TSX: TVE

CREATING SUSTAINABLE VALUE

July 2025 | Investor Presentation

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Corporate and Operational Snapshot

The Largest Public Clearwater Producer

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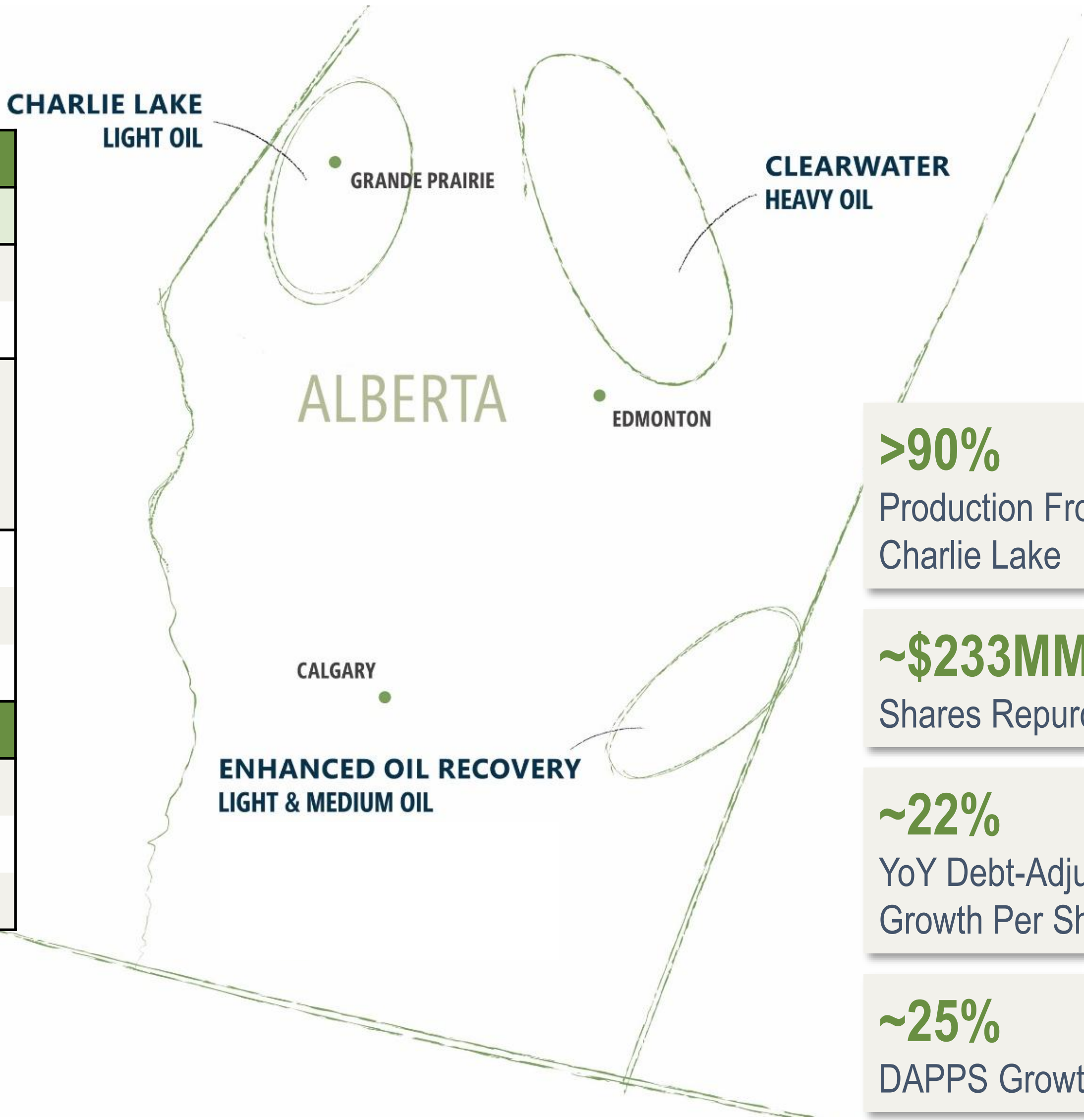
Corporate Overview		
Ticker Symbol		**TSX: TVE**
Shares Outstanding (Basic)[1]	*(MM)*	500
Share Price (July 29, 2025)[1]	*($/Sh.)*	*$5.33*
Market Capitalization[1]	***($B)***	**$2.7**
Q2 2025 Net Debt	***($B)***	**$0.7**
Enterprise Value	***($B)***	**$3.4**
Annual Base Dividend[1]	*($/Sh.)*	$0.153
Annual Base Dividend Yield[1]	*(%)*	~2.9%
Q2 2025 Net Debt / LTM EBITDA	*(x)*	0.7x
2025 Updated Guidance Highlights		
Production[2]	*(boe/d)*	67,000 – 69,000
Average Liquids Weighting	*(%)*	83% – 85%
Capital Expenditures[3]	*($MM)*	$400 – $420



>90%
Production From Clearwater and Charlie Lake

~$233MM | ~10%[4]
Shares Repurchased Since Dec. 2023

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

~25%
DAPPS Growth (Q2/25 vs. Q4/23)[5]

1) Share count as at the end of June 2025. Dividend yield uses Tamarack share price as at July 29, 2025.
2) 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 NGL 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 June 30, 2025.
5) Debt adjusted with a TVE share price of ~$3.81/Sh. (2024A average trading price). 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 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

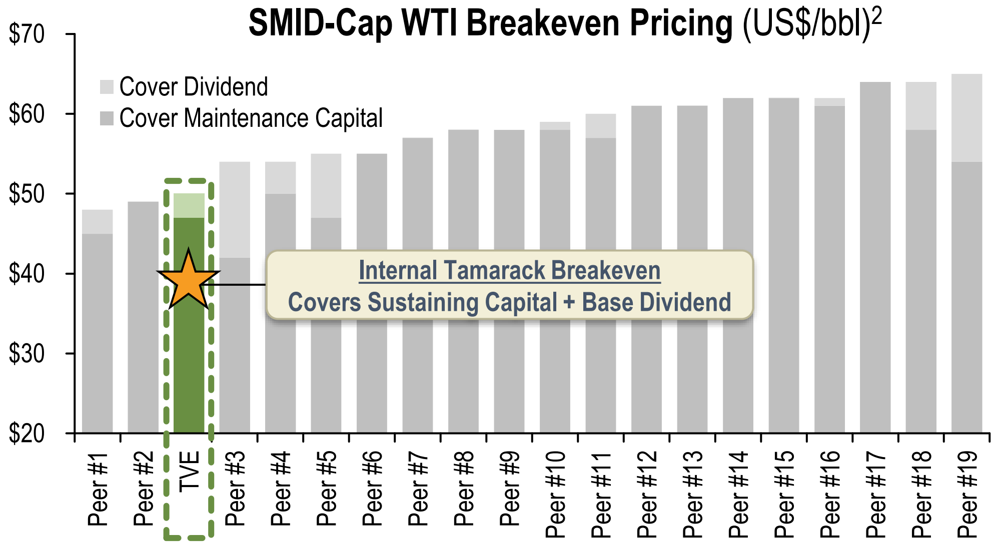
Low Sustaining Cost & Resilient Breakeven Price

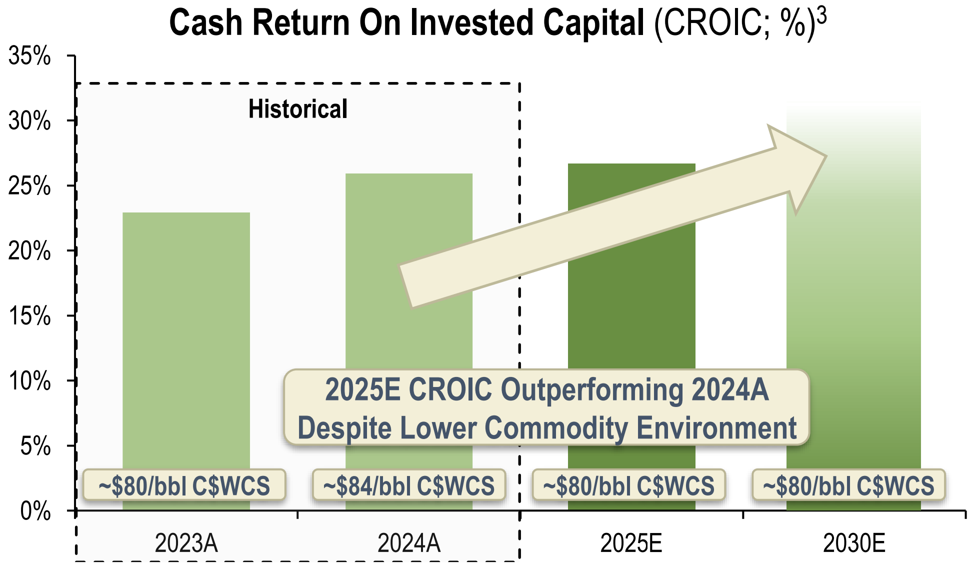
- Breakeven <US$40/bbl WTI covering maintenance capital + base dividend

Increasing Cash Return On Invested Capital

Capital Allocation Flexibility Allows For Optionality

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





See Disclaimers – "Specified Financial Measures".

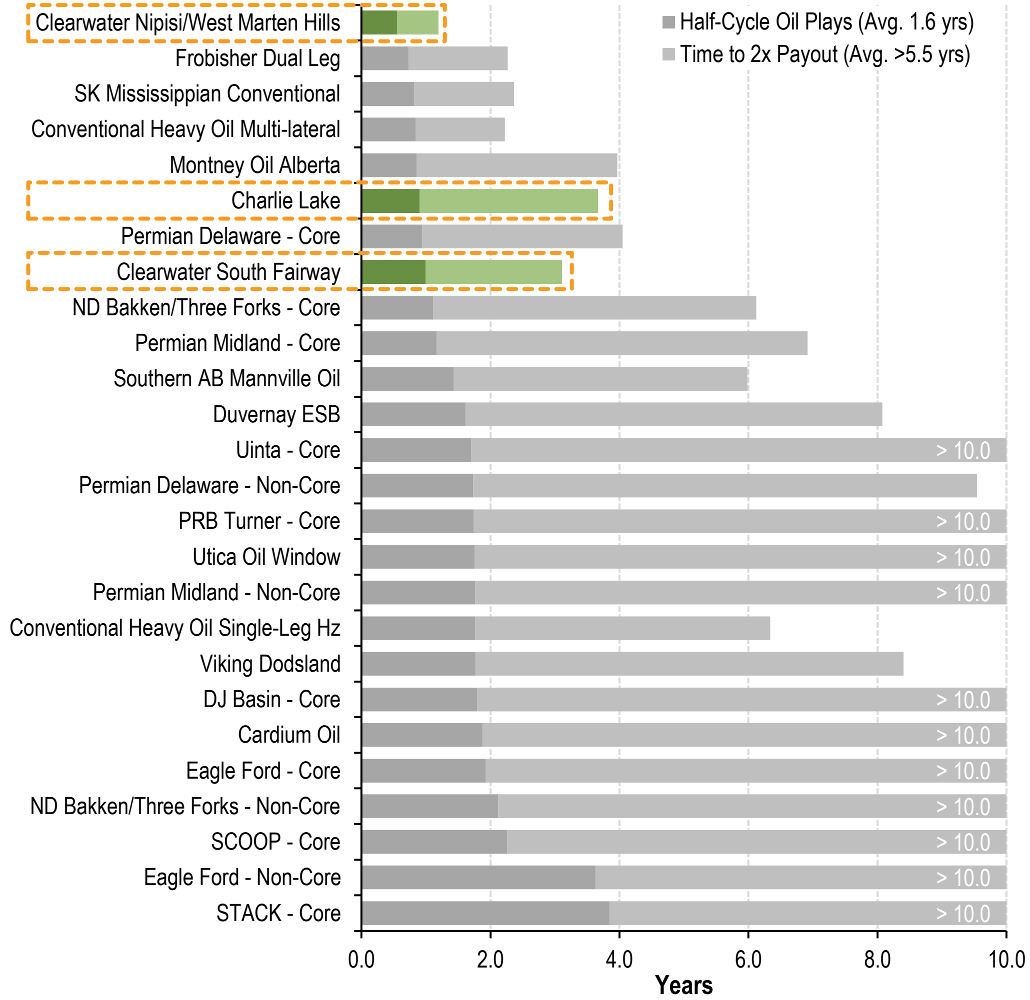
1) OOIP – original oil in place based on internal estimates; excludes PrivateCo. lands.
2) Breakeven estimates per Peters & Co.
Peer group includes ATH, BNE, BTE, CJ, GFR, HWX, IPCO, JOY, KEC, LCX, LTC, MEG, OBE, SCR, SGY, SOIL, VET, WCP, and YGR.

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.

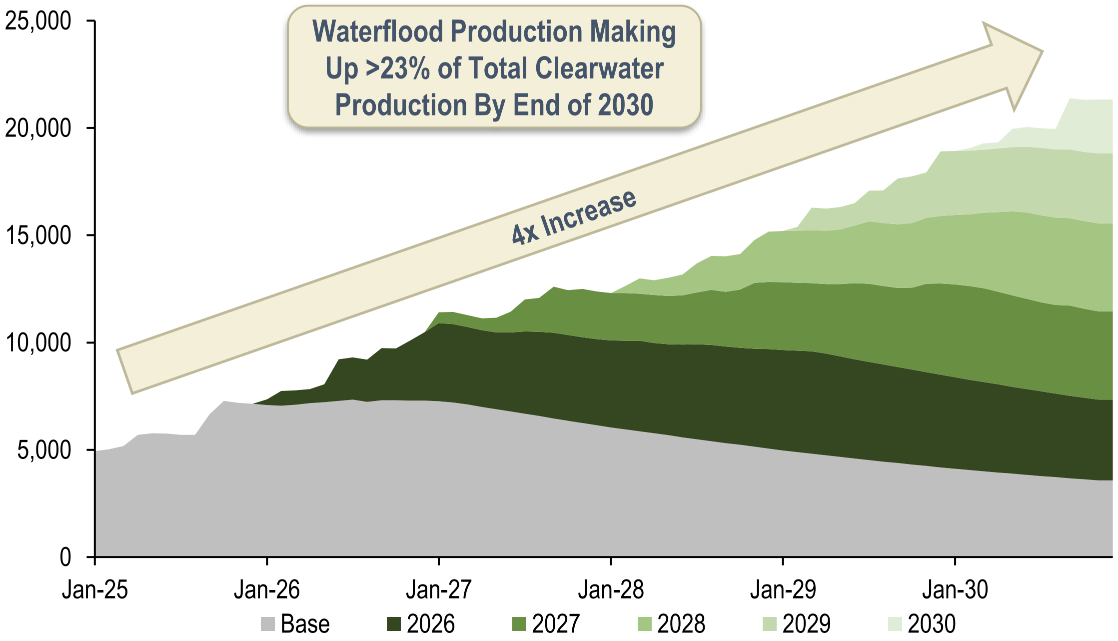
Top Tier Primary Assets and Proven Waterflood

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

Primary Payout Periods (Years)



Clearwater Oil Under Waterflood By Year (bbl/d)



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Conventional Play Economics

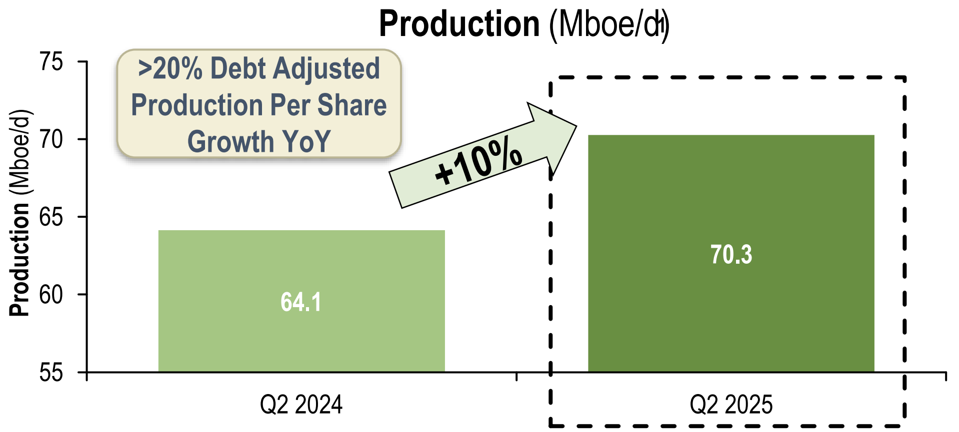
Unconventional Resource Scale

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.

Q2 2025 Highlights: Higher Production With Improved Costs

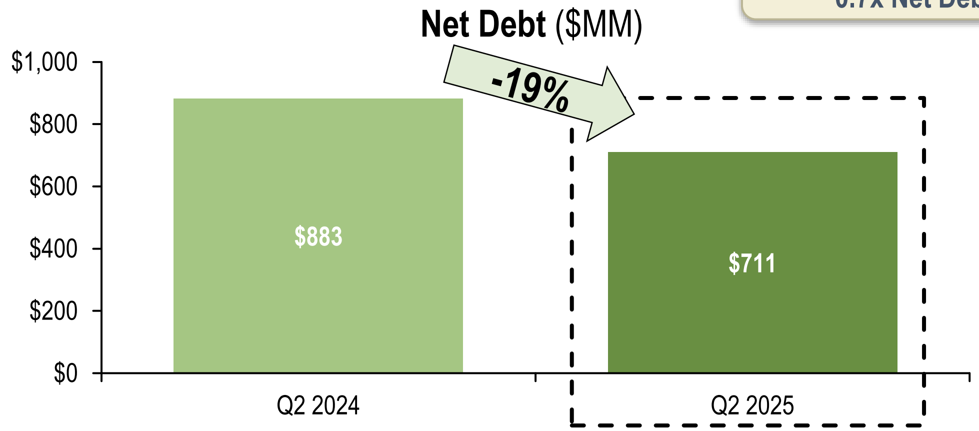
Achieved Another Record High Quarterly Production Driven By Clearwater Waterflood Success

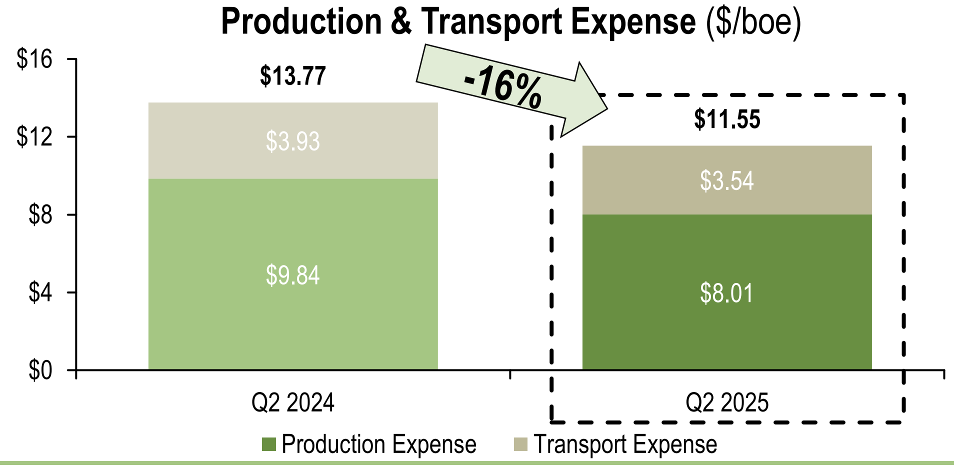
- Record average production: 70.3 Mboe/d[2], highlighted by **4% growth in heavy oil volumes vs. Q1/25**
- Adjusted funds flow[1] of **$197MM or $0.39/share** and including capital spending, generated free funds flow[1] of **$133MM or $0.26/share**
- 19% and 10% YoY improvement in net production and transport expense to **$8.01/boe** and **$3.54/boe,** respectively
- Since YE 2024, bought back **10.1MM shares, YTD Tamarack has repurchased 22.6MM shares or 4%** of the share float while continuing to reduce net debt by 8% through Q2/25



Higher Margin Barrel Growth
Clearwater Production Increased 16% YoY, with 6% Charlie Lake Growth YoY

Q2/25 Net Debt ~19% Lower Than Q2/24
~0.7x Net Debt/LTM EBITDA[1]

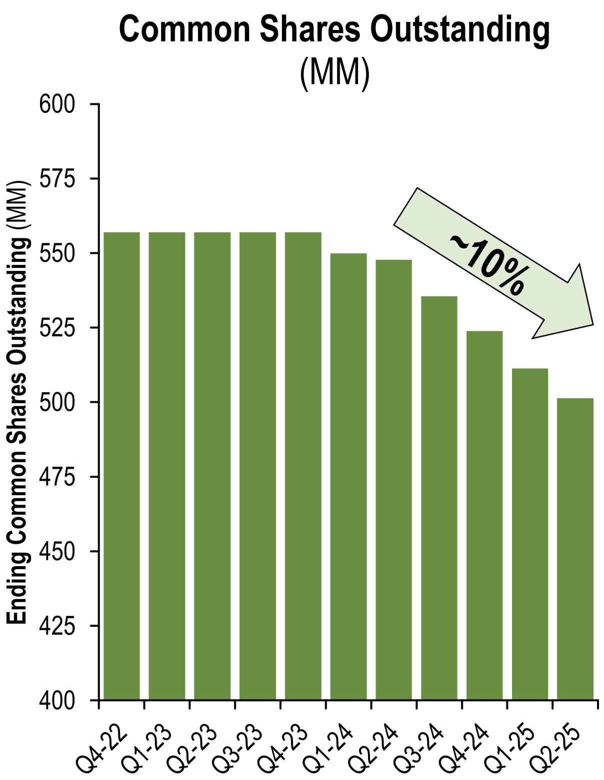


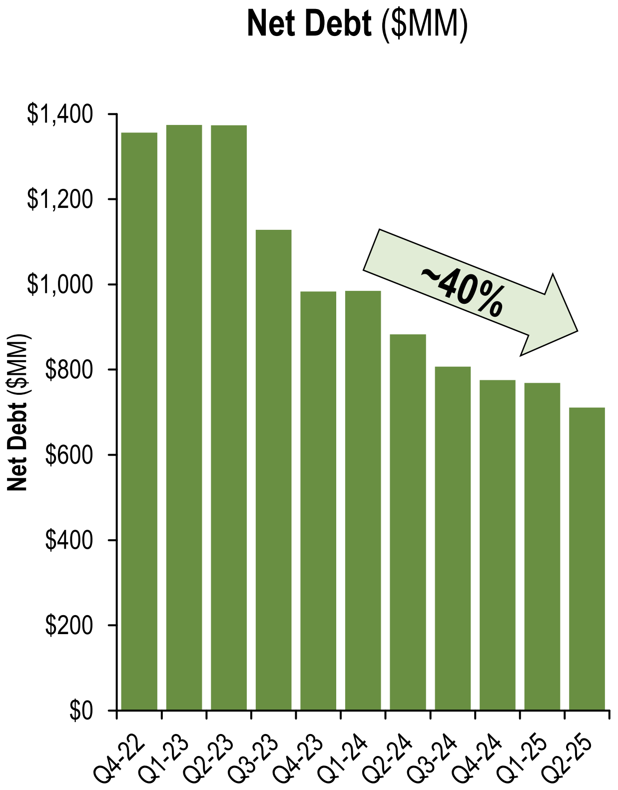


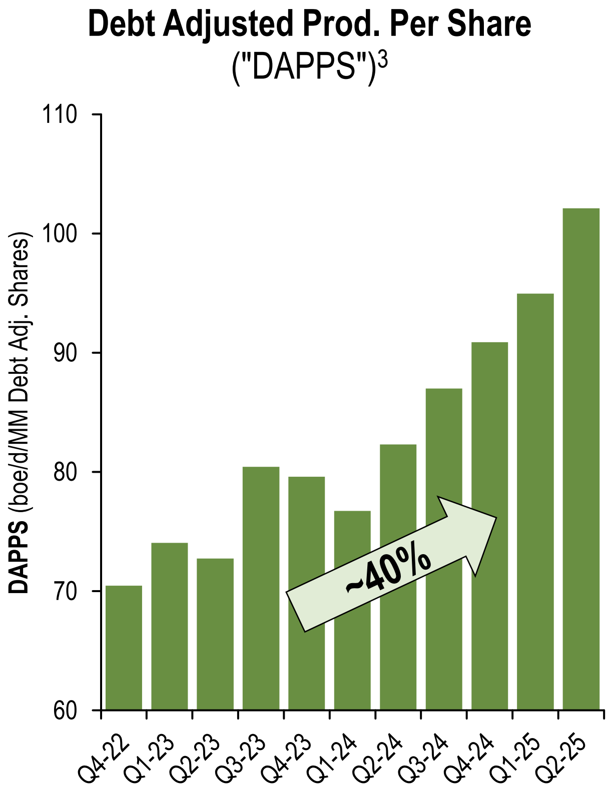
1) See "Specified Financial Measures".
2) Production of 70,260 boe/d: 14,149 bbl/d light/medium oil, 42,004 bbl/d heavy oil, 3,120 bbl/d NGL, 65,922 mcf/d natural gas.

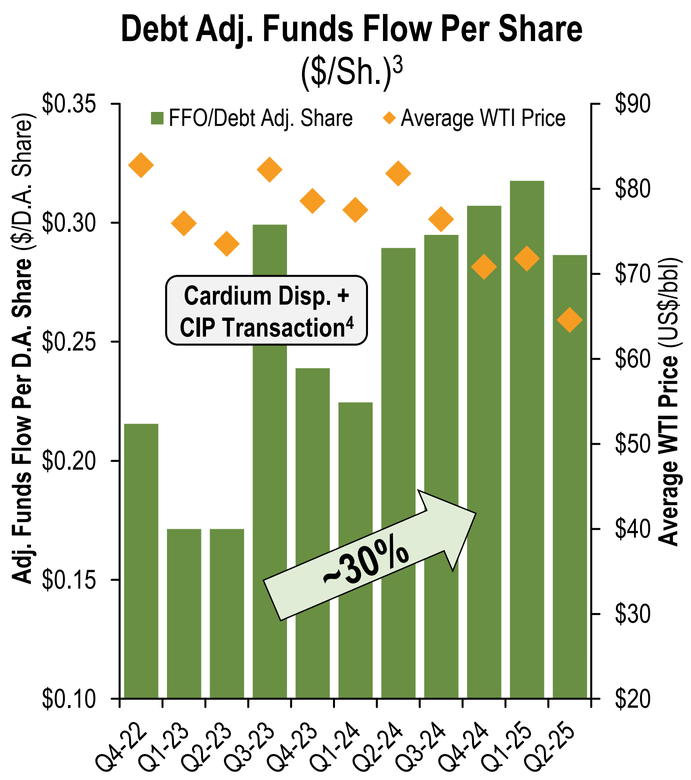
Demonstrated Per Share Value Creation

Compounding Success On a Per Share Basis









Repurchased ~10% of 2023YE Share Count (as at Q2/2025)[1]

Reduced Net Debt by ~$700 MM (~$1.40/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 December 31, 2023 vs. June 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 $3.81/Sh. (2024A average 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.

Strategic Tuck-In Acquisition Enhances Clearwater Position

Consolidation of Joint Interest Lands Through The Acquisition of a Private Company ("PrivateCo.")

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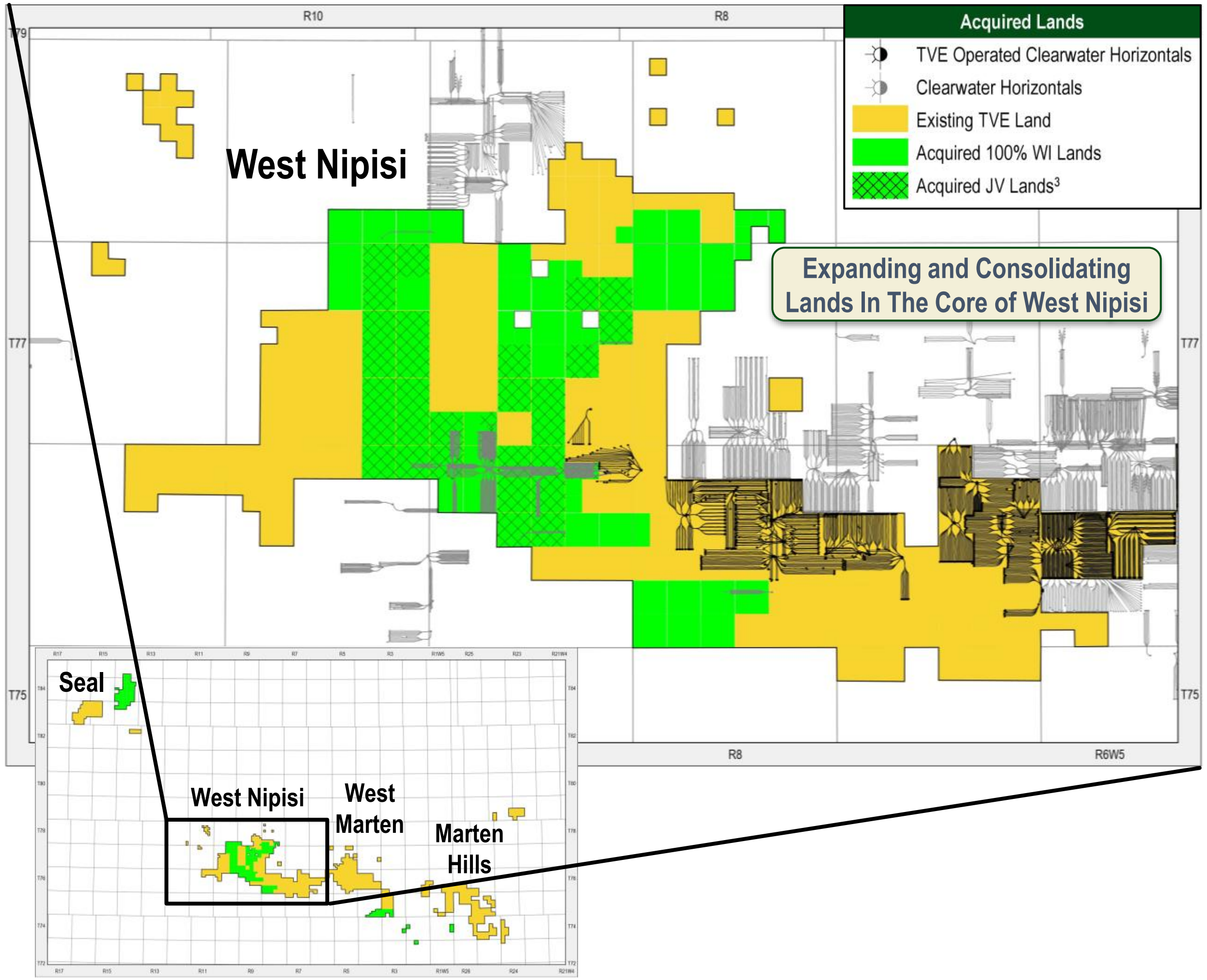

Tamarack Acquired PrivateCo. Cash Consideration of $51.5MM[1]

- 1,100 bbl/d of heavy oil production through the balance of the year
- Accretive to Tamarack's 5-year plan on a debt adjusted per share basis for production and free funds flow; enhancing overall CROIC[2]
- Enhances Tamarack's contiguous footprint across the Clearwater fairway
  - Adds >114 net sections of Clearwater lands

Future Growth

- Stacked Clearwater zones drives half cycle efficiencies
- Waterflood upside through continued reservoir delineation

Operational Synergies Associated by Acquiring Joint Interest[3] Lands

- Development and cost efficiencies established by consolidating the land base
- Wellhead / price realization upside through Tamarack's marketing & infrastructure

1) Prior to transaction costs.
2) Cash Return On Invested Capital ("CROIC") calculated as EBITDA divided by the net carrying value of oil & natural gas assets on the balance sheet.
3) PrivateCo. held working interests on certain blocks ranging from 30% - 70% in addition to their 100% lands.

2025 Capital Budget

2025 Annual Corporate Guidance

Updated Guidance To Reflect Overall Outperformance

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2025 Budget Pricing	Guidance
WTI (US$/bbl)	$70.00
WTI / MSW Diff (US$/bbl)	-$4.00
WTI / WCS Diff (US$/bbl)	-$14.00
AECO ($/GJ)	$2.00
FX (US$/C$)	1.35

2025 Annual Guidance	Guidance *(Dec. 2024)*	*Guidance Δ*	Updated Guidance
2025 Capital Budget[1] ($MM)	$430 – $450	*-$30 & -$30*	**$400 – $420**
Production[2] (boe/d)	65,000 – 67,000	*+2,000 & +2,000*	**67,000 – 69,000**
Average Oil & NGL (%)	83% – 85%	-	**83% – 85%**
Expenses:			
Royalties (%)	20% – 22%	-	**20% – 22%**
Wellhead Oil Price Differential ($/bbl)	$1.50 – $2.50	-	**$1.50 – $2.50**
Production Expense[3] ($/boe)	$8.40 – $8.90	*-$0.40 $ -$0.40*	**$8.00 – $8.50**
Transportation Expense ($/boe)	$3.75 – $4.25	*- & -$0.25*	**$3.75 – $4.00**
G&A ($/boe)	$1.30 – $1.45	-	**$1.30 – $1.45**
Interest[4] ($/boe)	$2.90 – $3.30	*-$0.20 $ -$0.20*	**$2.70 – $3.10**
Income Tax[5] (%)	10% – 12%	-	**10% – 12%**

Updated Guidance To Reflect Stronger Overall Performance Plus Acquisition and Dispositions

- Reduced capital by $30MM or 7% given ongoing efficiencies from expanded multi-well-pad development
  - In addition, redirected capital for additional waterflood expansion in the Clearwater to further reduce declines in future years
- Production: increased by 3% reflecting core asset performance
- Production expense: reduced by 5% reflecting continued improvements to lifting costs and higher production with improved run times
- Transportation expense: range narrowed reflecting the ongoing impact of infrastructure investments and reduced trucking activities

Production Performance, Lower Capital and Lower Cost Structure Are Driving a Full Year Free Funds Flow Outlook Ahead of December 2024 Guidance

1) Excludes ARO capital.
2) 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 NGL and 61,550-63,550 mcf/d natural gas.
3) Includes CIP fee for service and minimal carbon tax budgeted.
4) Includes CIP ToP Capital fee.
5) Income tax percentage is based on the percentage of adjusted funds flow before tax.

Return of Capital Framework

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

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	Net Debt[1] ($MM) & *Net Debt / LTM EBITDA (x)*	**$900MM – $1,100MM** & *~ 1.0x Net Debt / EBITDA*	**$500MM – $900MM** & *~ 1.0x Net Debt / EBITDA*	**≤ $500MM** & *~ 1.0x Net Debt / EBITDA*
Adjusted Funds Flow[1]	**Free Funds Flow[1] Allocation**	**60% Net Debt Reduction**	**40% Net Debt Reduction & Strategic Growth Capital Allocation**	**20% Strategic Growth Capital Allocation**
		Up to 40% Base Dividend + Enhanced Returns	**Up to 60% Base Dividend + Enhanced Returns**	**Up to 80% Base Dividend + Enhanced Returns**
	Capital Expenditures			

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 ~$500MM

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

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

Share Count Reduced By ~56.5 MM Since 2023YE (~10%)[3]

1) See Disclaimers – "Specified Financial Measures".
2) Flat US$45/bbl WTI pricing assumes US$(12.75)/bbl WCS basis, US$(2.50)/bbl MSW basis, 1.30 US$/C$, and C$3.00/GJ AECO.
3) Share buybacks from January 1, 2024 up to and including June 30, 2025.

2025 Free Funds Flow Allocation

Low Breakeven Drives Resiliency, Increasing Returns to Shareholders

Production Growth & Disciplined Capital Allocation

~6% Annual Production Growth; >10% Growth Per Debt Adj. Share[1]

Strong Free Funds Flow Generation

>$300MM Annual Free Funds Flow[2] & ~15% FFF Yield[2] at Budget Pricing

Financial Strength & Resiliency

Corporate Sustaining Free Funds Flow Breakeven[2] of <US$40/bbl

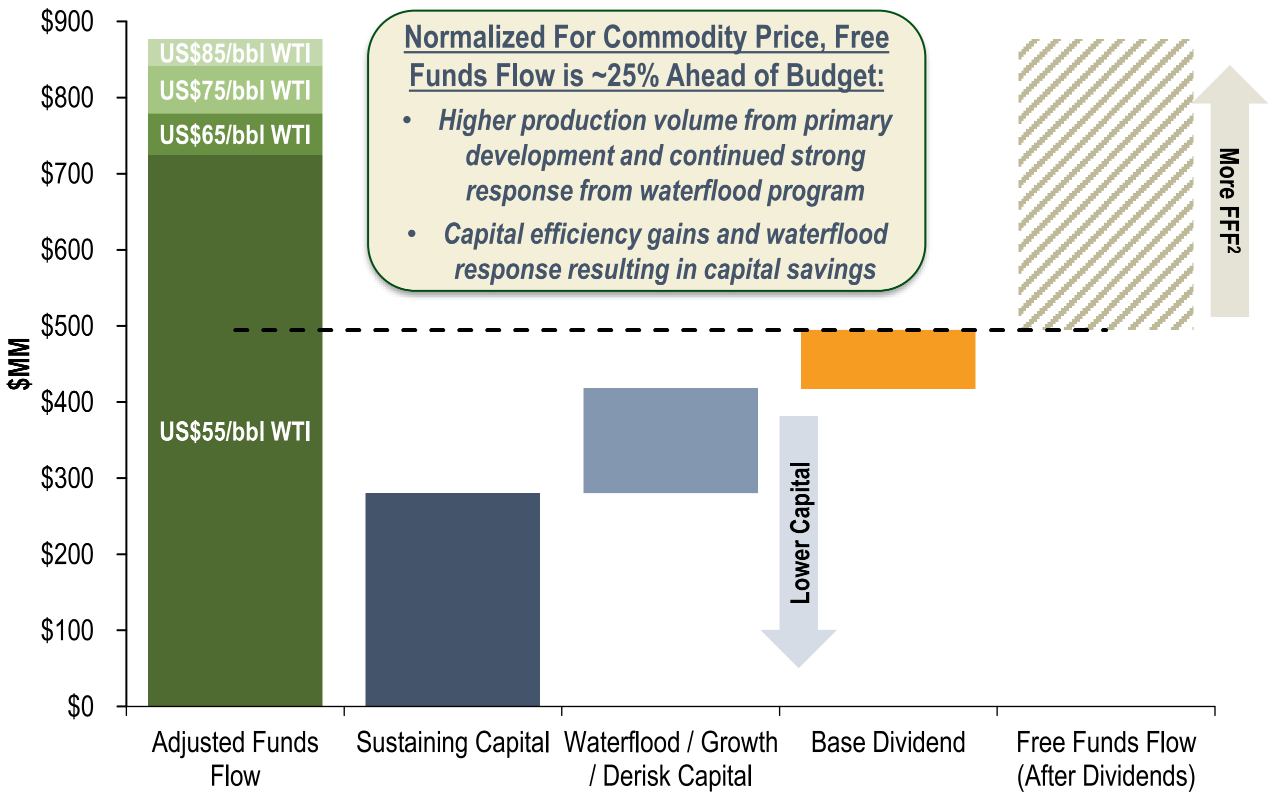
Long Dated Laddered Credit Structure with Significant Liquidity and Low Debt/EBITDA Ratios

Returns To Shareholders

60% of Free Funds Flow[2] Returned via Base Dividends & Share Buybacks

Total Shareholder Return Yield of >15%[2,3,4]

2025 Free Funds Flow Allocation ($MM)[2,5]



2025 Capital Program & Base Dividend Funded at <US$55/bbl WTI

1) Growth measured as 2025E average production at the midpoint of guidance relative to 2024A annual average production. Budget pricing for rest of year.
2) See Disclaimers – "Specified Financial Measures". Free funds flow yield is annual free funds flow divided by market capitalization.
3) Total shareholder return based on Budget price and includes base dividend + share buyback yield, debt reduction yield and production growth. Yields are based on a share price of $5.25/share. Common share count is net of shares repurchased through the year per the enhanced return framework.
4) Based on 2025 Budget pricing.
5) 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).

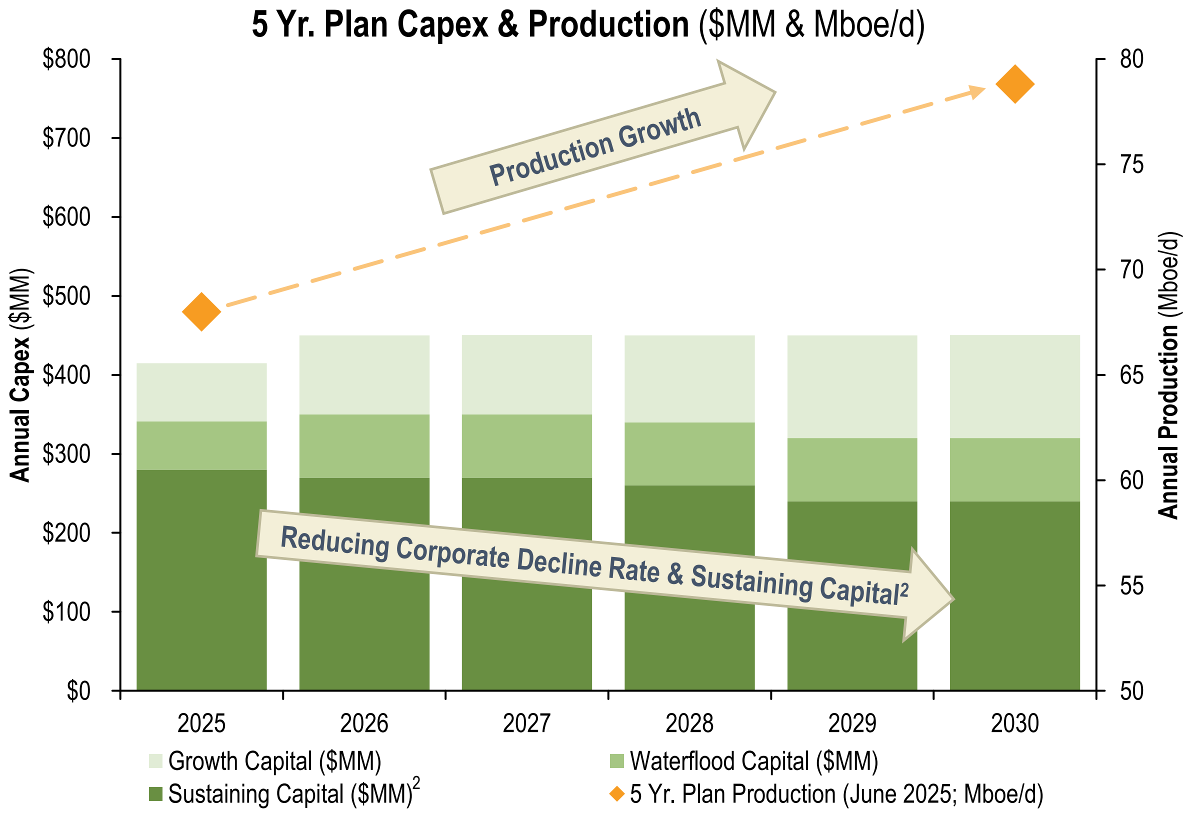
5-Year Plan: Compounding Returns

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

Focused Clearwater Growth With Charlie Lake Light Oil Development

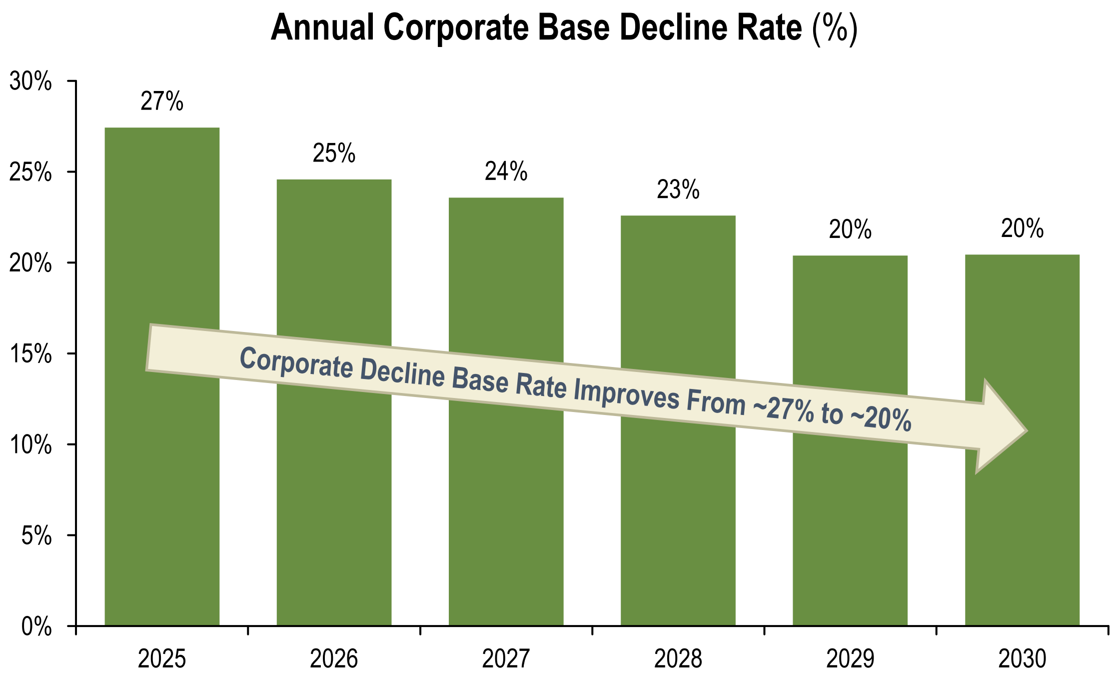
5-Year Production Growth CAGR of 3% - 5%[1]

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



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]



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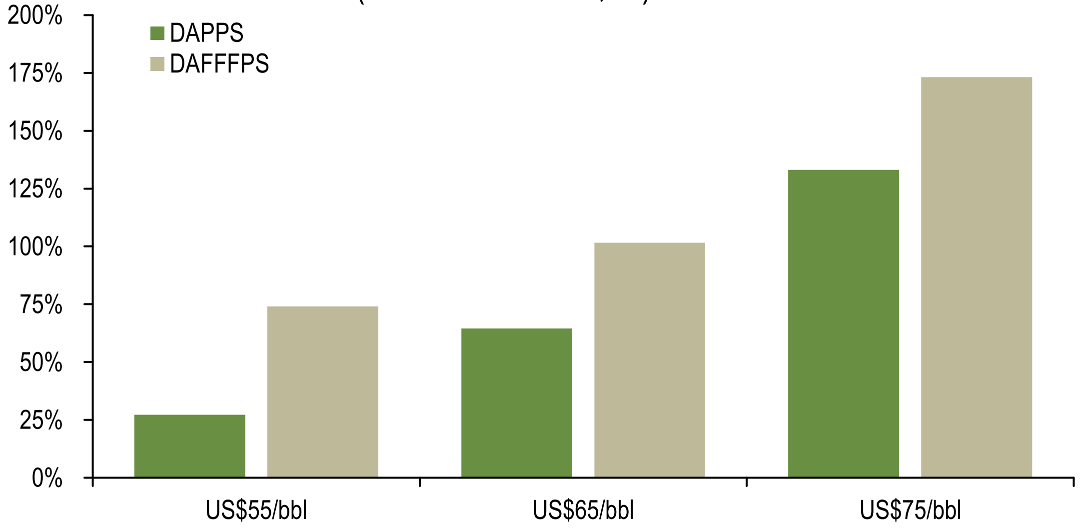
Total DAFFFPS & DAPPS Growth of >100%[1,2,3] Over 5 Years (Flat US$75/bbl WTI)[4]

- 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

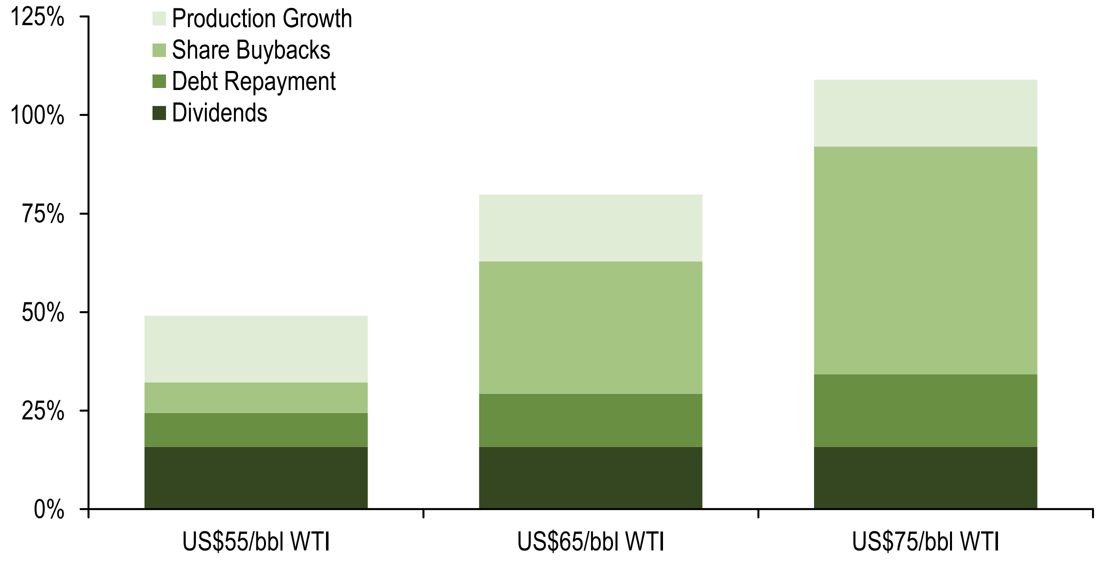
Cumulative Total Shareholder Return of >100% Over 5 Years (Flat US$75/bbl WTI)[4]

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

Cumulative ∆ 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".
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.

Asset Portfolio

Largest Public Clearwater Producer

Established Extensive Exposure Through The Heart of The Clearwater Fairway

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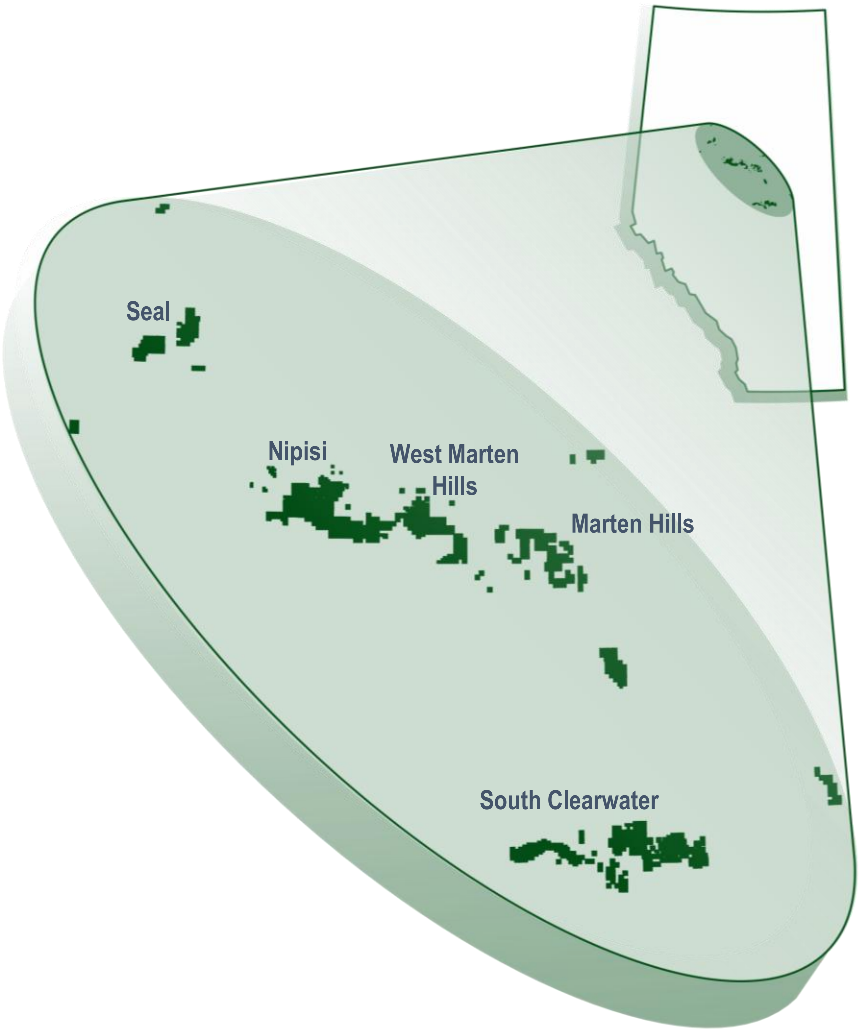


Scale

- Extensive holdings across the Clearwater fairway; 790 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

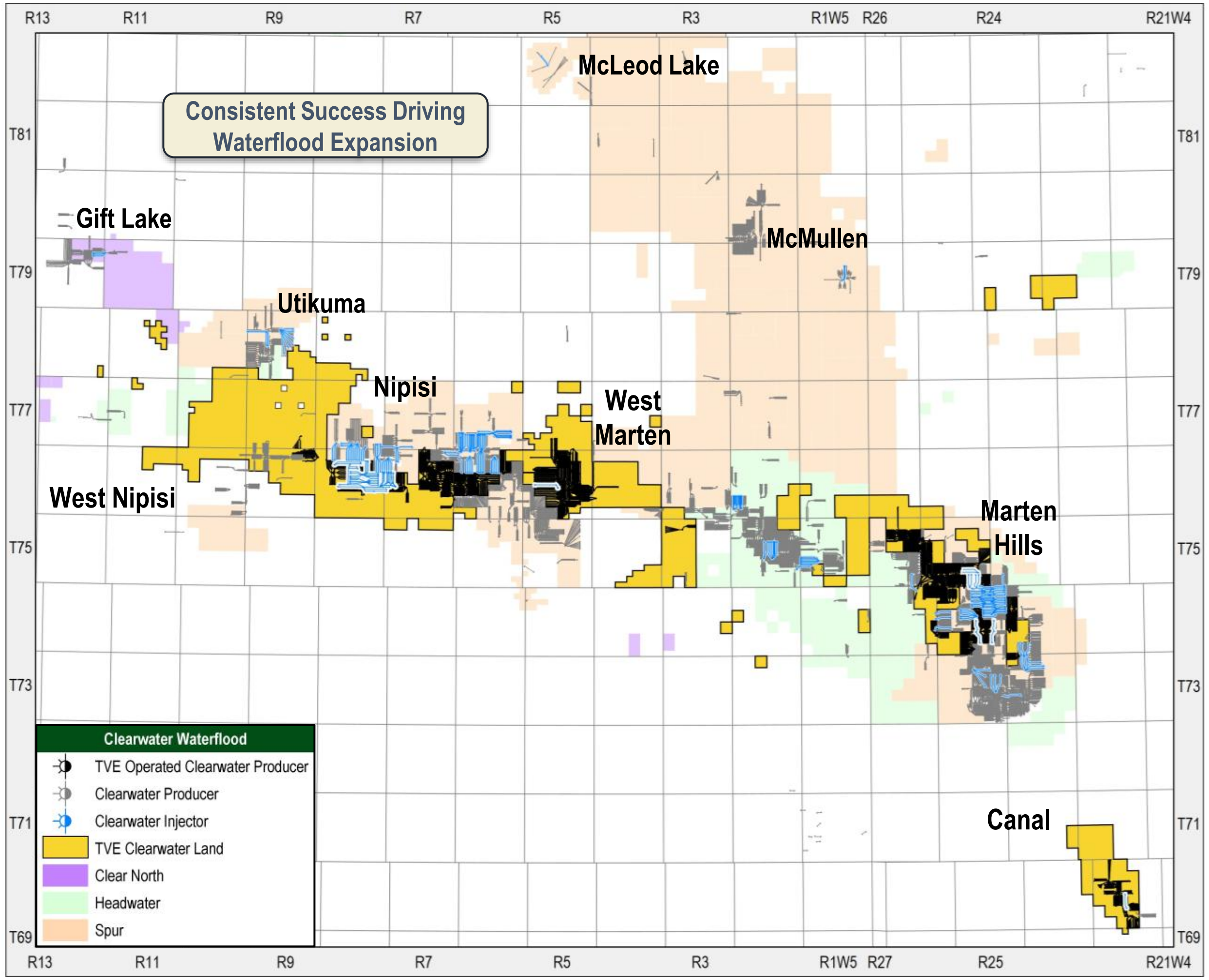
Duration

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

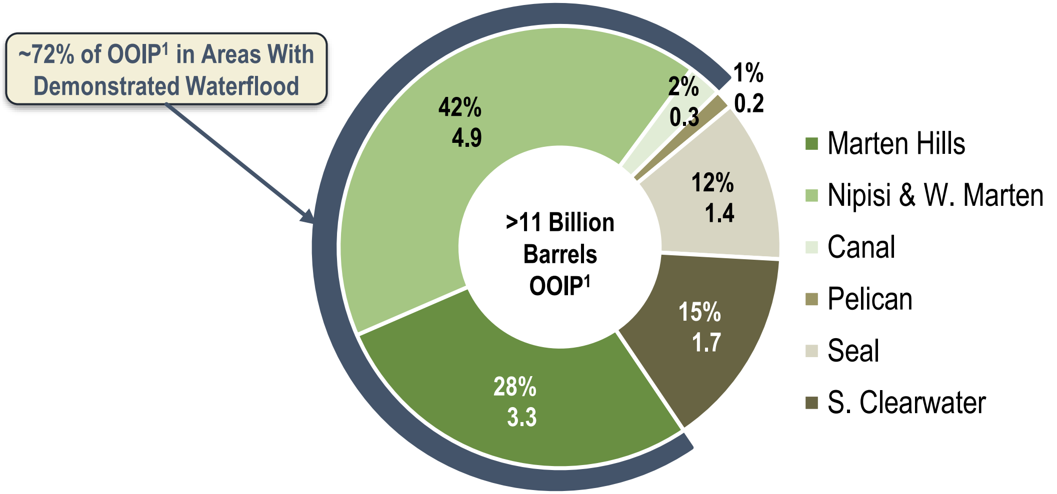
1) As at July 29, 2025 (includes PrivateCo. lands).
2) OOIP – original oil in place based on internal estimates.
3) Based on 2024 Clearwater oil production of ~13.9 MMbbls.
4) Net primary locations as at 2024YE, see Disclaimers – "Drilling Locations" (excludes PrivateCo. locations).

Clearwater Waterflood Expansion

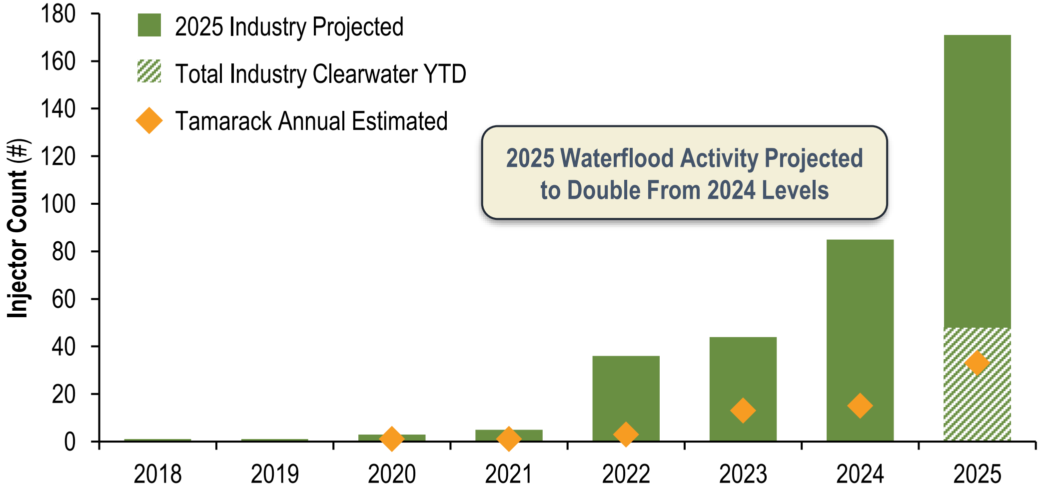
Activity Expansion Following Consistent Success



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



Industry Clearwater Injector Count by Year [2,3]

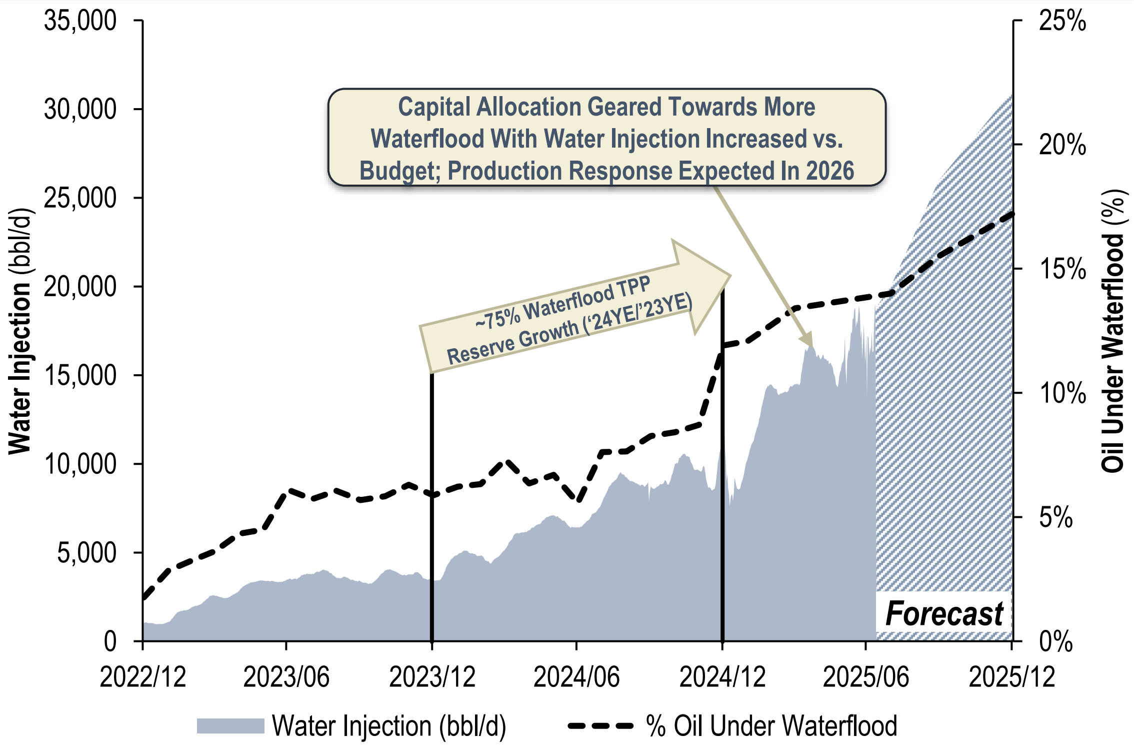


1) OOIP – original oil in place based on internal estimates, excluding PrivateCo. lands.
2) 2025 clearwater Injector count includes industry activity up to and including April 2025.
3) 2025 projected industry count is based on Clearwater peer guidance and internal estimates.

Clearwater Waterflood Progression

Advancing Secondary Recovery To Drive Incremental Resource Capture

Clearwater Injection & Production Under Waterflood



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

~17% of Clearwater Production Under Waterflood by YE 2025

Waterflood Reserve Growth[1]

Performance Pointing Towards Further Technical Revisions

In June, After 6.5 Years On-Stream, 15-02 & 16-02-075-25W4 Patterns Ranked as The Top Two Clearwater Multi-Lateral Producers of the Month

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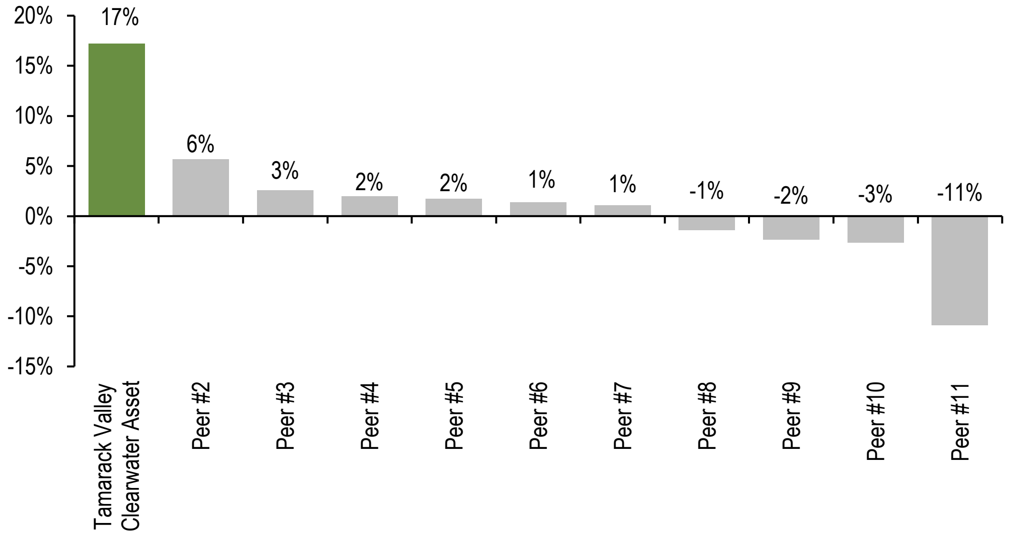
Clearwater Waterfloods Have Outperformed Reserve Forecasts

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

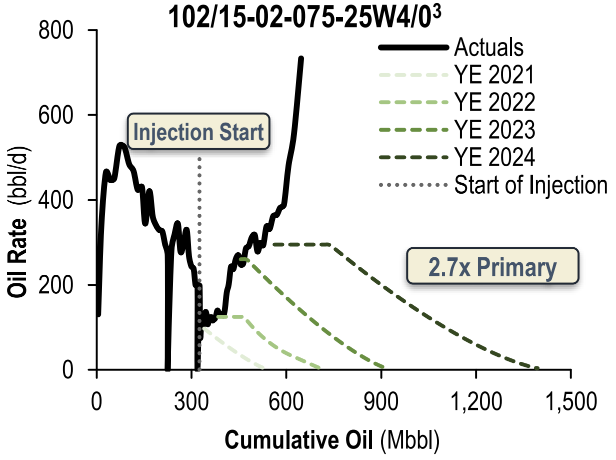
Waterflood Success Adds Tailwinds to Reserves

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

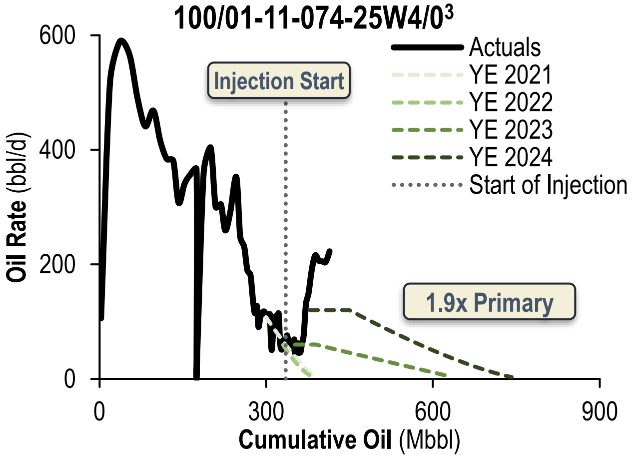
Total Proved Technical Revisions[2]
(as % of the reserves opening balance)



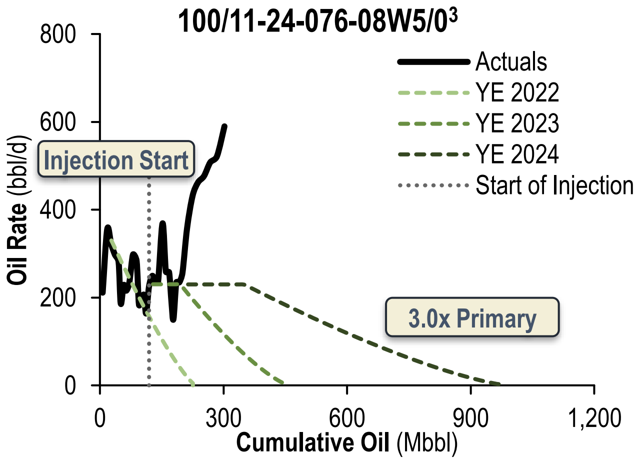
Marten Hills Stacked Pattern Pilot



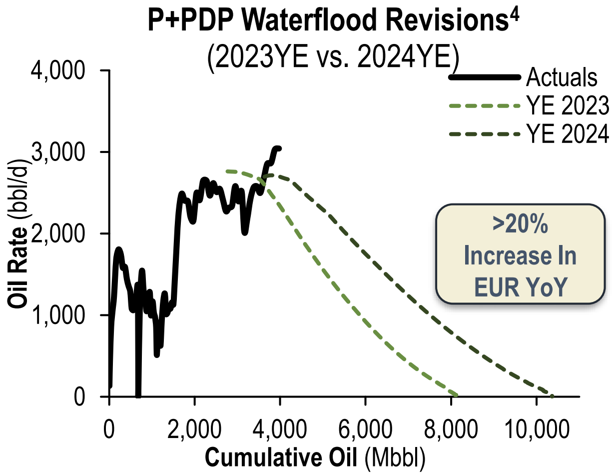
Marten Hills W Pattern Pilot



Nipisi Waterflood Pattern



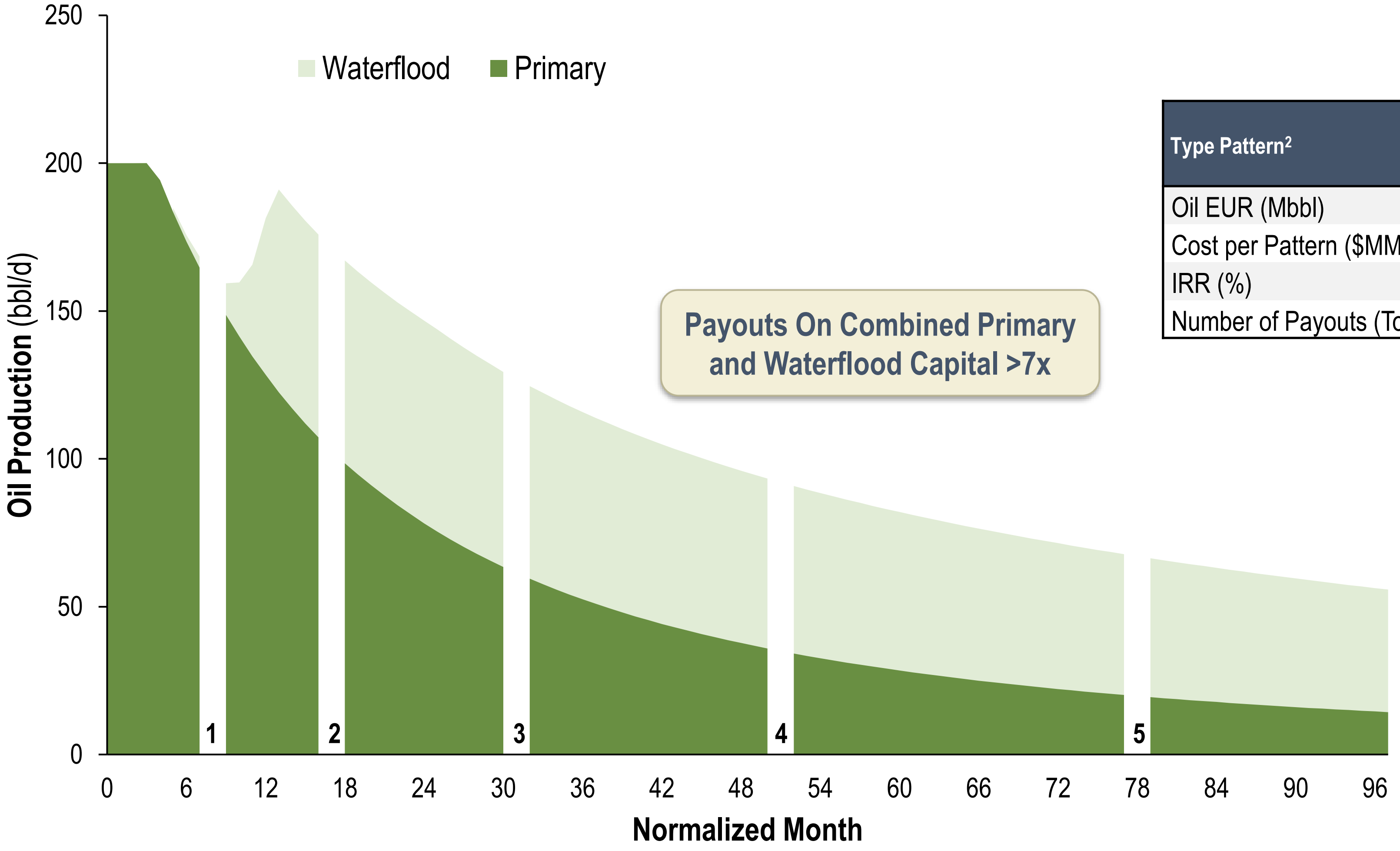
Nipisi & Marten Hills



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 Type Curve

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



Waterflood Economics

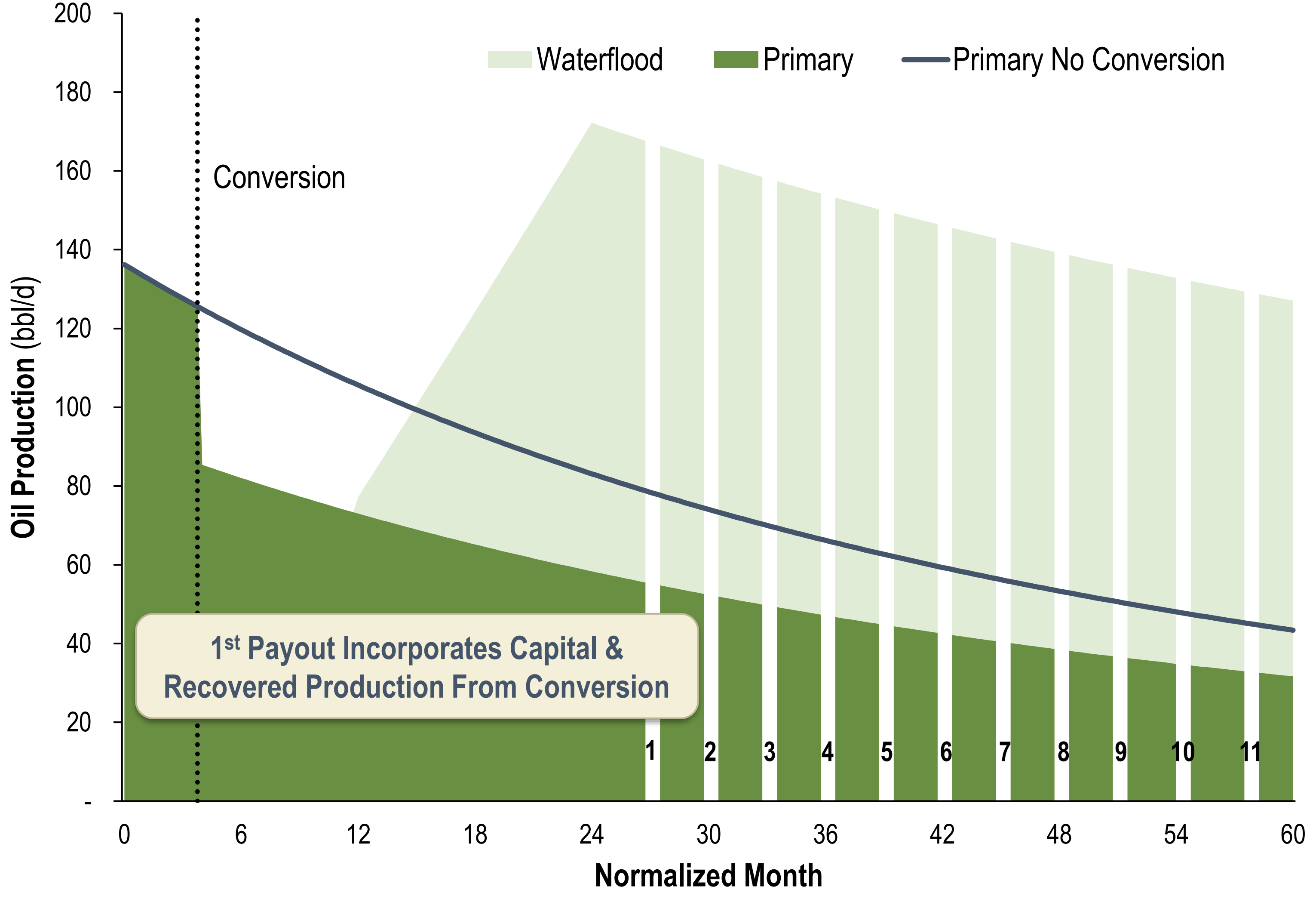
Type Pattern[2]	Primary[3] – West Marten "B" Sand Tier I	Waterflood Injector Wedge[4] – Internal Estimate	Total Project
Oil EUR (Mbbl)	205	308	513
Cost per Pattern ($MM)	$1.8	$1.2	$3.0
IRR (%)	>200%	100%	>200%
Number of Payouts (Total)	5.8	9.0	7.1

- **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".
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".
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.

Largest Charlie Lake Oil Producer In Industry

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; 238 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 June 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

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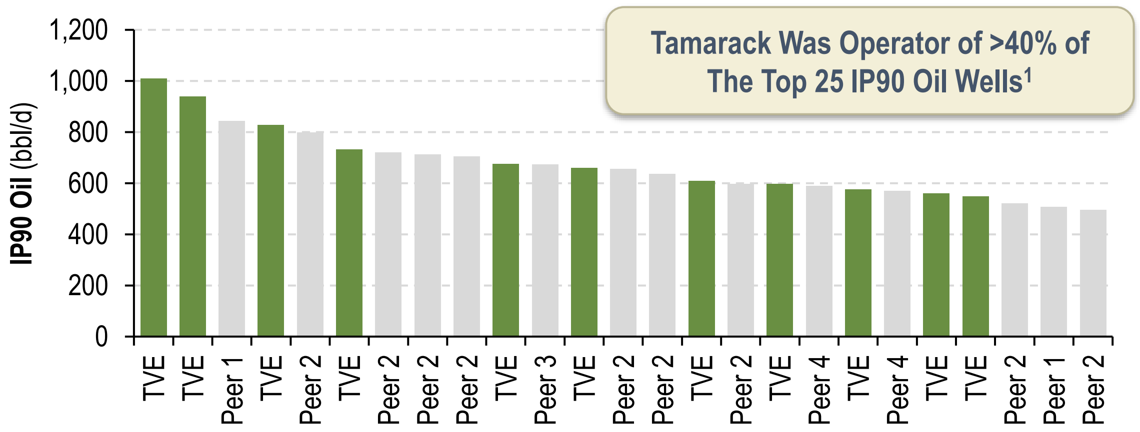
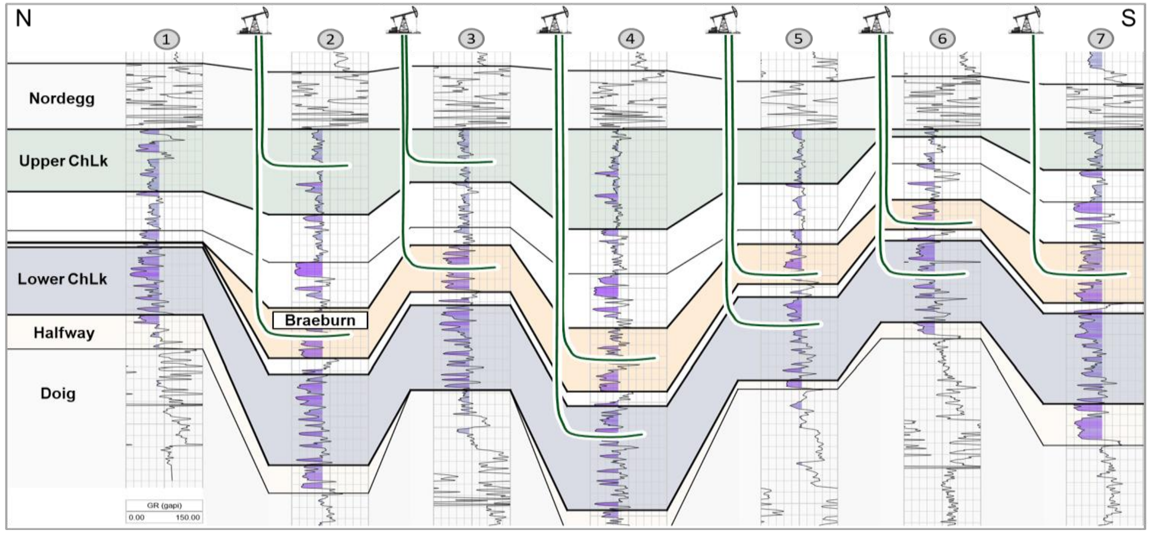
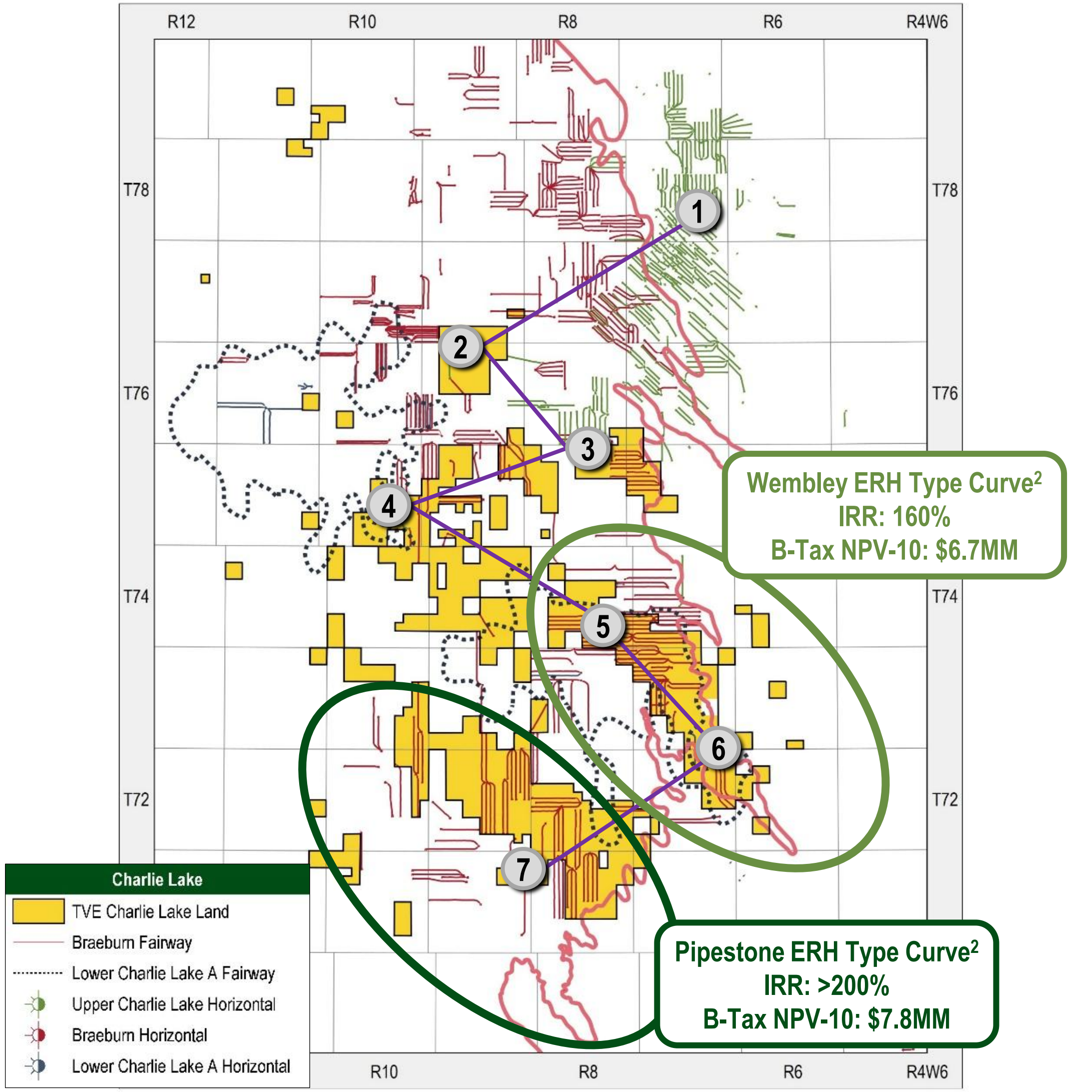
Well Design and Program Execution Driving Sustained Outperformance In Core Areas

Charlie Lake – 2024 IP90 Oil Performance[1]







1) Source: GeoSCOUT, representing the peak three consecutive months for each Charlie Lake well brought on stream in 2024, where at least three 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.

Charlie Lake Steady Growth and Reliable Performance

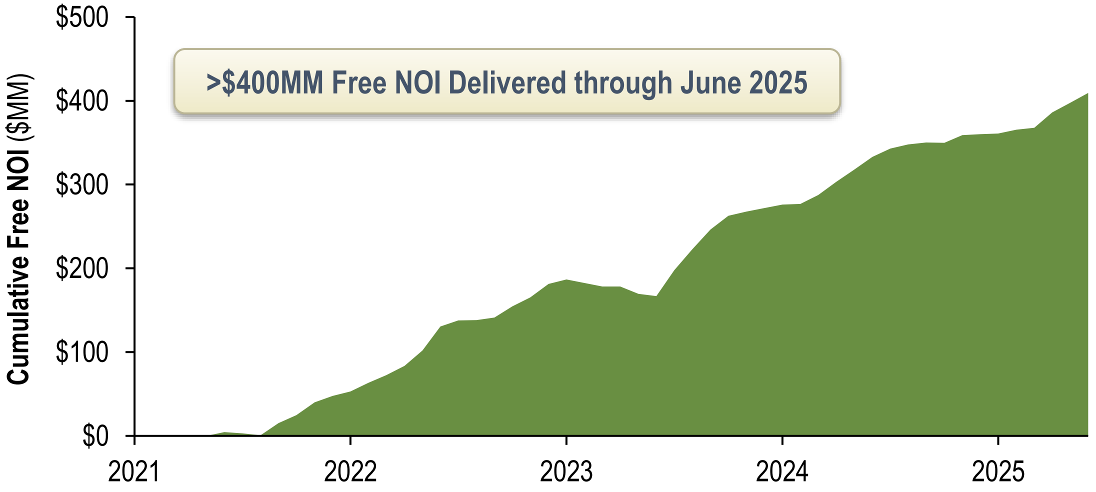
Largest Charlie Lake Oil Producer Generating Superior Economics

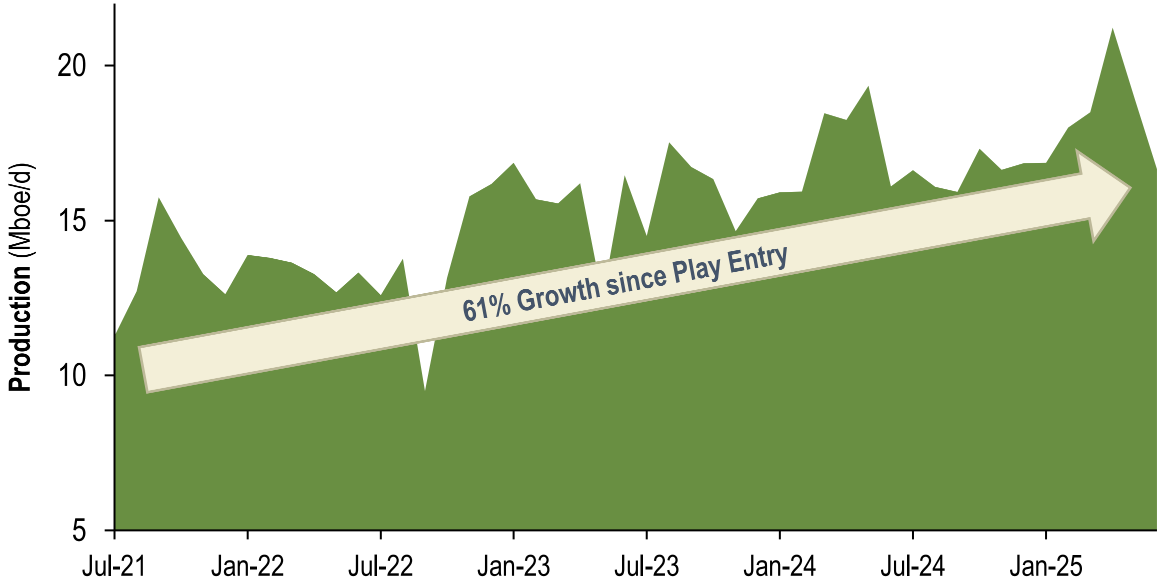
Growth & Performance

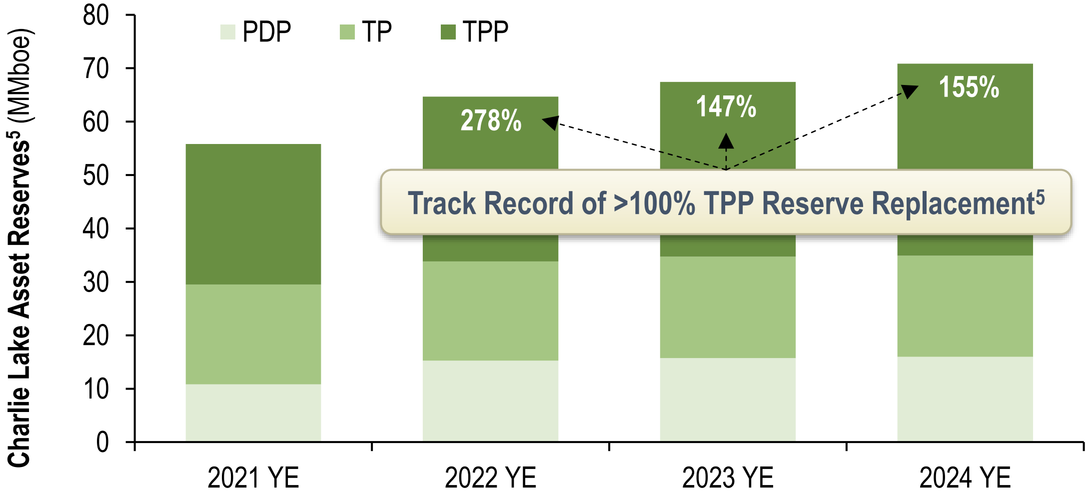
- **Production Up 61%:** 11,800 boe/d[1] (Apr. 2021) to 18,940 boe/d[2] (Q2/25)
- **46% Sustaining Reinvestment Ratio in 2024:** $96MM sustaining capital[3], $113MM of free net operating income (NOI)

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) 18,940 boe/d comprised of approximately 9,990 bbl/d light/medium oil, 2,800 bbl/d NGL and 36.9 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.

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

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

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: Allocating 60% of Free Funds Flow**
- ✓ **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*

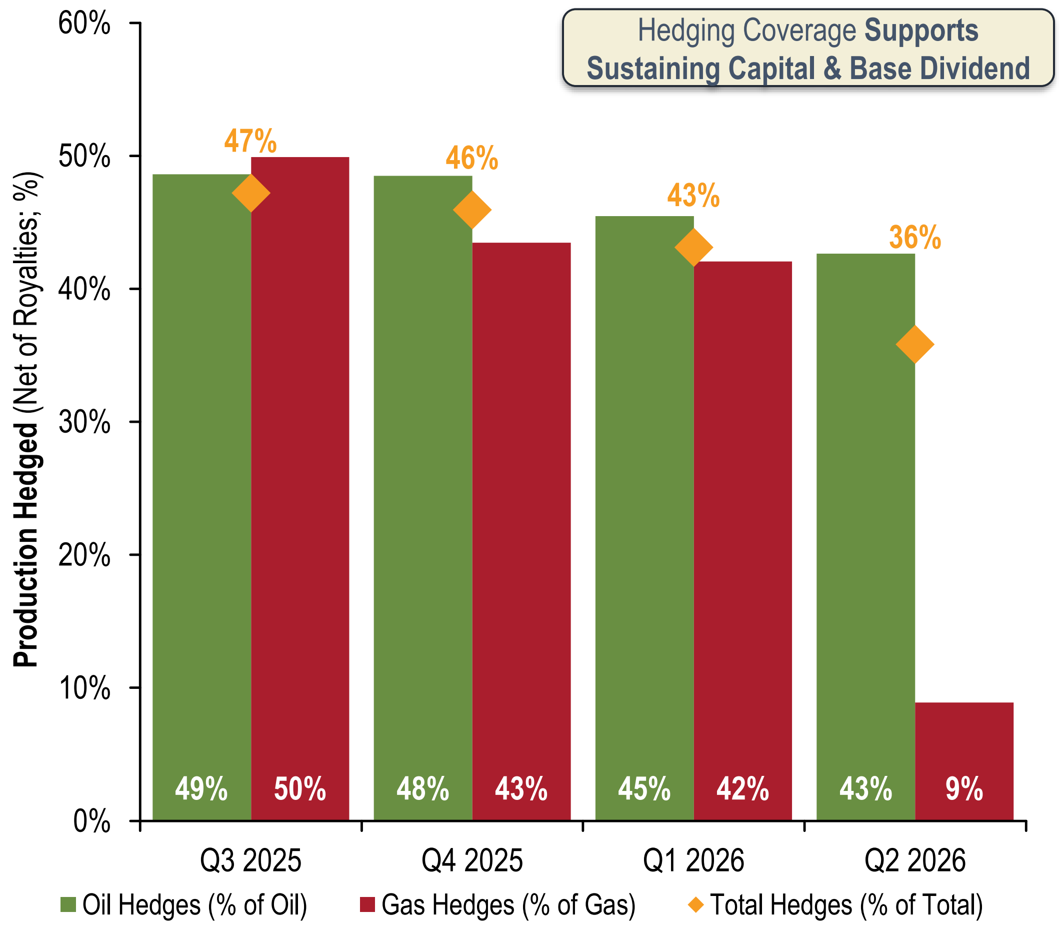
1) See Disclaimers – “Specified Financial Measures”.
2) OOIP – original oil in place based on internal estimates. Excludes PrivateCo.

Appendix: Financial

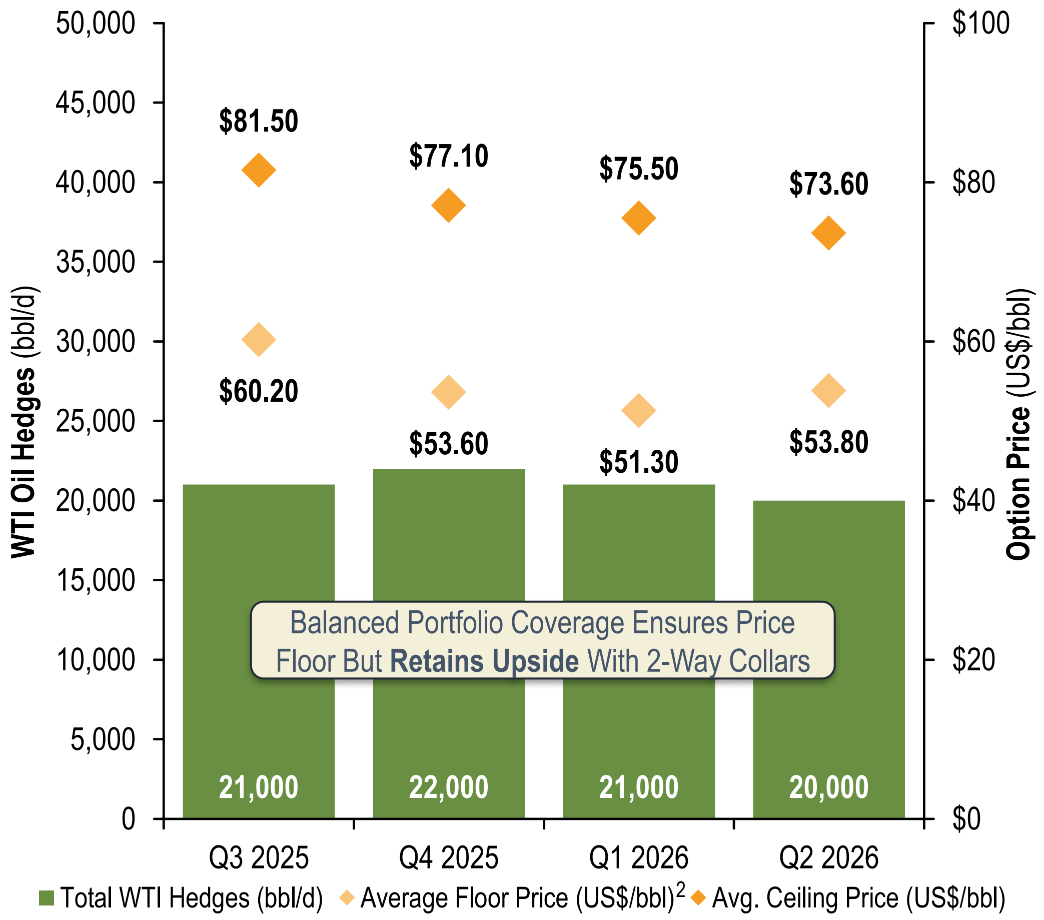
Risk Management[1]

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 July 29, 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	Q3 2025	Q4 2025	Q1 2026	Q2 2026	Q3 2026	Q4 2026
WTI Collars							
Volume	*bbl/d*	21,000	22,000	21,000	20,000	2,500	-
Avg. Floor Price	*US$/bbl*	$60.16	$53.64	$51.31	$53.75	$55.00	-
Avg. Ceiling Price	*US$/bbl*	$81.50	$77.14	$75.50	$73.55	$73.90	-
Avg. Premium	*US$/bbl*	$0.24	$0.69	$0.54	$0.13	$0.12	-
WTI - WCS Basis Swaps							
Volume	*bbl/d*	13,000	16,000	8,500	-	-	-
Avg. Fixed Price	*US$/bbl*	($12.68)	($15.09)	($13.67)	-	-	-
WTI - MSW Basis Swaps							
Volume	*bbl/d*	5,000	5,000	-	-	-	-
Avg. Fixed Price	*US$/bbl*	($3.93)	($3.93)	-	-	-	-

Natural Gas Hedges	Units	Q3 2025	Q4 2025	Q1 2026	Q2 2026	Q3 2026	Q4 2026
AECO 5A Swaps							
Volume	*GJ/d*	25,500	8,592	-	5,000	5,000	1,685
Avg. Fixed Price	*C$/GJ*	$2.69	$2.69	-	$2.50	$2.50	$2.50
NYMEX Collars							
Volume	*MMbtu/d*	-	14,918	22,500	-	-	-
Avg. Floor Price	*US$/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	Q3 2025	Q4 2025	Q1 2026	Q2 2026	Q3 2026	Q4 2026
US$/C$ Collars							
Notational	*US$MM/Month*	$5.0	$5.0	$4.0	$4.0	-	-
Avg. Floor Price	*US$/C$*	1.336	1.336	1.345	1.345	-	-
Avg. Ceiling Price	*US$/C$*	1.394	1.394	1.411	1.411	-	-
US$/C$ Swaps							
Notational	*US$MM/Month*	$3.0	$3.0	$3.0	$3.0	-	-
Avg. Fixed Price	*US$/C$*	1.348	1.348	1.357	1.357	-	-
US$/C$ Variable Collars(2)							
Notational	*US$MM/Month*	$31.5	$31.5	$4.0	$4.0	-	-
Avg. Floor Price	*US$/C$*	1.342	1.342	1.353	1.353	-	-
Avg. Ceiling Price	*US$/C$*	1.402	1.402	1.424	1.424	-	-
Avg. Knock-In Price	*US$/C$*	1.372	1.372	1.394	1.394	-	-
US$/C$ Variable Collars (Ext. Option)(3)							
Notational	*US$MM/Month*	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0
Avg. Floor Price	*US$/C$*	1.350	1.350	1.358	1.358	1.358	1.358
Avg. Ceiling Price	*US$/C$*	1.442	1.442	1.458	1.458	1.458	1.458
Avg. Knock-In Price	*US$/C$*	1.387	1.387	1.404	1.404	1.404	1.404

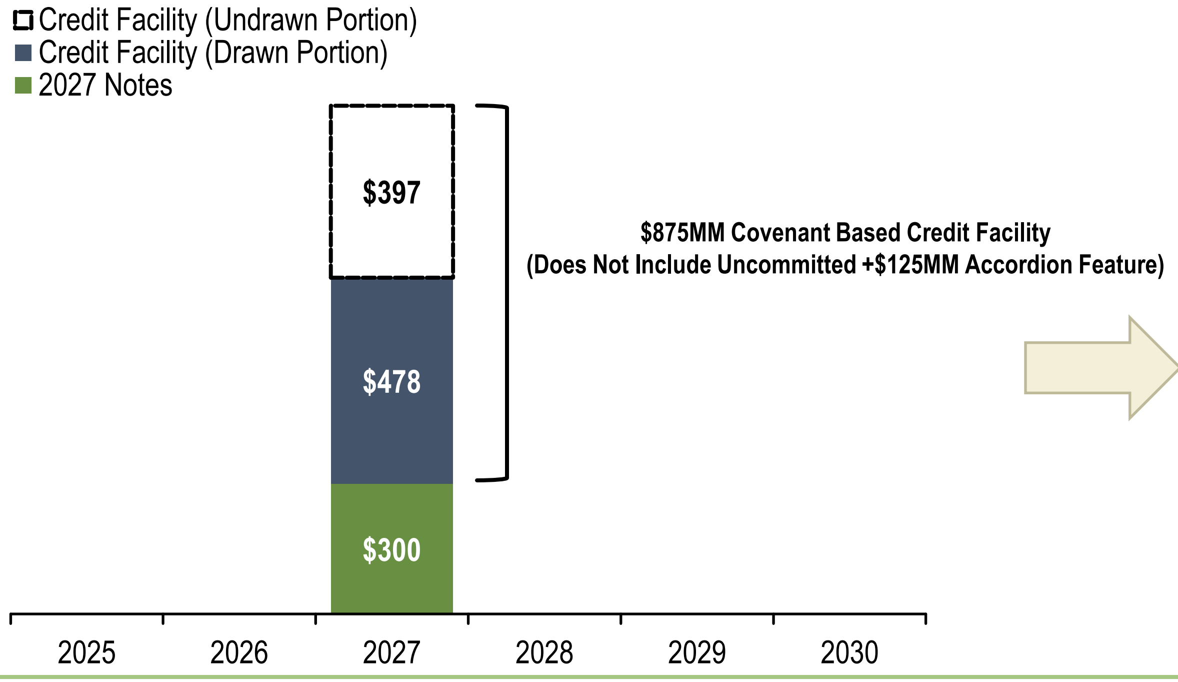
1) Hedges in place as at July 29, 2025.
2) If the average rate for the month exceeds the call, Tamarack receives an average rate forward equivalent to the knockout rate.
3) Includes an extension option at the end of a collar, at the counterparty's option, for a predetermined term, notational value and swap rate. Extension contracts not included in this table.

Long Dated Laddered Credit Structure

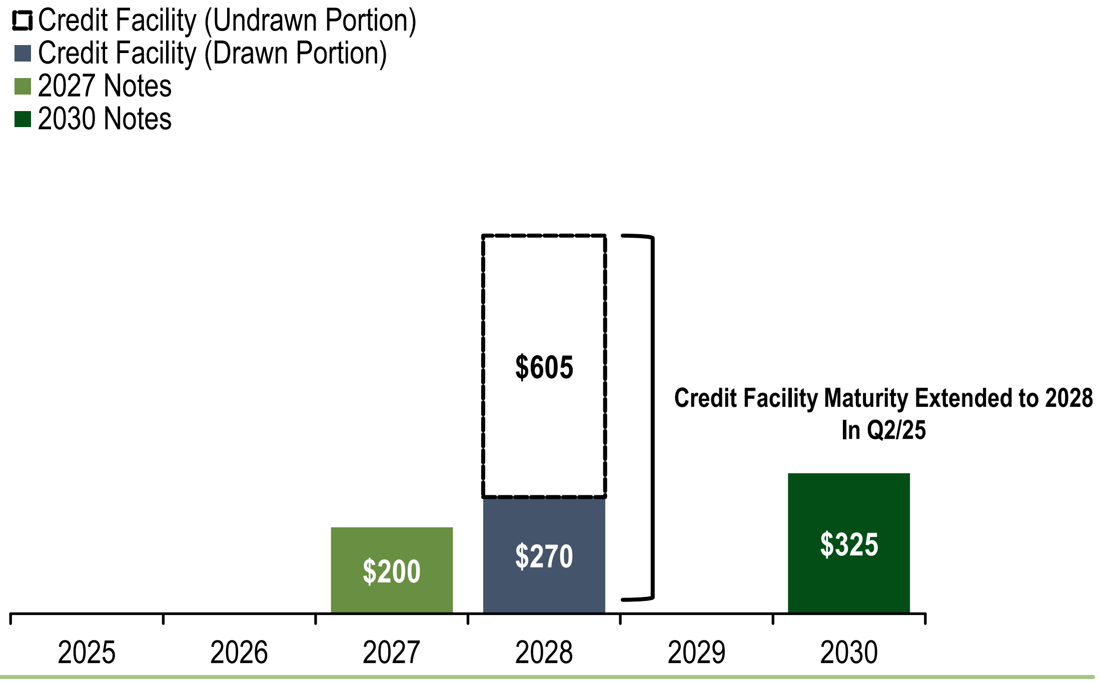
Robust Credit Profile With Significant Liquidity & Low Debt/EBITDA Ratios

- On July 25, 2025, the Company 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
- Subsequent to Q2/2025, Tamarack acquired a PrivateCo. for cash consideration of $51.5MM
- June 30, 2025 net debt of ~$711MM (~0.7x Nebt Debt/LTM EBITDA[1])

Q1 2025 (Prior To Credit Facility Maturity Extension)[2]



Q2 2025 (Pro Forma 2030 Note Issuance & Tuck-In)[2]



1) See disclaimers - "Specified Financial Measures"; LTM EBITDA – Last 12 months EBITDA.
2) Credit facility draw includes $5.9 MM of LCs.

3) Pro forma credit facility draw for issuance of the 2030 notes calculated as: Q2 drawn portion of credit facility – net proceeds from 2030 note offering used to repay credit facility ($216 MM) + cash purchase price of PrivateCo. ($51.5MM). Credit facility draw includes $5.9 MM of LCs.

Tailwinds For Canadian Heavy Producers

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

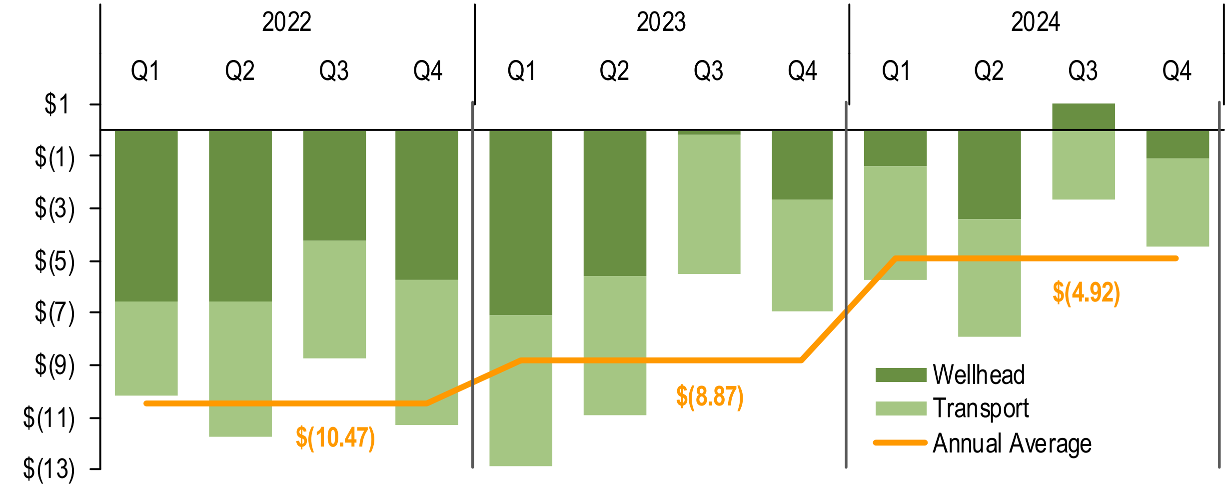
WCS Continues to Trade Exceptionally Strong Since the Start-Up of TMX (~US$9/bbl); Expected to Stay Strong in Future Years:

- 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

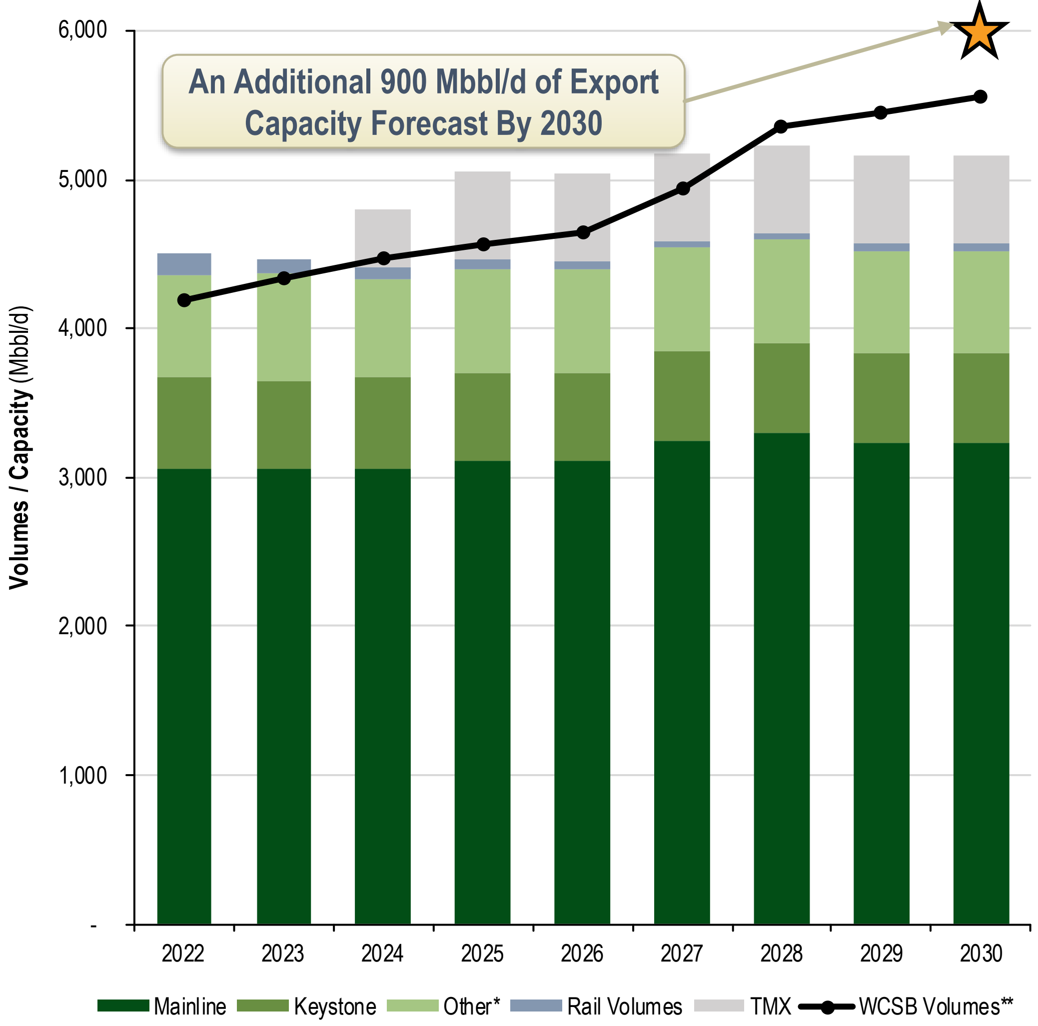
Tamarack Executed its Strategic Plan to Significantly Improve Heavy Oil Wellhead And Transportation Deductions:

- 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



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.

2025 Outlook Sensitivity[1]

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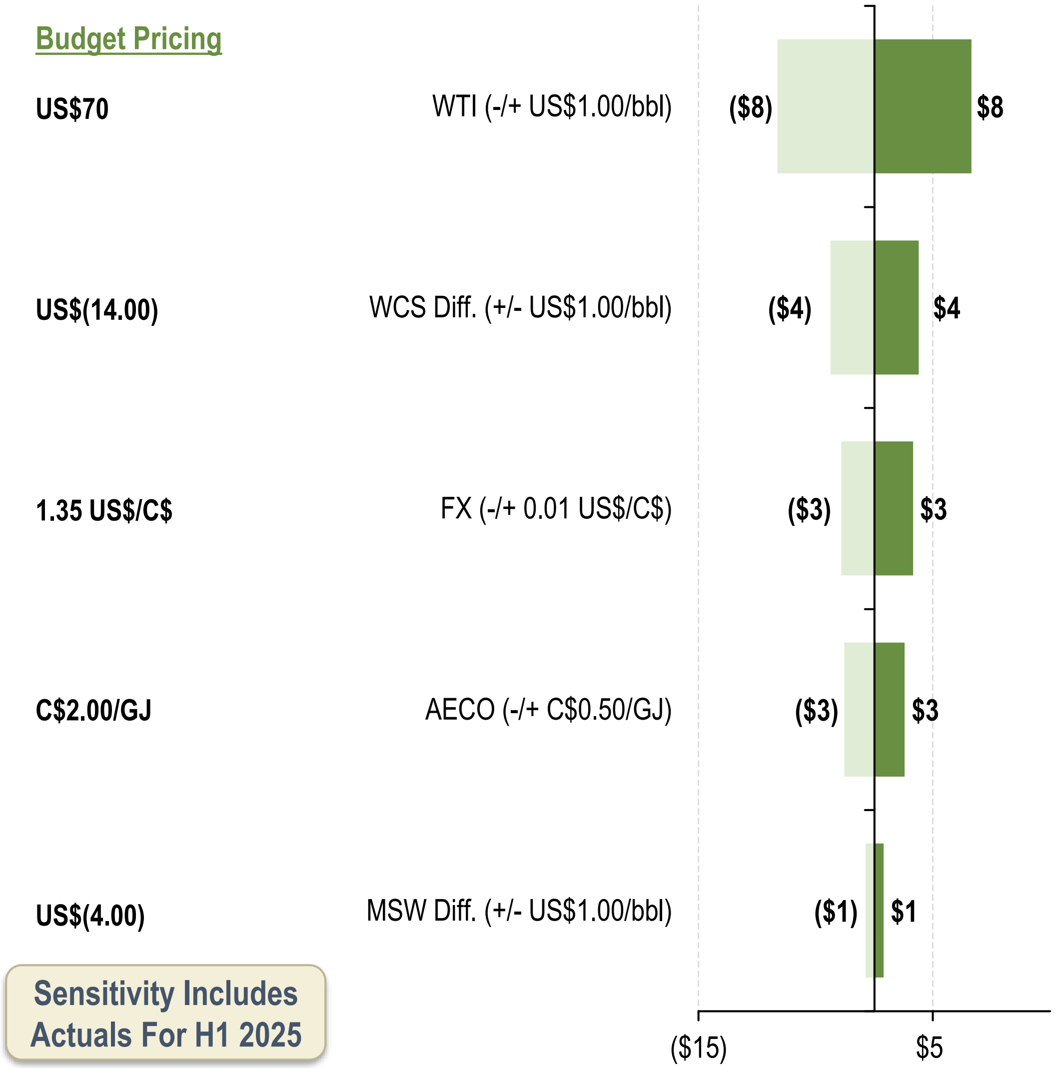
A-Tax Adjusted Funds Flow[1,2] (Hedged; $MM)



Sensitivity Includes Actuals For H1 2025

Strong Asset Base to Withstand Price Changes

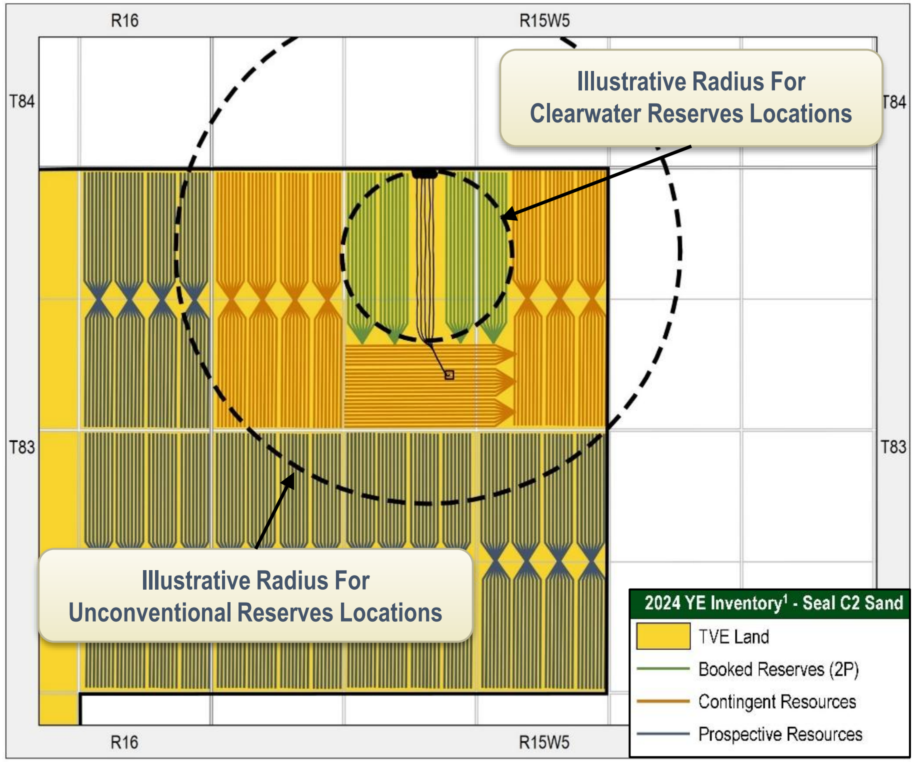
- Tamarack is most sensitive to WTI pricing given oil weighting of >80%
  - For every US$1.00/bbl change, AFF[2] changes by +/-$8 MM[1]
- WCS differential adds to the sensitivity, >65% heavy oil assets, AFF[2] changes by +/-$4 MM for every US$1.00/bbl change in differential[1]
  - Tamarack's heavy oil portfolio is made of highly economic Clearwater assets with best-in-class breakeven prices
- AECO and MSW differential have less of an impact on AFF[2]
- Tamarack manages commodity risk through its risk management program to support capital stability, base dividend and debt repayment
- Basis hedges reduce sensitivity to differentials

1) Sensitivity is for 2025ROY. Includes hedges in place as at July 29, 2025. Includes Q2/25 actuals and settled pricing up to & including June 2025.
2) See Disclaimers – "Specified Financial Measures"; AFF – Adjusted Funds Flow.

Appendix: Assets

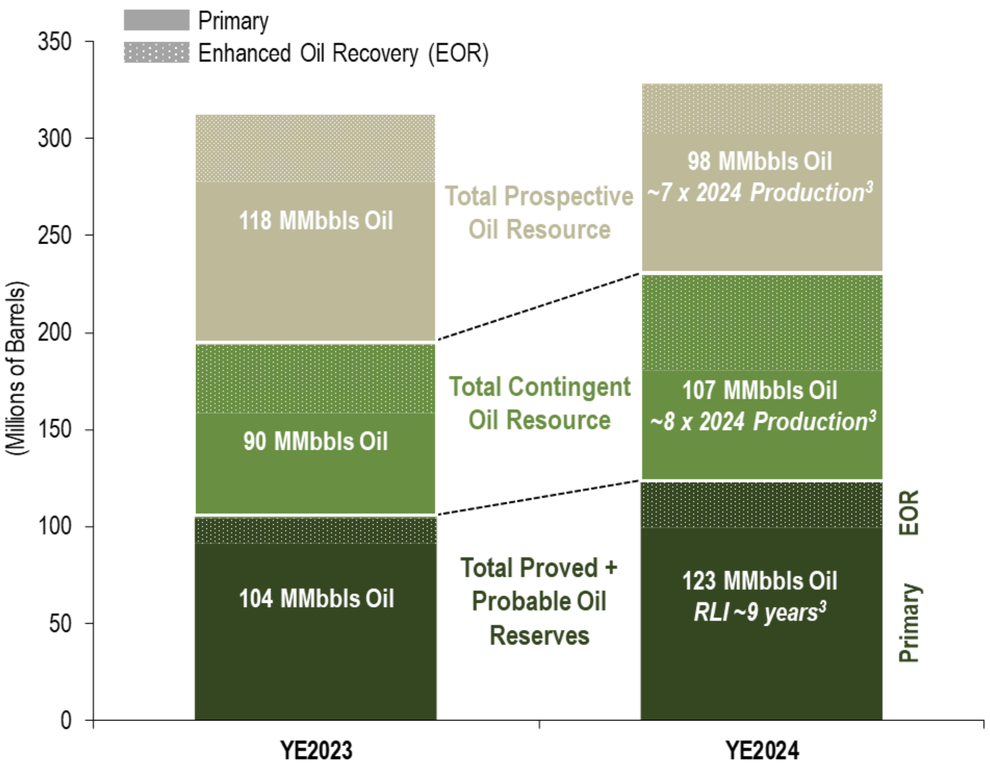
Clearwater Reserves and Resources

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]



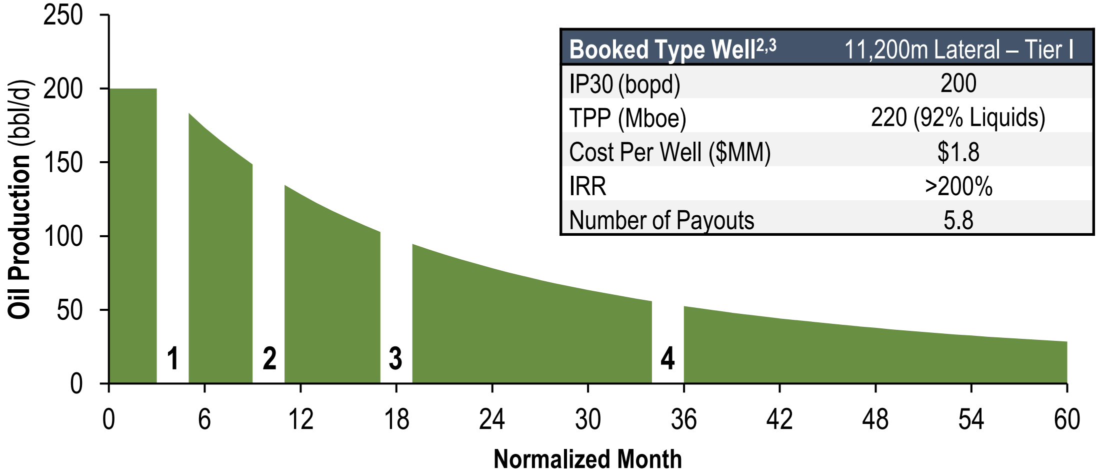
- Successful promotion of resources through delineation of inventory and waterflood in 2024 resulted in 19% growth in Contingent Oil Resource and 18% growth in TPP Oil Reserves

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 ~13.9 MMbbls.

Clearwater Economics: Primary Recovery

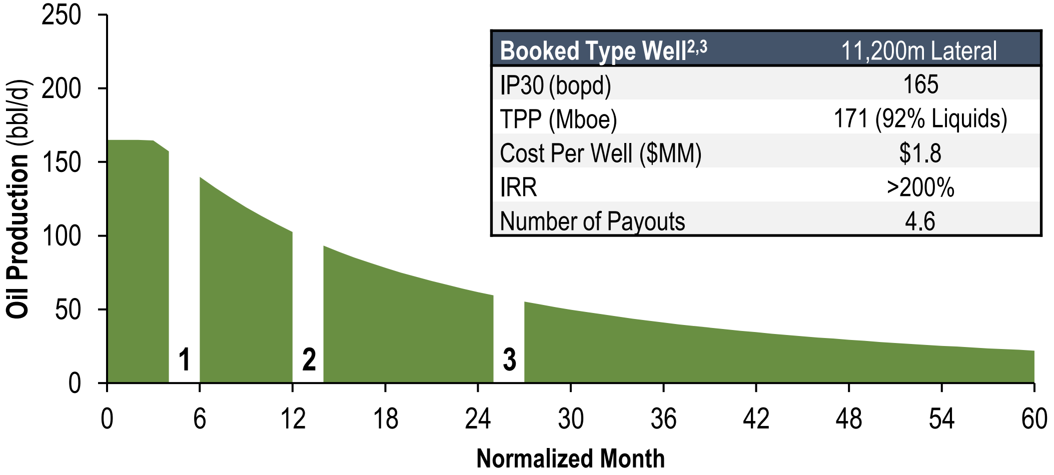
Multiple Payouts Compound Free Funds Flow[1] Growth

West Marten "B" Sand



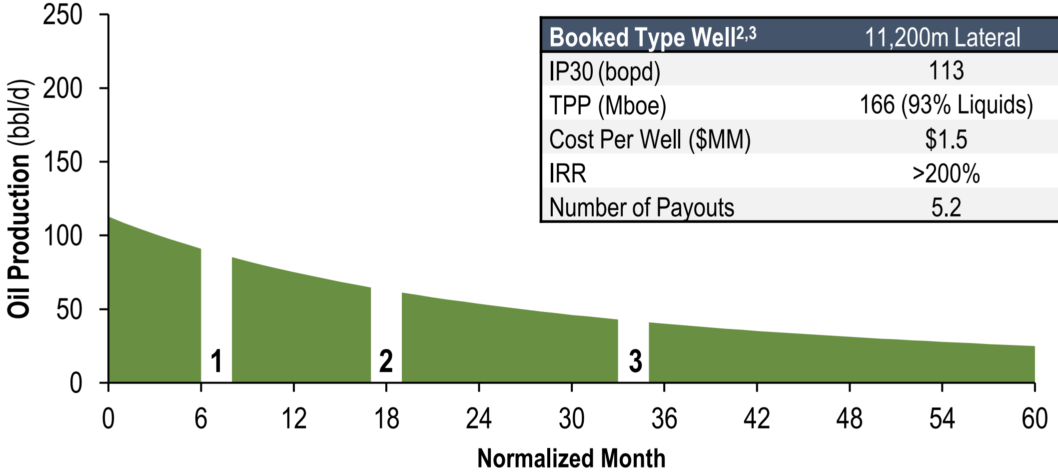
Booked Type Well[2,3]	11,200m Lateral – Tier I
IP30 (bopd)	200
TPP (Mboe)	220 (92% Liquids)
Cost Per Well ($MM)	$1.8
IRR	>200%
Number of Payouts	5.8

West Marten "C" Sand



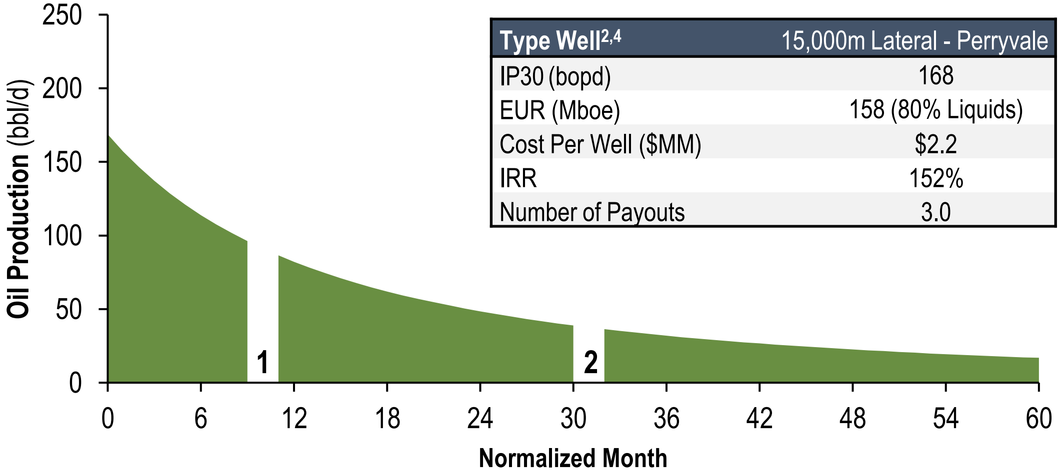
Booked Type Well[2,3]	11,200m Lateral
IP30 (bopd)	165
TPP (Mboe)	171 (92% Liquids)
Cost Per Well ($MM)	$1.8
IRR	>200%
Number of Payouts	4.6

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



Type Well[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".
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.

Corporate Information

Executive

Brian Schmidt (Aakaikkitstaki)	Chief Executive Officer
Steve Buytels	President & 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.

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Investor Contact Information

Brian Schmidt
President &
Chief Executive Officer

Steve Buytels
President &
Chief Financial Officer

Christine Ezinga
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 net debt target of $500 million in 2027), return of capital and growth optionality; Tamarack's revised 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; the acquisition of PrivateCo (the "Acquisition"), including anticipated benefits and strategic rationale; expectations surrounding the expansion of the Clearwater resource; expectations regarding improved field egress capacity; 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 business plan of Tamarack; the assets acquired pursuant to the Acquisition; 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 or failure to realize the benefits of acquisitions (including the Acquisition); 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 and six months ended June 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.

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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, revised 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 (including achieving $500MM net debt target in 2027), 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, including pro forma the Acquisition, 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 revised 2025 guidance are disclosed in the Company's press release dated July 30, 2025. 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 revised 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.

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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