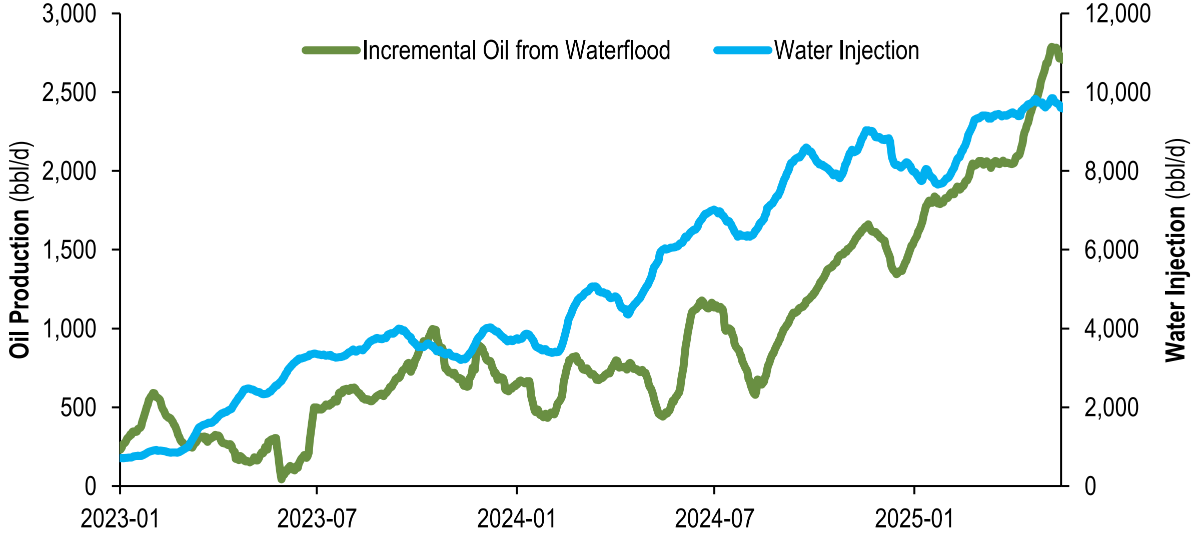


1) OOIP – original oil in place based on internal estimates.
2) 2025 Clearwater Injector count includes industry activity up to and including April 2025.
3) 2025 Projected industry count is based on Clearwater peer guidance and internal estimates.

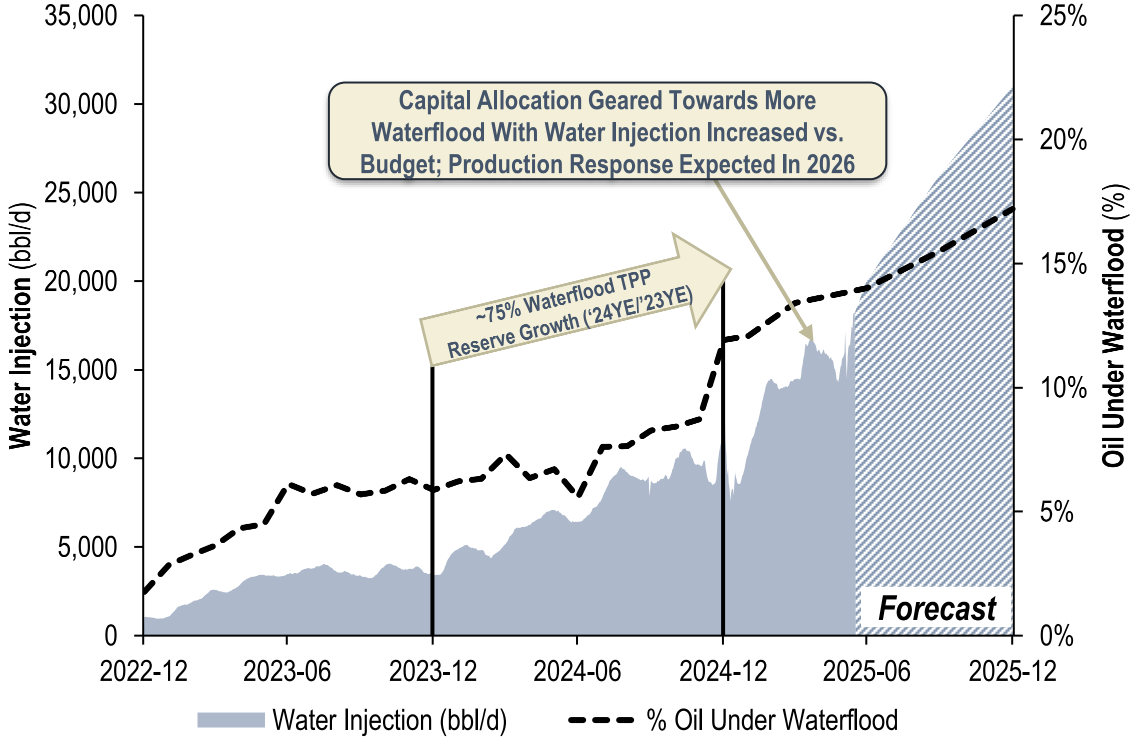
Injection Volume as a Leading Indicator

Correlation of Injection to Production Uplift





Clearwater Injection & Production Under Waterflood



- **Leading Indicator:** Increased injection correlating well with production uplift from waterflood
- **Ramping Up:** Maximizing per well injection and increasing pattern count in 2025 to more than double injection by year end

Clearwater Waterflood Design Concepts

Multi-Lateral Flexibility Provides Fit-For-Purpose Pattern Designs

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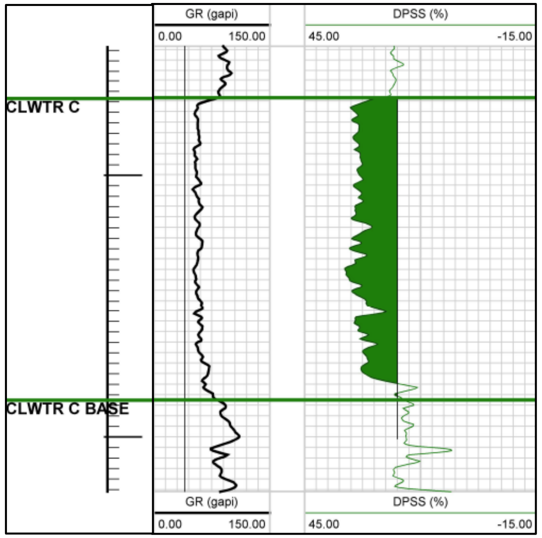
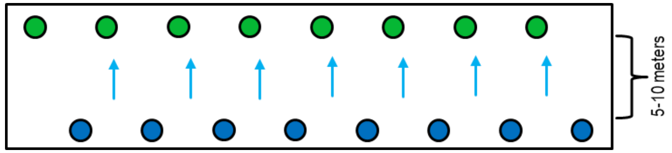
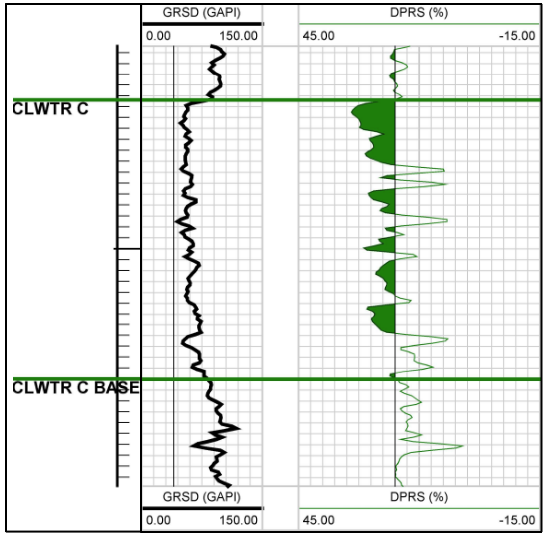
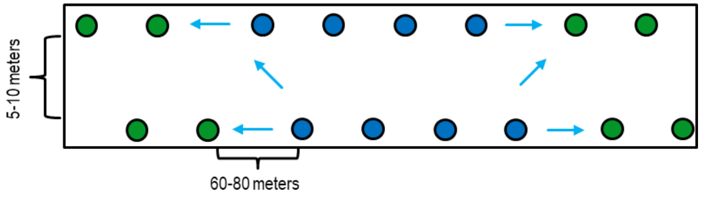
Stacked Pattern



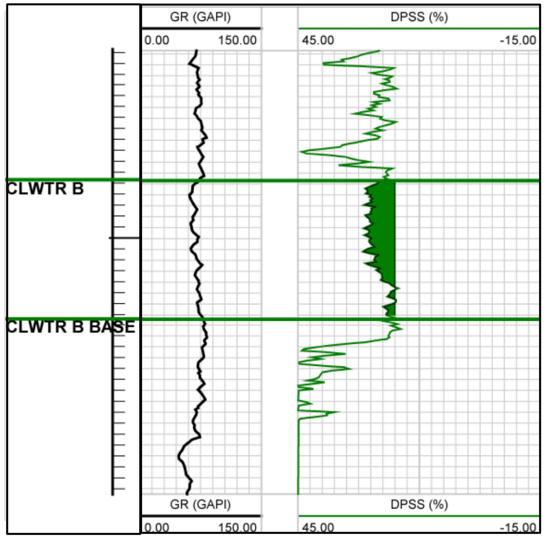


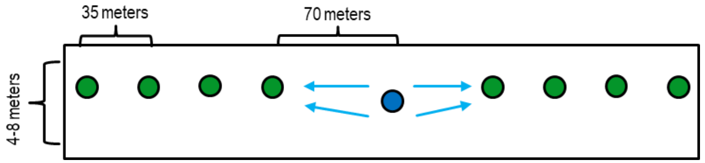
"W" Line Drive Pattern





Nipisi Line Drive Pattern





Stacked Pattern: Lower injection bench is highly effective in homogenous reservoir with limited barriers to vertical sweep

"W" Line Drive Pattern: Optimizing recovery and injectivity while overcoming vertical flow barriers; ensures efficient sweep of highest quality sand

Nipisi Line Drive Pattern: Effective pattern for targeting thinner sands with lateral waterflood

Tamarack Waterflood Performance

Achieving Stabilized Production at Scale

Clearwater Waterflood Continues to Exceed Expectations

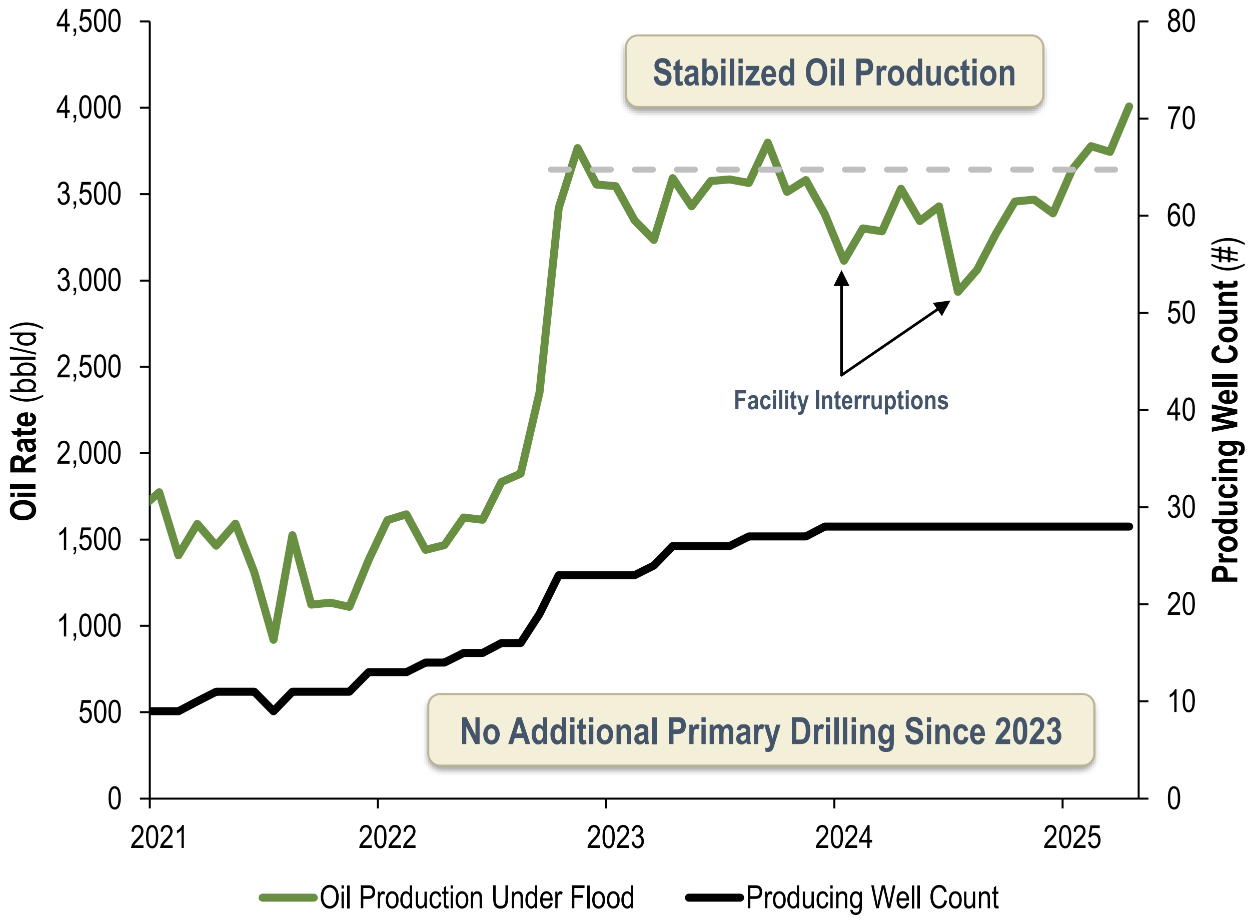
- In aggregate, pre-2024 wells under waterflood are not declining

Sustaining Capital Is Reduced as Decline Is Mitigated

- Low sustaining capital drives industry leading breakeven oil prices

Compounding Uplifts From Waterflood Expansion Supports Long-Term Durable Free Funds Flow Generation

Tamarack Oil Producers Under Waterflood Drilled Prior to 2024



Waterflood Reserve Growth[1]

Performance Pointing Towards Further Technical Revisions

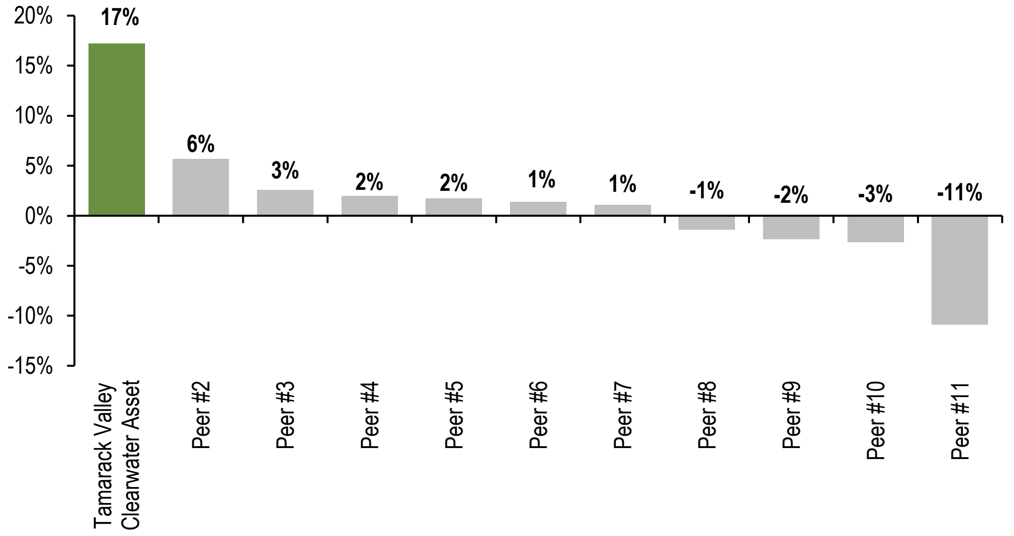
Clearwater Waterfloods Have Outperformed Reserve Forecasts

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

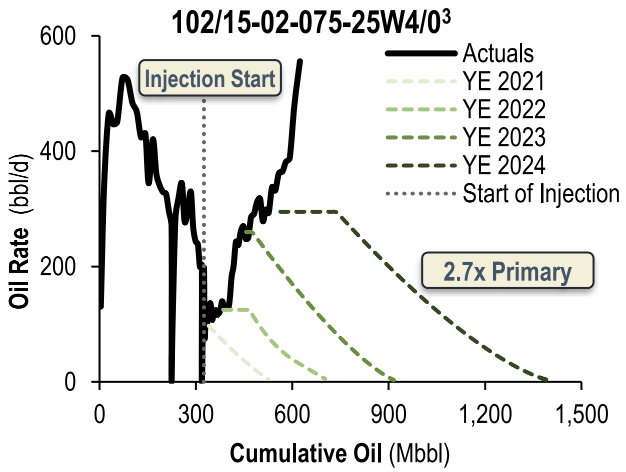
Waterflood Success Adds Tailwinds to Reserves

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

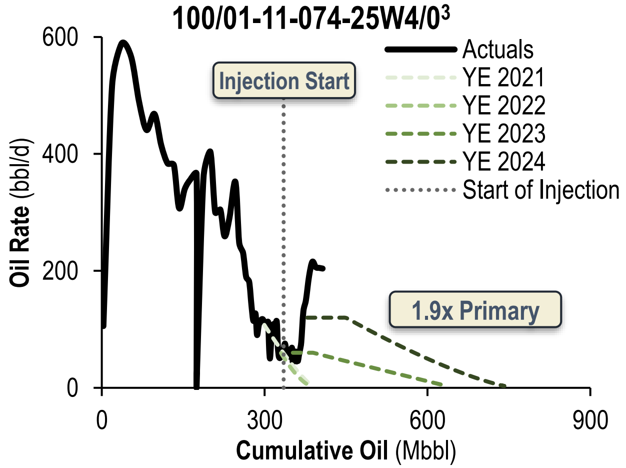
Total Proved Technical Revisions[2]
(as % of the reserves opening balance)



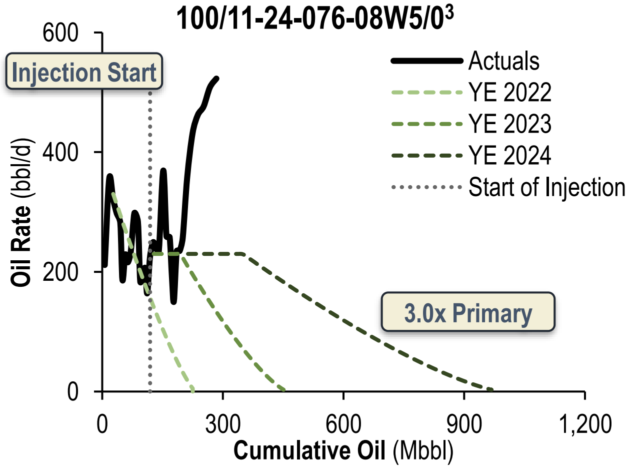
Marten Hills Stacked Pattern Pilot



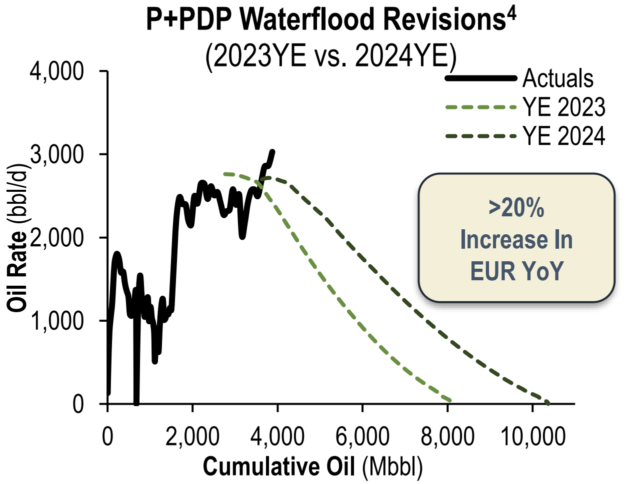
Marten Hills W Pattern Pilot



Nipisi Waterflood Pattern



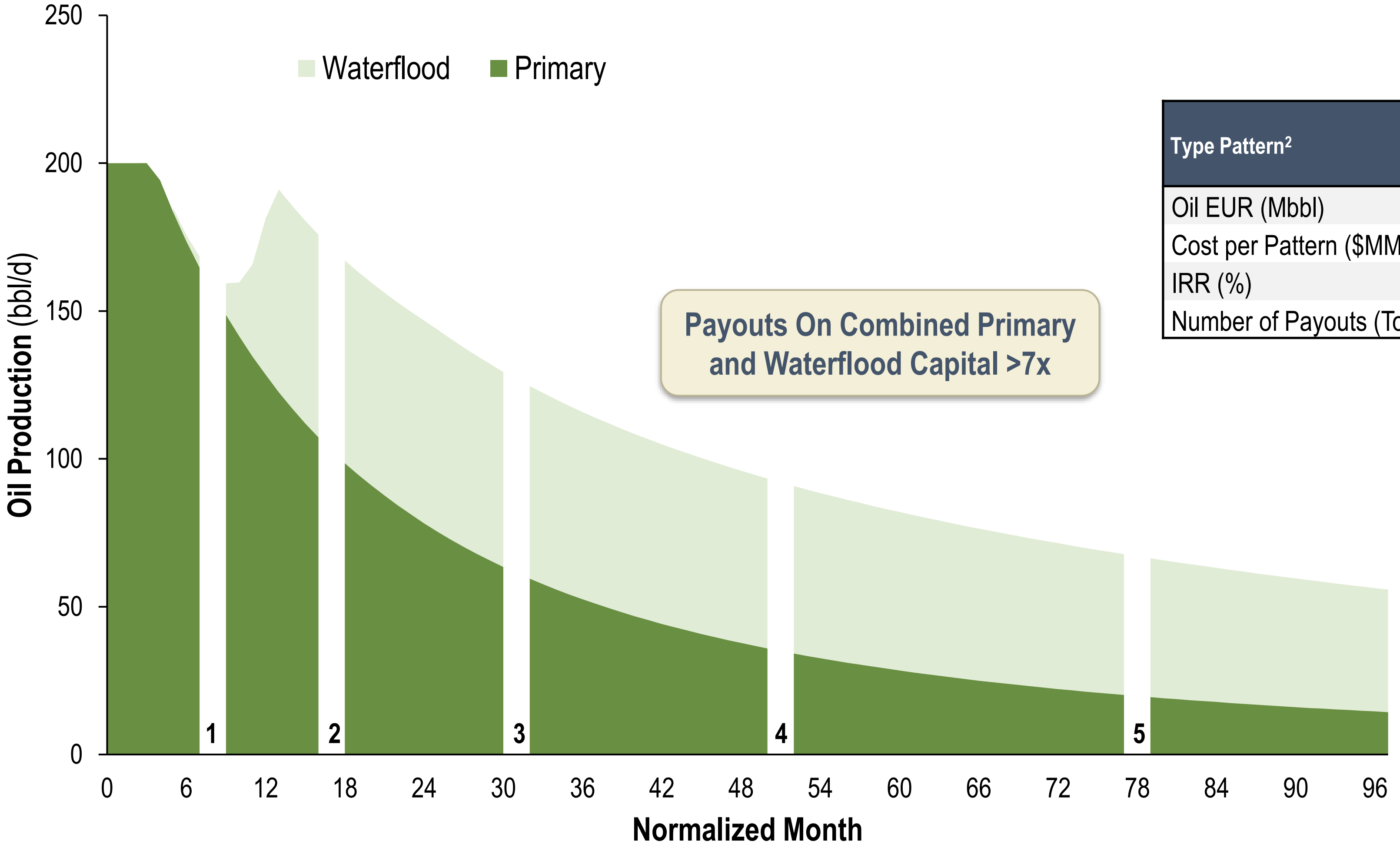
Nipisi & Marten Hills



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.

Clearwater Waterflood – New Injector Drill

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



Waterflood Economics

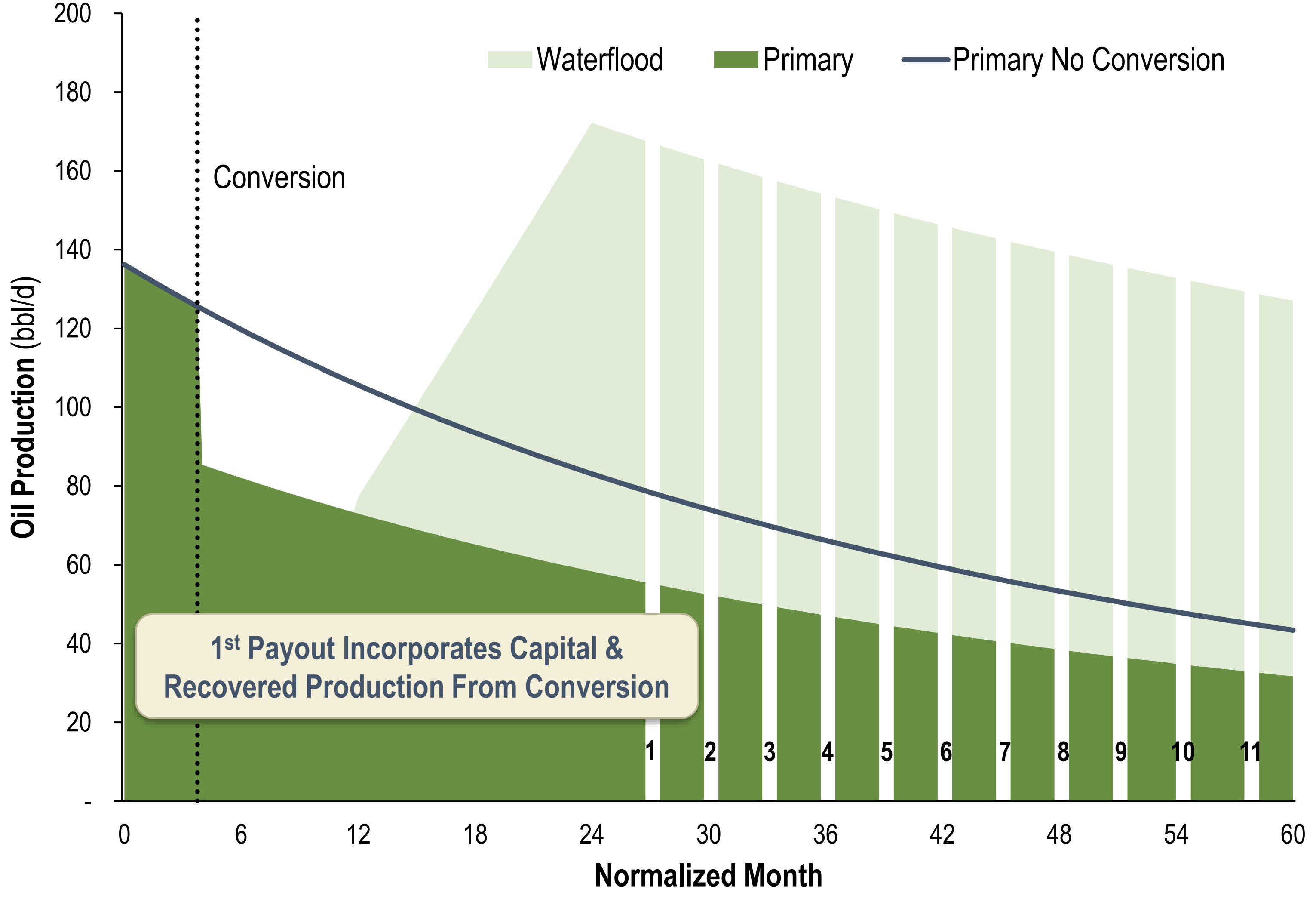
Type Pattern[2]	Primary[3] – West Marten "B" Sand Tier I	Waterflood Injector Wedge[4] – Internal Estimate	Total Project
Oil EUR (Mbbl)	205	308	513
Cost per Pattern ($MM)	$1.8	$1.2	$3.0
IRR (%)	>200%	100%	>200%
Number of Payouts (Total)	5.8	9.0	7.1

- **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".
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

Low-Cost Conversions Provide Substantial Returns



Waterflood Conversion Economics

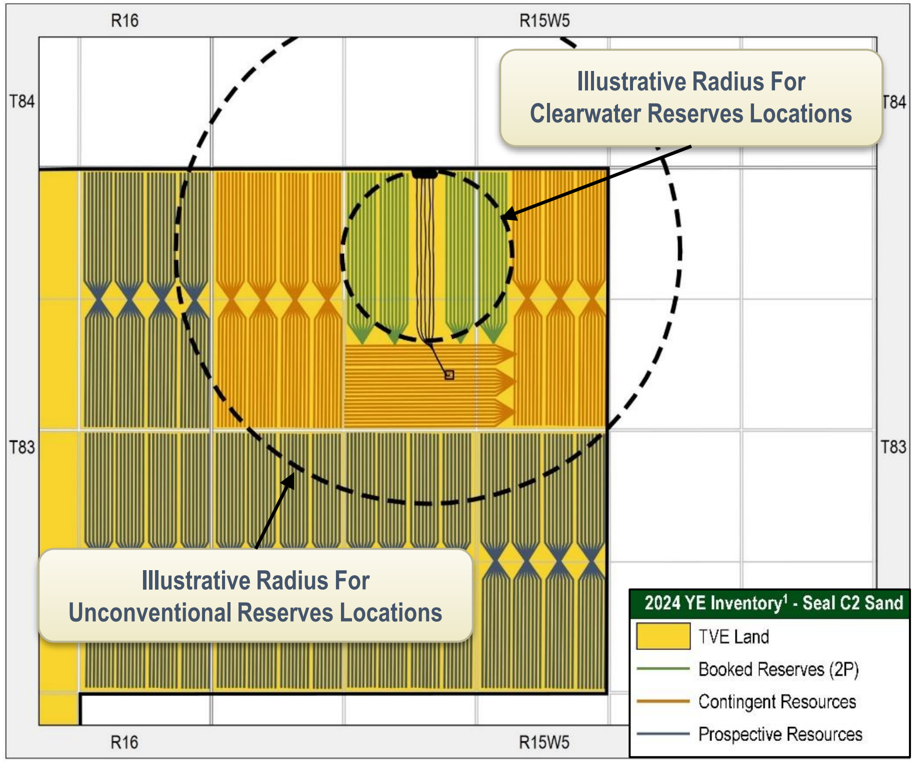
Type Pattern[2]	Waterflood Wedge[1] – Internal Estimate
Incremental Oil EUR (Mbbl)	850
Conversion Cost ($MM)	$0.4
IRR (%)	>100%
Number of Payouts (Total)	>30

- 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”.
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.

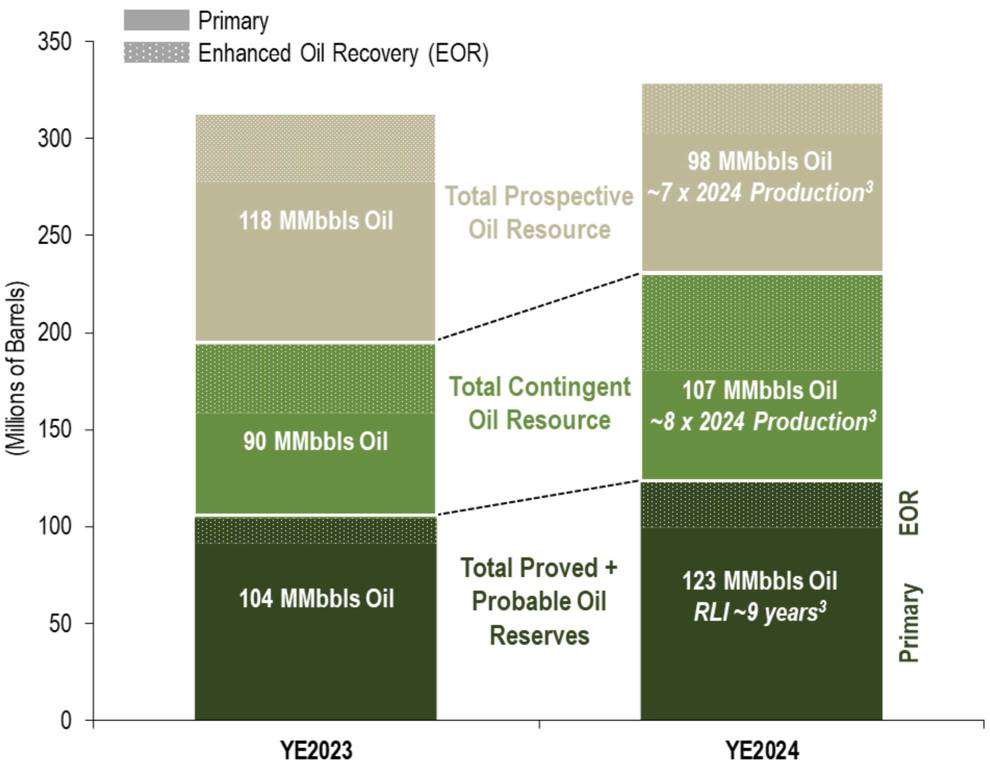
Clearwater Reserves and Resources

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]

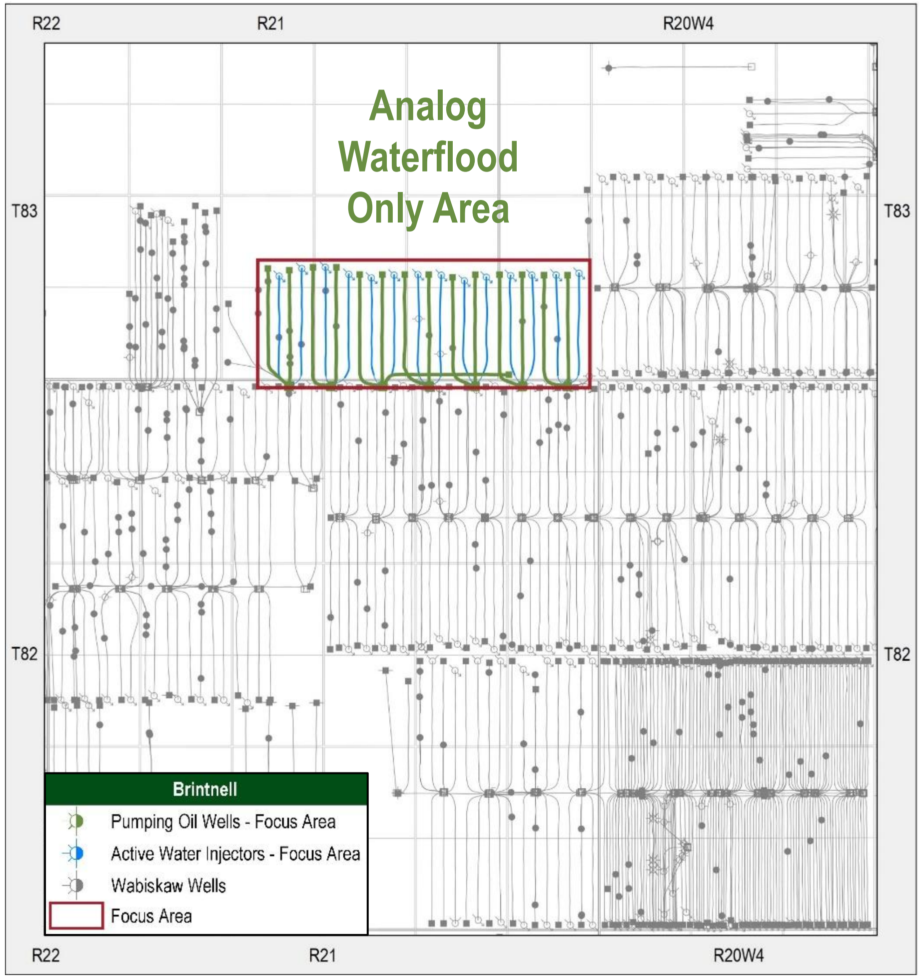


- Successful promotion of resources through delineation of inventory and waterflood in 2024 resulted in 19% growth in Contingent Oil Resource and 18% growth in TPP Oil Reserves

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 ~13.9 MMbbls.

Heavy Oil Waterflood Benchmark

Brintnell Provides Indications of Performance for Long-Life Heavy Oil Waterflood

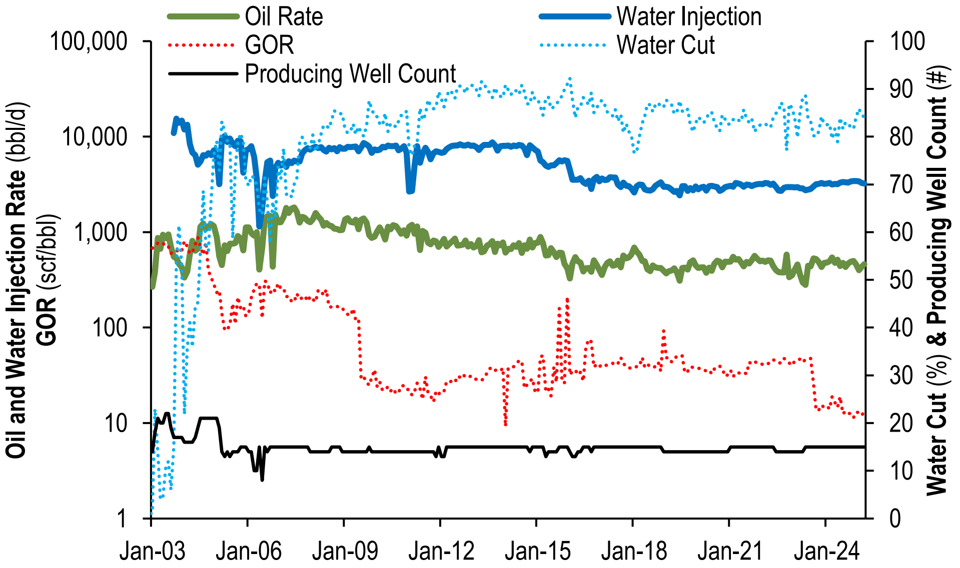


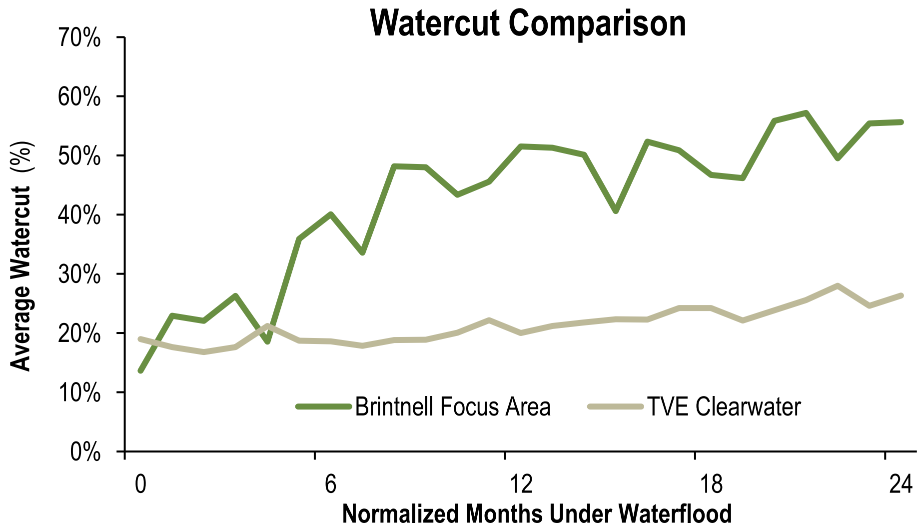
Expected Recovery Drastically Higher Than Initial Estimates:[1]

- Ultimate recovery estimated at ~25-30% of OOIP
- ~5-6x early primary recovery estimates and ~2x early total recovery estimates
- Very stable production profile for the last decade

Strong Relative Performance For Clearwater Floods:

- No major breakthrough events being observed
- Stable cuts or gradual cut changes being observed
- Producing more oil prior to breakthrough





1) Source: AER Performance Reports for In Situ Oil Sands Scheme Approval 9404.

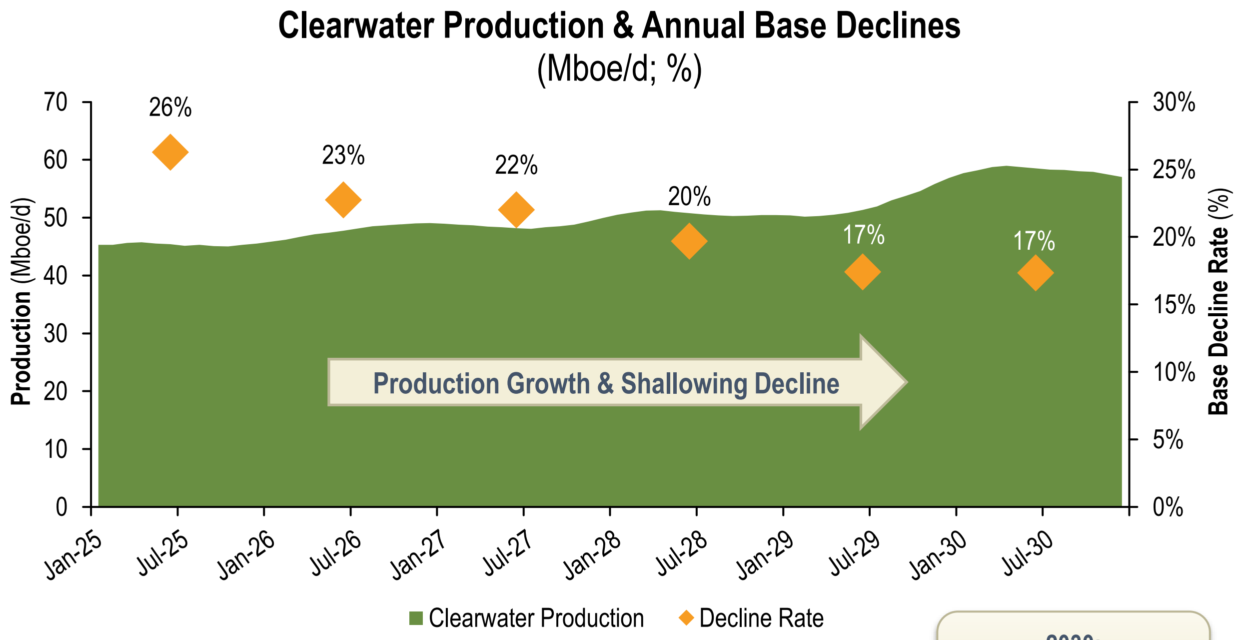
Clearwater 5-Year Plan

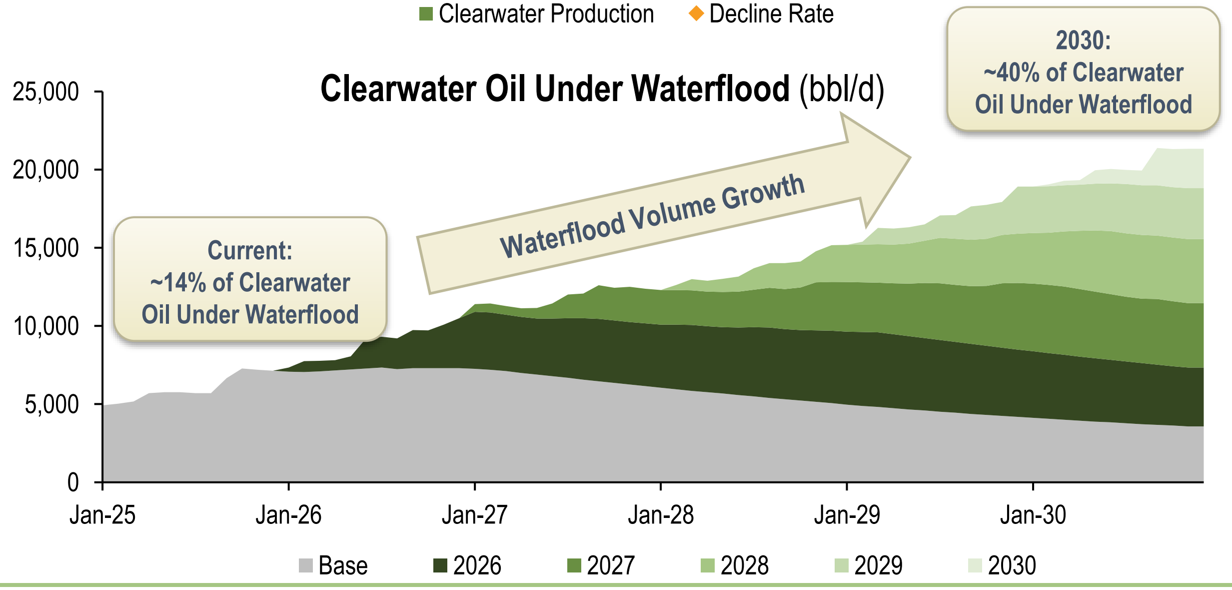
Waterflood Extends Asset Duration for Decades

Waterflood Provides Unique Combination of Shallowing Declines and Production Growth

- Waterflood investment drives Clearwater decline to ~17% by end of 5-year plan
- Sustaining capital reduction provides platform for enhanced production and free funds flow growth
- 5-year plan attains consistent growth in volumes supported by waterflood
- Post debt target, option for additional growth in Clearwater, including waterflood

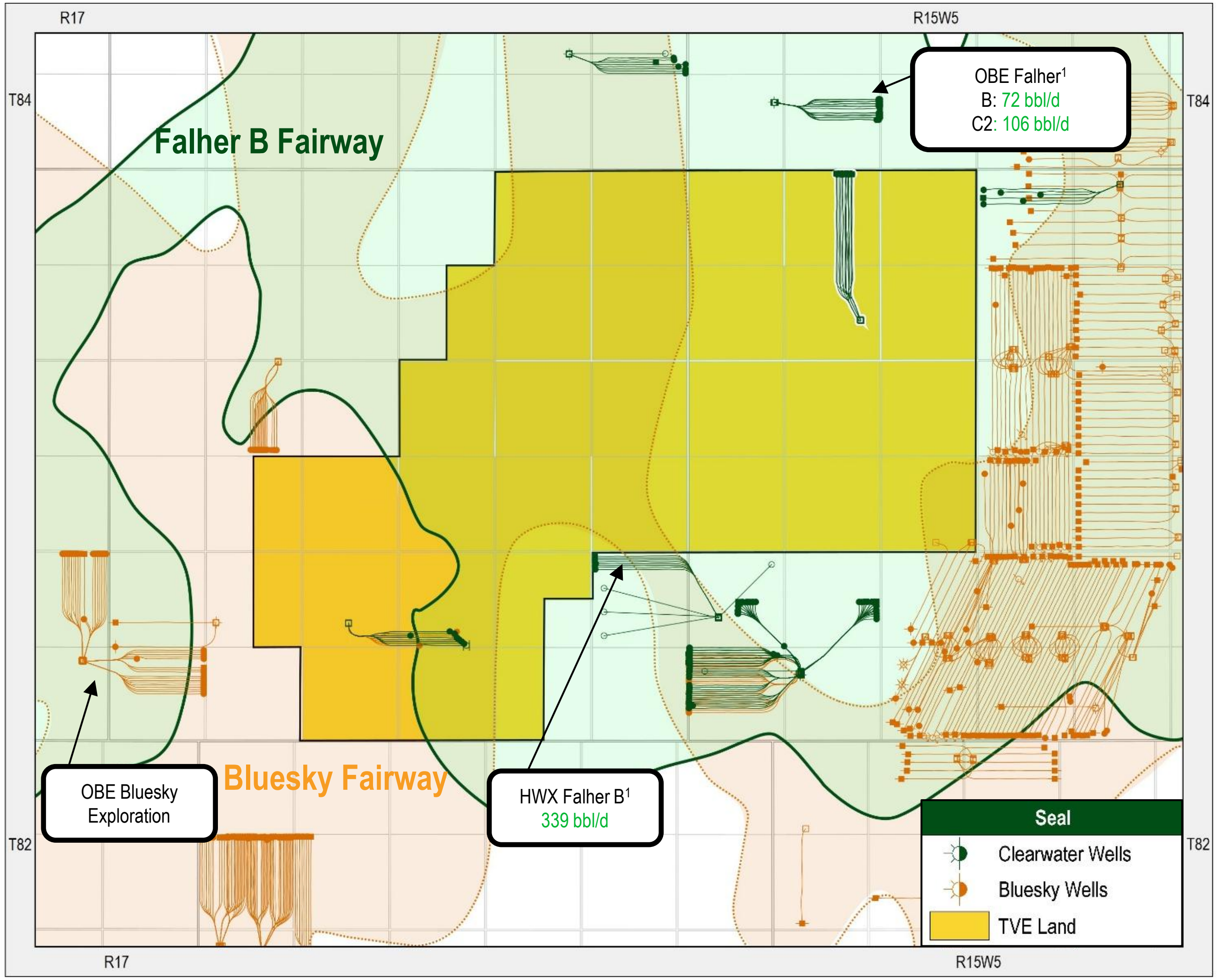
At 2030, Only 40% of Clearwater Oil Production Is Supported By Waterflood With Just 1.3% of Estimated Oil In Place Recovered





Seal: Future Growth Area

Continued De-Risking of Stacked Zone Potential



Seal

Land Position:

- ~30 gross sections (Oil Sands Tenure)

Stacked Development Upside:

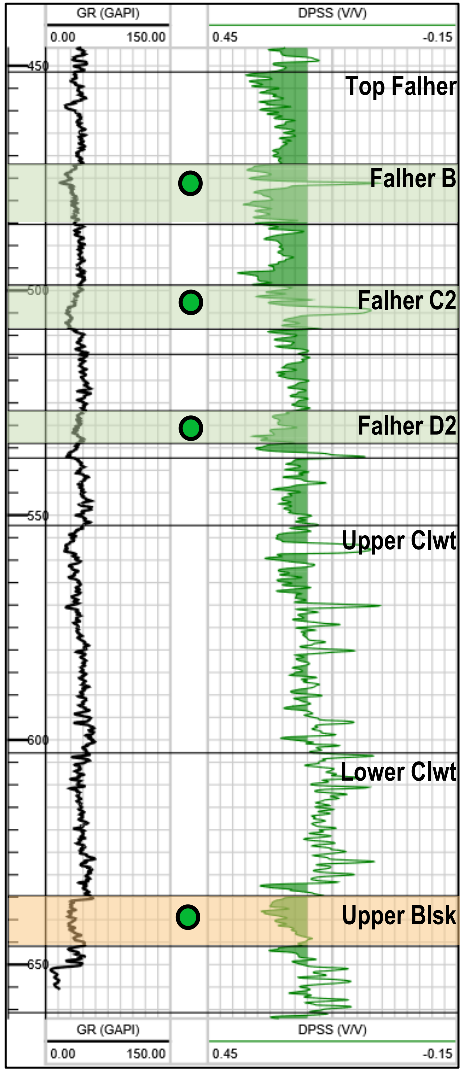
- Bluesky, Falher B, C2, & D2 Sands
- ≥70 MMbbl OOIP/Section
- 2.1 Billion Barrels OOIP

Offsetting Activity:

- Data used to help derisk TVE lands

Planned TVE Activity:

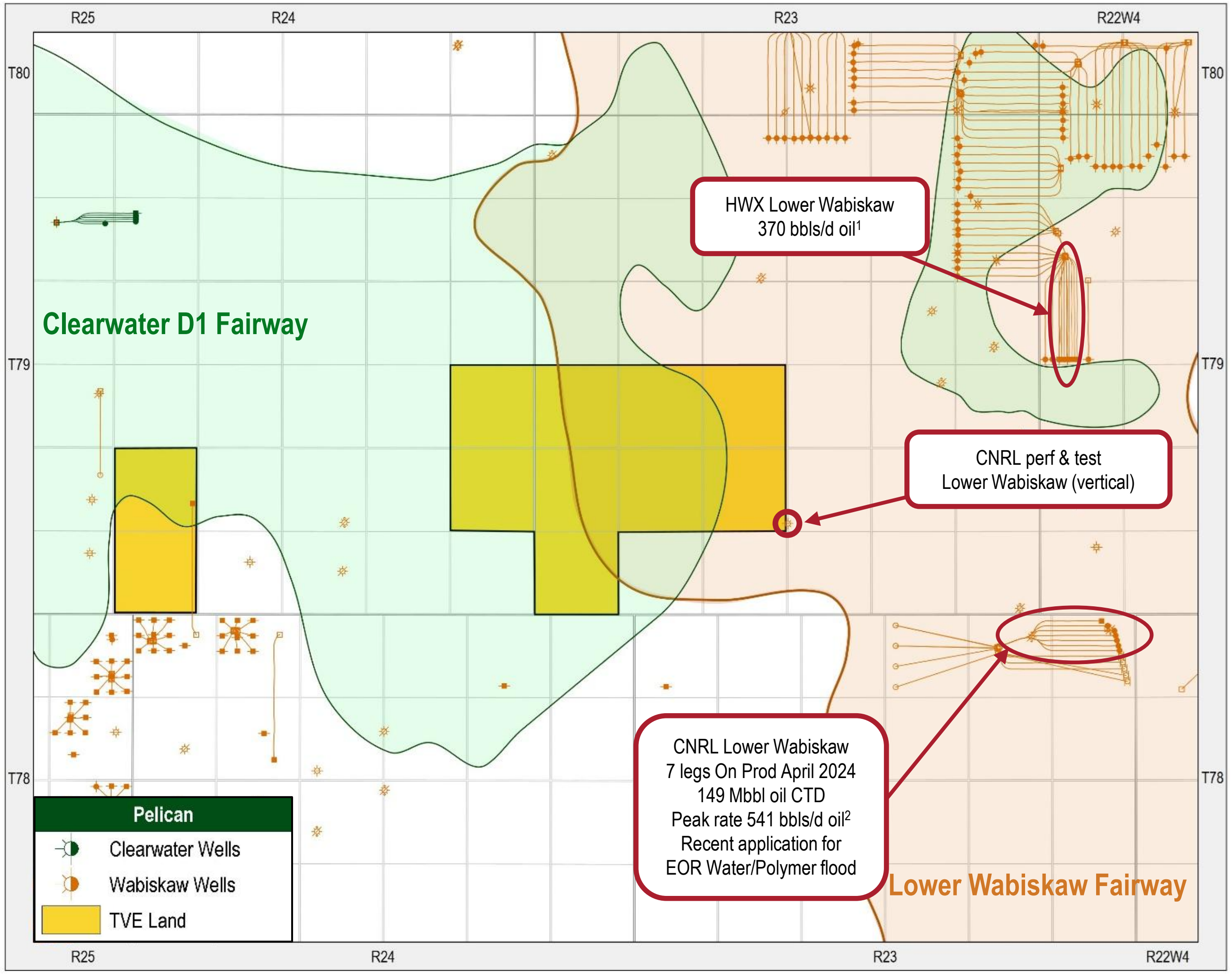
- Drill 1-2 derisk wells where multiple zones are stacked (targeting Bluesky, Falher B and/or Falher C2)



1) Source: GeoScout April 2025 Producing Day Average Oil Rate.

Pelican: Future Growth Area

Ongoing De-Risking of Stacked Zone Potential



Pelican

Land Position:

- ~11 gross sections (Oil Sands Tenure)

Stacked Development Upside:

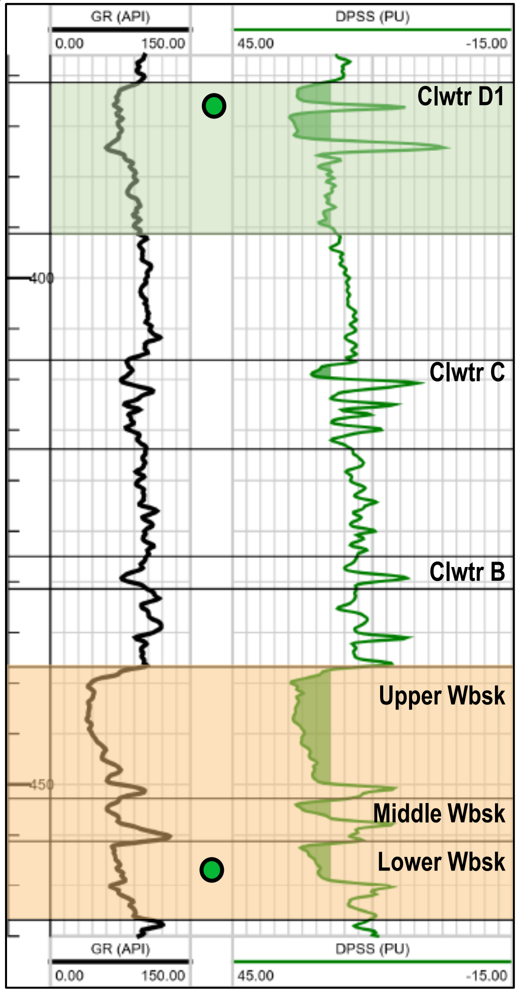
- Lower Wabiskaw & Clearwater
- ≥20 MMbbl OOIP/section
- 230 MMbbl OOIP

Offsetting Activity:

- Data used to help derisk TVE lands

Planned TVE Activity:

- Drill 2 derisk wells targeting Clearwater D1 and Lower Wabiskaw



1) Source: GeoScout April 2025 Producing Day Average Oil Rate.
2) Source: GeoScout Aug 2024 Producing Day Average Oil Rate.

Tailwinds for Canadian Heavy Producers

Tamarack Is In An Excellent Position To Capture Strong Netback Now and In The Future

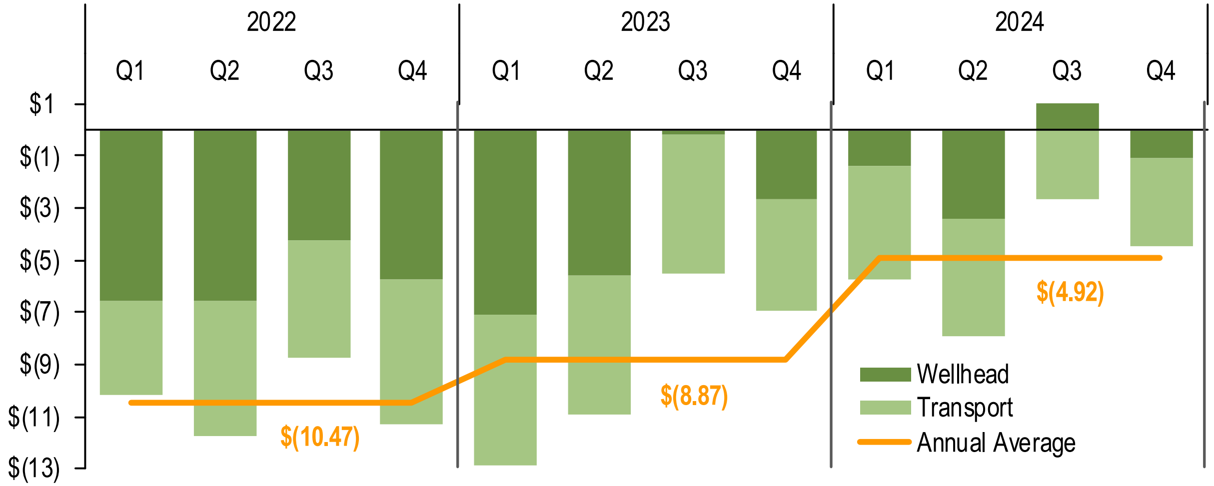
WCS Continues to Trade Exceptionally Strong Since the Start-Up of TMX (~US$9/bbl); Expected to Stay Strong in Future Years:

- Additional trunkline plans from Alberta hubs to eclipse producer development plans
- Increasing access to water / global refining market
- Lack of alternative heavy feedstock for USGC refiners

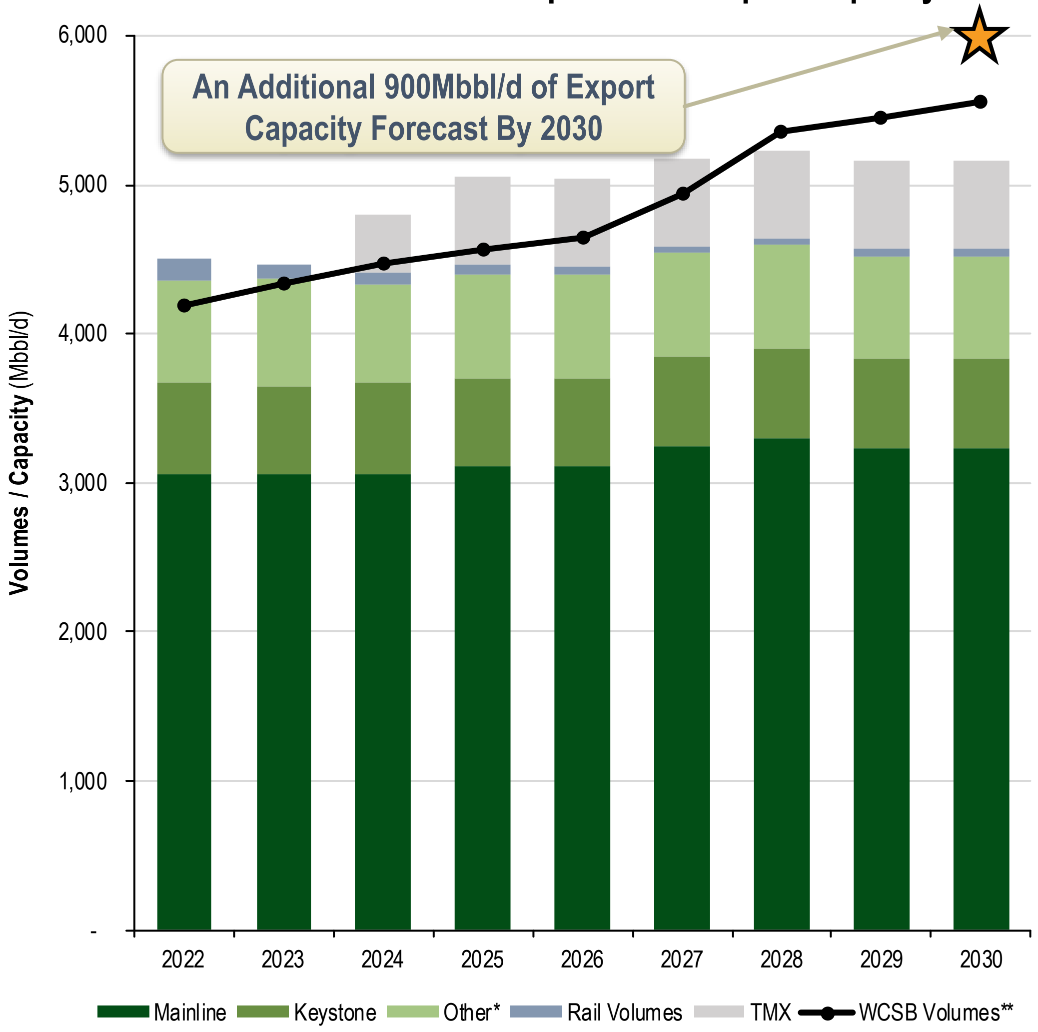
Tamarack Executed its Strategic Plan by Significantly Improving Heavy Oil Wellhead And Transportation Deductions:

- 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

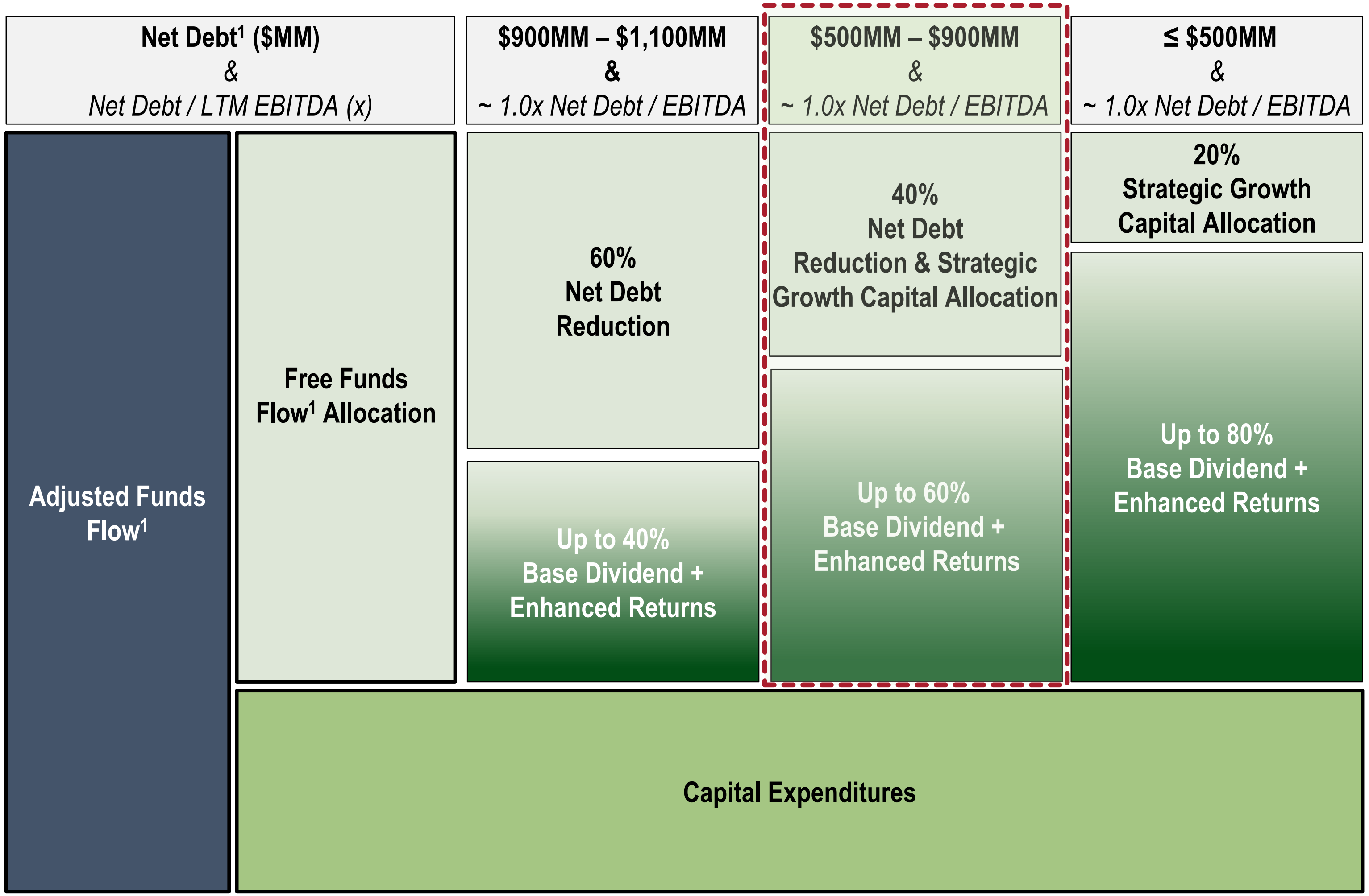


Sources: Peters & Co. Limited estimates, company reports, and government data.
Note: *Other includes Express, Rangeland and Trans Mountain pipelines.
**Volumes presented net of domestic WCSB refinery demand. TMX presented as half capacity in 2024 for illustrative purposes.

Returns to Shareholders & Closing Remarks

Return of Capital Framework

Allocating 60% of Free Funds Flow To Shareholders Through Sustainable Dividend & Share Buybacks



Simplified Framework

- Free funds flow[1] to be allocated between:
  1. Debt
  2. Direct investor returns
     - Base dividend
     - Enhanced returns (long-term share buybacks)
  3. Strategic growth capital

Tamarack Has a Net Debt Target of ~$500 MM

~1.0x Net Debt / EBITDA at US$45/bbl WTI[2]

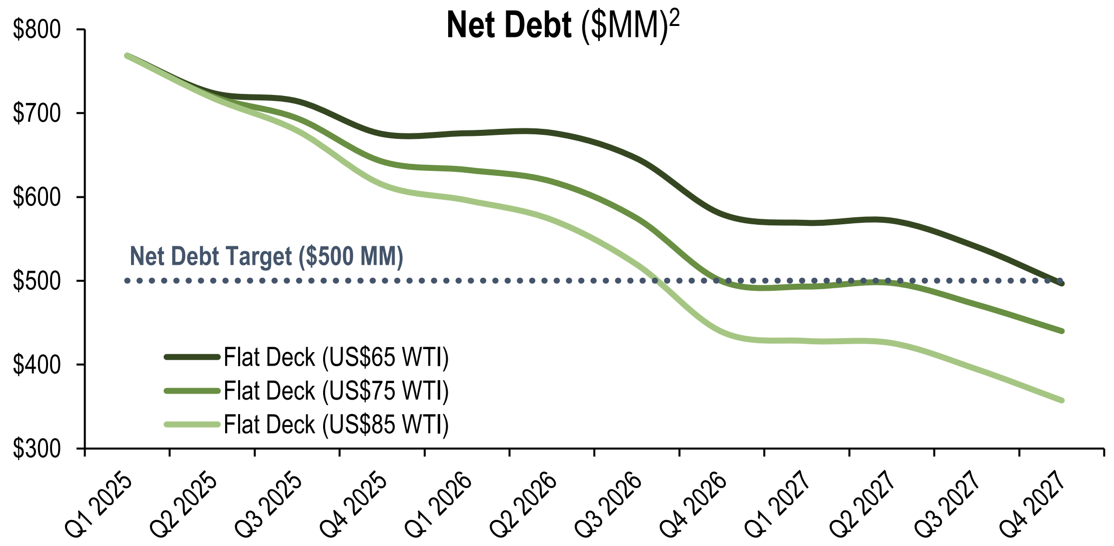
Q4/24: Increased Base Dividend Per Share by ~2%

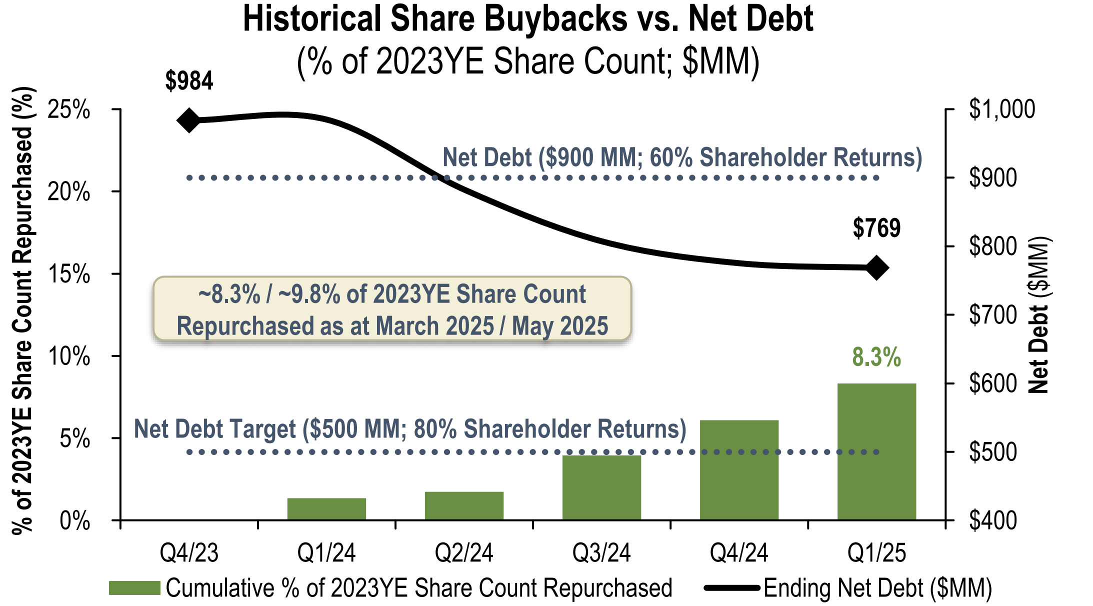
1) See Disclaimers – "Specified Financial Measures".
2) Flat US$45/bbl pricing assumes US$(12.75)/bbl WCS basis, US$(2.50)/bbl MSW basis, 1.30 US$/C$, and C$3.00/GJ AECO.

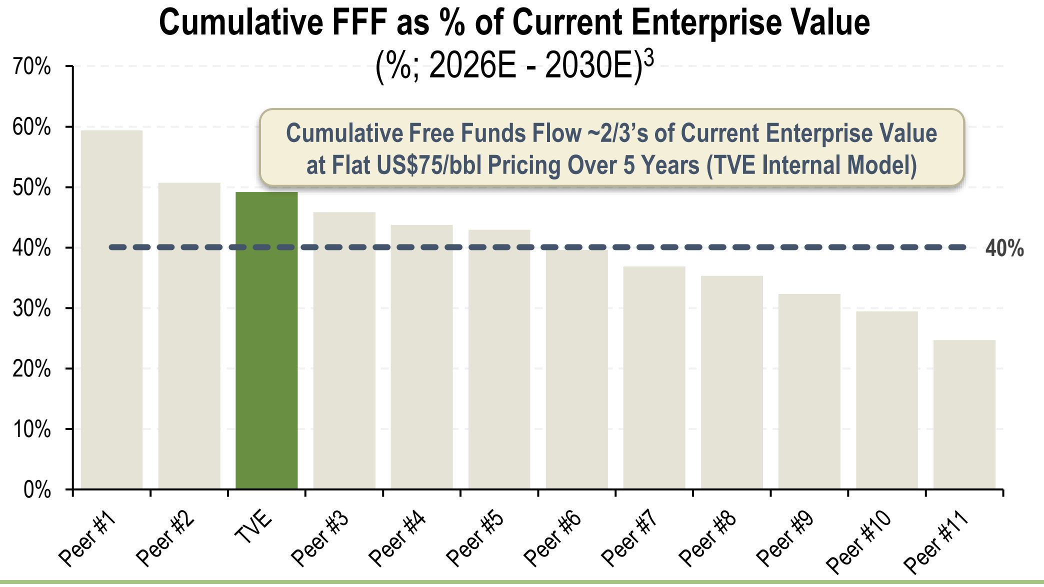
Maintaining Balanced Debt Reduction and Shareholder Returns

Compounding Success On a Per Share Basis

- **Since the major Clearwater Acquisition (Oct. 2022), Tamarack Has Returned >$2.00 / Sh.**
  - Reduced debt by ~$650MM or ~$1.30 per current share (as at Q1/25)
  - Cumulative buybacks of ~$192MM (8.3% of 2023 YE Shares) or ~$0.38 per current share (as at Q1/25)
  - Cumulative base dividends of ~$199MM or ~$0.40 per current share (as at Q1/25)
- **Updated 5 Year Plan Forecast to Meet Debt Target ($500MM) In 2027, Two Years Earlier Than Previous Plan, Including Shareholder Returns[1]**
  - Increasing production, lowering declines and sustaining capital
  - Once debt target achieved: additional strategic growth capital allocation optionality







See Disclaimers – "Specified Financial Measures". Current share count as at May 2025.
1) Based on updated 5 yr. plan at flat US$75/bbl pricing.
2) Estimated net debt assumes current return of capital framework.
3) Source: Peters & Co. forward estimates on strip pricing as at June 16, 2025. TVE estimate per Peters & Co.
Peer group includes ATH, BTE, CJ, HWX, MEG, NVA, OBE, SCR, SGY, VET, and WCP.
Flat internal US$75/bbl WTI price deck assumes US$(13.50) WCS basis, US$(3.00) MSW basis, C$3.00/GJ AECO and 1.30 US$/C$.

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

Leverage Top Tier Asset Quality and Waterflood To Mitigate Declines And Sustaining Capital

Unique Ability To Lower Declines & Grow Production

Proven Waterflood Mitigates Decline & Enhances Duration

Sustainable Long-Term Free Funds Flow

- Low Sustainable Capital & High Margin Barrels

Compounding Returns to Shareholders

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

Flexible Capital Allocation

- Balance Sheet Optimization, Long-Term Buybacks and Growth Optionality

DAFFFPS Growing Exponentially Given Multiple Payback Capital

Corporate Culture that Attracts and Retains High Performing People

Strong Partnership With Indigenous Communities

Wâpiscânis WASESKWAN NIPIY

Top Tier Asset Quality With Large OOIP:

Focused, Large Scale, Highly Economic Asset Portfolio

TAMARACK VALLEY ENERGY

Q&A Session

Corporate Information

tamarack valley ENERGY

Executive

Brian Schmidt (Aakaikkitstaki)	President & Chief Executive Officer
Steve Buytels	Chief Financial Officer
Kevin Screen	Chief Operating Officer
Rocky Baker	VP Marketing
Lynne Chrumka	VP Exploration
Christine Ezinga	VP Business Development & Sustainability
Kevin Johnston	VP Finance
Scott Shimek	VP Production & Operations
Ben Stoodley	VP Engineering

Board of Directors

John Rooney [1, 3, 4]	Chairman of the Board
Brian Schmidt (Aakaikkitstaki)	President & Chief Executive Officer
Caralyn Bennett [2, 4]	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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Suite 1700, 525 – 8th Avenue S.W.
Calgary, AB T2P 1G1

Phone: 403.263.4440

www.tamarackvalley.ca

Investor Contact Information

Brian Schmidt	**Steve Buytels**	**Christine Ezinga**
President & Chief Executive Officer	Chief Financial Officer	VP Business Development & Sustainability

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 "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 strategy, objectives, strength, focus; 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; plans in respect debt paydown (including achieving debt target of $500 million in 2027), return of capital and growth optionality; Tamarack's capital program, budget and guidance for the remainder of 2025 (including Tamarack's continued flexibility under its 2025 capital program and resilience in lower price environments), including future production levels, including annual average production; oil and liquids weighting and changes thereto; 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; 2025 free funds flow forecasts and allocations; application of EOR and expectations in respect of waterflood development including the expectation of 2x to 3x primary recovery and outperforming reserve forecasts; expectations surrounding the expansion of the Clearwater resource; development opportunities and drilling locations; expectations regarding economics and payouts of the Company's wells; the corporate decline rate and improvements thereto with greater exposure to assets under waterflood; and risk management activities, including hedging positions and targets. Statements relating to "reserves", "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 success of future drilling, development and completion 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 narrowing 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.

Disclaimers *(Cont.)*

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 2025 guidance; risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production; 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); competition for skilled labour; incorrect assessments of the value of acquisitions; failure to realize the benefits of acquisitions; 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 ongoing negotiations between the U.S. and Canadian governments are not successful and one or both of such 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, including hostilities in Iran, Gaza and Israel. 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 months ended March 31, 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); 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, capital budget and guidance for the remainder of 2025, 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, Tamarack's expectation of cumulative after-tax free funds flow of ~$1.8B at US$75/bbl, 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 2025 guidance are disclosed in the Company's press release dated December 4, 2024. Changes in forecast commodity prices, differences in the timing 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 and January 10, 2025 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.

Disclaimers *(Oil and Gas Advisories Cont.)*

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 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 thinks 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. 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: The term original-oil-in-place ("OOIP") is equivalent to total petroleum initially-in-place ("TPIIP"). TPIIP, as defined in the COGE Handbook, is that quantity of petroleum that is estimated to 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 TPIIP 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 TPIIP 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 TPIIP will never be recovered. OOIP disclosed herein was internally estimated by the Company's internal qualified reserve evaluators ("QRE") and prepared in accordance with NI 51-101 and the COGE Handbook. "Internally estimated" means an estimate that is derived by the Company's internal QRE and prepared in accordance with NI 51-101. Internal estimates contained in this presentation were prepared effective as of December 31, 2024.

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 calculated by taking cash-flow from operating activities, on a periodic basis, deducting current income tax expense and interest expense (excluding fees) and adding back income tax paid, interest paid, changes in non-cash working capital, expenditures on decommissioning obligations and transaction costs settled during the applicable period. since Tamarack believes the timing of collection, payment or incurrence of these items is variable. Management believes adjusting for estimated current income taxes and interest in the period expensed is a better indication of the adjusted funds generated by the Company. Expenditures on decommissioning obligations may vary from period to period depending on capital programs and the maturity of the Company's operating areas. Expenditures on decommissioning obligations are managed through the capital budgeting process which considers available adjusted funds flow. Tamarack uses adjusted funds flow as a key measure to demonstrate the Company's ability to generate funds to repay debt, pay dividends and fund future capital investment. 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 calculated by taking adjusted funds flow and subtracting capital expenditures, excluding acquisitions and dispositions. Management believes that free funds flow provides a useful measure to determine Tamarack's ability to improve returns and to manage the long-term value of the business. "Free funds flow breakeven (capital management measure)" is determined by calculating the minimum WTI price in US/bbl required to generate free funds flow after base dividends equal to zero, sustaining current production levels and all other variables held constant. Management believes that free funds flow breakeven provides a useful measure to establish corporate financial sustainability. "Net debt (capital management measure)" is calculated as credit facilities plus senior unsecured notes, plus deferred acquisition payment notes, plus working capital surplus or deficiency, plus other liability, including the fair value of cross-currency swaps, plus government loans, plus facilities acquisition payments, less notes receivable and excluding the current portion of fair value of financial instruments, decommissioning obligations, lease liabilities and the cash award incentive plan liability. "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 by taking production expenses less third-party processing income from Tamarack’s facilities. 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 and GLJ Reserve Reports 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