

Corporate Presentation
May 2026

Tourmaline Overview

- Largest natural gas producer in Canada
- 3rd largest Canadian gas processing midstream operator
- 6.1 Billion Boe 2P Reserves; 27.7 Tcf Gas, 1,480 MMbbls liquids
- Lowest capital cost operator in the basin
- First producer in Canada to achieve MiQ Certification “A”
- Peer-leading cash flow growth & free cash flow generation
- Investment Grade BBB (High) rated by DBRS
- Largest insider ownership amongst Sr E&P Peers

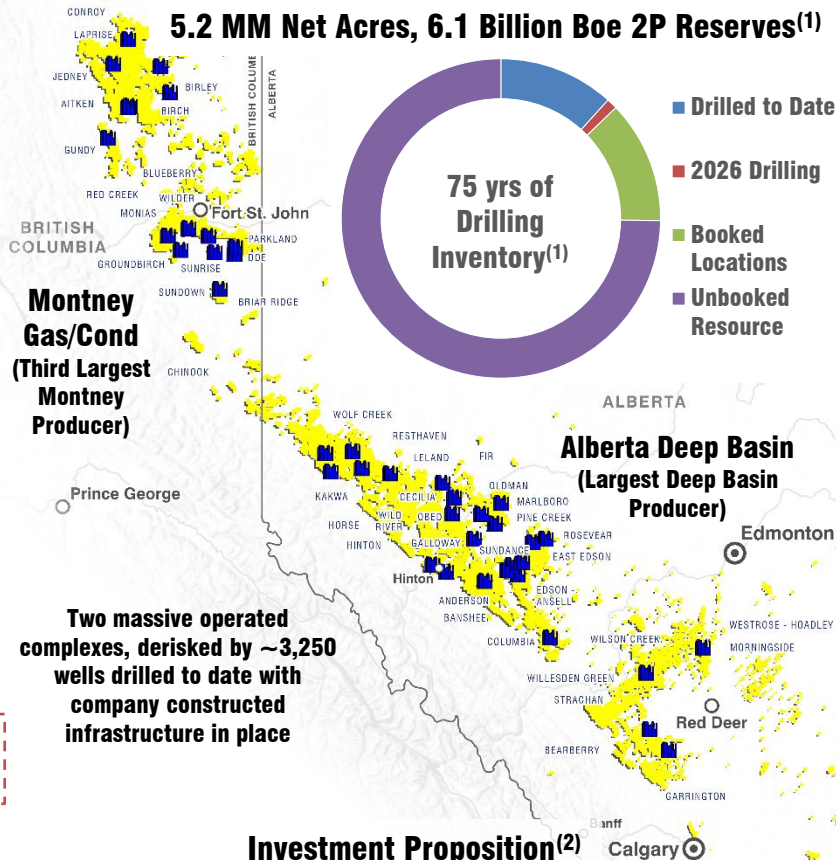
Tourmaline’s scale in Canada’s premium gas plays, production base and low cost infrastructure, provide investors a suite of advantages with efficiency, profitability, growth, and return on (and of) capital unparalleled by peers

Current Production Forecasts (boepd)

- 2Q26E: 595,000 – 605,000
- 2026E: 620,000 – 640,000 (630,000 EP Plan)

Financial Position⁽²⁾

Market Capitalization (Apr 27 th)	\$24.5B
Net Debt (1Q26) ⁽³⁾ / net of TPZ Equity Stake (Apr 15 th) ⁽²⁾	\$1.5B / \$0.8B
Enterprise Value	\$25.3B
2026E Cash Flow ⁽³⁾	\$3.6B
2026E Free Cash Flow ⁽³⁾⁽⁴⁾	\$0.9B



Investment Proposition⁽²⁾

Total Return CAGR (1/5/10/15yr)	6% / 30% / 13% / 9%
2026 FCF Yield + Organic Prod Growth (26/27)	11%
Dividend Yield	3%
EP Growth Plan Production Growth CAGR ('26-'31)	5%
YE 2025 2P PV10% ATax Reserve Value Per Share	\$76/Sh

⁽¹⁾ See schedule A in corporate presentation appx; inventory life at 300 wells/year pace of development (hz locations only), reserves and acreage and wells drilled as of December 31st 2025 and before impact of PRH Sale (Feb 2nd Close)

⁽²⁾ Free Cash Flow and dependent ratios and yields are based on current EP Growth Plan; all market data as per Apr 27th, 2026; EV presented net of TPZ equity value.

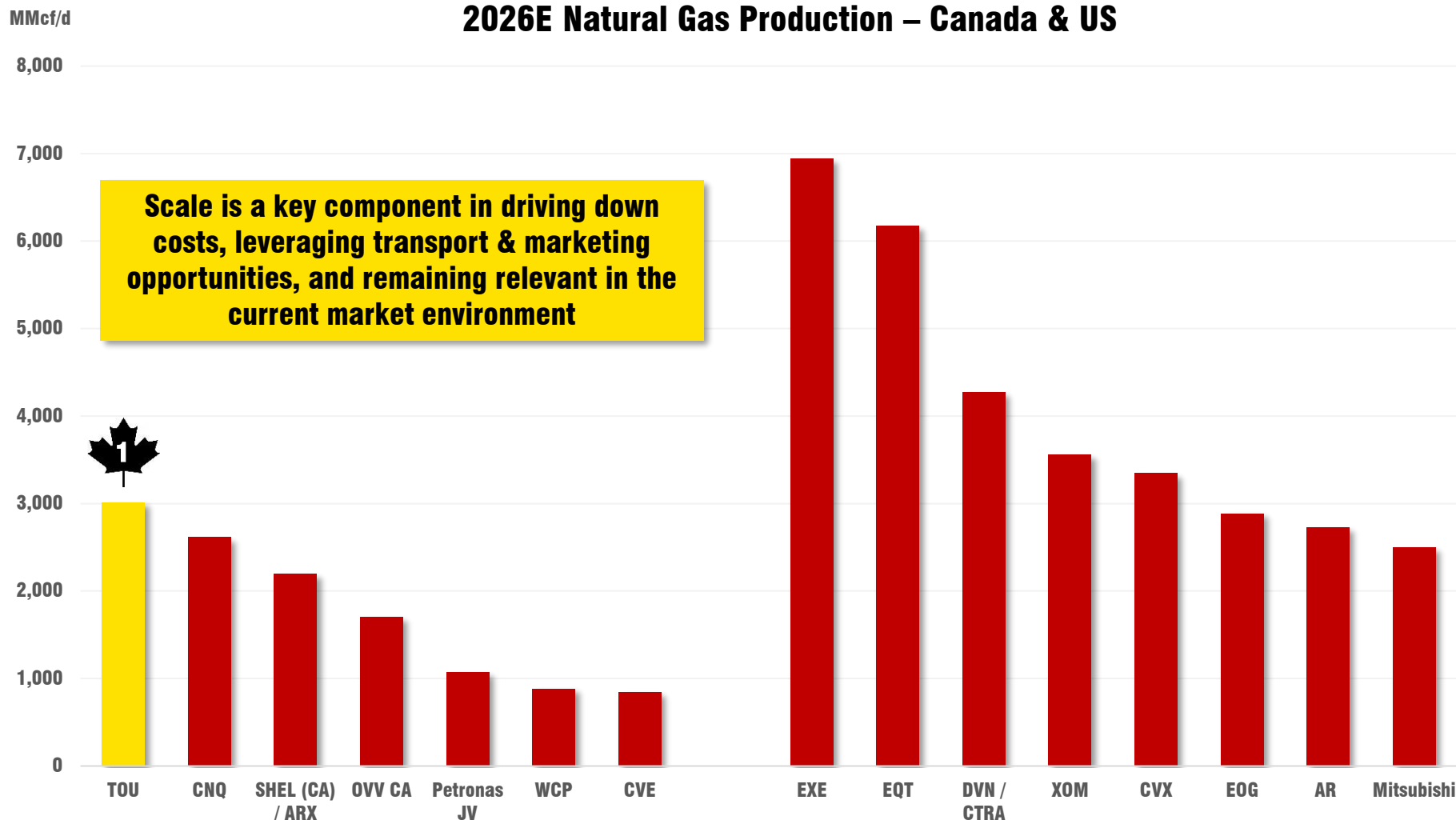
⁽³⁾ See “Non-GAAP and Other Financial Measures” in Forward Looking Statement Advisories of this presentation. ⁽⁴⁾ Free Cash Flow is defined as Cash Flow less Capital Expenditures⁽³⁾, excluding acquisitions and dispositions.

Largest North American Natural Gas Producers

May 2026

Tourmaline is the largest natural gas producer in Canada, and the sixth largest gas focused producer in North America

2026E Natural Gas Production – Canada & US



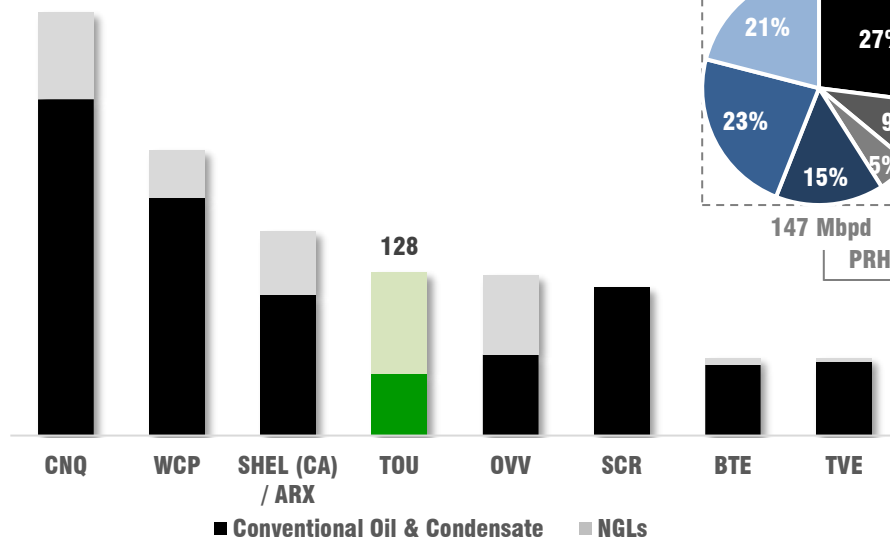
Tourmaline: A Significant Canadian Liquids Producer

May 2026

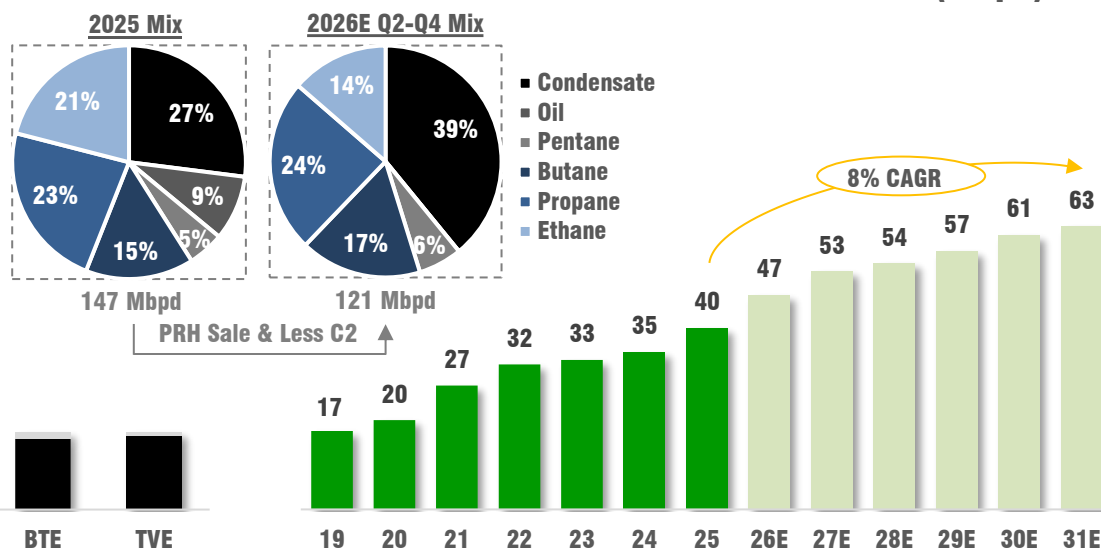
Tourmaline is a significant liquids producer in Canada, with continued peer leading growth

- **Tourmaline is a ~50 mbpd condensate producer, and the second largest producer of NGLs**
- **Tourmaline is planning strong liquids growth with the first phase of the North and South Montney development in the EP Growth plan, adding ~50 Mbpd of condensate and high value C3/4/5 liquids production since beginning development in 2024**
- **Starting in Q2-26, Tourmaline has elected to terminate certain discretionary deep cut deliveries in the Deep Basin. This reduces ethane production by ~20 mbpd but will improve '27+ operating netback by approximately \$110mm**

**Conventional Liquids (Mbpd)
Canadian Peer Producers**

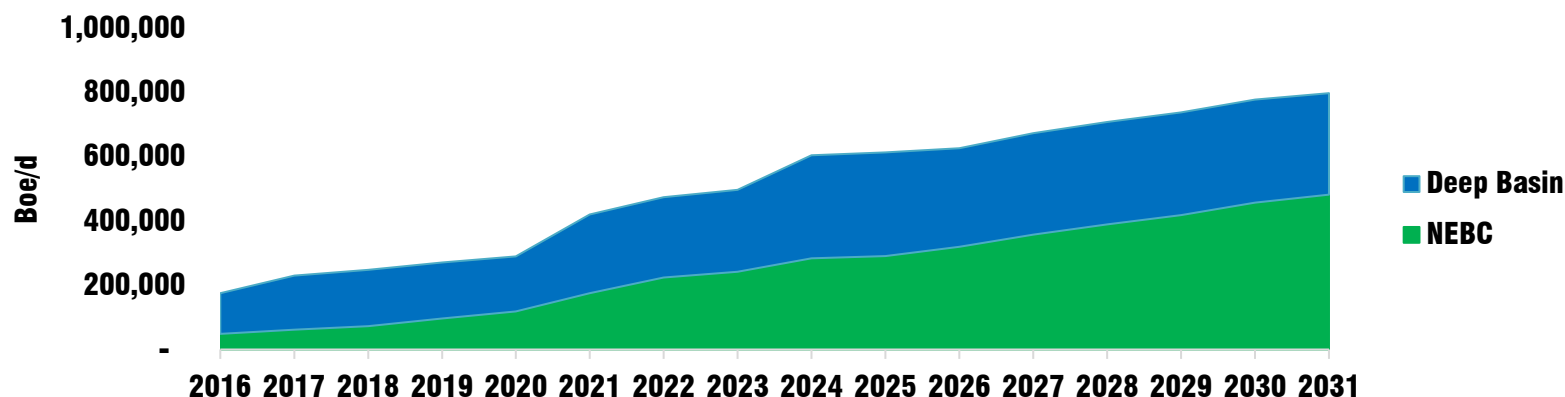


Tourmaline Condensate Growth (Mbpd)



EP Growth Plan⁽¹⁾

May 2026



	Prod'n BOEPD	After-tax Cash Flow \$MM ⁽²⁾⁽³⁾	After-tax CFPS – Diluted	E&P Capital Program ⁽⁴⁾ \$MM	Free Cash Flow ⁽⁵⁾ \$MM	Base Dividend \$MM	Ending Surplus (Net Debt) ⁽³⁾ \$MM
2026E (Strip)	630,000	\$3,595	\$9.22	\$2,550	\$945	(\$775)	(\$1,325)
2027E (Strip)	675,000	\$3,730	\$9.56	\$2,700	\$880	(\$775)	(\$1,220)
2028E (Flat)	710,000	\$5,020	\$12.87	\$2,690	\$2,175	(\$775)	\$175
2029E (Flat)	740,000	\$5,225	\$13.39	\$2,530	\$2,535	(\$775)	\$1,930
2030E (Flat)	780,000	\$5,440	\$13.95	\$2,615	\$2,665	(\$775)	\$3,820
2031E (Flat)	800,000	\$5,615	\$14.40	\$2,455	\$3,000	(\$775)	\$6,045

(1) EP Growth Plan derived by utilizing, among other assumptions, historical Tourmaline production performance and current cost assumptions, adjusted annually after 2026. 2027 and beyond provided for illustration only. Budgets and forecast beyond 2026 have not been finalized and are subject to a variety of factors including prior year's results. See Forward Looking Information.

(2) Price assumptions: Apr 27th, 2026 Strip Pricing for 2026 and 2027 and a flat price deck for 2028 onwards: Gas price - \$3.63/mmbtu 2026 NYMEX US, \$3.55/mmbtu 2027 NYMEX US, \$4.00/mmbtu 2028 to 2031 NYMEX US, \$1.68/mcf 2026 AECO, \$2.33/mcf 2027 AECO, \$4.08/mcf 2028 to 2031 AECO, \$2.32/mcf 2026 PG&E Citygate US, \$3.36/mcf 2027 PG&E Citygate US, \$5.50/mcf 2028 to 2031 PG&E Citygate US, \$15.71/mcf 2026 JKM US, \$13.30/mcf 2027 JKM US, \$12.00/mcf 2028 to 2031 JKM US. Oil price - \$81.83/bbl 2026 WTI US, \$72.91/bbl 2027 WTI US, \$65.00/bbl 2028 to 2031 WTI US. Foreign Exchange – 0.73 2026 USD/CAD, .74 2027 – 2031 USD/CAD

(3) See “Non-GAAP and Other Financial Measures” in Forward Looking Statement Advisories.

(4) E&P Capital Program is defined as Capital Expenditures⁽³⁾, excluding acquisitions, dispositions, exploration capital and other corporate expenditures.

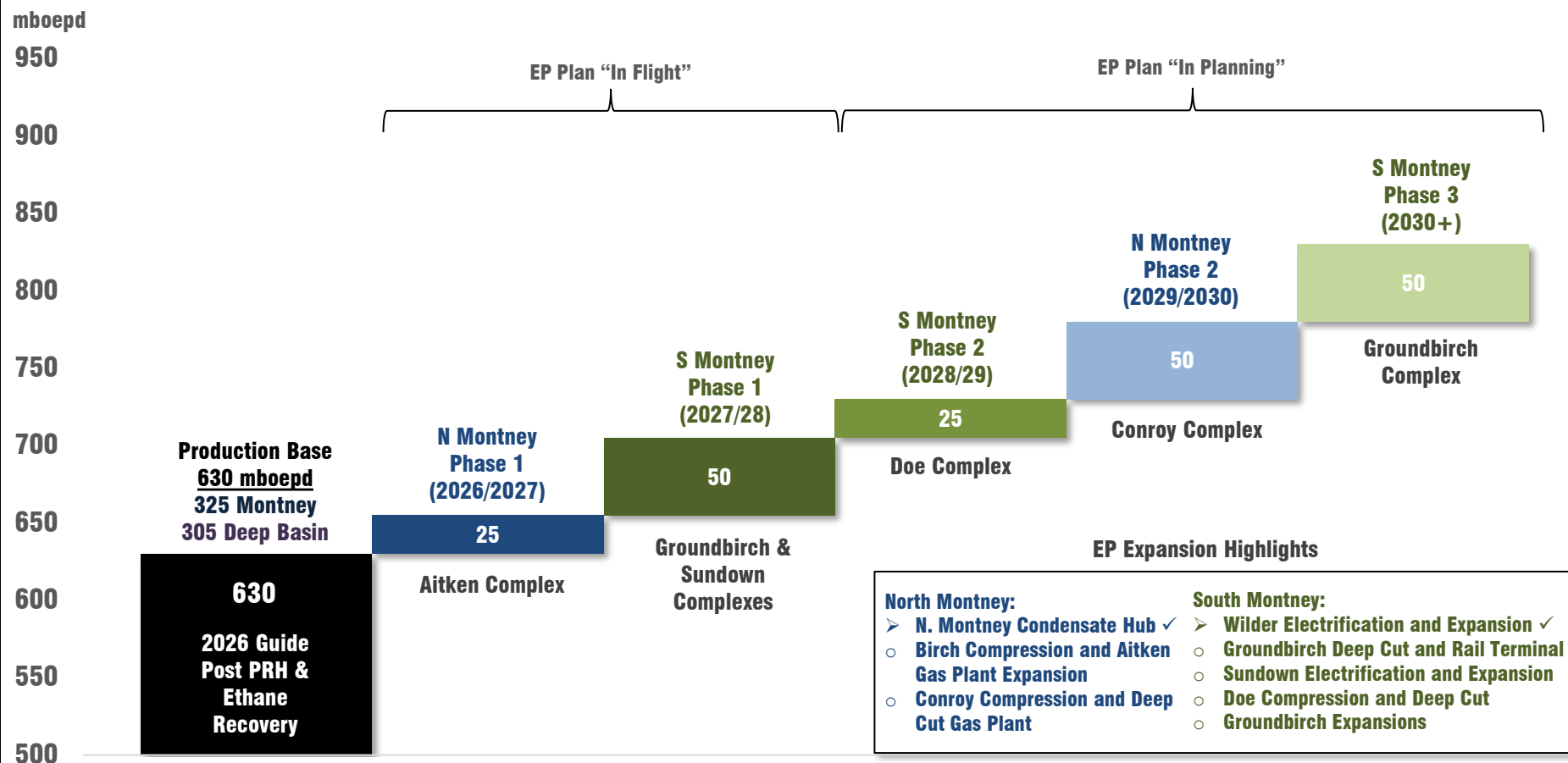
(5) Free Cash Flow is defined as Cash Flow less Capital Expenditures⁽³⁾, excluding acquisitions and dispositions. Free Cash Flow is prior to dividend payments made by Tourmaline.

Tourmaline EP Project Summary

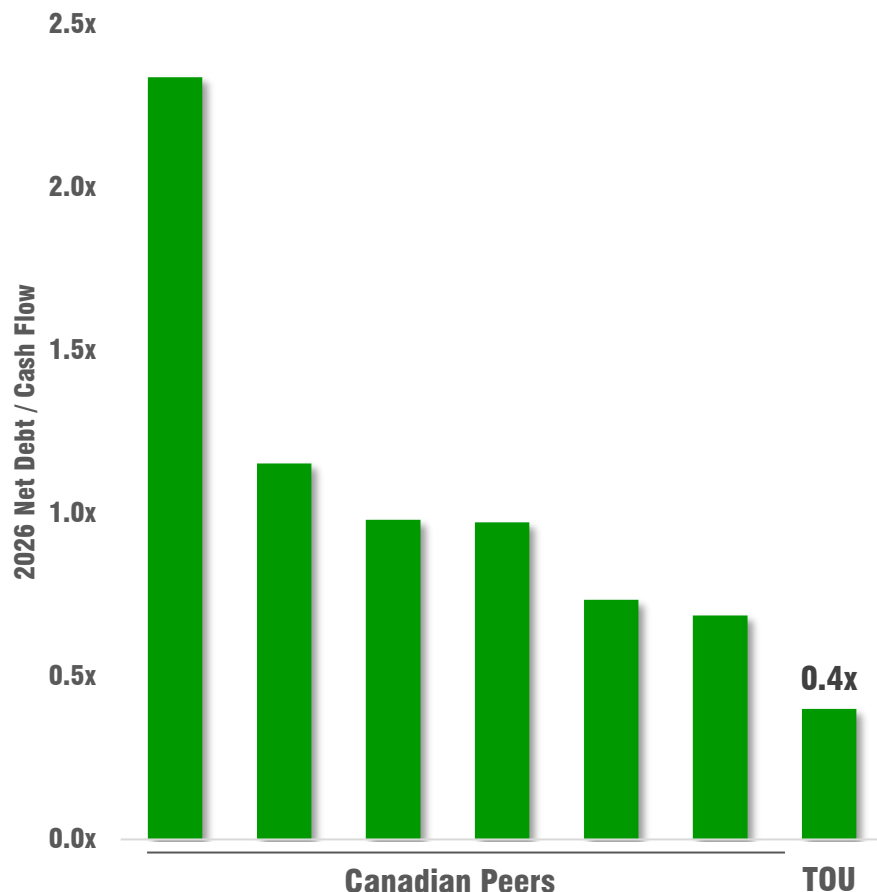
Mar 2026

Tourmaline's NEBC build out will consist of thoughtfully timed expansions of 5 major processing complexes, providing >200 mboepd of high margin volume growth into the next decade

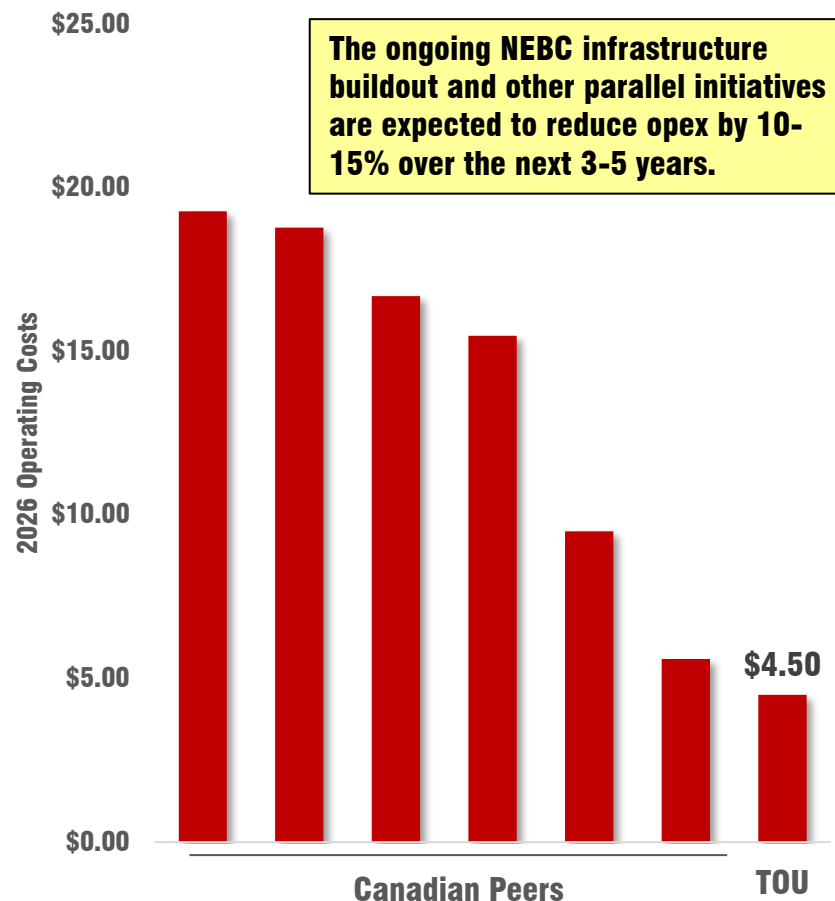
Production Outlook



Large Canadian Producer
2026 Net Debt / Cash Flow



Large Canadian Producers
2026 E&P Opex



NEBC Montney Gas/Condensate Complex

Mar 2026

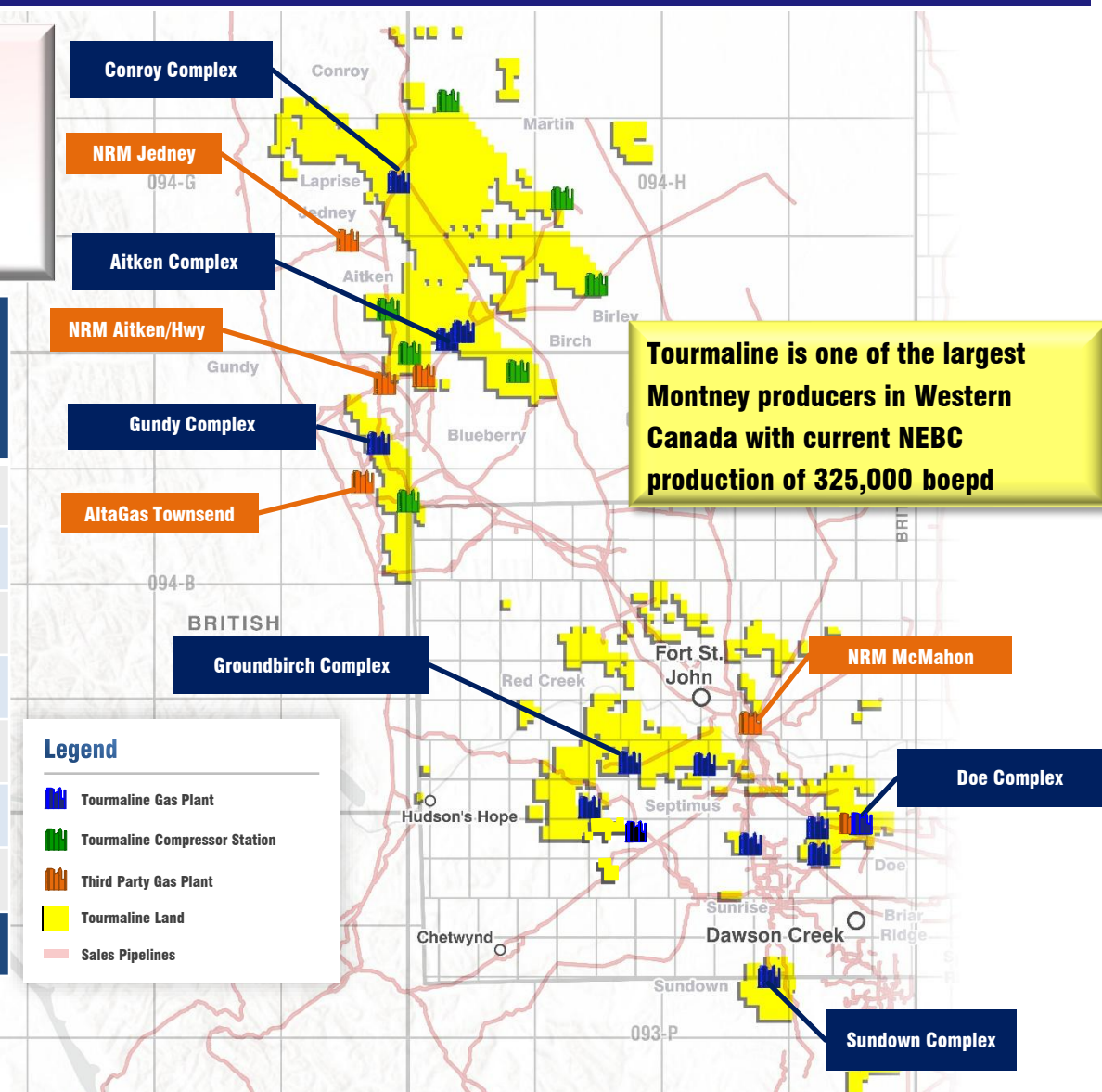
Current Prod. 325,000 boepd

Current Reserves 3,866 mmboe (Dec 31, 2025)

Montney Drilling Inventory 8,814 horizontal locations (Dec 31, 2025)

Processing Complex Name	Current Capacity (mmcf/d)	Planned Capacity (mmcf/d)
Gundy	400	400
Aitken	325	450
Groundbirch	280	Up to 700
Doe*	250	400
Sundown	140	250
Conroy	0	Up to 300
3 rd Party	350	~350
Total	1.7 Bcfpd	~2.9 Bcfpd

*Includes West Doe



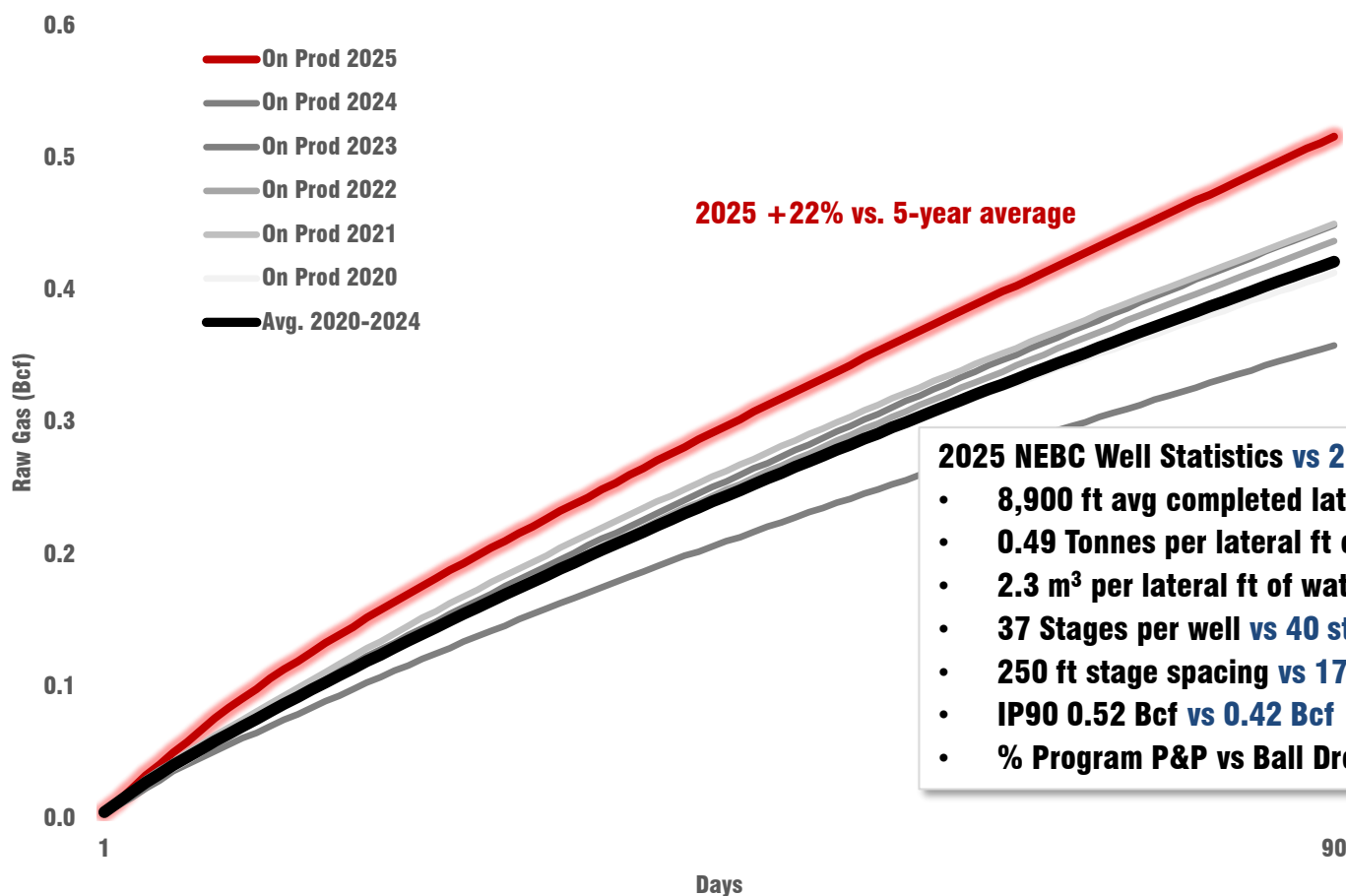
NEBC Gas Complex Well Performance

Mar 2026

Through longer laterals, improved completions, and accessing new prolific resource areas, the NEBC Montney posted 'vintage best' type curve performance in 2025

NEBC Well Performance

Wellhead IP90 Bcf



2025 NEBC Well Statistics vs 2020-2024

- 8,900 ft avg completed lateral length vs 6,600 ft
- 0.49 Tonnes per lateral ft of proppant vs 0.38 t/ft
- 2.3 m³ per lateral ft of water volume vs 2.0 m³/ft
- 37 Stages per well vs 40 stages
- 250 ft stage spacing vs 170 ft
- IP90 0.52 Bcf vs 0.42 Bcf
- % Program P&P vs Ball Drop: 77% vs 14%

Alberta Deep Basin

Mar 2026

The contiguous Tourmaline interconnected Deep Basin Cretaceous gas asset is effectively Alberta's Largest Gas Field

- **Current Production** 330,000 boepd
- **Current Reserves** 1,950 mmboe (as at Dec 31, 2025)
- **Tourmaline Land Base** 3.2 million acres
- **Drilling Inventory** 15,223 hz locations

The Company has drilled 1,500 wells to date with a future drilling inventory of 15,223 hz locations

Doe Creek *

Cardium *

Dunvegan *

Viking *

Notikewin *

Falher *

Wilrich *

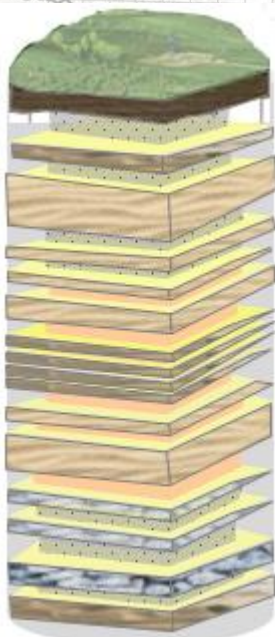
Bluesky/

Glauconitic

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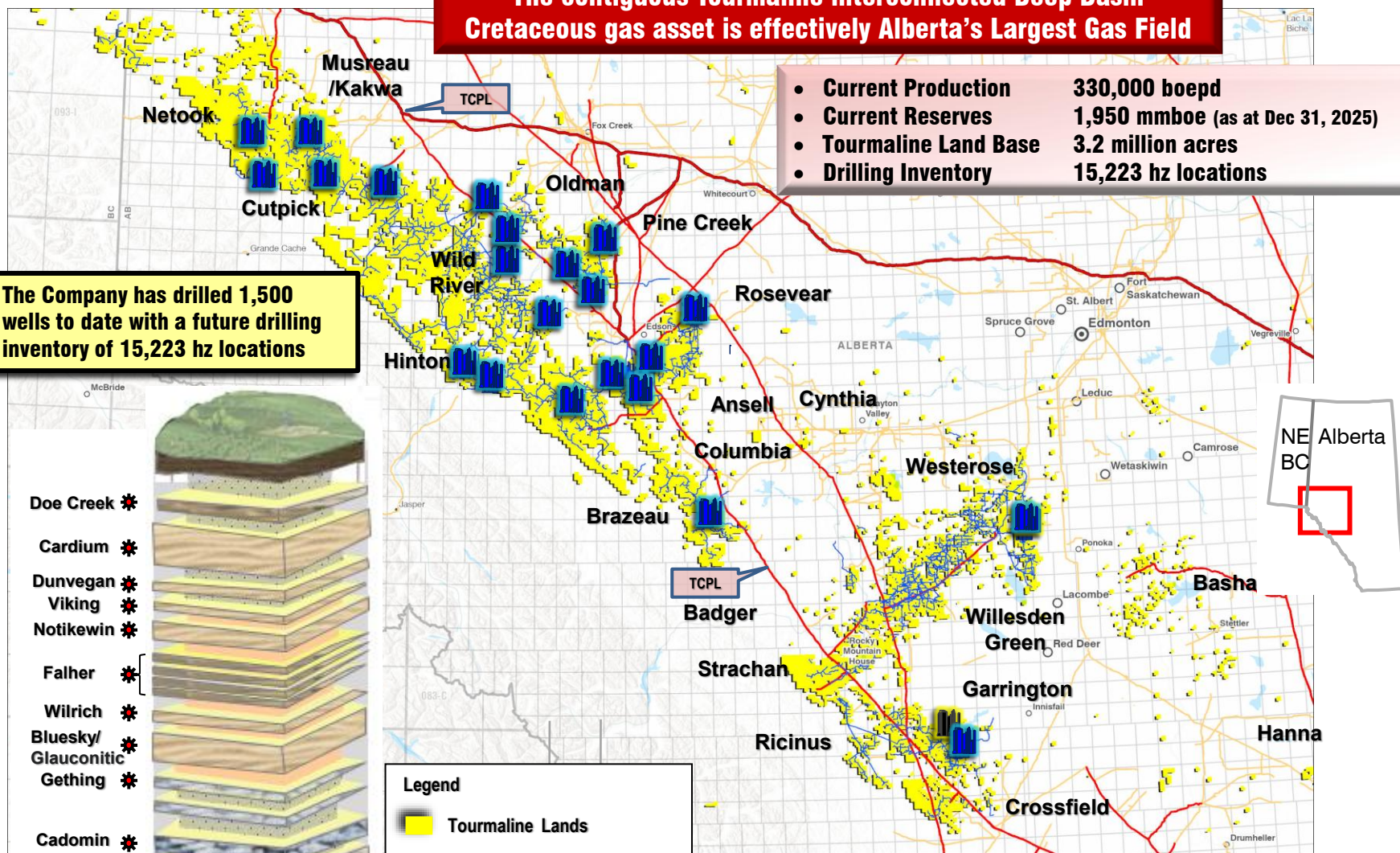
Cadomin *

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Legend

-  Tourmaline Lands
-  Tourmaline Gas Plant



Aitken Basal Montney

- D-F66-I / 094-B-16
- IP. 180 - 6.32 mmcf/d & 72 bbl/d cond/C5+
- EUR - 9.3 bcf & 74 mbbls cond/C5+
- 70 Incremental locations
- Follow up locations in 2026

Exploration program success has created significant incremental value in existing core complexes, the majority of the discoveries can access Tourmaline infrastructure. 24 new zones discovered, with 178 successful new zone or follow up wells drilled since inception. 2,550 bcfe booked in YE 2025 reserve report, since starting the program. 1,356 incremental locations added to inventory to date.

Doe Seq 2 Montney Program

- H16-24-080-16W6 (late 2024 drill)
- IP. 180 - 3.4 mmcf/d & 310 bbl/d cond/C5+
- EUR - 6.2 bcf & 409 mbbls cond/C5+
- 65 Incremental locations in Doe
- Follow up locations in 2026

Wild River WLRC A 2025 follow up

- 14-21-055-22W5 Pad (2 wells)
- Ave IP. 30 - 8.14 mmcf/d from 2 wells

Wilson Creek Belly River

- 03-24-042-06W5
- IP. 180 - 427 bbl/d cond/C5+ & 1.2 mmcf/d
- EUR - 380 mbbls cond/C5+ & 1.5 bcf
- 33 Incremental locations
- Follow up locations in 2026

2025 Resthaven Cardium 2025 follow up

- 01-36-060-04W6
- IP. 30- 406.3 bbls/d cond/C5+/Oil
- IP. 30- 2.4 mmcf/d gas IP
- 85 Incremental locations

2025 Strachan Notikewin Test

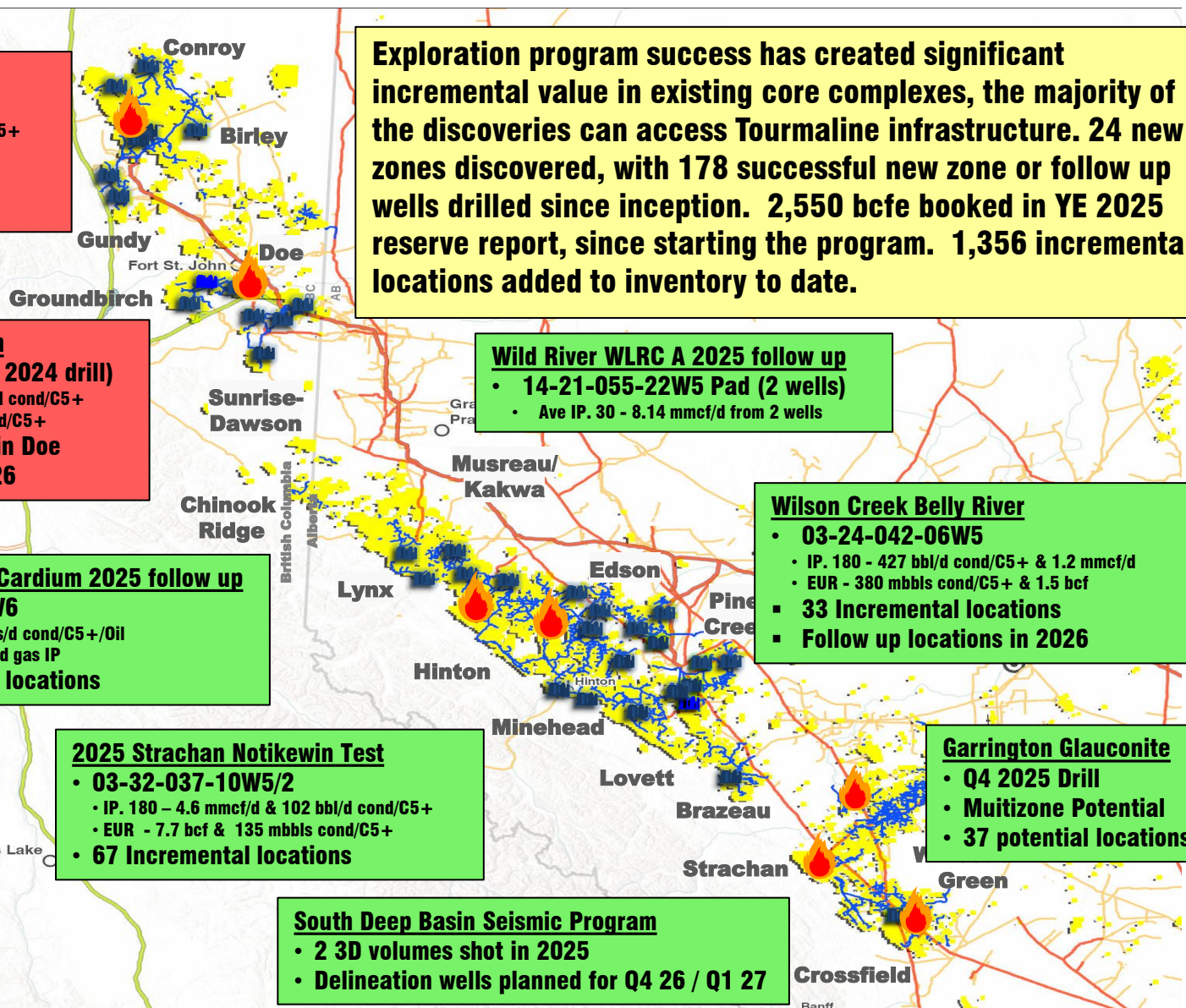
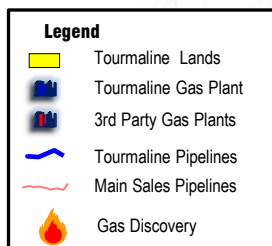
- 03-32-037-10W5/2
- IP. 180 - 4.6 mmcf/d & 102 bbl/d cond/C5+
- EUR - 7.7 bcf & 135 mbbls cond/C5+
- 67 Incremental locations

Garrington Glauconite

- Q4 2025 Drill
- Multizone Potential
- 37 potential locations

South Deep Basin Seismic Program

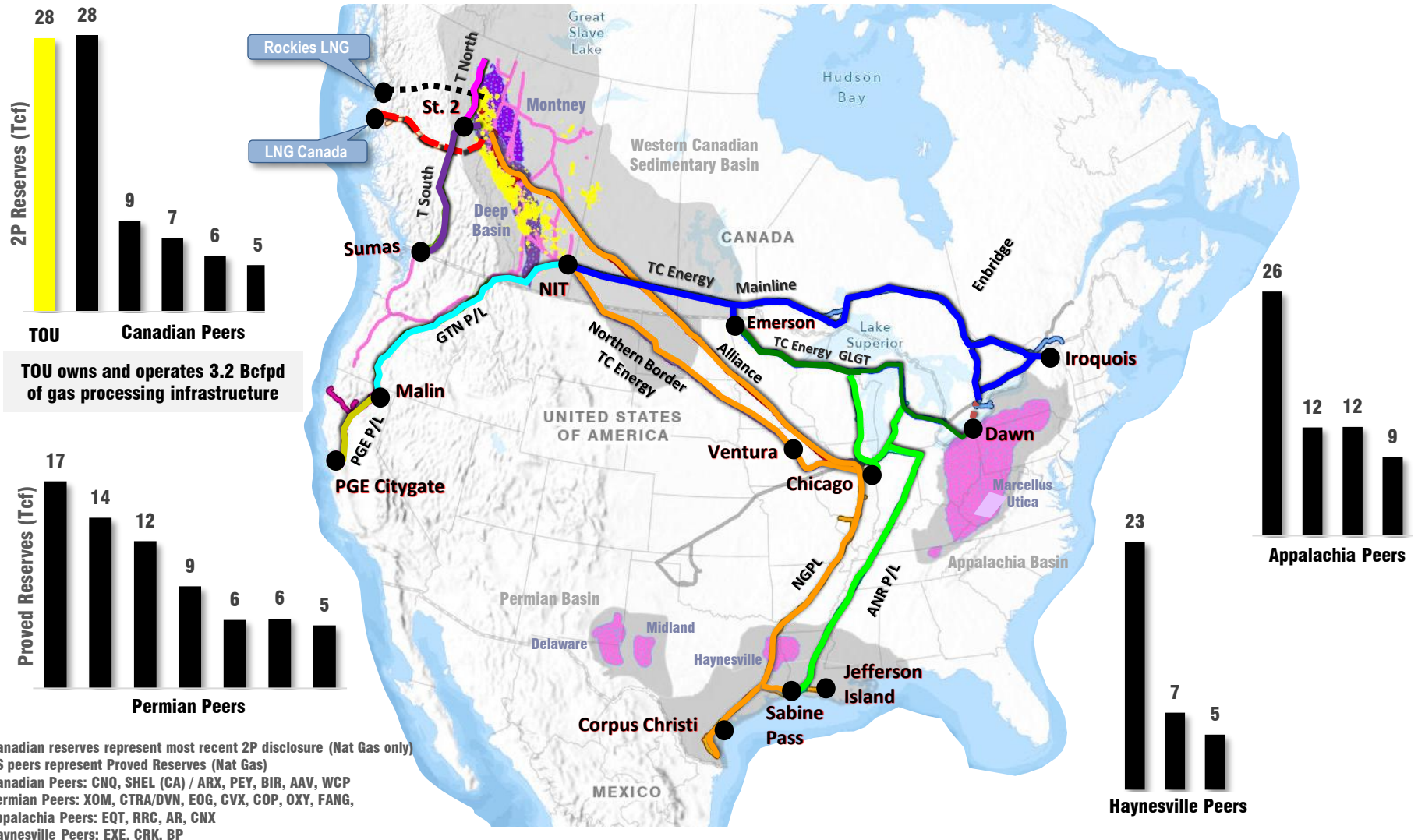
- 2 3D volumes shot in 2025
- Delineation wells planned for Q4 26 / Q1 27



North American Natural Gas Reserves

May 2026

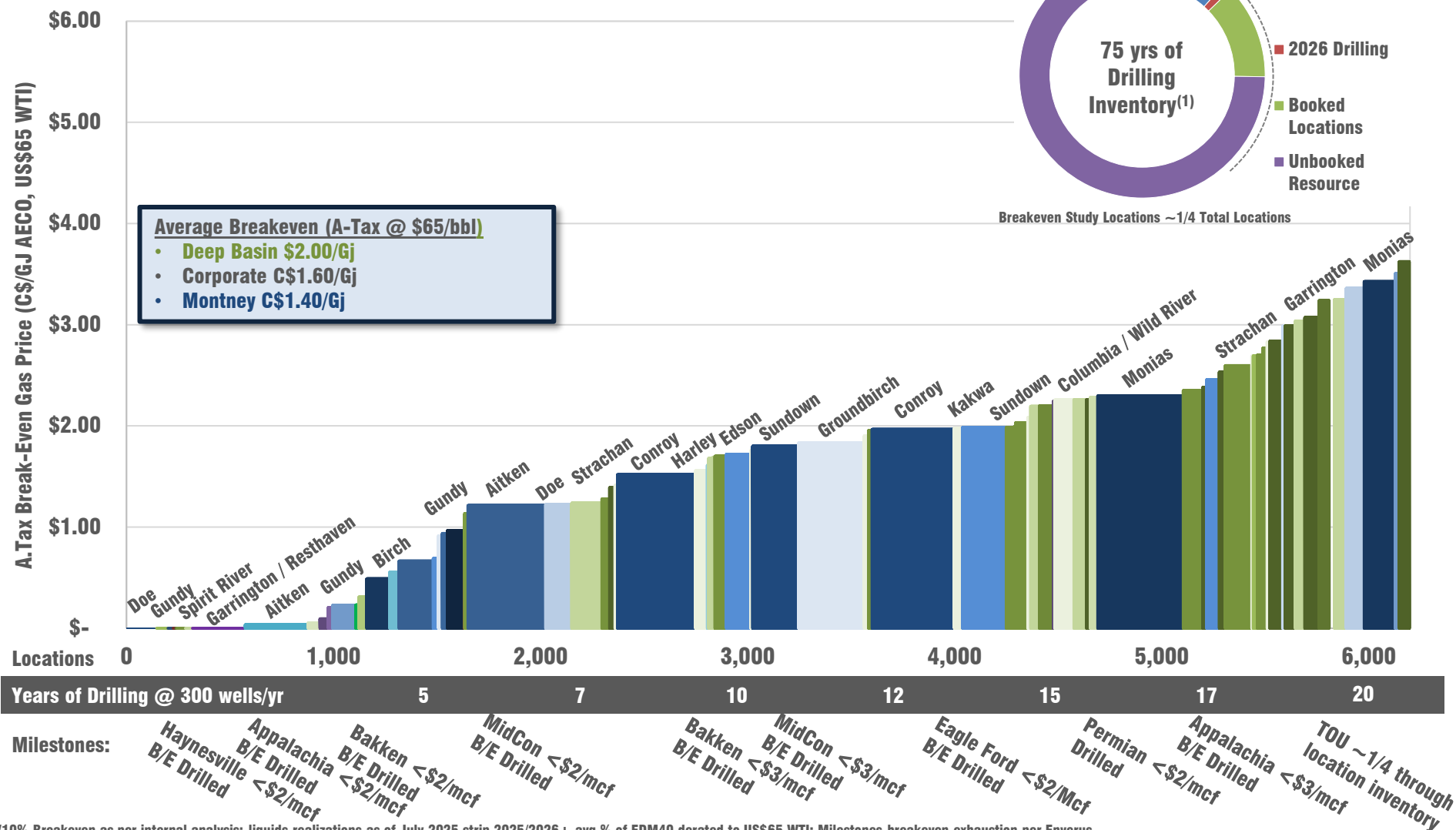
Companies that own the largest, lowest development cost, transport-integrated natural gas reserves, will increasingly dominate the Energy space in the next 20 – 30 years



Multiple Decades of Tier 1 Inventory

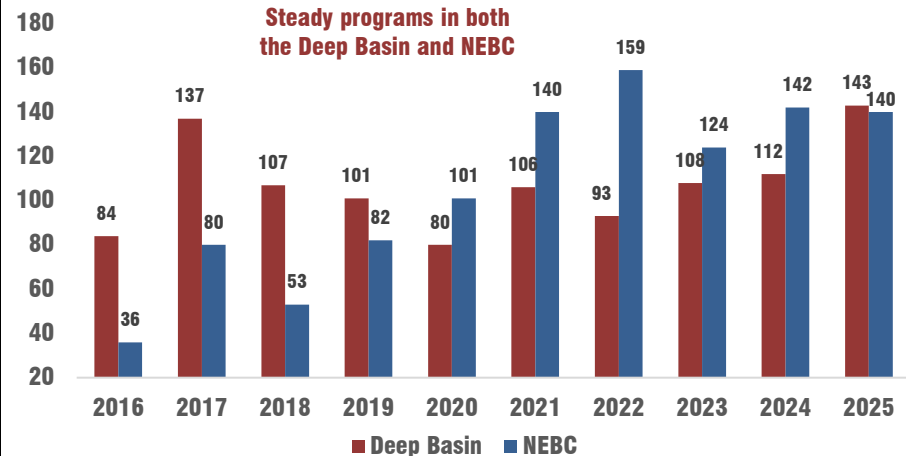
Mar 2026

Tourmaline's deep inventory ownership provides multiple decades of very profitable development, plus no need to pursue large "resource reloads" in A&D market



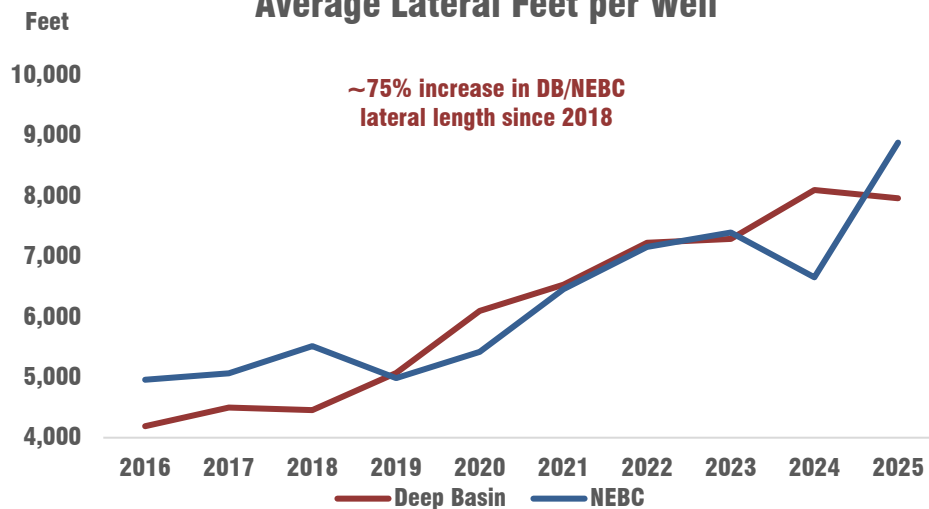
Wells Placed on Production

Steady programs in both
the Deep Basin and NEBC



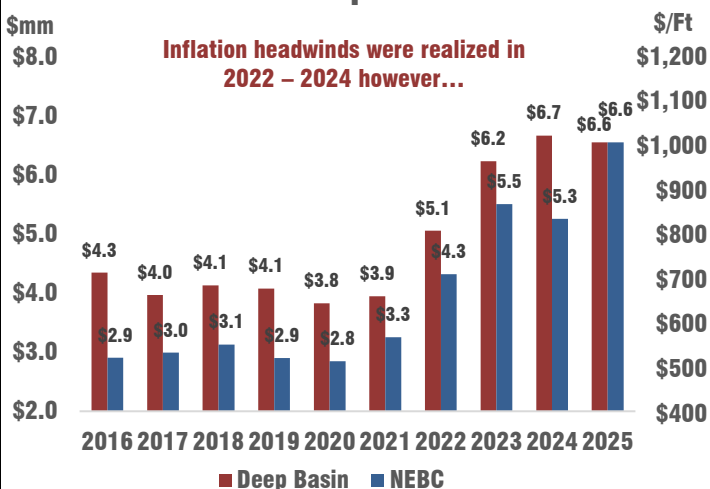
Average Lateral Feet per Well

~75% increase in DB/NEBC
lateral length since 2018



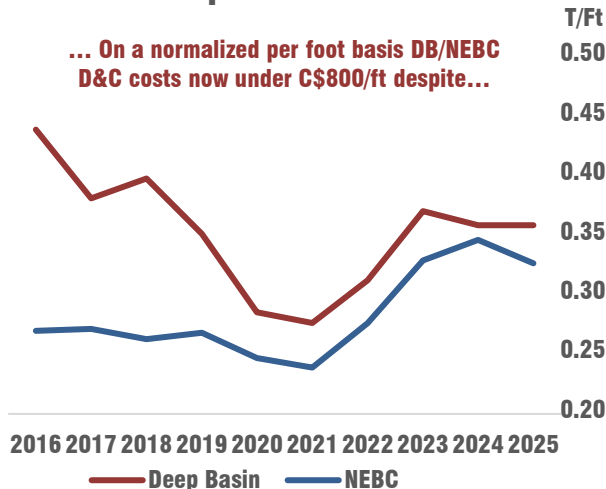
D&C Costs per Well

Inflation headwinds were realized in
2022 – 2024 however...



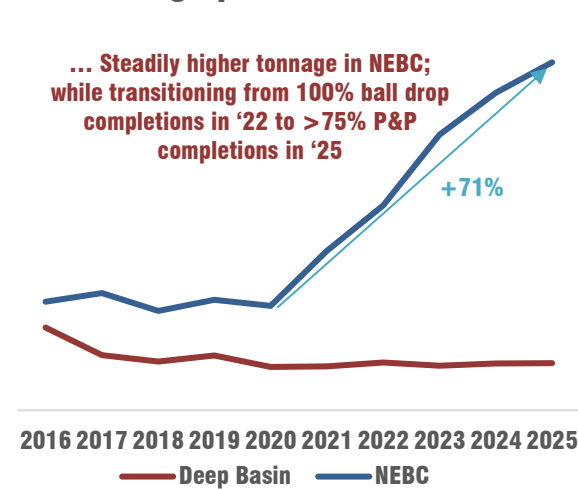
D&C Cost per Lateral Foot

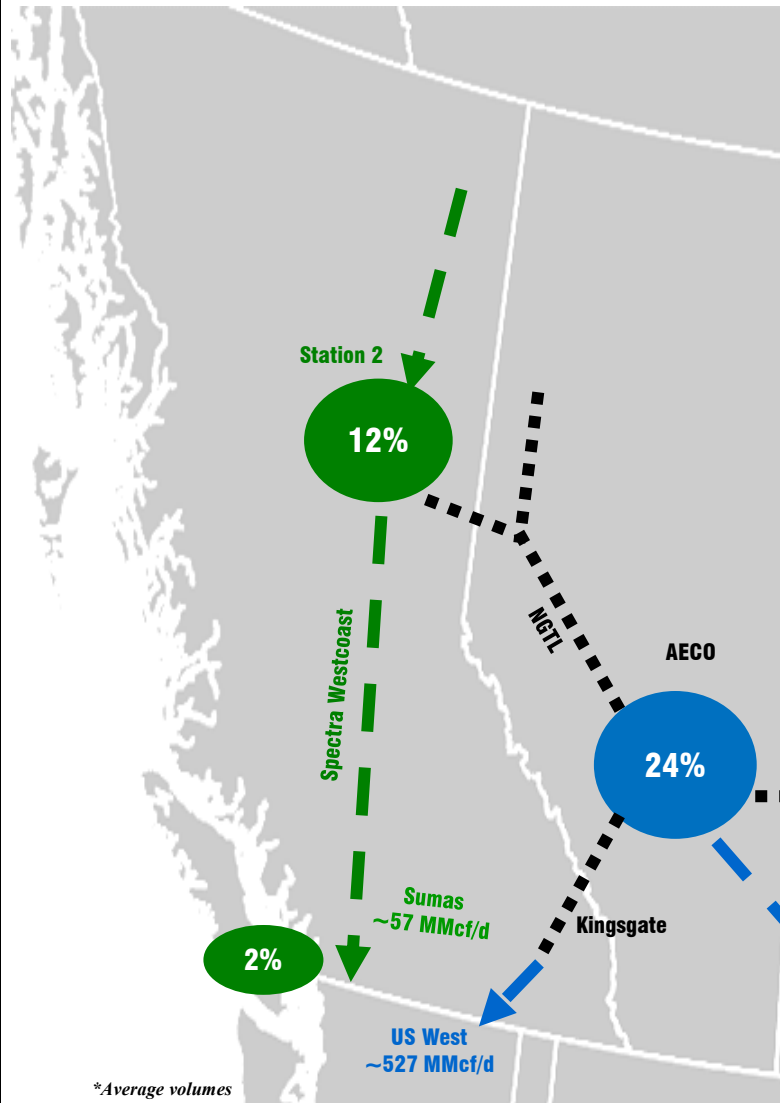
... On a normalized per foot basis DB/NEBC
D&C costs now under C\$800/ft despite...



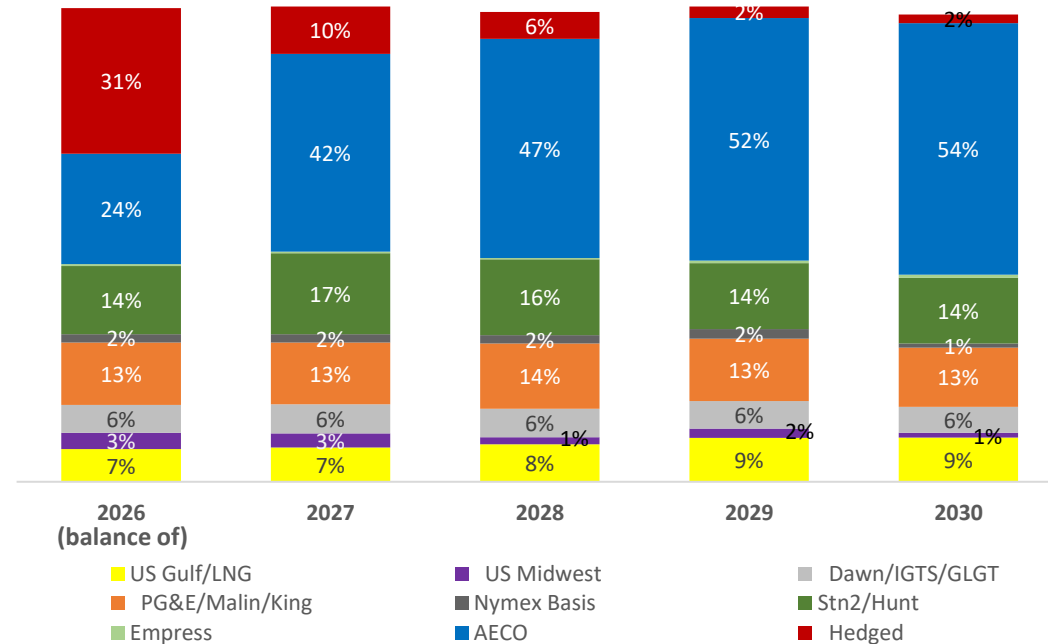
Tonnage per Lateral Foot

... Steadily higher tonnage in NEBC;
while transitioning from 100% ball drop
completions in '22 to >75% P&P
completions in '25





Natural Gas Price Exposure



- 2026 Exit: 1.28 Bcf/d of gas will flow to US/Other Markets
- 2026 Exit: 220,000 MMBtu/d of JKM/TTF exposure
- 2027 Exit: 252,500 MMBtu/d of JKM/TTF exposure
- 2028-2030 Exit: 332,500 MMBtu/d of JKM/TTF exposure

Tourmaline LNG Overview

Nov 2025

Tourmaline continues to grow its international pricing exposure



Rockies LNG - Partner

- A partnership of Western Canadian natural gas producers working together to supply Ksi Lisims LNG
- Ksi Lisims has received a British Columbia Environmental Assessment Certificate and a positive Decision Statement from the Government of Canada
- SPA's executed with Shell and Total

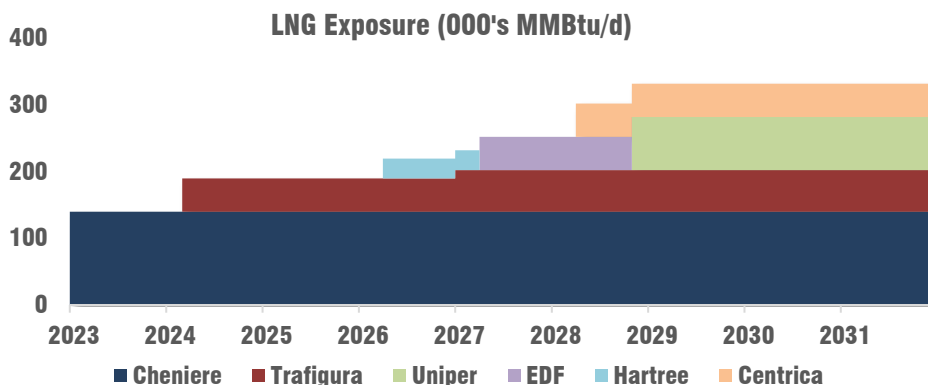
NeeStaNaN Utility Corridor (Hudson Bay LNG) - Supporter

- Access to Northern Ports and interprovincial and international trade
- Ownership consortium of Indigenous groups
- Tourmaline is an initial industry supporter of NeeStaNaN and is helping to fund feasibility studies for the project

LNG Agreements

- **Cheniere:** 140 MMcfpd with JKM Exposure, 15-year term starting Jan 2023
- **Trafigura:** 50 MMcfpd TTF Exposure (NIT delivery), from Mar 2024-Dec 2026
- **Hartree:** 30 MMcfpd TTF Exposure, 1-year term starting Apr 2026
- **EDF:** 50 MMcfpd TTF Exposure, 19-month term starting Apr 2027
- **Trafigura:** 62.5 MMcfpd JKM Exposure, 7-year term starting Jan 2027*
- **Uniper:** 80 MMcfpd TTF Exposure, 8-year term starting Nov 2028
- **Centrica:** 50 MMcfpd TTF Exposure (NIT delivery), 10-year term starting Apr 2028

*Potential extension to 2039



Guidance

May 2026

	<u>2026</u>⁽¹⁾
Production – Boe/d	620,000 – 640,000
Cash Flow⁽ⁱ⁾ - \$MM	\$3,595 (at 630,000 boepd)
CFPS - Diluted⁽ⁱ⁾	\$9.22 (at 630,000 boepd)
E&P Capital Program⁽ⁱⁱⁱ⁾ - \$MM	\$2,550
Capital Expenditures⁽ⁱ⁾ - \$MM	\$2,650
Free Cash Flow⁽ⁱⁱⁱ⁾ - \$MM	\$945 (at 630,000 boepd)

(1) Price Assumptions: Apr 27th, 2026 Strip Pricing: Gas price - \$3.63/mmbtu 2026 NYMEX US, \$1.68/mcf 2026 AECO, \$2.32/mmbtu 2026 PG&E Citygate US, \$15.71/mcf 2026 JKM US; Oil price - \$81.83/bbl 2026 WTI US; Foreign Exchange – 0.73 2026 USD/CAD.

(i) See “Non-GAAP Measures and Other Financial Measures” in the Forward Looking Statement Advisories section of this presentation.

(ii) E&P Capital Program is defined as Capital Expenditures⁽ⁱ⁾, excluding acquisitions, dispositions, exploration capital and other corporate expenditures.

(iii) Free Cash Flow is defined as Cash Flow less Capital Expenditures⁽ⁱ⁾, excluding acquisitions and dispositions. Free Cash Flow is prior to dividend payments made by Tourmaline.

Tourmaline 2027 After Tax Cash Flow Sensitivity & Allocation

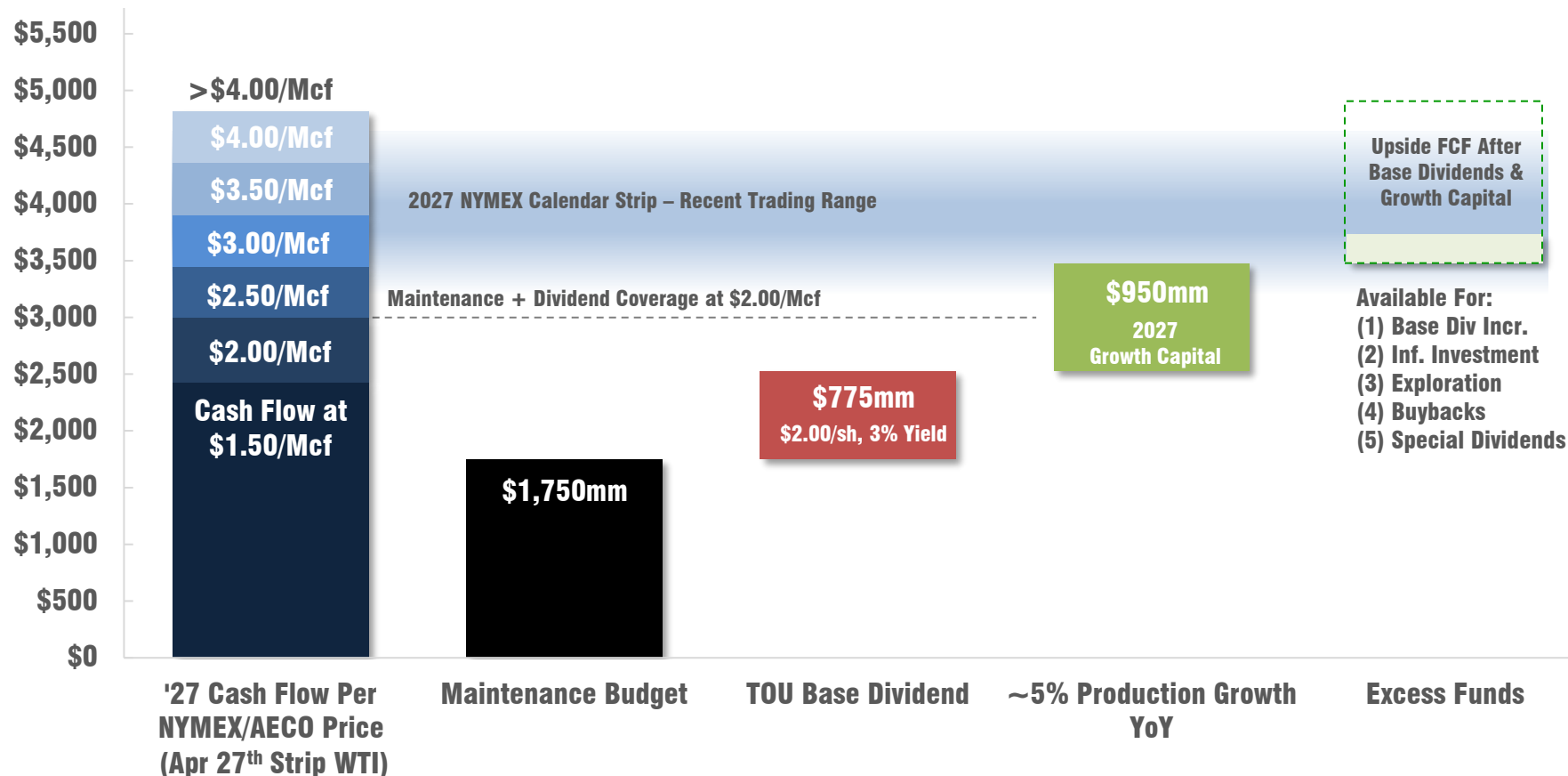
May 2026

Tourmaline's low cost structure drives sustainable return on, and of, capital opportunities

- TOU's maintenance budget, and dividend is fully funded at US\$2.00/mcf NYMEX & C\$2.00/Mcf AEEO on April strip liquids
- TOU will manage growth capital in the EP program to balance base dividend funding and long term growth
- FCF in excess of the base dividend will be allocated to margin enhancing infrastructure investments, exploration, special dividends in times of sustained strong commodity prices or defensive buybacks in times of market turmoil

(C\$m)

2027 AT Cash Flow NYMEX/AECO Sensitivity & Allocation



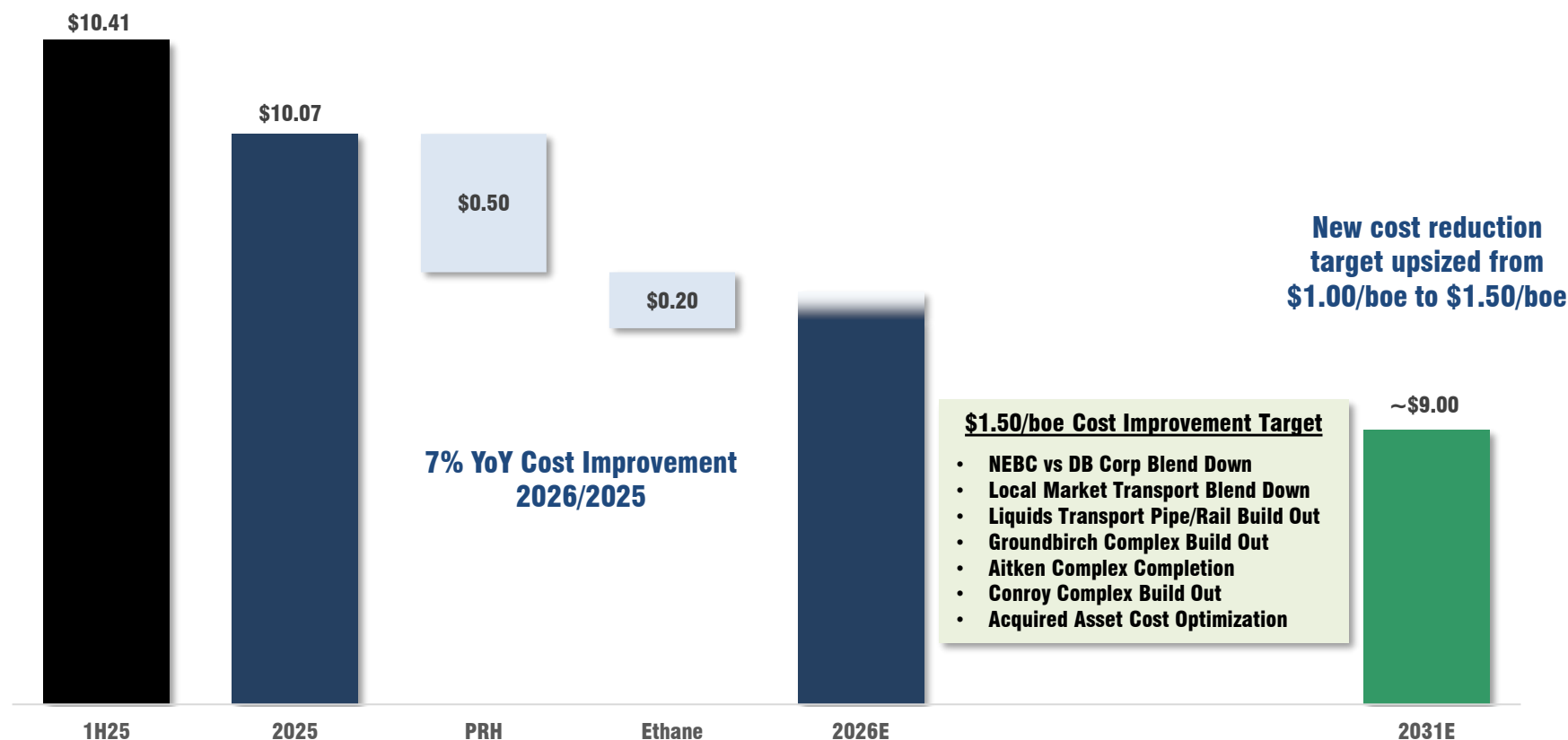
For sensitivity capital and basis assumptions and definition of free cash flow please see EP Growth Plan slide; C\$ AEEO assumed to match US\$ NYMEX at each sensitivity level, all other basis as of April 27th Strip

Growing Corporate Margins Through NEBC Development

Mar 2026

With 2026 cost reduction initiatives allowing for 7% YoY cost improvement (\$0.70/boe), Tourmaline has raised its cost reduction target from \$1.00/boe to \$1.50/boe with additional opportunities to upsize through the NEBC Montney buildout

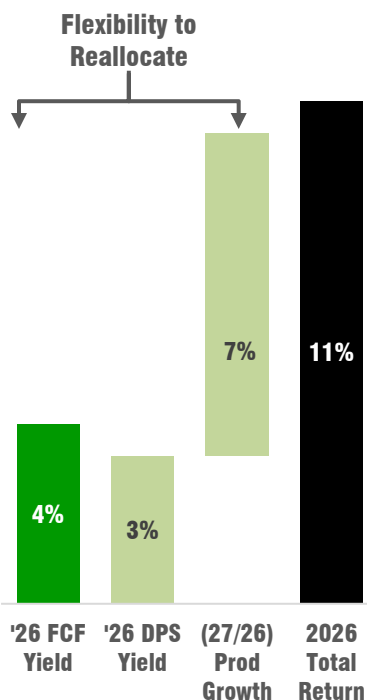
Opex & Transport Cost Structure Outlook (\$/boe)



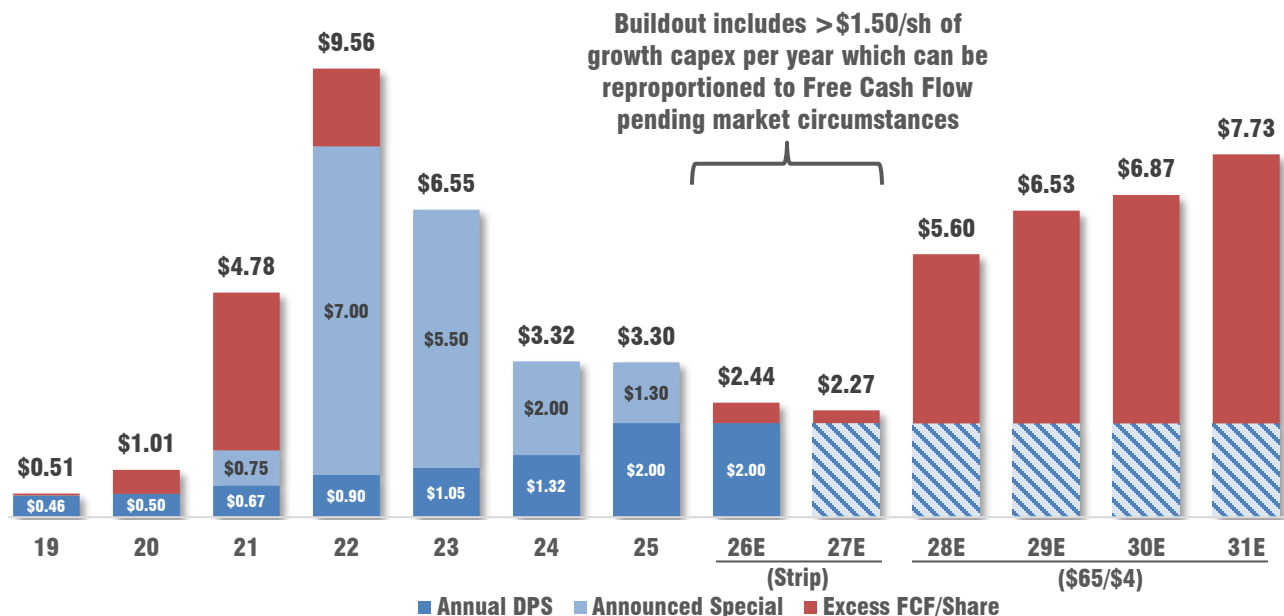
The majority of Tourmaline's free cash flow will be returned to shareholders; a growing base dividend will be the preferred method of shareholder returns

- Base dividend will continue to grow alongside the base EP business with FCF coverage even in \$2/mcf gas prices
- Special dividend can offer additional cash return to shareholders during sustained strong commodity prices
- Alongside dividends, free cash flow will be allocated towards: (1) maintaining a pristine balance sheet, (2) high return infrastructure investment opportunities, (3) modest exploration, (4) defensive share buybacks
- Tourmaline plans to continue to provide a total return of >10% through income and growth through the EP plan

2026 Total Return

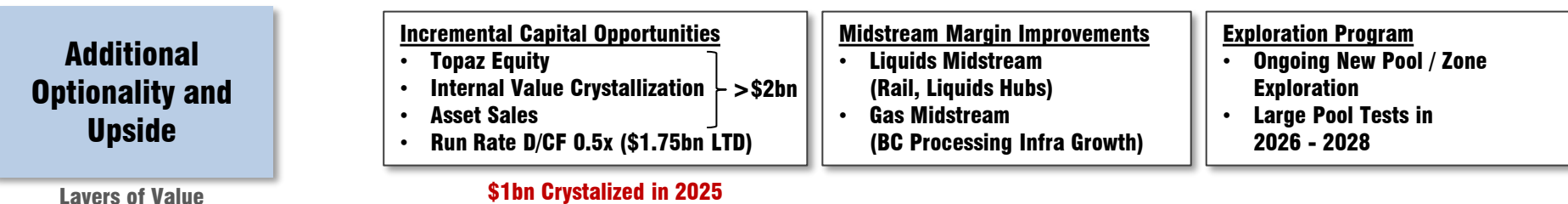
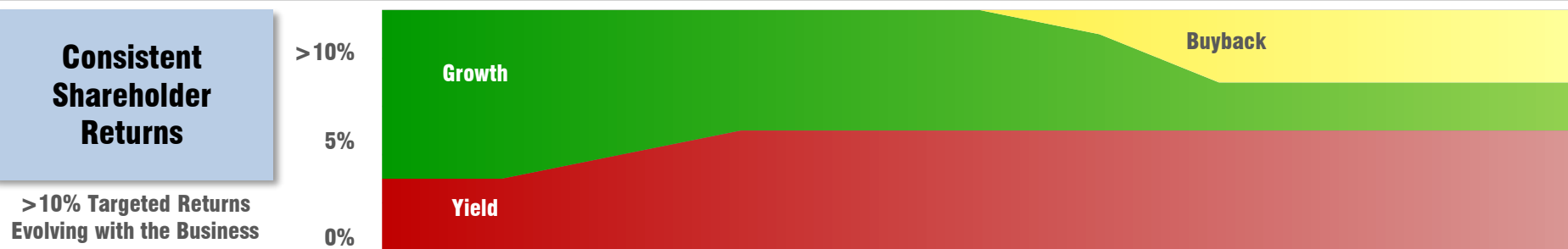
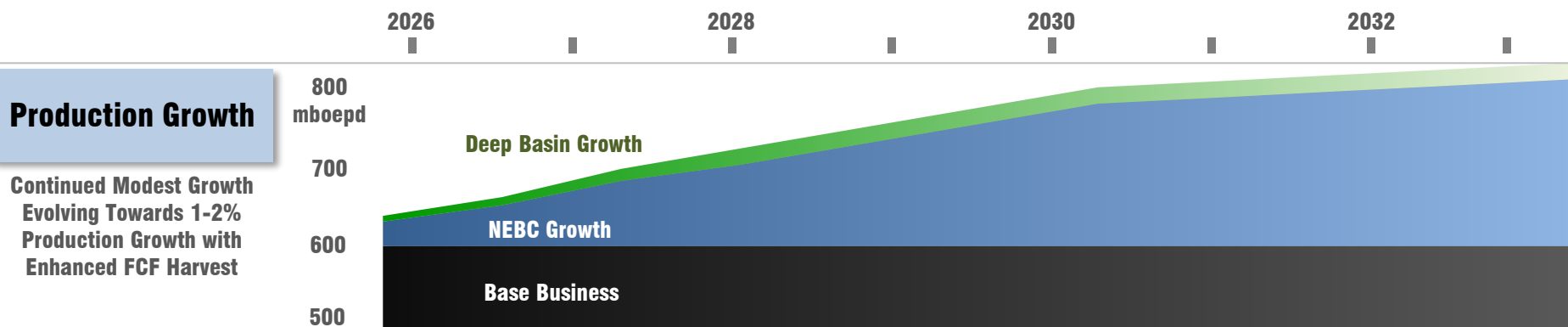


Free Cash Flow & Dividends per Share



Tourmaline Long Term Business Plan Growth & Leading Shareholder Returns

Mar 2026



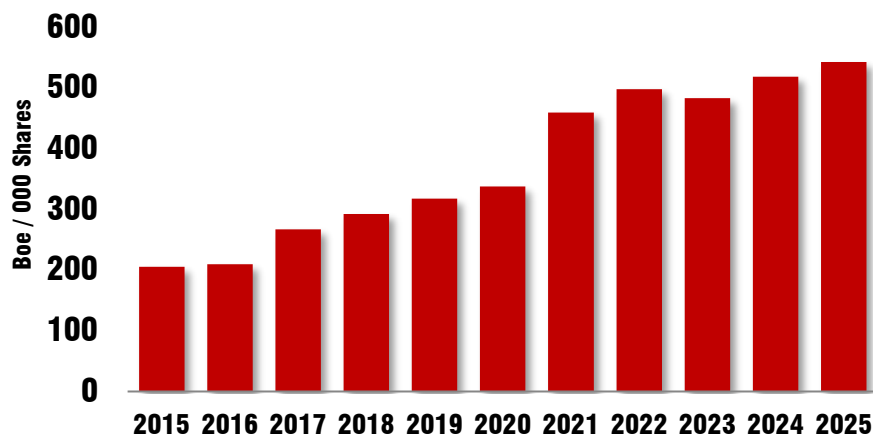
APPENDIX



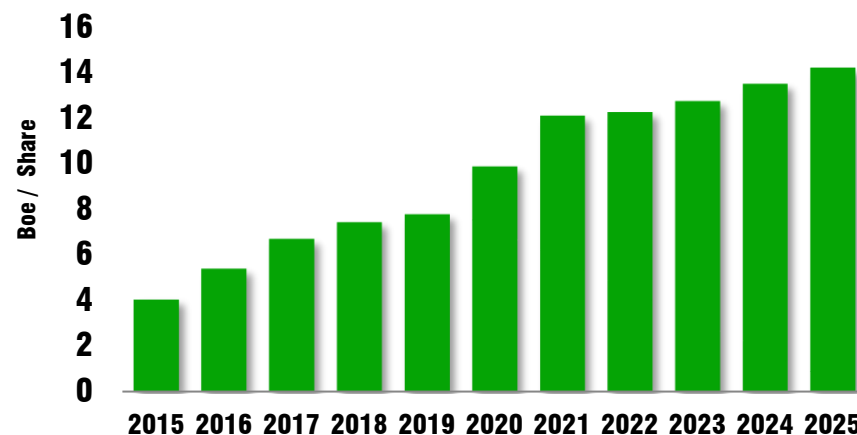
Historical EP Performance

Mar 2026

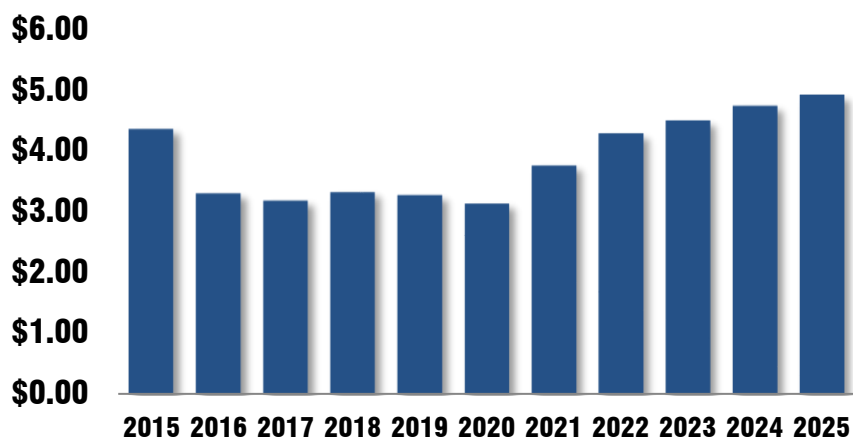
Production Per Share*



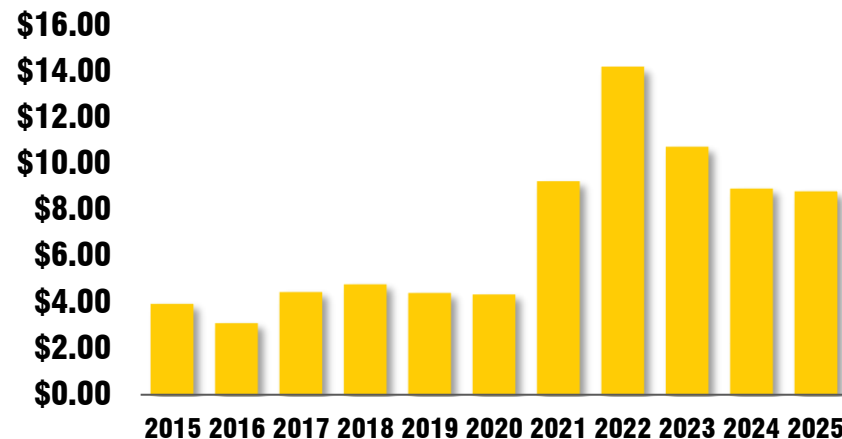
Reserves Per Share*



Operating Costs / BOE



Cash Flow Per Share

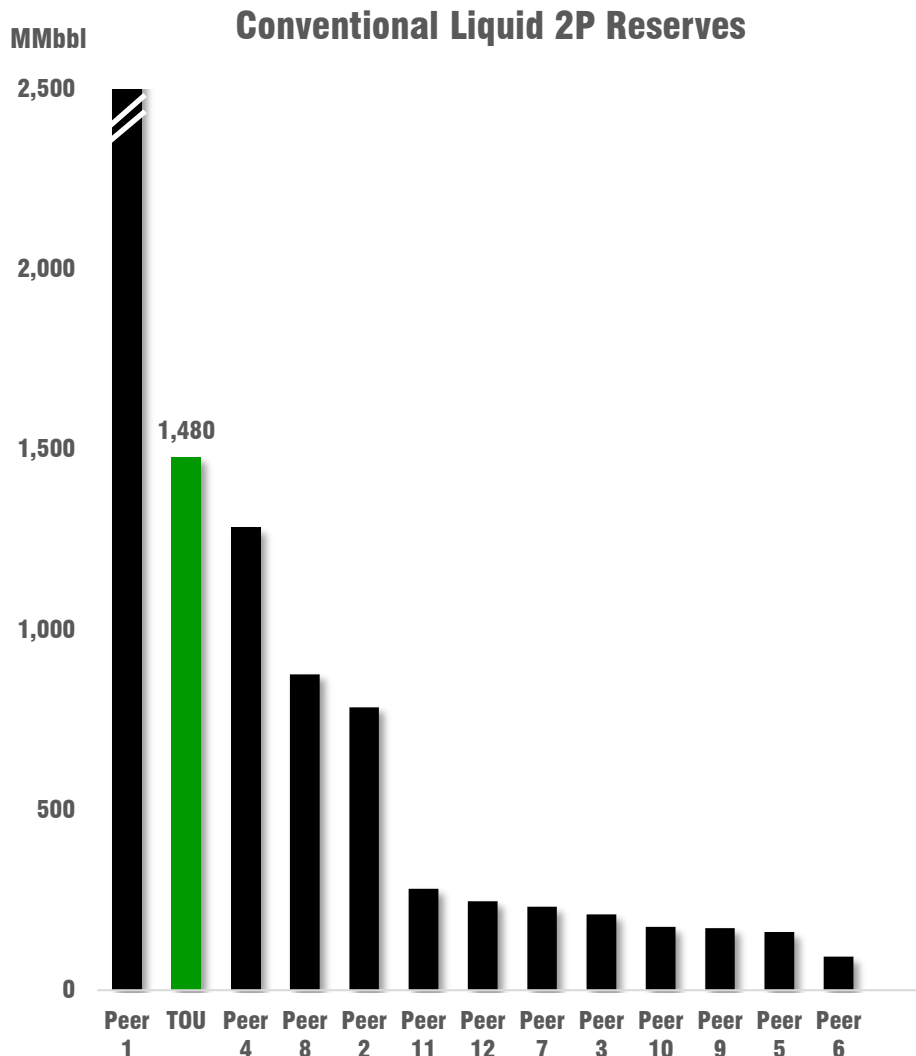
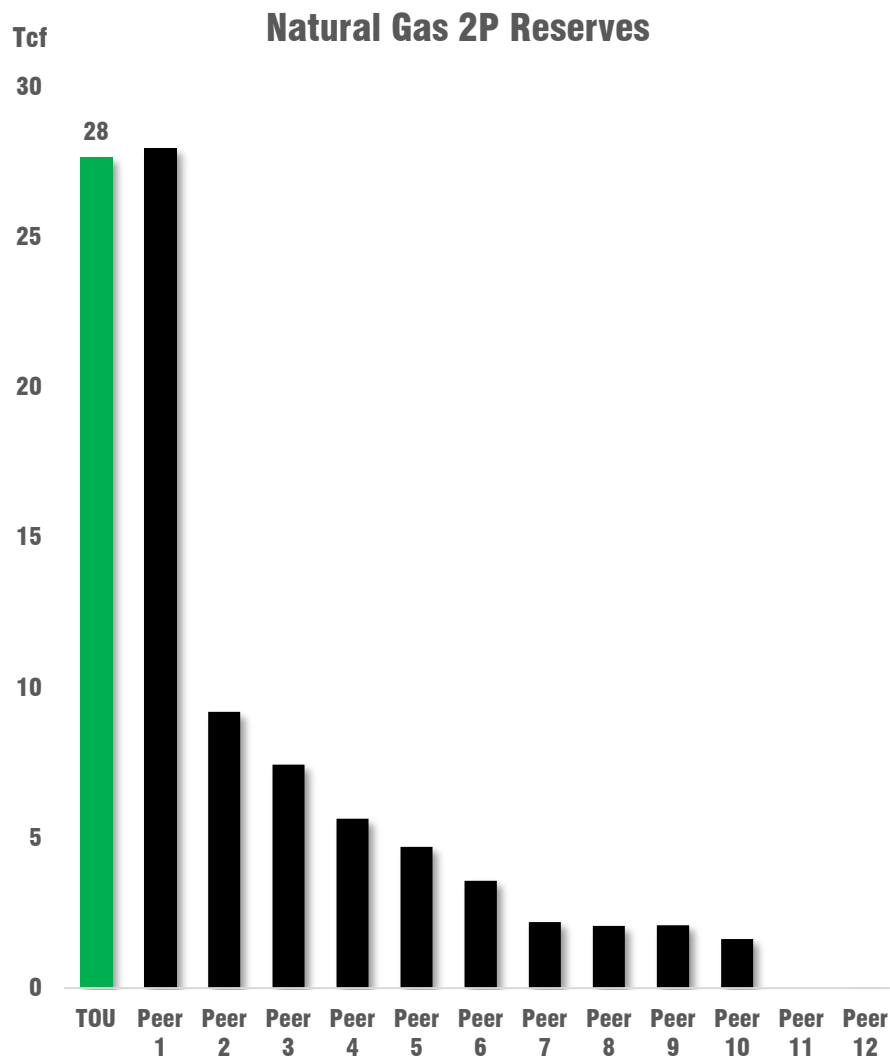


- 2015-2025 Production growth per share CAGR of 10%
- 2P BTax NPV 10% Reserve Value of \$38 billion
- Leading low capital and cash costs allow Tourmaline to grow profitably and pay a meaningful dividend in all parts of the natural gas price cycle

* Debt adjusted

Independently Recognized Canadian 2P Reserves⁽¹⁾

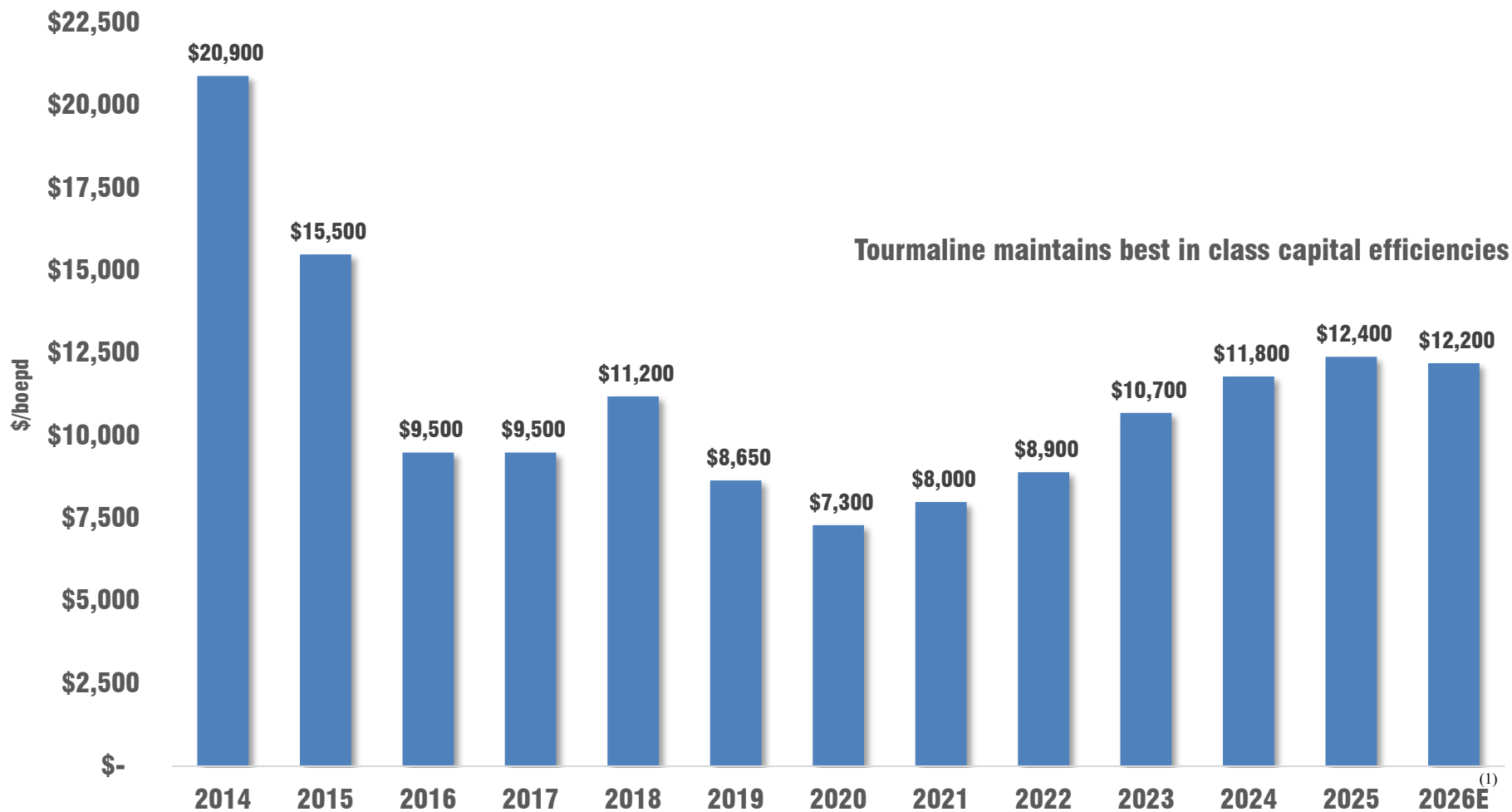
May 2026



⁽¹⁾ Canadian Protocol, most recent disclosure. Peers include Advantage, SHEL (CA) / Arc, Birchcliff, CNRL, Cenovus, Kelt, Paramount, Peyto, Strathcona, Suncor, Tamarack, Whitecap

Continuous Capital Efficiency Improvements

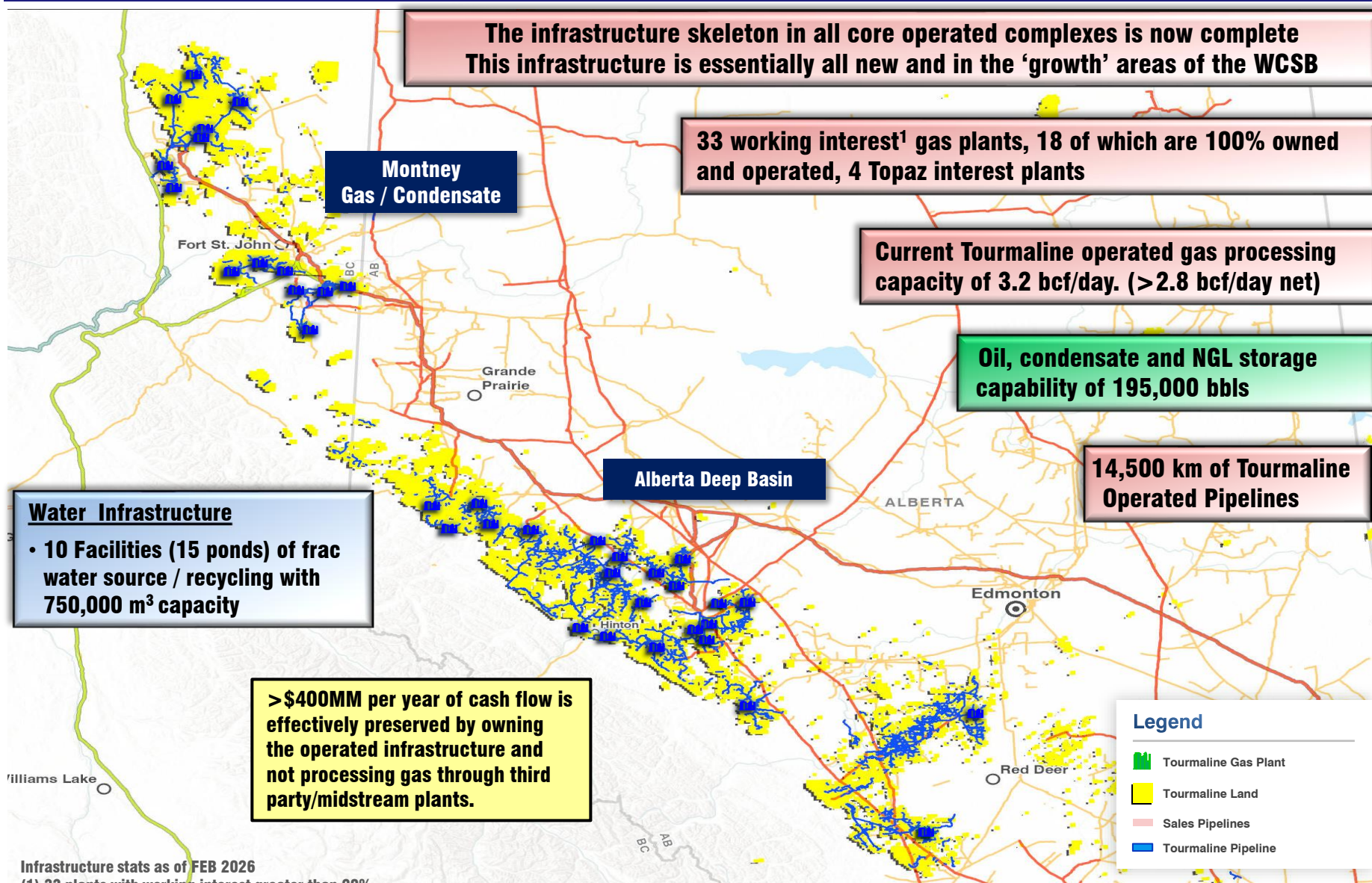
Mar 2026



(1) Based on EP Growth Plan Guidance

Tourmaline Midstream Assets

Mar 2026



Tourmaline's diverse and profitable liquids marketing business

- Liquids receive diversified pricing: WTI, FSPL, Naoao/Peace, CRW, Mt. Belvieu, Conway, Far East Index, and Polypropylene netbacks
- NGL volumes are meaningfully exposed to all Canadian west coast waterborne export terminals (RIPET, PRT)
- Tourmaline ships liquids to markets on pipelines traversing our core areas – most cost-efficient method of transport

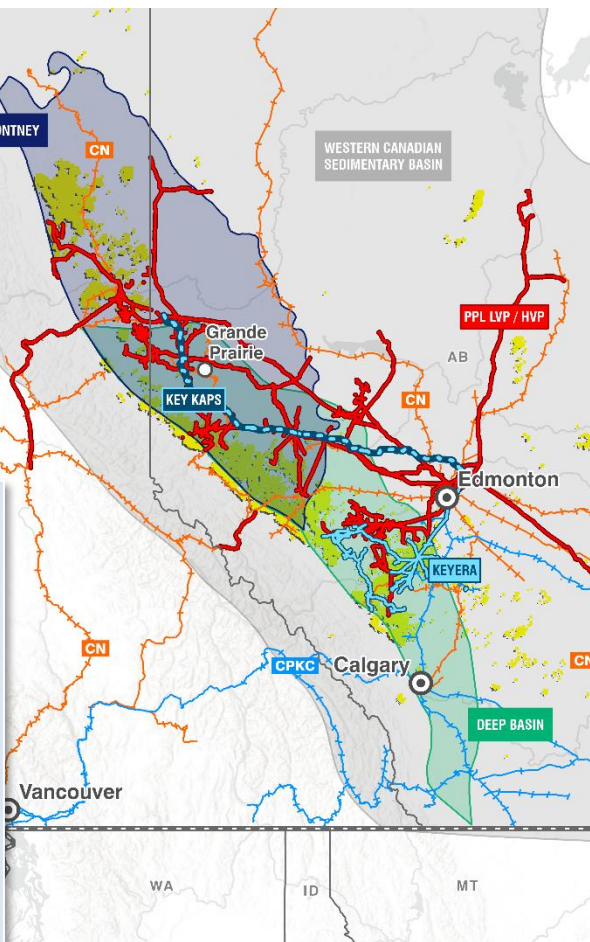
Approx. 45% of TOU propane receives Far East Index pricing, provided through multiple long-term liquid processing and handling agreements

PPL RPT
Propane Export

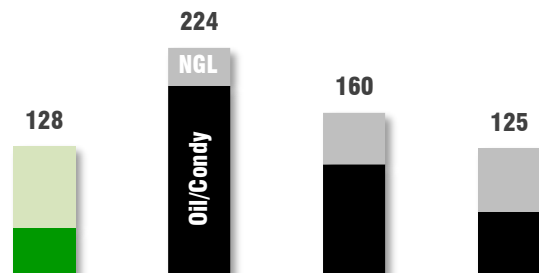
ALA RIPET
Propane Export

Tourmaline Margin Improving Activities

- MMLP North Montney Liquids Pipeline
- Aitken Plant Consolidation
- West Doe Plant Acquisition / Ownership
- Pembina NEBC Liquids Agreement (Frac & Transport)
- South Montney Rail / Frac Site
- Gundy NGL Dual Connection
- North Pine Rail & PPL NEBC Pipe
- Access to All Fractionation in Ft Sask (+ Take in Kind Rights)

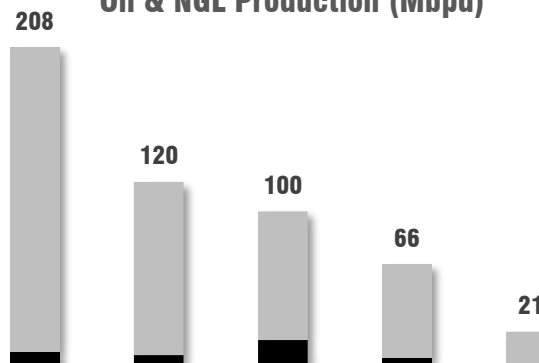


Canadian Peer Producers Oil & NGL Production (Mbpd)



TOU Canadian Peer Producers

US Gas Producers Oil & NGL Production (Mbpd)



US Gas Producer Peers



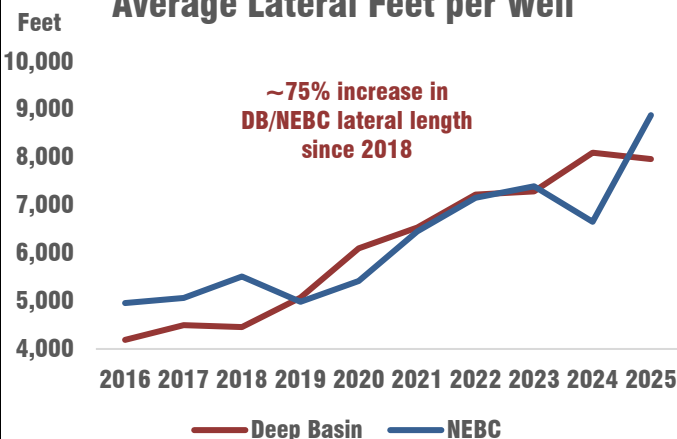
TOURMALINE
OIL CORP.

The Ever-Evolving Tourmaline Development Approach

Mar 2026

In the Alberta Deep Basin and the BC Montney Tourmaline is constantly seeking the balance between maximizing deliverability (growth), EUR (value), and overall economic return (CF/FCF). Tourmaline ultimately prioritizes IRR maximization, this results in faster well payouts, lower supply costs, and a free cash flow flywheel that can service both capital investment and capital return in all commodity price environments.

Average Lateral Feet per Well



~75% increase in
DB/NEBC lateral length
since 2018

IRR

Optimize
CF/FCF
Maximize
Earnings/ROCE
Minimize Costs, Larger Pads
Optimize Payout, Capital Recycling

\$ The Sweet Spot \$

Longer Laterals
Casing tie-ins
Optimized Pad Frac Order
3d Seismic, Geosteering, Structural Optimization

Deliverability

Maximize Liquid Prod.
High Intensity Completions
Downhole Chokes/Restricted Flow
Wine-Racking, Cube, Mega Frac

EUR



2024-2031 NEBC Infrastructure Project Overview

July 2025

- This is the largest EP growth project in the WCSB over the next 5 years and is timed to the growing Canadian LNG business.
- Tourmaline expects to add 1.1 bcf/d of new gas production and over 50,000 bpd of condensate and ngl's over the next six years
- The two-phase project will systematically develop Tourmaline's most profitable resource inventory (lowest capital cost, lowest operating cost, most liquid rich, highest margin), resulting in Tourmaline's operating metrics improving as production from this new development project becomes a larger proportion of the corporate production base.
- The build out consists of two new gas processing complexes with C3+ deep cut recoveries, expansion of four existing gas processing complexes, three new hydrocarbon liquids hubs including evaluation of an LPG terminal at Groundbirch, five water recycling facilities, electrification of four processing plants of which two are existing, and several large pipeline corridors connecting our large resource base to the existing and new gas processing complexes.
- The infrastructure build-out commenced in 2024 with one of the liquid storage projects, one of the connector pipeline projects, a water facility, the compression expansion at Birch, and one of the electrification projects all expected to be completed by end 2025 on approximately \$350 million of aggregate capital spending.
- The first material production addition occurs in Q4 2026 with the Aitken C-38-C plant expansion, the next significant production addition is phase one of the Groundbirch 15-25 deep cut planned for 2H 2027. Both projects are permitted and long-lead procurement is underway.
- Tourmaline expects production growth of 30%, cash flow growth of over 40% and free cash flow growth of 2.5 times at flat pricing once the project is completed and the EP program trends towards maintenance capital levels (\$>3.0 billion FCF per Annum).

'We're not just growing the business; we're improving the business.'

Gas Development Location Inventory and Economics⁽¹⁾

Mar 2026

	AB Deep Basin North & West <u>Horizontal</u>	AB Deep Basin South <u>Horizontal</u>	NEBC Gundy MNTN <u>Horizontal</u>	NEBC North MNTN <u>Horizontal</u>	NEBC South MNTN <u>Horizontal</u>
Total Well Costs (Drill, Case, Complete, \$ Million)	6.20	6.05	5.70	5.80	6.72
Average Reserves/Well (bcfe)	6.4	4.8	5.8	7.2	6.3
Lateral Length (metres)	2,214	2,786	2,439	2,655	2,707
Year 1 Production Rate ⁽²⁾	5.4 mmcfepd	3.3 mmcfepd	4.4 mmcfepd	4.1 mmcfepd	3.7 mmcfepd
Development Cost/boe	\$5.80	\$7.61	\$5.89	\$4.83	\$6.37
Operating Expenses/boe ⁽³⁾	\$3.70	\$6.54	\$1.72	\$4.65	\$3.17
Net Present Value @ 10% (000's)	\$4,287	\$4,022	\$8,431	\$7,091	\$4,316
Internal Rate of Return ⁽⁴⁾	51%	42%	140%	73%	35%
Payback Period (months)	21	24	11	17	30
Year 1 Gas Price ⁽⁵⁾	\$2.72	\$2.88	\$2.64	\$2.64	\$2.63
Future Development Locations ⁽⁶⁾	Total - Deep Basin: 15,223		Total - NEBC: 8,814		

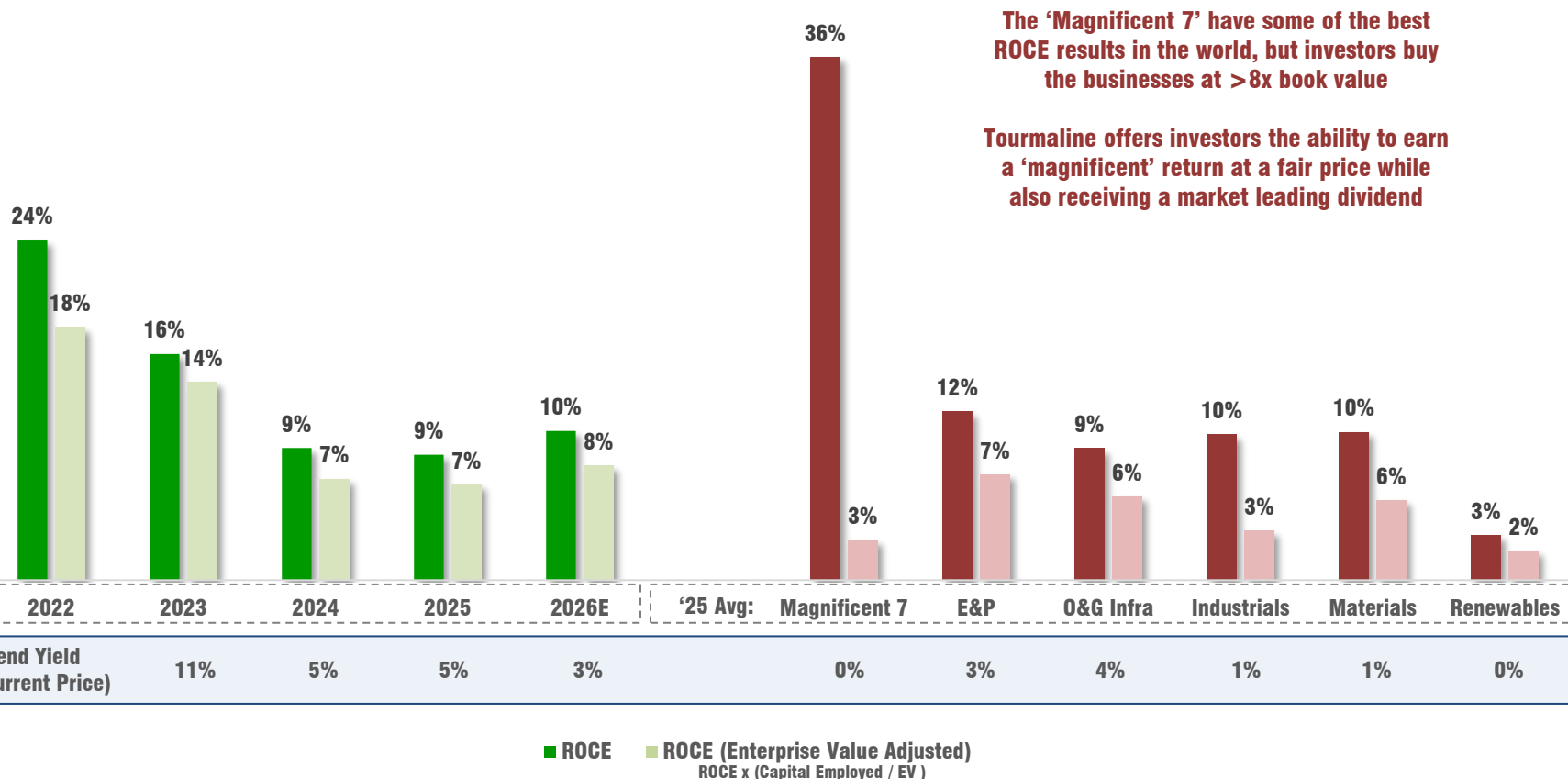
Notes:

- (1) All amounts are before tax.
- (2) Assumes on production date of January 1, 2026.
- (3) Weighted average operating expenses over the initial five years of production.
- (4) Internal Rate of Return calculation is based on monthly cash flows.
- (5) Independent Reserve Engineer January 1, 2026 escalated price forecast, adjusted for transportation, quality and heat content.
- (6) See Schedule A.

Market Leading Return on and of Capital

May 2026

Tourmaline's return on capital employed ("ROCE") cycles between 15-25% in strong commodity price environments and 5-15% in low commodity price environments with base dividends offering a 3% income yield with upside during strong pricing



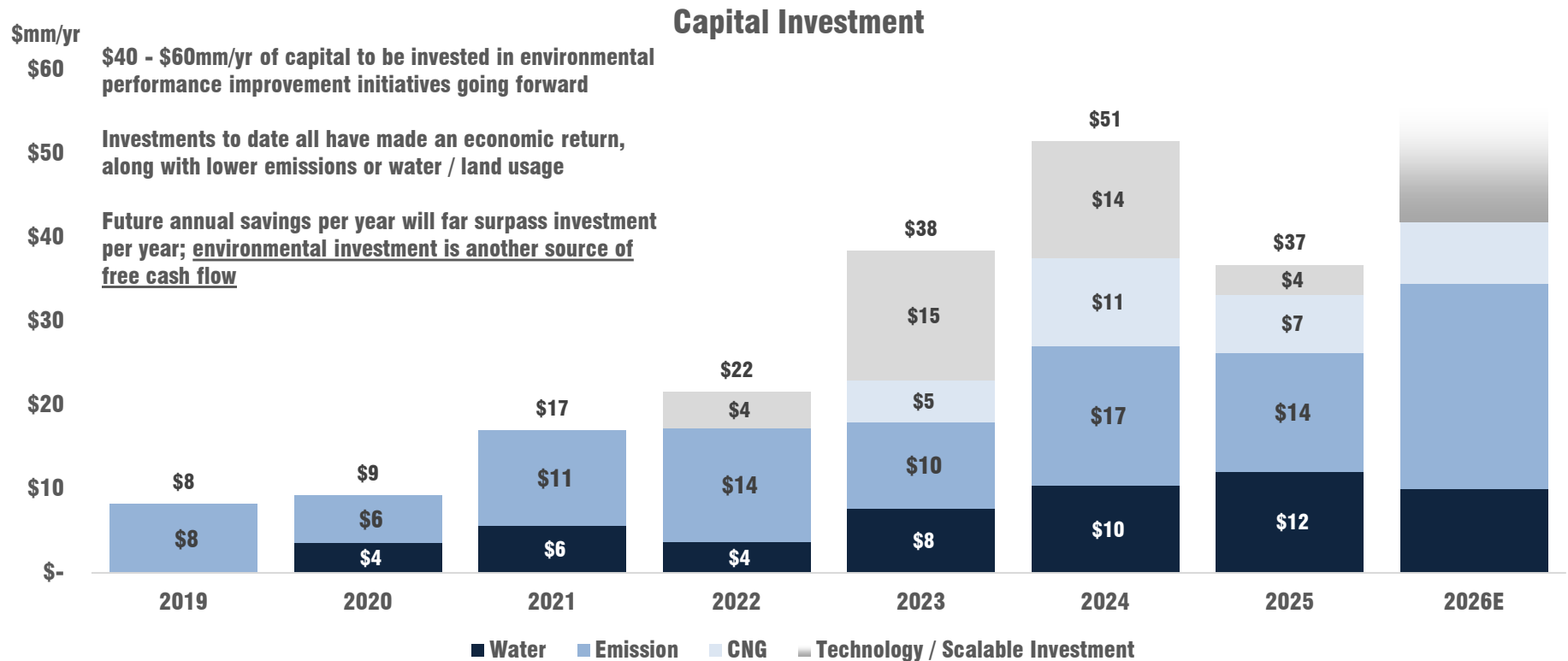
ROCE defined as Income before taxes and Finance expense divided by Capital Employed, where Capital Employed is defined as the average of Total Assets less the average of Current Liabilities for the respective year.
ROCE (Enterprise Value Adjusted) is calculated by multiplying ROCE by the Capital Employed to Enterprise Value ratio implied in the annum.
Tourmaline adjusts non cash one time gain's or losses in historical annuums (i.e., unrealized hedge gains, A&D non cash gains / losses).
Magnificent 7 = META, AAPL, AMZN, NFLX, NVDA, TSLL, GOOG; Renewables = ENPH, ALB, ON, QS, VWS, FSLR; O&G Infra = TRP, PPL, PAA, KMI, LNG, ENB; Industrials = CNR, CP, UNP, WCN, CAT, BA, GE, TRA;
Materials = FM, NTR, TECK/B, AA, BTU, NUE, FCX, K. E&P = ARX, CNQ, EOG, RRC, OVV, EQT, EXE; All market data as of Apr 27th 2026 as reported by Bloomberg; All Tourmaline data as per the EP plan and company filings

Environmental Performance Investment

Mar 2026

Focusing on investment opportunities that maximize cost savings & environmental impact

- **Water:** recycling, & pipeline infrastructure; ~95% recycling in NEBC, advancing AB towards 100%
- **Air:** diesel displacement, pneumatic / venting reduction, power (highline), energy efficiency, CCUS, RNG, Methane ETC (Emission Testing Center)
- **CNG – Clean Energy / Tourmaline JV (\$70mm JDA – 15-20 stations over five years)**
- **Technology:** CCUS, NGIF, RNG, other initiatives

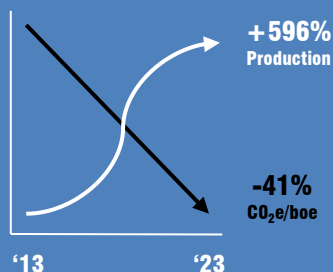


Environmental Performance Improvement

Mar 2026

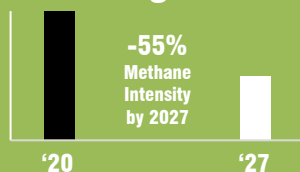
Tourmaline has been aggressively and successfully pursuing a comprehensive environmental performance improvement strategy for over seven years. The Company is systematically improving its performance and reducing the impact of all aspects of activities upon air, land and water.

Achievements



- Achieved Grade A certificate from MiQ, highest certification possible
- 95% of completion water recycled from gas operations
- Initiation of methane reduction retrofit compliance plan in 2019; 3,700 controllers replaced
- 75% reduction in surface area per producing well
- Broad replacement of diesel in drilling and completion operations with natural gas
- Performed lifecycle assessments of both Sundown (NEBC) & Banshee (DB) natural gas production

Targets



- Targeting 55% reduction in methane emission intensity from 2020 levels by 2027
- Reduce corporate emissions intensity by 25% by 2027⁽²⁾, through the application of new, innovative technologies including the electrification of assets
- Targeting elimination of fresh water usage in well stimulation operations (NEBC ✓)

Initiatives

- ✓ Methane Mitigation
- ✓ Fuel Switching
- ✓ Energy Efficiency
- ✓ Water Recycling

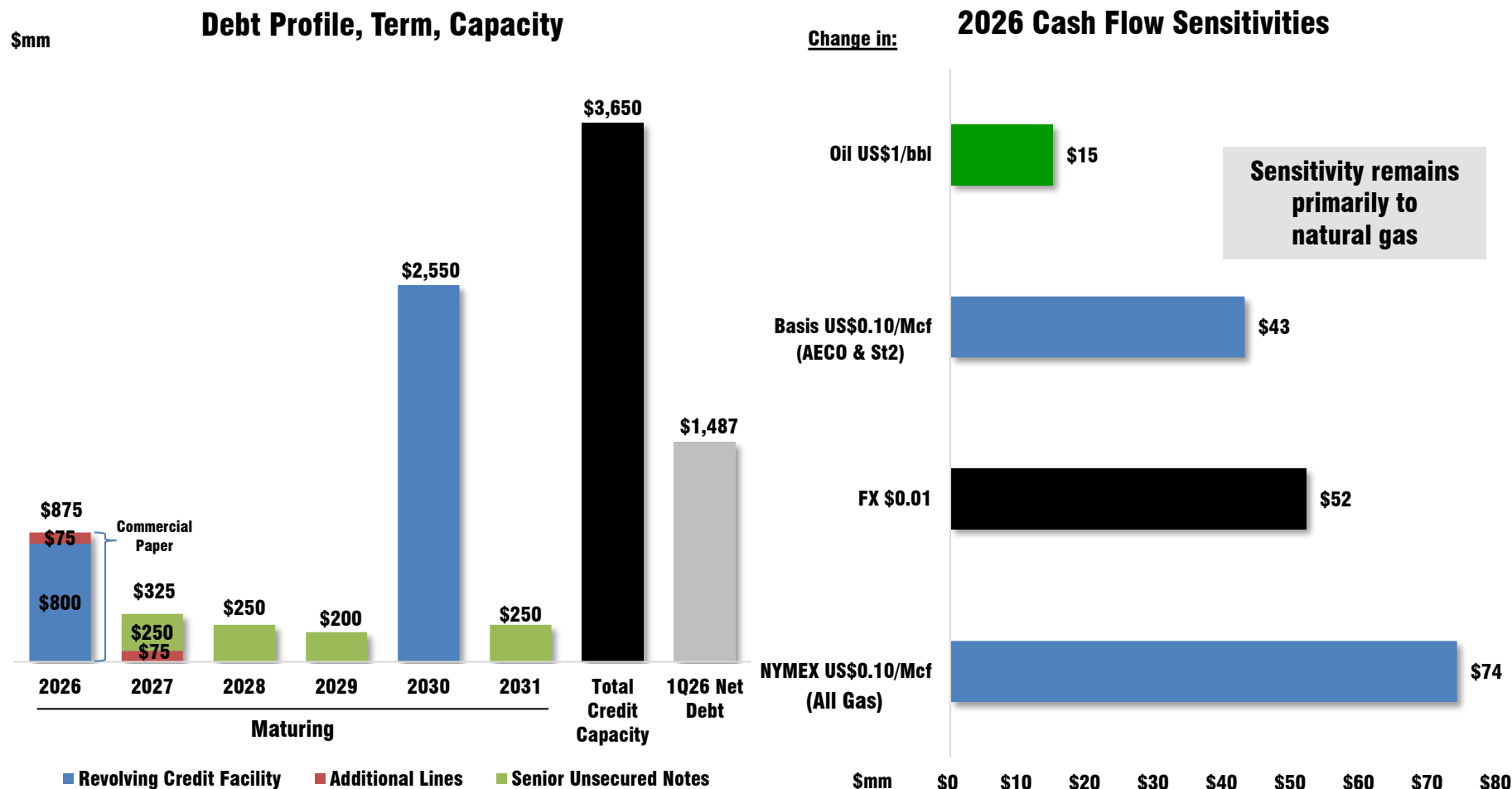
- Full top-down methane surveillance with aircraft & satellite. Replaced over 3,700 pneumatic devices
- All drilling/frac rigs/fleets have natural gas blending, 1 highline rig, 3 battery hybrids, 1 tier 4 frac fleet
- Waste heat recovery, compressor valve upgrades, battery hybrid gas plant
- Produced water recycling with current capacity of 750,000 m³ across 10 water recycling facilities & 15 produced water ponds.

Tourmaline Financial Position

Excellent Liquidity, Resiliency & Capacity

May 2026

Tourmaline has ample liquidity and capacity to weather adverse commodity prices



Tourmaline Technology Curve/Future Concepts, Requirements & Opportunities



- Alternative hz frac programs/processes
 - Concurrent pairs, delayed flow-backs etc.
- Novel drilling technology to reduce time/cost in drilling builds
- Refine drilling techniques/cost savings for frontal foothills Wilrich/Notikewin hz drlg
- Ball drop/sliding sleeve completion technique in vertical wells
- Understanding controls on Wilrich deliverability/develop predictive tools
- New shale/source rock plays
- Pasquia Hills oil shale recovery mechanisms
- Cost saving via novel frac water sourcing/recycling
- Waste heat recovery technology
- Utilizing gas fired turbines to reduce costs for drilling, completions, facilities
- New mud systems to reduce drilling times
- Improved horizontal stimulation techniques, new approaches to maximize deliverability and recovery
- Sour frac water sweetening technology
- Develop predictive reservoir/reserve tools for horizontal clastic gas wells
- Improved Wilrich seismic imaging in strat settings and Outer Foothills settings
- Paleozoic/New Deep Play concepts
- AI applications in geophysical interpretation, reservoir prediction and predictive drilling problem identification.

Schedule A

DRILLING LOCATIONS

Estimated Drilling Inventory

This document discloses drilling locations, as at December 31, 2025, and prior to the impact of the Peace River High Disposition, in four categories: (i) proved undeveloped locations; (ii) probable undeveloped locations; (iii) unbooked locations; and (iv) an aggregate total of (i), (ii) and (iii). Of the 26,512 (gross) locations (24,123 gross locations after the impact of the Peace River High Disposition), 2,316 are proved undeveloped locations including Drilled-Uncompleted locations (“DUCs”), 1,757 are probable undeveloped locations, and 22,439 are unbooked locations. Proved undeveloped locations including Drilled-Uncompleted locations (“DUCs”) and probable undeveloped locations are booked and derived from the Consolidated Reserve Report and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on the Company's prospective acreage and an assumption 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 or resources (including contingent and prospective). Unbooked locations have been identified by management as an estimation of the Company's 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 will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While a certain number of the unbooked drilling locations have been derisked 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.

The following provides additional information on the Company's estimation of unbooked locations.

Schedule A continued

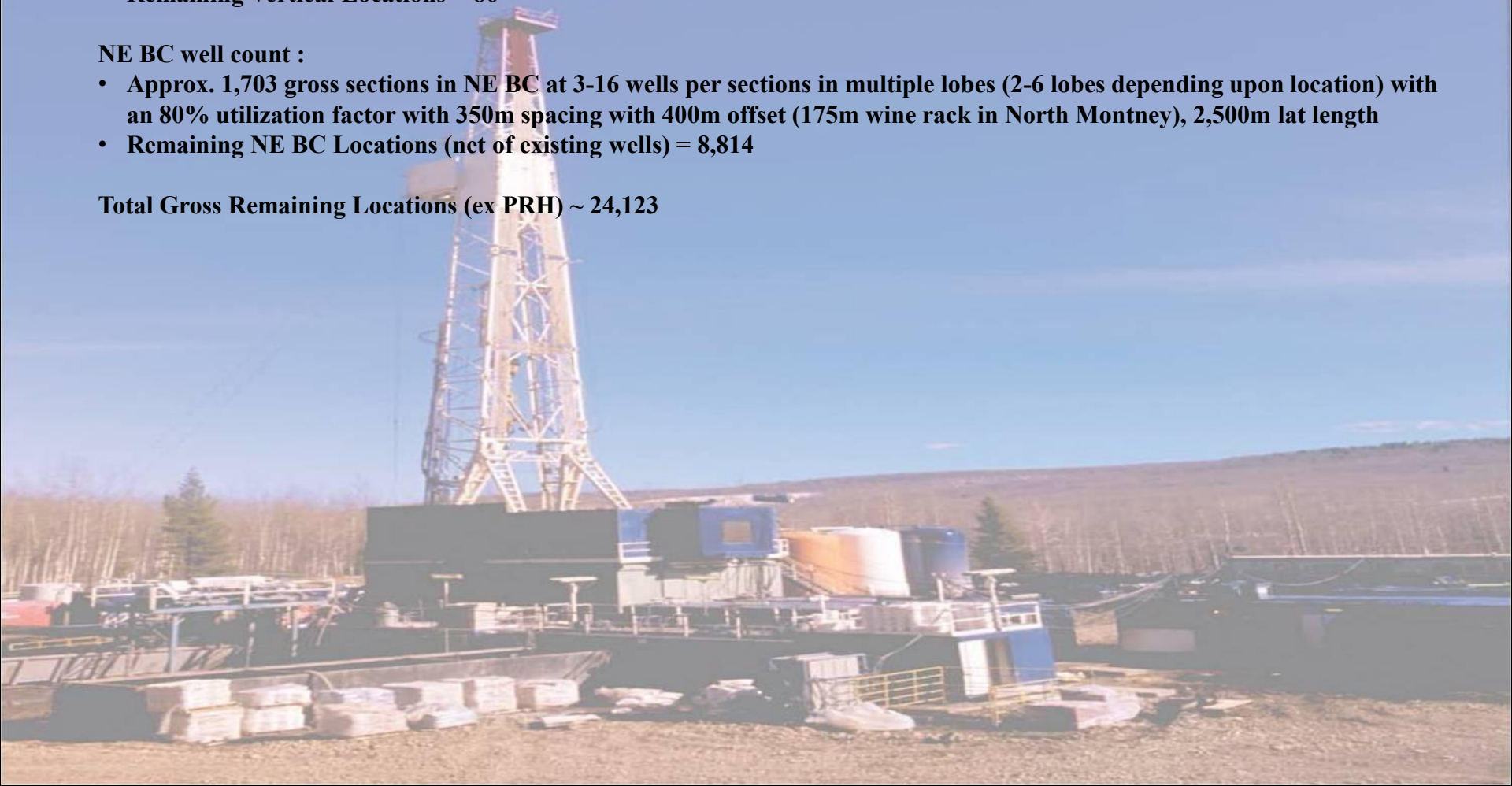
Deep Basin well count :

- Total horizontal Deep Basin locations = 18,407 (1-2 wells per section per zone depending on zone)
- Less existing horizontals, and less 20% of existing vertical producers = 3,271
- Remaining Horizontal Locations = 15,223
- Remaining Vertical Locations = 86

NE BC well count :

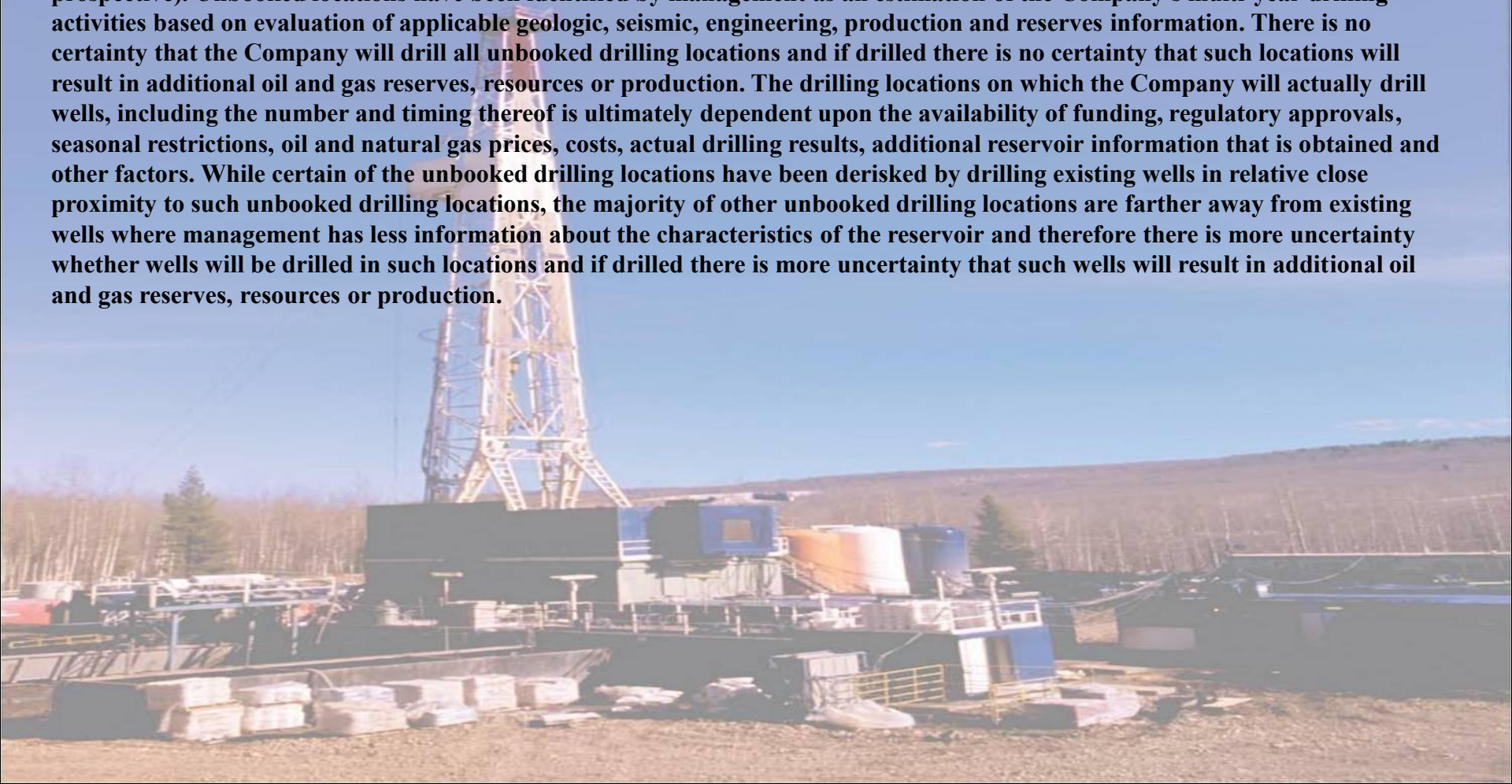
- Approx. 1,703 gross sections in NE BC at 3-16 wells per sections in multiple lobes (2-6 lobes depending upon location) with an 80% utilization factor with 350m spacing with 400m offset (175m wine rack in North Montney), 2,500m lat length
- Remaining NE BC Locations (net of existing wells) = 8,814

Total Gross Remaining Locations (ex PRH) ~ 24,123



Schedule B

Prospective locations are unbooked locations that are not included in inventory. Unbooked locations are internal estimates based on the Company's prospective acreage and an assumption 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 or resources (including contingent and prospective). Unbooked locations have been identified by management as an estimation of the Company's 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 will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, 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 derisked 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.



Forward Looking Information

Certain information contained in this presentation constitutes forward-looking information within the meaning of applicable securities laws. This information relates to future events or the Company's future performance. All information other than information of historical fact is forward-looking information. The use of any of the words "anticipate", "plan", "contemplate", "continue", "estimate", "expect", "intend", "propose", "might", "may", "will", "shall", "project", "should", "could", "would", "believe", "predict", "forecast", "pursue", "potential" and "capable" and similar expressions are intended to identify forward-looking information. This information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. No assurance can be given that these expectations will prove to be correct and such forward-looking information should not be unduly relied upon. This information speaks only as of the date of this presentation or, if applicable, as of the date specified in those documents specifically referenced herein. In addition, this presentation may contain forward-looking information attributed to third-party sources.

Without limitation of the foregoing, this presentation contains forward-looking information pertaining to the following: the reserve potential of the Company's assets; the anticipated production from the Company's assets and anticipated future cash flows from such assets; the Company's growth strategy and opportunities; the Company's capital exploration and development programs and future capital requirements; the estimated quantity and value of the Company's proved and probable reserves; expectations regarding the ability to raise capital and to continually add to reserves; the Company's estimates of future interest and foreign exchange rates; the Company's environmental considerations; the Company's assumptions regarding commodity prices; the Company's expectations regarding reduction in its operating costs; the timing of commencement of certain of the Company's operations and the level of production anticipated by the Company; the potential for production disruption and constraints; supply and demand fundamentals for crude oil and natural gas; the Company's access to adequate pipeline and other gathering, transportation and processing capacity; the Company's access to third-party infrastructure; the Company's drilling and recompletion plans; the Company's expected capital expenditures; expected debt levels and credit facilities; industry conditions pertaining to the oil and gas industry; the Company's plans for, and results of, exploration and development activities; the planned construction of the Company's gathering, transportation and processing facilities and related infrastructure; the timing for receipt of regulatory approvals; the Company's treatment under governmental regulatory regimes and tax laws and potential changes in such regimes and laws; the Company's future general and administrative expenses; and the Company's expectations regarding having adequate human resource staffing.

Forward Looking Information

With respect to forward-looking information contained in this presentation, assumptions have been made regarding, among other things: future crude oil and natural gas prices; future interest rates and currency exchange rates; the Company's ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the regulatory framework governing royalties, taxes and environmental matters; the Company's ability to market production of oil and natural gas successfully; the Company's future production levels; the applicability of technologies for recovery and production of the Company's reserves; the recoverability of the Company's reserves; future capital expenditures to be made by the Company; future cash flows from production meeting the expectations stated in this presentation; future sources of funding for the Company's capital program; the Company's future debt levels; geological and engineering estimates in respect of the Company's reserves; the geography of the areas in which the Company is conducting exploration and development activities; the impact of competition on the Company; and the Company's ability to obtain financing on acceptable terms.

Actual results could differ materially from those anticipated in this forward-looking information as a result of a number of factors including the risk factors set forth in the Company's reports and documents on file with Canadian securities regulatory authorities at www.sedarplus.ca or the Company's website at www.tourmalineoil.com, which risk factors should not be construed as exhaustive. See specifically "Forward-Looking Statements" and "Risk Factors" in the Company's most recently filed Annual Information Form and "Forward-Looking Statements" in the Company's most recently filed Management's Discussion and Analysis.

Included in this presentation are estimates of the Company's 2026-2031 cash flow, free cash flow and cash flow per share which are based on various assumptions as to production levels, commodity prices, the anticipated receipt of drilling permits and other assumptions and in the case of the years other than 2026, such estimates are provided for illustration only and are based on budgets and forecasts that have not been finalized and are subject to a variety of contingencies including prior years' results. To the extent such estimates constitute a financial outlook, they were approved by management of the Company in May 2026 and are included to provide readers with an understanding of the Company's anticipated cash flow based on the capital expenditures and other assumptions described and readers are cautioned that the information may not be appropriate for other purposes.

In addition, information relating to "reserves" is deemed to be forward-looking information, as it involves the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and that the reserves described can be profitably produced in the future. See also "Statement of Reserves Data and Other Oil and Gas Information" and "Certain Reserves Data Information" in the Company's Annual Information Form.

Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed herein or otherwise and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, unless specifically required to do so pursuant to applicable law.

Forward Looking Statement Advisories

Oil and Gas Advisories

Certain crude oil and natural gas liquids ("NGLs") volumes have been converted to millions of cubic feet equivalent ("mmcf") or thousands of cubic feet equivalent ("mcf") on the basis of one barrel ("bbl" of crude oil or NGLs to six thousand cubic feet ("mcf") of natural gas. Also, certain natural gas volumes have been converted to barrels of oil equivalent ("boe"), thousands of boe ("mboe") or millions of boe ("mmboe") using the same equivalency measure. Such equivalency measures may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

This presentation contains disclosure regarding finding and development costs. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

The estimated net present values disclosed in this presentation do not represent fair market value.

Unless otherwise expressly stated, the information in this presentation pertaining to future drilling locations or drilling inventories is based solely on internal estimates made by management and such locations have not been reflected in any independent reserve or resource evaluations and have not been recognized as reserves or resources as defined in NI 51-101. See Schedule A - Drilling Locations.

Similarly, unless otherwise expressly stated, the information in this presentation pertaining to targeted reserve volumes from future drilling is intended to indicate that in making its internal drilling decisions, the Company seeks to target drilling locations that, based on previous drilling results and its own internal assessments, it believes will on average ultimately generate the indicated volumes.

Initial Production Rates

Any references to initial production rates are useful in confirming the presence of hydrocarbons; however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter and are not necessarily indicative of long-term performance or ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company. Such rates are based on field estimates and may be based on limited data available at this time.

Non-GAAP and Other Financial Measures

This presentation includes references to "cash flow", "capital expenditures", "E&P capital program" and "free cash flow" which are considered "non-GAAP financial measures" and the terms "cash flow per diluted share" and "cash flow per boe" which are considered "non-GAAP financial ratios". These terms do not have a standardized meaning prescribed by GAAP. In addition, this news presentation contains the terms "adjusted working capital" and "net debt", which are considered "capital management measures" and do not have standardized meanings prescribed by GAAP. Accordingly, the Company's use of these terms may not be comparable to similarly defined measures presented by other companies. Investors are cautioned that these measures should not be construed as an alternative to or more meaningful than the most directly comparable GAAP measures in evaluating the Company's performance. Additional information on these terms are included in the Company's most recently filed Management's Discussion and Analysis (See "Non-GAAP and Other Financial Measures" therein) and other reports on file with applicable securities regulatory authorities and may be accessed through the SEDAR+ website (www.sedarplus.ca) or Tourmaline's website (www.tourmalineoil.com).

Forward Looking Statement Advisories

Non-GAAP Financial Measures

Cash Flow

Management uses the term “cash flow” for its own performance measure and to provide shareholders and potential investors with a measurement of the Company’s efficiency and its ability to generate the cash (net of current income taxes) necessary to fund its future growth expenditures, to repay debt or to pay dividends. The most directly comparable GAAP measure for cash flow is cash flow from operating activities. A summary of the reconciliation of cash flow from operating activities to cash flow, is set forth below:

	Three Months Ended March 31,	
(000s)	2026	2025
Cash flow from operating activities (per GAAP)	\$ 942,627	\$ 1,088,311
Current tax (expenses) recovery	5,188	(37,882)
Current taxes paid	4,800	-
Change in non-cash working capital	(90,460)	(87,383)
Cash flow	\$ 862,155	\$ 963,046

Capital Expenditures

Management uses the term "capital expenditures" as a measure of capital investment in exploration and production activity, as well as property acquisitions and dispositions, and such spending is compared to the Company's annual budgeted capital expenditures. The most directly comparable GAAP measure for capital expenditures is cash flow used in investing activities. A summary of the reconciliation of cash flow used in investing activities to capital expenditures, is set forth below:

	Three Months Ended March 31,	
(000s)	2026	2025
Cash flow used in investing activities (per GAAP)	\$ 34,257	\$ 714,079
Change in non-cash working capital	(125,541)	110,939
Capital expenditures	\$ (91,284)	\$ 825,018

Forward Looking Statement Advisories

Non-GAAP Financial Measures (con't)

E&P Capital Program

Management uses the term "EP expenditures" or exploration and production expenditures as a measure of capital investment in exploration and production activity which is defined as capital expenditures (a Non-GAAP Financial Measure), excluding property acquisitions and dispositions and other corporate expenditures. The most directly comparable GAAP measure for EP expenditures is cash flow used in investing activities. See "Non-GAAP Financial Measures – Capital Expenditures" above. A summary of the reconciliation of capital expenditures to EP expenditures is set forth below:

	Three Months Ended	
	March 31,	
(000s)	2026	2025
Cash flow used in investing activities (per GAAP)	\$ 34,257	\$ 714,079
Change in non-cash working capital	(125,541)	110,939
Property acquisitions	(1,829)	(12,143)
Proceeds from divestitures	753,275	1,023
Other	(16,710)	(16,166)
EP Expenditures	\$ 643,452	\$ 797,732

Forward Looking Statement Advisories

Non-GAAP Financial Measures (con't)

Free Cash Flow

Management uses the term “free cash flow” for its own performance measure and to provide shareholders and potential investors with a measurement of the Company’s efficiency and its ability to generate the cash necessary to fund its future growth expenditures, to repay debt and provide shareholder returns. Free cash flow is defined as cash flow less capital expenditures, excluding acquisitions and dispositions. Free cash flow is prior to dividend payment. The most directly comparable GAAP measure for cash flow is cash flow from operating activities. See "Non-GAAP Financial Measures – Cash Flow" and " Non-GAAP Financial Measures – Capital Expenditures" above.

	Three Months Ended March 31,	
(000s)	2026	2025
Cash flow	\$ 862,155	\$ 963,046
Capital expenditures	91,284	(825,018)
Property acquisitions	1,829	12,143
Proceeds from divestitures	(753,275)	(1,023)
Free Cash Flow	\$ 201,993	\$ 149,148

Operating Netback

Management uses the term “operating netback” as a key performance indicator and one that is commonly presented by other oil and natural gas producers. Operating netback is defined as the sum of commodity sales from production, premium on risk management activities and realized gains (loss) on financial instruments less the sum of royalties, transportation costs and operating expenses. A summary of the reconciliation of operating netback from commodity sales from production, which is a GAAP measure, is set forth below:

	Three Months Ended March 31,	
(000s)	2026	2025
Commodity sales from production	\$ 1,447,049	\$ 1,457,567
Premium on risk management activities	257,897	337,609
Realized gain (loss) on financial instruments	(11,056)	96,417
Royalties	(168,836)	(179,159)
Operating expenses	(285,015)	(295,661)
Transportation expenses	(321,684)	(317,197)
Operating netback	\$ 918,355	\$ 1,099,576

Forward Looking Statement Advisories

Non-GAAP Financial Ratios

Operating Netback per-boe

Management calculates “operating netback per-boe” as operating netback divided by total production for the period. Operating netback per-boe is a key performance indicator and measure of operational efficiency and one that is commonly presented by other oil and natural gas producers. A summary of the calculation of operating netback per boe, is set forth below:

	Three Months Ended March 31,	
(\$/boe)	2026	2025
Revenue, excluding processing income	\$ 28.26	\$ 32.95
Royalties	(2.82)	(3.12)
Operating expenses	(4.75)	(5.15)
Transportation expenses	(5.37)	(5.53)
Operating netback	\$ 15.32	\$ 19.15

Cash Flow per-boe

Management uses cash flow per boe to highlight how much cash flow is generated by each boe produced. The ratio is calculated by dividing cash flow by total production for the period. See “Non-GAAP Financial Measures – Cash Flow”.

Cash Flow per diluted share

Management uses cash flow per diluted share as a measurement of the Company’s efficiency and its ability to generate the cash necessary to fund its future growth expenditures, to repay debt or to pay dividends on a per diluted share basis. Cash flow per diluted share is calculated using cash flow divided by the weighted average diluted shares outstanding.

Forward Looking Statement Advisories

Capital Management Measures

Adjusted Working Capital

Management uses the term “adjusted working capital” for its own performance measures and to provide shareholders and potential investors with a measurement of the Company’s liquidity. A summary of the composition of adjusted working capital (deficit), is set forth below:

	As at March 31, 2026	As at December 31, 2025
<i>(000s)</i>		
Working capital (deficit)	\$ (232,167)	\$ (419,306)
Fair value of financial instruments – short-term (asset)	(379,216)	(135,676)
Lease liabilities – short-term	7,406	8,034
Decommissioning obligations – short-term	64,000	75,000
Unrealized foreign exchange in working capital – liability (asset)	1,116	991
Adjusted working capital (deficit)	\$ (538,861)	\$ (470,957)

Net Debt

Management uses the term “net debt”, as a key measure for evaluating its capital structure and to provide shareholders and potential investors with a measurement of the Company’s total indebtedness. A summary of the composition of net debt, is set forth below:

	As at March 31, 2026	As at December 31, 2025
<i>(000s)</i>		
Long-term debt	\$ (947,664)	\$(1,052,914)
Adjusted working capital (deficit)	(538,861)	(470,957)
Net debt	\$(1,486,525)	\$(1,523,871)