



Rubellite Energy Corp.

Corporate Overview

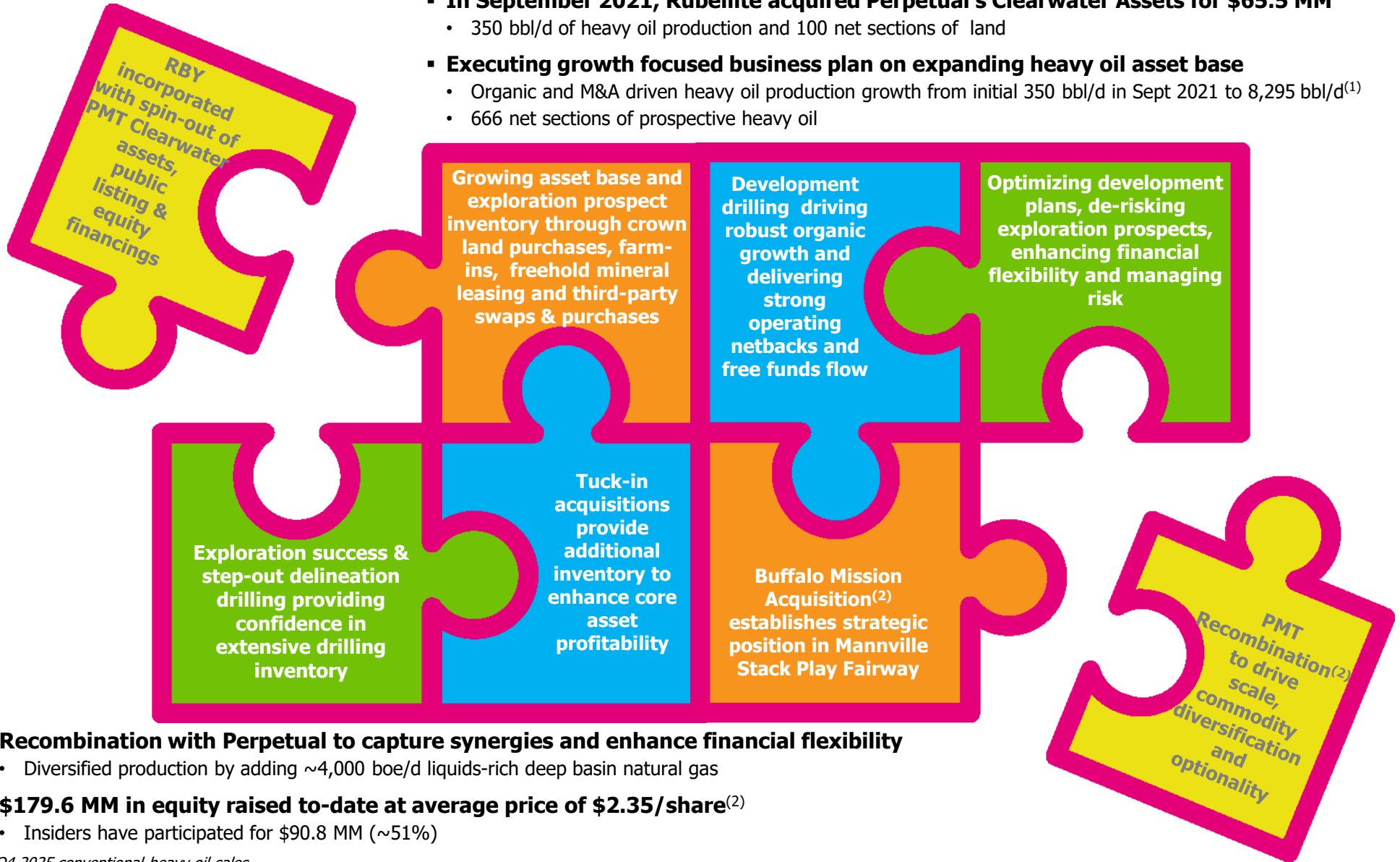
March 10, 2026

Corporate History



Incorporated in July 2021 as pure play Clearwater multi-lat focused junior E&P

- **In September 2021, Rubellite acquired Perpetual’s Clearwater Assets for \$65.5 MM**
 - 350 bbl/d of heavy oil production and 100 net sections of land
- **Executing growth focused business plan on expanding heavy oil asset base**
 - Organic and M&A driven heavy oil production growth from initial 350 bbl/d in Sept 2021 to 8,295 bbl/d⁽¹⁾
 - 666 net sections of prospective heavy oil



- **Recombination with Perpetual to capture synergies and enhance financial flexibility**
 - Diversified production by adding ~4,000 boe/d liquids-rich deep basin natural gas
- **\$179.6 MM in equity raised to-date at average price of \$2.35/share⁽²⁾**
 - Insiders have participated for \$90.8 MM (~51%)

1. Q4 2025 conventional heavy oil sales
 2. See Appendix for details of Historical Financing and 2024 Strategic Transactions

Corporate Profile

Fully funded growth-focused heavy oil multi-lat E&P Company **TSX:RBY**



Investment Highlights

Large scale, focused asset base in the South Clearwater and Mannville Stack fairways

- Rank as amongst the top conventional plays in the WCSB on half-cycle returns

Fully funded, double-digit growth supported by strong netbacks and quick payouts

- Q4 2025 sales production of 13,042 boe/d (67% oil & liquids – 8,295 bbl/d of heavy oil)

Significant captured and derisked heavy oil drilling inventory to support growth plans

- 396 net booked and unbooked heavy oil development drilling locations⁽⁸⁾ in core properties
- Inventory to organically grow heavy oil production by 10% to 15% per year through 2030

>300 heavy oil exploration & >140 new zone appraisal prospects to de-risk & grow NAV

- Heavy oil multi-lat or lined horizontal drilling locations contingent on drilling success

Exposure to Enhanced Oil Recovery potential on base assets with large OOIP

Strategic exposure to high quality natural gas asset in the Deep Basin

Recent track record of acquisitions to expand growth opportunities and scale

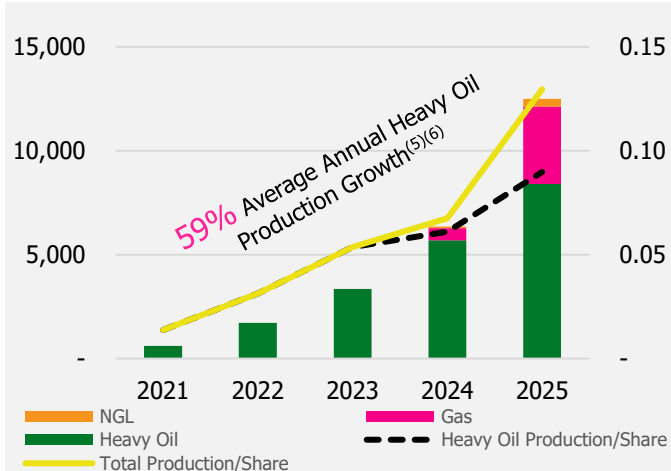
Strong management alignment to drive returns with significant insider ownership

Capitalization

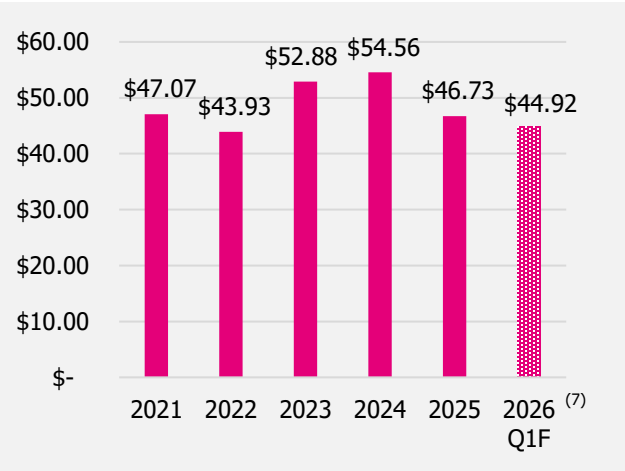
TSX	RBY
Shares Outstanding ⁽¹⁾	93.6 MM
Market Capitalization ⁽²⁾	\$287.3 MM
Revolving Bank Debt ⁽³⁾	\$92.6 MM
Term Loan ⁽⁴⁾	\$20.0 MM
Working Capital Deficit ⁽³⁾	\$30.5 MM
Net Debt ⁽³⁾	\$143.1 MM
Enterprise Value	\$430.4 MM
Insider Ownership	~45.3%

- 102.8 MM fully diluted
- TSX:RBY March 9, 2026 closing price of \$3.07/share
- At December 31, 2025
- Third lien security; 11.5% coupon, matures August 2029

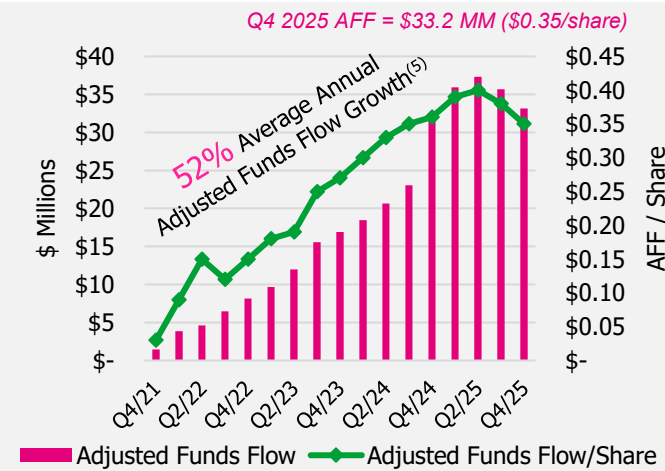
Production Growth (boe/d)



Heavy Oil Operating Netback (\$/boe)



Adjusted Funds Flow



5. Average Annual Growth is calculated as the average growth rate of the prior four quarters over the four quarters preceding it.

6. Production per share calculated using shares outstanding as at December 31 of each fiscal year.

7. Forecast based on March 10, 2026 guidance and forward strip prices as at March 9, 2026; Includes conserved natural gas sales volumes for heavy oil assets and realized gains (losses) on risk management oil contracts.

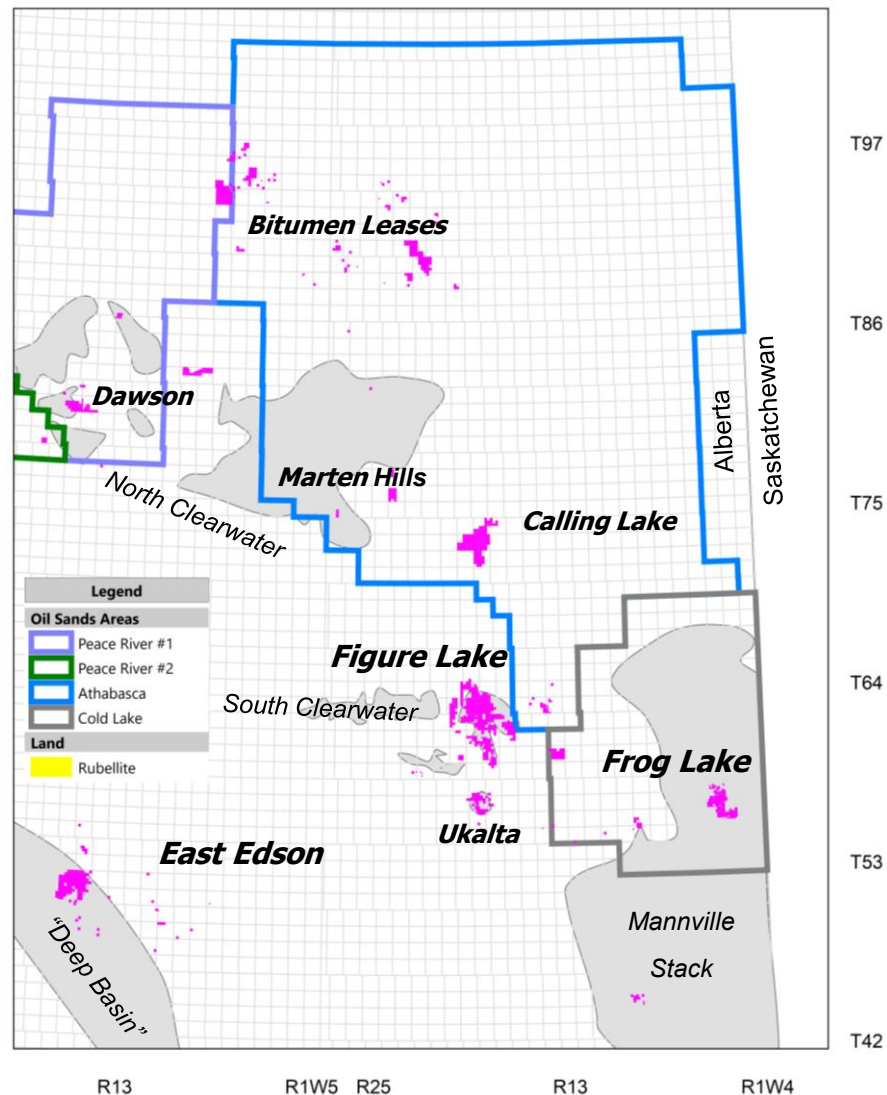
8. Of the 396 net heavy oil drilling development locations disclosed, 101.6 net are proved and 53.6 net are probable locations in the McDaniel Reserve Report at Year End 2025.

Rubellite Asset Profile

Heavy oil production of 8,295 bbl/d & total production of 13,042 boe/d



Asset Map



Asset Summary

Area	Land (net acres) ⁽¹⁾	Well Count (net producing)	Production Q4 2025 (boe/d)
Figure Lake	157,332	112.0	5,754 ⁽²⁾
Frog Lake	21,816	52.0	2,985
Ukalta	21,916	25.0	306
Marten Hills	576	3.3	184
Multi-Lat Exploration	224,734	1.5	11
Heavy Oil Assets	426,374	193.8	9,240
East Edson	28,791	46.8	3,802 ⁽³⁾
Other Exploration	78,425	-	-
Bitumen	72,960	-	-
Total	606,550	240.6	13,042

Q4 2025 Production⁽²⁾⁽³⁾: 13,042 boe/d

- 64% heavy oil; 67% oil & NGL

Property Status:

- Figure Lake** - Development and Step-out delineation; Piloting enhanced recovery waterfloods, polymer flood, and gas injection schemes; following-up Sparky exploration success
- Frog Lake** - Continuous Development in Waseca Sand and GP zones
- Marten Hills** - Developed on primary; Advancing "bottoms up" waterflood
- Ukalta** - Advancing waterflood pilot
- Heavy Oil Exploration** - De-risking secondary zones at Frog Lake and Figure Lake; Other prospects in various stages of land capture & assessment
- East Edson** - Participating to drill to maintain average production & optimize value

1. Includes farm-in exploratory lands at after payout working interest, Frog Lake JED Agreement lands at 50% working interest.
 2. Q4 2025 sales at Figure Lake comprised of 4,809 bbl/d of heavy oil, 5.6 MMcf/d of natural gas, and 7 bbl/d of natural gas liquids.
 3. Q4 2025 sales at East Edson production comprised of 20.3 MMcf/d and 426 bbl/d natural gas liquids.

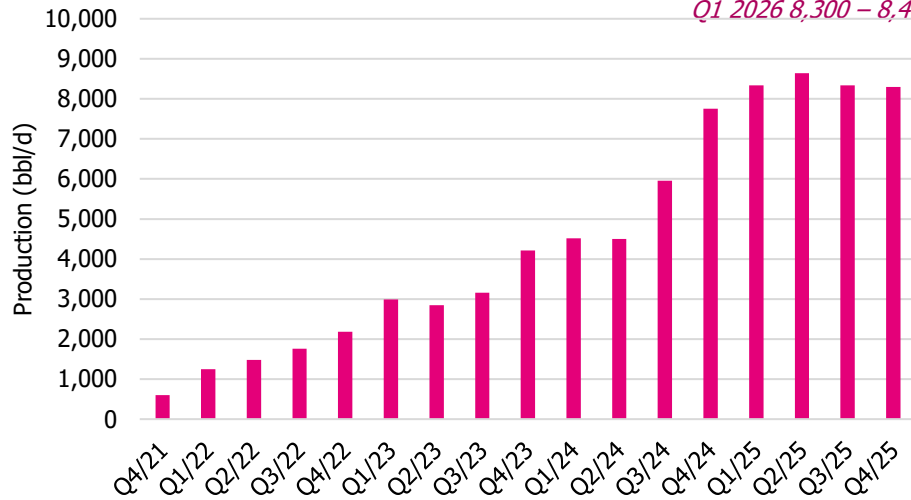
Heavy Oil Asset Performance

Strong operational momentum in Clearwater and Mannville Stack heavy oil asset base



Heavy Oil Sales (bbl/d)

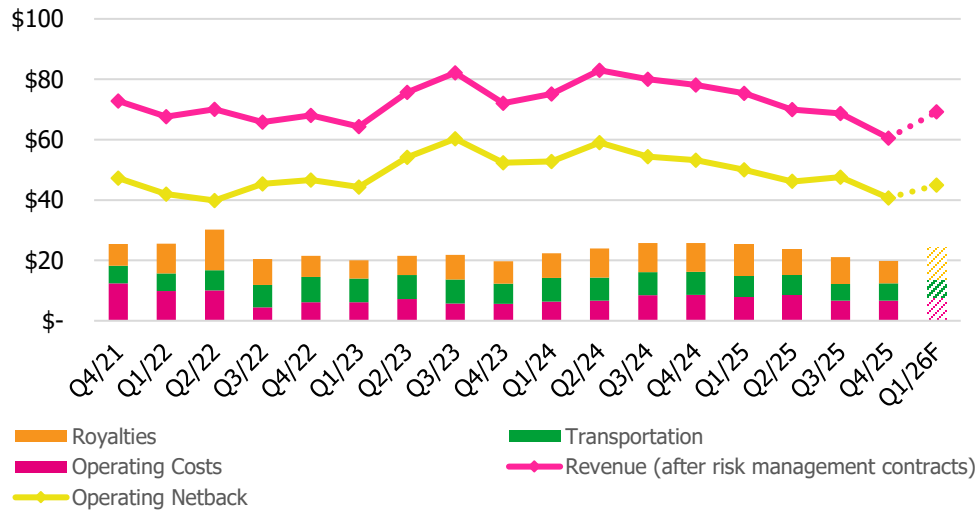
March 10, 2026 Guidance
Q1 2026 8,300 – 8,400 bbl/d



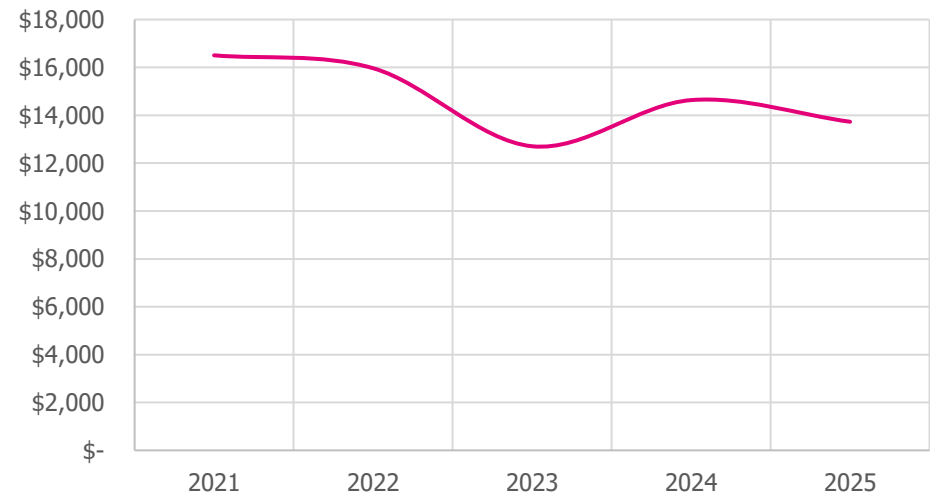
Key Operational Metrics

- >1,825** Lateral legs drilled
- 15,000m** Average open hole per well
- >189** Multi-lats drilled to date
- 19,838m** Highest open hole meters in single well drilled to date
- >2,100,000m** Total horizontal open hole length drilled to date

Operating Netback of Heavy Oil Assets (\$/bbl) (1)



Average Capital Efficiency IP30(2)



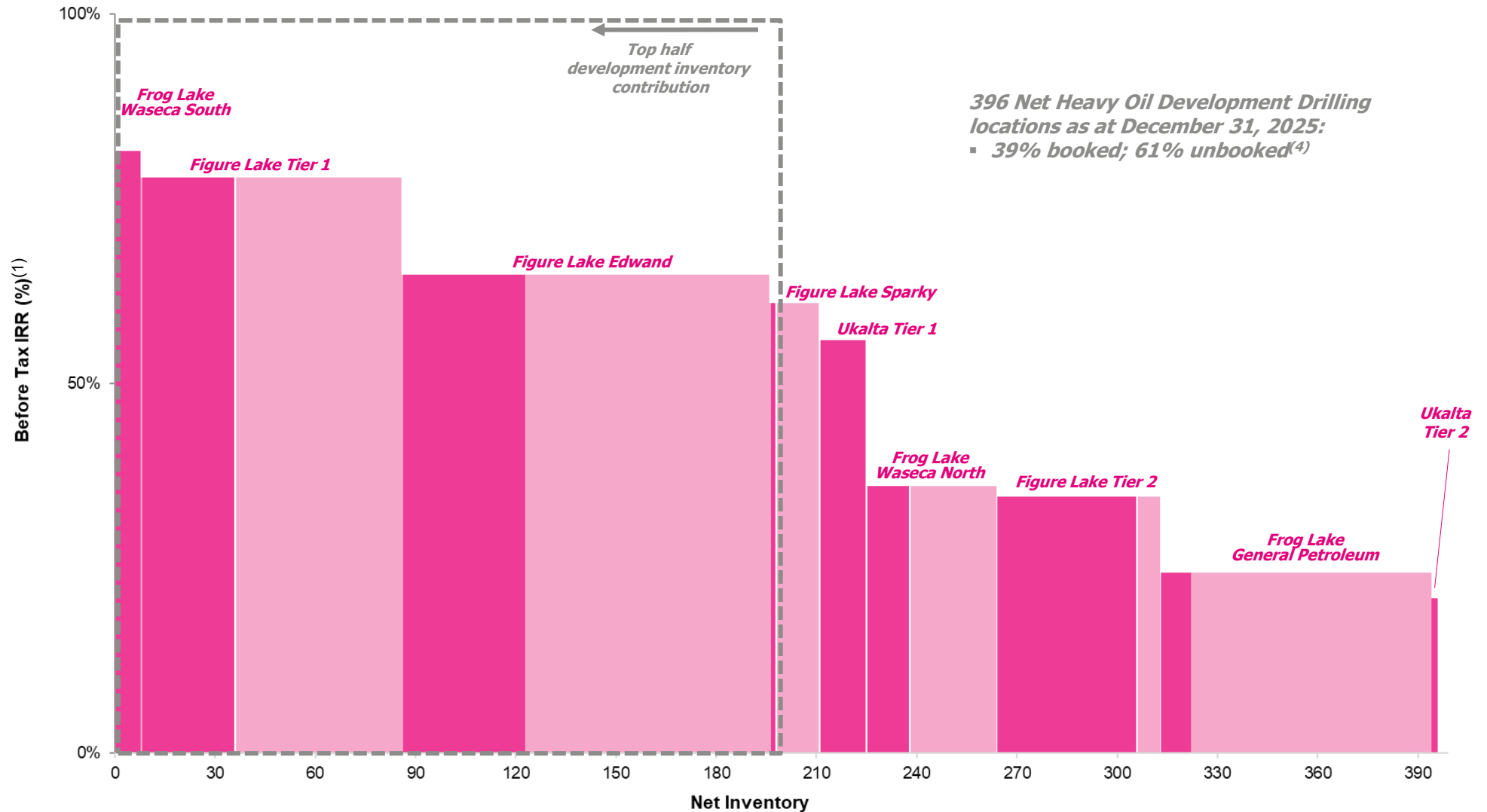
1. Forecast sales production and operating netbacks as per March 10, 2026 guidance and forward strip prices as at March 9, 2026. Includes conserved natural gas sales volumes for heavy oil assets and gains (losses) related to oil risk management contracts

2. Average capital efficiency is calculated as total D,C,E&T capital for a well divided by IP30 in \$/flowing bbl/d

Heavy Oil Development Inventory YE 2025



396 net booked and unbooked development heavy oil drilling inventory⁽²⁾⁽³⁾ in core properties



396 Net Heavy Oil Development Drilling locations as at December 31, 2025:
 ▪ 39% booked; 61% unbooked⁽⁴⁾

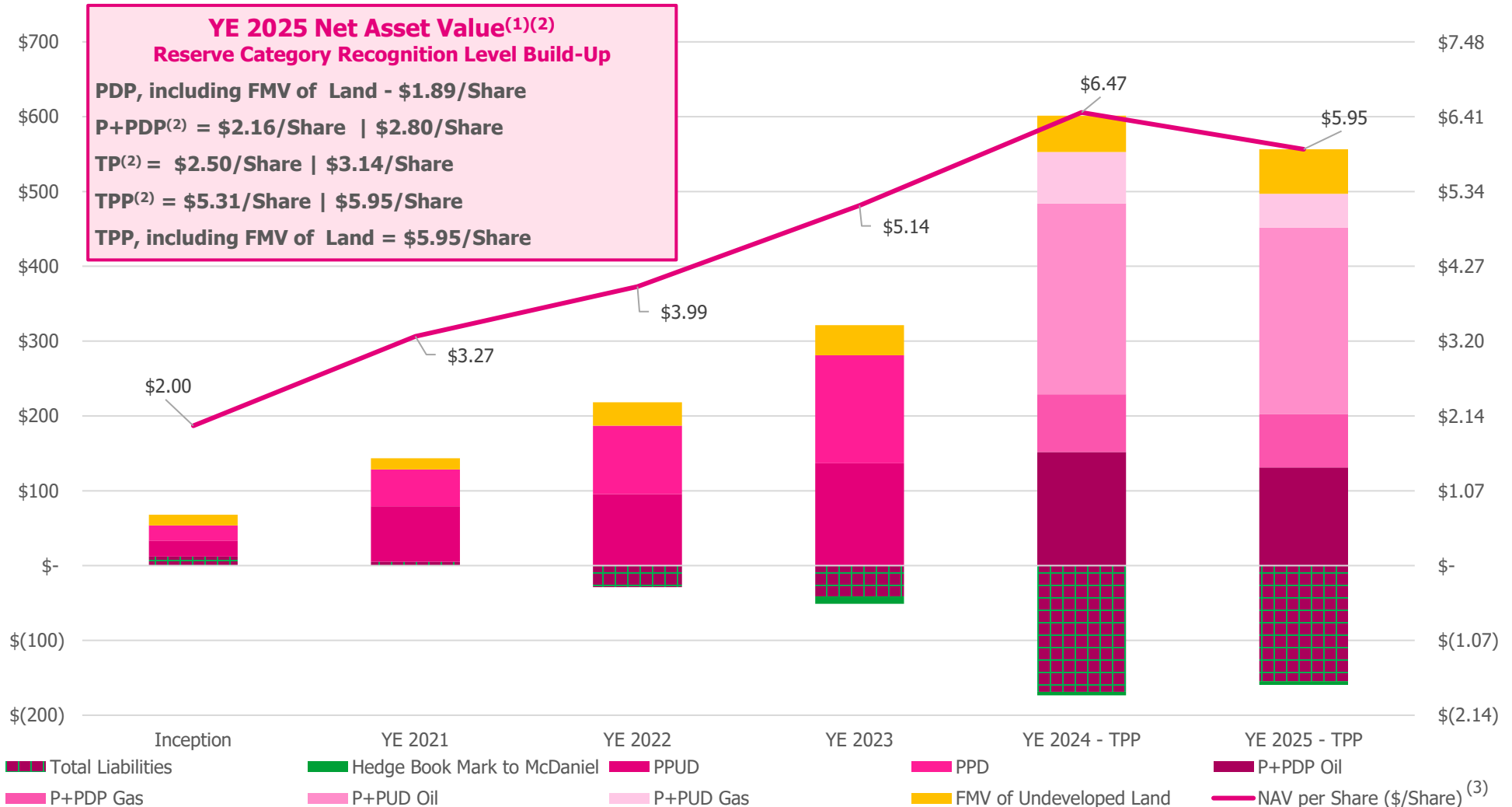
1. Before Tax IRR as per Rubellite Year End 2025 McDaniel Reserve Report Type Wells and Economic Inputs, evaluated at 3 Consultant Average Jan 1, 2026; IRR at 10% discount rate.
2. Booked inventory for Rubellite in darker colour; Unbooked inventory in lighter colour. There are 101.6 net proved and 53.6 net probable locations in the McDaniel Reserve Report at Year End 2025.
3. Total Proved Plus Probable Undeveloped (P+PUD) location count, reserve and economic parameters as per Rubellite Year End 2025 McDaniel Reserve Report. Tier 1 and Tier 2 Figure Lake Type Curve Net Inventory includes both solution gas conservation and no gas conservation type curves, shown at the lower IRR (no gas conservation).
4. Net unbooked development inventory locations based on internal estimates and assume participation elections by FLERC at a 50% working interest in all future drilling activity; See "Drilling Locations" in Advisories.

Net Asset Value ("NAV")



Year End 2025 Price Deck Decline of ~23% Offset Operational Gains in Reserve-based NAV

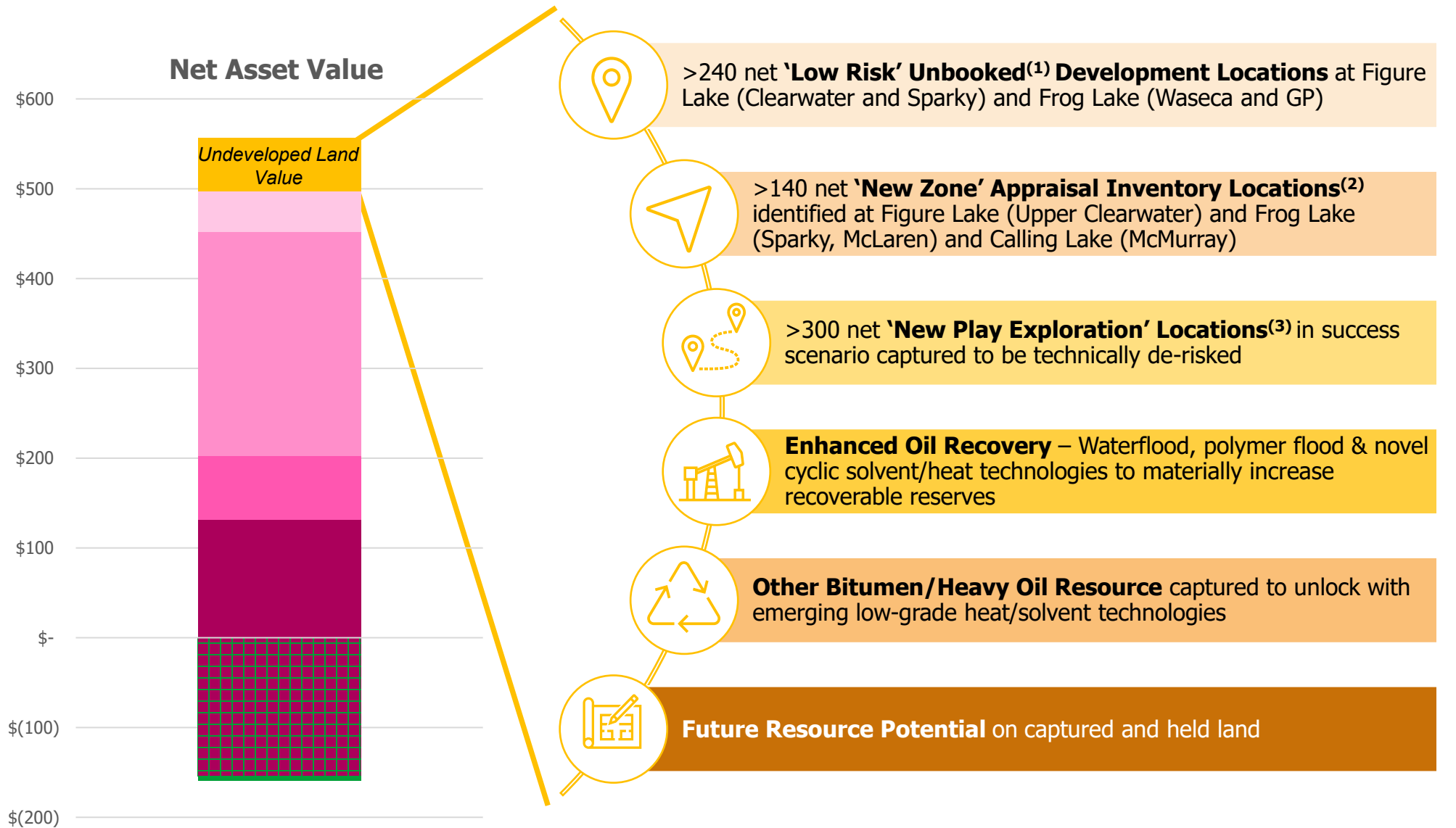
Net Asset Value (discounted at 10%)



1. Based on Proved Developed Producing (PDP), Proved (PUD) and Proved Plus Probable (TPP) reserves BTAX values as per Year End McDaniel Reserve Report based on Consultant Average Price Forecast for respective years; Year end total liabilities; Fair market value ("FMV") of acreage not assigned reserves as per respective year end Seaton-Jordan undeveloped land reports.
 2. NAV/Share presented as Excluding | Including the FMV of acreage not assigned reserves at YE 2025 of \$59.6 MM (\$0.64/Share).

Converting FMV of Undeveloped Land to Reserve-based NAV

Investing to Shift 'Unbooked Potential' to Production, Adjusted Funds Flow & Reserves to Grow Net Asset Value



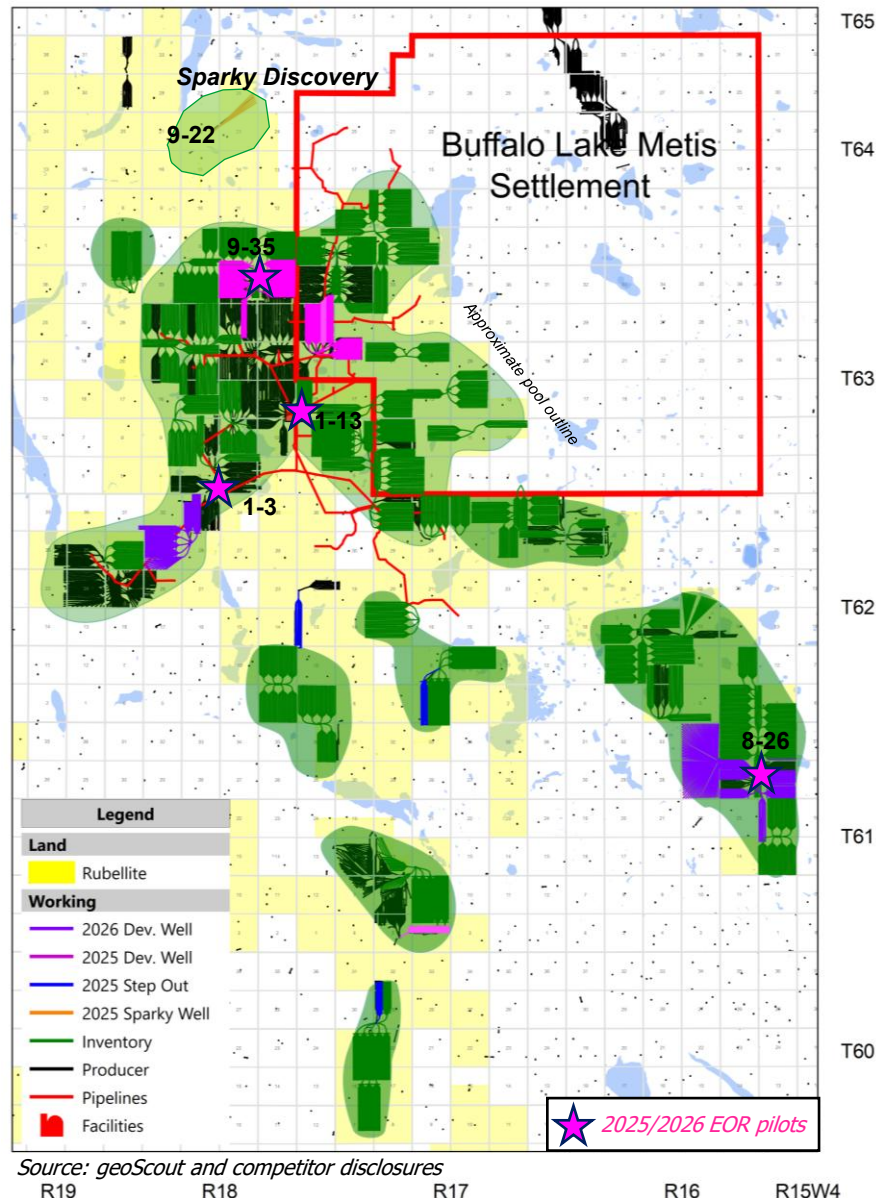
1. Locations estimated by Management that are identified but not included in the Year End 2025 McDaniel Reserve Report.
 2. Location count subject to final well design and inter-well spacing.
 3. Includes locations targeting secondary zones in core producing properties that are still exploratory in nature.

Rubellite Asset Profile | Figure Lake

Clearwater and Sparky Development



Asset Map



Asset Summary

Working Interest: 100%

Q4 2025 Production: 5,754 boe/d (84% oil and liquids)

- 4,809 bbl/d 100% heavy oil; 5.6 MMcf/d natural gas; 7 bbl/d NGL
- 112.0 net multi-lat wells on sales production

2025 Activity – 20 (20.0 net) wells

- One rig continuous drilling 33m inter-leg design
 - 14.0 Development Wells – McDaniel Type Curve⁽¹⁾ IP30 177 bbl/d; IP60 169 bbl/d
 - Actual IP30: 205 bbl/d (15 wells)⁽²⁾; IP60 192 bbl/d (14 wells)⁽²⁾ average 2025 wells
 - 3.0 net Step-Out / Delineation Wells – 50m inter-leg spacing well design
 - 1.0 net 8 leg waterflood producing well and 1.0 net injection well at 9-35 Pad pilot
 - 1.0 net Sparky exploration well – IP30 286 bbl/d

Gas Conservation Project

- Constructed 3 - 4 MMcf/d gas plant & gathering system; On-stream Jan 23, 2025
- Expanded to 6.4 MMcf/d in H2 2025 to accommodate growth

H1 2026 Activity – One Rig Clearwater Drilling Program at 8-26 Pad

Clearwater Development Inventory

- 237.7 net Clearwater locations (Wabiskaw Member; as at Jan 1, 2026 - 56% unbooked)
 - 44% booked in 2025 McDaniel Reserve Report (107.7 net locations)
 - 69.1 net proven undeveloped and 38.6 net probable undeveloped booked⁽³⁾
 - 130.0 net additional unbooked Clearwater drilling locations⁽⁴⁾ on captured lands
- >13 years of development for one-rig program at 18 wells/year

Sparky Development Inventory

- 15.0 net locations (as at Jan 1, 2026 - 87% unbooked)
 - 2.0 net proved undeveloped locations booked⁽³⁾

Enhanced Oil Recovery

- Primary Recovery ~5% of OOIP (estimated OOIP >1.1 Billion barrels⁽⁵⁾)
- Core, fluid compatibility analysis and competitor analog information informing pilots
- 4 Waterflood Pilots and 1 polymer flood pilot advancing in H1 2026
- Cyclic Gas Injection Pilot ongoing

- Total Proved Plus Probable Undeveloped (P+PUD) reserve and economic parameters as per Year End 2024 McDaniel Reserve Report – Figure Lake Type Curve run on Jan 1, 2025 3 Consultant Average Price Deck.
- No wells excluded from calculation of average rates, other than meeting minimum criteria of producing days.
- Total Proved Plus Probable Undeveloped (P+PUD) location count as per Rubellite Year End 2025 McDaniel Reserve Report.
- Figure Lake internally-recognized additional development location inventory not recognized in McDaniel Report; See "Drilling Locations" in Advisories.
- OOIP – Original Oil In Place based on internal estimates.

Rubellite Asset Profile | Figure Lake Type Curves



33m down-space wells exceeding YE2025 type curve⁽¹⁾ IP30 by 10%

Clearwater Development

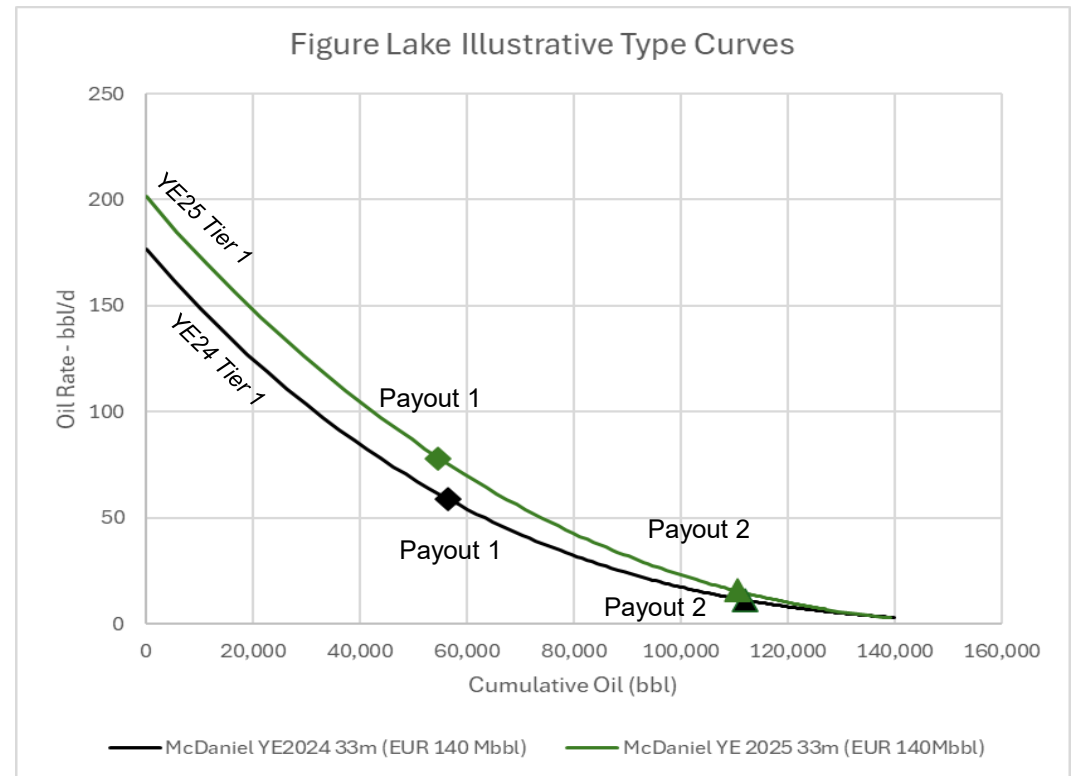
- Historical well design: ~50m inter-leg spacing
 - 8 open hole lateral legs with oil-based mud
 - ~10,000m MD of open hole
- Down-space well design: ~33m inter-leg spacing
 - 12 open hole lateral legs; >15,000m MD of open hole
 - Average IP30 222 bbl/d (23 wells) IP60 205 bbl/d (21 wells) to date⁽³⁾

Improvements to 33m inter-leg spacing type curve from YE 2024:

- Increased Type Curve IP30 by 16% to 201 bbl/d (YE 2025 vs YE 2024)⁽¹⁾
- Increased NPV per Location by 16% to \$2.2 MM (YE 2025 vs YE 2024)⁽¹⁾
- Accelerates Payout by 21% from 1.6 to 1.3 years⁽¹⁾

Type Curve Sensitivities – Figure Lake

Assumptions	33m Inter-leg Spacing Tier 1	33m Inter-leg Spacing Tier 1
	McDaniel Type Curve (YE 2024) ⁽¹⁾	McDaniel Type Curve (YE 2025) ⁽¹⁾
Drainage Area (Ha)	50	50
Horizontal Length (m)	15,000	15,000
IP30/100m (bbl/d)	1.18	1.34
IP30 (bbl/d)	177	201
IP360 (bbl/d)	120	136
Estimated Ultimate Recovery TPP (Mbbbl)	140	140
Economics⁽¹⁾ (gross per well)		
D,C&E Capex (\$MM)	2.5	2.5
D,C&E Capex (\$/m)	165	165
TPP F+D (\$/bbl)	17.80	17.74
NPV10 (\$MM)	1.9	2.2
First Payout (months)	19	15
Second Payout (months)	92	68
Third Payout (months)	-	-
# of Payouts	2.3	2.3
Rate of Return	57%	78%



- Total Proved Plus Probable (P+PUD) reserve and economic parameters as per Year End 2024 and 2025 McDaniel Reserve Reports – Figure Lake Type Curve run on Jan 1, 2026 3 Consultant Average Price Deck.
- Recovery Factor is defined by the estimated amount of hydrocarbons that can be produced from a reservoir vs. original amount in place, expressed as a percentage.
- No wells excluded from count except for producing day criteria for wells drilled with 33m inter-leg spacing.

Clearwater Enhanced Oil Recovery Pilots

Advancing Multiple Waterflood Pilots and Other EOR Experiments through 2026

Marten Hills Bottom Up Waterflood

12-34 Pad Waterflood Pilot

Multi-lat Injector placed below Multi-lat Producer
Injection commenced May 2025

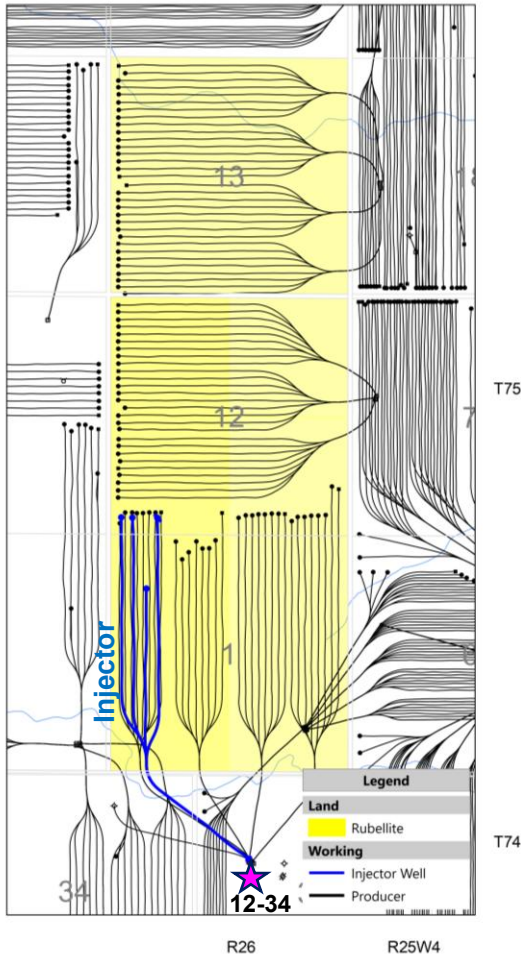
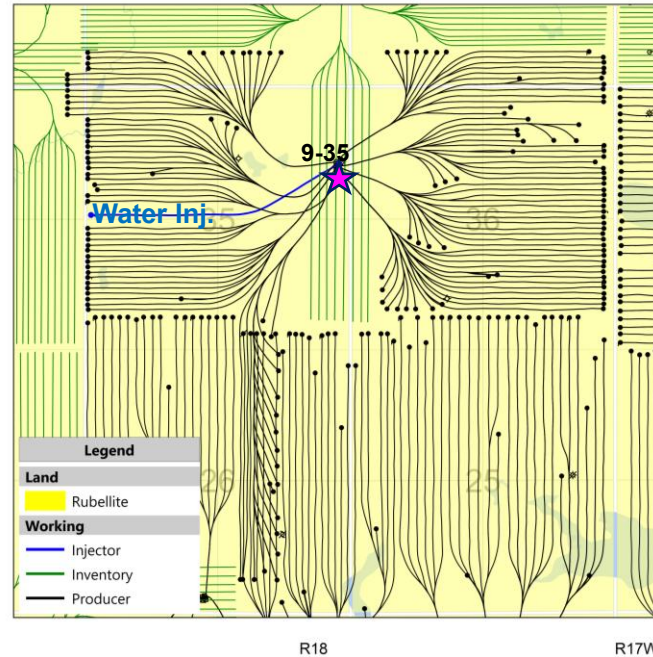


Figure Lake Line Drive Waterflood and Polymer Flood

9-35 Pad Waterflood Pilot

Single Leg water Injector placed in middle of 8-leg Multi-lat Producer
Injection commenced March 2026



8-26 Pad Waterflood & Polymer Pilots

Single Leg Injectors placed in middle of 8-leg Multi-lat Producers
Water injection Q2/26; Polymer Injection Q4/26

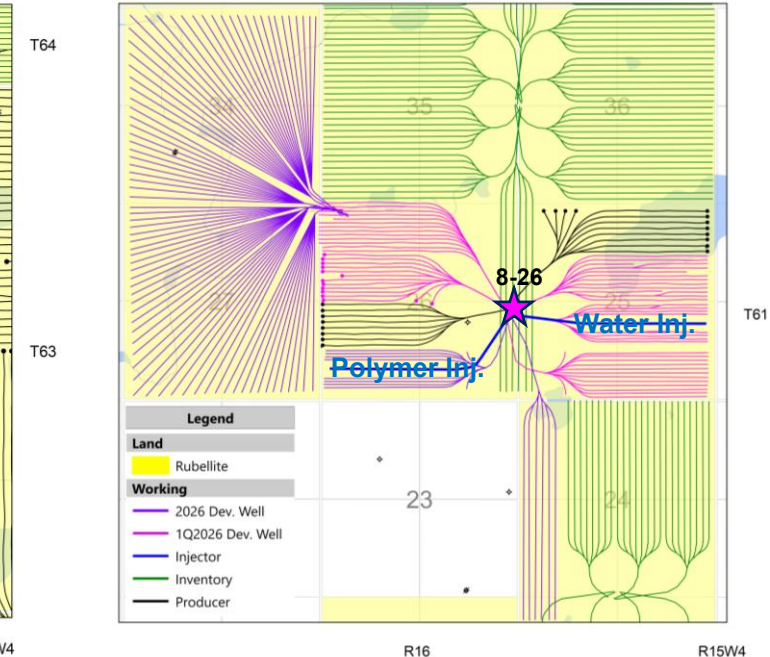


Figure Lake Multi-lat Conversion Waterflood

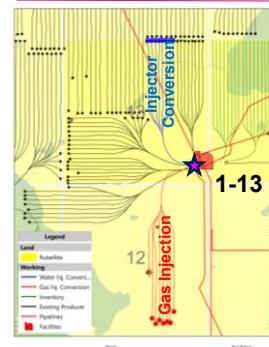


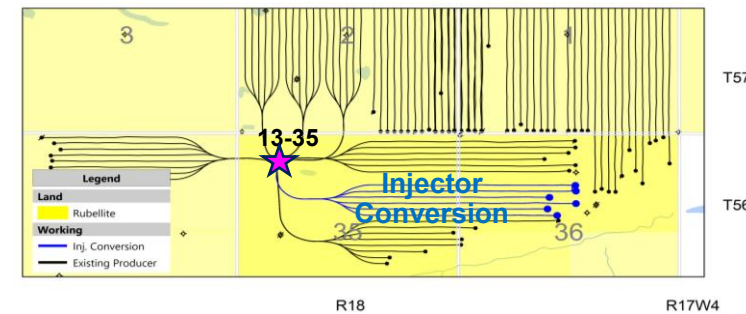
Figure Lake 1-3 & 1-13 Pads

2 existing Multi-lats to be converted from Producer to Injector
Injection to commence Q2/26
Cyclic Gas Injection ongoing

Ukalta 13-35 Pad

1 existing Multi-lats to be converted from Producer to Injector
Injection to commence Q2/26

Ukalta Multi-lat Conversion Waterflood

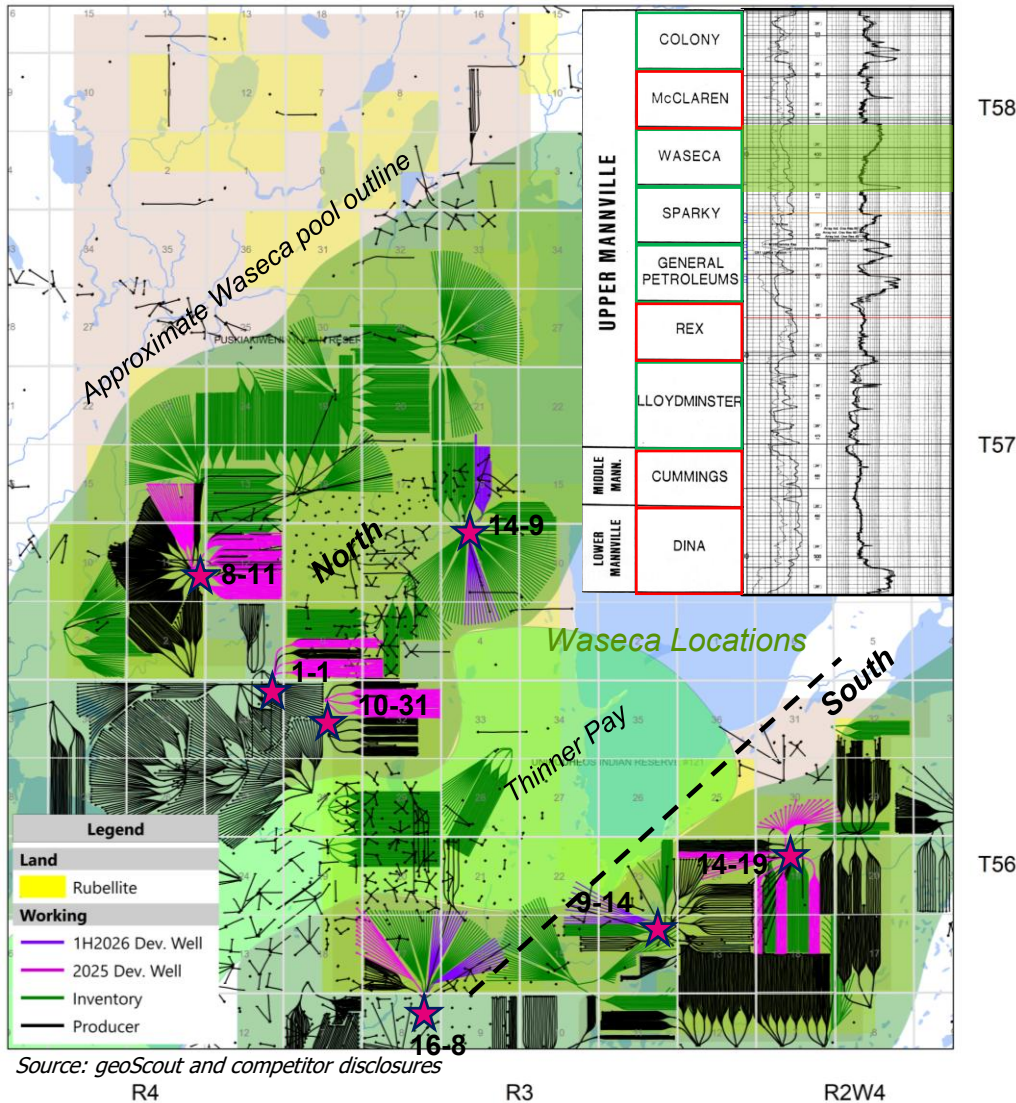


Rubellite Asset Profile | Frog Lake

Active Waseca development and GP delineation



Asset Map



Source: geoScout and competitor disclosures

Asset Summary

Primary Target: Waseca member of the Mannville Stack

Emerging New Zone targets: General Petroleum (GP) and Sparky

Working Interest: ~50%

- Joint Economic Development Agreements in place with Frog Lake First Nation Energy Resource Corp. (FLERC)
- FLERC can elect to participate as a 50% WI non-op partner or receive a gross overriding royalty of 5% on JED I & II, 6.5% on JED III

Key Statistics:

- 21,816 net acres (39,725 gross); 34.1 net sections (62.1 gross)
- Q4 2025 Production 2,985 bbl/d (100% heavy oil)
 - 52.0 net (80 gross) producing wells
- 94 gross (47.0 net) Waseca locations (as at Jan 1, 2026)
 - 16.0 net proven and 5.0 net probable booked⁽¹⁾ Waseca locations
 - 26.0 net additional Waseca inventory locations⁽²⁾ on existing lands
 - >3.5 years of Waseca development at 24 gross (12.0 net) wells/year
- 220 gross (110 net)⁽³⁾ additional potential locations across other zones within Mannville Stack (GP, Sparky, Rex, Lloyd, and McLaren)

2025 Activity: Focus on Waseca development & New Zone exploration

- 21 (15.5 net) Waseca Hz multi-lateral development wells
 - Waseca North IP30 133 bbl/d (14 wells) and IP60 112 bbl/d (14 wells) vs. McDaniel Waseca North Type Curve⁽²⁾ of 107 bbl/d and 104 bbl/d
 - Waseca South IP30 153 bbl/d (7 wells) and IP60 145 bbl/d (7 wells) vs. McDaniel Waseca South Type Curve⁽²⁾ 145 bbl/d and 145 bb/d
- 5 (4.0 net) New Zone (Sparky and GP) wells drilled as single leg horizontals

2026 Activity:

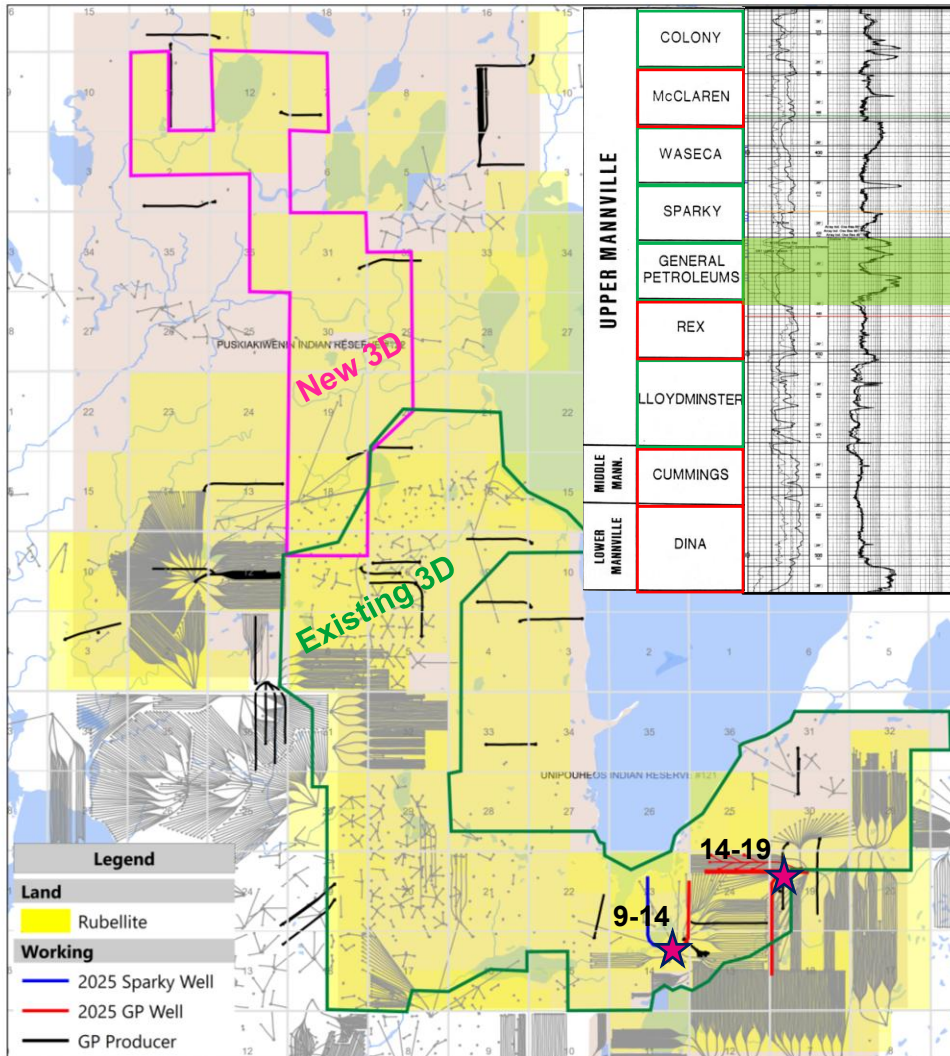
- Continued Focus on Waseca development & follow up GP delineation

1. Total Proved Plus Probable (P+PUD) reserves, economic parameters and Type Curve as per Year End 2025 McDaniel Reserve Report proved ; See "Drilling Locations" in Advisories.
 2. Frog Lake additional development location inventory and secondary zone exploration location inventory not recognized in McDaniel Report assumes 50% working interest; See "Drilling Locations" in Advisories.
 3. Assumed FLERC participation of 50%.

Rubellite Asset Profile | Frog Lake

GP Delineation

Asset Map



Source: geoScout and competitor disclosures

1. Location count subject to final inter-well spacing and well design.
2. Total Proved Plus Probable Undeveloped (P+PUD) reserve and economic parameters as per Year End 2025 McDaniel Reserve Report.

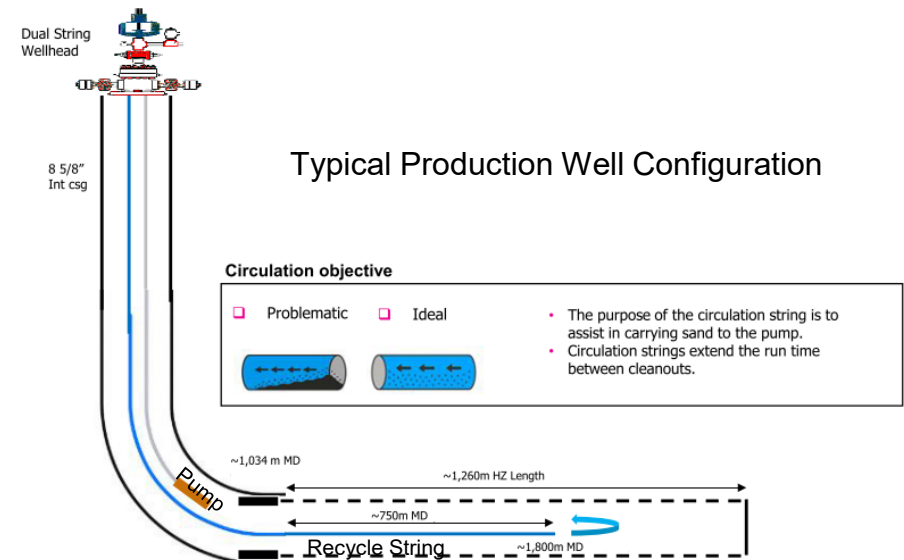
Asset Summary

Multiple 'New Zone' Targets in Mannville Stack

- McLaren, Sparky, GP, Rex and Lloyd
- >110.0 net Locations⁽¹⁾ delineated by existing and 25 km² new shoot 3D Seismic

General Petroleum ("GP") Delineation

- GP historically developed in greater Frog Lake region using single lined laterals, proving productivity
- Modern well designs are incorporating "recycle" strings to circulate produced water along the horizontal section, clearing the well bore of solids to enhance productivity
- 4 (3.0 net) GP wells drilled in 2025 – Monitoring production performance
 - 1 (1.0 net) Fish Bone Design
 - 3 (2.0 net) Single Lined Lateral with Re-circulating String Design
- 80 net locations (as at Jan 1, 2026) (90% unbooked)
 - 3.5 net Proved Undeveloped and 5.0 Probable Undeveloped locations booked⁽²⁾



Rubellite Asset Profile | Frog Lake Type Curves



Mannville Stack – Waseca North, Waseca South, and General Petroleum

Waseca Development

- Historical well design:
 - ~25m inter-leg spacing
 - ~15,000m MD of open hole multi-lateral
 - Multiple different mud and well designs to improve hole cleaning, decrease time to on first oil sales, and increase production and reserves

Testing 20,000m Waseca wells in 2026

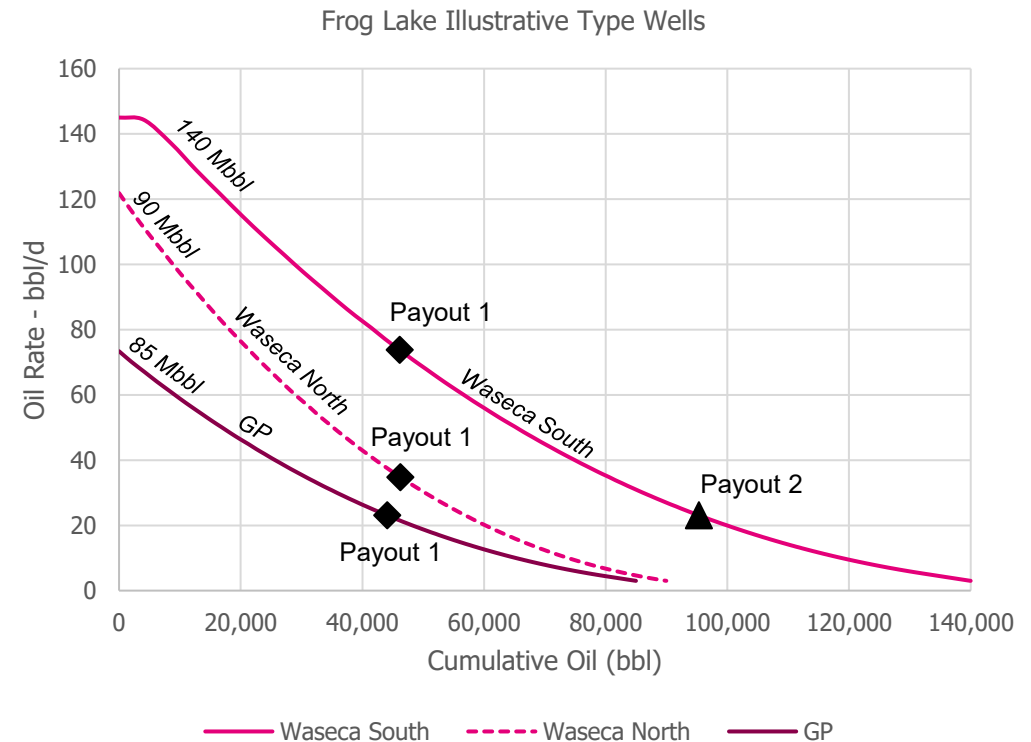
- Larger drainage area, well bore diameter, and overall length to improve capital cost per meter drilled
- Implementing water-based mud with new amine system to lower drilling costs

GP Development

- Single lined laterals equipped with recycle strings to lift solids

Frog Lake Type Curves

Assumptions (gross per well)	Frog Lake Type Curve		
	Waseca North ⁽¹⁾	Waseca South ⁽¹⁾	GP ⁽¹⁾
Drainage Area (Ha)	50	50	12
Horizontal Length (m)	15,000	15,000	1,200
Inter-leg Spacing (m)	25	25	-
IP30/100m (bbl/d)	0.8	1.0	6.1
IP30 (bbl/d)	122	145	73
IP360 (bbl/d)	85	114	58
Estimated Ultimate Recovery TPP (Mbbbl)	90	140	85
Economics⁽¹⁾ (gross per well)			
D,C&E Capex (\$MM)	2.0	2.0	1.7
D,C&E Capex (\$/m)	133	133	1,446
TPP F+D (\$/bbl)	23.47	14.88	21.78
Net NPV10 (\$MM) (50%WI)	0.38	1.06	0.25
First Payout (months)	24	15	36
Second Payout (months)	-	54	-
Third Payout (months)	-	-	-
# of Payouts	1.6	2.6	1.6
Rate of Return (%)	36	82	24



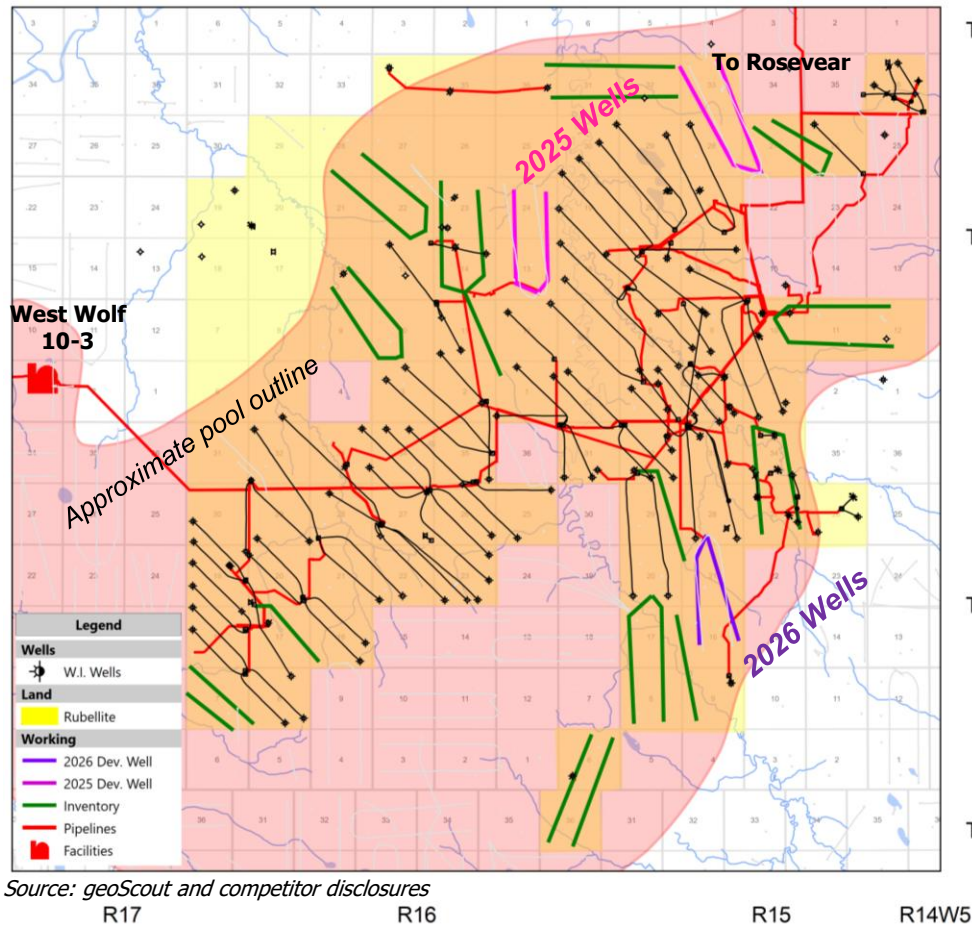
1. Total Proved Plus Probable (P+PUD) reserves and economics as per Year End 2025 McDaniel Reserve Report run on Jan 1, 2026 3 Consultant Average Price Deck. NPV10 is shown as Net (50% WI to Rubellite). All other parameters are gross.

Rubellite Asset Profile | East Edson

Deep Basin Wilrich Liquids-Rich Gas



Asset Map



Asset Summary

Working Interest: 50%

- Non-operated interest with best-in-class operator (Tourmaline – TSX:TOU)

Net Production:

- 4Q25 sales: 3,802 boe/d (20.3 MMcf/d; 426 bbl/d NGL)
- 18.8 bbl/MMcf NGL yield
- Processing Capacity: 78 MMcf/d gross (39.0 MMcf/d net)
 - West Wolf: 65 (32.5 net) MMcf/d
 - Rosevear: 13 (6.5 net) MMcf/d

2025 Capital Activity

- 4 (2.0 net) wells required to sustain current production
 - >3,000m Hz length per well

2026 Capital Activity

- 2 (1.0 net) wells drilled in Q1 2026 and placed on production

Location Inventory

- Wilrich drilling inventory to sustain production at infrastructure capacity through 2029
 - 7.5 net proven undeveloped and 4.4 net probable undeveloped booked⁽²⁾ Primary Zone HZ Development locations
- Secondary Zone potential in multiple proven horizons
 - Resource in Cardium, Viking, Notikewin, Falher, Rock Creek, Gething, and Second White Specks Shale proven in vertical producers

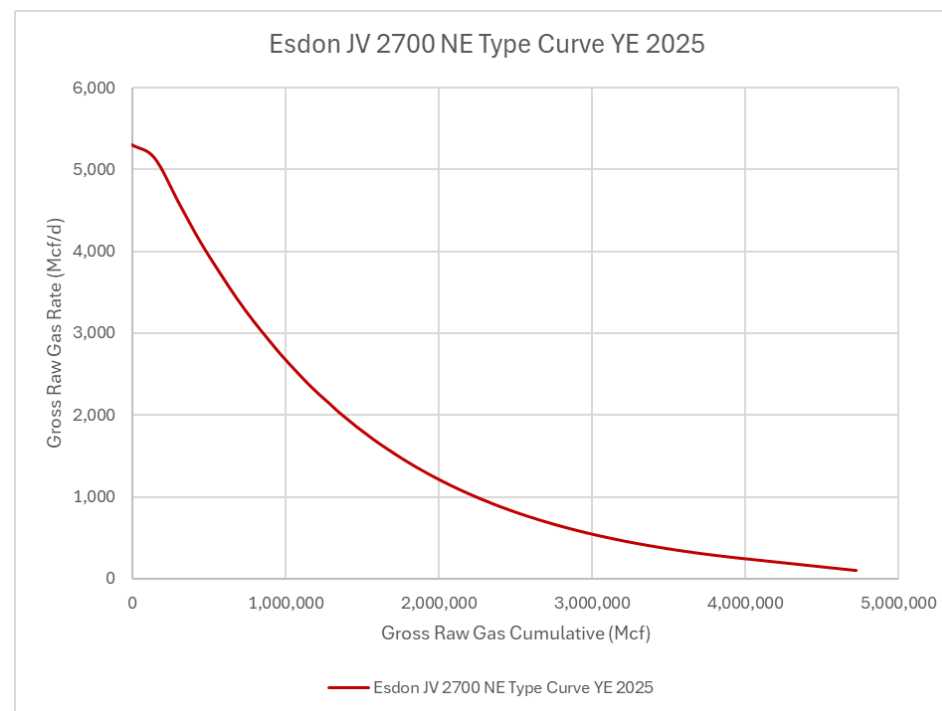
1. Total Proved Plus Probable Undeveloped (P+PUD) location count, reserve and economic parameters as per Rubellite Year End 2025 McDaniel Reserve Report

Rubellite Asset Profile | East Edson Liquids Rich Gas

Deep Basin Liquids-Rich Gas – Illustrative Price Sensitivities



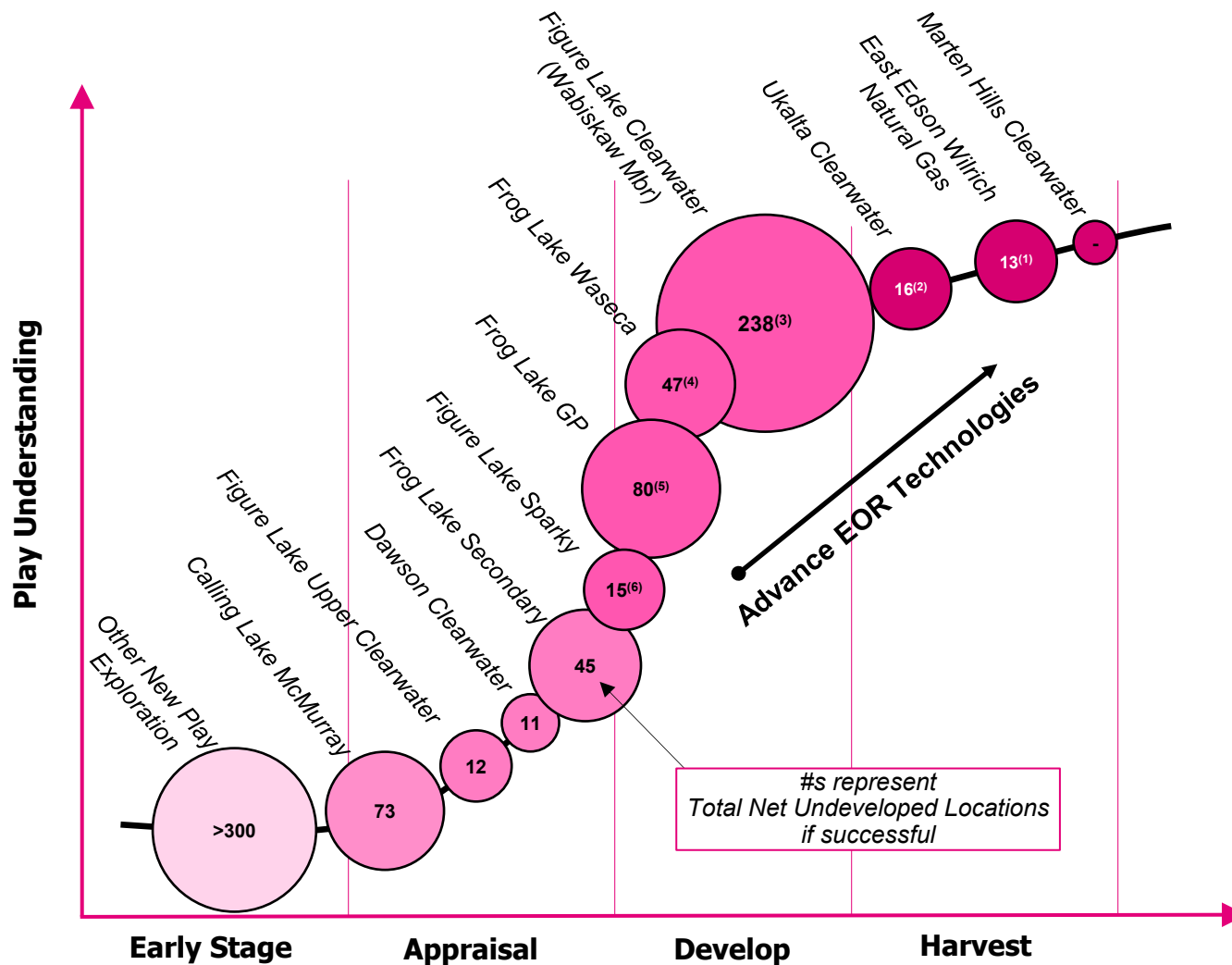
Assumptions	East Edson ⁽²⁾⁽³⁾		
	Strip ⁽¹⁾	\$3/GJ	\$4/GJ
Horizontal Length (m)		2,700	
IP30 (boe/d) (Gross)		905	
IP360 (boe/d) (Gross)		600	
Ultimate Recovery (Mboe) ⁽²⁾ (Gross)		807	
Economics (50% WI)		McDaniel Type Well ⁽³⁾	
D,C&E Capex (\$MM)		\$3.3	
NPV10 (\$MM)	\$0.5	\$1.4	\$2.9
First Payout ⁽⁴⁾ (years)	5.0	2.4	1.4
Second Payout (years)	-	19.0	7.4
Third Payout (years)	-	-	20.7
# of Payouts	1.9	2.1	2.8
Rate of Return (%)	15%	31%	62%



1. Strip pricing March 2, 2026.
2. IP data, length, and Expected Ultimate Recovery ("EUR") are gross per well as per Rubellite Year End 2025 McDaniel Reserve Report, run on different price sensitivities. \$3, \$4/GJ sensitivities are constant, no inflation. IP and Ultimate Recovery include liquid yields, and shrinkage.
3. McDaniel YE 2025 2700-Northeast Edson Joint Venture Type Well EUR and economic parameters, run at different price sensitivities, noted above. All Economics are at 50% WI, net to Rubellite.
4. Undiscounted Payout(s).

Exploration Prospect Pipeline

Feeding a "pipeline" of primary development projects from new exploration plays



'New Zone' Appraisal⁽⁷⁾

Frog Lake Secondary Zones: 45 net⁽⁸⁾ Locations

- Sparky, Lloyd, Rex, and McLaren Zones

Figure Lake Upper Clearwater: 12 net Locations

- New pools mapped

Dawson Clearwater: 11 net Locations

- 23.0 net sections
- Horizontal test well drilled in Q1 2023 – Winter production only

Calling Lake McMurray: 73 net Locations

- 108.0 net sections
- One (1.0 net) Horizontal test well drilled in Q4 2024
- Likely hole collapse affecting inflow

'New Play' Exploration⁽⁷⁾

Other Early-Stage Exploration

- Land capture ongoing in new heavy oil plays
- Targeting new zones and formations amenable to open-hole horizontal multi-lat development
- Test well drilled Q1 2026

As per Rubellite Year End 2025 McDaniel Reserve Report:

1. East Edson Wilrich has 7.5 (net) Proved Undeveloped and 4.4 (net) Probable Undeveloped Locations.
2. Ukalta Clearwater has 11.0 (net) Proved Undeveloped and 5.0 (net) Probable Undeveloped Locations.
3. Figure Lake Wabiskaw has 69.1 (net) Proved Undeveloped and 38.6 Probable Undeveloped.
4. Frog Lake Waseca has 16.0 (net) Proved Undeveloped and 5.0 (net) Probable Undeveloped Locations.
5. Frog Lake GP has 3.5 Proved Undeveloped and 5.0 Probable Undeveloped Locations.
6. Figure Lake Sparky has 2.0 Proved Undeveloped Locations.
7. Location count subject to final inter-well spacing and well design.
8. Frog Lake secondary zones assumed at 50% working interest.

Guidance and Balance Sheet



Debt reduction driven by \$11.6 MM in free funds flow & \$7.8 MM in non-core land dispositions in 2025

Guidance (March 10, 2026)

	2025A	Q1 2026
E&D Spending ⁽¹⁾⁽²⁾ (\$ MM)	\$114.6	\$30 - \$32
Average Sales Production (boe/d)	12,494	13,300 – 13,400
Production mix (% oil and liquids) ⁽³⁾	70%	67%
Heavy Oil Production (bbl/d)	8,402	8,300 – 8,400
Heavy Oil Wellhead Differential ⁽⁴⁾ (\$/bbl)	\$3.76	\$3.50 - \$4.00
Royalties ⁽⁵⁾ (% of revenue)	13.4%	13% - 14%
Operating Costs (\$/boe)	\$6.48	\$6.50 - \$7.25
Transportation Costs (\$/boe)	\$5.18	\$4.50 - \$5.00
G&A (\$/boe)	\$3.48	\$3.00 - \$3.50

1. Exploration and Development spending for 2026 includes the drilling of 4 (4.0 net) horizontal multi-lateral development wells (15,000 meter, 12 leg, standard well design), 1 (1.0 net) waterflood pilot producer-injector pair (10,000 meter, 8 leg, producer and a single leg waterflood injector) and 1 (1.0 net) polymer flood pilot producer-injector pair (10,000 meter, 8-leg producer and a single leg polymer injector with the producer expected to be drilled over quarter end and included in the Q2/26 well count and the injector drilled in Q2/26) in the Greater Figure Lake area and 3 (2.5 net) at Frog Lake, 2 (1.0 net) wells at East Edson and 1 (1.0 net) additional exploration well.
2. Excludes land purchases, land dispositions and acquisitions, if any. During 2025, land and other spending was \$10.5 million, \$5.0 million was spent on seismic. In addition, the Company received cash proceeds of \$7.8 million for land dispositions during 2025.
3. Liquids means oil, condensate, ethane, propane and butane.
4. Realized wellhead price relative to Western Canadian Select (C\$/bbl) benchmark pricing.
5. Includes Crown, freehold and GORRs.

Balance Sheet Reconciliation through 2024 Strategic Transactions

	Perpetual Q2/24	Rubellite Q3/24	Year End 2024 ⁽¹⁾	Year End 2025 ⁽¹⁾
Bank Debt Borrowing Capacity ⁽²⁾ (\$ MM)	\$30.0	\$100.0	\$140.0	\$140.0
Revolving Bank Debt Draw ⁽³⁾ (\$ MM)	\$1.5	\$72.2	\$105.9	\$92.6
Bank Syndicated Term Loan (\$ MM)		\$20.0	<i>Fully repaid</i>	
Rubellite Term Loan ⁽⁴⁾ (\$ MM)		\$20.0	\$20.0	\$20.0
Working Capital Deficit ⁽⁵⁾ (\$ MM)	-\$3.0	\$35.8	\$28.1	\$30.5
Perpetual Senior Notes ⁽⁶⁾ (\$ MM)	\$26.2		<i>Converted into shares</i>	
Total Net Debt⁽⁷⁾ (\$ MM)	\$24.7	\$147.9	\$154.0	\$143.1

1. Rubellite Yer End Balance sheet as at December 31, 2024; December 31, 2025.
2. Syndicate of four Canadian lenders; Bank line at September 30, 2024 of \$100 million for Rubellite and \$30 million for Perpetual; Bank line increased to \$140 million upon Recombination on October 31, 2024.
3. Rubellite Revolving Bank Debt Draw as at September 30, 2024; Perpetual as at June 30, 2024.
4. Rubellite Term Loan with 11.5% coupon and maturing in August 2029 subordinate in security to Perpetual's ongoing \$3.75 million annual payments under the "Settlement Agreement", announced on March 22, 2024, which has second lien security behind the recombined Company's consolidated credit facility until \$16.2 million remaining outstanding settlement amount to be fully paid prior to March 2030.
5. Rubellite Working Capital Deficit as at September 30, 2024; Perpetual as at June 30, 2024.
6. Based on the five-day volume weighted average price ("VWAP") for the Rubellite Shares prior to the Recombination Transaction announcement of \$2.25 per share.
7. Pre-Recombination Transaction - Rubellite Total Net Debt as at September 30, 2024; Perpetual as at June 30, 2024.

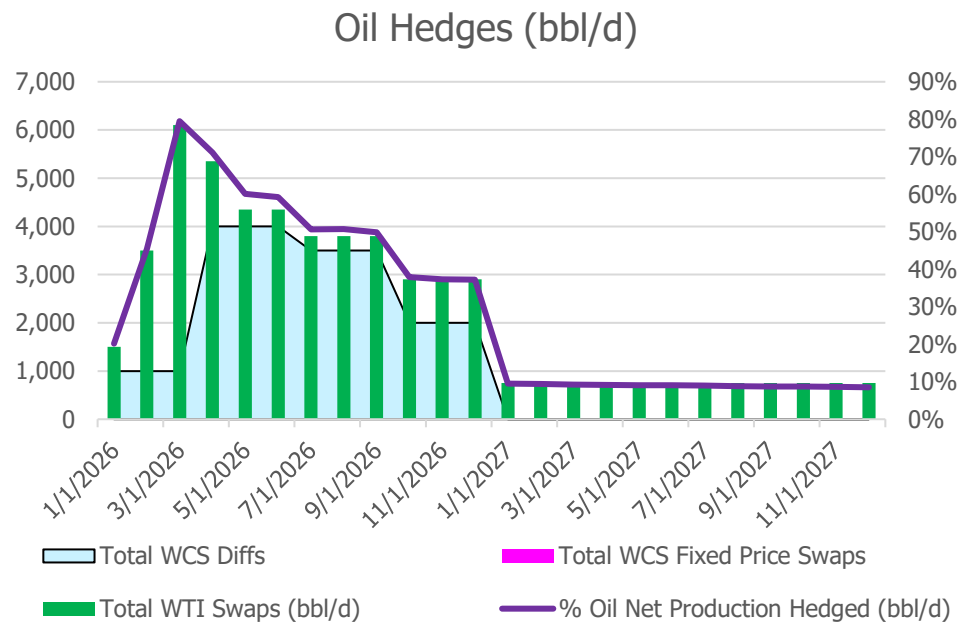
Generating material free funds flow after sustaining capital - Excess free funds flow to be directed to organic growth, exploration land capture & evaluation, acquisitions & debt repayment

Commodity Price Risk Management

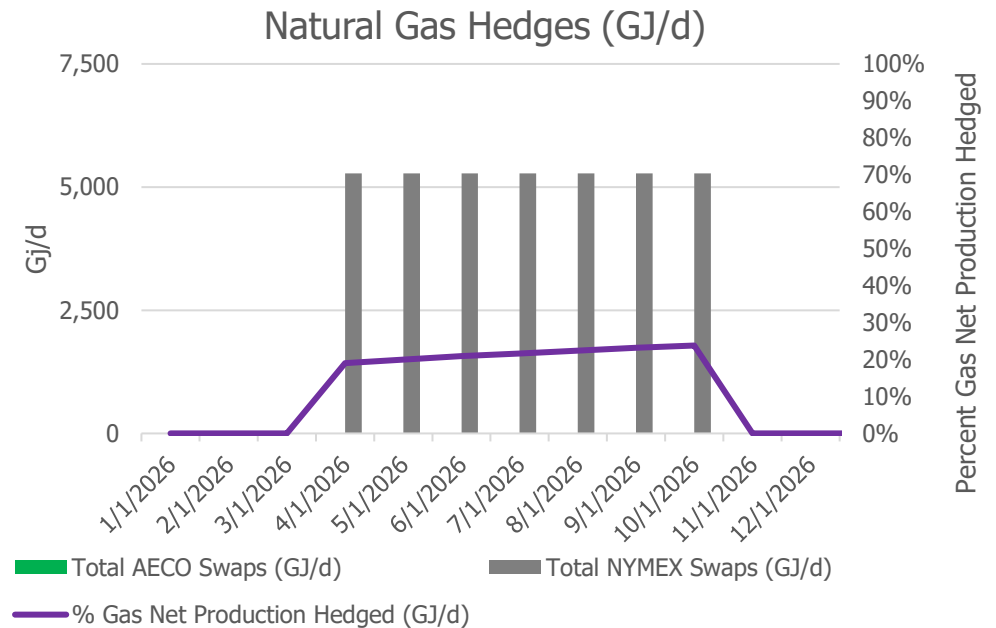


Price protection on ~50% of Q2-Q4 2026 and 9% of 2027 oil production, net of royalties⁽¹⁾

Oil Price Risk Management



Natural Gas Price Risk Management



- Physical forward sales contracts and financial derivatives used to:
 - Increase certainty in adjusted funds flow
 - Manage the balance sheet
 - Ensure adequate funding for capital programs
 - Lock in investment returns
 - Take advantage of perceived anomalies in commodity markets
- 2025 Hedge positions added \$11.4 MM of realized value for the twelve months ended December 31, 2025
- RBY Average Oil Hedge Price (WCS Q2-Q4 2026) of ~C\$71.55/bbl

1. As at March 10 2026; See Appendix for detailed Risk Management positions.

Creating Differentiated Value for Shareholders

Junior E&P growth opportunity in the Clearwater and Mannville Stack multi-lat heavy oil plays



Expanding Pure Play Heavy Oil Multi-lat Asset Base

- 666 net sections of prospective Clearwater, Mannville Stack and Heavy Oil exploration lands
- Major producing properties at Figure Lake (Clearwater) and Frog Lake (Mannville Stack)
- Multiple exploration prospects captured with material success case location inventory identified
- Line of sight to additional exploratory land capture and M&A opportunities
- Several properties with near cold flow prospects to unlock with evolving solvent & low-grade heat technology

Robust Organic Heavy Oil Production Growth Profile

- Organic and M&A driven heavy oil production growth from initial 350 bbl/d in Sep 2021 to 8,295⁽¹⁾ bbl/d
- Highly profitable, full cycle IRRs with attractive payout periods under 1 year at historical prices since inception
- 396 net defined Development/Step-out heavy oil locations; >300/140 net potential exploration/appraisal locations
- Systematic evaluation of exploration/appraisal prospect inventory to inform sustainable target production levels
- Future waterflood and EOR potential to mitigate production declines and increase recovery

Fully Funded Development Generating Material Free Funds Flow

- Organic growth plan on development acreage funded through free funds flow
- Low royalties of ~13% and opex / transport costs of ~\$14.00 per boe on heavy oil CGU drive attractive netbacks
- Generating sustainable free funds flow at current commodity price strip
- Excess discretionary free funds flow after sustaining capital directed to accelerated organic growth, exploration land capture and evaluation, acquisitions, debt repayment and ultimately returns to shareholders

Conservative Capitalization and Risk Mitigation

- \$140 MM bank credit facility, drawn \$92.6 MM, and \$20 MM Term Loan at December 31, 2025
- Risk management with hedging to protect capital investment plans and returns during growth ramp up
- Net Debt to Q4 2025 Annualized Adjusted Funds Flow at ~1.1x
- Perpetual recombination added ~4,000 boe/d of liquids-rich gas-focused production, diversified revenue, synergies, financial flexibility and optionality

Management Alignment and Operational Excellence

- Strong management alignment with insider share ownership of 45.3% and 100% ownership of the Term Loan
- Six independent board members (50% women); Team-focused, inclusive corporate culture
- Focused operations using multi-lateral drilling technology from multi-well pads with limited surface footprint
- Negligible use of freshwater given no fracture stimulation and oil-based mud drilling systems
- Profitable solution gas conservation projects advancing to reduce emissions

1. Q4 2025 sales 100% heavy oil.

2026 Strategic Priorities

Value Creation through Heavy Oil Multi-lat Driven Play Strategies





Additional Information

*Sue Riddell Rose, President & CEO
Ryan Shay, Vice President, Finance & CFO*

*3200, 605 – 5 Avenue SW
Calgary, Alberta Canada T2P 3H5*

APPENDIX

2025 Annual Capital Spending

Development, Step-out Delineation, Exploration and Enhanced Oil Recovery Pilots



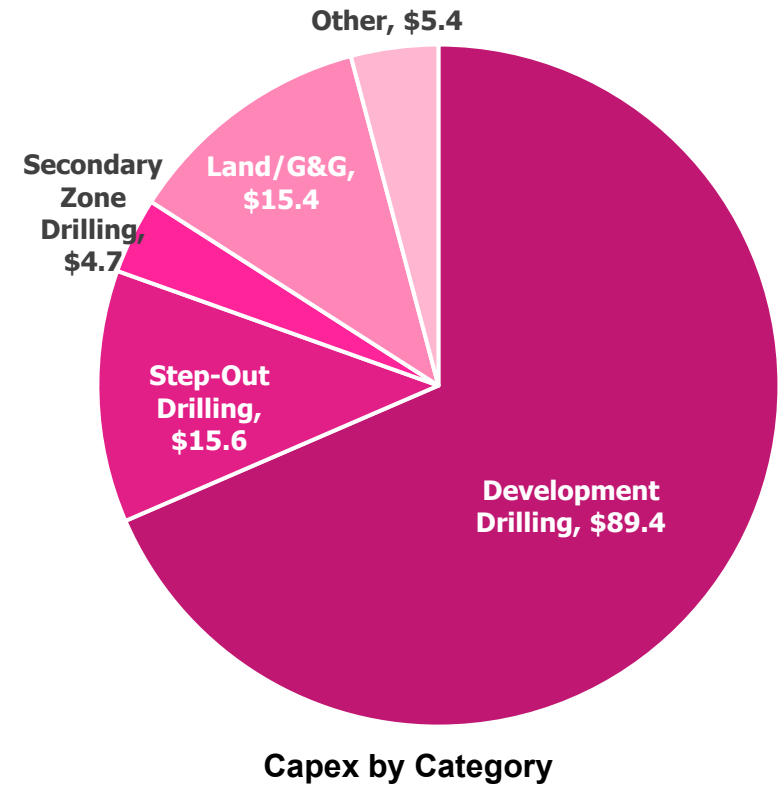
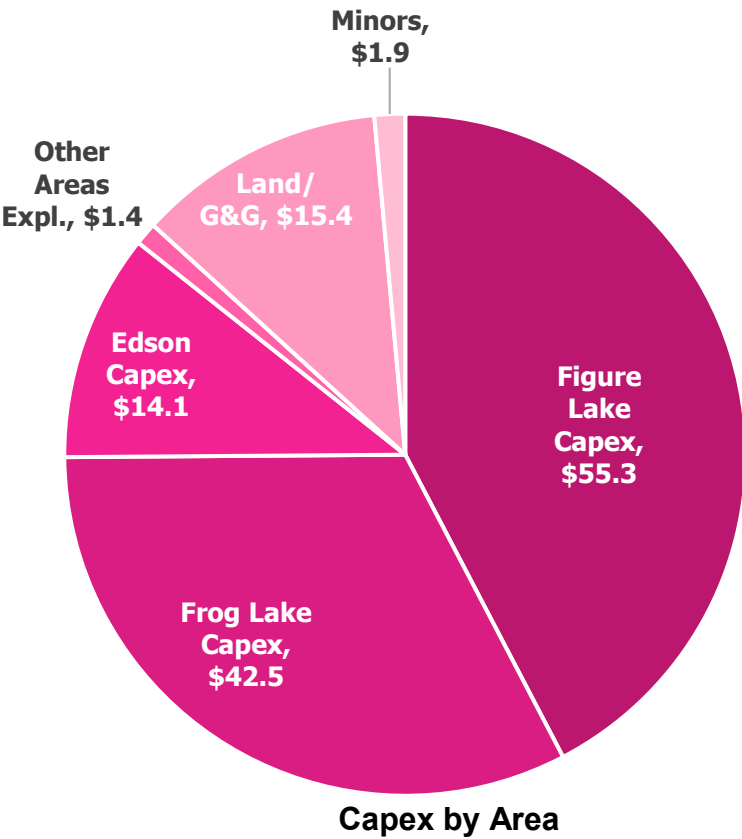
2025 Exploration and Development Spending

\$130.5 MM⁽¹⁾

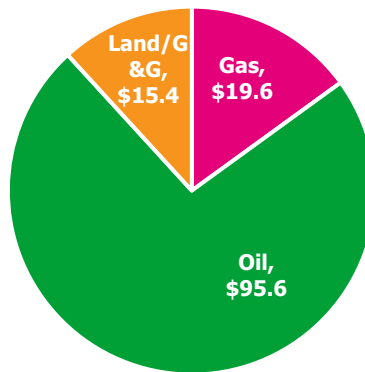
2025 E&D Spending:
53 gross / 43.8 net wells
Development and Exploration:

- Figure Lake⁽⁴⁾: 21 (21.0 net)
- Frog Lake⁽³⁾: 26 (19.5 net)
- Marten Hills⁽⁵⁾: 1 (0.3 net)
- East Edson: 4 (2.0 net)

Other Exploration: 1 (1.0 net)



Capex by Commodity⁽¹⁾



1. Excluding ARO, other corporate, net of inventory draws of \$0.5MM.
2. 'Gas' and 'Other' capital spending includes gas conservation infrastructure at Figure Lake.
3. Capital at Frog Lake includes 21 (15.5 net) Waseca development wells, 4 (3.0 net) General Petroleum ("GP") wells and one (1.0 net) Sparky well.
4. Capital at Figure Lake includes 15 (15.0 net) Clearwater development wells, 3 (3.0 net) Clearwater step out wells, 1.0 (1.0 net) injection well and 1 (1.0 net) well targeting the Sparky.
5. Development drilling at Marten Hills includes 1 (0.3 net) waterflood injector well.
6. Secondary Zone capital includes 1 (1.0 net) Sparky well at Figure Lake, 4 (3.0 net) GP wells at Frog Lake, 1 (1.0 net) Sparky wells at Frog Lake, and 1 (1.0 net) other exploration well.
7. Step out capital includes 3 (3.0 net) Clearwater wells at Figure Lake.
8. Development drilling includes 15 (15.0 net) Clearwater wells and 1 (1.0 net) injection well at Figure Lake, 21 (15.5 net) Waseca wells at Frog Lake, and 4 (2.0 net) Wilrich wells at East Edson.

2025 Corporate Reserves Highlights

All capital and including technical revisions



2025 Corporate Reserves Additions⁽¹⁾

Proved plus Probable

- TPP flat year-over-year, up 0.1% Mboe
- TPP per Debt Adjusted Share increased 9.2% year-over-year
- TPP Replaced 2025 Annual Production by 101%

Proved Developed Producing

- PDP increased 2.3% year-over-year
- PDP per Debt Adjusted Share increased 12.7% year-over-year
- PDP additions replaced 2025 Annual Production by 109%

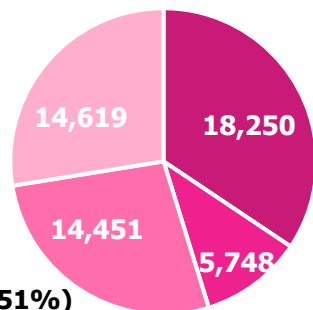
Reserve Life Index

- 2025 Annual Production 12,494 boe/d
- RLI ranging from 4.0 years (PDP) to 11.6 years (TPP)

Heavy Oil CGU Recycle Ratio⁽²⁾⁽³⁾ of 2.0 times

- 2025 Operating Netback of \$45.15/boe
- TPP Adjusted F&D, including cash proceeds, and changes in FDC of \$22.93/boe

YE 2025 Reserves (Mboe)⁽¹⁾



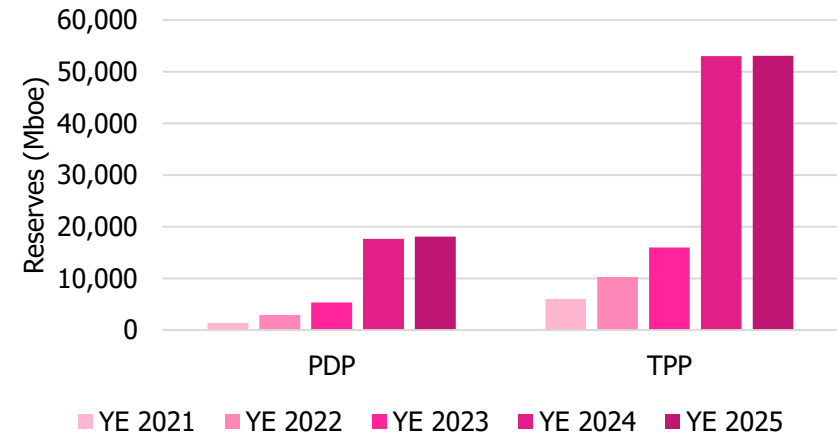
- Proved Developed
- Probable Developed
- Probable Undeveloped
- Proved Undeveloped

TP 32.9 MMboe

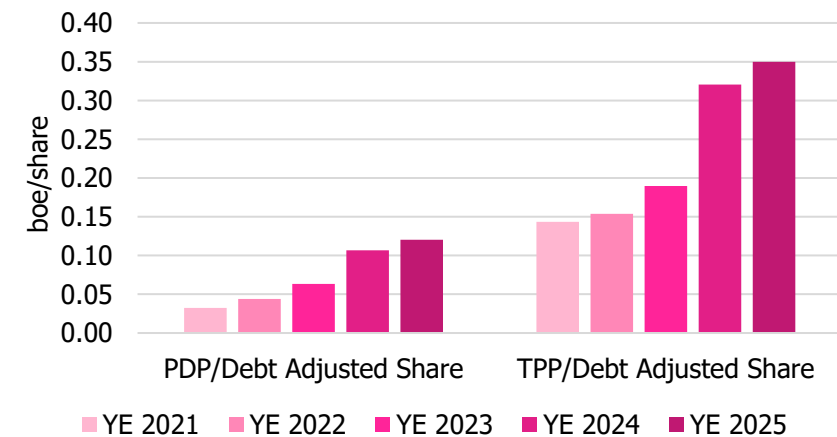
TPP 53.1 MMboe

TPP 55 % Heavy Oil (2024 - 51%)

Reserves⁽¹⁾



Reserves / Debt-Adjusted Share⁽¹⁾



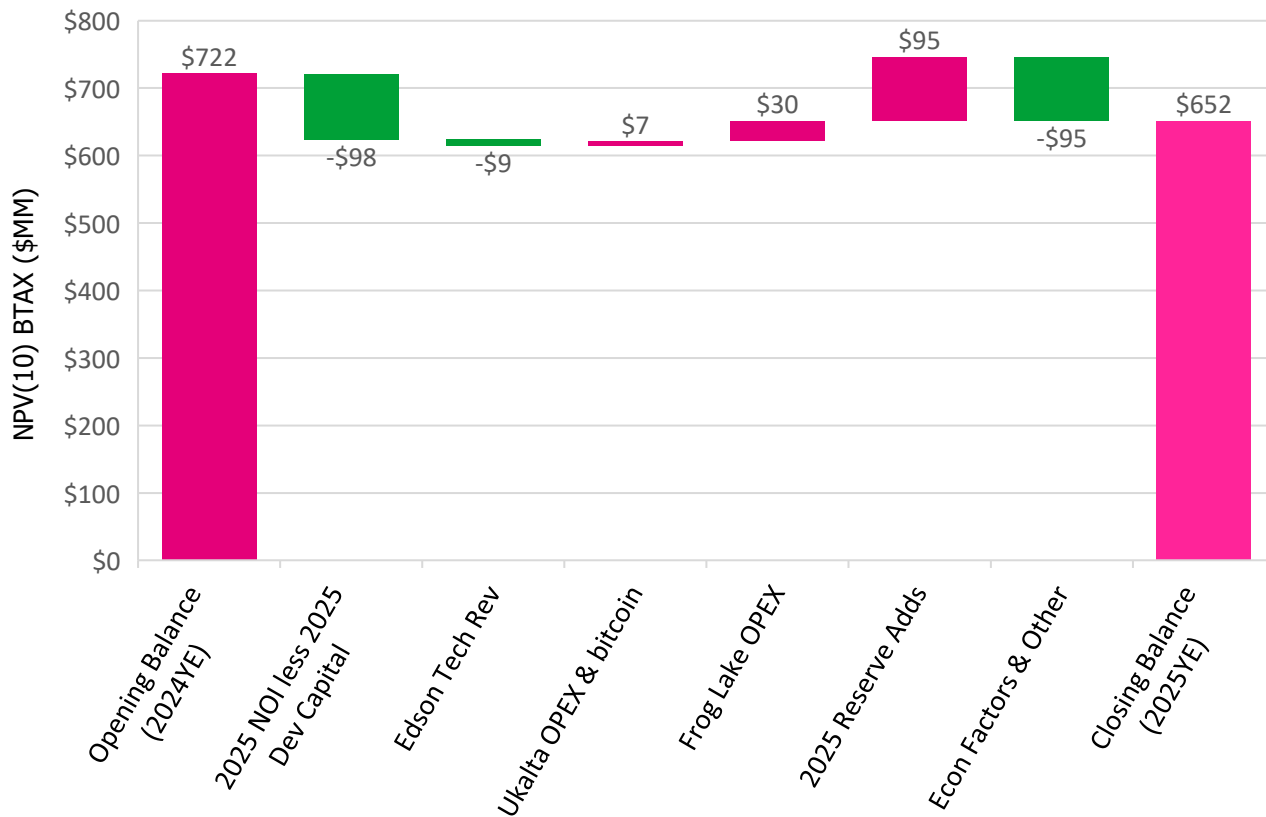
1. Proved Developed Producing (PDP), Proved (PUD) and Proved Plus Probable (TPP) reserves as per Year End 2025 McDaniel Reserve Report. Debt adjusted reserves per share is calculated by year end reserves volume divided by debt adjusted shares for reserves. Debt adjusted shares for reserves is calculated by converting the total debt to equity based on share price at Dec. 31, 2025 and adding to the share count at Dec. 31, 2025.
2. Based on 2025 operating netbacks as noted (excluding hedging gains/losses) and including technical revisions.
3. Includes cash proceeds from dispositions of undeveloped land of \$7.8 million which had no reserves assigned prior to the disposition.

Net Present Value of Reserves – Annual Reconciliation

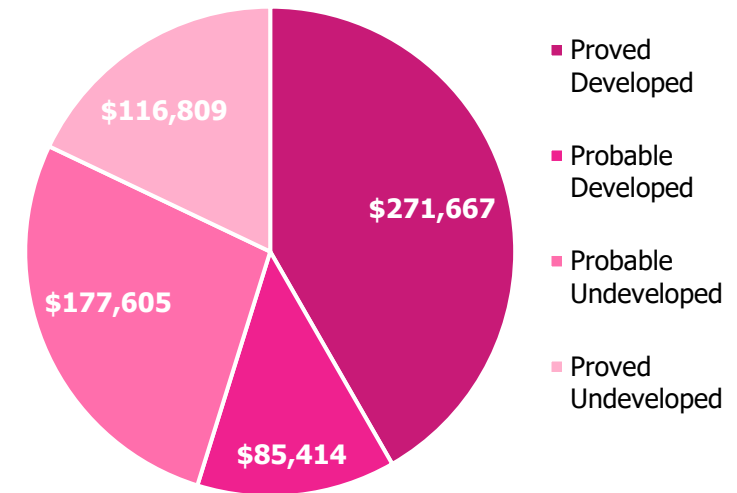
Price Impact reducing value of reserves



YE 2025 NPV(10) of TPP⁽¹⁾ Reconciliation to YE 2024



YE 2025 Reserves NPV(10)⁽¹⁾ (\$M)



TP \$388.5 MM (2024 - \$440.4)

TPP \$651.5 MM (2024 - \$721.5)

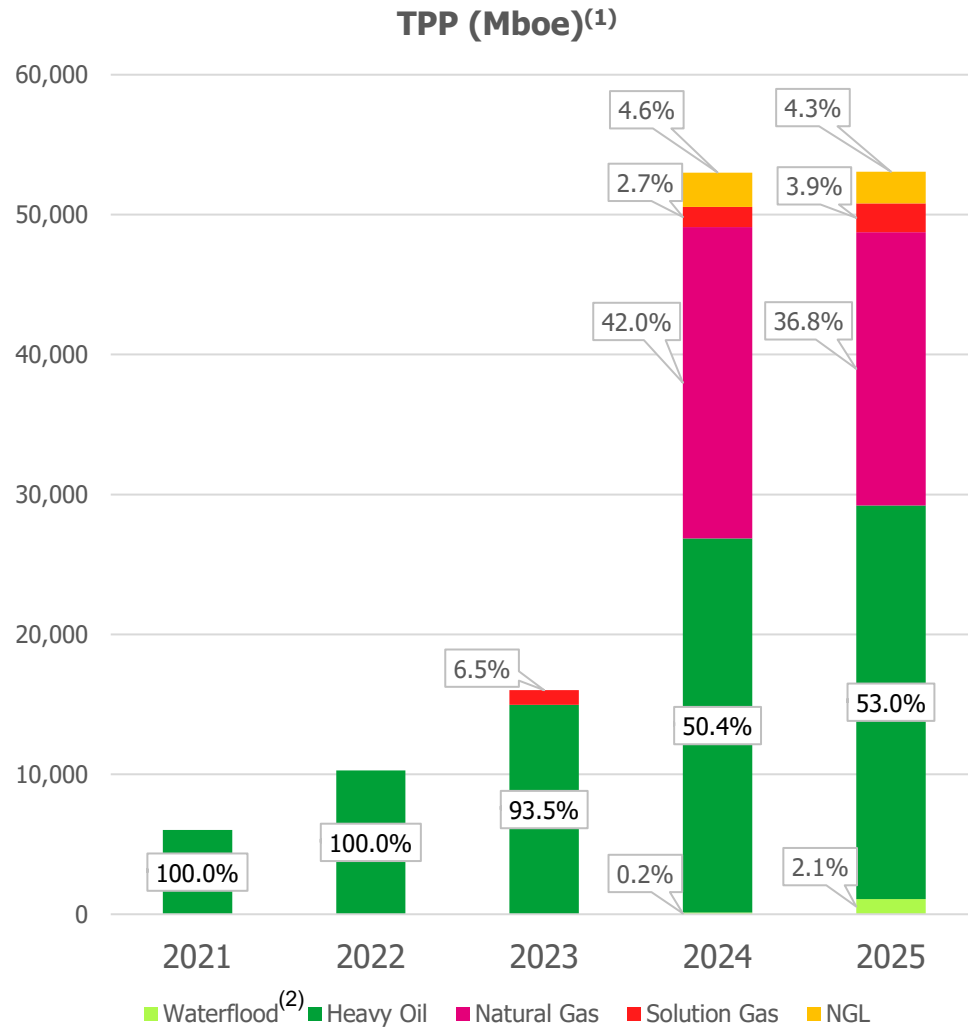
1. Proved Developed (PD), Proved (PUD), Total Proved (TP), Proved plus Probable Developed (P+PDV) and Proved plus Probable (TPP) reserves BTAX values discounted at 10% as per Year End 2025 McDaniel Reserve Report based on the Jan 1, 2026 Consultant Average Price Forecast.

Reserves and NPV(10) by Commodity

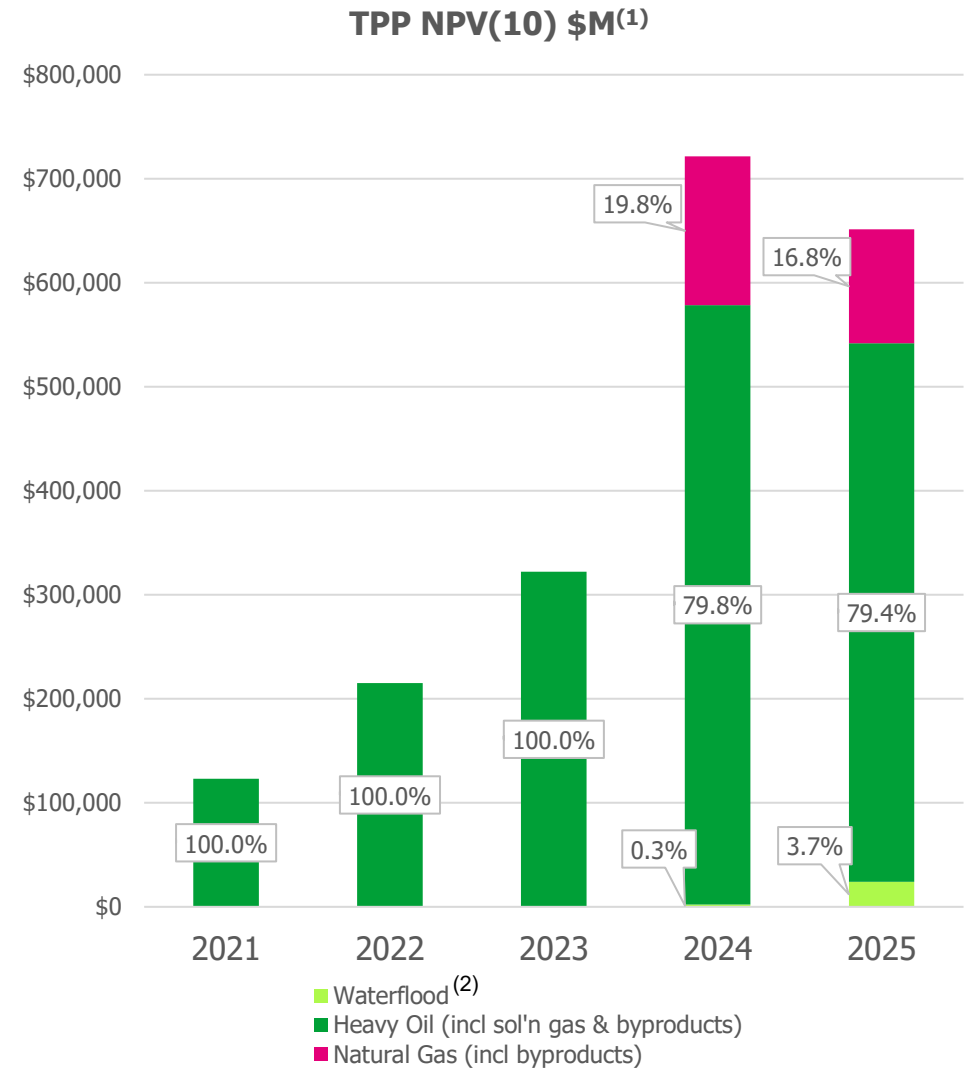
Initiating Waterflood in 2025



Reserves



Value



1. Total Proved plus Probable Reserves and Value for Rubellite as per Year End McDaniel Reserve Reports (Dec.31, 2021 through Dec.31, 2025).
 2. Waterflood reserves include all TPP reserves and net present value where production is supported by an existing or booked pattern.

Historical Financing

Strong insider support for equity and subordinated debt financings

- Rubellite acquired all of Perpetual's Clearwater Assets for total consideration of \$65.5 MM (including \$59.2 MM in cash)
 - Incorporated on July 12, 2021; Clearwater Assets conveyed on July 15th
 - Plan of Arrangement closed on September 3rd
 - Equity Financings closed / released from Escrow on Oct 5, 2021
- \$83.5 MM in Equity Financings (October 5, 2021)
 - \$30.0 MM Brokered Sub-Receipts Financing (closed into escrow July 13th)
 - \$20.0 MM Non-Brokered Private Placement
 - \$33.5 MM Arrangement Warrant ("rights offering") – Fully Back-stopped
 - All components of the financings priced at \$2.00/share
- \$38.7 MM in Equity Financings (March 30, 2022)
 - \$25.3 MM Brokered Financing; \$13.4 MM Non-Brokered Private Placement
 - Both financings priced at \$3.55/share
- \$20.0 MM Flow-Through Equity Financing (March 28, 2023)
 - Non-Brokered Private Placement priced at \$2.85/share
- \$97.5 MM purchase of Buffalo Mission Energy (August 2, 2024)⁽¹⁾
 - Funded with \$11.3 MM in equity (5 million shares @ \$2.25/share), expanded bank credit facilities and \$20 MM second-lien Term Loan
- Recombination Transaction – Rubellite and Perpetual exchanged shares for Rubellite Energy Corp. by way of a Plan of Arrangement
 - Rubellite Energy Inc. shareholders received 1 Rubellite Energy Corp share for every 1 Rubellite Energy Inc share held
 - Perpetual shareholders received 1 Rubellite Energy Corp. share for every 5 Perpetual shares held (issuance of 13.7 MM shares to Perpetual shareholders)
 - Closed October 31, 2024
- \$26.2 MM of Perpetual Senior Notes converted to Rubellite Energy Corp. shares
 - Closed October 31, 2024 with Recombination Transaction
 - 11.6 million shares at \$2.25 per share based on the 5-day VWAP prior to the announcement of the Rubellite / Perpetual Recombination Transaction
- *\$179.6 MM in equity raised to-date at average price of \$2.35/share*
 - *Insiders have participated for \$90.8 MM (~51%)*

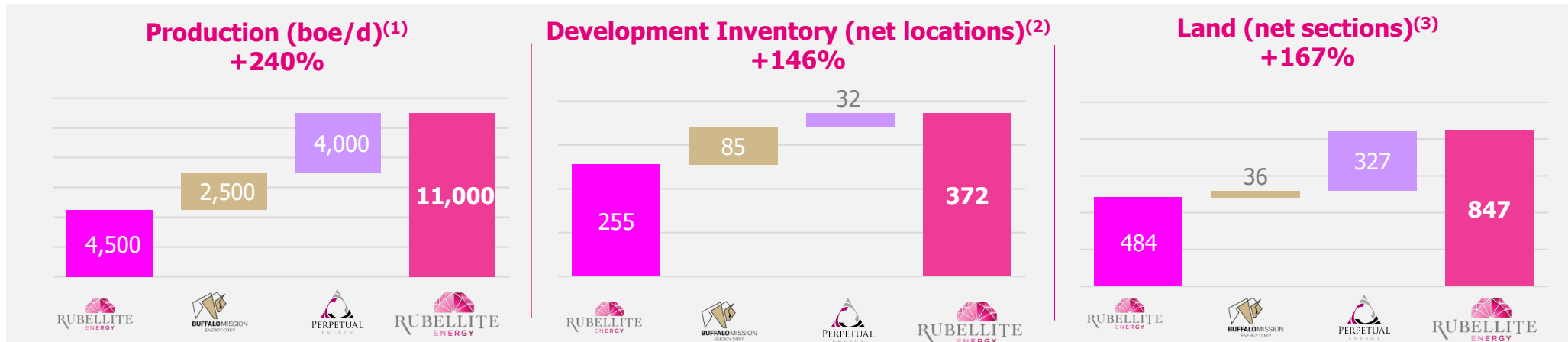
1. Based on the Rubellite's closing share price of \$2.07 per share on August 2, 2024, the fair value of the share consideration was \$10.4 million, resulting in a total purchase price of \$96.6 million

2024 Strategic Transactions

Strategic transactions since Q2/24 drive scale, enhanced financial flexibility and optionality



Buffalo Mission and Perpetual Recombination Transactions



1. Rubellite ~Q2 2024; ~Buffalo Mission at Close August 2, 2024; ~Perpetual Q2 2024
2. Frog Lake inventory assumes 50% working interest in locations in the Waseca and excludes potential drilling locations in other prospective zones
3. Net sections assuming 50% working interest in Frog Lake lands; excluding option lands

Rubellite Asset Highlights

- Large scale exposure to heavy oil in the Clearwater & Mannville Stack multi-lat plays
- Significant heavy oil development drilling inventory to support long-term growth
- Deep inventory of heavy oil multi-lat exploration prospects
- Exposure to enhanced oil recovery on assets with large OOIP
- Commodity diversification and financial optionality with Deep Basin natural gas asset

Buffalo Mission Energy Corp. Acquisition – Closed August 2, 2024

Highly complimentary Mannville Stack Asset Base added to existing Clearwater operations



Acquisition Highlights

- \$97.5 million total consideration⁽¹⁾
 - \$23.5 million of assumed net debt, \$62.7 million in cash & 5 million RBY shares at a deemed value of \$11.3 million
- ~2,500 boe/d net (100% heavy oil) (July field estimate)
- 67.3 gross (36.3 net) sections of contiguous Mannville Stack rights at ~54% working interest
- 170 gross (85 net)⁽²⁾ identified drilling locations in primary producing Waseca formation
- 220 gross (110 net)⁽²⁾ additional potential locations across other zones within Mannville Stack
- Focused operations in partnership with Frog Lake First Nation & FLERC⁽³⁾ through 50% JED participation

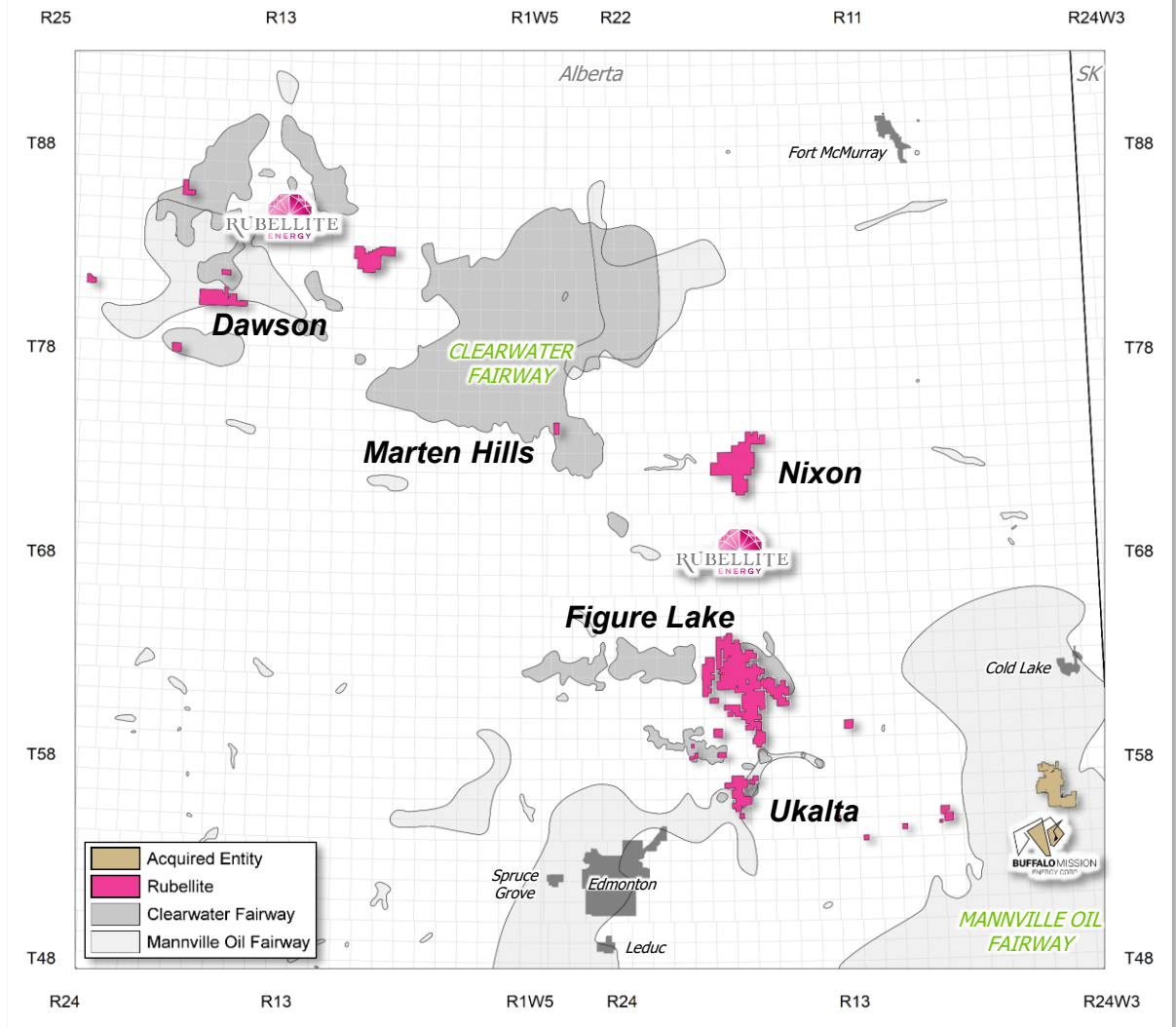
Transaction and FLERC Metrics

- 2.3x annualized net operating income with ~\$47/bbl operating netback at US\$75/bbl WTI
- \$39,000 per flowing boe acquired (100% heavy oil)

Strategic Rationale

- Attractive land, production and inventory base to ground a growth strategy in the complementary Mannville Stack play in the Cold Lake Oil Sands Region
- Positions Rubellite as a leading explorer, developer and consolidator in the Clearwater & Mannville Stack plays
- Increases size and scale
 - Increases high netback heavy oil production base by ~ 56%
 - Increases adjusted funds flow by approximately 38%
- Value-add inherent through synergies
- Enhances free funds flow to accelerate organic growth, advance exploration activities and reduce debt
- Expands strong relations with Indigenous communities through partnership with Frog Lake First Nation and FLERC

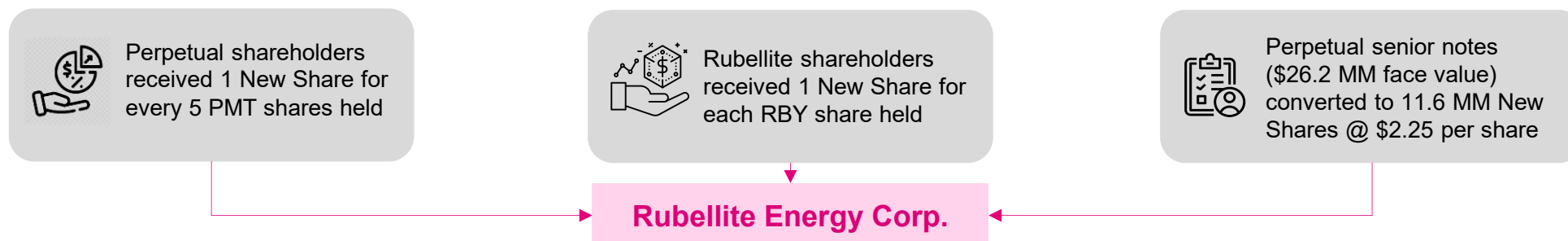
Clearwater and Mannville Stack Play Fairways



1. Based on the Rubellite's closing share price of \$2.07 per share on August 2, 2024, the fair value of the share consideration was \$10.4 million, resulting in a total purchase price of \$96.6 million in the Q3 2024 Financial Statements
2. Buffalo Mission inventory assumes 50% working interest; See "Drilling Locations" in Advisories
3. Frog Lake First Nation Energy Resource Corp. (FLERC) through Joint Economic Development (JED) Agreements

Rubellite & Perpetual Recombination – Closed October 31, 2024

Valuable synergies with increased scale, greater liquidity, funds flow diversification and optionality



Recombination Highlights

Rubellite Contributed - Large scale exposure to operated heavy oil assets in the Clearwater and Mannville Stack plays

- Over 7,000 boe/d (100% oil) of conventional heavy oil production
- 582 net sections of prospective Clearwater, Mannville Stack and Heavy Oil exploration lands
- Multiple exploration prospects captured with material upside location inventory potential if successful
- Significant heavy oil resource captured beyond primary recovery in core development assets representing future enhanced recovery potential

Perpetual Contributed - Strategic exposure to high quality natural gas assets in the Deep Basin & Exploratory New Ventures

- Over 4,000 boe/d (~90% natural gas) of conventional natural gas and liquid production
- Predictable base production profile, attractive half cycle economics, operated by JV partner Tourmaline Oil Corp.
- Infrastructure in place to restore sales production to >6,500 boe/d when natural gas prices improve
- Land capture strategy advancing on several new exploration plays
- Substantial bitumen resource potential
- Helium exploration joint venture

Valuable Synergies to enhance free funds flow

- Material synergies of \$40 to \$50 million captured over next four years through lower combined G&A and interest costs, along with over \$550 million in combined resource tax pools and non-capital losses

Strong financial position to support business plan

- Increased liquidity with expanded bank borrowing base and continuation of the existing \$20 million Rubellite Term Loan due in 2029
- Fully-funded growth focused 2025 drilling program supported by both Rubellite and Perpetual's hedging risk management programs
- Funds flow diversification to manage commodity price cycles
- Increased scale to support expanded bank syndicate, capital partners and shareholder base
- Enhanced financial flexibility and optionality

Commodity Price Risk Management

Position Details



	Q1 26	Q2 26	Q3 26	Q4 26	Q1 27	Q2 27	Q3 27	Q4 27
WTI CAD/bbl Swap								
Volume (bbl/d)	-	-	-	-	-	-	-	-
(\$CAD/bbl)	-	-	-	-	-	-	-	-
WTI USD/bbl Swap								
Volume (bbl/d)	3,707	4,680	3,800	2,900	750	750	750	750
(\$USD/bbl)	\$66.44	\$65.43	\$61.77	\$63.78	\$66.50	\$66.50	\$66.50	\$66.50
WCS CAD/bbl Swap								
Volume (bbl/d)	-	-	-	-	-	-	-	-
(\$CAD/bbl)	-	-	-	-	-	-	-	-
WCS Differential CAD/bbl Swap								
Volume (bbl/d)	-	-	-	-	-	-	-	-
(\$CAD/bbl)	-	-	-	-	-	-	-	-
WCS Differential USD/bbl Swap								
Volume (bbl/d)	1,000	4,000	3,500	2,000	-	-	-	-
(\$USD/bbl)	(\$12.50)	(\$12.61)	(\$12.44)	(\$13.00)	-	-	-	-
AECO CAD/GJ Swap								
Volume (GJ/d)	-	-	-	-	-	-	-	-
(\$CAD/GJ)	-	-	-	-	-	-	-	-
NYMEX Swap(Sell)								
Volume (MMbtu/d)	-	5,000	5,000	1,685	-	-	-	-
(\$USD/MMbtu)	-	\$3.89	\$3.89	\$3.89	-	-	-	-
CAD/USD FX Swap								
Notional period amount (\$USD)	\$22,500,000	\$22,500,000	\$22,500,000	\$22,500,000	-	-	-	-
(\$USD/month)	\$7,500,000 ⁽²⁾	\$7,500,000 ⁽²⁾	\$7,500,000 ⁽²⁾	\$7,500,000 ⁽²⁾	-	-	-	-
(\$CAD/\$USD)	\$1.39487	\$1.39487	\$1.39487	\$1.39487	-	-	-	-
(\$CAD/month)	\$10,461,525	\$10,461,525	\$10,461,525	\$10,461,525	-	-	-	-
CAD/USD FX Knock-in Option								
Notional period amount (\$USD)	-	-	-	-	-	-	-	-
(\$USD/month)	-	-	-	-	-	-	-	-
(\$CAD/\$USD) Floor	-	-	-	-	-	-	-	-
(\$CAD/\$USD) Ceiling	-	-	-	-	-	-	-	-
(\$CAD/\$USD) Reset	-	-	-	-	-	-	-	-

1. At expiry on December 31, 2026, if the Calendar 2027 forward strip is above \$1.3890 \$CAD/\$USD, Rubellite knocks into a \$5.0 million \$USD/month contract at \$1.3890 for calendar 2027

Operational Excellence

Striving for continuous performance improvement



Environment

Water: Oil based mud drillings with no fresh water-based fracture stimulation in Clearwater play and minimal fresh water usage in the Mannville Stack area

Land: Surface footprint minimized with multi-well pad development. Onsite drill cutting cleaning and oil-based mud recovery reduce trucking and landfill waste

Air: Gas conservation project implemented to drive **emissions reductions**. Lower emissions pad site battery design implemented. Consolidated land positions present future pipeline tie-in opportunities to reduce trucking

Innovation: Engaged with industry **clean** tech alliances to drive **sustainable solutions**



Social

- **Ranked #1** out of 243 oil and gas companies on **Workplace Compensation Board** scorecard
- Comprehensive health and safety program driving strong performance
- Community-focused **Indigenous relations** approach based on **listening** and **capacity building**
- **Joint Venture operations with Metis and First Nations Communities**
- Extensive and purposeful **indigenous contractor engagement strategy**
- Over **\$2 MM** donated to the United Way of Calgary since Perpetual / Rubellite team's inception in 2003
- Leadership and volunteer involvement in industry, community, and charitable organizations



Governance

- Environment, Health and Safety programs and performance oversight since inception
- Performance-based compensation practices
- Triple Zero EH&S Goal of Zero spills/Zero injuries/Zero vehicle accidents embedded in operational excellence bonus
- Field and office team have **long established tenure** of working together through **20-year+** operating history
- Values-driven corporate culture rooted in **'Be in Spirit'** principles
- Inclusion element of DEI firmly embedded in corporate culture and accountability practices
- **50% female** representation on Board

SLIDE NOTES AND ADVISORIES

Slide Notes

Slide 1

1. All the land is shown net to Rubellite's working interest
2. See "Drilling Locations" in the Advisories
3. Free funds flow is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
4. Operating netback is determined by deducting royalties, net operating expenses, and transportation costs from oil and natural gas revenue, as determined in accordance with IFRS

Slide 2

1. Current shares outstanding as at March 10, 2026 and 9.3 million share awards outstanding (excluding 1.6 million legacy Perpetual awards that are settled outside of treasury)
2. See "Drilling Locations" in the Advisories
3. Enterprise value is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
4. Market capitalization is non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories and is calculated based on basic common shares outstanding as at March 9, 2026 and a share price of \$3.07 per share
5. Net debt is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
6. Adjusted funds flow is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
7. Adjusted funds flow per share is calculated by dividing adjusted funds flow by the total amount of shares outstanding
8. Heavy oil operating netback per bbl is determined by deducting royalties, net operating expenses, and transportation costs on heavy oil production from oil revenue net of realized gains and losses from risk management contracts, as determined in accordance with IFRS, divided by the Company's total heavy oil sales production
9. Payout is a non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in the Advisories
10. "OOIP" or "Original Oil In Place" means the quantity of petroleum which is estimated to be contained in known accumulations
11. Heavy oil production per share is calculated by dividing heavy oil production by the total number of shares outstanding
12. Total production per share is calculated by dividing total oil production by the total number of shares outstanding

Slide Notes (continued)

Slide 3

1. See "Drilling Locations" in the Advisories
2. All the land is shown net to Rubellite's working interest
3. Before Payout and After Payout is a non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in the Advisories

Slide 4

1. Capital is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
2. Operating netback of heavy oil assets per bbl is determined by deducting royalties, net operating expenses or "operating costs", and transportation costs on heavy oil production from oil revenue net of realized gains and losses on risk management contracts, as determined in accordance with IFRS, divided by the Company's total sales production
3. Average capital efficiency is calculated as total capital to drill, complete, equip and tie in a well divided by bbl/d based on IP30 in \$/flowing bbl/d

Slide 5

1. See "Drilling Locations" in the Advisories
2. IRR is a non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in the Advisories
3. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
4. "McDaniel Reserve Report" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026
5. The "McDaniel Type Curve" assumptions and economics are based on the Total Proved Plus Probable reserves contained in the McDaniel Reserve Report using the "Consultants Average Jan 1, 2026 Pricing" as disclosed in the Company's Annual Information Form which is available under the Company's profile on SEDAR+ at www.sedarplus.ca
6. "P+PUD" means locations that have been booked in the proved plus probable category in the McDaniel Reserve Report
7. "NPV10" refers to the before tax net present value of future net revenue of the applicable reserves category in the McDaniel Reserve Report, discounted at 10%
8. The Consultant Average Price Forecast at December 31, 2025, used for the purpose of preparing the McDaniel Reserve Report is summarized as follows:

Year	WTI @ Cushing (US\$/bbl)	WCS @ Hardisty (C\$/bbl)	AECO/NIT spot (C\$/MMbtu)	Exchange Rate (\$US/\$CDN)
2026	59.92	65.13	3.00	0.728
2027	65.10	70.43	3.30	0.737
2028	70.28	76.90	3.49	0.740
2029	71.93	78.71	3.58	0.740
2030	73.37	80.29	3.65	0.740
2031	74.84	81.90	3.72	0.740
2032	76.34	83.53	3.80	0.740
2033	77.87	85.20	3.88	0.740
2034	79.42	86.91	3.95	0.740
2035	81.01	88.65	4.03	0.740
2036+	+2%	+2%	+2%	constant

Slide Notes (continued)

Slide 6

1. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
2. "McDaniel Reserve Report" or "YE 2025" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026 based on the "Consultants Average Jan 1, 2026 Pricing"
3. "YE 2024 Reserves" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2024 and a preparation date of March 10, 2025 based on the "Consultants Average Jan 1, 2025 Pricing"
4. "YE 2023 Reserves" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2023 and a preparation date of March 14, 2024 based on the "Consultants Average Jan 1, 2024 Pricing"
5. "YE 2022 Reserves" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2022 and a preparation date of March 9, 2023 based on the "Consultants Average Jan 1, 2023 Pricing"
6. "YE 2021 Reserves" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2021 and a preparation date of March 9, 2022 based on the "Consultants Average Jan 1, 2022 Pricing"
7. "June 2021 (inception) Reserves" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of June 1, 2021, adjusted for June 15, 2021 strip pricing
8. "FMV of Land" means the value of Rubellite's land as assessed by an independent third party, Seaton-Jordan & Associates Ltd., as at December 31, 2025 in a report dated January 26, 2026 (the "Seaton-Jordan Report")
9. No land value in the Seaton-Jordan Report is assigned where reserves have already been booked, even if the corresponding lease contains multiple prospective formations that have not yet been assigned reserves
10. "Hedge Book Mark to McDaniel" means Rubellite's outstanding risk management contract position as at December 31, 2025 re-valued using the Consultants Average Jan 1, 2026 Pricing
11. Estimates of the value of Rubellite's acreage presented in the Seaton-Jordan Report was prepared in accordance with NI 51-101 5.9(1)(e) for purposes of the net asset value calculation and is based on past Crown land sale activity, adjusted for tenure and other considerations
12. "TP" means total proved reserves in the McDaniel Reserve Report
13. "TPP" means total proved plus probable reserves in the McDaniel Reserve Report
14. "PDP" means locations that have been booked in the proved developed producing category in the McDaniel Reserve Report
15. "P+PDP" means locations that have been booked in the proved plus probable developed producing category in the McDaniel Reserve Report
16. "PUD" means locations that have been booked in the proved category in the McDaniel Reserve Report
17. "P+PUD" means locations that have been booked in the proved plus probable category in the McDaniel Reserve Report
18. References to "PDP oil", "PDP gas", "PUD oil" and "PUD gas" have the same meaning as previously disclosed, specific to reserves for properties that produce heavy oil or natural gas
19. Net asset value ("NAV") and NAV per share represents a non-GAAP measure or ratio. See "Non-GAAP and Other Financial Measures" in the Advisories
20. "NPV10" or "discounted at 10%" refers to the before tax net present value of future net revenue of the applicable reserves category in the McDaniel Reserve Report, discounted at 10%

Slide Notes (continued)

Slide 7

1. See "Drilling Locations" in the Advisories
2. Adjusted funds flow is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
3. Net asset value ("NAV") is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
4. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
5. "McDaniel Reserve Report" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026 based on the "Consultants Average Jan 1, 2026 Pricing"
6. "TPP" means total proved plus probable reserves in the McDaniel Reserve Report
7. Estimates of the value of Rubellite's acreage presented in the Seaton-Jordan Report was prepared in accordance with NI 51-101 5.9(1)(e) for purposes of the net asset value calculation and is based on past Crown land sale activity, adjusted for tenure and other considerations
8. No land value in the Seaton-Jordan Report is assigned where reserves have been assigned

Slide 8

1. See "Drilling Locations" in the Advisories
2. All the land is shown net to Rubellite's working interest
3. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
4. "McDaniel Reserve Report" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026
5. The "McDaniel Type Curve" assumptions and economics are based on the Total Proved Plus Probable reserves contained in the McDaniel Reserve Report using the "Consultants Average Jan 1, 2026 Pricing" as disclosed in the Company's Annual Information Form which is available under the Company's profile on SEDAR+ at www.sedarplus.ca
6. "P+PUD" means locations that have been booked in the proved plus probable category in the McDaniel Reserve Report
7. "EOR" means enhanced oil recovery
8. "OOIP" or "Original Oil In Place" means the quantity of petroleum which is estimated to be contained in known accumulations, see "Original Oil in Place ("OOIP") in the advisories

Slide Notes (continued)

Slide 9

1. See "Drilling Locations" in the Advisories
2. All the land and the drilling locations shown are net to Rubellite's working interest
3. Payout is a non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in the Advisories
4. Capital or CAPEX is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
5. Capital efficiency per meter drilled is calculated by dividing capital by the total number of meters drilled per well
6. "Rate of Return" is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
7. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
8. "McDaniel Reserve Report" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026 based on the "Consultants Average Jan 1, 2026 Pricing" and "McDaniel Type Curve (YE25)" are based on Total Proved Plus Probable reserves contained in the McDaniel Reserve Report using the "Consultants Average Jan 1, 2026 Pricing"
9. "McDaniel YE 2024 Reserves" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2024 and a preparation date of March 10, 2025 based on the "Consultants Average Jan 1, 2025 Pricing" and "McDaniel Type Curve (YE24)" are based on Total Proved Plus Probable reserves contained in the McDaniel Reserve Report using the "Consultants Average Jan 1, 2025 Pricing"
10. The "McDaniel Type Curve" assumptions and economics are based on the Total Proved Plus Probable reserves contained in the McDaniel Reserve Report using the "Consultants Average Price Forecast" as disclosed in the Company's Annual Information Form which is available under the Company's profile on SEDAR+ at www.sedarplus.ca
11. "TPP" means total proved plus probable reserves in the McDaniel Reserve Report
12. "PPUD" means locations that have been booked in the proved plus probable category in the McDaniel Reserve Report
13. "NPV10" refers to the before tax net present value of future net revenue of the applicable reserves category in the McDaniel Reserve Report, discounted at 10%
14. "F&D" and "FD&A" are finding and development costs and are a non-GAAP financial ratio. See "Non-GAAP and Other Financial Measures" in the Advisories
15. IRR is a non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in the Advisories
16. Estimated ultimate recovery ("EUR") represents the estimated ultimate recovery of resources included in the McDaniel Reserve Report
17. "Ultimate Recovery" is defined as the estimated ultimate recoverable reserves as recognized in the McDaniel reserve report
18. Recovery factor is defined by as the estimated amount of hydrocarbons that can be produced from a reservoir relative to the original amount in place, expressed as a percentage

Slide 10

1. See "Drilling Locations" in the Advisories
2. "EOR" means enhanced oil recovery

Slide Notes (continued)

Slide 11

1. See "Drilling Locations" in the Advisories
2. All the land and the drilling locations shown are net to Rubellite's working interest
3. "P+PUD" means locations that have been booked in the proved plus probable category in the McDaniel Reserve Report
4. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
5. "McDaniel Reserve Report" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026 based on the "Consultants Average Jan 1, 2026 Pricing"

Slide 12

1. See "Drilling Locations" in the Advisories
2. "McDaniel Reserve Report" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026 based on the "Consultants Average Jan 1, 2026 Pricing"

Slide 13

1. See "Drilling Locations" in the Advisories
2. All the land and the drilling locations shown are net to Rubellite's working interest
3. Payout is a non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in the Advisories
4. Capital or CAPEX is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
5. Capital efficiency per meter drilled is calculated by dividing capital by the total number of meters drilled per well
6. "Rate of Return" is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
7. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
8. "McDaniel Reserve Report" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026 based on the "Consultants Average Jan 1, 2026 Pricing" and "McDaniel Type Curve (YE25)" are based on Total Proved Plus Probable reserves contained in the McDaniel Reserve Report using the "Consultants Average Jan 1, 2026 Pricing"
9. The "McDaniel Type Curve" assumptions and economics are based on the Total Proved Plus Probable reserves contained in the McDaniel Reserve Report using the "Consultants Average Price Forecast" as disclosed in the Company's Annual Information Form which is available under the Company's profile on SEDAR+ at www.sedarplus.ca
10. "TPP" means total proved plus probable reserves in the McDaniel Reserve Report
11. "PPUD" means locations that have been booked in the proved plus probable category in the McDaniel Reserve Report
12. "NPV10" refers to the before tax net present value of future net revenue of the applicable reserves category in the McDaniel Reserve Report, discounted at 10%
13. "F&D" and "FD&A" are finding and development costs and are a non-GAAP financial ratio. See "Non-GAAP and Other Financial Measures" in the Advisories
14. Estimated ultimate recovery ("EUR") represents the estimated ultimate recovery of resources included in the McDaniel Reserve Report
15. "Ultimate Recovery" is defined as the estimated ultimate recoverable reserves as recognized in the McDaniel reserve report
16. Recovery factor is defined by as the estimated amount of hydrocarbons that can be produced from a reservoir relative to the original amount in place, expressed as a percentage

Slide Notes (continued)

Slide 14

1. See "Drilling Locations" in the Advisories
2. Capital is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
3. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
4. "McDaniel Reserve Report" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026
5. "P+PUD" means locations that have been booked in the proved plus probable category in the McDaniel Reserve Report

Slide 15

1. See "Drilling Locations" in the Advisories
2. Capital or CAPEX is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
3. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
4. "McDaniel Reserve Report" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026
5. The "McDaniel Type Curve" assumptions and economics are based on the Total Proved Plus Probable reserves contained in the McDaniel Reserve Report using the "Consultants Average Jan 1, 2026 Pricing" as disclosed in the Company's Annual Information Form which is available under the Company's profile on SEDAR+ at www.sedarplus.ca
6. "TPP" means total proved plus probable reserves in the McDaniel Reserve Report
7. "NPV10" refers to the before tax net present value of future net revenue of the applicable reserves category in the McDaniel Reserve Report, discounted at 10%
8. Estimated ultimate recovery ("EUR") represents the estimated ultimate recovery of resources included in the McDaniel Reserve Report
9. "Ultimate Recovery" is defined as the estimated ultimate recoverable reserves as recognized in the McDaniel reserve report
10. Payout is a non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in the Advisories
11. "Rate of Return" is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories

Slide 16

1. See "Drilling Locations" in the Advisories
2. All the land and the drilling locations shown are net to Rubellite's working interest
3. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
4. "McDaniel Reserve Report" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026 based on the "Consultants Average Jan 1, 2026 Pricing"
5. "EOR" means enhanced oil recovery

Slide Notes (continued)

Slide 17

1. See "Drilling Locations" in the Advisories
2. Capital and E&D Spending is a non-GAAP measure. See "Non-GAAP and other Financial Measures" in the Advisories
3. Net debt is a non-GAAP measure. See "Non-GAAP and other Financial Measures" in the Advisories
4. Copies of the Company's credit agreements are available under the Company's profile on Sedar+ website at www.sedarplus.ca
5. Free funds flow is a non-GAAP measure. See "Non-GAAP and other Financial Measures" in the Advisories
6. Adjusted funds flow is a non-GAAP measure. See "Non-GAAP and other Financial Measures" in the Advisories
7. Operating costs refer to net operating costs and is a non-GAAP measure. See "Non-GAAP and other Financial Measures" in the Advisories

Slide 18

1. Prices reported are the weighted average prices for the period
2. Western Canadian Select ("WCS")
3. Adjusted funds flow is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
4. Capital is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
5. Forecasted production based on current guidance
6. "Hedge" or risk management contract positions current to March 10, 2026. Full positions by product are as follows:

Commodity	Volumes Sold (bbl/d)	Term	Reference/Index	Contract Traded Bought/Sold	Average Price (\$/bbl)
Crude Oil	1,500 bbl/d	Jan 2026	WTI (US\$/bbl)	Swap - sold	\$65.13
Crude Oil	3,500 bbl/d	Feb 2026	WTI (US\$/bbl)	Swap - sold	\$63.88
Crude Oil	6,100 bbl/d	Mar 2026	WTI (US\$/bbl)	Swap - sold	\$68.09
Crude Oil	5,350 bbl/d	Apr 2026	WTI (US\$/bbl)	Swap - sold	\$67.18
Crude Oil	4,350 bbl/d	May 2026	WTI (US\$/bbl)	Swap - sold	\$64.48
Crude Oil	4,350 bbl/d	Jun 2026	WTI (US\$/bbl)	Swap - sold	\$64.26
Crude Oil	3,800 bbl/d	Jul 2026 - Sep 2026	WTI (US\$/bbl)	Swap - sold	\$61.77
Crude Oil	2,900 bbl/d	Oct 2026 - Dec 2026	WTI (US\$/bbl)	Swap - sold	\$63.78
Crude Oil	750 bbl/d	Jan 2027 - Dec 2027	WTI (US\$/bbl)	Swap - sold	\$66.50
Crude Oil	1,000 bbl/d	Jan 2026 - Mar 2026	WCS Differential (US\$/bbl)	Swap - sold	(\$12.50)
Crude Oil	4,000 bbl/d	Apr 2026 - Jun 2026	WCS Differential (US\$/bbl)	Swap - sold	(\$12.61)
Crude Oil	3,500 bbl/d	Jul 2026 - Sep 2026	WCS Differential (US\$/bbl)	Swap - sold	(\$12.44)
Crude Oil	2,000 bbl/d	Oct 2026 - Dec 2026	WCS Differential (US\$/bbl)	Swap - sold	(\$13.00)

Commodity	Volumes Sold	Term	Reference/Index	Contract Traded Bought/Sold	Average Price (\$/GJ)
Natural gas	5,000 GJ/d	Jan 2026 - Mar 2026	AECO 5A (CAD\$/GJ)	Swap - sold	\$4.00
Natural gas	5,000 GJ/d	Jan 2026 - Mar 2026	AECO 5A (CAD\$/GJ)	Swap - bought	\$3.31
Natural gas	5,276 GJ/d	Apr 2026 - Oct 2026	NYMEX (US\$/GJ)	Swap - sold	\$3.89

Fixed Contract	Notional amount	Term	Price (CAD\$/US\$)
Average rate forward (CAD\$/US\$)	\$2,500,000 US\$/month	Jan - Dec 2026	1.4066
Average rate forward (CAD\$/US\$)	\$5,000,000 US\$/month	Jan - Dec 2026	1.3890

(1) At expiry on December 31, 2026 if the calendar 2027 forward strip is above 1.3890 CAD\$/US\$, Rubellite knocks into a \$5.0 million US\$/month contract at 1.3890 CAD\$/US\$ for the 2027 calendar year.

Slide Notes (continued)

Slide 19

1. See "Drilling Locations" in the Advisories
2. Capital is a non-GAAP measure. See "Non-GAAP and other Financial Measures" in the Advisories
3. All the land and drilling locations are shown net to Rubellite's working interest
4. Free funds flow is a non-GAAP measure. See "Non-GAAP and other Financial Measures" in the Advisories
5. Net debt is a non-GAAP measure. See "Non-GAAP and other Financial Measures" in the Advisories
6. Payout is a non-GAAP ratio. See "Non-GAAP and other Financial Measures" in the Advisories
7. IRR is a non-GAAP ratio. See "Non-GAAP and other Financial Measures" in the Advisories
8. Adjusted funds flow is a non-GAAP measure. See "Non-GAAP and other Financial Measures" in the Advisories
9. Annualized adjusted funds is calculated by annualizing Q4 2025 adjusted funds flow and net debt to Q4 2025 annualized adjusted funds flow by dividing net debt by the Q4 annualized adjusted funds flow prior to transaction costs
10. "EOR" means enhanced oil recovery
11. "Heavy oil CGU" means the Company's heavy oil cash generating unit, which is determined in accordance with IFRS
12. Operating netback per boe is determined by deducting royalties, net operating expenses or "OPEX", and transportation costs from oil and natural gas revenue, as determined in accordance with IFRS, divided by the Company's total sales production

Slide 20

1. Free funds flow is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
2. Capital efficiency is calculated by dividing capital by the total number of meters drilled per well
3. "EOR" means enhanced oil recovery

Slide 23

1. Capital or "CAPEX" is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
2. Exploration and Development Spending or "E&D Spending" is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
3. See "Drilling Locations" in the Advisories
4. All the land and drilling locations are shown net to Rubellite's working interest
5. "EOR" means enhanced oil recovery

Slide Notes (continued)

Slide 24

1. Heavy oil operating netback per bbl is determined by deducting royalties, net operating expenses, and transportation costs on heavy oil production from oil revenue, as determined in accordance with IFRS, divided by the Company's total heavy oil sales production
2. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
3. "McDaniel Reserve Report" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026
4. "June 2021 Reserves" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of June 1, 2021, adjusted for June 15, 2021 strip pricing
5. "YE 2021 Reserves" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2021 and a preparation date of March 9, 2022 based on the "Consultants Average Jan 1, 2022 Pricing"
6. "YE 2022 Reserves" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2022 and a preparation date of March 9, 2023 based on the "Consultants Average Jan 1, 2023 Pricing"
7. "YE 2023 Reserves" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2023 and a preparation date of March 14, 2024 based on the "Consultants Average Jan 1, 2024 Pricing"
8. "YE 2024 Reserves" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2024 and a preparation date of March 10, 2025 based on the "Consultants Average Jan 1, 2025 Pricing"
9. "YE 2025 Reserves" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026 based on the "Consultants Average Jan 1, 2026 Pricing"
10. "TPP" means total proved plus probable reserves in the McDaniel Reserve Report
11. "PDP" means locations that have been booked in the proved developed producing category in the McDaniel Reserve Report
12. "PPDP" means locations that have been booked in the proved plus probable producing category in the McDaniel Reserve Report
13. "PUD" means locations that have been booked in the proved category in the McDaniel Reserve Report
14. "F&D" and "FD&A" are finding and development costs and are a non-GAAP financial ratio. See "Non-GAAP and Other Financial Measures" in the Advisories
15. "Adjusted F&D" are adjusted finding and development costs and are a non-GAAP financial ratio. See "Non-GAAP and Other Financial Measures" in the Advisories
16. Recycle ratio is a non-GAAP financial ratio. See "Non-GAAP and Other Financial Measures" in the Advisories
17. "RLI" means Reserve Life Index and is calculated by dividing the reserves in the McDaniel Reserve Report by total annualized production
18. "TPP per debt adjusted share" is determined by dividing year end total proved plus probable reserves by debt adjusted shares. Debt adjusted shares is determined by dividing total debt outstanding at period end by the closing share price and adding the resulting quotient to total shares outstanding at period end by the applicable reserve category F&D costs
19. "PDP per debt adjusted share" is determined by dividing year end total proved plus probable reserves by debt adjusted shares. Debt adjusted shares is determined by dividing total debt outstanding at period end by the closing share price and adding the resulting quotient to total shares outstanding at period end by the applicable reserve category F&D costs
20. "FDC" means the aggregate exploration and development costs incurred on reserves that are categorized as development reserves

Slide Notes (continued)

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1. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
2. "McDaniel Reserve Report" or "YE 2025 Reserves" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026 based on the "Consultants Average Jan 1, 2026 Pricing"
3. "YE 2024 Reserves" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2024 and a preparation date of March 10, 2025 based on the "Consultants Average Jan 1, 2025 Pricing"
4. "NPV10" refers to the before tax net present value of future net revenue of the applicable reserves category in the McDaniel Reserve Report, discounted at 10%
5. "TP" means total proved reserves in the McDaniel Reserve Report
6. "TPP" means total proved plus probable reserves in the McDaniel Reserve Report
7. "P+PDV" means locations that have been booked in the proved plus probable developed category in the McDaniel Reserve Report
8. "PD" means locations that have been booked in the proved developed category in the McDaniel Reserve Report
9. "PDP" means locations that have been booked in the proved developed producing category in the McDaniel Reserve Report
10. "PUD" means locations that have been booked in the proved undeveloped category in the McDaniel Reserve Report
11. "NOI" means net operating income, which is calculated by deducting royalties, net operating expenses or "OPEX", and transportation costs from oil revenue, as determined in the McDaniel Reserve Report using the Consultants Average Jan 1, 2026 Pricing
12. Capital is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories

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1. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
2. "McDaniel Reserve Report" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026 based on the "Consultants Average Jan 1, 2026 Pricing"
3. "TPP" means total proved plus probable reserves in the McDaniel Reserve Report

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1. See "Drilling Locations" in the Advisories
2. All the land is shown net to Rubellite's working interest
3. "OOIP" or "Original Oil In Place" means the quantity of petroleum which is estimated to be contained in known accumulations, see "Original Oil in Place ("OOIP") in the advisories
4. "EOR" means enhanced oil recovery

Slide Notes (continued)

Slide 29

1. See "Drilling Locations in the Advisories"
2. All the land is shown net to Rubellite's working interest
3. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
4. "McDaniel Reserve Report" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026
5. Per flowing barrel is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
6. Annualized net operating income is determined by deducting royalties, net operating expenses, and transportation costs from oil and natural gas revenue, as determined in accordance with IFRS, multiplied by twelve months
7. Adjusted funds flow is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
8. Free funds flow is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
9. Net debt is a non-GAAP measure and excludes inventory and other items which were included in the new capital acquired. See "Non-GAAP and Other Financial Measures" in the Advisories
10. Operating netback per boe is determined by deducting royalties, net operating expenses, and transportation costs from oil and natural gas revenue, as determined in accordance with IFRS, divided by the Company's total sales production

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1. See "Drilling Locations" in the Advisories
2. All the land is shown net to Rubellite's working interest
3. Free funds flow is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories

Advisories

General

This Corporate Overview (this "presentation") of Rubellite Energy Corp. ("Rubellite" or the "Company") is for discussion and information purposes only and any unauthorized use is strictly prohibited. These materials should be read in conjunction with the Company's most recently filed Annual Information Form, the consolidated financial statements for the year ended December 31, 2025 and Management's Discussion and Analysis for the year ended December 31, 2025 ("December 31, 2025 MD&A") which are available on SEDAR+ at www.sedarplus.ca. The additional advisories, disclaimers, cautionary statements and other risk factors contained therein are incorporated by reference herein.

This presentation contains information relating to Rubellite's business as well as historical and projected future performance, Rubellite expectations, forecasts and guidance and other market data. When considering this data, investors should bear in mind that historical results and market data may not be indicative of the future results that investors should expect from Rubellite. Moreover, you should assume that the information appearing herein (including the illustrative outlooks, projections, forecasts, estimates and guidance contained herein) is accurate as of the date on the front cover of this presentation only. Rubellite's business, financial condition, results of operations and prospects may change after such date. Accordingly, this presentation is subject to updating, completion, revision, verification and amendment at any time without notice which may result in material changes.

By accessing this presentation you will be deemed to acknowledge and agree to the matters set forth above and below.

The information contained in this presentation does not purport to be all-inclusive or to contain all information that prospective investors may require, nor does it provide any legal, tax, financial, accounting or investment advice. Prospective investors are encouraged to conduct their own analysis and reviews of the Company and of the information contained in this presentation. Prospective investors should consult their own professional advisors to assess their potential investment in the Company and before making an investment decision. An investment in the Common Shares is subject to a number of risks that should be considered by a prospective investor. In this presentation, all amounts are in Canadian dollars, unless otherwise indicated. Any graphs, tables or other information in this presentation demonstrating the historical performance of the Company or of any other entity are intended only to illustrate past performance and are not necessarily indicative of future performance of the Company. Certain totals, subtotals and percentages may not reconcile due to rounding. See also "Forward-Looking Information" and "Non-GAAP and Other Financial Measures" below and in the December 31, 2025 MD&A and "Risk Factors" in the Company's most recently filed Annual Information Form.

Non-GAAP and Other Financial Measures

Throughout this presentation and in other materials disclosed by the Company, Rubellite employs certain measures to analyze financial performance, financial position and cash flow. These non-GAAP and other financial measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities. The non-GAAP and other financial measures should not be considered to be more meaningful than GAAP measures which are determined in accordance with IFRS, such as net income (loss), cash flow from operating activities, and cash flow from investing activities, as indicators of Rubellite's performance. See "*Non-GAAP and Other Financial Measures*" in the December 31, 2025 MD&A for further information on the definition, calculation and reconciliation of these measures.

Non-GAAP Financial Measures

"Enterprise value" is equal to net debt plus the market value/capitalization of issued equity and is used by management to analyze leverage. Enterprise value is calculated by multiplying the current shares outstanding by the market price and then adjusting it by net debt. The Company considers enterprise value as an important measure as it normalizes the market value of the Company's shares for its capital structure.

"Market capitalization" is calculated by multiplying the current shares outstanding by the market price. The Company considers market capitalization as an important measure as it is part of the calculation of enterprise value which normalizes the market value of the Company's shares for its capital structure.

"Net debt" is calculated by adding borrowings under the credit facility and term loan debt less adjusted working capital. Adjusted working capital is calculated by adding cash, accounts receivable, prepaid expenses and deposits and product inventory less accounts payable and accrued liabilities. Management considers net debt as an important measure in assessing the liquidity of the Company.

Advisories (continued)

Non-GAAP and Other Financial Measures (continued)

"Adjusted working capital" deficiency or surplus is calculated by adding cash, accounts receivable, prepaid expenses and deposits and product inventory less accounts payable and accrued liabilities.

"Adjusted funds flow" is calculated based on net cash flows from operating activities, excluding changes in non-cash working capital and expenditures on decommissioning obligations, other provisions and cash-settled share based compensation since the Company believes the timing of collection, payment or incurrence of these items is variable. Expenditures on decommissioning and share based compensation obligations may vary from period to period and are managed as expenditures through the corporate budgeting process which considers available adjusted funds flow. Management uses adjusted funds flow and adjusted funds flow per boe as key measures to assess the ability of the Company to generate the funds necessary to finance capital expenditures, expenditures on decommissioning obligations, expenditures on share based compensation and meet its financial obligations.

Net Asset Value ("NAV") is total proved plus probable reserves as per the McDaniel Report, plus independently verified third party valuation of undeveloped lands, less net debt and the other provision at an undiscounted value. This measure is used to show the net asset value of the Company at a point in time under which the reserves are produced at forecasted future prices and costs.

"Free funds flow" is calculated as adjusted funds flow generated during the period less total capital expenditures, excluding non-cash items and acquisitions and dispositions. Management uses certain industry benchmarks, such as free funds flow, to analyze financial and operating performance. Management believes that free funds flow provides a useful measure to determine the Company's ability to improve returns and manage the long-term value of the business.

"Capital expenditures", "Capital", "E&D Spending" are used to measure its capital investments compared to the Company's annual capital budgeted expenditures. Rubellite's capital budget excludes acquisition and disposition activities. Total capital expenditures includes exploration and development, land, geological and geophysical and corporate spending. Exploration and development spending is comprised of the non-GAAP measure total capital expenditures less land and other, geological and geophysical and corporate spending.

"NPV10%" is the net present value (net of capital expenditures) of the operating income of a well from the McDaniel's report discounted at a 10% discount rate.

Non-GAAP Financial Ratios

"Cash costs" is calculated as the total of net operating costs, transportation costs, general and administration costs (G&A) and cash finance expense divided by the Company's total sales oil production. Management considers cash costs as an important measure to evaluate the Company's efficiency and overall cost structure.

"G&A (\$/boe)" is comprised of G&A expense, as determined in accordance with IFRS, divided by the Company's total sales oil production.

"IRR", or internal rate of return, is 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.

"Rate of return", is 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 the ROR, the more desirable the project.

"Operating netback per boe" is determined by deducting royalties, net operating expenses, and transportation costs from oil and natural gas revenue. Operating netback is also calculated on a per boe basis using total production sold in the period.

"Recycle ratio" is determined by dividing the operating netback per boe by F&D costs.

"F&D" and "FD&A" costs are used as a measure of capital efficiency. The F&D cost calculation includes all capital expenditures, excluding acquisition and disposition capital, for the booked location in the McDaniel's report divided by the total proved plus probable reserves booked to that location in the McDaniel's report. FD&A includes the impact of acquisition and disposition capital.

Advisories (continued)

"Per Flowing barrel" is a metric used to estimate the value of assets acquired and is calculated by dividing the cost of acquired assets by the number of barrels it produces.

Non-GAAP Financial Ratios (continued)

"Payout" is calculated as the time at which a well or project's cumulative operating netback equals total capital expenditures.

"Before payout" or "BPO" is the working interest before the point in time when the well has recovered from production all costs stated in the underlying farmout or arrangement.

"After payout" or "APO" is the working interest after the point in time when the well has recovered from production all costs stated in the underlying farmout or arrangement.

"Operating costs" is comprised of net operating expense, as determined in accordance with IFRS, divided by the Company's total sales oil production.

"Transportation costs" is comprised of transportation expense, as determined in accordance with IFRS, divided by the Company's total sales oil production.

"Heavy oil wellhead differential" represents the differential the company receives for selling its heavy crude oil production relative to the Western Canadian Select reference price (CAD\$/bbl) prior to any price or risk management activities.

"Royalties (\$/boe)" is comprised of royalties, as determined in accordance with IFRS, divided by the Company's total sales oil production.

Reserve Measures

This presentation contains the terms FDC, F&D costs per boe, FD&A costs per boe, Adjusted F&DA costs per boe, recycle ratio and replacement. 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. These measures have been calculated on a total company basis and based on the Eastern Heavy Oil CGU. Such measures have been included in this presentation to provide readers with additional measures to evaluate Rubellite's performance; however, such measures are not reliable indicators of Rubellite's future performance and future performance may not compare to Rubellite's performance in previous periods and therefore such measures should not be unduly relied upon.

"Finding and Development Capital" ("FDC") is comprised of total exploration and development costs incurred on reserves that are categorized as development reserves. For this calculation, development capital includes land expenditures and excludes acquisitions and dispositions.

"Finding and development" ("F&D") costs per boe are calculated as the sum of the non-GAAP measure "total capital expenditures" (as calculated above) less corporate spending, plus the change in FDC for the period divided by the change in reserves that are characterized as development for the period which takes into account reserve revisions during the period. This measure is then divided by the Company's total sales production on a per barrel basis. The aggregate of the total capital expenditures, less corporate spending, incurred in during the period and changes during that period in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that period.

"Finding, development and acquisition" ("FD&A") costs per boe are calculated as the sum of development costs, acquisition and disposition costs and the change in FDC for the period, divided by the reserves within the applicable reserves category, including changes due to acquisitions and dispositions.

"Adjusted finding and development" ("F&D") costs per boe are calculated as the sum of development costs, adjusted for the cash proceeds of acquisitions and dispositions, rather than the net back value component used in determining F&D costs. The change for the period, is then divided by the reserves within the applicable reserves category.

"Recycle ratio" is calculated by dividing the non-GAAP measure "operating netback" by F&D costs per boe. The recycle ratio compares the netback from existing reserves to the cost of finding new reserves and may not accurately indicate the investment success unless the replacement reserves are equivalent quality as the produced reserves.

"Production replacement" measures how much annual production has been replaced by new reserve additions. It is calculated by taking the total change in reserves on a per boe basis ~~dividend by the annual sales production on a per boe basis.~~

Advisories (continued)

Forward-Looking Information

Certain information in this presentation including management's assessment of future plans and operations, and including, without limitation the information contained under the headings "Corporate Profile", "Investment Highlights", "2026 Annual Capital Spending Plan", "Project Pipeline", "Guidance & Balance Sheet", "Rubellite Asset Profile" and "Creating Differentiated Value for Shareholders" may constitute forward-looking information or statements (together "forward-looking information") under applicable securities laws. The forward-looking information includes, without limitation, statements with respect to: future capital expenditures, production and various cost forecasts; the anticipated sources of funds to be used for capital spending; expectations as to future exploration, development and drilling activity, and the benefits to be derived from such drilling including drilling techniques, pilot projects and production growth; the plan to advance strategic initiatives including multiple enhanced oil recovery pilots, exploration activities, new land capture, capital spending activities in the Company's core properties at Figure Lake, Frog Lake and East Edson, anticipated average heavy oil sales volumes and total production sales volumes in the first quarter of 2026; the expectation that capital spending activity will be funded from adjusted funds flows, with excess free funds flow to reduce net debt and for other balance sheet obligations; operating and transportation cost forecasts for the first quarter of 2026; the expectation that blending demand for Clearwater and Mannville Stack heavy oil will continue to translate into attractive offsets to WCS benchmark pricing, planned ARO spending; Rubellite's business plan; and including the other information and statements contained under the heading "Guidance & Balance Sheet".

Forward-looking information is based on current expectations, estimates and projections that involve a number of known and unknown risks, which could cause actual results to vary and in some instances to differ materially from those anticipated by Rubellite and described in the forward-looking information contained in this presentation. In particular and without limitation of the foregoing, material factors or assumptions on which the forward-looking information in this presentation is based include: the successful operation of the Company's assets, forecast commodity prices and other pricing assumptions; forecast production volumes based on business and market conditions; foreign exchange and interest rates; near-term pricing and continued volatility of the market; accounting estimates and judgments; future use and development of technology and associated expected future results; the ability to obtain regulatory approvals; the successful and timely implementation of capital projects; ability to generate sufficient cash flow to meet current and future obligations and future capital funding requirements (equity or debt); the ability of Rubellite to obtain and retain qualified staff and equipment in a timely and cost-efficient manner, as applicable; the retention of key properties; forecast inflation, supply chain access and other assumptions inherent in Rubellite's current guidance and estimates; climate change; severe weather events (including wildfires, floods and drought); the continuance of existing tax, royalty, and regulatory regimes; the accuracy of the estimates of reserves volumes; ability to access and implement technology necessary to efficiently and effectively operate assets; risk of wars or other hostilities or geopolitical events (including the ongoing war in Ukraine and conflicts in the Middle East, South America and elsewhere), civil insurrection and pandemics; risks relating to Indigenous land claims and duty to consult; data breaches and cyber attacks; risks relating to the use of artificial intelligence; changes in laws and regulations, including but not limited to tax laws, royalties and environmental regulations (including greenhouse gas emission reduction requirements and other decarbonization or social policies) and including uncertainty with respect to the interpretation and impact of omnibus Bill C-59 and the related amendments to the Competition Act (Canada), and the interpretation of such changes to the Company's business); political, geopolitical and economic instability; trade policy, barriers, disputes or wars (including new tariffs or changes to existing international trade requirements) and general economic and business conditions and markets, among others.

Undue reliance should not be placed on forward-looking information, which is not a guarantee of performance and is subject to a number of risks or uncertainties, including without limitation those described herein and under "Risk Factors" in Rubellite's most recently filed Annual Information Form and the December 31, 2025 MD&A and in other reports on file with Canadian securities regulatory authorities which may be accessed through the SEDAR+ website (www.sedarplus.ca) and at Rubellite's website (www.rubelliteenergy.com). Readers are cautioned that the foregoing list of risk factors is not exhaustive. Forward-looking information is based on the estimates and opinions of Rubellite's management at the time the information is released, and Rubellite disclaims any intent or obligation to update publicly any such forward-looking information, whether as a result of new information, future events or otherwise, other than as expressly required by applicable securities law.

Advisories (continued)

Oil and Gas Industry Metrics

This presentation contains certain oil and gas industry metrics which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this document to provide readers with additional measures to evaluate Rubellite's performance; however, such measures are not reliable indicators of Rubellite's future performance and future performance may not compare to Rubellite's performance in previous periods and therefore such metrics should not be unduly relied upon.

Initial Production Rates

Any references in this presentation to initial production rates, including IP30, IP60, IP90, IP180 and IP270 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. 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 the time.

Drilling Locations

This presentation discloses Rubellite's estimated drilling locations in three categories: (i) booked locations, (ii) unbooked development / step-out locations, and (iii) exploration / appraisal locations. Booked locations are proved and probable locations, and are derived from; the Rubellite McDaniel Reserve Report ("McDaniel Year End 2025 Report") with an effective date of December 31, 2025 and a preparation date of March 10, 2026 and account for drilling locations that have associated proved and/or probable reserves prepared in accordance with NI 51-101 and the COGE handbook and account for drilling locations that have associated proved and/or probable reserves, as applicable; and had not yet been drilled at the time of the preparation of the respective report. Unbooked locations are internal estimates based on Rubellite'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 our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. Unbooked development and step-out locations are located within the mapped outline of existing Clearwater zones where economic production has been established. Exploration and appraisal locations are those locations identified by management in areas considered prospective or with known resource, but lacking in commercial production history or Type Curves, and which require additional drilling and/or production history to be proven economic and should therefore be considered higher risk.

Of the 396 net heavy oil drilling development locations disclosed in this presentation, 101.6 net are proved and 53.6 net are probable undeveloped locations in the McDaniel Year End 2025 Report. At Edson, there are 7.5 net proven natural gas locations and 4.4 net probable natural gas locations in the McDaniel Year End 2025 Report. As of December 31, 2025, there are greater than 400 net exploration / appraisal locations targeting heavy and medium crude oil plays.

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 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.

Advisories (continued)

Original Oil in Place ("OOIP")

OOIP is that quantity of petroleum that is estimated to originally 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 OOIP 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 OOIP 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 OOIP will never be recovered. OOIP disclosed herein was internally estimated by the Company. There is no certainty that the Company's OOIP estimates were prepared in accordance with the COGE Handbook. The estimates may not be comparable to similar measures presented by other companies and therefore should not be used to make such comparisons.

Reserve Data and Other Metrics

There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and natural gas liquids ("NGL") reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only and there is no guarantee that the estimated reserves will be recovered. In general, estimates of economically recoverable crude oil, natural gas and NGL reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For those reasons, estimates of the economically recoverable crude oil, NGL and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

All evaluations and reviews of future net revenue are stated prior to any provisions for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. The after-tax net present value of the Company's oil and gas properties reflects the tax burden on the properties on a stand-alone basis and utilizes the Company's tax pools. It does not consider the corporate tax situation, or tax planning. It does not provide an estimate of the after-tax value of the Company, which may be significantly different. The Company's financial statements and the December 31, 2025 MD&A should be consulted for information at the level of the Company.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to effects of aggregations. The estimated values of future net revenue disclosed in this presentation do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material.

The reserve data provided in this presentation presents only a portion of the disclosure required under NI 51-101. All of the required information is contained in the Company's Annual Information Form for the year ended December 31, 2025 filed on SEDAR+ (accessible at www.sedarplus.ca).

Advisories (continued)

Oil and Gas Reserve Definitions

Reserves: are estimated remaining quantities of crude oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of capital assumptions, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates as follows.

Proved Reserves (1P): are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable Reserves (2P): are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the estimated proved plus probable reserves.

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production.

Developed Producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed Non-Producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserve's classification (proved, probable, possible) to which they are assigned.

Advisories (continued)

Third Party Information

This presentation includes market, industry and economic data which was obtained from various publicly available sources and other sources believed by Rubellite to be true. Although Rubellite believes it to be reliable, it has not independently verified any of the data from third party sources referred to in this presentation or analyzed or verified the underlying reports relied upon or referred to by such sources or ascertained the underlying economic and other assumptions relied upon by such sources. Rubellite believes that its market, industry and economic data is accurate and that its estimates and assumptions are reasonable, but there can be no assurance as to the accuracy or completeness thereof. The accuracy and completeness of the market, industry and economic data used throughout this presentation are not guaranteed and Rubellite makes no representation as to the accuracy of such information.

BOE Volume Conversions

Barrel of oil equivalent ("boe") may be misleading, particularly if used in isolation. In accordance with NI 51-101, a conversion ratio for conventional natural gas of 6 Mcf:1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, utilizing a conversion on a 6 Mcf:1 bbl basis may be misleading as an indicator of value as the value ratio between conventional natural gas and heavy crude oil, based on the current prices of natural gas and crude oil, differ significantly from the energy equivalency of 6 Mcf:1 bbl. A conversion ratio of 1 bbl of heavy crude oil to 1 bbl of NGL has also been used throughout this presentation.

The following abbreviations used in this presentation have the meanings set forth below:

bbbl	barrels
bbbl/d	barrels per day
boe	barrels of oil equivalent
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
Mcf	thousand cubic feet
MMcf	million cubic feet
MMcf/d	million cubic feet per day
Bcf	billion cubic feet