TSX: TVE

Tamarack Valley Energy

CREATING SUSTAINABLE VALUE

Clearwater Sites at West Marten Hills

February 2025 | World Outlook Financial Conference

Corporate and Operational Snapshot

The Largest Public Clearwater Producer

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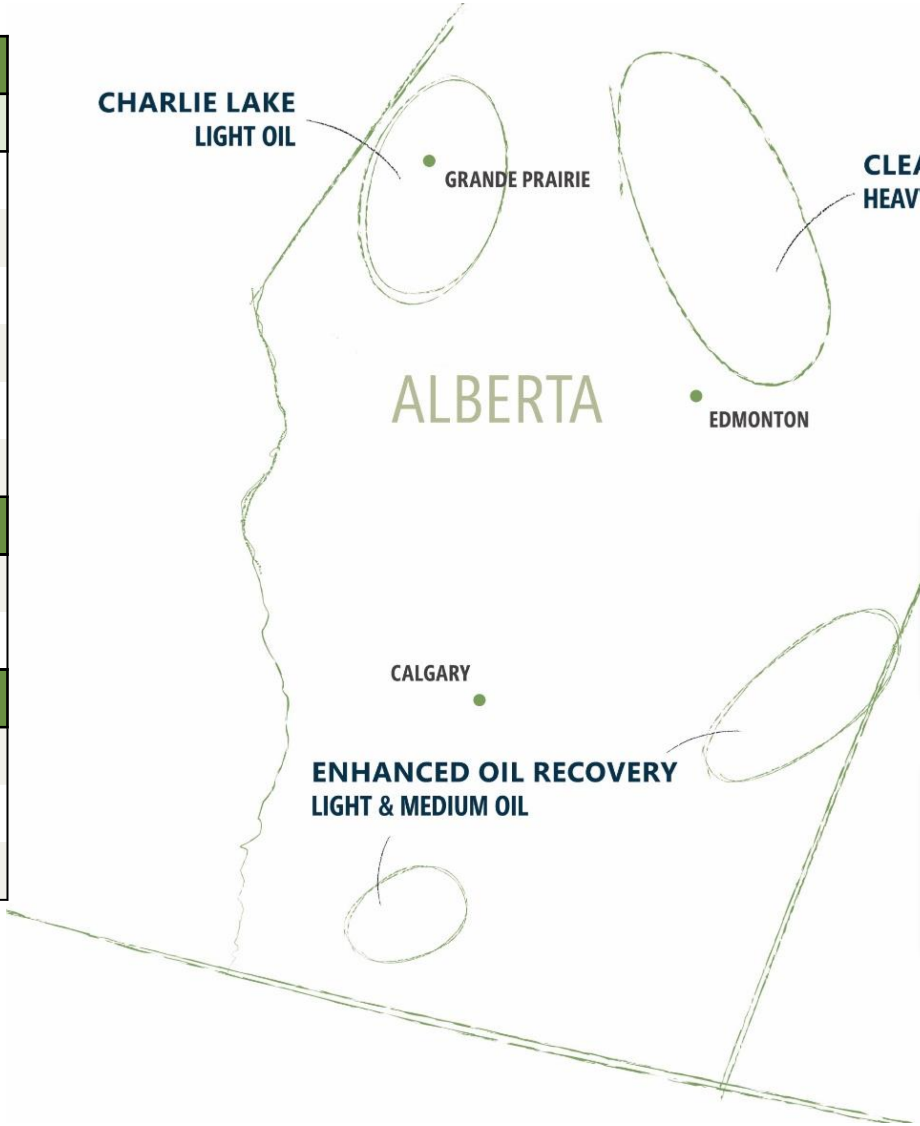
Corporate Overview		
Ticker Symbol		**TSX: TVE**
Shares Outstanding (Basic)[1]	*(MM)*	523
Market Capitalization[1]	*($MM)*	$2,542
Q3 2024 Net Debt	*($MM)*	$807
Enterprise Value	*($MM)*	$3,349
Annual Base Dividend[1]	*($/Sh.)*	$0.153
Implied Annual Base Yield[1]	*(%)*	3.1%
2024 Guidance Highlights		
Production[2]	*(boe/d)*	63,000 – 64,000
Capital Expenditures[4]	*($MM)*	$440
2025 Guidance Highlights		
Production[3]	*(boe/d)*	65,000 – 67,000
Average Liquids Weighting	*(%)*	83% – 85%
Capital Expenditures[4]	*($MM)*	$430 – $450



>90%
Production From Clearwater and Charlie Lake

~$135 MM
Shares Repurchased In 2024

1) Share count as at December 31, 2024. Share price and dividend yield uses Tamarack share price as at January 6, 2025.
2) Production of 63,000 – 64,000 boe/d: 37,900-38,600 bbl/d heavy oil, 13,600-13,750 bbl/d light and medium oil, 2,300-2,400 bbl/d NGLs and 55,000-55,500 mcf/d natural gas.
3) 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.
4) Capital expenditures excluding ARO spending. 2024 capital expenditures excludes CIP capital.

Maximizing Free Funds Flow[1] Per Share Growth

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

- ✓ *Premium netbacks, higher price realization and lower cost structure*
- ✓ *US$38/bbl Sustaining Breakeven*

- ✓ **Commitment to Returns: Allocating 60% of Free Funds Flow**
- ✓ **Leveraging Scale and Quality To Deliver Sustainable Long-Term Returns Per Share**
- ✓ **Financial Flexibility To Take Advantage of Strategic Opportunities and/or Growth**

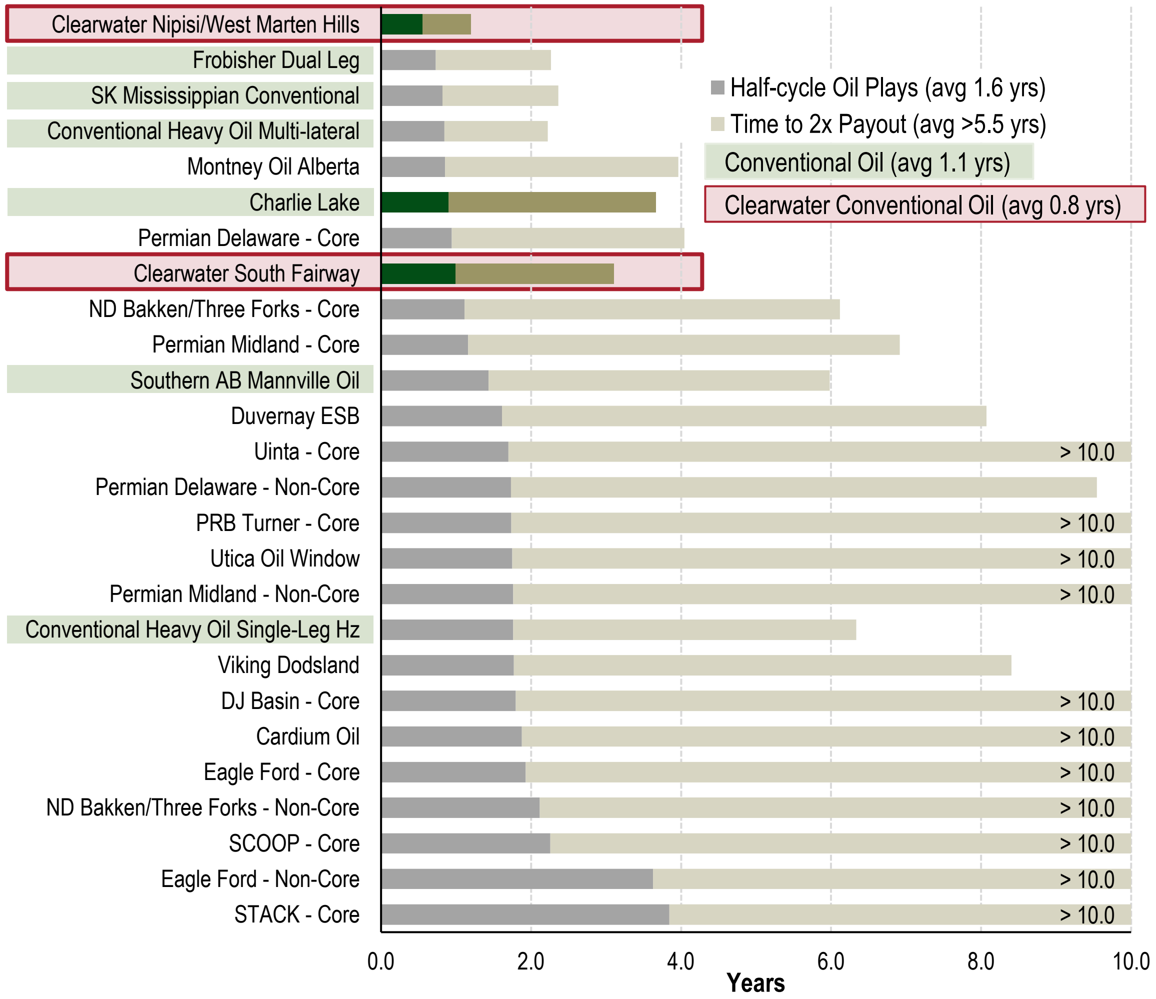
- ✓ *Waterflood mitigating production decline*
- ✓ *Reducing sustaining capital requirements*

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

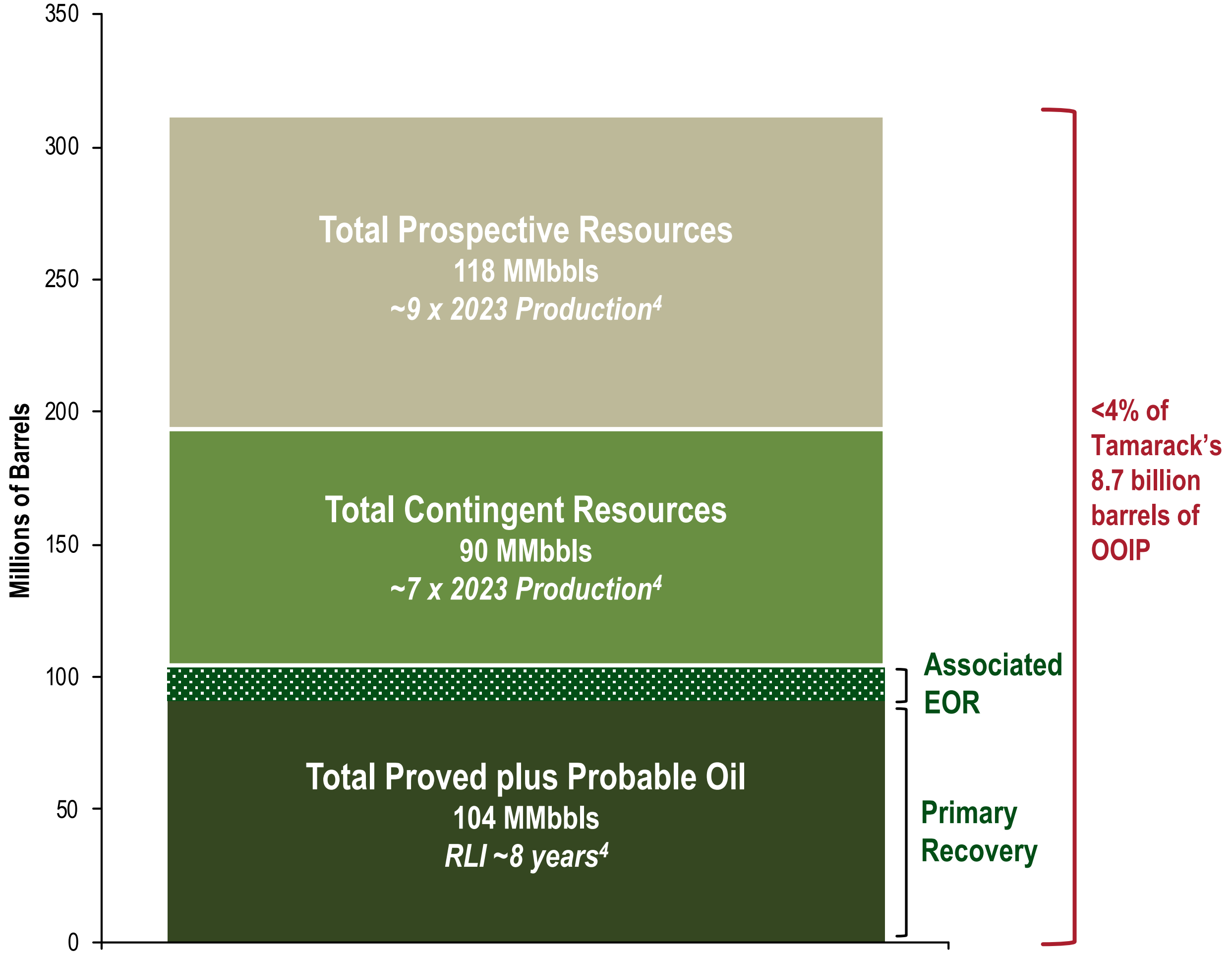
Clearwater Resources Support Long-Term Development

Top Tier Resource With Considerable Scale To Support Future Growth

North American Oil Plays: Half-Cycle and 2x Payout Period[1]



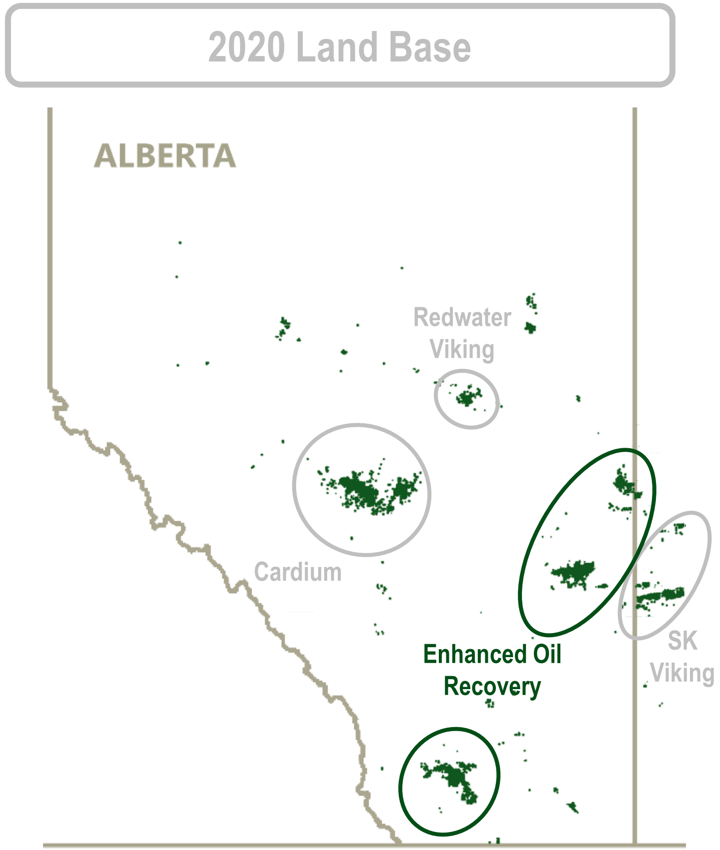
2023 Clearwater Reserves & Resources[2,3]



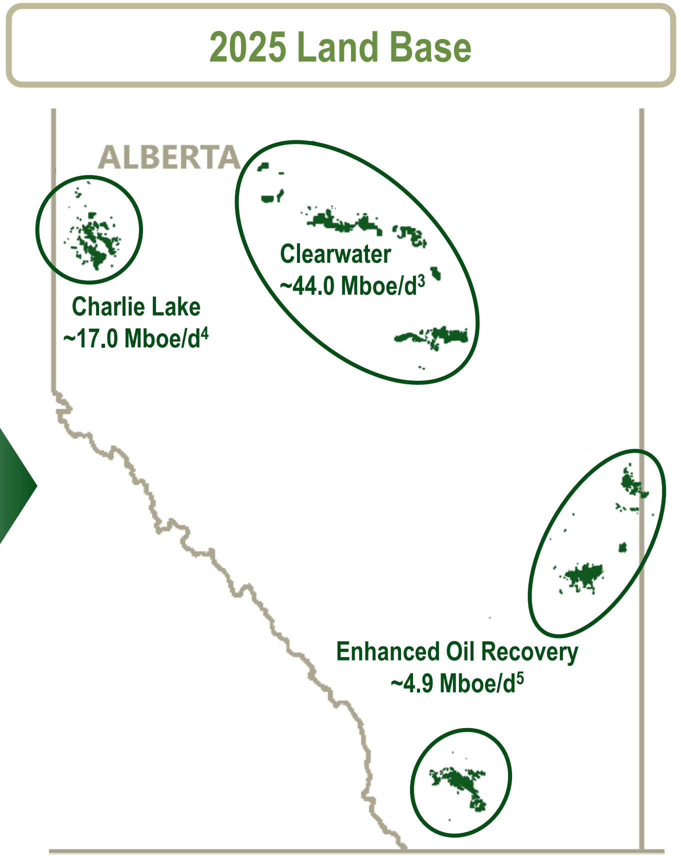
1) Source: Peters & Co. Limited estimates based on US$69.00/B WTI, US$13.37/B WCS Differential, US$4.25/B PAR Differential, US$3.60/Mcf NYMEX, $2.75 AECO, and $0.71 CAD/USD. Note: Sorted by half-cycle payout.
2) Based on McDaniel & Associates Consultants Ltd Resource Report effective December 31, 2023. See Disclaimers – "Resource Disclosure".
3) Reserves, contingent resources, and prospective resources should not be combined without recognition of the significant differences in the criteria associated with their classification.
4) Based on 2023 Clearwater oil production of 13MMbbls.

Transformation To The Largest Public Clearwater Producer

Portfolio Has A Significant Depth of Premium Inventory To Deliver Long-Term Returns For Shareholders



Average 2020 Production:
~22,000 boe/d[1] & ~60% Liquids



Average 2025 Production Estimate:
~66,000 boe/d[2] (Midpoint) & ~84% Liquids

>90% of Corporate Production In Clearwater and Charlie Lake

1) ~22,000 boe/d: 204 bbl/d heavy oil, 11,155 bbl/d light oil, 3,408 bbl/d NGLs, and 52.4 MMcf/d of natural gas.
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.
4) ~44.0 Mboe/d: ~39,700 bbl/d heavy oil, ~300 bbl/d light oil, ~250 bbl/d NGLs, and ~23.0 MMcf/d of natural gas.
5) ~17.0 Mboe/d: ~9,000 bbl/d light and medium oil, ~2,050 bbl/d NGLs and ~36.0 MMcf/d of natural gas.
6) ~4.9 Mboe/d: ~4,200 bbl/d light and medium oil, ~50 bbl/d NGLs and ~3.9 MMcf/d of natural gas.

Road Map For Value Generation

Strategic Transformation Complete... Consistent & Predictable Path Forward to Grow Shareholder Returns

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Phase I

Asset Transformation

Completed in 2023

☑

- Largest public Clearwater producer
- Top tier asset portfolio with ~85% liquid weighting
- Decades of premium inventory development
- Low free funds flow[1] breakeven

Phase II

Debt Paydown & Return of Capital

~ In Progress ~

- Total return balancing debt and returns to shareholders through enhanced return framework
- Execution quarter over quarter
  - **Q2/24: Achieved 2nd Phase of Return of Capital (Up To 60% of FFF)**
  - **Q3/24: Increased Base Dividend By 2%**
- Triggers for Phase III:
  - Target debt
  - Improved equity valuation

Phase III

Growth Optionality

~ Future Outlook ~

- Focus on per share growth including:
  - Organic production growth
  - Long-term share buybacks
  - Opportunistic M&A

1) See "Specified Financial Measures".

Return of Capital Framework

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

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Within 5 Yr. Plan

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*
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			

Adjusted Funds Flow[1]

2024 Share Buybacks of ~34 MM Shares[2]
(~6.0% of 2023YE Share Count)

Q3/24: Increased Base Dividend Per Share by ~2%

Simplified Framework

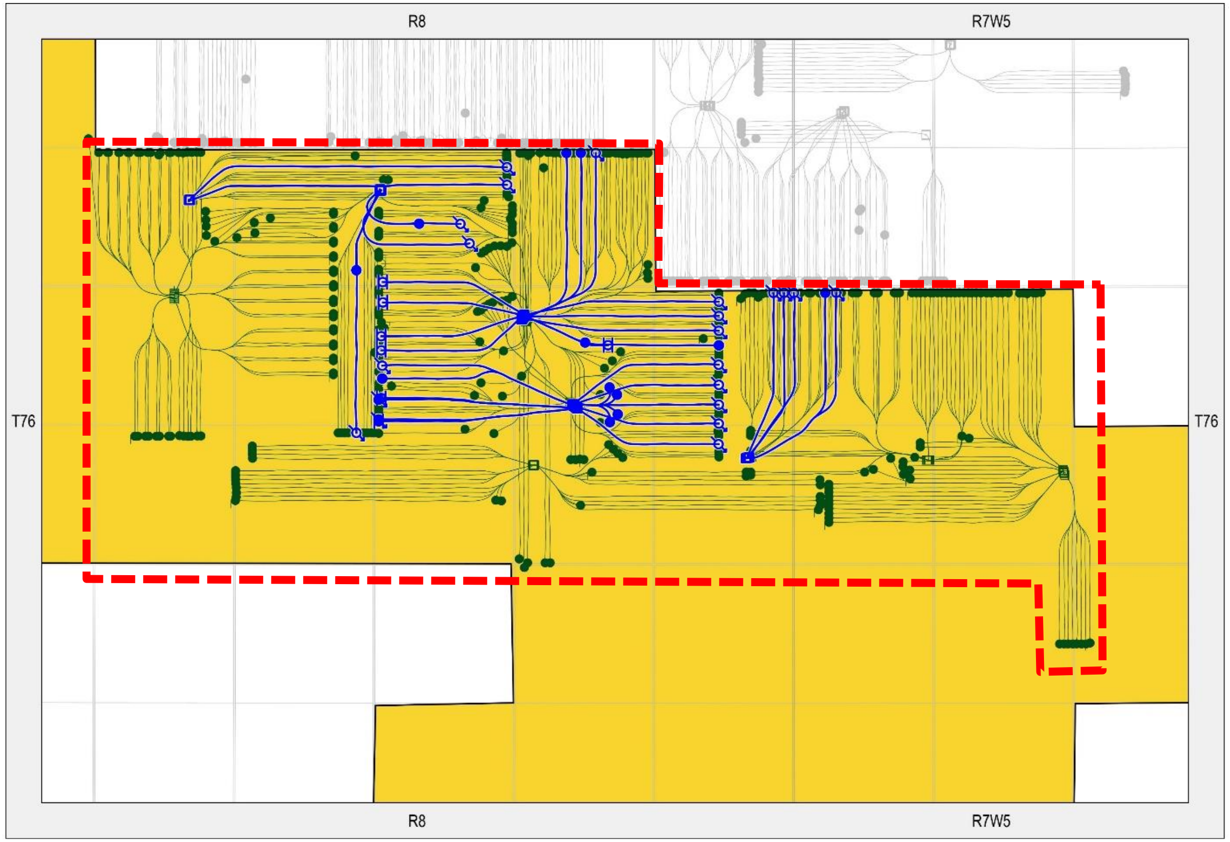
- Future free funds flow[1] to be allocated between:
  1. Debt
  2. Direct investor returns
     - Base dividend
     - Enhanced returns (long-term share buybacks)
  3. Strategic growth capital

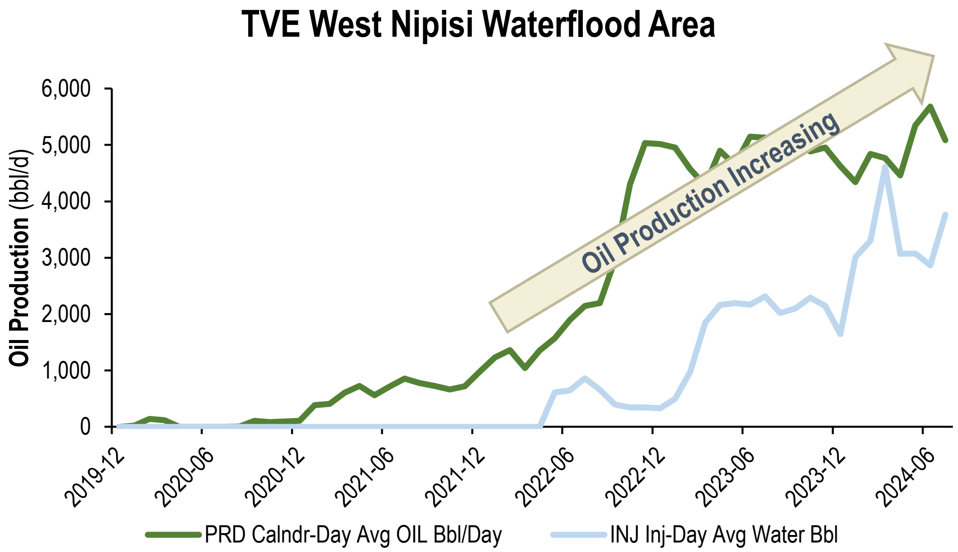
1) See Disclaimers – "Specified Financial Measures"
2) Share buybacks from January 2024 up to and including December 2024.

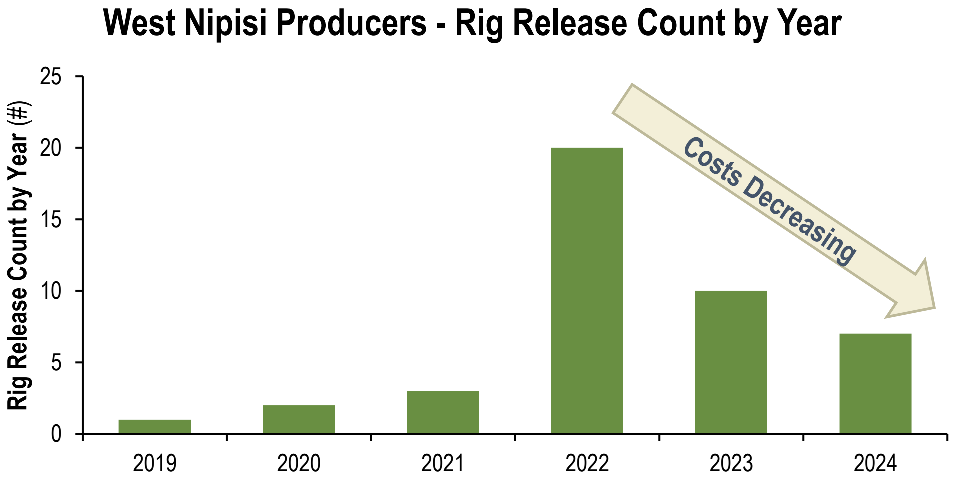
West Nipisi Waterflood Area

Waterflood Stabilizing Production With Reduced Drilling Activity

- Primary development commenced in 2019 and ramped up through 2022
- Pilot waterflood commenced in 2022 with broad implementation in 2023-24
    - Oil production has stabilized with reduced primary drilling activity
    - Inventory of injectors in the area continue to strengthen production base

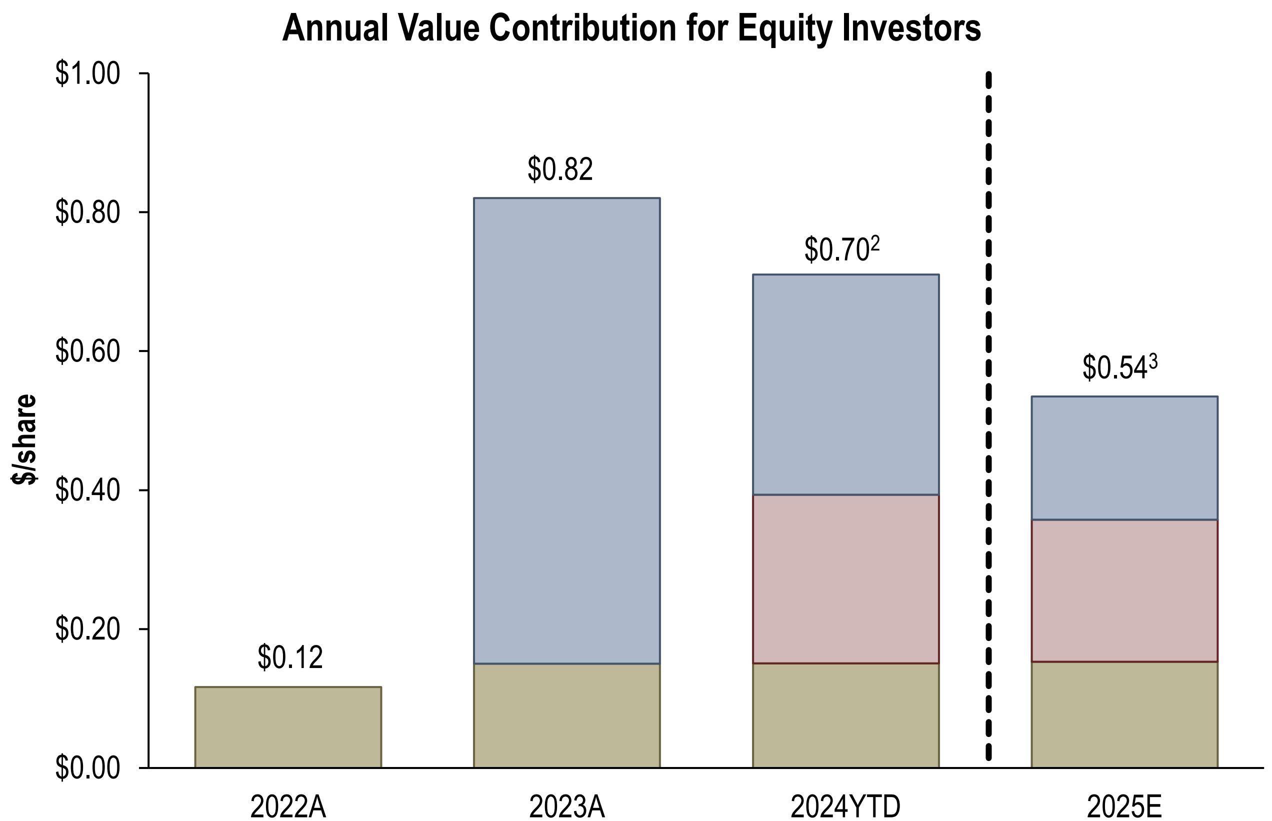






Delivering Returns and Value to Shareholders

Equity Investors Provided with ~$1.65/share of Cumulative Return Value From Multiple Sources 2022-2024



WTI Oil Price	US$94.23/boe	US$77.62/boe	US$75.72/boe	US$70.00/boe

Debt Reduction

Q4/22 – Q4/23 net debt reduced by $373MM (~$0.67/share of value[1])
Q4/23 – Q3/24 net debt reduced by $176MM (~$0.32/share of value[2])
2025E Budget ~$300MM Free Funds Flow ~(40% for debt repayment[3])

Enhanced Returns Through Share Buybacks

Since initiating enhanced returns in 2024 Tamarack bought back 6% of shares outstanding[2] for a total of >$135MM

Base Dividends

Tamarack announced three dividend increase since it was initiated
Dividends provided for ~3% annual yield in 2024

Strategic asset dispositions in 2023 and 2024 accelerated debt reduction achieving key debt thresholds for enhanced returns

1) Based on shares outstanding at December 31, 2022.
2) Based on shares outstanding at December 31, 2023 and debt reduction as reported to Q3 2024
3) 2025E budget as press released December 4, 2024. Forward estimates at US$70/bbl WTI, US$(4.00)/bbl MSW, and US$(14.00)/bbl WCS.

Delivering Outsized Returns

Leveraging Scale & Asset Quality To Deliver Sustainable Long-Term Returns Per Share

Asset Transformation Complete:
Focused, Large Scale, Highly Economic Asset Portfolio

Rate of Change:
Lower Costs and Enhanced Capital Efficiencies Drives Higher Margins

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

Compounding Returns:
Production Growth + Lowering Sustaining Capital + Long Term Buybacks = Outsized Per Share Returns

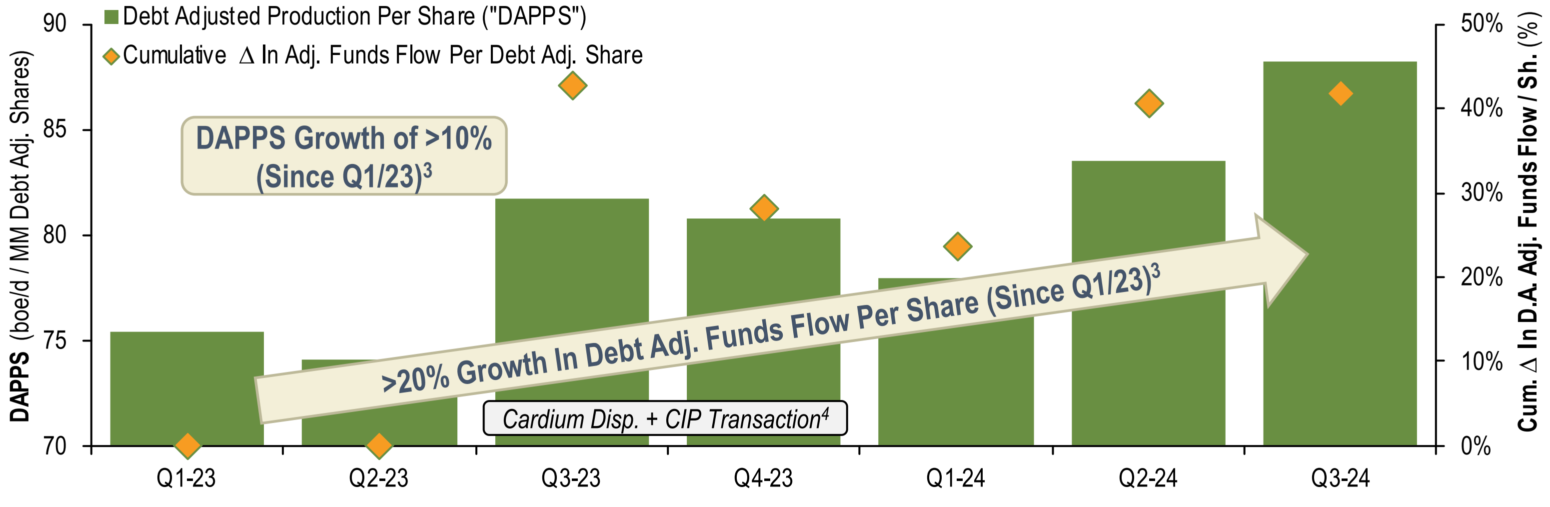
Appendix: Financial

Driving Per Share Growth

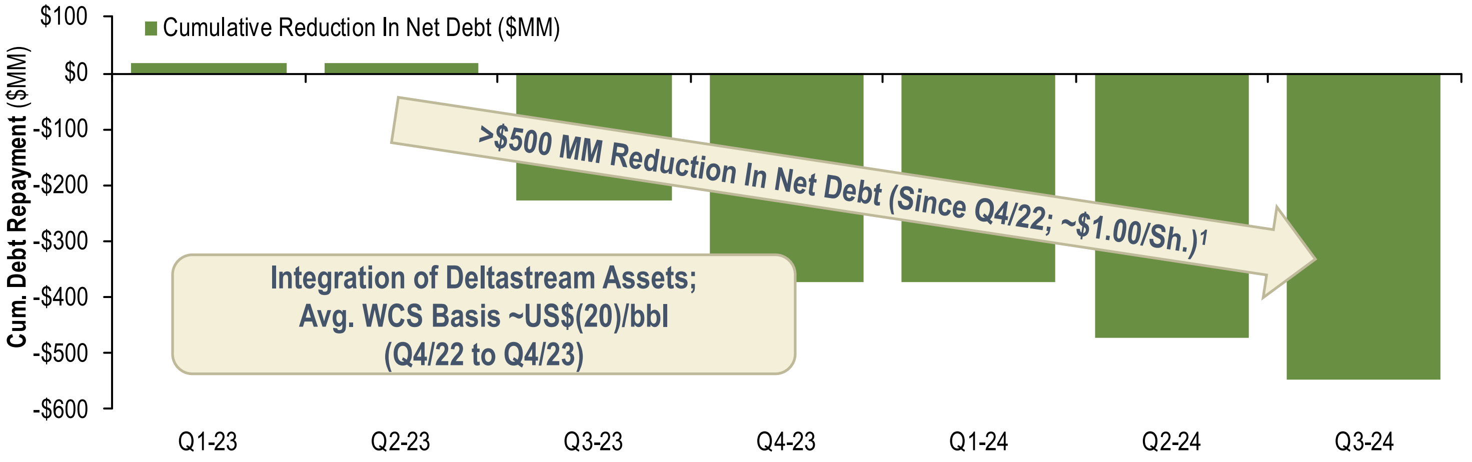
Deleveraging & Buybacks Drive Per Share Value

- Net debt **reduced by >$500 MM** since Deltastream acquisition closed in Q4/22 (~$1.00/Sh.)[1]
- Tamarack repurchased **~34 MM shares** in 2024 **(~6.0% of 2023YE share count)[2]**
- Debt adjusted production per share **increased by >10%**[3] (Q1/23 vs. Q3/24)
- Net production expenses **reduced by >10%** per boe (Q4/22 vs. Q3/24)
- Liquids weighting **increased by ~3% to ~85%** (Q4/22 vs. Q3/24)

Debt Adj. Prod. / Sh. & Cum. ∆ In Debt. Adj. Funds Flow / Sh. (boe/d / MM shares; %)[3]



Cumulative ∆ In Net Debt ($MM)



See "Specified Financial Measures".
1) Calculated using Q3/2024 share count.
2) 2024 share buybacks from January to December.
3) Debt adjusted using a Tamarack share price of $4.00/Sh.
4) Cardium disposition closed in Q4/2023. Assets were held for sale as at Q3/2023.

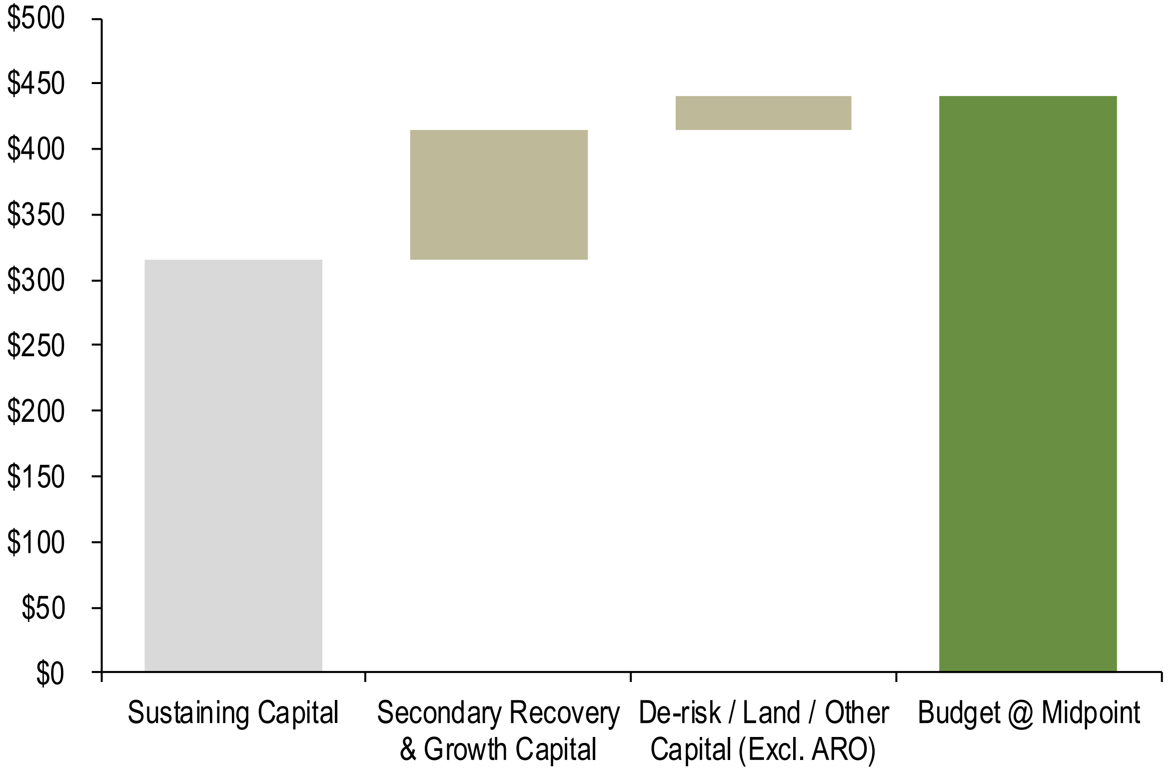
2025 Annual Corporate Guidance

Developing Expanded Clearwater Assets & Investing To Enhance Margins

2025 Budget Pricing	
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	Units	Annual Guidance
Capital Expenditures[1]	*$MM*	$430 – $450
Average Annual Production[2]	*boe/d*	65,000 – 67,000
Average Oil & NGL	*%*	83% – 85%
Royalties	*%*	20% – 22%
Wellhead Oil Price Differential	*$/bbl*	$1.50 – $2.50
Production Expense[3]	*$/boe*	$8.40 – $8.90
Transportation Expense	*$/boe*	$3.75 – $4.25
G&A	*$/boe*	$1.30 - $1.45
Interest[4]	*$/boe*	$2.90 – $3.30
Income Tax[5]	*%*	10% - 12%

2025 Capital Program ($MM)



1) Excludes ARO.
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) Includes CIP fee for service.
4) Includes CIP ToP capital fee.
5) Income tax percentage is based on the percentage of adjusted funds flow before tax.

2025 Free Funds Flow Allocation

Low Breakeven Drives Resiliency, Increasing Returns to Shareholders

Production Growth & Disciplined Capital Allocation

~4% Annual Production Growth; ~9% Growth Per Share @ Budget Pricing[1]

Strong Free Funds Flow Generation

~$300 MM Annual Free Funds Flow[2] & ~13% FFF Yield[2] @ Budget Pricing

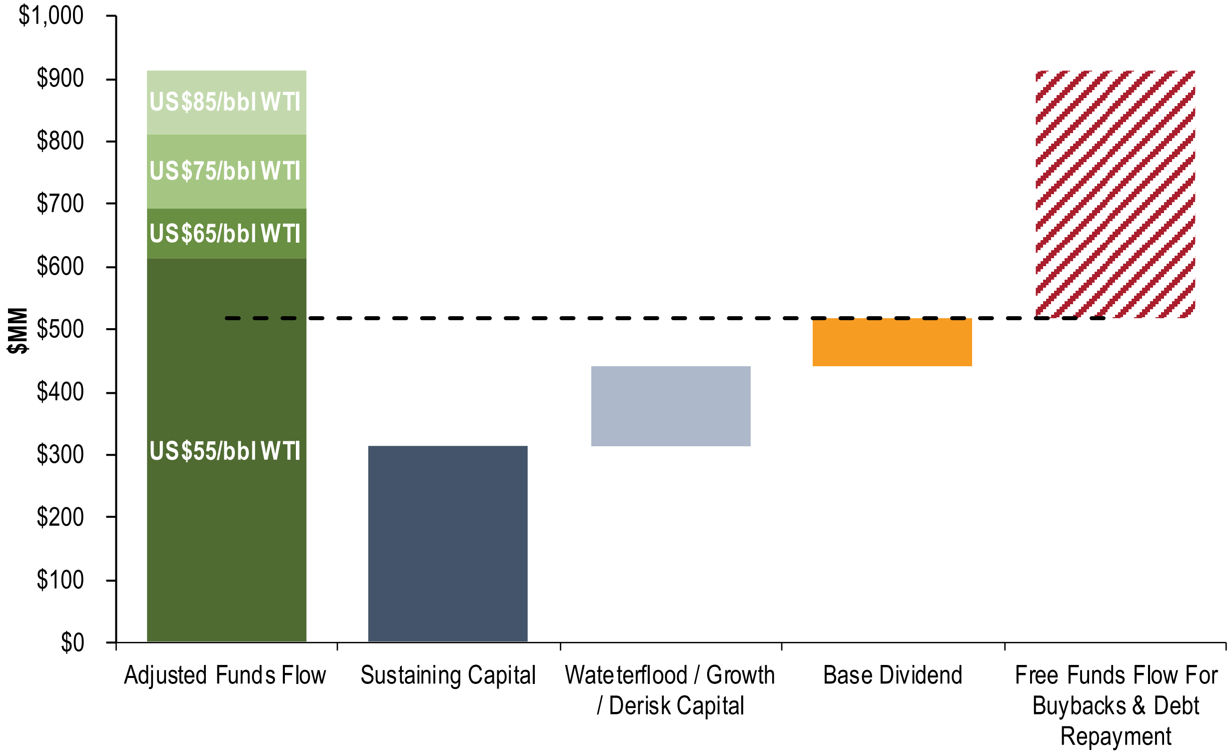
Financial Strength & Resiliency

Corporate Sustaining Free Funds Flow Breakeven[2] of ~US$38/bbl

Returns To Shareholders

60% of Free Funds Flow[2] Returned via Base Dividends & Share Buybacks
Total Shareholder Return Yield of ~16%[2]

2025 Free Funds Flow Allocation ($MM)

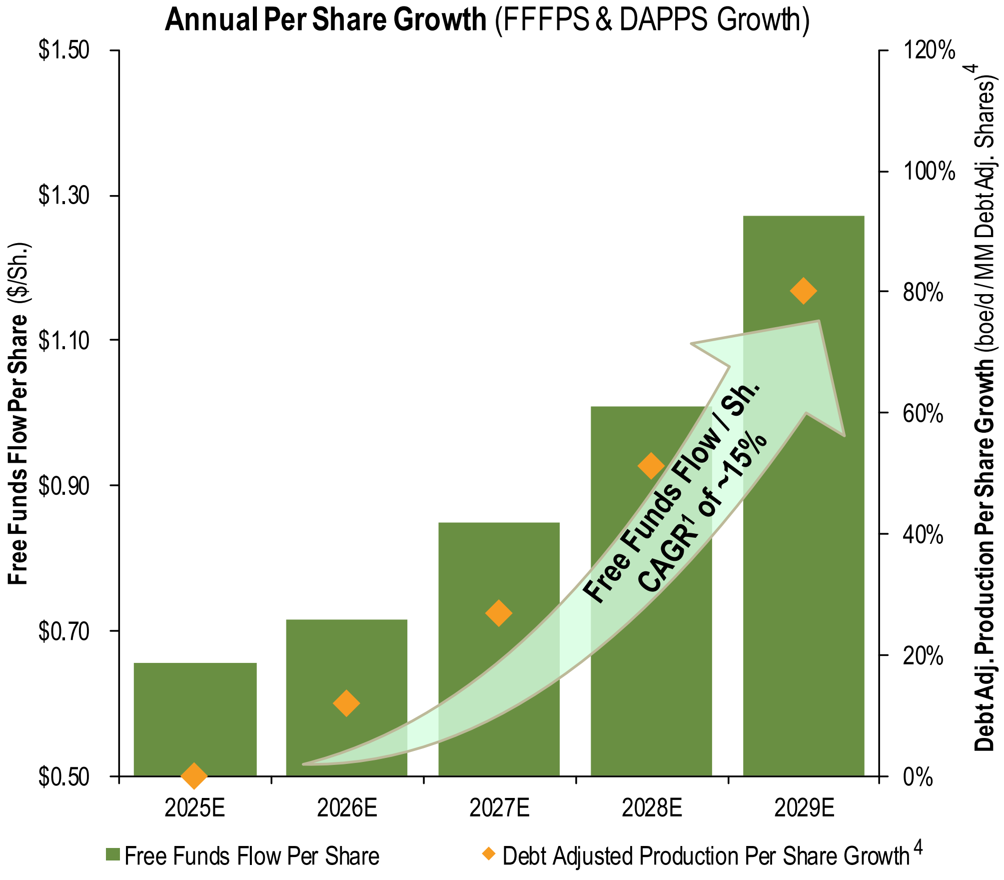


2025 Capital Program & Base Dividend Funded at <US$55/bbl WTI

1) Growth measured as 2025E annual average production at the midpoint of guidance relative to 2024E annual average production.
2) See Disclaimers – "Specified Financial Measures".
3) Sensitivity decks assume C$3.00/GJ AECO and 1.30 US$/C$.
3) (cont.). 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

Striking Balance Between Production Growth & Shallowing Declines (EOR) For Ultimate Value Creation



2025 Budget Reflects An Out Performance On Both Capital and Production vs. 5-Year Plan That Was Established In June 2024

5-Year Production Growth CAGR[1] 3%-5%
Cumulative After-Tax Free Funds Flow of ~$1.8 billion
Long Term Buybacks

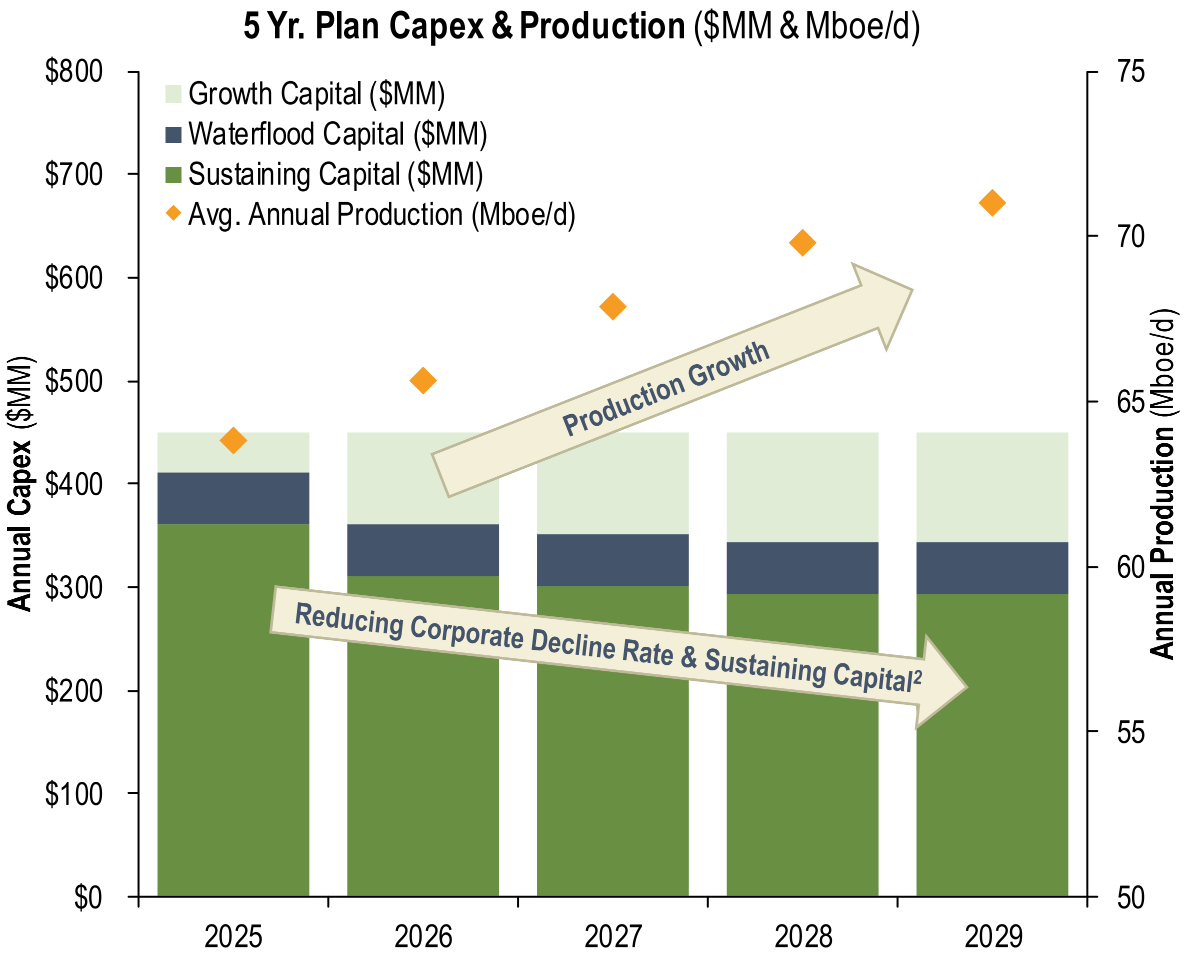
Key 5-Year Plan Metrics	
Annual Reinvestment:[1,2]	50% - 60% (Annual Capital: ~$450 MM)
Annual Free Funds Flow:[2,3]	$325 - $425 MM
Annual Returns to Shareholders:[6]	~10% - 15%
Net Debt / Funds Flow (2029E):[1]	~0.5x (Incl. Enhanced Return)

Total Free Funds Flow Per Share Growth of ~100%[5]
Total Debt Adjusted Production Per Share Growth of ~80%[4]

1) See Disclaimers – "Specified Financial Measures".
2) 2025E+ 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$.
3) 5 Yr. Plan includes Q3 2024 actuals, enhanced returns, and hedges currently in place as of September 2024.
4) Debt adjusted using a Tamarack share price of $4.00, average annual share counts and net debts. DAPPS growth uses 2025E as the base year.
5) Free Funds Flow per share growth from 2025E to 2029E. Free funds flow before dividends and buybacks.
6) Annual direct returns to shareholders include share buybacks and dividends. Percentages assumes a market capitalization of ~$2.2 B.

Waterflood Mitigates Decline Rates & Reduces Sustaining Capital

Reducing Sustaining Capital Drives Free Funds Flow[1]



2025 Budget Reflects An Out Performance On Both Capital and Production vs. 5-Year Plan That Was Established In June 2024

5-Year Plan Illustrates Reduced Sustaining Capital[2] and Corporate Decline

- Waterflood production forecast to grow by >30% in 5-Year Plan
- Corporate decline expected to shallow by 3% - 5%
- Shallowing decline rate allows for reduced sustaining capital requirements increasing annual free funds flow[1] for incremental debt repayment, returns, and growth optionality

1) See Disclaimers – "Specified Financial Measures"
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) 5 Year plan established in June 2024 for annual investor day presentation; Current 2025 Budget outperforming plan.

Five Year Plan Compounding Per Share Returns

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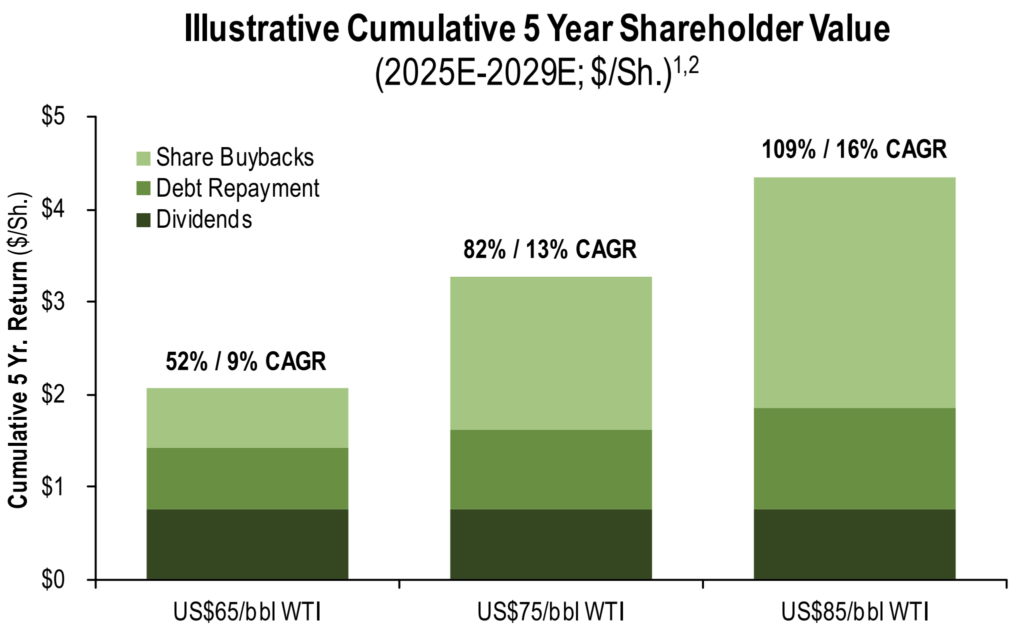
Production Growth + Lowering Sustaining Capital + Long Term Buybacks = Outsized Per Share Returns

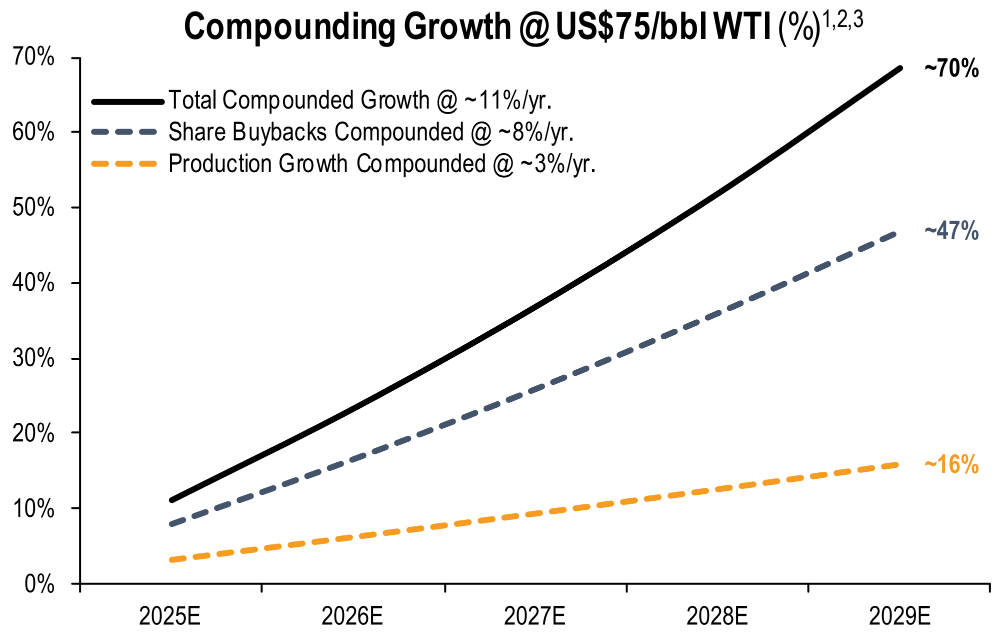
Total Shareholder Value of ~$1.8B or ~$3.25/Sh. Including Debt Reduction Over Next 5 Years at Flat US$75/bbl WTI

- Pay ~$420MM of base dividends (~$0.75/Sh.)
- Reduce debt by ~$450MM from 2024YE (~$0.85/Sh.)
- Balancing enhanced return of ~$875MM (~$1.65/share)

Compounding Growth For Production and Share Buyback Totals ~70% over 5 years at Flat US$75/bbl WTI

- Compounding production per share growth of >15% over 5 years[3]
- Compounding share buyback growth of >45% over 5 years[3]





1) See Disclaimers – "Specified Financial Measures". Shareholder Returns on 3% - 5% Growth Development Plan. Includes Q3 2024 actuals and hedges in place as at September 2024. Assume shares are repurchased at $4.00/Sh. Sensitivities assume budget pricing for remainder of 2024E (US$75/bbl WTI).

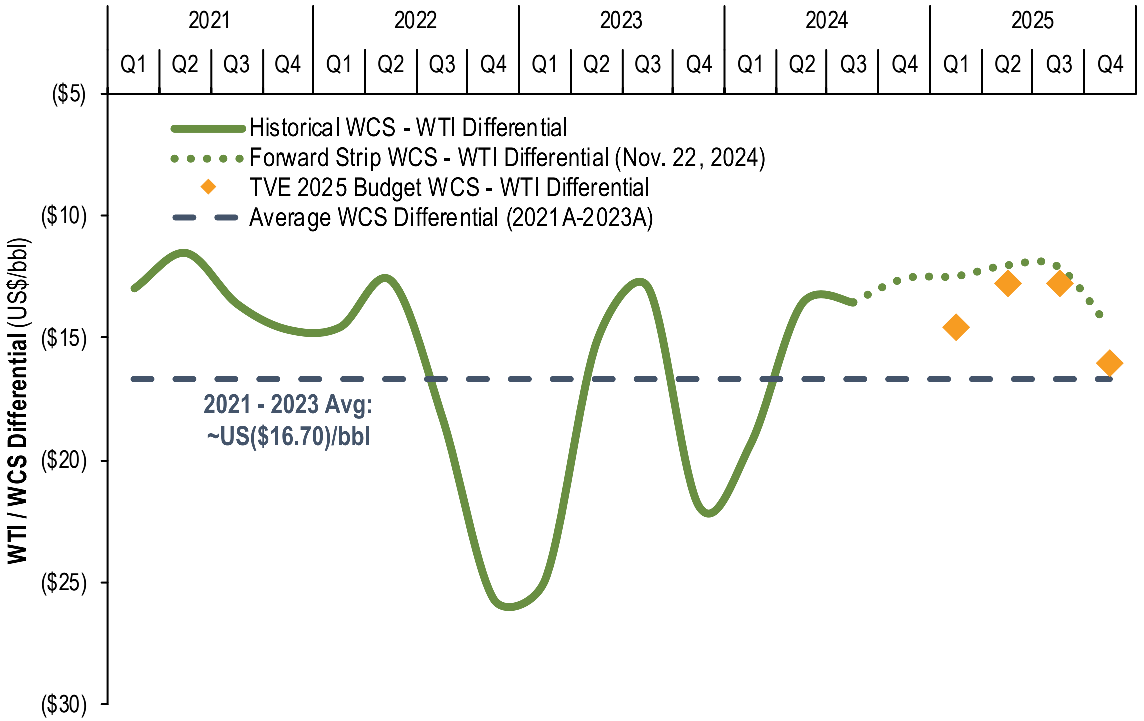
2) Assumes annual dividend payout ($MM) is flat. Returns for buybacks, debt repayment, and dividends are based on changes/totals relative to 2024YE. Share count & net debt at 2024YE assumes current return of capital framework. Total return % based on a share price of $4.00/Sh.

3) Totals will not add due to compounding. Compounded share buybacks based on a share price of $4.00/sh.

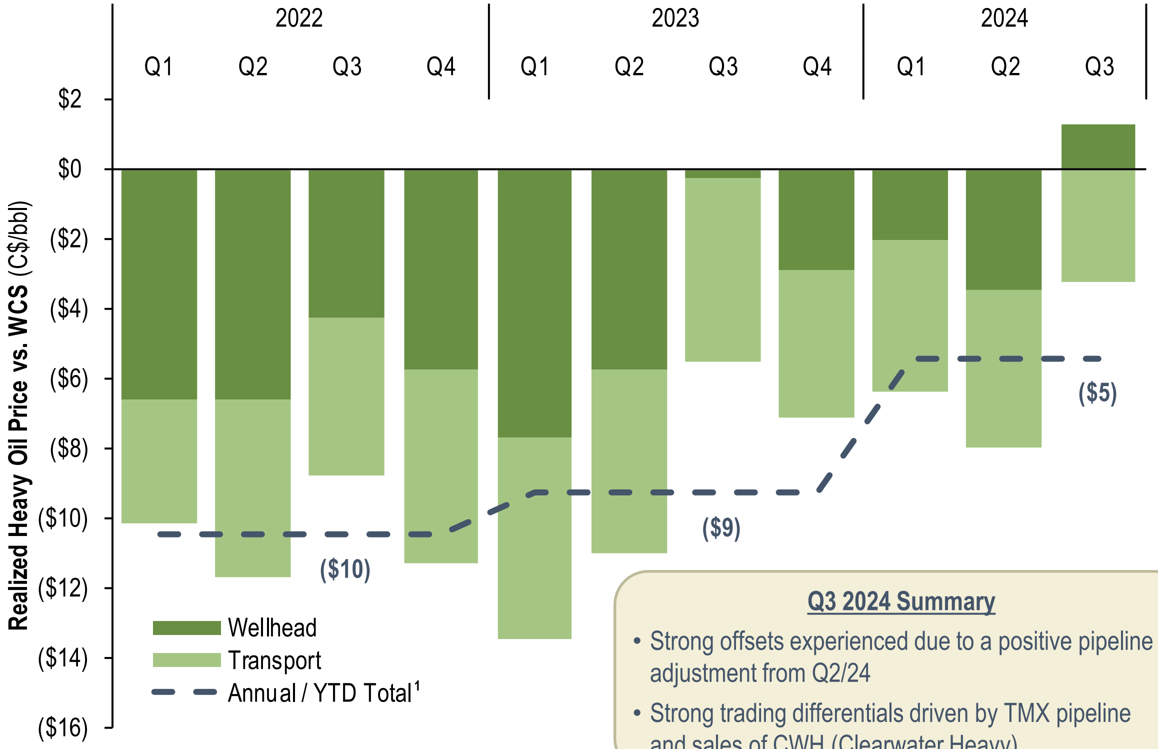
Canadian Heavy Oil Differential Narrowing

WCS Differential Tighter Due to TMX

WCS Differential (US$/bbl)



Tamarack Realized Heavy Oil Price (C$/bbl)



Q3 2024 Summary

- Strong offsets experienced due to a positive pipeline adjustment from Q2/24
- Strong trading differentials driven by TMX pipeline and sales of CWH (Clearwater Heavy)

TMX Having a Significant Impact to Differentials

- Experiencing narrower differentials even into Q4 due to improved market access and ability to service more markets globally
- 2025 WCS basis strip >US$3.00/bbl stronger than 2021A-2023A average

TVE Heavy Netbacks Showing Sizable Step Changes in Past Two Years

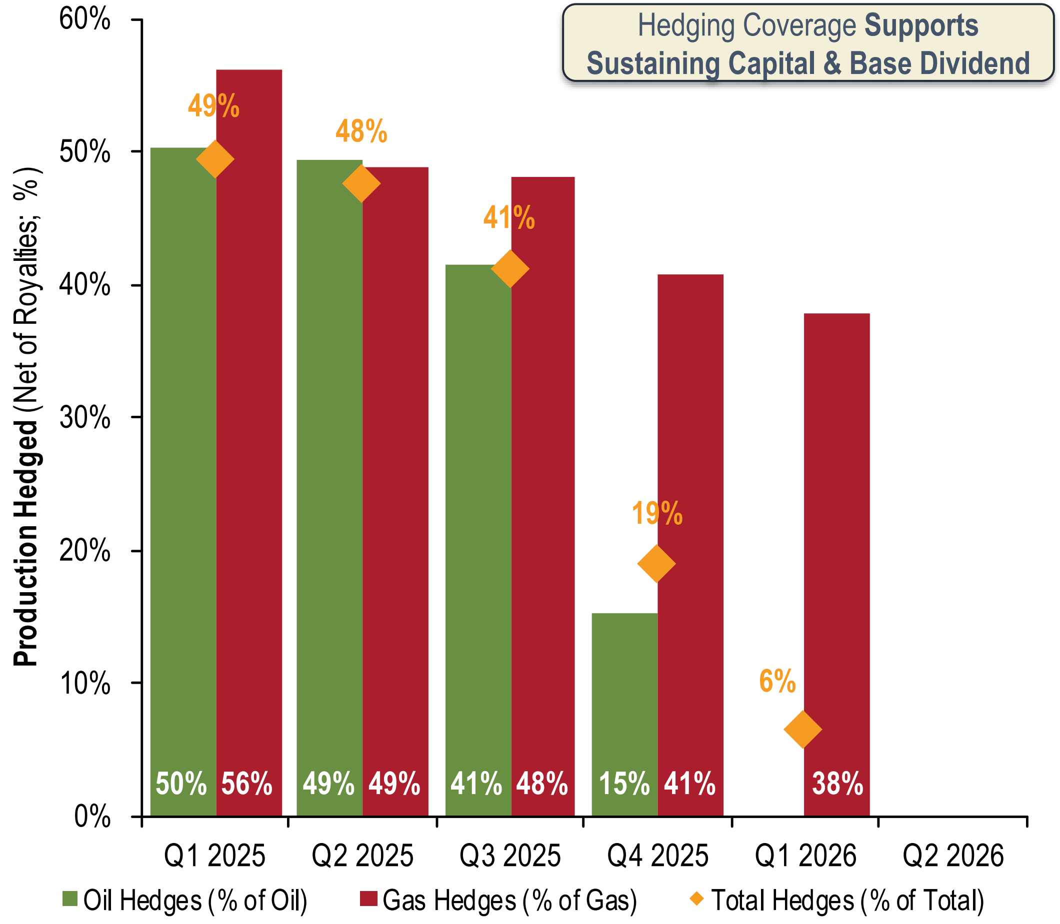
- Improved selling differentials (CHV & CWH)
- Lower transportation costs due to long-term pipeline contracts & infield piping
- Reduce diluent requirements from butane blending & lighter production

1) See Disclaimers – "Forward Looking Statements". TVE 2024E offset includes both deduct and transport.

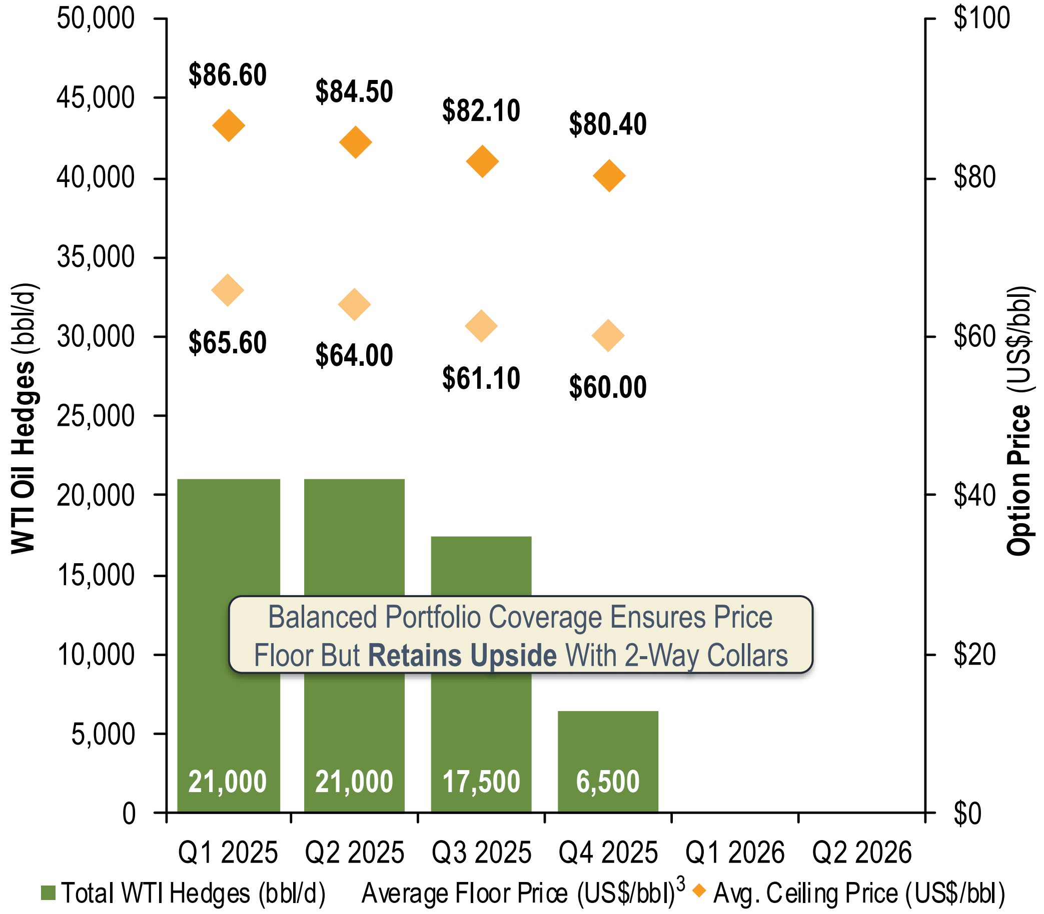
Risk Management[1]

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 January 6, 2025. WTI hedge prices rounded to nearest $0.10/bbl. Percent hedged is net after royalties ("NAR").
2) See Disclaimers – "Specified Financial Measures"; AFF – Adjusted Funds Flow.
3) 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	Q1 2025	Q2 2025	Q3 2025	Q4 2025	Q1 2026	Q2 2026
WTI Collars							
Volume	*bbl/d*	21,000	21,000	17,500	6,500	-	-
Avg. Floor Price	*US$/bbl*	$65.57	$64.02	$61.05	$60.00	-	-
Avg. Ceiling Price	*US$/bbl*	$86.62	$84.49	$82.08	$80.35	-	-
Avg. Premium	*US$/bbl*	$0.18	$0.43	$0.29	$0.40	-	-
WTI - WCS Basis Swaps							
Volume	*bbl/d*	16,500	3,000	2,000	3,000	-	-
Avg. Fixed Price	*US$/bbl*	($15.02)	($13.43)	($13.90)	($14.43)	-	-
WTI - MSW Basis Swaps							
Volume	*bbl/d*	5,000	5,000	5,000	5,000	-	-
Avg. Fixed Price	*US$/bbl*	($3.93)	($3.93)	($3.93)	($3.93)	-	-

Natural Gas Hedges	Units	Q1 2025	Q2 2025	Q3 2025	Q4 2025	Q1 2026	Q2 2026
AECO 5A Swaps							
Volume	*GJ/d*	-	25,500	25,500	8,592	-	-
Avg. Fixed Price	*C$/GJ*	-	$2.69	$2.69	$2.69	-	-
AECO 7A Collars							
Volume	*GJ/d*	2,500	-	-	-	-	-
Avg. Floor Price	*C$/GJ*	$2.50	-	-	-	-	-
Avg. Ceiling Price	*C$/GJ*	$4.35	-	-	-	-	-
NYMEX Collars							
Volume	*MMbtu/d*	23,500	-	-	13,592	20,500	-
Avg. Floor Price	*US$/MMbtu*	$3.05	-	-	$3.50	$3.50	-
Avg. Ceiling Price	*US$/MMbtu*	$4.24	-	-	$5.13	$5.13	-
NYMEX - AECO Basis Swaps							
Volume	*MMbtu/d*	11,000	-	-	-	-	-
Avg. Fixed Price	*US$/MMbtu*	($1.04)	-	-	-	-	-

FX Hedges	Units	Q1 2025	Q2 2025	Q3 2025	Q4 2025	Q1 2026	Q2 2026
C$/US$ Collars							
Notational	*US$MM/Month*	-	-	$7.0	$7.0	$2.0	$2.0
Avg. Floor Price	*US$/C$*	-	-	1.337	1.337	1.360	1.360
Avg. Ceiling Price	*US$/C$*	-	-	1.393	1.393	1.418	1.418
C$/US$ Swaps							
Notational	*US$MM/Month*	$1.0	$4.0	$3.0	$3.0	-	-
Avg. Fixed Price	*US$/C$*	1.360	1.351	1.348	1.348	-	-
C$/US$ Variable Collars(2)							
Notational	*US$MM/Month*	$32.0	$34.5	$29.5	$29.5	$3.0	$3.0
Avg. Floor Price	*US$/C$*	1.343	1.342	1.342	1.342	1.350	1.350
Avg. Ceiling Price	*US$/C$*	1.404	1.401	1.400	1.400	1.416	1.416
Avg. Knock-In Price	*US$/C$*	1.376	1.373	1.374	1.374	1.385	1.385
C$/US$ Variable Collars (Ext. Option)(3)							
Notational	*US$MM/Month*	$9.0	$5.0	$3.0	$3.0	-	-
Avg. Floor Price	*US$/C$*	1.338	1.342	1.350	1.350	-	-
Avg. Ceiling Price	*US$/C$*	1.414	1.425	1.442	1.442	-	-
Avg. Knock-In Price	*US$/C$*	1.377	1.384	1.387	1.387	-	-

1) Hedges in place as at January 6, 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 an equivalent term at an average rate forward fixed price equal to the call. Extension volumes not include in tables herein.

Appendix: Assets

Largest Public Clearwater Producer

Established Extensive Exposure Through The Heart of The Clearwater Fairway

Scale

- Extensive holdings across the Clearwater fairway; 676 net sections of land[1]
- 8.7 billion barrels of OOIP[2] in the Clearwater
- TPP reserve life index of ~8 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

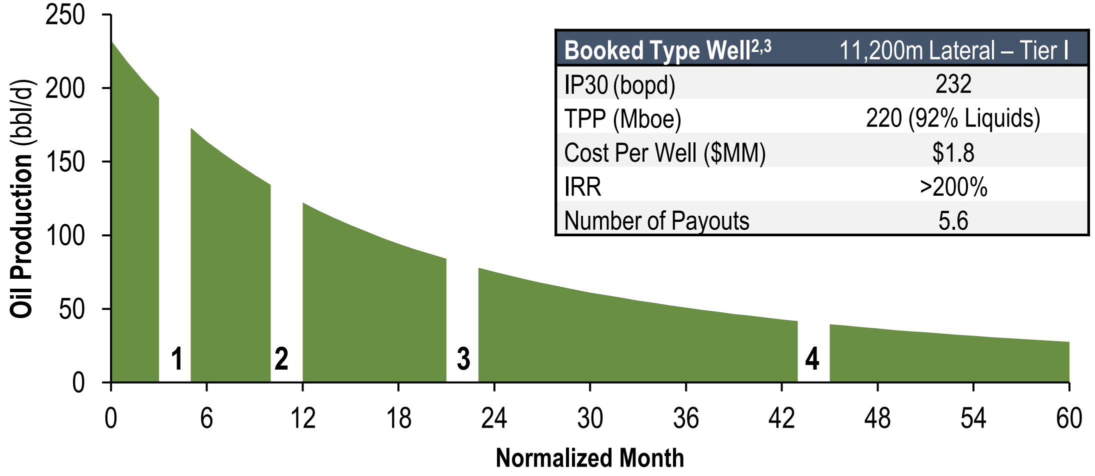
- Successful implementation of waterflood program increasing ultimate recoveries by 2x to 3x primary recovery
- Significant asset duration driven by >2,100 drilling locations[4]

1) As at September 30, 2024.
2) OOIP – original oil in place based on internal estimates.
3) Net primary locations as at 2023YE, see Disclaimers – "Drilling Locations".
4) Net primary locations as at 2023YE, see Disclaimers – "Drilling Locations".

Clearwater Economics: Primary Recovery

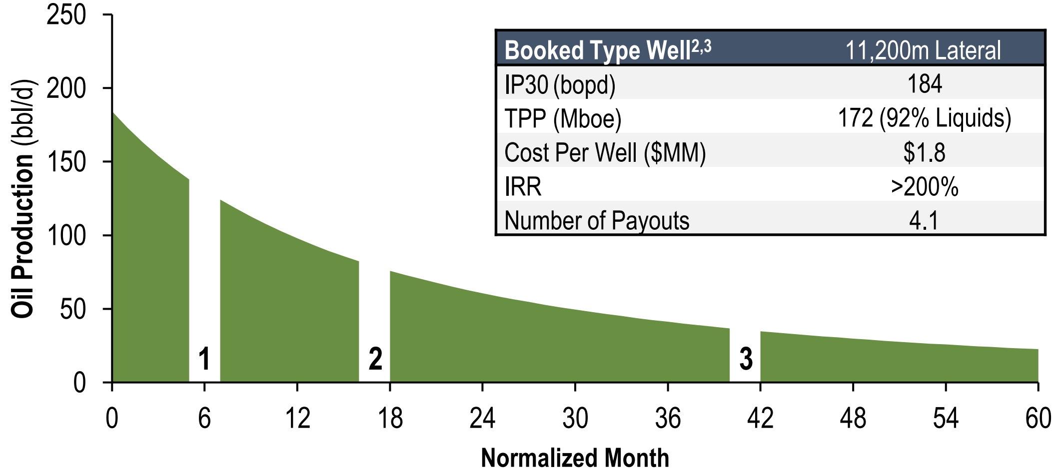
Multiple Payouts Compound Free Funds Flow[1] Growth

West Marten "B" Sand



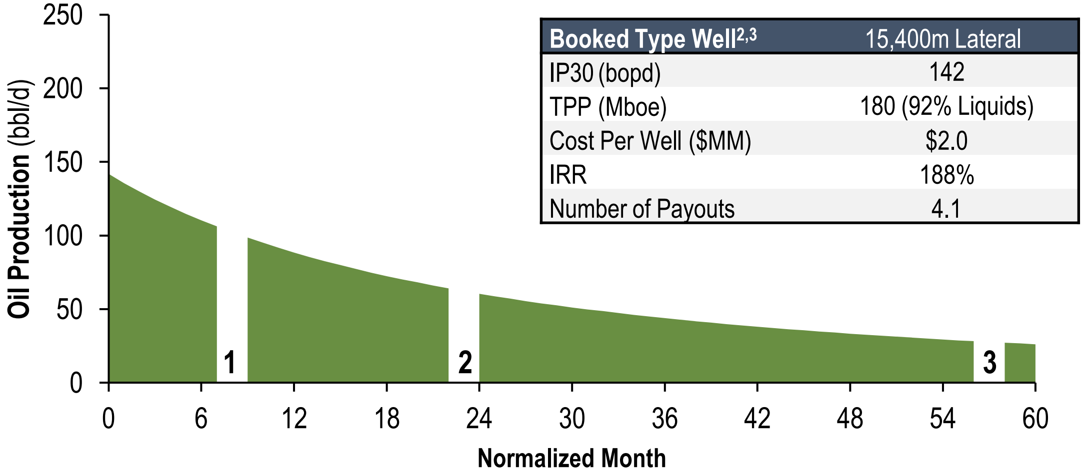
Booked Type Well[2,3]	11,200m Lateral – Tier I
IP30 (bopd)	232
TPP (Mboe)	220 (92% Liquids)
Cost Per Well ($MM)	$1.8
IRR	>200%
Number of Payouts	5.6

West Marten "C" Sand



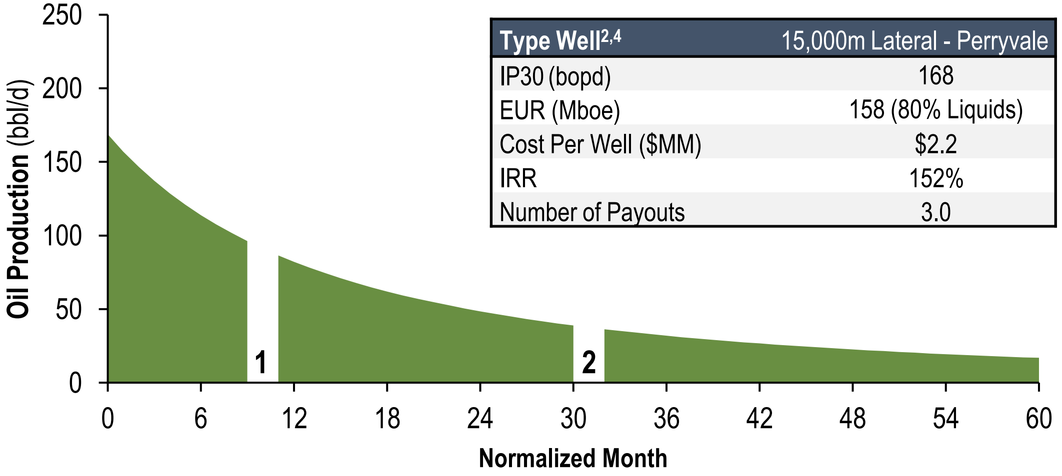
Booked Type Well[2,3]	11,200m Lateral
IP30 (bopd)	184
TPP (Mboe)	172 (92% Liquids)
Cost Per Well ($MM)	$1.8
IRR	>200%
Number of Payouts	4.1

Marten Hills "C" Sand



Booked Type Well[2,3]	15,400m Lateral
IP30 (bopd)	142
TPP (Mboe)	180 (92% Liquids)
Cost Per Well ($MM)	$2.0
IRR	188%
Number of Payouts	4.1

South Clearwater Fan

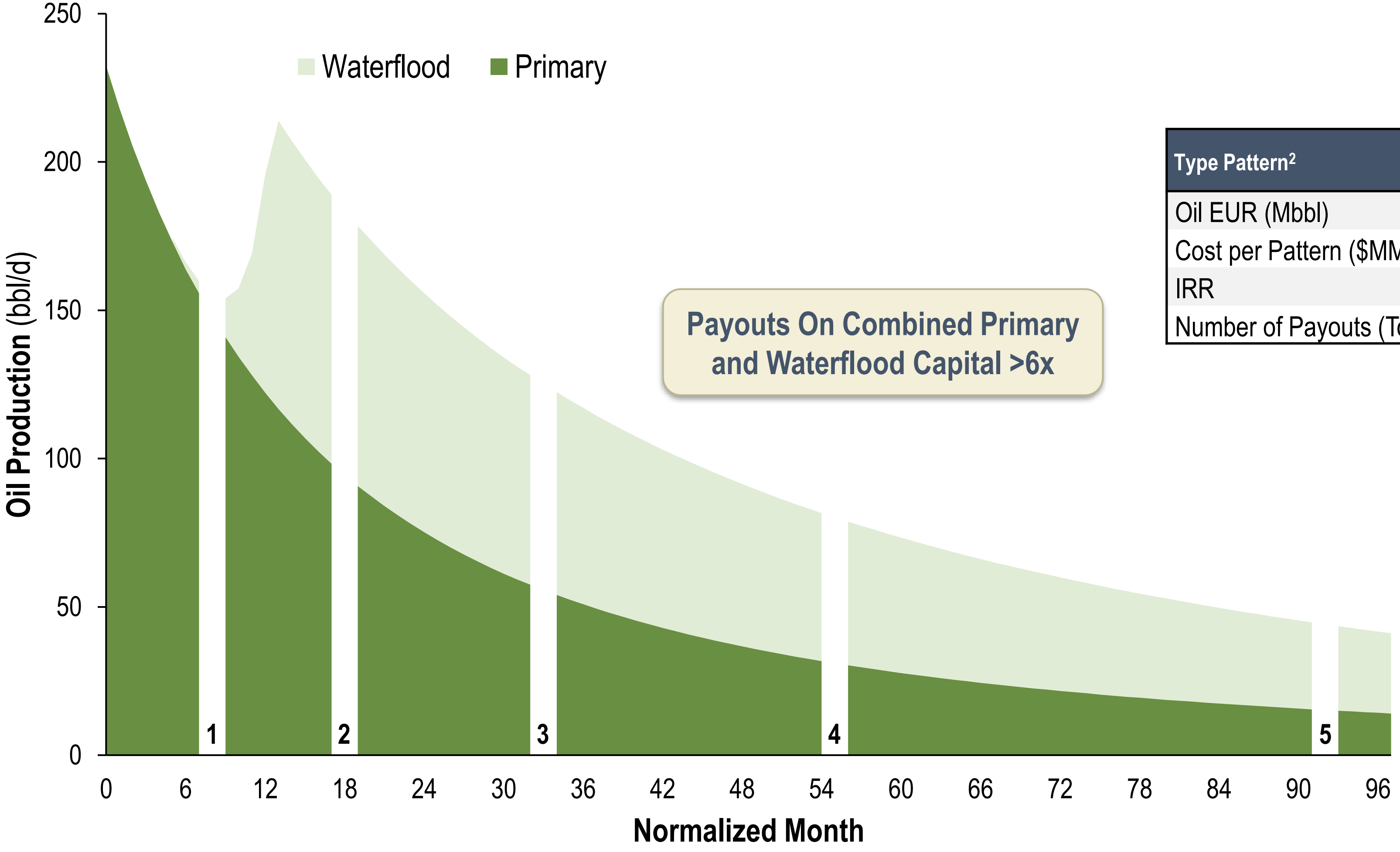


Type Well[2,4]	15,000m Lateral - Perryvale
IP30 (bopd)	168
EUR (Mboe)	158 (80% Liquids)
Cost Per Well ($MM)	$2.2
IRR	152%
Number of Payouts	3.0

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, 2023.
4) Based on internal estimate using most recently available data; limited in-field data available prior to 2023 YE.

Clearwater Waterflood

Secondary Recovery Provides Additional Payouts & Reduces Long Term Sustaining Capital



Waterflood Economics

Type Pattern[2]	Primary[3] – West Marten "B" Sand Tier I	Waterflood Wedge[4] – Internal Estimate	Total Project
Oil EUR (Mbbl)	200	200	400
Cost per Pattern ($MM)	$1.8	$1.2	$3.0
IRR	>200%	116%	>200%
Number of Payouts (Total)	5.6	7.0	6.1

- **Early Success:** Waterflood has been successfully implemented broadly across the Clearwater
- **Asset Duration:** Mature patterns indicate >2x recovery compared to primary development
- **Free Funds Flow:** Significant free funds flow generated from incremental payouts of waterflood capital

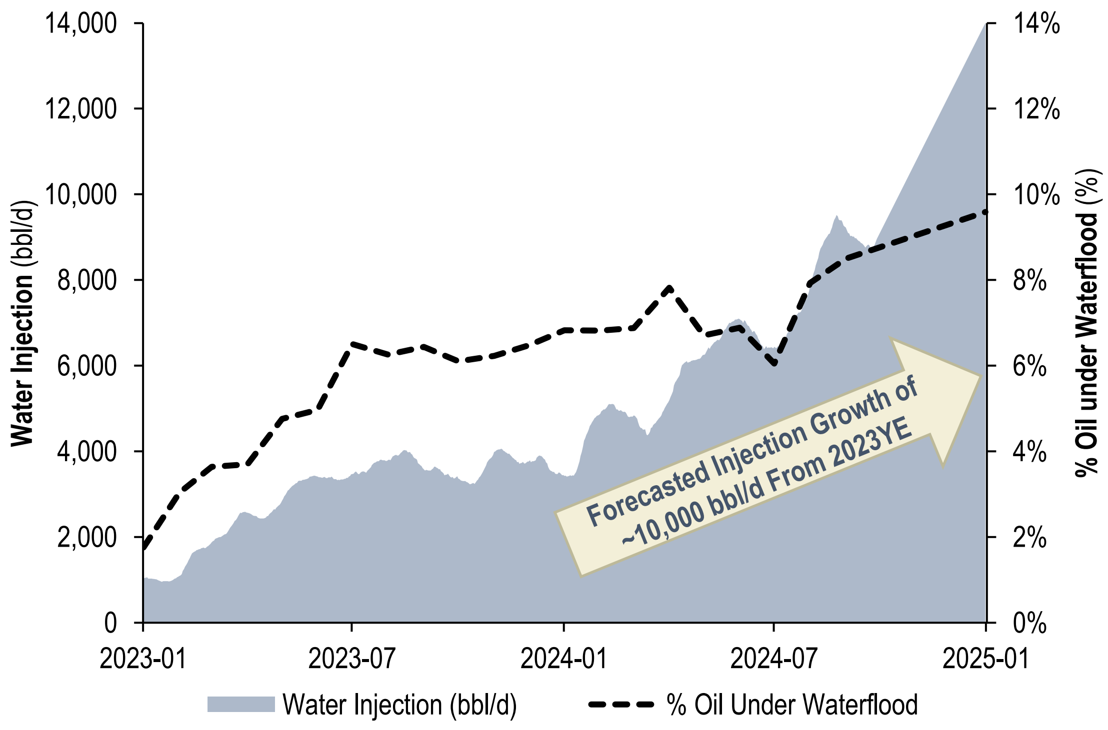
1) See Disclaimers – "Specified Financial Measures".
2) Flat pricing assumes US$75/bbl WTI, US($13.50)/bbl WCS Diff, CDN $3.00/GJ AECO and 1.30 C$/US$.
3) Based on McDaniel & Associates Consultants Ltd Reserves Report effective December 31, 2023.

4) Waterflood incremental wedge based on internal estimates for a single leg injector with 2-mile lateral length achieving a total pattern oil recovery equal to 2x primary at an incremental capital cost of $1.2 MM.

Clearwater Waterflood Progression

Advancing Secondary Recovery To Drive Incremental Resource Capture

Clearwater Injection & Production Under Waterflood



EUR's > 2x 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

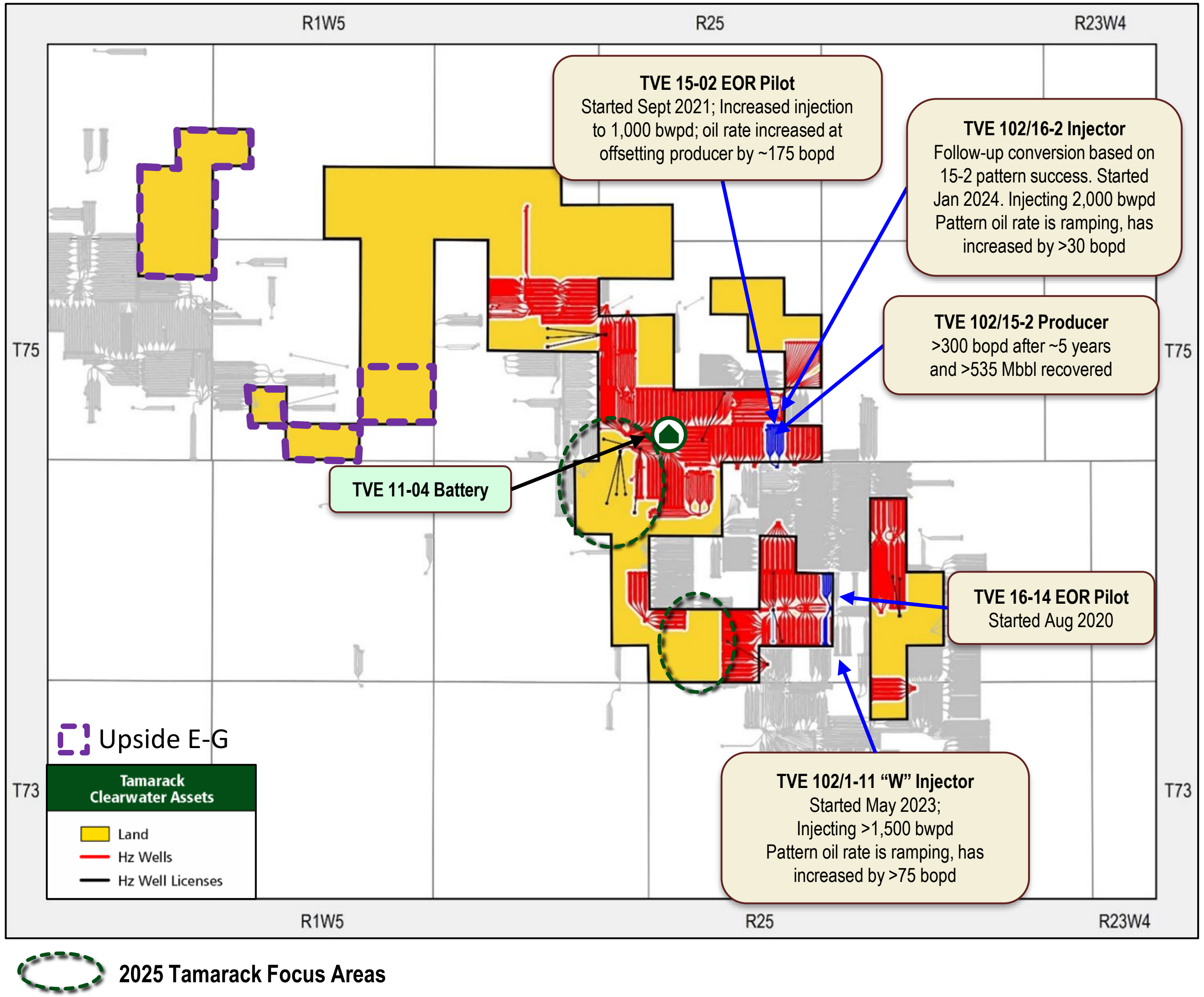
Superior Economics

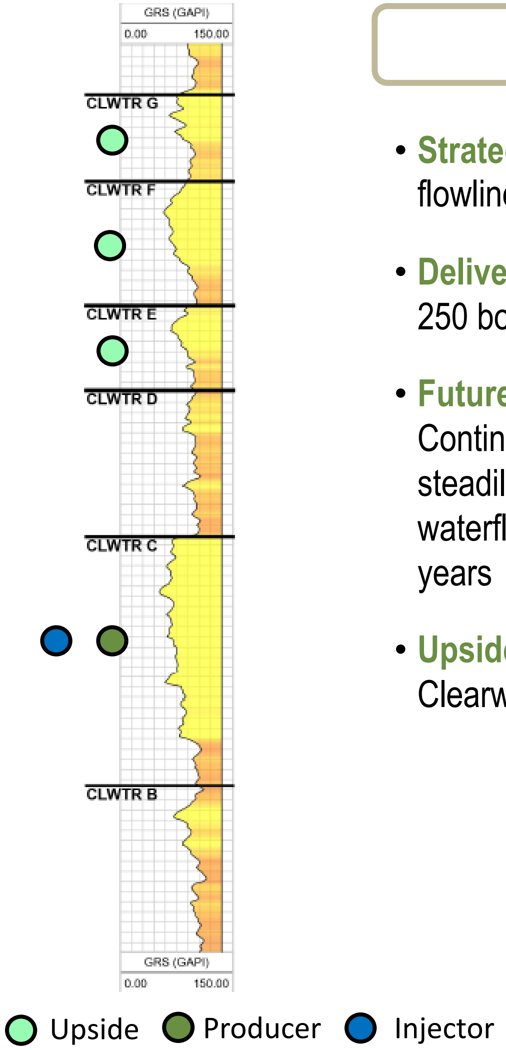
Stacked multi-zone waterflood potential and large, contiguous resource result in economies of scale

>9% of Clearwater Production Under Waterflood by YE 2024E

Marten Hills: Maximizing OOIP Recovery With Waterflood

Strong Positive Correlation Between Injectivity and Oil Response Across the Clearwater Fairway





Marten Hills

- **Strategic Infrastructure:** >60% oil flowline connected to centralized facility
- **Deliverability:** IP30[1] rates in excess of 250 bopd; ~20° API
- **Future Development Strategy:** Continued development drilling and steadily increasing lateral and vertical waterflood development over the next 8+ years
- **Upside:** potential in younger sands: Clearwater E - G

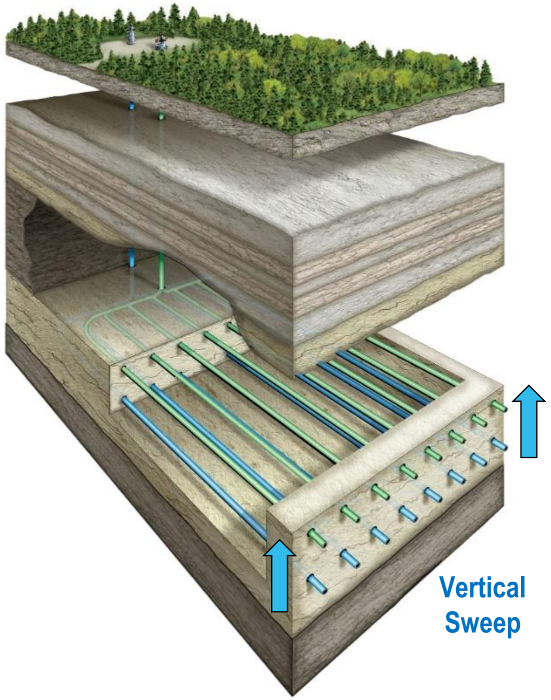
Note: Oil rates shown represent peak monthly rates per well unless otherwise noted.
See Disclaimers – "Specified Financial Measures"; IP30 - initial 30-day production rates.

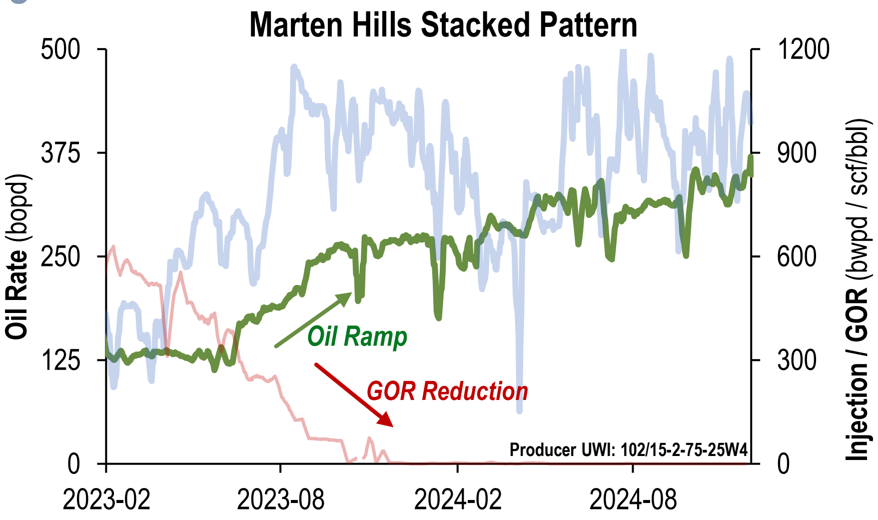
Marten Hills Waterflood

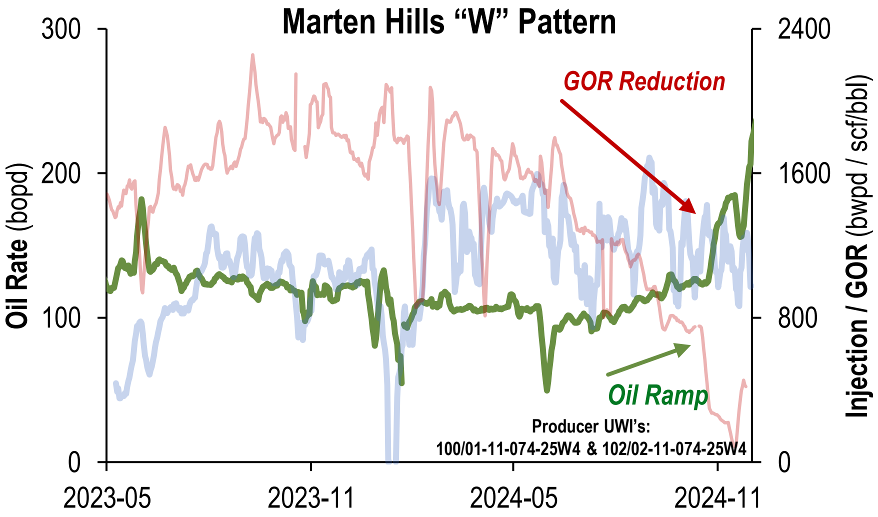
Observing Success In Both Pattern Configurations

Stacked Pattern

- Lower injection bench is highly effective in homogenous reservoir with limited barriers to vertical sweep
- Robust response exhibited by >200 bbl/d incremental oil production and suppressed gas oil ratio

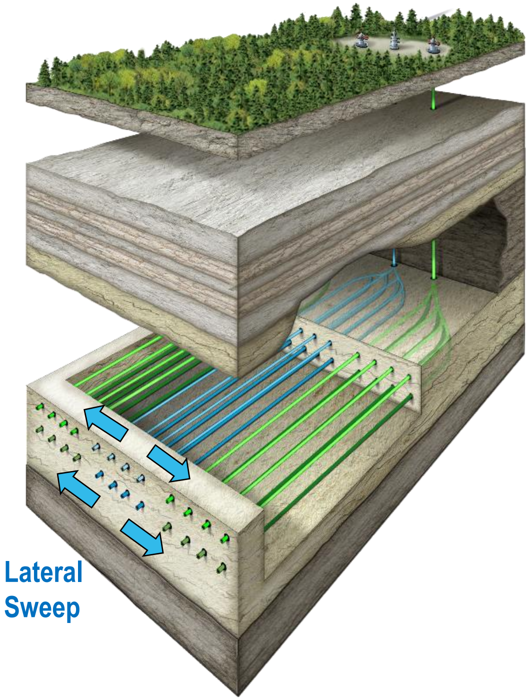






"W" Flood Pattern

- Optimizing recovery and injectivity while overcoming vertical flow barriers
- Accelerated response with increased injectivity, oil production now ramping



Nipisi & West Marten: Enhancing Inventory

Focusing On Top Tier Lands In Support of Long-Term Sustainable Development

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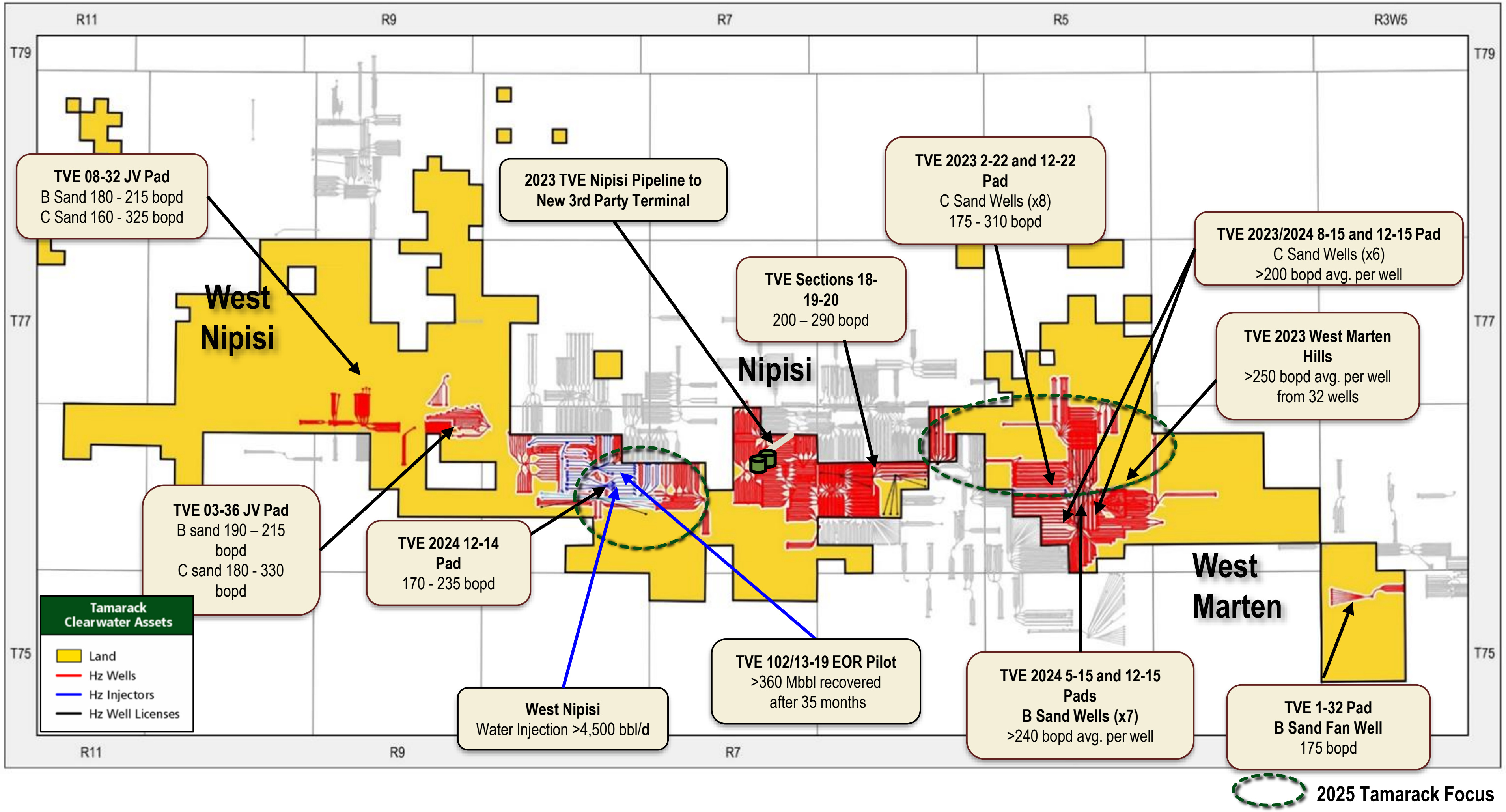
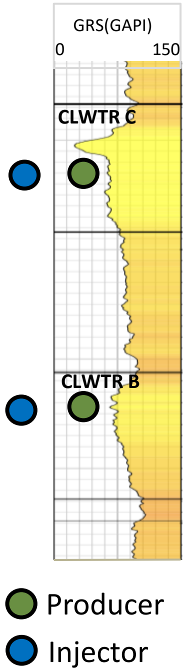




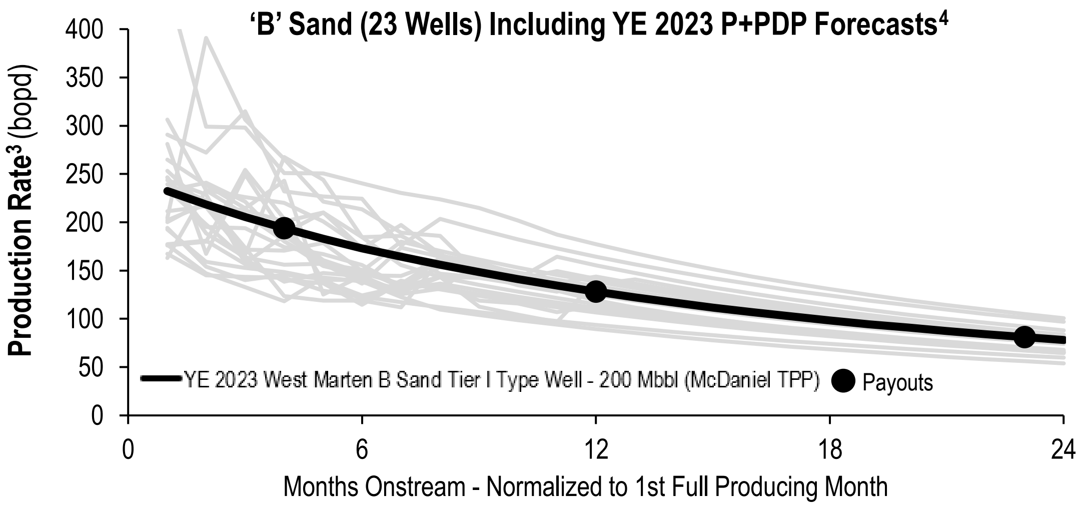
Stacked Potential: Building on success with drilling in both B sand (42 wells) and C sand (8 wells)

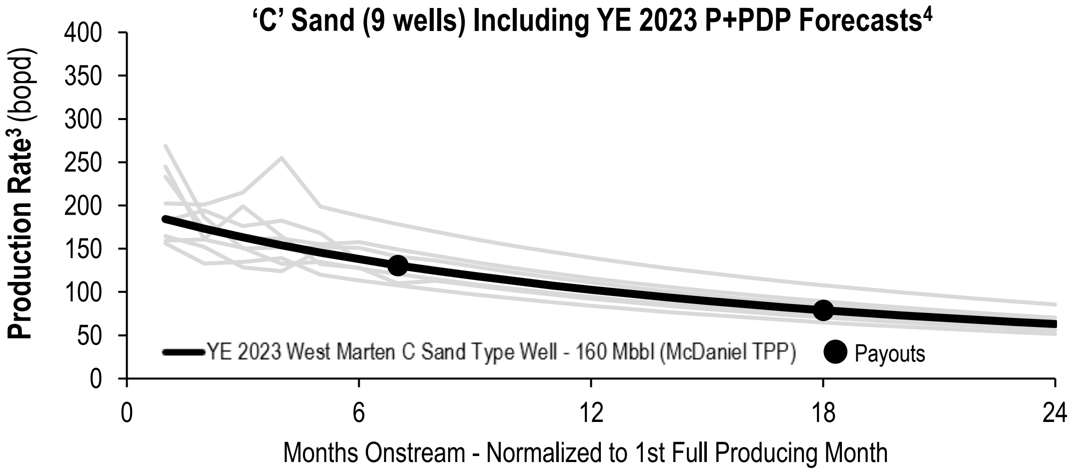
1) Note: Oil rates shown represent peak monthly rates per well unless otherwise noted.

West Marten: Stacked Pay Continuing To Outperform

Deltastream Legacy Lands Generating Free Funds Flow[1] With Multiple Quick Payouts

West Marten 2023 Drills[2]: Primary Recovery





Booked Type Wells[4,5]	Clearwater 'B' Sand (Tier I)	Clearwater 'C' Sand
IP30 (bopd)	232	184
P+P EUR (Mboe)	220 (92% Liquids)	172 (92% Liquids)
Cost Per Well ($MM)	$1.83	$1.83
Payout (Years)	0.4	0.6
Number of Payouts (Total)	5.6	4.1
IRR	> 200%	> 200%
NPV10% ($MM, Before Tax)	$6.1	$4.1

- Strong performance translates to premium half-cycle metrics in both development zones
- Stacked pay provides substantial full cycle capital efficiency benefits for both primary and future waterflood development

1) See "Specified Financial Measures".
2) Includes wells with one full month of production as at December 2023.
3) Production rates normalized to 11,200m total lateral length.
4) Based on McDaniel & Associates Consultants Ltd Reserves Report effective December 31, 2023.
5) Flat pricing assumes US $75/bbl WTI, US($13.50)/bbl WCS Diff, CDN $3.00/GJ AECO and 1.30 C$/US$.

West Marten: Leveraging Waterflood Learnings from Nipisi

Excellent Primary Results In Stacked Sands With Waterflood Upside

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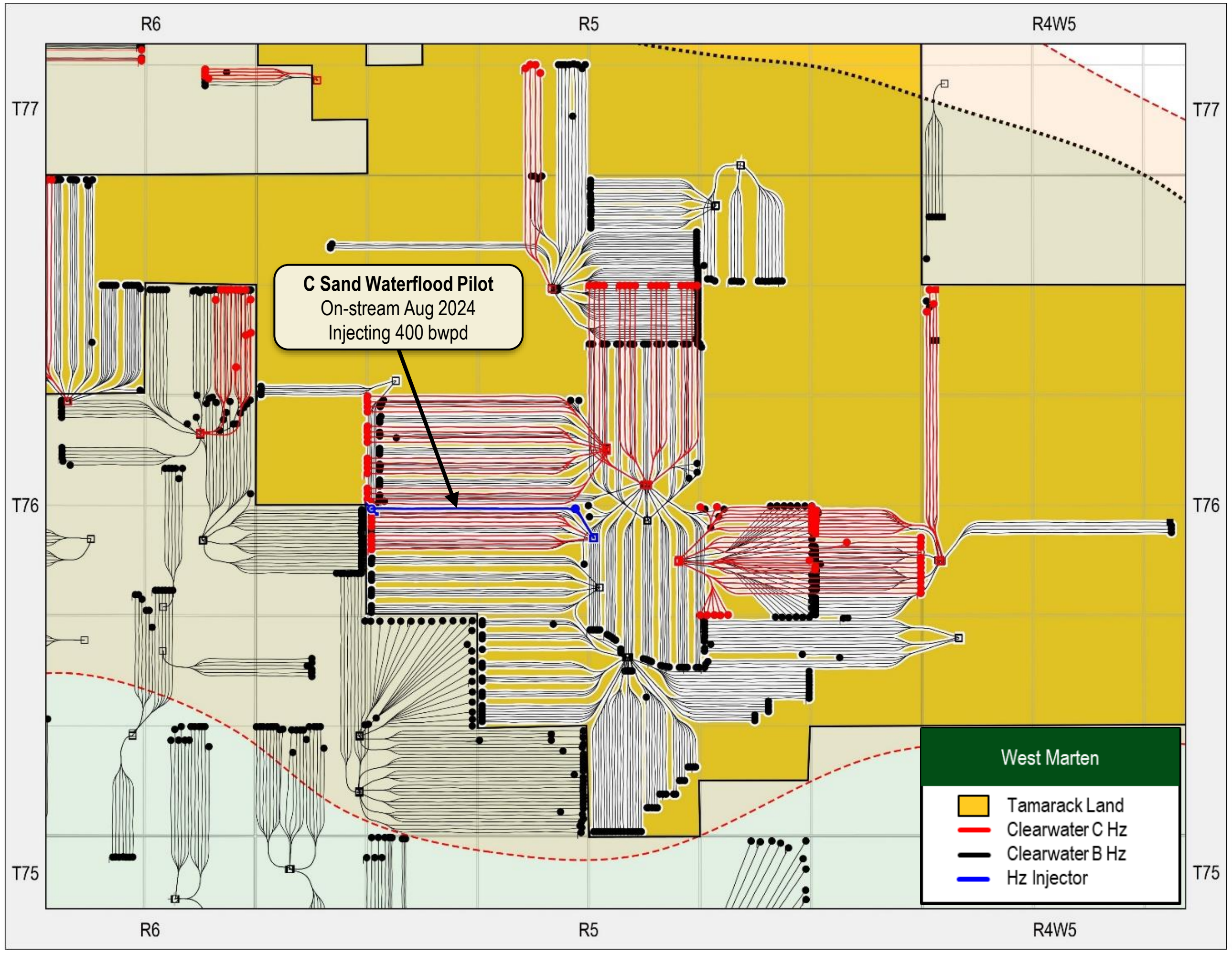


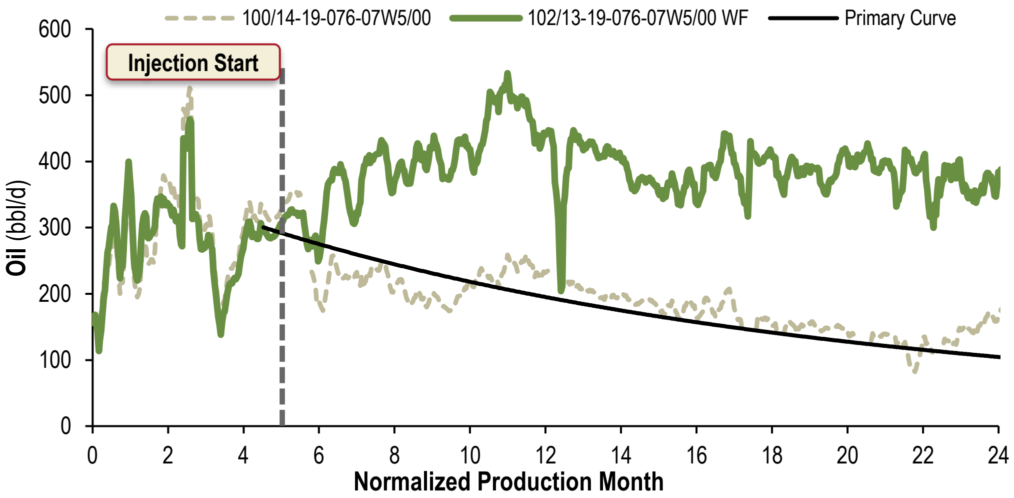
West Marten

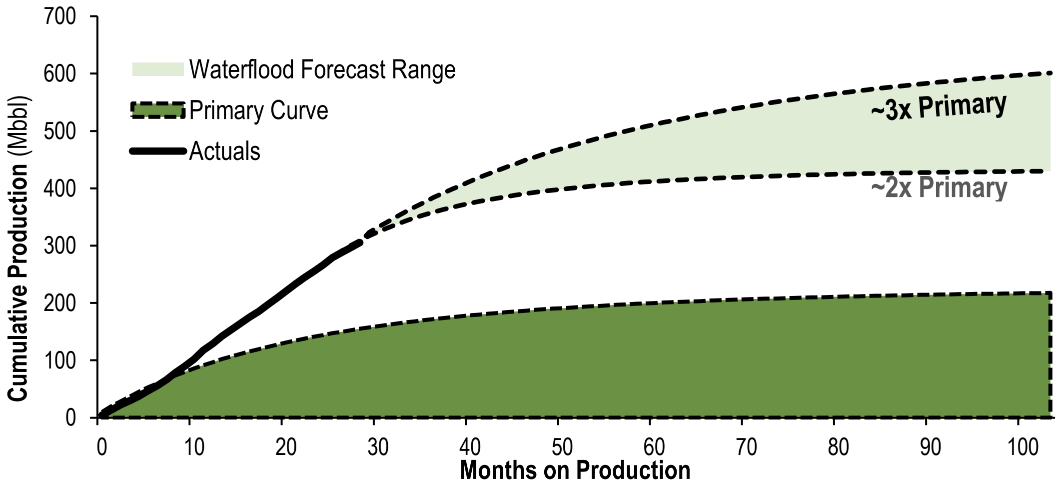
- **Stacked Resource:** Total B and C sand OOIP upwards of 50 MMbbl/section across >35 sections in West Marten
- **Deliverability:** Excellent results in both sands has resulted in rapid area growth to ~7,000 bopd
- **Capital Efficiency:** Concentrated development and shared infrastructure driving reduced cost structure
- **Waterflood:** Primary recovery factor of 6-8% expected to double with secondary recovery

Nipisi ‘B’ Sand Pilot Exhibits Exceptional Response

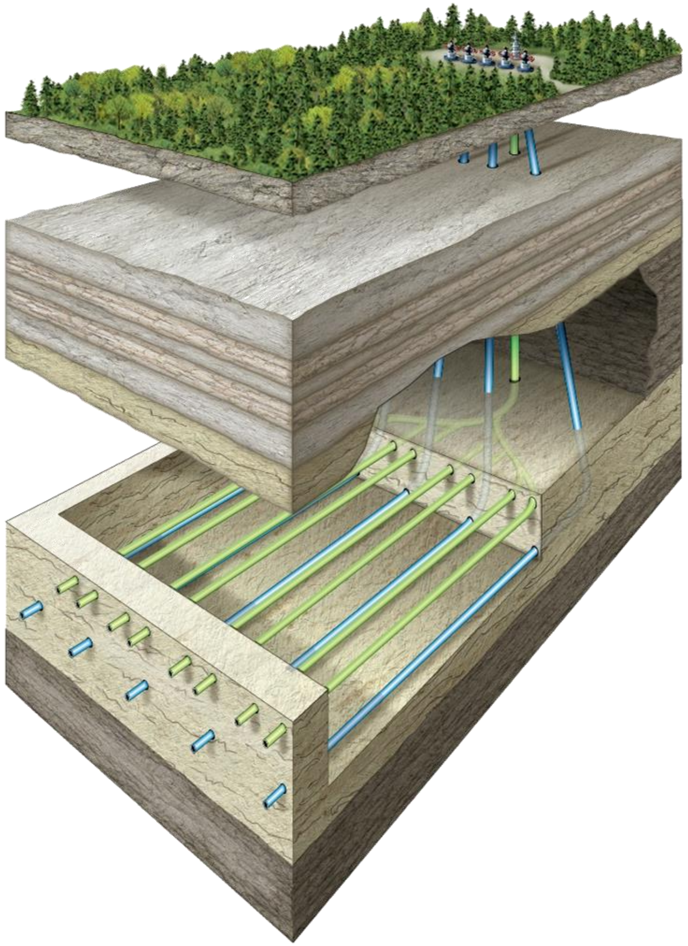
Waterflood Success Indicative of Significant Asset Duration

Nipisi 102/13-19-076-07W5 Pilot





Quick Response:
Waterflood pilot substantially outperformed offsetting primary producer shortly after injection start



Incremental Recovery:
Stable production and water cuts trending towards >2x primary recovery estimates capable of delivering >6 payouts[1,2,3]

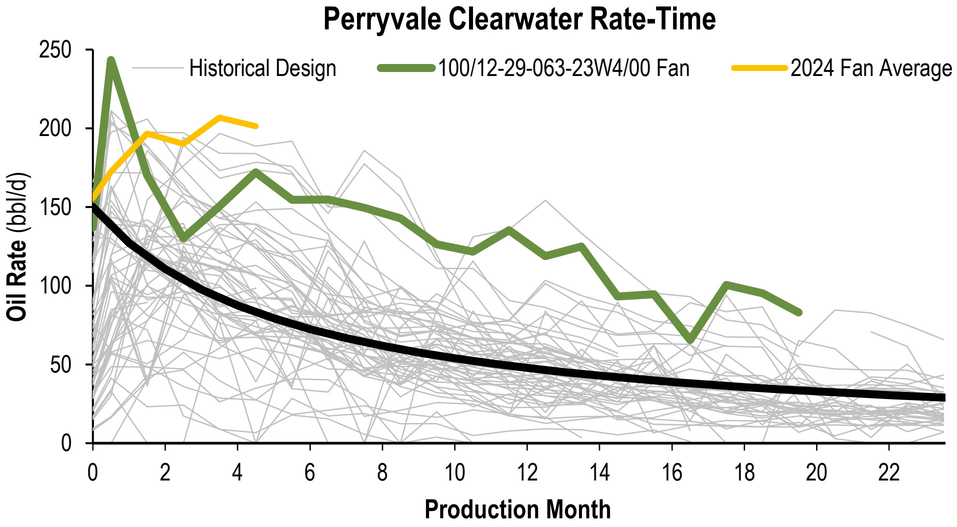
1) Flat pricing assumes US$75/bbl WTI, US($13.50)/bbl WCS Diff, CDN $3.00/GJ AECO and 1.30 C$/US$.
2) Primary based on West Marten B Sand Tier I type well per McDaniel & Associates Consultants Ltd Reserves Report effective December 31, 2023.
3) Waterflood incremental wedge based on internal estimates for a single leg injector with 2-mile lateral length achieving a total pattern oil recovery equal to 2x primary at an incremental capital cost of $1.2 MM.

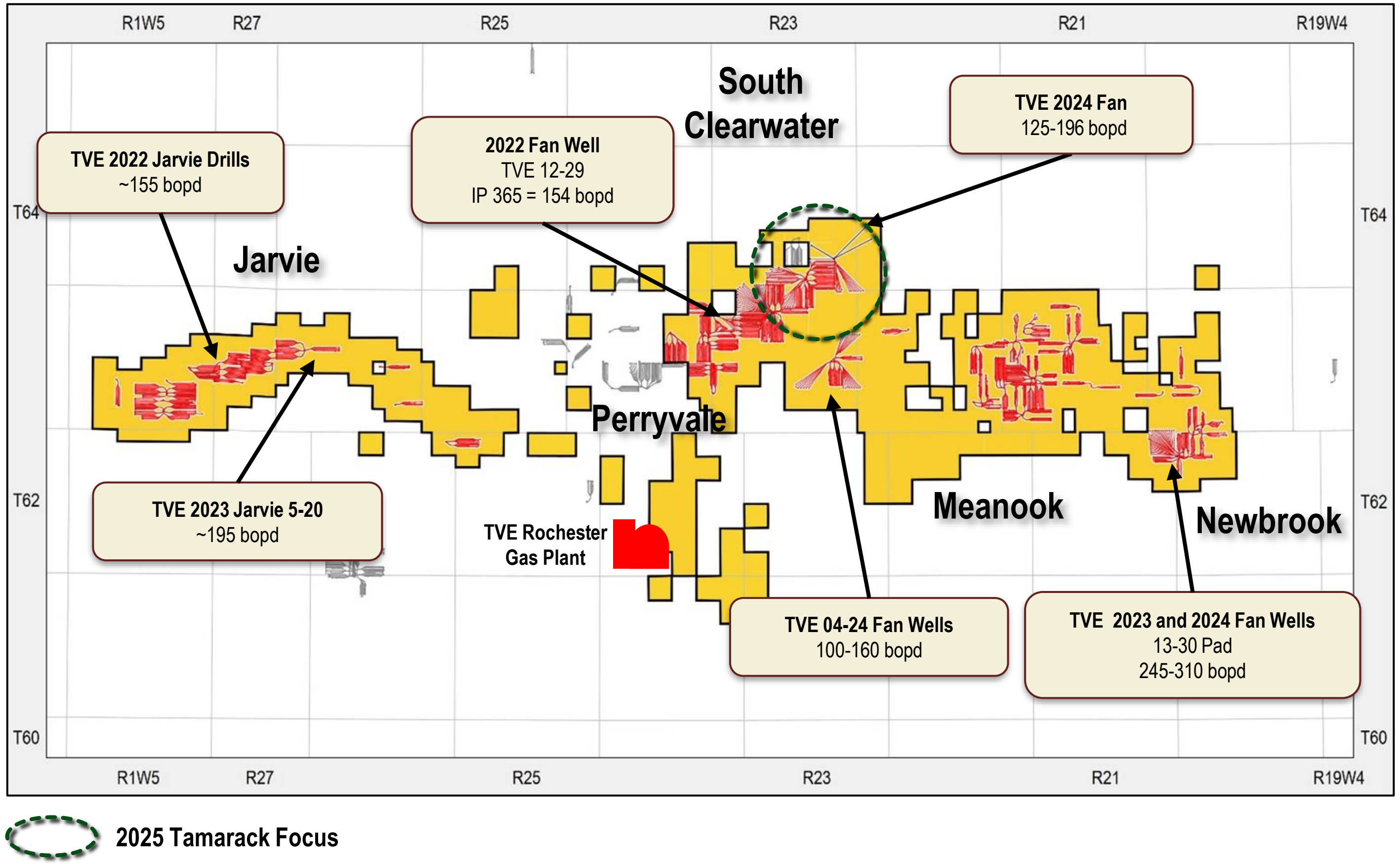
South Clearwater: Substantial Delineated Inventory

Scalable Development Provides Capital Deployment Flexibility Across the Asset Portfolio

South Clearwater

- **Infrastructure:** Commissioned Rochester gas plant Q1 2024
- **Well Design:** Broad implementation of the fan well design improving development efficiency and increasing oil recovery per well





1) Note: Oil rates shown represent peak monthly rates per well unless otherwise noted.

South Clearwater: Fan Well Design Case Study

Improving Capital Efficiencies Through Reduced Infrastructure and Increased Recovery Per Well

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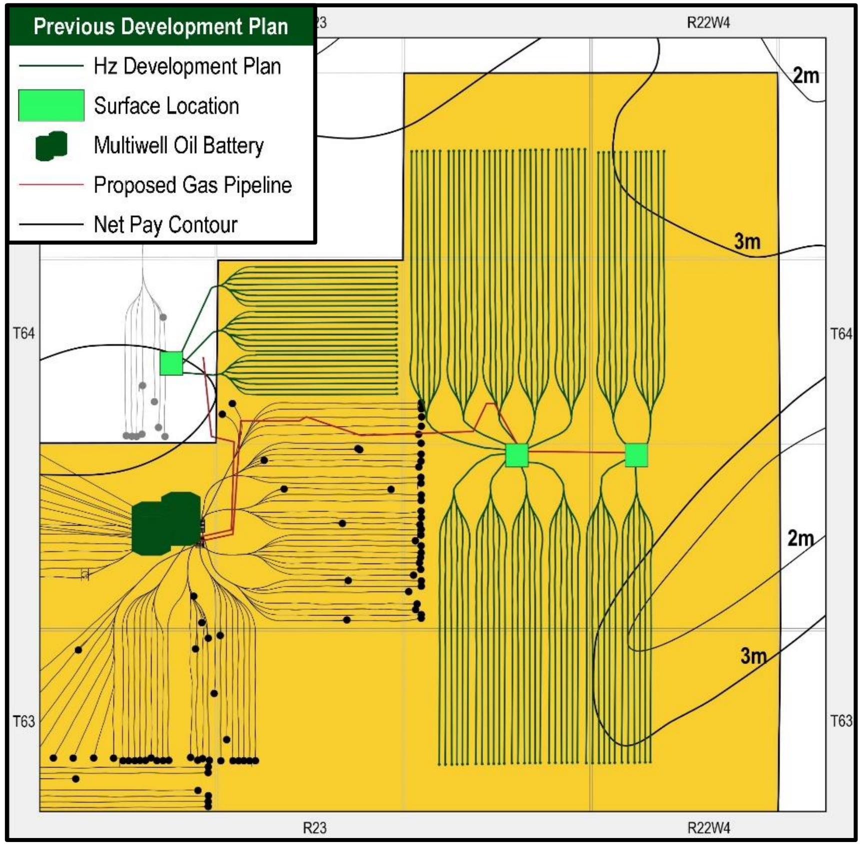


Previous Development Plan[1,2]	16 Wells – 3 Surface Pads
Project Capital ($MM)	36.0
Total EUR (MBOE)	1,711 (80% Liquids)
Number of Payouts	2.0

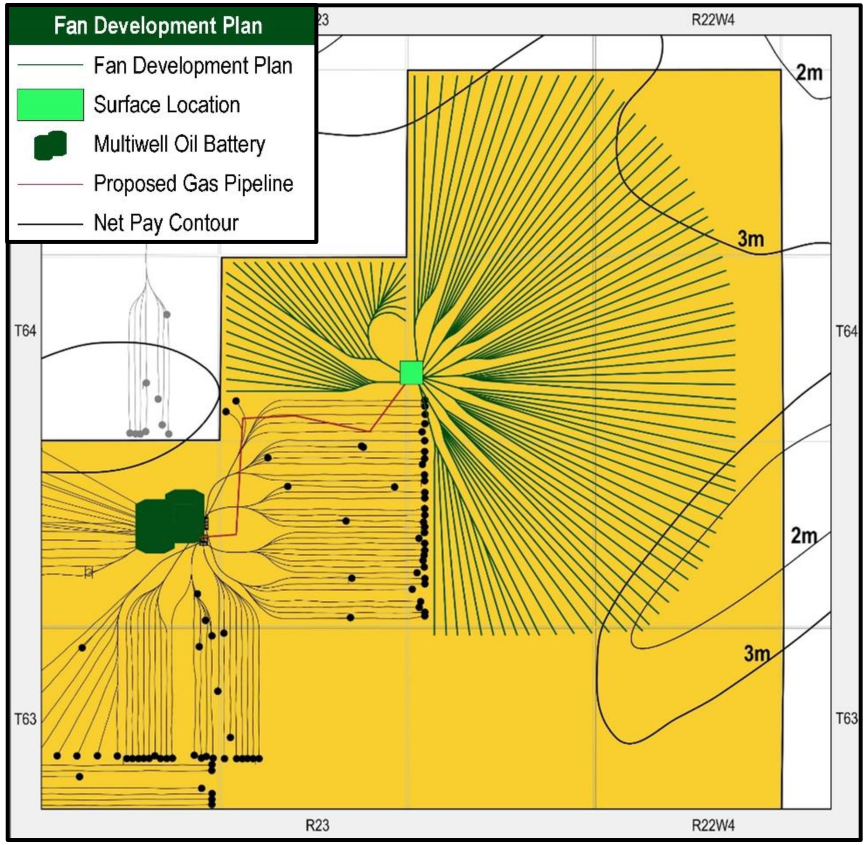
Reduced Surface Footprint

Lower Infrastructure Costs

Higher Recovery Per Well

Efficient Delineation of Pool Edges

>25% Reduction In F&D Costs



Fan Development Plan[1,3]	13 Wells – 1 Surface Pad
Project Capital ($MM)	30.2
Total EUR (MBOE)	2,051 (80% Liquids)
Number of Payouts	3.0

1) Flat pricing assumes US$75/bbl WTI, US($13.50)/bbl WCS Diff, CDN $3.00/GJ AECO and 1.30 C$/US$.
2) Scenario based on internal company estimates for capital and well performance, includes IP30 of 1.0 bbl/d per 100m and average 12,000m lateral length, development pace of 5 to 6 wells per year.
3) Scenario based on internal company estimates for capital and well performance, includes IP30 of 1.0 bbl/d per 100m and average 15,000m lateral length, development pace of 6 to 7 wells per year.

High Quality Charlie Lake Light Oil

Optionality With Inventory

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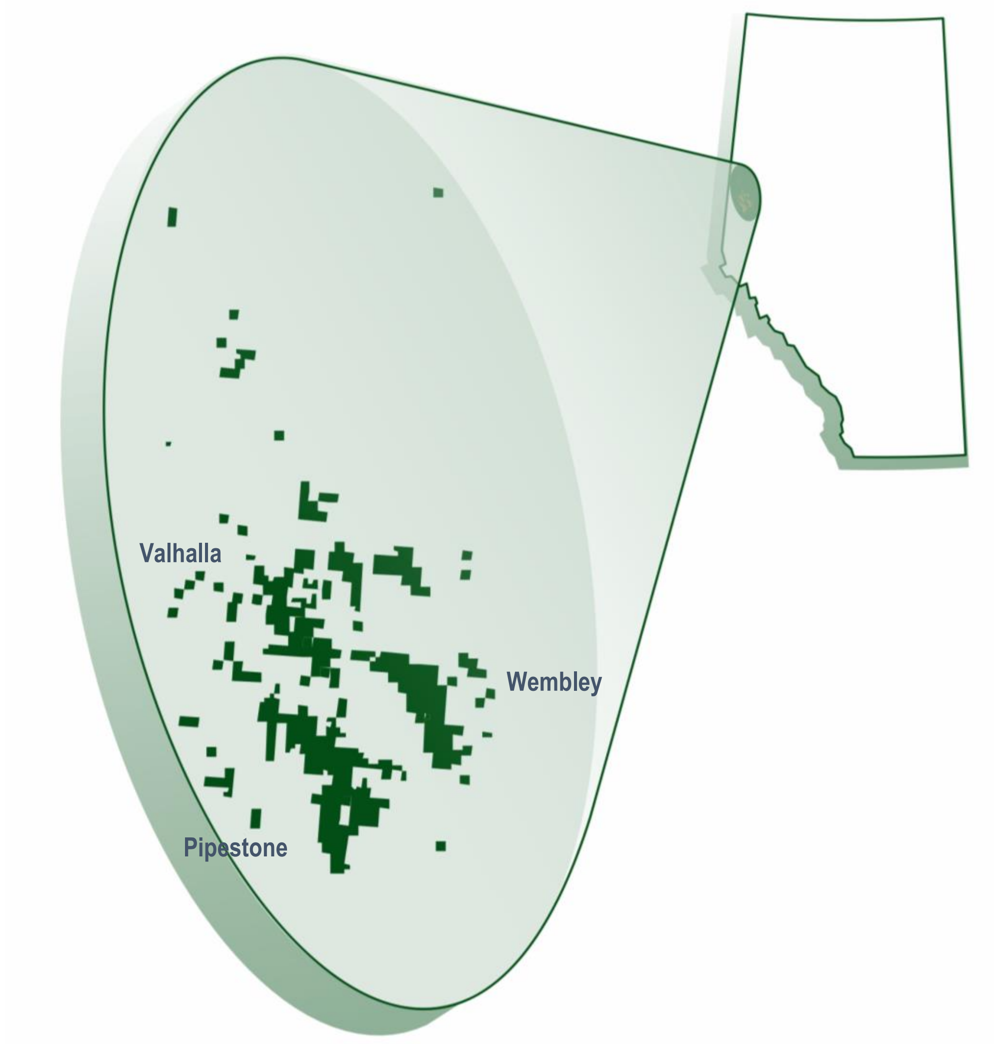


Inventory

- Top tier light oil reservoir continues to result in exceptional well performance
- Inventory supports 16,000 boe/d[1] for >10 years; multi-zone potential
- Extensive holdings across the Charlie Lake fairway; 244 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

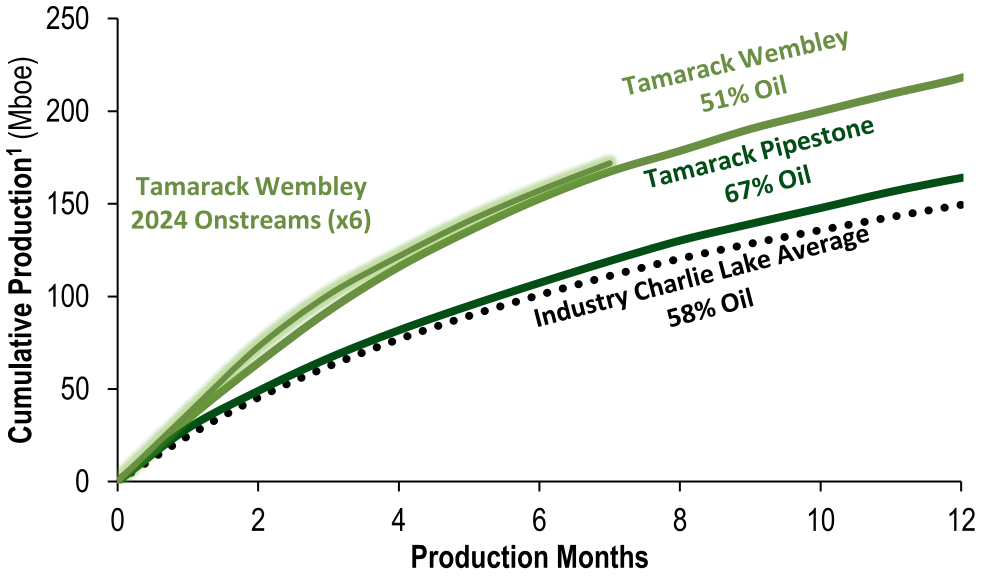
Operational Reliability

- 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

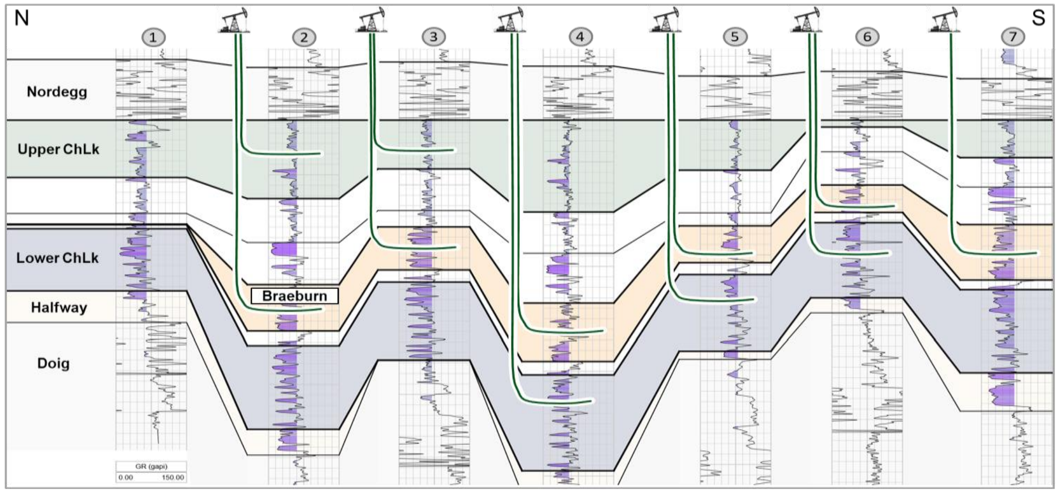
1) 16.0 Mboe/d comprised of approximately 8,500 bbl/d light and medium oil, 1,900 bbl/d NGL and 33.6 MMcf/d.
2) As at September 30, 2024.
3) Cycle times defined as pad rig release date to first oil, 2024 year to date average = 25 days.

Charlie Lake: Superior Economics in the Heart of the Play

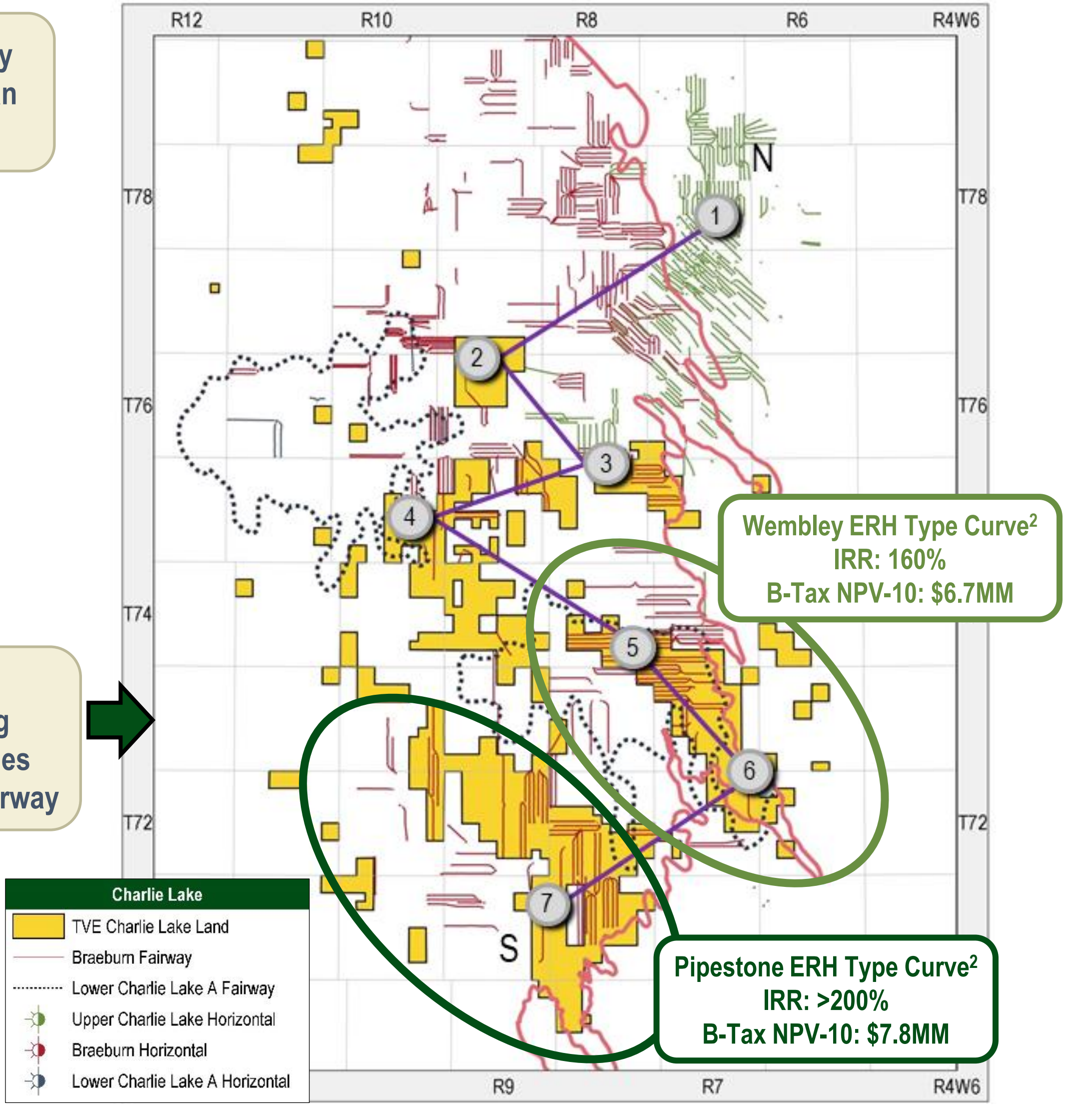
Well Design and Program Execution Driving Continued Sustained Outperformance In Core Areas



Tamarack's 2024 Wembley Wells Are 10% Higher Than Historical Area Average



Actively Developing Multiple Zones Across the Fairway



1) Source: GeoSCOUT, 2024 Tamarack well data as of October 2024. Averages for Tamarack Wembley, Tamarack Pipestone, and industry are averages of demonstrated well performance. Oil % is on a 1st year cumulative basis.

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.

Corporate Information

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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	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.

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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 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 (including that it will produce <1% of the OOIP of 8.7 billion within its 5-year plan); plans in respect of phase II (debt paydown and return of capital) and phase III (growth optionality) of the Company's road map for continued plan execution and value generation potential of the Company's current portfolio to deliver long-term returns for shareholders; Tamarack's 2025 capital program, budget and guidance, 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; 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" and "prospective resources" 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 the "fan" well design; 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 tariffs, tax laws, royalty regimes and environmental legislation); changes to demand for Tamarack's products; adverse weather or break-up conditions; uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects; capital expenditures; pandemics; impacts of conflicts in Eastern Europe and the Middle East. Production forecasts are directly impacted by commodity prices and the actual timing of Tamarack's capital expenditures. Actual results may vary materially from forecasts due to changes in interest rates, oil differentials, exchange rates and the timing of expenditures and production additions. These and other risks are set out in more detail in Tamarack's annual information form for the year ended December 31, 2023 (the "AIF") and Tamarack's management's discussion and analysis for the three and nine months ended September 30, 2024 (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; 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 2025, prospective results of operations and production, breakeven costs, timing of payout of wells and number of payouts, IRR, EUR, debt, net debt, net debt reduction, debt targets and utilization, balance sheet strength, NPV-10%, TPP reserve life index of ~8 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 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, 2023 and preparation dates of February 9, 2024 and January 29, 2024 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"). 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, 2023, 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 28, 2024, 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, 2023.

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)" (previously referred to as "free adjusted funds flow breakeven") is determined by calculating the minimum WTI price in US/bbl required to generate free funds flow 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) and "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). 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.

Disclaimers (Oil and Gas Advisories Cont.)

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 drilling locations two categories: (i) booked locations; and (ii) unbooked locations. Booked locations are proved and probable locations derived from reserves assessments and evaluations prepared by McDaniel and GLJ, qualified independent reserves evaluators, each with an effective date of December 31, 2023, and preparation dates of February 9, 2024, and January 29, 2024, respectively, prepared in accordance with NI 51-101 and the most recent publication of the COGE Handbook. They account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates prepared by the Company's internal QRE in accordance with NI 51-101 and the most recent publication of the COGEH based on the Company's assumptions as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. The unbooked Charlie Lake locations do not have attributed resources. The unbooked Clearwater locations have attributed contingent or prospective resources, based on the Resource Report prepared by McDaniel effective December 31, 2023. See Disclaimers - "Resource Disclosure". Of the corporate inventory of 2,569.2 net drilling locations identified herein, 452.6 net are proved locations, 226.2 net are probable locations and 1,890.3 net are unbooked locations. This presentation also discloses locations specific to the Clearwater and Charlie Lake assets. Of the Clearwater inventory of 2,154.8 net drilling locations identified herein, 257.8 net are proved locations, 123.0 net are probable locations, and 1,774.0 net are unbooked locations. Of the Charlie Lake inventory of 226.7 net drilling locations identified herein, 65.1 net are proved locations, 45.3 net are probable locations and 116.3 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	kep 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