Creating Sustainable Value

June 2022

See Disclaimers and Forward-Looking Statements attached

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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 suggesting future outcomes or statements regarding an outlook. Forward-looking information in this presentation may include, but is not limited to, statements about: our corporate strategy, objectives, strength, focus and updated five year plan and the anticipated benefits thereof; the proposed acquisition of all of the issued and outstanding common shares of Rolling Hills Energy Ltd. (“Rolling Hills”) pursuant to which the Company will further establish its position as a leading operator in the Clearwater area (the “Acquisition”), including the terms, timing and anticipated benefits and strategic rationale of such Acquisition; second strategic Peavine Metis settlement agreement; future intentions with respect to return of capital including dividends and share buybacks, including annual shareholder return potential; the Company's sustainability-linked lending and notes, including sustainability performance targets in relation thereto and the anticipated achievement of such targets; net debt reduction and debt targets; Tamarack's intention to return free funds flow to shareholders; the dividend policy; future enhanced return of capital of shareholders, including the granting of any special dividends or any share buybacks or other supplements to the base dividend; statements regarding plans or expectations for the declaration of future dividends and the amount thereof; Tamarack’s commitment to ESG principles and Indigenous relationships, including as disclosed in the Company’s 2021 Sustainability Report; Tamarack’s liquidity and financial position, the factors contributing thereto, the impact thereof and plans relating thereto; and Tamarack’s 2022 capital budget and guidance and capital program, including the timing and level capital expenditures and optionality; future production levels, including annual average production; oil and liquids weighting and changes thereto; development opportunities; drilling locations; economics and payouts of our wells; corporate decline rate and improvements thereto with greater exposure to assets under waterflood; application of EOR; hedging positions and targets; future waterflood potential, plans, outlook, estimates and forecasts; future land and seismic investments; additional consolidation opportunities; and future commodity prices including sustaining breakeven prices and exchange rates. Statements relating to “reserves” are also deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. Without limitation of the foregoing, future dividend payments, if any, and the level thereof, is 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 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, Rolling Hills and the assets to be acquired pursuant to the Acquisition 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 this presentation, assumptions have been made regarding and are implicit in, among other things, satisfaction or waiver of the closing conditions to the Acquisition, receipt of required regulatory approvals for the completion of the Acquisition (including approval of the Toronto Stock Exchange), the success of future drilling, development and completion activities, the performance of existing wells, the performance of new wells, the performance of EOR projects, the availability and performance of facilities and pipelines, the geological characteristics of Tamarack’s properties, including the assets to be acquired pursuant to the Acquisition, the successful application of drilling, completion and seismic technology, prevailing weather and break-up conditions and access to our drilling locations, commodity prices, price volatility, price differentials and the actual prices received for the Company’s products, royalty regimes and exchange rates, the application of regulatory and licensing requirements, the availability of capital, labour and services, our ability to complete planned capital expenditures within budgeted cost estimates, the ability to market our and gas successfully, our ability to integrate assets and employees acquired through acquisitions, the creditworthiness of industry partners and our ability to acquire additional assets. Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used. Although Tamarack believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because Tamarack can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, risks 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 or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), incorrect assessment of the value of acquisitions, failure to realize the benefits of acquisitions, constraint in the availability of services, commodity price and exchange rate fluctuations, changes in legislation (including but not limited to tax laws, royalty regimes and environmental legislation), adverse weather or break-up conditions and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures. Production forecasts are directly impacted by commodity prices and the actual timing of our 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. In addition, the Company cautions that current global uncertainty with respect to the spread of the COVID-19 virus and its effect on the broader global economy may have a significant negative effect on the Company. While the precise impact of the COVID-19 virus on the Company remains unknown, rapid spread of the COVID-19 virus and variants may continue to have a material adverse effect on global economic activity, and may continue to result in volatility and disruption to global supply chains, operations, mobility of people and the financial markets, which could affect interest rates, credit ratings, credit risk, inflation, business, financial conditions, results of operations and other factors relevant to the Company. These and other risks are set out in more detail in Tamarack’s annual information form for the year ended December 31, 2021 (the “AIF”) and Tamarack’s management’s discussion and analysis for the period ended March 31, 2022 (the “MD&A”) . The AIF and MD&A can be accessed on Tamarack’s website at www.tamarackvalley.ca or under Tamarack’s profile on www.sedar.com. 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 the proposed management and described in the forward-looking information. The forward-looking information contained in this presentation is made as of the date hereof and the proposed 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 updated five year plan, including generating sustainable long-term growth in free funds flow, dividends and share buybacks, prospective results of operations and production, debt, net debt, debt targets and utilization, cash flow, adjusted funds flow, free funds flow breakeven, half-cycle returns, long-term free funds flow growth, balance sheet strength, cash costs, ARO, netbacks, corporate netbacks, operating netbacks, operating costs, corporate decline rate, tax pools, 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. 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 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 (i) a reserves assessment and evaluation prepared by GLJ Ltd., a qualified independent reserves evaluator, dated January 25, 2022 with an effective date of December 31, 2021; and (ii) in the case of the assets to be acquired pursuant to the Acquisition, an internal estimate prepared on November 30, 2021 by the Company's internal Qualified Reserve Evaluators, with an effective date of June 1, 2022, in each case 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. References in this presentation to peak rates, IRR, initial 30 day production rates (IP30), initial 90 day production rates (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/Rolling Hills'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 (including as a result of the Acquisition); 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 report are derived from converting gas to oil in the ratio mix of six thousand cubic feet of gas to one barrel of oil. 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.

bbls	barrels	WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
bbls/d	barrels per day	AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
boe/d	barrels of oil equivalent per day	IFRS	International Financial Reporting Standards as issued by the International Accounting Standards Board
GJ	gigajoule	ROR	rate of return

mmcf/d	million cubic feet per day	P3	proved + probable + possible reserves
BOPD	barrels of oil per day	ERH	extended reach horizontal
NAV	net asset value	EUR	estimated ultimate recovery
TTM	trailing twelve months	FX	foreign exchange
EOR	Enhanced Oil Recovery	ESG	Environmental, Social and Governance

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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 and adding back changes in non-cash working capital, expenditures on decommissioning obligations and transaction costs since Tamarack believes the timing of collection, payment or incurrence of these items is variable. 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 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 loss per share. “Free funds flow (capital management measure)” (previously referred to as “free adjusted funds flow”) 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 (non-IFRS financial 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. "Free funds flow yield" is calculated as free funds flow, adjusted for growth (to add back capital in excess of maintenance and ARO capital and to remove the adjusted funds flow associated with growth volumes), plus finance costs, the sum of which is divided by enterprise value. “Operating field netback (non-IFRS financial measure or ratio)” is calculated as total petroleum and natural gas sales, less royalties, net production expenses and transportation expense. These metrics can also be calculated on a per boe basis. Management considers operating netback and operating field netback important measures to evaluate Tamarack’s operational performance, as it demonstrates field level profitability relative to current commodity prices. See the MD&A for a detailed calculation and reconciliation of operating netback per boe to the most directly comparable measure calculated and presented in accordance with IFRS. “Operating netback (non-IFRS financial measure or ratio)” is calculated as total petroleum and natural gas sales, including realized gains and losses on commodity and foreign exchange derivative contracts, less royalties, net production expenses and transportation expense (non-IFRS financial measure). This metrics can also be calculated on a per boe basis (non-IFRS financial ratio). Management considers operating field netback an important measure to evaluate Tamarack’s operational performance, as it demonstrates field level profitability relative to current commodity prices. See the MD&A for a detailed calculation and reconciliation of operating netback per boe to the most directly comparable measure calculated and presented in accordance with IFRS. “Net debt (capital management measure)” is calculated as bank debt plus working capital surplus or deficit, plus other liability, including the fair value of cross-currency swaps and excluding the fair value of financial instruments and lease liabilities. “Year-end Net Debt to Annualized Adjusted Funds Flow (capital management measure)” is calculated as estimated year-end net debt divided by the annualized adjusted funds flow for the preceding quarter (multiplied by 4 for annualization). "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. 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 profile on www.sedar.com.

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%), RLI (calculated by dividing reserves volumes by estimated production), 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), internal rate of return ("IRR") (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), and recycle ratio (measured by dividing the operating netback for the applicable period by finding and development cost per boe for the year, which is intended to compare 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), finding and development costs (calculated as the sum of field capital plus the change in future development capital (“FDC”) for the period divided by the change in reserves that are characterized as development for the period) and finding, development and acquisition costs (calculated as the sum of field capital plus acquisition capital plus the change in FDC for the period divided by the change in total reserves, other than from production, for the period). 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.

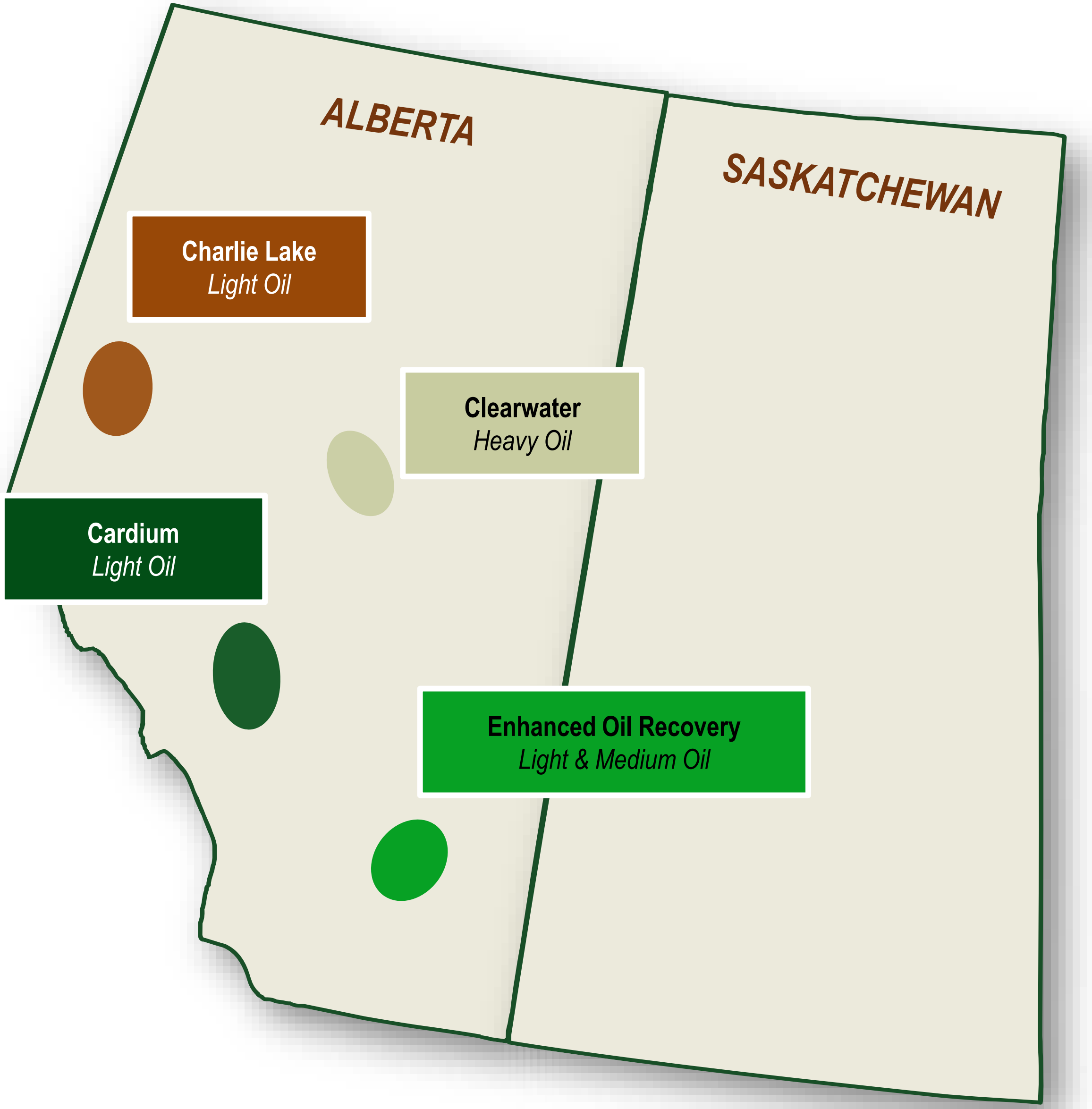
Drilling Locations: This presentation discloses drilling locations two categories: (i) booked locations; and (ii) un-booked locations. Booked locations are proved and probable locations derived from an internal evaluation using standard practices as prescribed in the most recent publication of the COGE Handbook and account for drilling locations that have associated proved and/or probable reserves, as applicable. Un-booked locations are internal estimates and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Un-booked locations do not have attributed reserves or resources. Of the approximately 992 (952.8 net) drilling locations identified herein, including in respect of the Acquisition, 190 (185.8 net) are proved locations, 100 (92.7 net) are probable locations and 702 (674.3 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.

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.

Corporate Snapshot (TSX: TVE)

Corporate/Market Summary[1]	Tamarack (excl. RHE)
Market Capitalization ($MM)	$2,342
Net Debt[2],[3] ($MM)	$556
Enterprise Value[2] ($MM)	$2,898
Tax Pools[4] ($MM)	$943

2022 Capital Budget and Guidance[5]	2022 Full Year (incl. RHE)
Average Production[6] (boe/d)	46,200 – 47,200
Capital Expenditures ($MM)	$280 – $300
Royalties	19% – 21%
Transportation ($/boe)	$2.35 – $2.45
Operating Costs ($/boe)	$9.45 – $9.65
G&A[7] ($/boe)	$1.35 – $1.45



Tamarack Strategic Principles

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Sustainable Returns Focused Strategy with Repeatable and Predictable Long-Life Resource Plays in the WCSB

Strategic Principles	Tactical Execution
Low Leverage & Active Risk Management	• <0.5x 2022 YE net debt to Q4 annualized adjusted funds flow(1) • Consistent hedging policy to manage exposure to commodity price volatility
Inventory Depth & Diversity	• Diverse multi-play asset portfolio enables flexibility • Added >1,000 locations through a successful acquisition strategy over the past year
Free Funds Flow(1) Generation	• FFF breakeven(1) to ~US$35/bbl WTI supported by low cost structure and repeatable results • Economic assets and inventory runway provide visibility for FFF(1) growth
Prudent Return of Capital and Strategic M&A Strategy	• Base dividend increase in Q2; outlook for enhanced dividend and/or NCIB mid-2022 • Excess free funds flow(1) and lower leverage support capital allocation optionality
Strong ESG Commitment	• Target 39% emissions intensity reduction by 2025 (scope 1+2 over 2020 baseline) • ARO spend > AER targets; increasing Indigenous partnerships and workforce participation

Capital Allocation Optionality Delivers Sustainability

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Portfolio that can deliver near-term and long-term free funds flow(1)

Asset Value Expansion

Highly Economic Production and Inventory

Nipisi Clearwater Oil Wells
Jarvie Clearwater Oil Wells
Peavine Clearwater Oil Wells

~35%

Free Cash Maximization

Highly Economic Inventory that Sustains Meaningful Production While Generating Significant Free Funds Flow(1)

Charlie Lake Light Oil Wells
Viking Primary Oil Wells
Cardium/Falher Wells

~40%

Waterflood Management

Low Decline, Stable Production Base

Veteran Viking Light Oil
Eyehill Sparky Medium Oil
Slave Point and Penny Light Oil

~25%

Capital Allocation Across a Portfolio of High Quality, Long-Life Oil Assets that Delivers Production and Free Funds Flow(1) per Share Growth

Percent of 2022 Capital Program

Sustainability-Linked Lending & Notes

Strengthening Our Commitment to Responsible Energy Production

All of Tamarack's debt has been converted to **sustainability-linked debt** and includes:

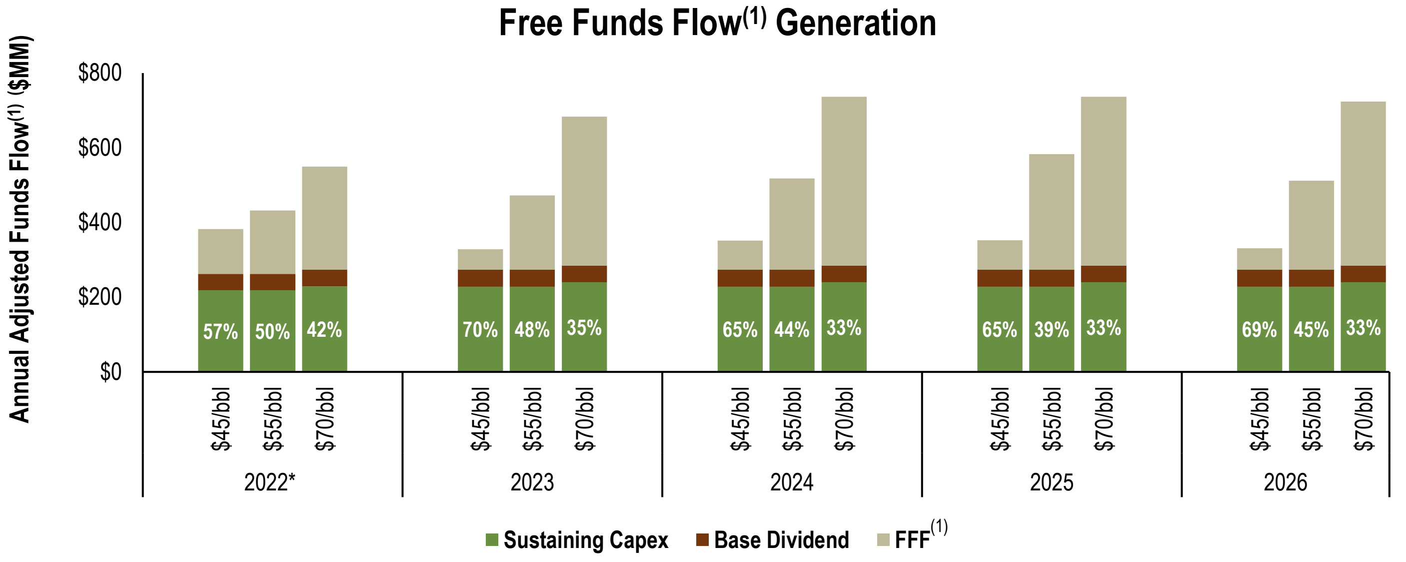
- A $600 million revolving **sustainability-linked lending facility** (**SLL**) with a lending syndicate – 3 KPIs with potential annual penalty or benefit
- $200 million notes issued as **sustainability-linked bonds** (**SLB**) that trade in the open market – 2 KPIs with step-up interest penalty in 2026

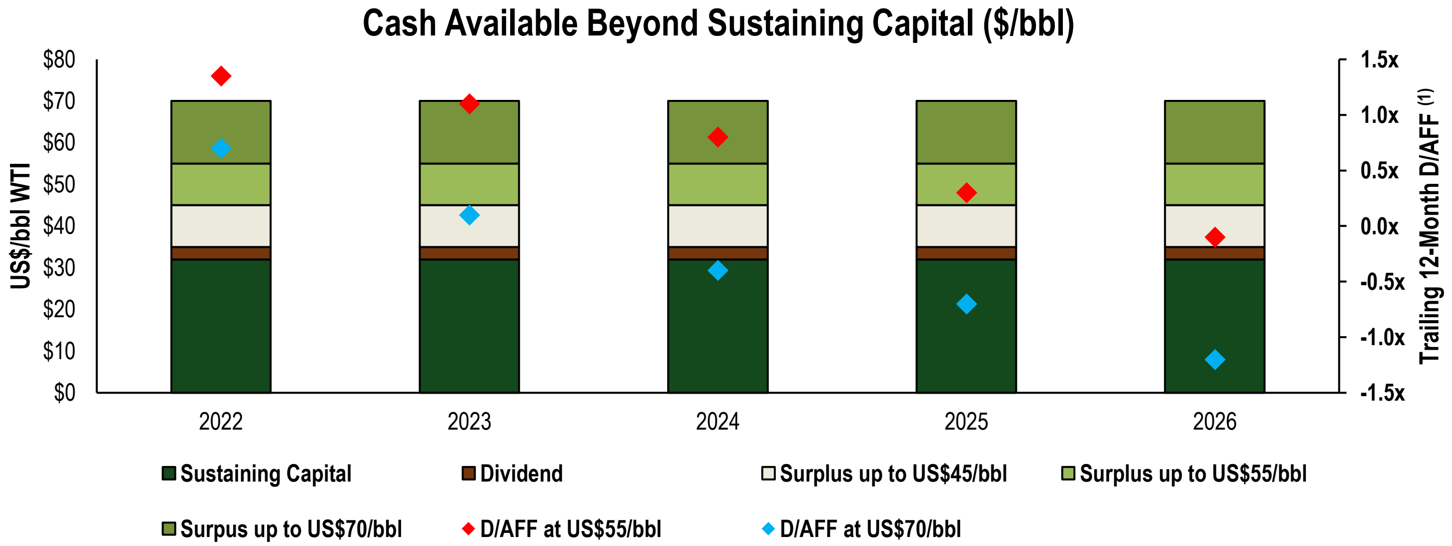
KPIs and SPTs selected strongly align with Tamarack's **existing priority topics and commitments**

Key Performance Indicator	Tamarack Priority	UN Sustainable Development Goal	2020 Baseline	SLL ($600 million)		SLB ($200 million)	
				Sustainability Performance Target	Penalty/ Benefit	Sustainability Performance Target	Penalty
Scope 1 and 2 emissions intensity		13 CLIMATE ACTION	37.5 kg CO_2e/boe	**39%** reduction by 2025	**+/- 0.025%** +/- $0.75MM over 5 years	**39%** reduction by 2025	**+ 0.75%** $1.0 MM in 2026
Decommissioning Management – ARO spend		15 LIFE ON LAND	5.6%	**150%** of the regulatory target spend annually	**+/- 0.015%** +/- $0.45MM over 5 years		
Indigenous representation in the workforce		10 REDUCED INEQUALITIES	3.5%	**>6.0%** by 2025 with a minimum 2 FTE additions each year	**+/- 0.010%** +/- $0.30MM over 5 years	**>6.0%** representation by 2025	**+ 0.25%** $0.50MM in 2026
Total Potential Penalty					**$1.5MM**		**$1.5MM**

5-Year Plan Anchors Long-Term Sustainability

5-Year Plan Overview *(BTAX US$55/bbl WTI & $2.50/GJ AECO)*	
E&D Capital Spending	**$1.2B - $1.4B** *($260MM - $290MM/yr)*
Corporate FFF(1) Generation	**$1.1B - $1.2B** *($190MM - $250MM/yr)*
Free Funds Flow Breakeven(1)	**~US$35/bbl WTI** *(includes Base Dividends)*
Sustaining Capital as % of Adjusted Funds Flow(1)	**45% - 50%**
Target Long-term Leverage	**0.5x – 1.0x D/AFF(1)**





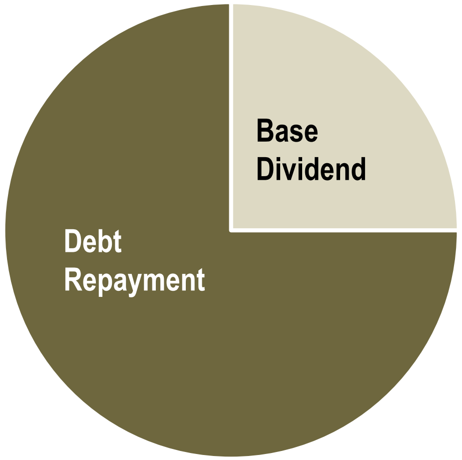
Framework for Returning Capital to Shareholders

Sustaining Capital & Base Dividend Protected Down to US$35/bbl WTI

Delivering Enhanced Returns to Shareholders

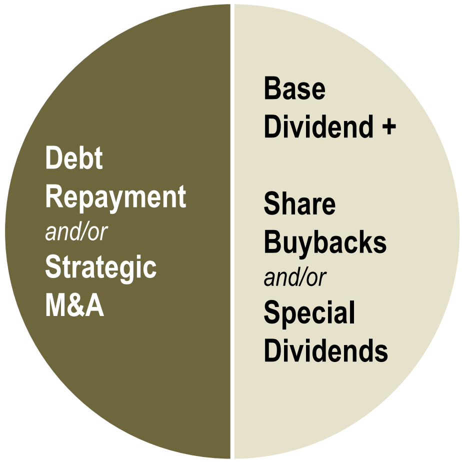
Free Funds Flow[1] Allocation

Net Debt[1] ≥$400MM



Return of Capital (up to 25%) Balance Sheet (up to 75%)

Net Debt[1] $350MM-$400MM



Return of Capital (up to 50%) Balance Sheet (up to 50%)

Continuing to Build for the Future w/ 10+ Years of Drilling Inventory

Sustaining Capital Reinvestment Requires <50% of Free Funds Flow[1]

Illustrating Annual Shareholder Return Potential

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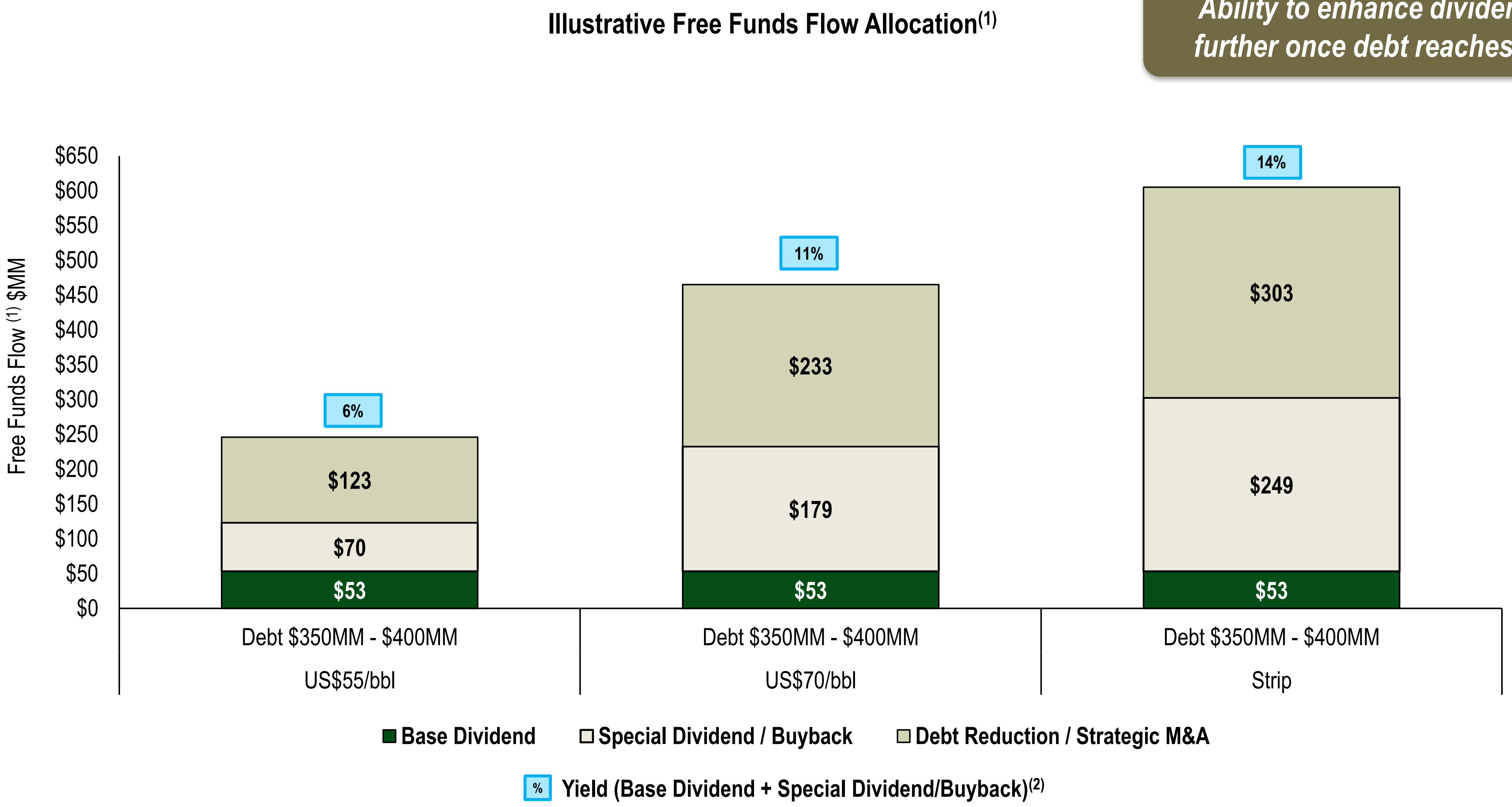
Strip Pricing Supports Enhanced Return in mid-2022

Ability to enhance dividends even further once debt reaches $200MM



Positioned in the Top FFF[1] Oil Plays in North America

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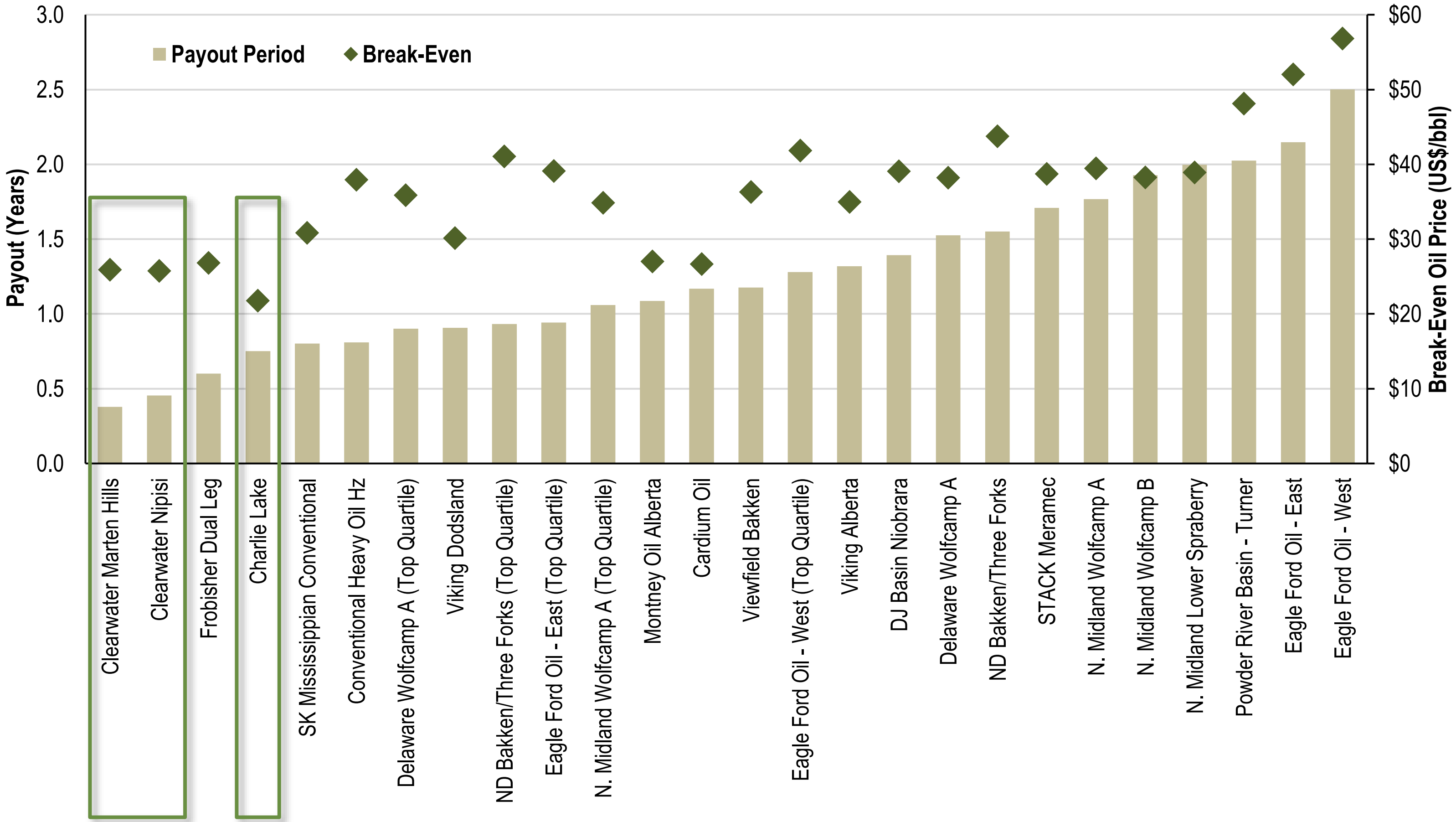
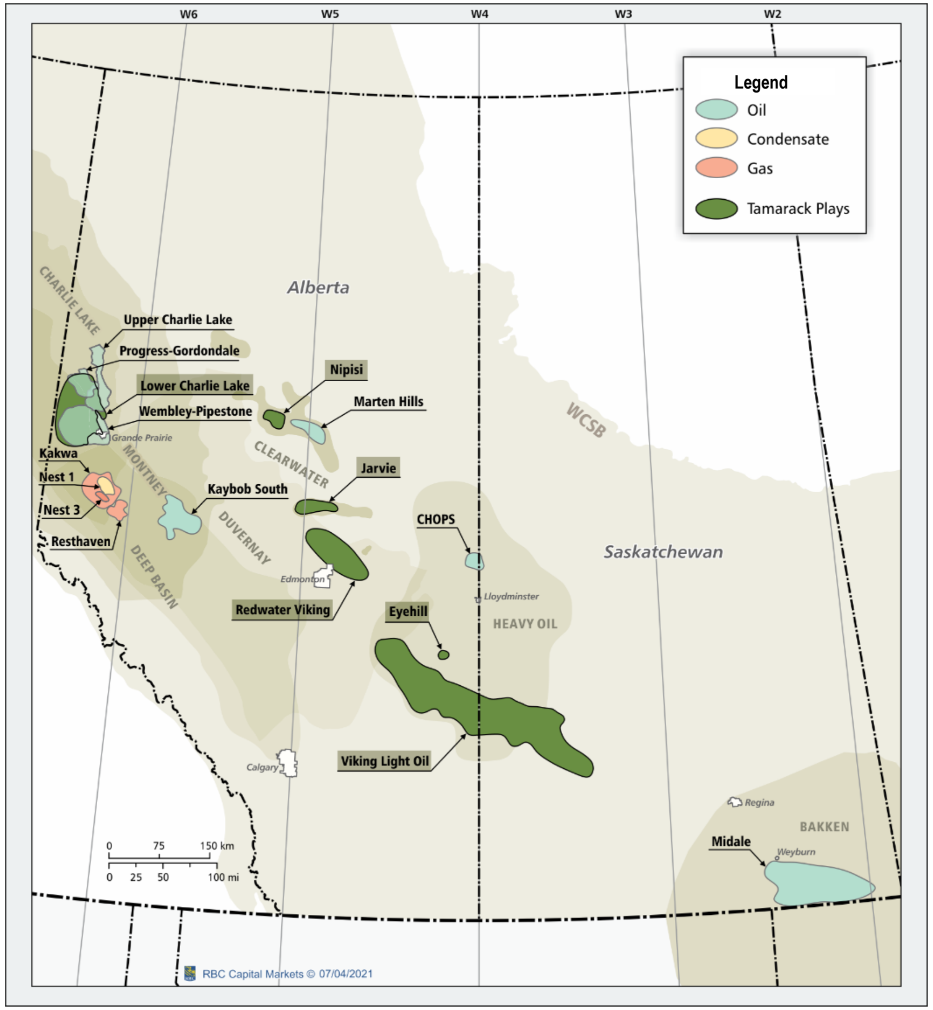
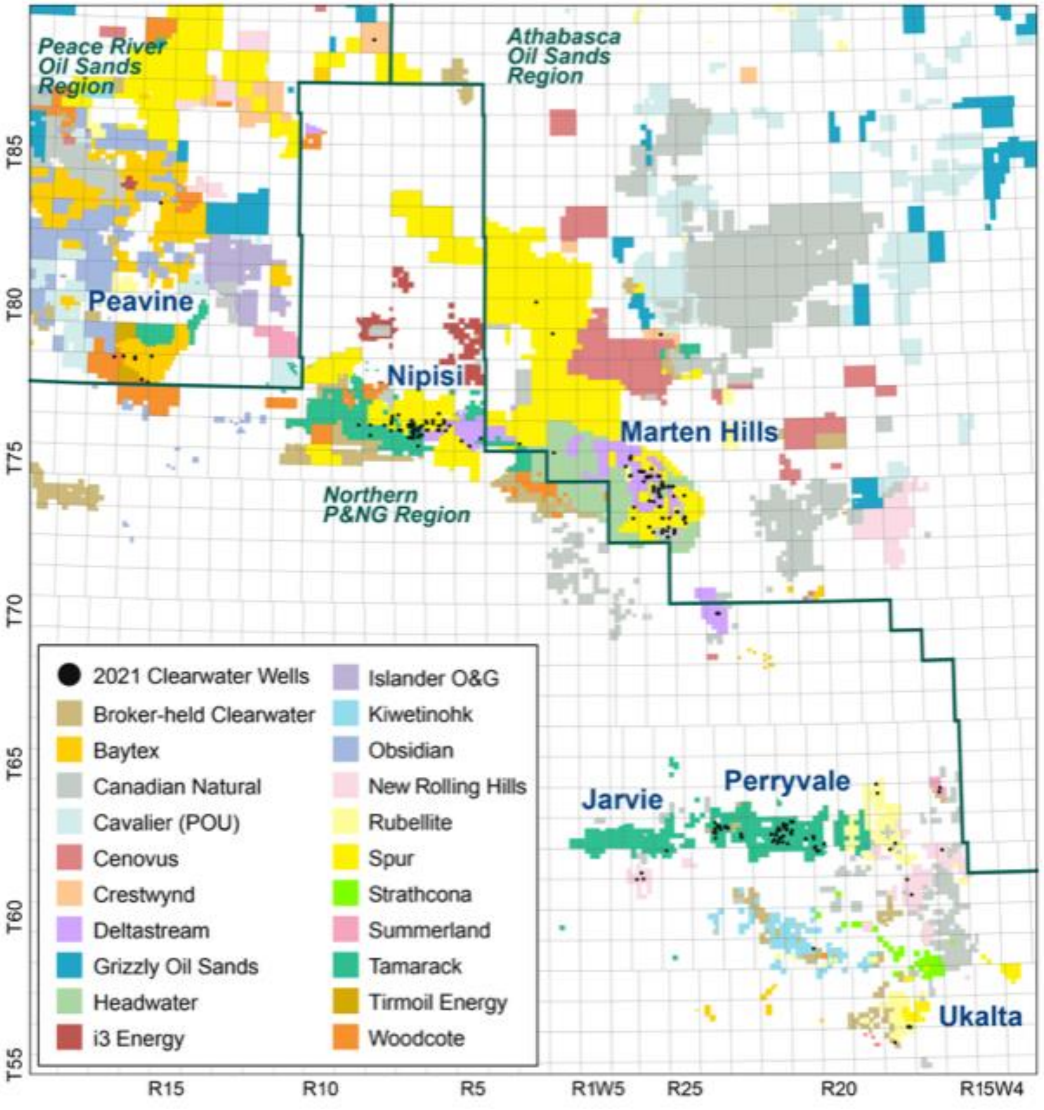
North American Payout Period & Half-Cycle Breakeven by Play





Source: Peters & Co. Limited estimates based on US$70/B WTI, US$3.50/Mcf NYMEX and C$3.25/Mcf AECO prices.

Clearwater Fairway



Source: Peters & Co. Limited and geoSCOUT

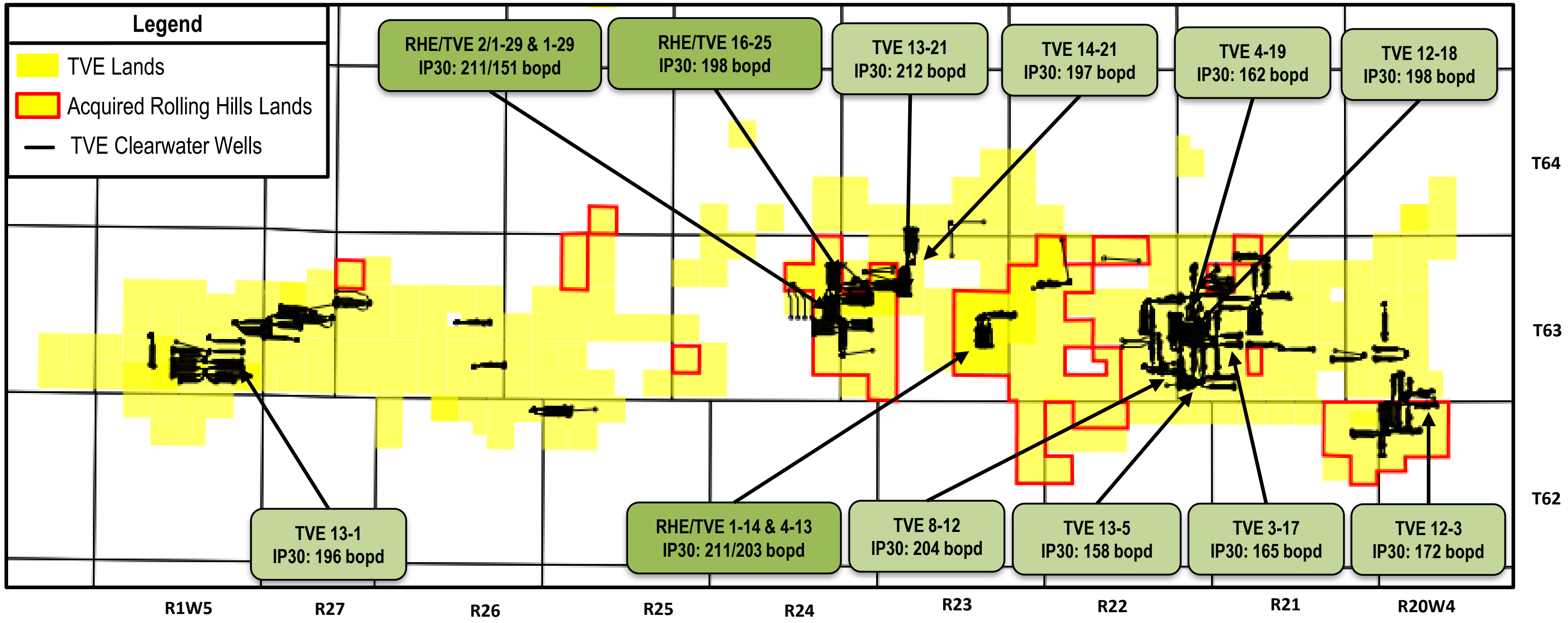
Tamarack Clearwater Land Holdings	
Peavine	**70.5** net section in conjunction with the Peavine Metis Settlement strategic land arrangement
Nipisi	**162.3** net sections through corporate and asset acquisitions in 2020 and 2021
West Marten Hills	**38.4** net sections in West Marten Hills in the early stage of development
South Clearwater	**322.0** net sections in South Clearwater including Jarvie, Perryvale and Ukalta
Total Clearwater	**593.2** net sections in the Clearwater fairway

Southern Clearwater[1]

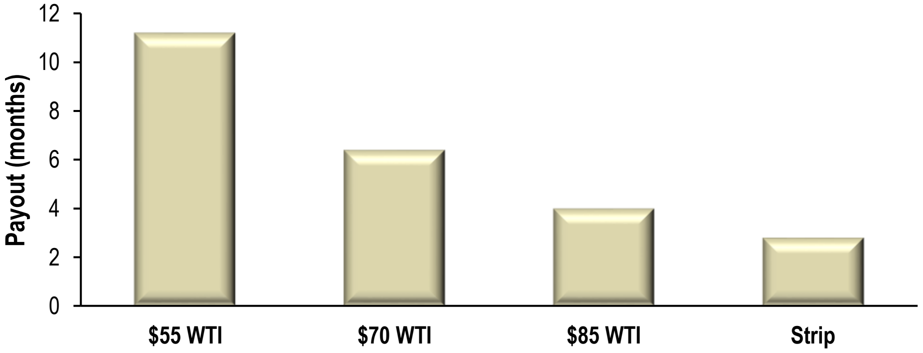
Achieving payout[2] in ~4 months at US$85/bbl to drive free funds flow[3]

Southern Clearwater

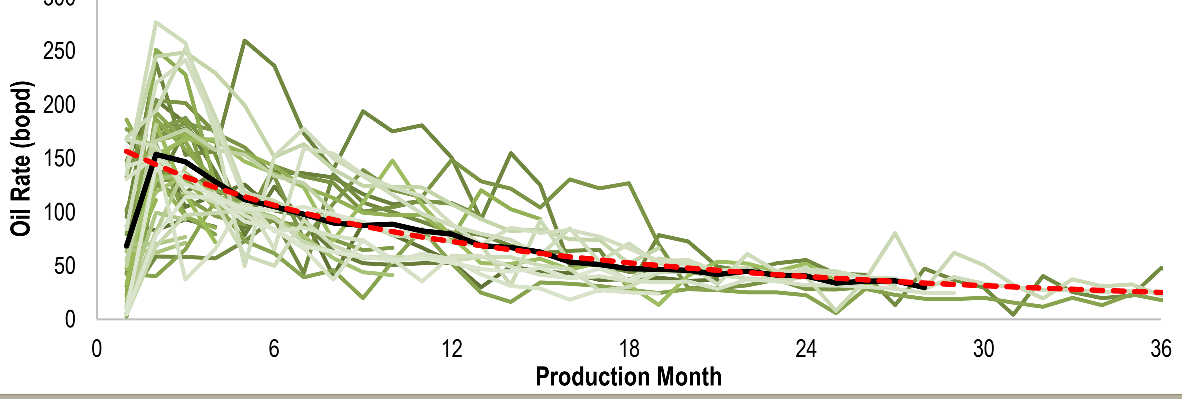
Dominant Position	322 net Clearwater sections
Long-term Inventory[4]	112 net booked wells 190 net unbooked wells
Low Cost Structure	Free funds flow breakeven[3] <$35/boe



South Clearwater Well Payouts[2]



Rate-Time Normalized to 11,000m Well Length



Nipisi & West Marten Hills

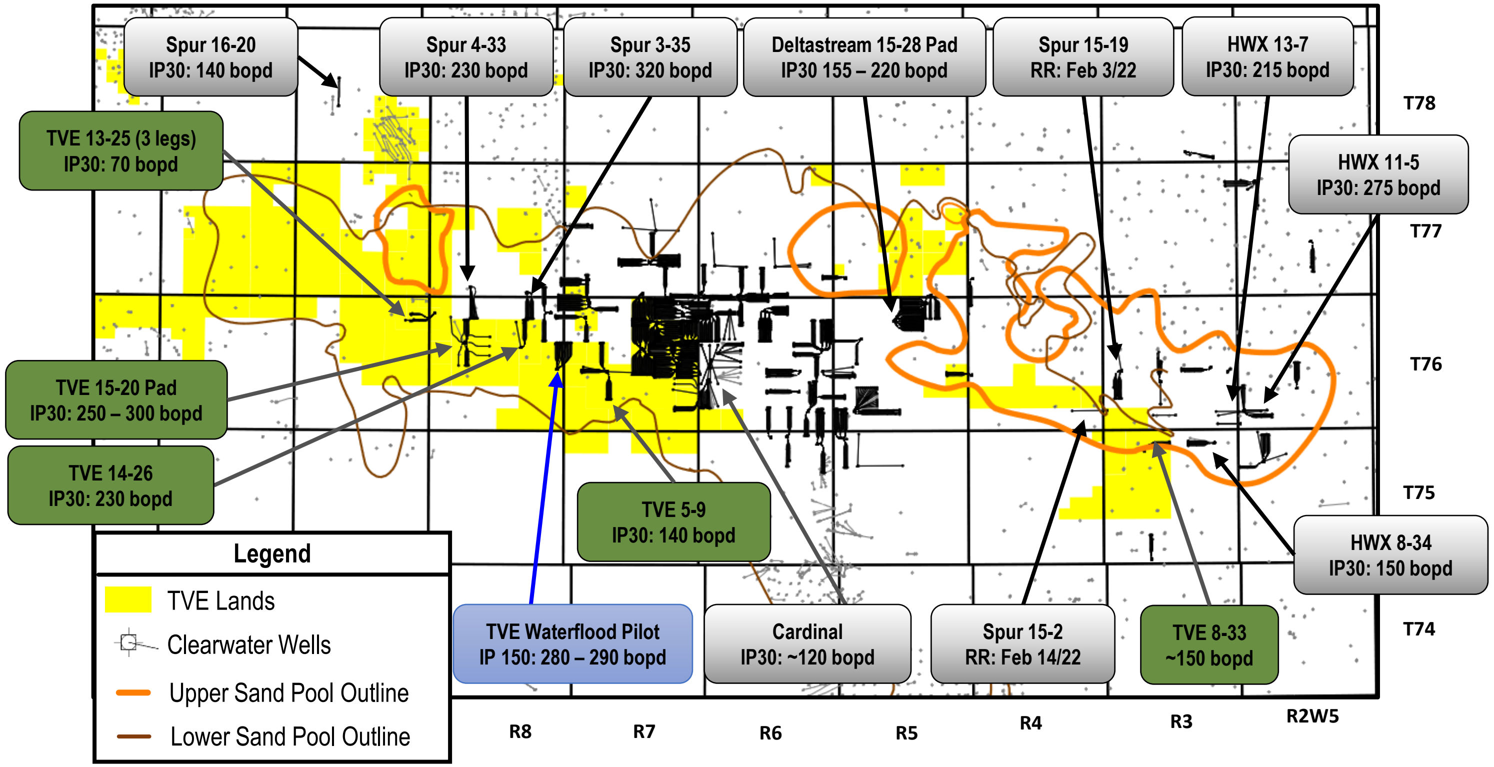
Derisking acreage to enhance development inventory

West Marten Hills

Increased Activity	Multiple sands tested by TVE & regional competitors
Derisking Results	IP30 rates of 155 – 275 bopd Oil gravity upper ~19° API range

West Nipisi

Increased Activity	Spur 16-20 offsetting TVE's northern lands
Derisking Results	IP30 rates of 250 – 300 bopd Oil gravity ~19° API
Waterflood Pilot	TVE to commence injection Q2/22 12 additional waterflood wells planned for '22



200.7 net Clearwater sections
41 net booked locations(1)
>310 net unbooked locations(1)

Clearwater Waterflood Potential

Leveraging promising results from offsetting competitor pilots

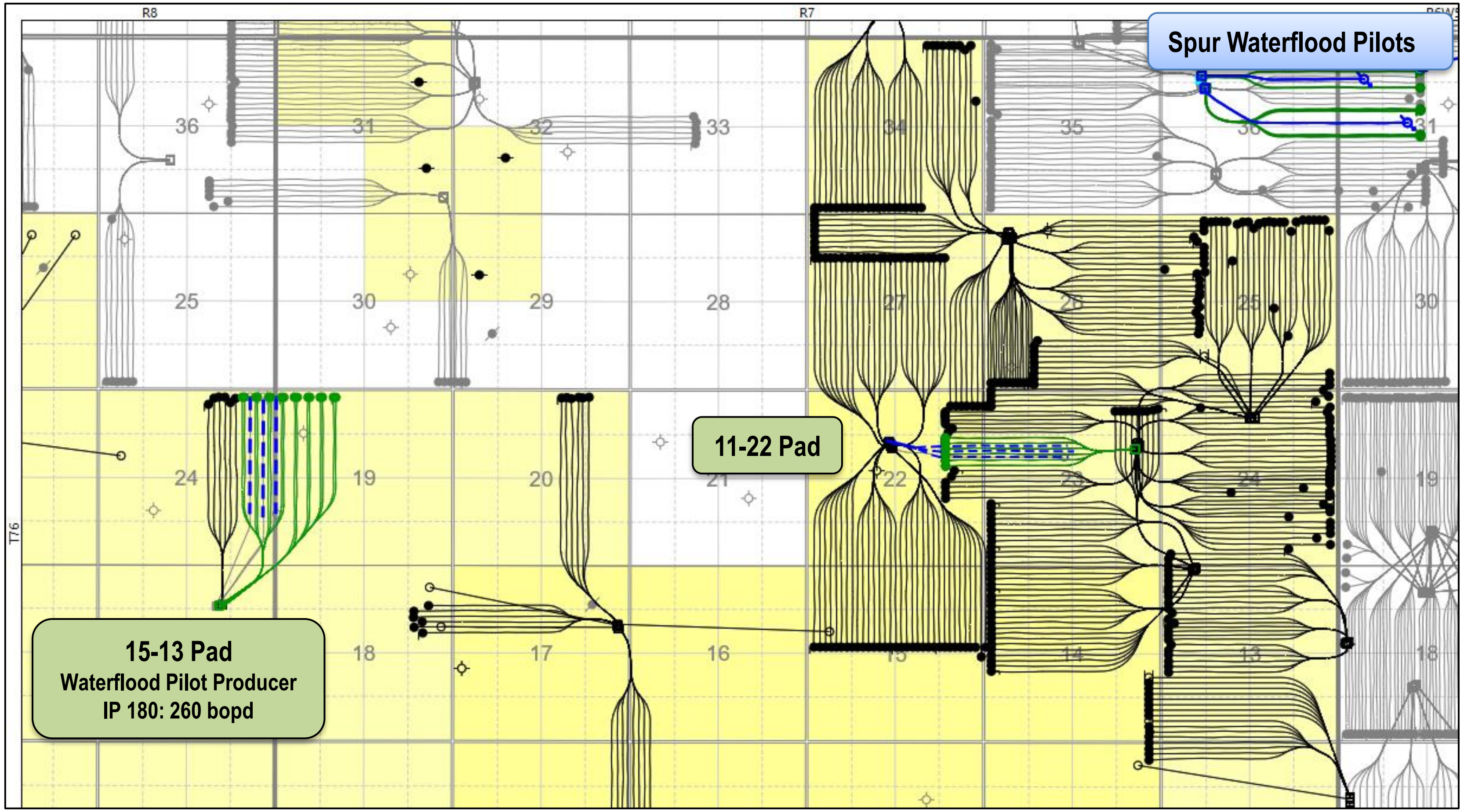
15-13 Pad Pilot

- 2 x 8-leg producers onstream Q4-2021
- Staggered leg spacing ("two-step") allows for water injection corridors while maintaining initial productivity
- 3 x single leg injectors onstream May-2022 will maximize appraisal information, currently injecting >600 bbl/d combined

11-22 Pad Pilot

- Multi-lateral injector trial in primary development region in H2-2022
- Appraisal of well spacing and interlocking multi-lateral layout

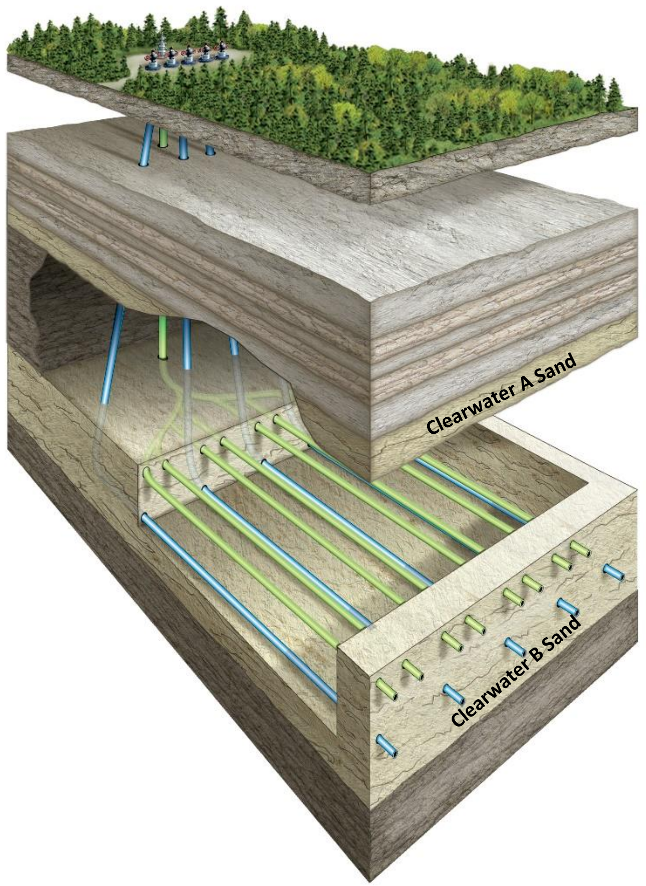
Upcoming Tamarack Nipisi EOR Pilots



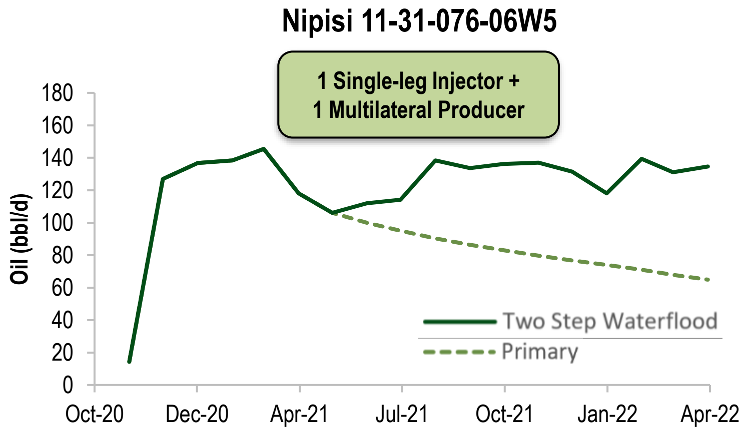
Nipisi Waterflood Design

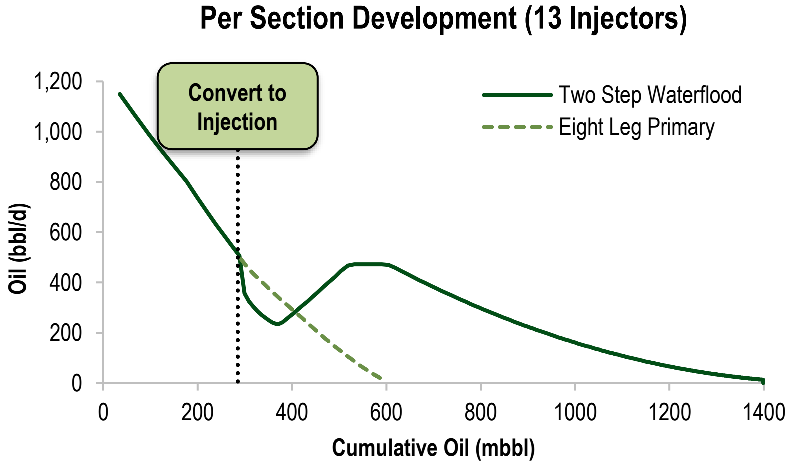
Substantial fairway has been delineated and is ready for development

"Two-Step" Waterflood Design

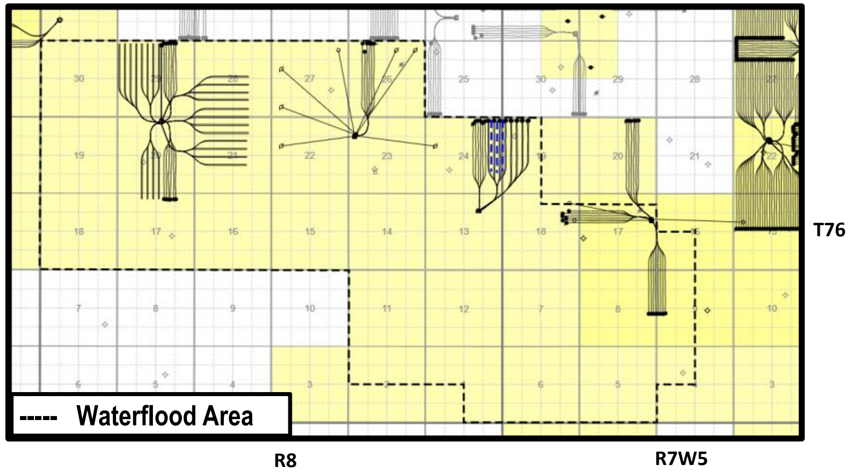


"Two Step" Waterflood Pilot





Potential Waterflood Development Area



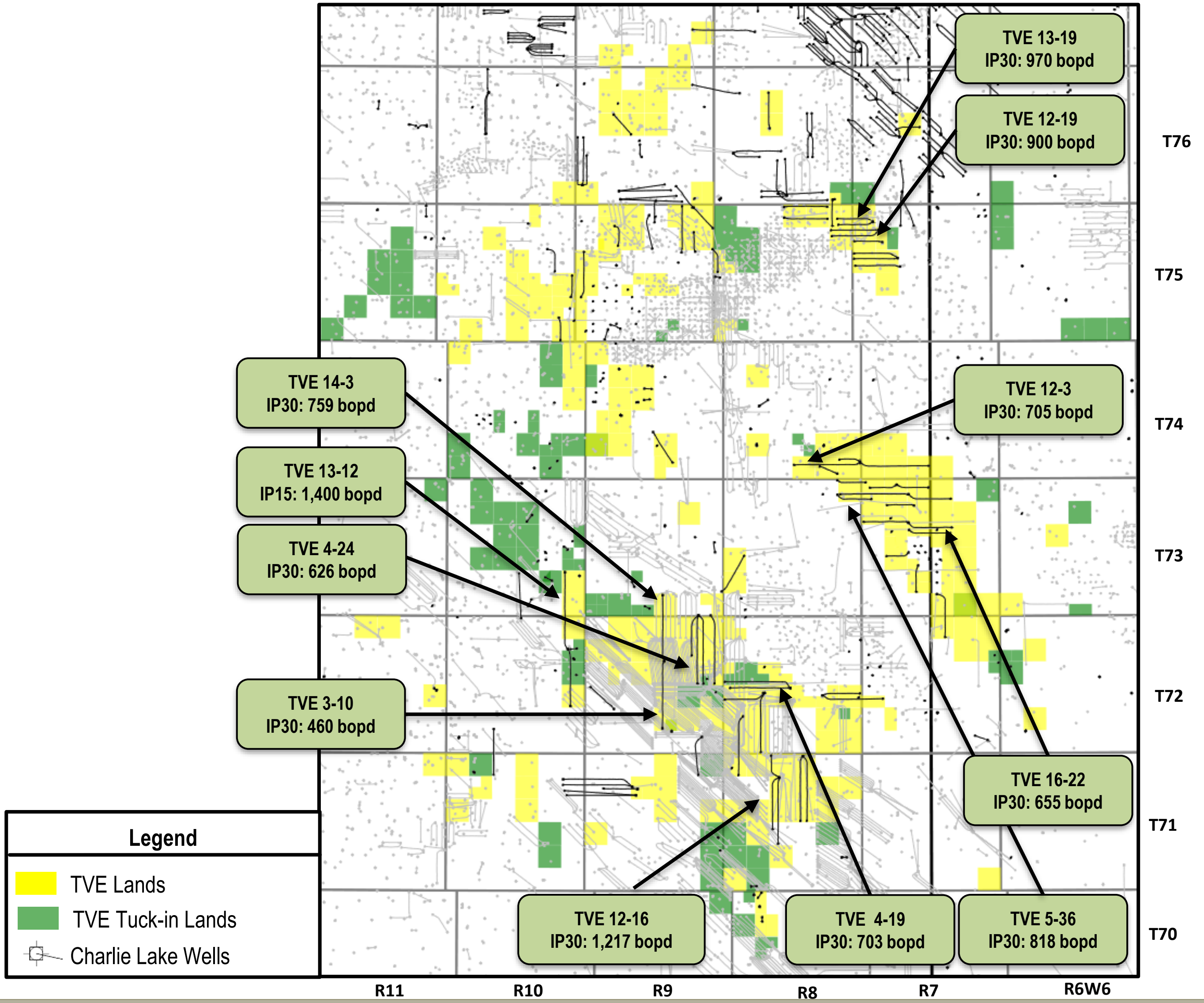
Per Developed Section (50m Spacing)	Capex ($MM)	NPV10 ($MM)[1]
Primary	5.1	19.4
Waterflood	10.1	25.9

Charlie Lake Development

Continuing to Increase Our Presence With Added Lands & Prolific Wells

Charlie Lake	
Expanded Footprint	2021 tuck-ins added 35.9 net sections and 63 net Hz locations(1)
Unlocking Inventory	Drilling our first Upper Charlie Lake well at Saddle Hills
Step Out Success	Pipestone wells delivering IP30 rates of 460 – 1,400 bopd
Infrastructure Ownership	Ownership interest in key gas plants
Capacity for Growth	Processing and egress contracts to facilitate long-term development

326.5 net Charlie Lake sections
96 net booked locations(1)
150 net unbooked locations(1)



Tamarack's Waterflood Assets

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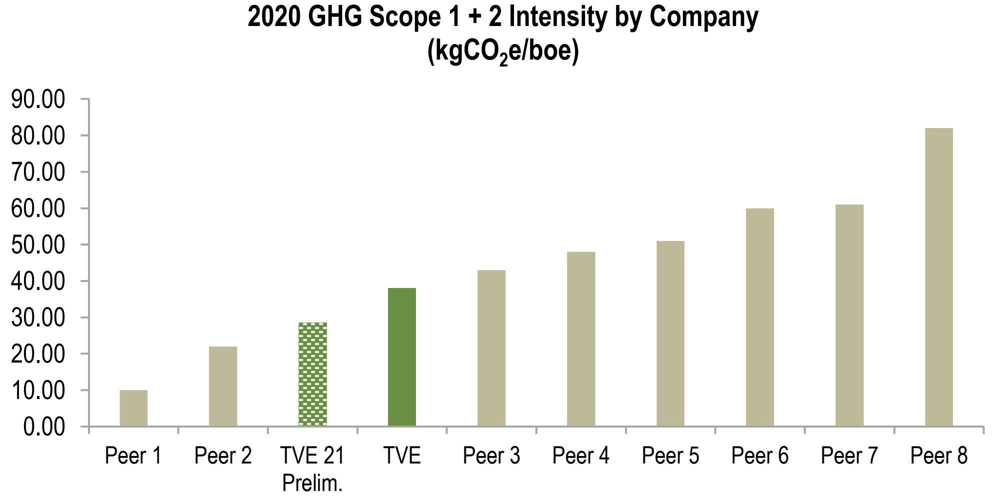
Improving corporate declines with increasing exposure to assets under waterflood

Asset	Total Area Prod.	Prod. Under Waterflood	Total Asset OOIP[1]	Est. Recovery to Date[2]	Est. Ultimate Recovery[2]	Injection Start	% of P+P Reserves	Current Initiatives
Veteran Viking *Light Oil*	3,400 bbl/d	2,200 bbl/d	900 to 1,000 MMbbl	2%	17%	2018	65%	Focus on new linedrive pattern development in North Veteran (including pipeline infrastructure) and start injection on first East Consort stepout injection pattern during 2022
Eyehill Sparky *Medium Oil*	2,100 bbl/d	1,700 bbl/d	200 MMbbl	2%	15%	2014	95%	Continue to increase make-up water supply, complete 5 injector conversions and add 9 new Sparky producers during 2022
Penny Barons *Light Oil*	825 bbl/d	825 bbl/d (entire pool)	60 MMbbl	15%	21%	2001	100%	Actively managing injection for optimal area-based recovery factors, additional infill locations identified
Nipisi Slave Point *Light Oil*	475 bbl/d	475 bbl/d (entire pool)	40 MMbbl	8%	20%	2013	100%	Identify injector conversions to improve waterflood performance, evaluate opportunities for infill producers after injection optimization
Nipisi Clearwater *Medium Oil*	6,100 bbl/d	300 bbl/d	15 to 20 MMbbl per section in selected areas	<1%	Up to 20% in selected areas	2022	-	3 single-leg injectors onstream in May-2022 supporting 1 multilateral two-step producer

>5,000 bbl/d under waterflood at <u>0% decline</u> (~20% of Tamarack's pro forma oil production)

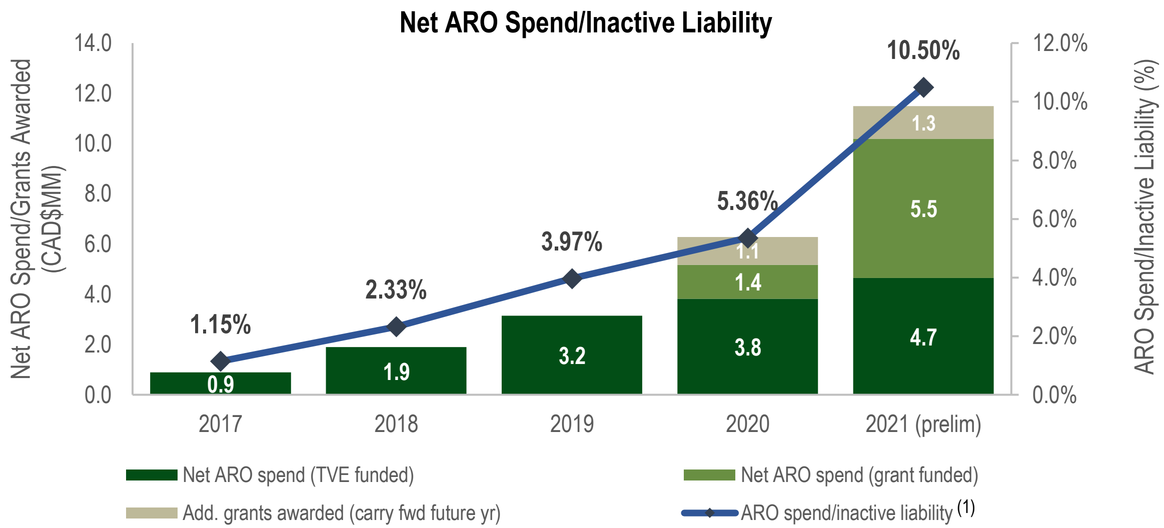
Tamarack Sustainability Results

Emissions Intensity



Peers Include: ARC, Baytex, Cenovus, CNRL, Crescent Point, Enerplus, Suncor, Whitecap

Land Management



*Understanding and managing risks enables sustainability and ESG to **drive profit** and **enhance future value***

LAND & BIODIVERSITY PROTECTION

WATER MANAGEMENT

EMISSIONS MANAGEMENT

STAKEHOLDER ENGAGEMENT

ETHICAL GOVERNANCE

Sustainability Initiatives at Tamarack

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Indigenous Engagement

Tamarack is **committed to** the **principles of UNDRIP** and participating in reconciliatory activities. 2021 and 2022 year-to-date projects include:

- Furthered **workforce participation** goals – team members include three Indigenous women in head office
- **Cultural initiatives** including interactive educational tools for teens and internal **cultural awareness training**
- **Economic opportunities** and **employment** for First Nations individuals and businesses
- **Indigenous site rehabilitation program support** for indigenous business opportunities and reduction of environmental liabilities

Tamarack is **actively engaging** with **Treaty 8 Nations** in the Nipisi area and the **Kainai Nation** in the Lethbridge area. In **2022**, Tamarack signed **two partnership agreements** with the **Peavine Metis Settlement.**

Environmental Initiatives

To ensure achievement of long-term goals and targets, Tamarack undertakes regular initiatives including:

Nipisi Gas Conservation	***60 → 28 kgCO_2e/boe*** *through process modifications and gas conservation in the new Nipisi asset*
Operational Efficiency Reviews	***↓~6,000 tCO_2e annually*** *through the removal of six booster compressors in the Westerose asset*
Eyehill Fresh Water Reductions	***100% utilization*** *of non-freshwater in Eyehill for EOR and completion on a go forward basis*
Area Based Abandonment	***85 gross wells*** *abandoned through efficient area-based programs designed to maximize efficiency*
Increasing Leg Count in Multileg Wells	***6 → 8 legs*** *in multileg horizontals enables more efficient drainage with less surface land disturbance*

Investment Summary

Track record of meeting and exceeding estimates

Sustainable Returns Focused Strategy to Grow Production and Free Funds Flow[1] per Share

Management team that has demonstrated its ability to execute and capitalize on opportunities

Stable Base Production and AFF[1]	Economic Oil Weighted Inventory	Optionality	Balance Sheet Strength and Risk Management	Leading ESG Practices
46,200 – 47,200 boe/d ~US$35 WTI free funds flow breakeven[1]	Highly economic oil plays focused in the Charlie Lake and Clearwater with EOR in Viking & Sparky	Commodity exposure, exploration upside and decline management through waterflood	Low leverage and consistent hedging	Indigenous partners, low GHG intensity and responsible ARO management

APPENDIX

Risk Management – Current Hedges[1]

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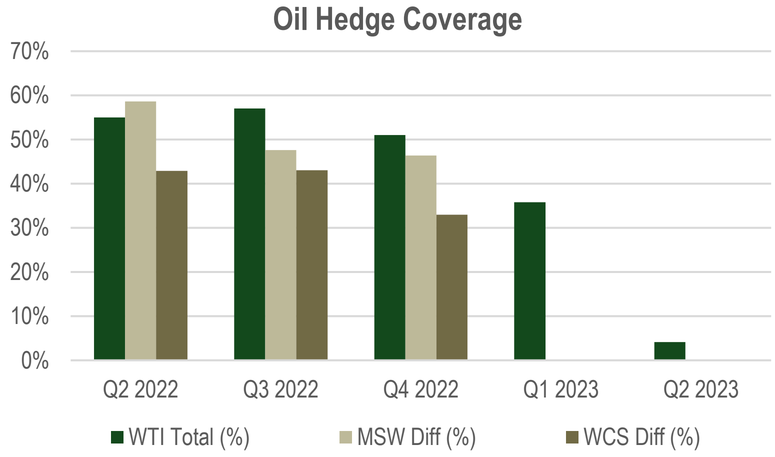
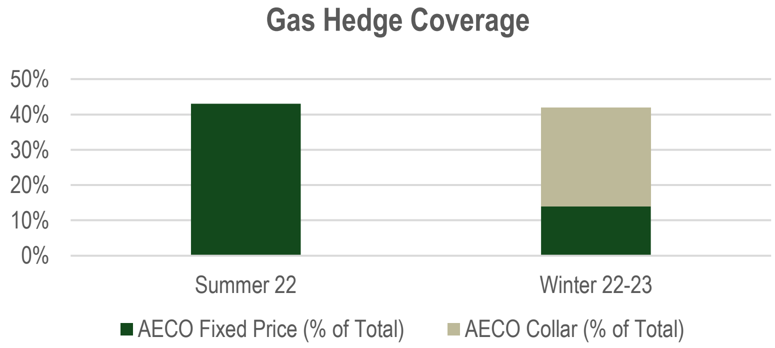
Enhancing certainty with flexibility to capture upside value

53%

Oil price protection in H2 2022[2]



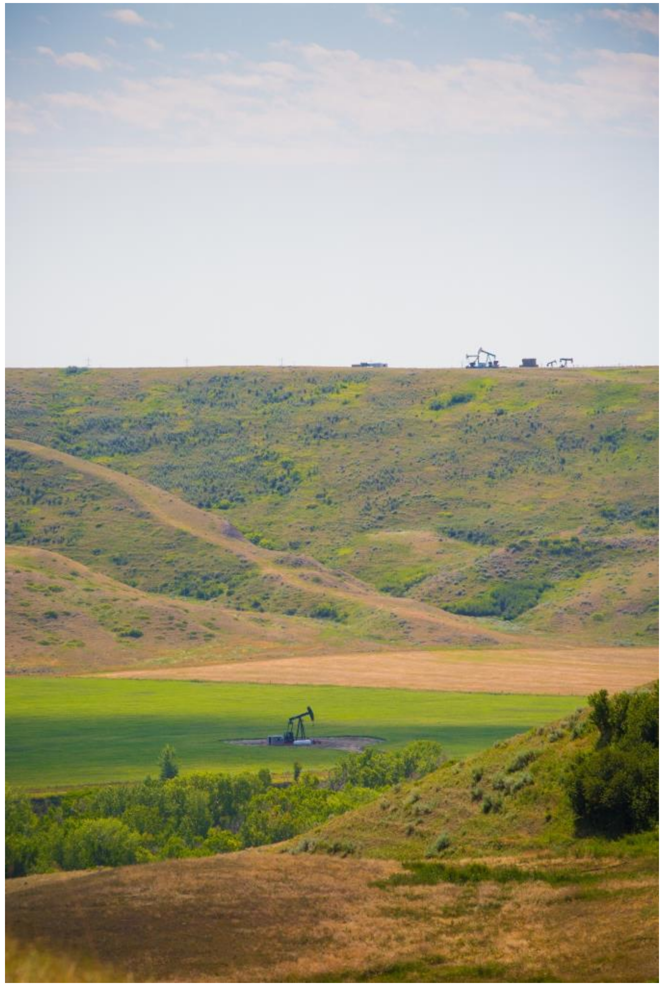


	Q2 2022	Q3 2022	Q4 2022	Q1 2023	Q2 2023
WTI Put					
Volume (bbls/d)	**9,000**	**4,750**	**4,250**	**5,500**	**500**
Average Put/Premium (USD/bbl)	$62.48 $3.68	$55.75 $3.00	$56.43 $3.18	$55.91 $3.10	$55.00 $2.99
WTI 2-way collar					
Volume (bbls/d)	**4,250**	**11,750**	**12,000**	**6,500**	**1,000**
Average Put/Call/Premium (USD/bbl)	$55.35 $90.46 $2.12	$58.87 $95.15 $1.95	$57.48 $106.18 $1.95	$62.31 $117.11 $2.00	$80.00 $108.50 $2.00
WTI 3-way collar (reverse)					
Volume (bbls/d)	**2,500**	**1,250**	**750**		
Average Put/Call/Sold Put/Premium (USD/bbl)	$54 $70 $73 $2	$55 $70 $73 $2	$55 $70 $74 $2		
Edm Par Diff					
Volume (bbls/d)	**10,500**	**7,500**	**7,500**		
Average Fixed Price (USD/bbl)	($3.66)	($3.64)	($3.64)		
WCS Diff					
Volume (bbls/d)	**5,000**	**7,500**	**6,500**		
Average Fixed Price (USD/bbl)	($11.82)	($12.00)	($12.12)		

	Crestwynd Q2 2022	Rolling Hills Jun - Dec 2022
WTI fixed price swaps		
Volume (bbls/d)		**598**
Average Fixed Price (CAD/bbl)		$87.04
WTI 2-way collar		
Volume (bbls/d)	**500**	**800**
Average Put/Call (CAD/bbl)	$75.00 $96.01	$79.85 $101.32
WCS Diff		
Volume (bbls/d)	**500**	
Average Fixed Price (CAD/bbl)	($14.85)	
AECO fixed price swaps		
Volume (GJ/d)		**1,500**
Average Fixed Price (CAD/GJ)		$3.07

	Summer 22	Winter 22-23
AECO 5A fixed price		
Volume (GJ/d)	**30,000**	**10,000**
Average Price (CAD/GJ)	$2.44	$3.85
AECO 7A collars		
Volume (GJ/d)		**15,000**
Average Put/Call (CAD/GJ)		$3.37 $5.17

Q1 2022 Highlights



Strategic Acquisitions
- *Closed the Crestwynd acquisition, further consolidating South Clearwater*
- *Executed on $18.6 million of Clearwater & Charlie Lake land acquisitions*

Financial Acuity
- *Issued $200.0 million senior unsecured sustainability-linked notes (SLB)(2)*
- *Returned capital through declared monthly dividends ($0.0083/share)*

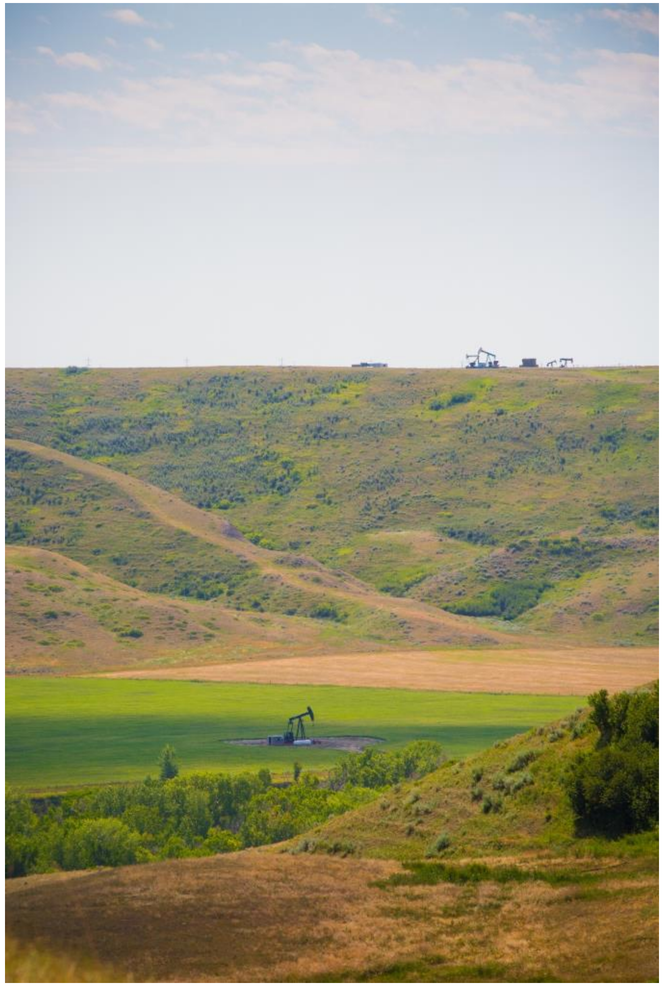
Program Execution
- *Q1/22 average production of 41,335 boe/d(3) (71% liquids)*
- *Invested $106.8 million in E&D capital to drill 38 (37.5 net) wells in Q1/22*

Meaningful Funds Flow(1)
- *Generated adjusted funds flow(1) of $166.6 million and $0.40/share(4) in Q1*
- *Generated free funds flow(1) of $41.2 million in Q1*

Financial Stability
- *Delivered 0.8x net debt to Q1 annualized adjusted funds flow(1)*
- *Exited Q1 with ~$275 million bank line liquidity and $556.4 million net debt*

Tamarack delivered on commitments through the completion of additional strategic acquisitions, the return of capital to shareholders and the continued execution of operational and capital results

Acquisition and Return of Capital Highlights



Strategic Corporate Acquisition	• *Acquisition of Rolling Hills Energy solidifies existing Southern Clearwater portfolio* • *Adds 2,100 boe/d[2], 54.0 net locations[3] and adds 54 net sections of land*
Continued Clearwater Consolidation	• *Second strategic Peavine Metis Settlement agreement adds 15 net sections* • *Additional land sales in Q1 2022 added 26 net sections in greater Peavine*
Free Funds Flow[1]	• *Acquisitions are accretive to free funds flow on an absolute and per share basis* • *Low sustaining capital on the acquisition supports long-term FFF[1] sustainability*
Dividend Increase	• *Improved prices and FFF[1] profile has enabled a 20% base dividend increase* • *Effective June 2022 declaration, monthly base dividend increase ($0.0083 to $0.010)*
Enhanced Return of Capital	• *Prior to effect of Clearwater transactions, debt target reached in Q2 2022* • *Tamarack to provide enhanced returns in Q3 2022*

Tamarack continues to demonstrate a disciplined focus on financial sustainability through stable free funds flow growth and accretive acquisitions, enabling increased flexibility in our return of capital strategy

Southern Clearwater Acquisition of Rolling Hills Energy

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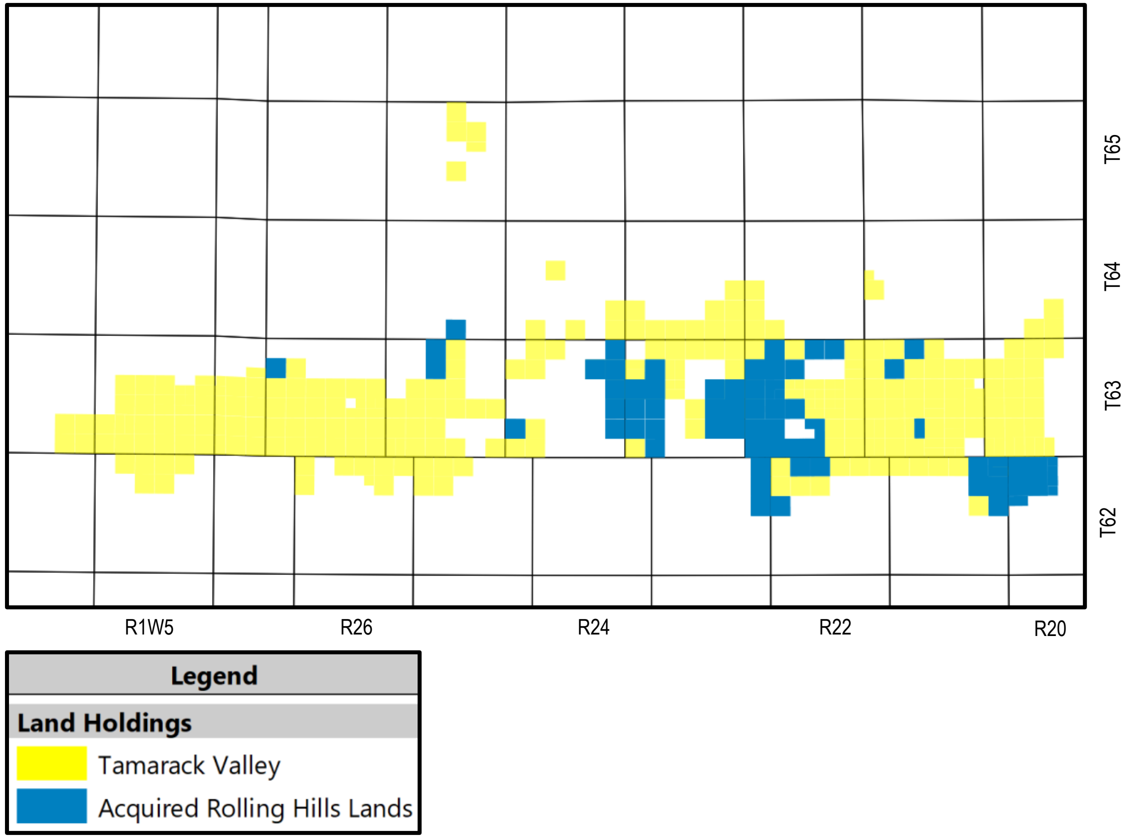
Southern Clearwater	
Acquisition Overview	***Purchase Price:*** $93 million ***Production:*** 2,100 boe/d[1] ***Operating Field Netback[2]:*** $61 million[3]
Asset Summary	***Drilling Locations[4]:*** 70 gross (54.0 net) ***Land Additions:*** 54.0 net sections ***Undiscounted ARO:*** $3.8 million
Strategic Addition	Consolidates existing Southern Clearwater portfolio Significant development and exploration potential
Accretive to Shareholders	Low annual sustaining capital of $15-20 million Adjusted and free funds flow[2] per share accretion
Enhances Sustainability	Increased debt adjusted FFF[2] supports return of capital Low ARO minimizes environmental liabilities



Corporate Information

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Executive

Brian Schmidt (Aakaikkitstaki)	President & Chief Executive Officer
Steve Buytels	VP Finance & Chief Financial Officer
Kevin Screen	Chief Operating Officer
Martin Malek	VP Engineering
Christine Ezinga	VP Corporate Planning & Business Development
Scott Shimek	VP Production & Operations

Board of Directors

John Rooney (1,3,4)	Chairman
Brian Schmidt (Aakaikkitstaki)	President & Chief Executive Officer
Jeff Boyce (1,2)	Independent Director
Ian Currie (2,4)	Independent Director
John Leach (1,2)	Independent Director
Marnie Smith (1,3)	Independent Director
Robert Spitzer (2,3)	Independent Director

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

Independent Reserve Evaluator

GLJ Petroleum Consultants

Auditors

KPMG LLP

Legal Counsel

Stikeman Elliott LLP

Banking Syndicate Lead

National Bank of Canada

Head Office

Jamieson Place

Suite 3300, 308 - 4th Ave S.W.

Calgary, AB T2P 0H7

Phone: 403.263.4440

www.tamarackvalley.ca

Investor Contact Information

Brian Schmidt	or	**Steve Buytels**
President & Chief Executive Officer		VP Finance & Chief Financial Officer

Notes

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1. Tamarack summary metrics before giving effect to the impact of the Rolling Hills Energy Ltd. acquisition
2. See Disclaimers – “Specified Financial Measures”
3. As disclosed in the Q1 2022 financial statements at March 31, 2022
4. Tax pools as at year-end 2021
5. Updated guidance including the Rolling Hill Acquisition with 2022 pricing assumptions of: WTI US$90/bbl, MSW/WTI differential of US$2.04/bbl, WCS/WTI differential of US$13.55/bbl, AECO at $4.70/GJ and exchange rate of 1.271
6. Comprised of 16,500-17,500 bbl/d light and medium oil, 14,000-15,000 bbl/d heavy oil, 3,750-4,000 bbl/d NGL and 69,000-71,000 mcf/d natural gas
7. G&A costs exclude the effect of one-time, non-recurring costs incurred in Q1 2022

Page 6

1. See Disclaimers – “Specified Financial Measures”; free funds flow and free funds breakeven were formerly referred to as free adjusted funds flow and free adjusted funds flow breakeven respectively

Page 7

1. See Disclaimers – “Specified Financial Measures”; free funds flow was formerly referred to as free adjusted funds flow

Page 9

1. See Disclaimers – “Specified Financial Measures”; FFF – Free Funds Flow; D/AFF – Net debt to annual adjusted funds flow; free funds flow was formerly referred to as free adjusted funds flow

Page 10

1. See Disclaimers – “Specified Financial Measures”; free funds flow was formerly referred to as free adjusted funds flow

Page 11

1. See Disclaimers – “Specified Financial Measures”; free funds flow was formerly referred to as free adjusted funds flow
2. Annual yield is calculated as (base dividend plus partial year special dividend where relevant) divided by current market capitalization

Page 12

1. See Disclaimers – “Specified Financial Measures”; FFF – Free Funds Flow; free funds flow was formerly referred to as free adjusted funds flow

Page 14

1. Asset details before giving effect to the Rolling Hills Energy acquisition
2. See “Oil and Gas Advisories”
3. See Disclaimers – “Specified Financial Measures”; free funds flow and free funds breakeven were formerly referred to as free adjusted funds flow and free adjusted funds flow breakeven respectively
4. See “Oil and Gas Advisories – Drilling Locations”

Notes

Page 15
1. See “Oil and Gas Advisories – Drilling Locations”

Page 17
1. Based on US$70/bbl WTI

Page 18
1. See “Oil and Gas Advisories – Drilling Locations”

Page 19
1. See “Oil and Gas Advisories”
2. See “Oil and Gas Advisories”

Page 22
1. See Disclaimers – “Specified Financial Measures”; AFF – Adjusted Funds Flow; free funds flow and free funds breakeven were formerly referred to as free adjusted funds flow and free adjusted funds flow breakeven respectively

Page 24
1. As at June 3, 2022
2. For Q3 through Q4 2022

Page 25
1. See Disclaimers – “Specified Financial Measures”; free funds flow was formerly referred to as free adjusted funds flow
2. Sustainability-linked notes (SLB) mature May 2027, with an annual coupon of 7.25% payable semi-annually in arrears
3. Comprised of 17,868 bbl/d light and medium oil, 7,522 bbl/d heavy oil, 4,113 bbl/d NGL and 70,989 mcf/d natural gas
4. Adjusted funds flow of $0.40/share basic equates to $0.39/share diluted

Page 26
1. See Disclaimers – “Specified Financial Measures”; FFF or free funds flow was formerly referred to as free adjusted funds flow
2. Comprised of 2,100 bbl/d heavy oil
3. See “Oil and Gas Advisories – Drilling Locations”

Page 27
1. Comprised of 2,100 bbl/d heavy oil
2. See Disclaimers – “Specified Financial Measures”; FFF or free funds flow was formerly referred to as free adjusted funds flow
3. 2022 pricing assumptions: WTI US$95.70/bbl, WCS/WTI differential of US$13.20/bbl and exchange rate of 1.26 US/CAD
4. See “Oil and Gas Advisories – Drilling Locations”