InPlay Oil

February 2025

TSX : IPO
OTCQX : IPOOF

BEST 50 OTCQX 2022

BEST 50 OTCQX 2023

Investment Highlights

- **Corporate Strategy: "*Disciplined light oil growth developing high rate of return assets focused on strong free adjusted funds flow (FAFF) with conservative leverage ratios while maximizing returns to shareholders*"**
- **Technically focused team with 8 year track record of shareholder returns through multiple cycles**
  - **Delivered production and cash flow per share growth while reducing debt**
  - **High rate of return assets and clean balance sheet with excess liquidity → positioned to be opportunistic**
  - **Operational & technical expertise and quality assets drive top quartile reserve adds and capital efficiencies**
- **2025 Guidance** (@ US $72.00 WTI)**:**
  - **Efficient and disciplined capital program of $41 – $44 mm prioritizing FAFF and maintaining balance sheet strength**
  - **Production growth of 2% (8,900 boe/d[2]) with a $20 mm reduction in capital compared to 2024**
    - Lower corporate decline rate averaging approximately 22% through 2025
    - Drilling 8 – 9 net wells vs 12.6 net in 2024
    - Drilling 6 PCU-7 wells after strong results in H2-24; best capital efficiencies in portfolio ($12,800/boed vs. 3 year average of $18,825/boed)
      - Last 3 well pad drilled for $2.95 mm/well; reduced go forward estimate to $3.4 mm/well (leaving room to beat)
    - Significant infrastructure spend in 2023 ($13.4 mm) and 2024 ($11.3 mm) results in minimal spend in 2025 ($3.9 mm) and beyond
  - **20% FAFF Yield (including 11% Dividend Yield) + 2% Production Growth = 22% Total Return**
    - $16.5 mm base dividend fully covered by $25 mm - $34 mm of FAFF[3]
    - Base monthly dividend of $0.015/share representing an 11% dividend yield; rewards investors patiently awaiting improved valuation multiples (currently near all time lows)
  - **Debt Reduction: Excess FAFF utilized to reduced debt**
    - Forecasted 2025 Year-end Net debt[1] of $52 mm – $58 mm
    - Net debt to EBITDA ratio[3] of 0.6x – 0.8x; among the lower leverage ratios amongst our peers
  - **Implemented strong hedge position, approximately 50% at favorable pricing levels to mitigate risk**

(1) Capital management measure. See "Non-GAAP and Other Financial Measures" in Reader Advisories
(2) See "Production Breakdown by Product Type" in the Reader Advisories
(3) Non-GAAP measure or ratio. See "Non-GAAP and Other Financial Measures" in Reader Advisories

Corporate Overview

OPERATING SUMMARY

2025 Average Production (light oil & liquids %)	8,650 – 9,150 boe/d (55% - 57%)(1)
2025 Hz Drilling Plans	8.0 – 9.0 net
2023 Reserves	
Proved Developed Producing	17.3 Mmboe
Total Proved Reserves	45.9 Mmboe
Total Proved and Probable Reserves	61.6 Mmboe
Total Proved and Probable NPV BT10% (mm)	$824

63% oil & NGL

in TPP reserve booking

MARKET SUMMARY

Basic Shares Outstanding (basic / FD) (mm)	90.1 / 92.8
Market Capitalization (@ $1.65 per share) (mm)	$150
Enterprise Value (@ $1.65 per share) (mm)	$210
Monthly Dividend ($ per share / Annualized Yield @ $1.65)	$0.015 / 11%
Liquidity (shares/day average over last 6 months / 1 month)	~ 215,000 / 205,000
Employee & Director Ownership (diluted)	5.9%
Large Insider Shareholders (diluted)	22.6%

DEBT SUMMARY ($mm)

Net Debt(2)(3) (estimated @ December 31, 2024)	$60
Credit Facilities	$110

(1) See "Production Breakdown by Product Type" in the Reader Advisories
(2) Capital management measure. See "Non-GAAP and Other Financial Measures" in Reader Advisories
(3) See "Preliminary Financial Information" in the Reader Advisories

Management and Directors

Management

Strong Technically and Value Creators

Doug Bartole, P. Eng., ICD.D

President and CEO, Director

Kevin Yakiwchuk, MSc., P. Geol.

Vice President Exploration

Darren Dittmer, CPA, CMA

CFO

Brent Howard, P. Eng.

Vice President Operations

Kevin Leonard, BComm

Vice President Business & Corporate Development

Directors

Experienced Industry Board

Doug Bartole, P. Eng., ICD.D

Regan Davis, P. Eng., ICD.D

Joan Dunne, FCPA, FCA, ICD.D

Craig Golinowski CFA, MBA

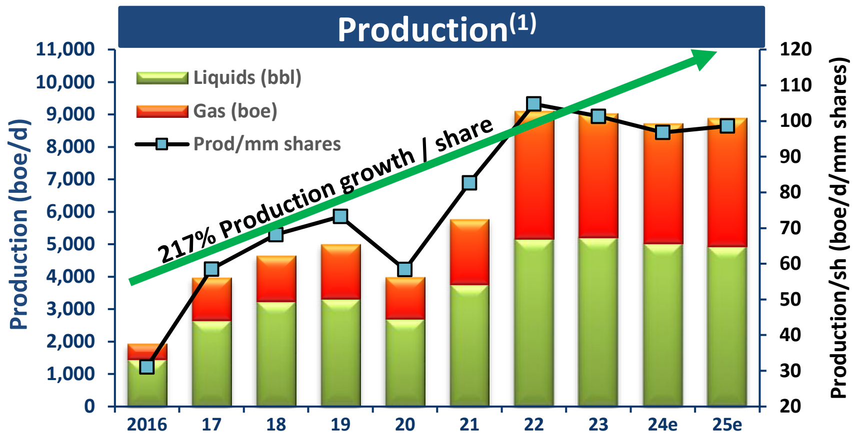
Steve Nikiforuk, CPA, CA, ICD.D

Dale Shwed

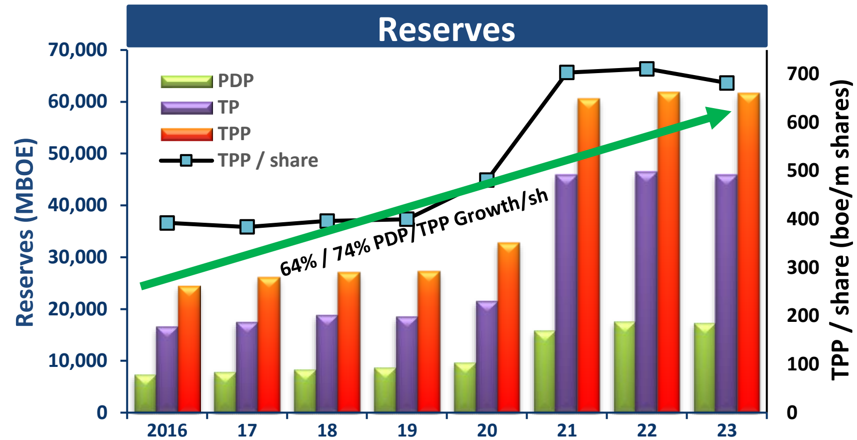
Please see appendix or InPlay's website for additional details on Management and Directors

8 Year Track Record

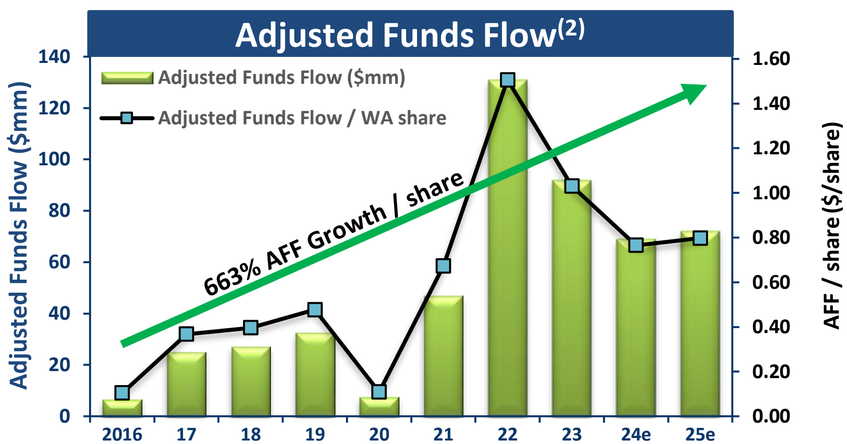
Historical track record of Per Share Growth, Free Cash Flow and Debt Reduction



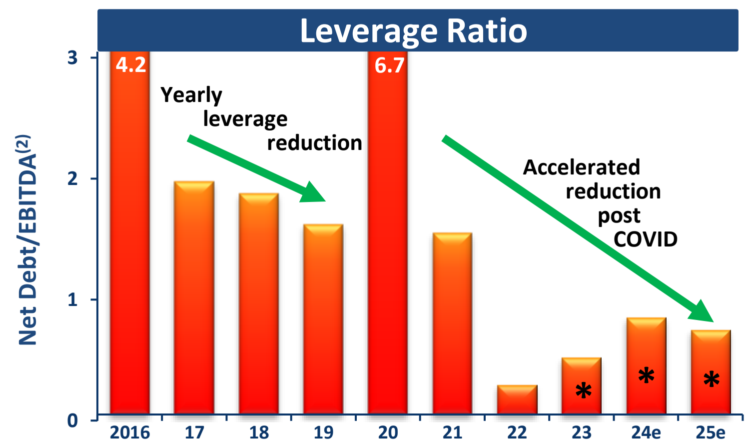
- 2025 production growth of 2% with a 33% reduction in capital
- Maintaining capital discipline and prioritizing free cash flow in current commodity pricing environment



- Top quartile 3 year average reserve adds and capital efficiencies
- Maintained reserve levels while returning $0.18/share to shareholders



- Strong AFF and reduction in capital drives $29.5 million of FAFF in 2025 with a FAFF yield of 20%



- Accelerated leverage reduction post-COVID
- 2025 forecast net debt/EBITDA of 0.6x – 0.8x (lower than peer average)

* Includes the impact of cash dividend beginning November 2022

(1) See "Production Breakdown by Product Type" in the Reader Advisories
(2) Capital management measure. See "Non-GAAP and Other Financial Measures" in Reader Advisories

2016 includes only 7 weeks as a new public company

2023 Year End Reserves & Efficiency Highlights

Reserve Highlights

	Reserves (Mboe)	NPV BT10% ($000s)	NAV BT10% ($/share)[3]	RLI (yrs)
Proved Developed[1]	*18,295*	*$260,898*	*$2.63*	*5.6*
Total Proved	*45,919*	*$571,097*	*$6.07*	*13.9*
Total Proved + Probable	*61,594*	*$823,589*	*$8.87*	*18.7*

Significant NPV despite weaker future commodity prices

TP NAV/share of $6.07; a 237% premium to current share price

Finding, Development & Acquisition Costs and Recycle Ratios

	3 Yr Avg FD&A ($/boe)	3 Yr Avg Recycle Ratio *	3 Yr Avg Peer		2023 FD&A ($/boe)	2023 Recycle Ratio
			FD&A ($/boe)[1]	Recycle Ratio ($/boe)[2]		
Proved Developed Producing	*$14.06*	*2.7*	*$22.78*	*2.2*	*$28.31*	*1.1*
Total Proved	*$14.86*	*2.5*	*$22.63*	*2.0*	*$28.92*	*1.1*
Total Proved + Probable	*$12.79*	*3.0*	*$19.38*	*2.3*	*$23.36*	*1.4*

**** Strong 3 Year Recycle Ratio: $1 capital invested returns $2.50+***

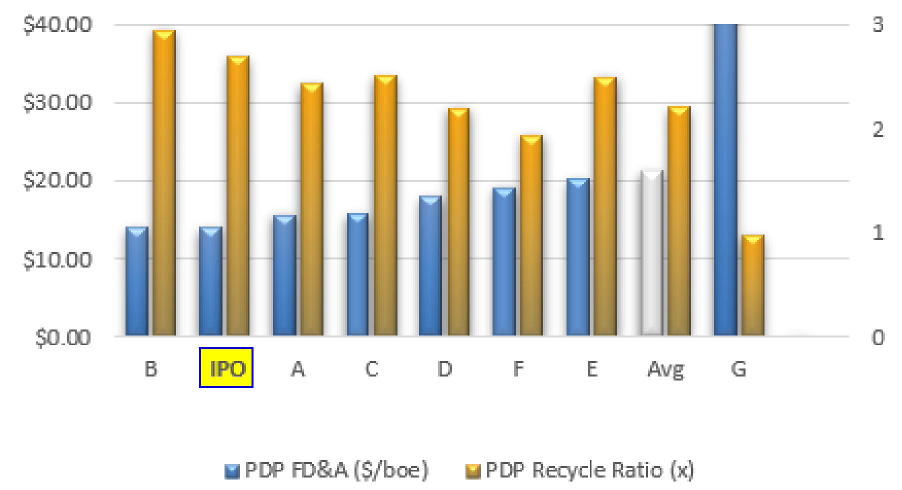
(1) *Proved developed reserves consist of Proved Developed Producing and Proved Developed Non-Producing ("PDNP") reserves.*

(2) *"Average peer FD&A" and "Average peer Recycle Ratio" for 2023 derived from publically disclosed values for peers defined as light oil weighted small to mid cap exploration and development companies having greater than 60% oil and liquids weighting (BNE, CJ, GXE, OBE, SGY, TVE, WCP)*

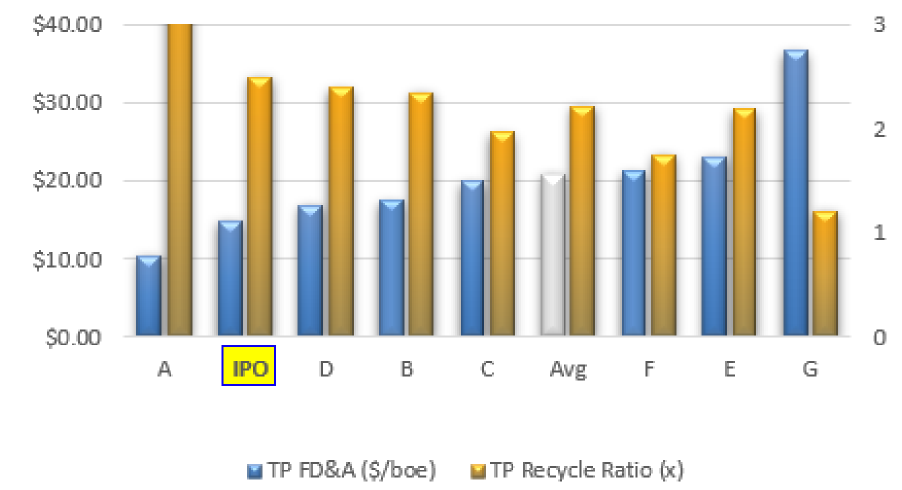
(3) *Net asset value is calculated as the NPV BT10% plus $22.7 million of undeveloped land, less $45.7 million of net debt at December 31, 2023*

IPO Consistently Providing Top-Tier Efficiencies in Finding Reserves and Adding Producing Barrels

3 Year Avg. PDP FDA & Recycle Ratios vs. Peers



3 Year Avg. TP FDA & Recycle Ratios vs. Peers



IPO Capital Efficiencies Adding Producing boe/d

3 year average capital efficiency of $18,825 per boe/d

The peers above are defined as light oil weighted small to large cap exploration and development companies having greater than 60% oil and liquids weighting (BNE, CJ, GXE, OBE, SGY, TVE, WCP)

Focused Asset Base

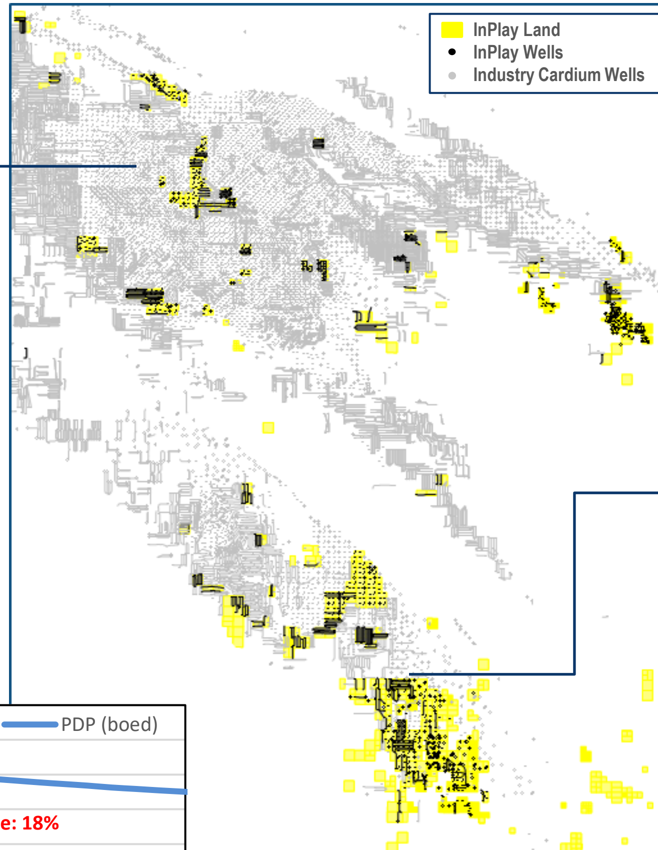
Drilling industry pacesetter horizontal wells and exceeding forecasted volumes

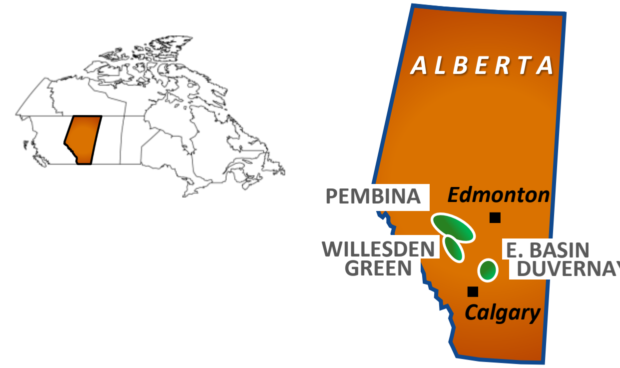
85% Cardium
production

PEMBINA

Production[(1)]:
- Cardium ~3,950 boe/d (51% oil & NGL)
- Belly River ~600 boe/d (89% oil & NGL)

Upside: 147 net Hz drilling locations
Land: 48,480 (38,350 net) acres
2025 Hz drilling plans: 6.0 – 8.0 net





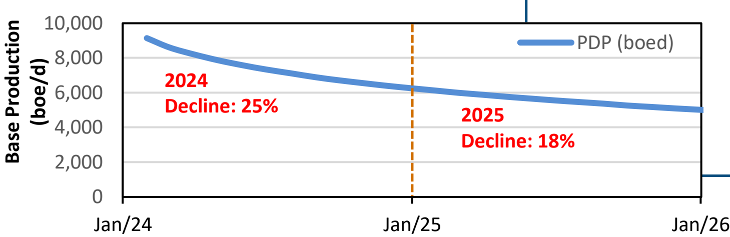
WILLESDEN GREEN

Production[(1)]: ~4,100 boe/d (56% oil & NGL)
Upside: 146 net Hz drilling locations
Land: 104,431 (69,148 net) acres Cardium
2025 Hz drilling plans: 1.0 – 2.0 net Cardium
1.0 Glauconite

OTHER

Production[(1)]: ~250 boe/d (48% oil & NGL)
Upside: 135 net Hz drilling locations
(Mannville, Nisku, Duvernay)

Top Quartile
declines in oil weighted growth universe



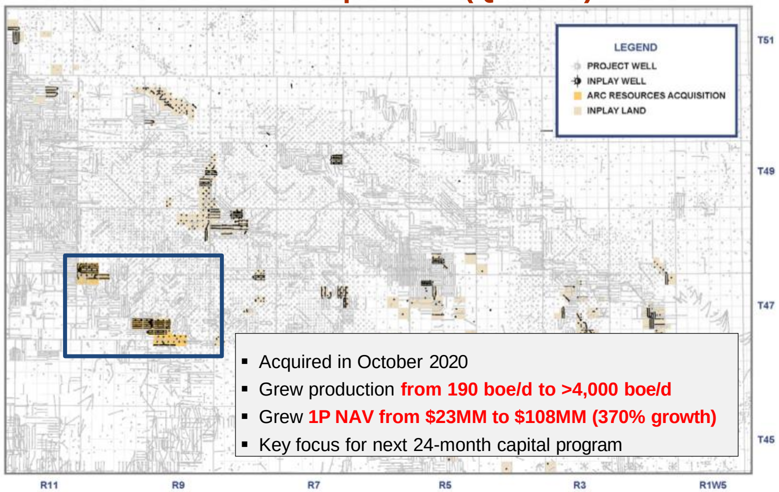
Low decline production + high netback light oil + quick payout inventory

= PER SHARE OIL GROWTH + FREE CASH FLOW

(1) *Approximate production by area, see "Production Breakdown by Product Type" in the Reader Advisories*

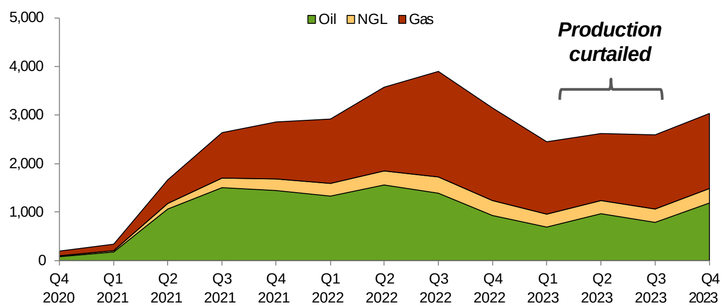
History of Highly Accretive Successful Acquisitions

Pembina Acquisition (Q4 2020)



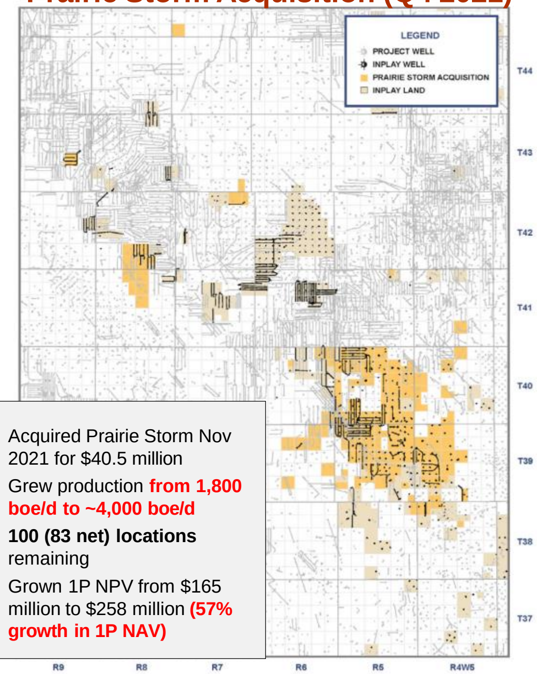
- Acquired in October 2020
- Grew production **from 190 boe/d to >4,000 boe/d**
- Grew **1P NAV from $23MM to $108MM (370% growth)**
- Key focus for next 24-month capital program

Production Profile Post Acquisition



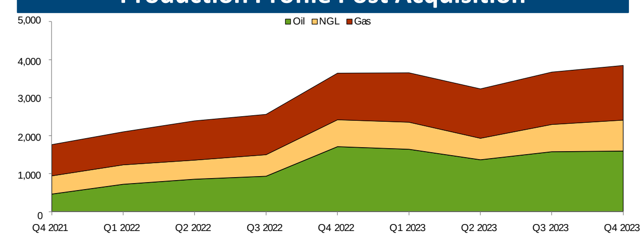
		PDP	1P	2P
Purchase Price	*($mm)*	**$1.9**	**$1.9**	**$1.9**
Free Cash Flow	*($mm)*	$58.3	$58.3	$58.3
BT NPV10	*($mm)*	$68.1	$108.2	$149.6
Total Value	*($mm)*	**$126.4**	**$166.5**	**$207.9**
Total Return to Date	*(x)*	**66.5x**	**87.6x**	**109.4x**

Prairie Storm Acquisition (Q4 2021)



- Acquired Prairie Storm Nov 2021 for $40.5 million
- Grew production **from 1,800 boe/d to ~4,000 boe/d**
- **100 (83 net) locations** remaining
- Grown 1P NPV from $165 million to $258 million **(57% growth in 1P NAV)**

Production Profile Post Acquisition

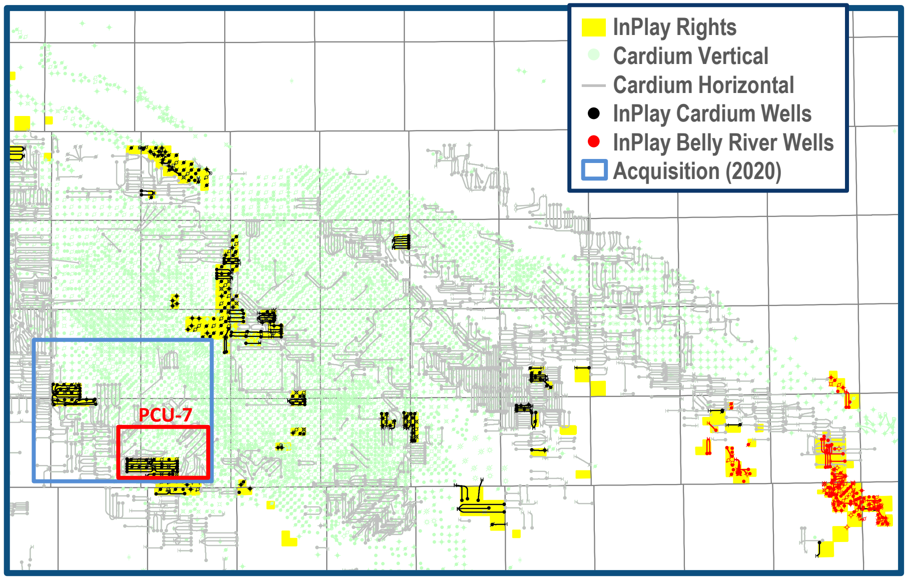


		PDP	1P	2P
Purchase Price	*($mm)*	**$40.5**	**$40.5**	**$40.5**
Free Cash Flow	*($mm)*	-$9.6	-$9.6	-$9.6
BT NPV10	*($mm)*	$103.0	$258.0	$352.0
Total Value	*($mm)*	**$93.4**	**$248.4**	**$342.4**
Total Return to Date	*(x)*	**2.3x**	**6.1x**	**8.5x**

Pembina

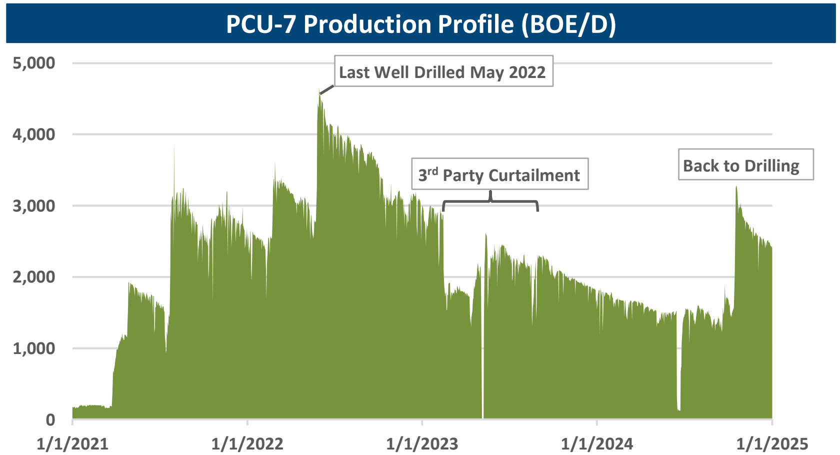
Low risk drilling with quick payouts; well established field with large oil in place and low recovery factors

Returned to our most prolific development area (PCU-7) in Q3 2024. Six well planned for 2025



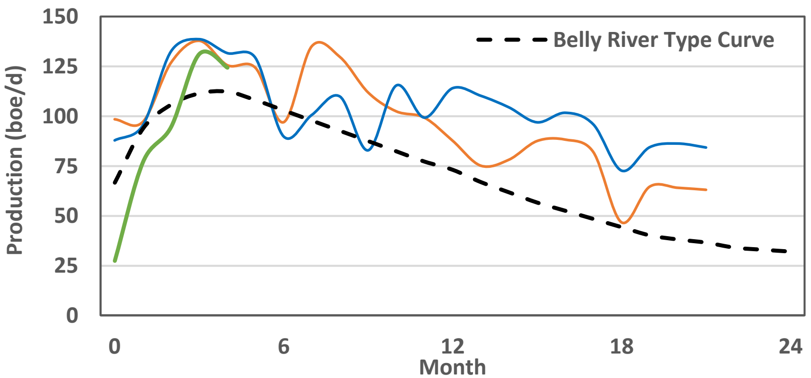
Cardium: 89 net drilling locations

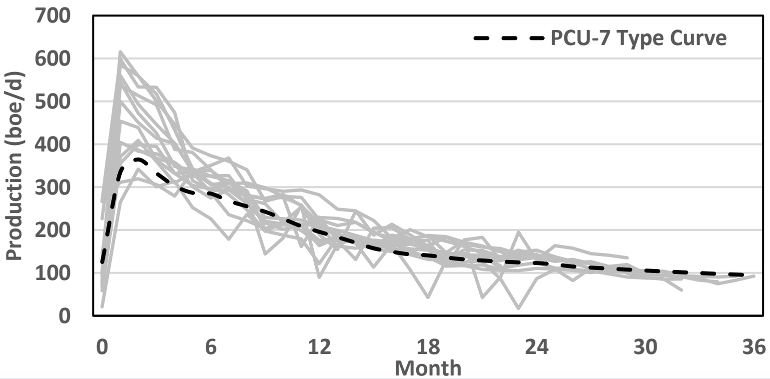
- Secured long-term access to gas processing capacity
- Resumed drilling at PCU-7, our most capital efficient property adding production at $12,800/boed
- History of materially outperforming type curves
- Key development area for next 24 months



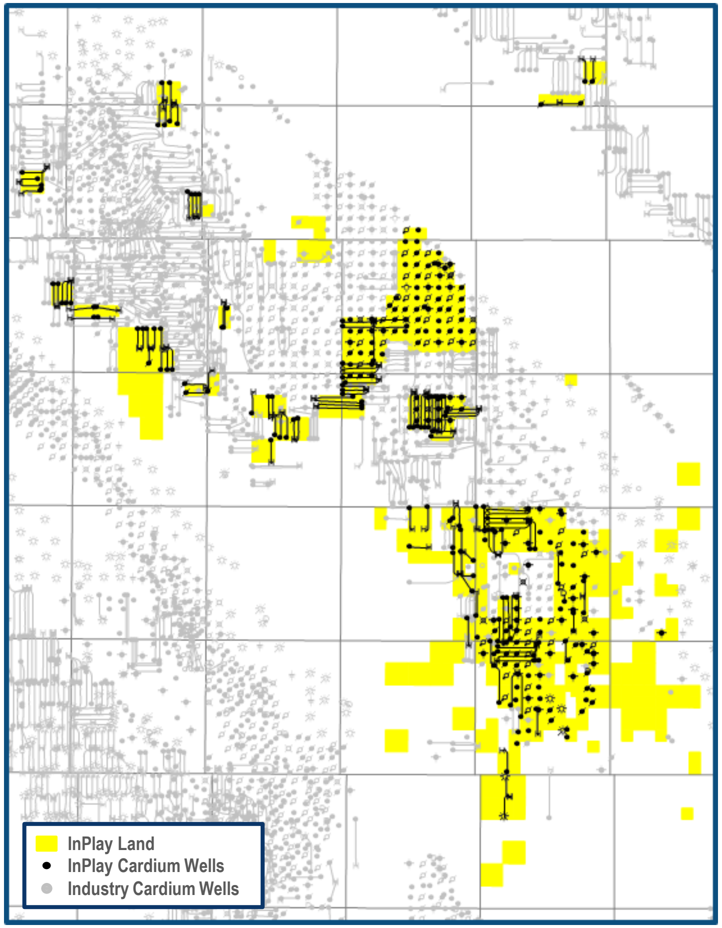
Belly River: 58 net drilling locations

- High oil weighting (~90%), low decline and premium price to MSW
- Two wells drilled in Nov 2022 paid out in <1 year





Willesden Green



Dominant land position in the Willesden Green Cardium trend

Low risk horizontal infill drilling in well established field with large oil in place and low recovery factors

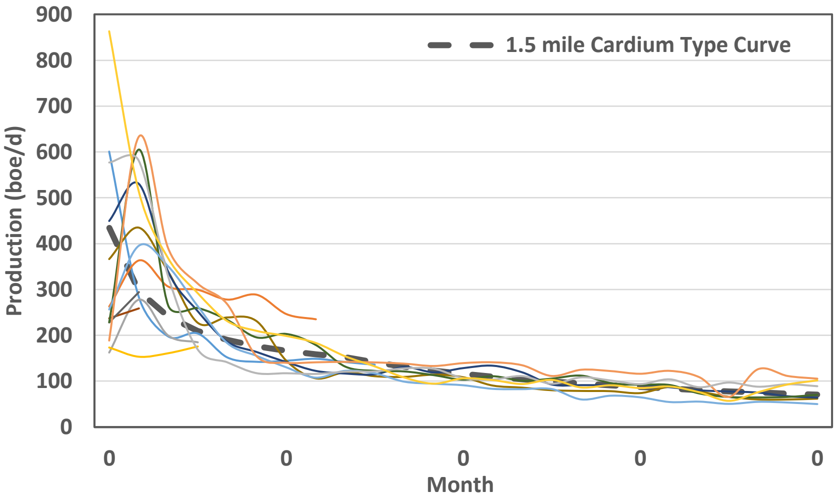
Quick payout drilling inventory

146 net drilling locations

Two required facility upgrades in 2023 increased natural gas processing and takeaway capacity from 8,400 mcf/d to 17,300 mcf/d

Completed Accretive Acquisition of Prairie Storm Nov 30, 2021

- >100% increase in land holdings and inventory
- >120% increase in production since acquisition
- Contiguous lands allow for extended reach horizontal drilling



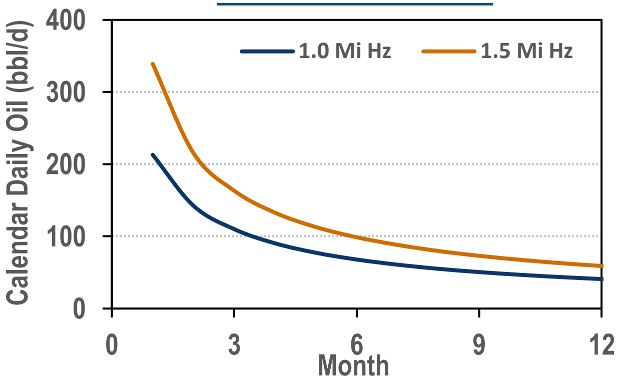
(1) See "Production Breakdown by Product Type" in the Reader Advisories
(2) Based on field estimates

Well Economics

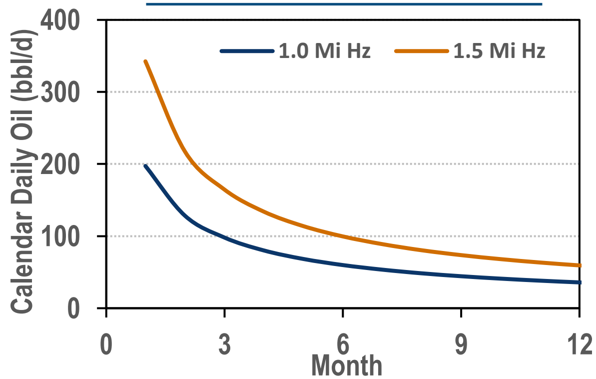
The Cardium and Belly River are well established plays providing some of the best low risk returns in the Western Canada Sedimentary Basin

	Pembina Cardium				Willesden Green Cardium				Belly River	
	1.0 Mile Hz		1.5 Mile Hz		1.0 Mile Hz		1.5 Mile Hz		1.0 Mile Hz	
Capex (mm)	$2.65		$3.40		$2.65		$3.40		$2.55	
Potential Recovery (mboe)	150		330		165		290		125	
IP90 (boe/d)	190		340		170		305		110	
IP365 (boe/d)	110		205		110		190		100	
Yr 1 Cap. Eff. (/ boe/d)	$23,661		$16,585		$24,537		$17,800		$25,000	
F&D (/boe)	$17.90		$10.25		$16.15		$11.64		$20.60	
WTI	$70	$80	$70	$80	$70	$80	$70	$80	$70	$80
Payout (yrs)	1.0	0.8	0.6	0.5	1.1	0.9	0.7	0.6	0.9	0.8
IRR (%)	93	139	251	391	84	120	194	304	92	116
NPV BT10% (mm)	$2.3	$2.9	$5.2	$6.1	$2.3	$2.9	$4.5	$5.4	$2.7	$3.2
Yr 1 Netback (CDN/boe)	$64.24	$71.78	$57.38	$63.34	$63.44	$70.72	$58.20	$64.74	71.09	$76.97
Yr 1 Recycle Ratio (times)	3.6	4.0	5.6	6.2	3.9	4.4	5.0	5.6	3.5	3.7

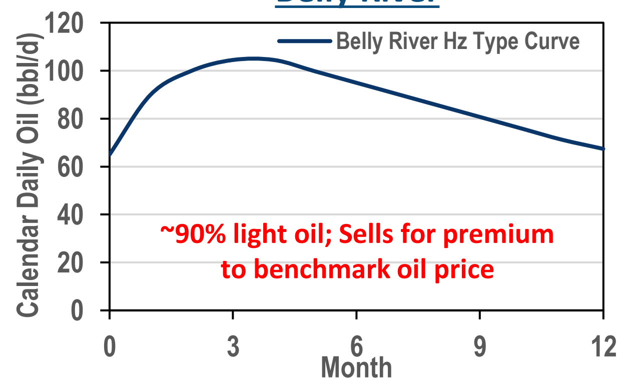
Pembina Cardium



Willesden Green Cardium



Belly River



2025 Forecast

Commodity Price Assumptions	2025 Forecast
WTI oil price *(US$/bbl)*	$72.00
Edmonton par *(C$/bbl)*	$97.15
AECO gas price *($/GJ)*	$1.90
Operational Forecast	
Average production *(boe/d) (% liquids)*[(1)]	8,650 – 9,150 (55% - 57%)
Operating netback ($/boe)[(2)]	$24.75 – $29.75
Adjusted funds flow *($mm)*[(3)]	$69 – $75
Capital program *($mm)*	$41 – $44
Net drilled and completed wells	8.0 – 9.0
Free adjusted funds flow ($mm)[(2)]	$25 – $34
FAFF Yield (%)[(2)]	17% – 23%
Dividend of $0.015/share per month ($mm)	$16.5
Net debt *($mm)* [(3)]	$52 – $58
Net debt/EBITDA[(2)(3)]	0.6x – 0.8x
Common shares outstanding, end of year *(mm)*	90.4
Sensitivities - Adjusted funds flow	
+/- $US 5/bbl WTI (mm)	$6 / ($5)
+/- $0.25/mcf AECO (mm)	$1 / ($1)

(1) See "Production Breakdown by Product Type" in the Reader Advisories
(2) Non-GAAP measure or ratio. See "Non-GAAP and Other Financial Measures" in Reader Advisories
(3) Capital management measure. See "Non-GAAP and Other Financial Measures" in Reader Advisories

Investment Summary

- **Executing our strategy of managing a highly sustainable Company**
  - Maximize FAFF
  - Smart, disciplined light oil production growth
  - Maintain clean balance sheet with low leverage ratios
- **8 year track record of shareholder returns through various commodity price cycles**
- **Operations have resumed at PCU-7, one of our most prolific and capital efficient development areas**
  - Completed first drilling in ~2.5 years (previously 3rd party capacity limitations)
  - CAPEX on latest 3 well pad 25% below budget with wells performing above expectations
  - Majority of 2025 capital directed to PCU-7
- **2025 forecasted to deliver strong FAFF as a result of improved capital efficiencies**
  - 2% production growth with a $20 mm reduction in CAPEX compared to 2024
    - Lower decline rate (22%) and improved capital efficiencies from PCU-7 ($12,800/boed)
  - $16.5mm base dividend (11% dividend yield) fully covered by $25 - $34 million of FAFF (19% FAFF yield)
    - Returned $37 million of capital to shareholders through dividends over the last 26 months
  - Implemented strong hedge position at favorable pricing levels to mitigate risk
- **High rate of return assets; clean balance sheet; excess liquidity → positioned to be opportunistic**
- **Maximize FAFF ensuring continued return of capital to shareholders**

(1) *Capital management measure. See "Non-GAAP and Other Financial Measures" in Reader Advisories*
(2) *Non-GAAP measure or ratio. See "Non-GAAP and Other Financial Measures" in Reader Advisories*

Appendix

InPlay Team

Doug Bartole, President and CEO and Director, P. Eng., ICD.D (over 32 years)

- Founder of InPlay; Founder, President and CEO of Vero Energy; VP Operations of True Energy; Management and Engineering roles at Husky Energy, Renaissance Energy and PanCanadian Petroleum
- Director of Invicta Energy (founder of Royal Acquisition Corp. which was the public RTO vehicle for Invicta)
- Member of APEGA, Institute of Corporate Directors, and a Governor of CAPP (Canadian Association of Petroleum Producers)

Kevin Yakiwchuk, Vice President Exploration, MSc, P. Geol. (over 31 years)

- Founder of InPlay; Founder and VP Exploration of Vero Energy; VP Exploration at True Energy; Geologist at Crestar Energy, Renaissance Energy and Shell Canada

Darren Dittmer, CFO, CPA, CMA (over 30 years)

- CFO of Barrick Energy Inc. from September 2008 until sale of all assets in July 2013
- Controller and CFO of Cadence Energy and prior Controller of Kereco Energy, Ketch Resources and Upton Resources

Brent Howard, Vice President Operations, P. Eng. (over 20 years)

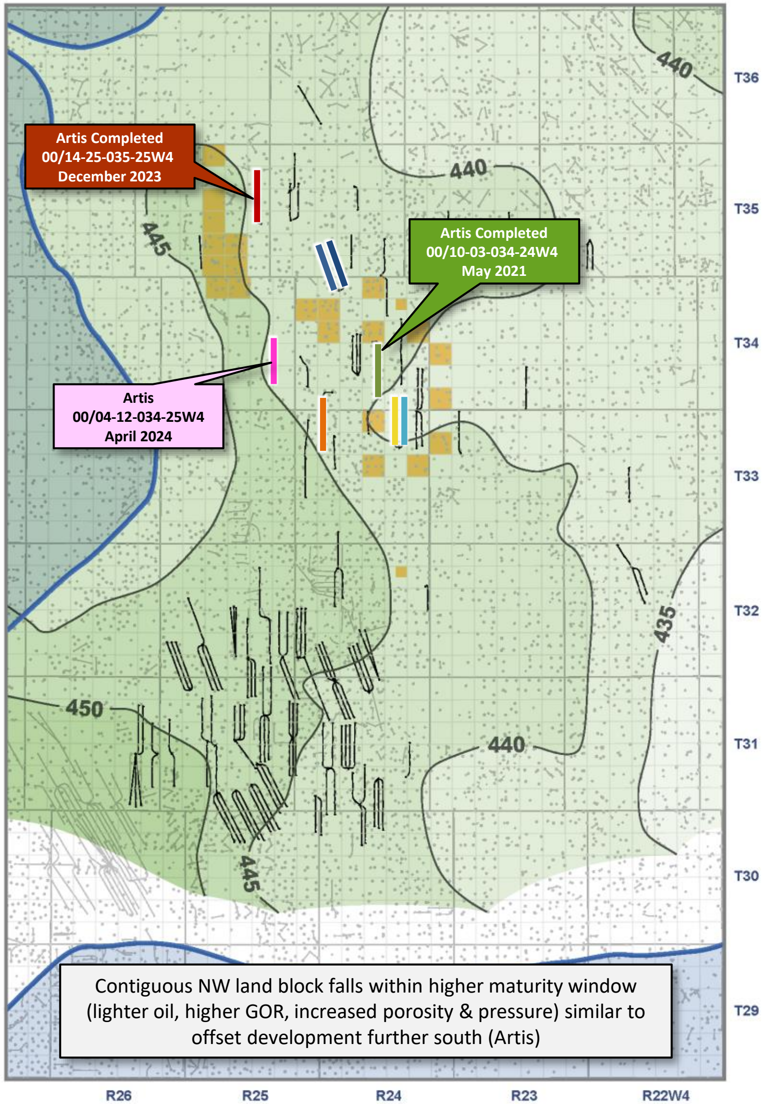
- Manager of Operations at Prairie Storm Energy and subsequently at InPlay after acquisition
- Previously VP Production at Coral Hill Energy Ltd. Prior Engineering roles at Bellamont Exploration Ltd., Wave Energy Ltd., and Penn West Energy Trust

Kevin Leonard, BComm, Vice President Business & Corporate Development (over 18 years)

- Founder, Managing Director Investment Banking Eight Capital; Managing Director Energy Investment Banking Dundee Capital Markets, Vice President Energy Investment Banking Canaccord Genuity

East Basin Duvernay Shale

Huxley Duvernay Tmax Map (°C)



12,960 acres (100% WI) of Predominantly Crown Land in the Huxley Area

- InPlay lands derisked via extensive industry activity directly offsetting
  - Long land tenure allows InPlay a measured pace of development
  - Large, contiguous land block falls within higher maturity window

Significant Light Oil Resource (high quality oil - premium to Edmonton Light)

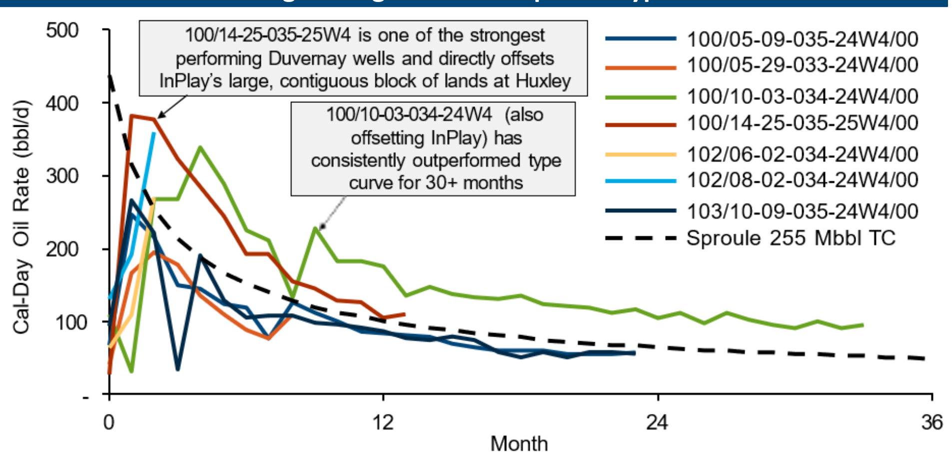
Upside Potential

- Offset performance supports 255 mbbl recovery per well (2 mile)
- 63 net locations (2 mile wells at 6 wells/section)
  - Hz wells drilled into Lower Duvernay show similar production results as Upper Duvernay

Compelling Economics ($80 WTI; $3.00/AECO)

- CAPEX: $8.4 million
- NPV: $4.6 million
- IRR: ~45%
- Payout: ~1.5 years
- Potential to reduce costs and improve payouts with sliding sleeves

Offsetting Drilling Results vs. Sproule Type Curve



Hedges (Derivative contracts)

	Q1/25	Q2/25	Q3/25	Q4/25	Q1/26	Q2/26 – Q4/26
Natural Gas AECO Swap (mcf/d) (1)	5,685	5,685	5,685	5,685	5,685	2,845
Hedged price ($AECO/mcf)	$2.47	$2.47	$2.47	$2.47	$2.47	$2.55
Natural Gas AECO Costless Collar (mcf/d) (2)	6,635	2,845	2,845	2,845	2,845	-
Hedged price ($AECO/mcf)	$2.32 - $3.16	$2.11 - $2.77	$2.11 - $2.77	$2.11 - $2.77	$2.11 - $2.77	-
Crude Oil WTI Swap (bbl/d) (3)	500	500	500	500	-	-
Hedged price ($CAD WTI/bbl)	95.60	95.60	95.60	95.60	-	-
Crude Oil WTI Three-way Collar (bbl/d) (3)	1,700	1,700	1,300	1,300	-	-
Low sold put price ($USD WTI/bbl)	$60.20	$60.20	$59.50	$59.50	-	-
Mid bought put price ($USD WTI/bbl)	$68.10	$68.10	$67.50	$67.50	-	-
High sold call price ($USD WTI/bbl)	$82.90	$82.90	$83.00	$83.00	-	-
Electricity AESO Swap (kW) (1)	1,000 (4)	1,000 (4)	1,000 (4)	1,000 (4)	1,000 (4)	1,000 (4)
Hedged price ($kWh)	$0.6217	$0.6217	$0.6217	$0.6217	$0.6217	$0.6217

(1) Fixed price swaps provide InPlay with a guaranteed price in lieu of realization of floating index prices.
(2) Costless collars indicate InPlay concurrently bought put and sold call options at strike prices such that the costs and premiums received offset each other, thereby completing the derivative contracts on a costless basis.
(3) The WTI three-way collars are a combination high priced sold call, low priced sold put and a mid-priced bought put. The high sold call price is the maximum price the Company will receive for the contract volumes. The mid bought put price is the minimum price InPlay will receive, unless the market price falls below the low sold put strike price, in which case InPlay receives market price plus the difference between the mid bought put price minus the low sold put price.
(4) The Company's electricity hedge has a four-year term from August 2024 – July 2028.

Slide Notes

Slide 2

1. 2025 Free adjusted funds flow, FAFF Yield, Dividend Yield, Net debt and Net debt to EBITDA are based on forecasted assumptions outlined in the "Forward Looking Information and Statements" in the Reader Advisories.

Slide 3

1. 2025 production rates and drilling plans are based on forecasted assumptions as outlined in the "Forward Looking Information and Statements" section in the Reader Advisories.
2. Reserves and NPV are derived from InPlay's independent reserve evaluation effective December 31, 2023. See "Reserves" and "Net Present Value Estimates" within "Oil and Gas Advisories" in the Reader Advisories.
3. Shares (basic and fully dilutive) outstanding at the date of this presentation.
4. Shares outstanding include shares held in trust to settle the future vesting of Restricted Awards and Performance Awards.
5. Market capitalization and Enterprise value based on current share price. Net debt is estimated as of December 31, 2024. See "Preliminary Financial Information" in the Reader Advisories
6. Enterprise value is calculated by the Company as the Company's market capitalization plus Net debt. Refer below for calculation of Enterprise Value.

Basic Shares Outstanding	90.1
Market Capitalization (@ assumed $1.65 per share) (mm)	$150
Net debt (mm)	$60
Enterprise Value (@ assumed $1.80 per share) (mm)	$210

Slide 5

1. 2025 forecasted annual average production, production/share, AFF, AFF/share, FAFF, FAFF Yield Net debt / EBITDA and growth rates are based on forecasted assumptions as outlined in the "Forward Looking Information and Statements" section in the Reader Advisories.
2. Reserves are derived from InPlay's independent reserve evaluation effective December 31, 2023. See "Reserves" and "Net Present Value Estimates" within "Oil and Gas Advisories" in the Reader Advisories.

Slide 6

1. Reserves and associated reserve values are derived from InPlay's independent reserve evaluation effective December 31, 2023.
2. See "Reserves" and "Net Present Value Estimates" under "Oil and Gas Advisories".
3. Duvernay land holdings attributed a value of $10.0 million ($700/acre) for 14,271 net acres based on internal valuations. The remaining undeveloped acreage is based on an internal valuation of $12.7 million ($261/acre) for 48,834 net acres. These internal valuations are based on land sales in the area.
4. Net debt and basic shares outstanding as at December 31, 2023.

Slide 7

1. Refer to notes in InPlay's press release dated March 13, 2024 for details of 2023 Capital efficiencies, FD&A and Recycle ratio calculations.
2. Peers are defined as light oil weighted small to large cap exploration and development companies having greater than 60% oil and liquids weighting (BNE, CJ, GXE, OBE, SGY, TVE, WCP).

Slide 8

1. See "Drilling Locations" within "Oil and Gas Advisories" in the Reader Advisories.
2. See "Type Curves and Potential Recovery Estimates" under "Oil and Gas Advisories" in the Reader Advisories.
3. 2025 drilling plans are based on forecasted assumptions as outlined in the "Forward Looking Information and Statements" section in the Reader Advisories.

Slide 9

1. The aggregate consideration ascribed to the Acquisition at the time the Acquisition Agreement was entered into is $50 million, comprised of $40 million of cash consideration and the issuance of 8,333,333 Common Shares at a deemed issuance price of $1.20 per Common Share. For accounting and financial statement purposes under IFRS, the value of the share consideration payable under the Acquisition will be based upon the market price of the Common Shares immediately prior to the Acquisition Closing Date. Had the Acquisition Closing Date occurred on October 1, 2021, the value ascribed to the share consideration, based on an October 1, 2021 closing price of $1.66 per Common Share, would have been approximately $13.8 million. The Adjusted Working Capital of Prairie Storm being assumed by InPlay upon closing of the Acquisition is estimated to be $9.5 million, after payment of Prairie Storm's estimated transaction costs resulting in net consideration ascribed to the Acquisition of $40.5 million. All figures are based upon the assumed exercise of all outstanding Prairie Storm Options effective immediately prior to completion of the Acquisition. See "Non-GAAP Measures and Ratios" for additional details.
2. Cumulative Free cash flow figures to September 30, 2024
3. See "Reserves" and "Net Present Value Estimates" under "Oil and Gas Advisories".

Slide 10

1. See "Type Curves and Potential Recovery Estimates" under "Oil and Gas Advisories" in the Reader Advisories.
2. See "Drilling Locations" within "Oil and Gas Advisories" in the Reader Advisories.

Slide Notes (continued)

Slide 11

1. See “Type Curves and Potential Recovery Estimates” under “Oil and Gas Advisories” in the Reader Advisories.
2. See “Drilling Locations” within “Oil and Gas Advisories” in the Reader Advisories.

Slide 12

1. See “Type Curves and Potential Recovery Estimates” under “Oil and Gas Advisories” in the Reader Advisories.
2. See “Drilling Locations” within “Oil and Gas Advisories” in the Reader Advisories.
3. Economics are based on: WTI/Edmonton Par light oil differential of negative $2.50 / $3.00 / $3.50 respectively over indicated WTI pricing range, AECO $3.50/GJ. CAD/USD FX rates of 0.72, 0.74 and 0.76 respectively over indicated WTI pricing range.

Slide 13

1. Refer to the “Forward Looking Information” section in the “Readers Advisories” for the assumptions used in the calculation of forecasted 2025 “Operating Netback”, “Adjusted funds flow”, “Free adjusted funds flow”, “FAFF Yield”, “Net Debt” and “Net Debt/EBITDA”

Slide 14

1. Free adjusted funds flow and FAFF Yield is based on forecasted assumptions outlined in the “Forward Looking Information and Statements” in the Reader Advisories.

Slide 17

1. See “Drilling Locations” within “Oil and Gas Advisories” in the Reader Advisories.
2. Potential recovery estimates for the area are internal estimates made by comparing industry historical well results surrounding InPlay’s land base in the area to the type curve library noted in the “Type Curves and Potential Recovery Estimates” section in “Oil and Gas Advisories” to identify the most applicable type curve and associated recovery. The referenced estimates are meant to closely approximate Proved Plus Probable Undeveloped reserves as defined by COGE. Given the process described above however, these estimates are considered internally generated recovery estimates prepared by InPlay’s technical team and are not reserve of resource estimates prepared in accordance with the requirements of COGE.
3. Economics are based on: WTI/Edmonton Par light oil differential of negative $3.50 / $4.00 / $4.50 respectively over indicated WTI pricing range, AECO $4.00/GJ
4. Economics assume Crown land for royalties payable on produced volumes (InPlay’s Duvernay lands are 100% Crown)
5. See “Estimated Ultimate Recovery” within “Oil and Gas Advisories” in the Reader Advisories.

All amounts in this presentation are stated in Canadian dollars unless otherwise specified. Throughout this presentation, the terms Boe (barrels of oil equivalent) and Mmboe (millions of barrels of oil equivalent) are used. Such terms when used in isolation, may be misleading. In accordance with Canadian practice, production volumes and revenues are reported on a company gross basis, before deduction of Crown and other royalties and without including any royalty interest, unless otherwise stated. Unless otherwise specified, all reserves volumes in this presentation (and all information derived therefrom) are based on "company gross reserves" using forecast prices and costs. Complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101 is available on our SEDAR profile at www.sedar.com. The recovery and reserve estimates contained herein are estimates only and there is no guarantee that the estimated reserves will be recovered. In relation to the disclosure of estimates for individual properties, such estimates may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. The Company's belief that it will establish additional reserves over time with conversion of probable undeveloped reserves into proved reserves is a forward-looking statement and is based on certain assumptions and is subject to certain risks, as discussed previously under the heading "Forward-Looking Information and Statements".

The information contained in this corporate presentation does not purport to be all-inclusive or to contain all information that a prospective investor may require. Prospective investors are encouraged to conduct their own analysis and reviews of InPlay and of the information contained in this corporate presentation. Without limitation, prospective investors should consider the advice of their financial, legal, accounting, tax and other advisors and such other factors they consider appropriate in investigating and analyzing InPlay.

Oil and Gas Advisories

The recovery and reserve estimates of InPlay's reserves provided herein are estimates only and there is no guarantee that the estimated reserves with be recovered. Throughout this presentation various references are made to "potential" and "targeted" resource and recoveries which have been prepared by management of InPlay and are not estimates of reserves or resources. Accordingly, undue reliance should not be placed on same. Such information has been prepared by management for the purposes of making capital investment decisions and for internal budget preparation only. In addition, forward-looking statements or information are based on a number of material factors, expectations or assumptions of InPlay which have been used to develop such statements and information but which may prove to be incorrect. Although InPlay believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because InPlay can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified herein, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which InPlay operates; the timely receipt of any required regulatory approvals; the ability of InPlay to obtain qualified staff, equipment and services in a timely and cost efficient manner; the ability of InPlay to add production and reserves through acquisition, development and exploration activities; drilling results; the ability of the operator of the projects in which InPlay has an interest in to operate the field in a safe, efficient and effective manner; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; risks associated with the degree of certainty in resource assessments; the timing and cost of pipeline, storage and facility construction and expansion and the ability of InPlay to secure adequate product transportation; future commodity prices; currency, exchange and interest rates; regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which InPlay operates; and the ability of InPlay to successfully market its oil and natural gas products.

Certain information in this document may constitute "analogous information" as defined in National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI-51-101"), including but not limited to, information relating to the areas in geographical proximity to lands that are or may be held by InPlay. Such information has been obtained from government sources, regulatory agencies or other industry participants. InPlay believes the information is relevant as it helps to define the reservoir characteristics in which InPlay may hold an interest. InPlay is unable to confirm that the analogous information was prepared by a qualified reserves evaluator or auditor. Such information is not an estimate of the reserves or resources attributable to lands held or potentially to be held by InPlay and there is no certainty that the reservoir data and economics information for the lands held or potentially to be held by InPlay will be similar to the information presented herein. The reader is cautioned that the data relied upon by InPlay may be in error and/or may not be analogous to such lands to be held by InPlay.

Any references in this presentation to initial, early and/or test or production/performance rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinate of the rates at which such wells will produce or continue production and to decline thereafter. Additionally, such rates may also include recovered "load oil" fluid used in well completion stimulation. Readers are cautioned not to place reliance on such rates in calculating the aggregate production for InPlay. The initial production rate may be estimated based on other third-party estimates or limited data available at this time. In all cases in this presentation, initial production or tests are not necessarily indicative of long-term performance of the relevant well or fields or of ultimate recovery of hydrocarbons. References to light oil, NGLs or natural gas production in this document refer to the light and medium crude oil, natural gas liquids and conventional natural gas product types, respectively, as defined in NI-51-101.

Reserves – All reserves disclosed in this presentation are derived from InPlay's independent reserve evaluation effective December 31, 2023, complete details of which can be found within our Annual Information form filed on SEDAR. Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical 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** 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.
>
> > **Proved Developed Producing Reserves** are those proved 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.
> >
> > **Proved Developed Non Producing Reserves** are those proved 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.
>
> **Probable Reserves** 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 sum of the estimated proved plus probable reserves.

Test Results and Initial Production Rates - A pressure transient analysis or well-test interpretation has not been carried out and thus certain of the test results provided herein should be considered to be preliminary until such analysis or interpretation has been completed. Test results and initial production rates disclosed herein may not necessarily be indicative of long term performance or of ultimate recovery. Initial Production ("IP") rates indicate the average daily production over the indicated daily period.

BOE equivalent - Barrel of oil equivalents or BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of 6:1, utilizing a 6:1 conversion basis may be misleading as an indication of value

Estimated Ultimate Recovery – Estimated Ultimate Recovery ("EUR") is an approximation of the quantity of oil or gas that is potentially recoverable or has already been recovered from a reserve or well. EUR is not a defined term within the COGE Handbook and therefore any reference to EUR in this presentation is not deemed to be reported under the requirements of NI 51-101. Readers are cautioned that there is no certainty that the Company will ultimately recover the estimated quantity of oil or gas from such reserves or wells.

Oil and Gas Advisories (cont'd)

Net Present Value Estimates - It should not be assumed that the net present value of the estimated future net revenues of the reserves of InPlay included in this presentation represent the fair market value of the reserves. There is no assurance that the forecast prices and cost assumptions will be attained and variances could be material.

Type Curves and Potential Recovery Estimates - The type curves presented herein reflect a selection from a type curves library provided by InPlay's independent reserve evaluator. In each case the type curve presented is that which in management's assessment feels best represents the expected average drilling results based upon InPlay producing wells in the area as well as non-InPlay wells determined by management to be analogous for purposes of the type curve assignments. Type curves presented incorporate the most recent data from actual well results and would only be representative of the specific drilled locations. There is no guarantee that InPlay will achieve the estimated or similar results derived therefrom. The referenced potential recovery estimates are meant to approximate Proved Plus Probable Undeveloped reserves as defined by COGE. The potential recovery estimates have been generated using the relevant oil type curve noted above and incorporating management assumptions relating to gas and NGL amounts which are based on historical results. These estimates are considered internally generated recovery targets developed by InPlay's technical team and are not reserve or resource estimates prepared in accordance with the requirements of COGE. Accordingly, undue reliance should not be placed on the same. Such information has been prepared by management for the purposes of making capital investment decisions and for internal budget preparation only.

Drilling Locations This presentation discloses drilling locations in two categories: (i) booked locations; and (ii) unbooked locations. Booked locations are proved locations and probable locations derived from InPlay's independent reserves evaluation effective December 31, 2023 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Of the 458 drilling locations identified herein, 173 are booked as proved locations, 24 are booked as probable locations and 262 are unbooked locations. Unbooked locations are management estimates based on 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. Unbooked locations have been identified by management as an estimation of the Company's potential multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the InPlay 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 InPlay actually drills wells will depend upon the availability of capital, regulatory approvals, seasonal natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been derisked by either InPlay restrictions, oil and other industry participants drilling existing wells in relative close proximity to such unbooked drilling locations, certain unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir. Therefore, there is uncertainty whether wells will be drilled in such unbooked locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

	Total Locations	Proved Locations	Probable Locations	Unbooked Locations
Willesden Green Cardium	176	50%	24%	32%
Pembina Cardium	89	26%	22%	15%
Pembina Belly River	58	18%	25%	8%
Duvernay	125	1%	30%	45%
Other	10	5%	0%	1%
Total	458	100%	100%	100%

Oil & Gas Metrics - This presentation may contain metrics commonly used in the oil and natural gas industry, such as "finding and development costs", "finding and development recycle ratio", "finding, development and acquisition costs", "finding, development and acquisition recycle ratio", "payout", "RLI" and "IRR". These terms do not have standardized meanings or standardized methods of calculation and therefore may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Management uses oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare InPlay's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this presentation, should not be unduly relied upon.

Finding and development costs ("F&D costs") are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on exploration and development activities in the year by the change in reserves from the prior year for the reserve category.

F&D recycle ratio is calculated by dividing the operating netback per boe for the period by the F&D costs per boe for the particular reserve category.

Finding, development and acquisition costs ("FD&A costs") are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on exploration and development activities and property acquisitions (net of dispositions) in the year by the change in reserves from the year for the reserve category.

FD&A recycle ratio is calculated by dividing the operating netback per boe for the period by the FD&A costs per boe for the particular reserve category.

Payout refers to the time required to pay back the capital expenditures (on a before tax basis) of a project.

Reserve Life Index ("RLI") is calculated by dividing the quantity of a particular reserve category of reserves by the forecast of the first year's production for the corresponding reserve category.

Reserve Replacement: The reserves replacement ratio is calculated by dividing the yearly change in reserves before production by the actual annual production for that year.

Internal Rate of Return ("IRR") refers to the discount rate that makes the net present value of all cash flows of a project equal zero.

Preliminary Financial Information

The Company's expectations set forth in the updated forecasted 2024 guidance are based on, among other things, the Company's anticipated financial results for the three and twelve month periods ended December 31, 2024. The Company's anticipated financial results are unaudited and preliminary estimates that: (i) represent the most current information available to management as of the date of hereof; (ii) are subject to completion of audit procedures that could result in significant changes to the estimated amounts; and (iii) do not present all information necessary for an understanding of the Company's financial condition as of, and the Company's results of operations for, such periods. The anticipated financial results are subject to the same limitations and risks as discussed under "Forward Looking Information and Statements" below. Accordingly, the Company's anticipated financial results for such periods may change upon the completion and approval of the financial statements for such periods and the changes could be material.

Production Breakdown by Product Type

Disclosure of production on a per boe basis in this document consists of the constituent product types as defined in NI 51-101 and their respective quantities disclosed in the table below:

	Light and Medium Crude oil (bbl/d)	NGLS (boe/d)	Conventional Natural gas (Mcf/d)	Total (boe/d)
2016 Average Production	1,318	143	2,871	1,940
2017 Average Production	2,310	352	7,857	3,972
2018 Average Production	2,756	492	8,431	4,653
2019 Average Production	2,627	697	10,058	5,000
2020 Average Production	2,031	668	7,715	3,985
2021 Average Production	2,981	782	12,030	5,768
Prairie Storm Closing Production	505	453	5,050	1,800
2022 Prairie Storm Estimate	965	585	7,230	2,755

	Light and Medium Crude oil (bbl/d)	NGLS (boe/d)	Conventional Natural gas (Mcf/d)	Total (boe/d)
2022 Average Production	3,766	1,402	23,623	9,105
Q3 2023 Average Production	3,697	1,420	23,316	9,003
2023 Average Production	3,822	1,396	22,839	9,025
Q3 2024 Average Production	3,279	1,418	21,052	8,206
2024 Previous Annual Guidance	3,735	1,435	22,080	8,850[1]
2024 Updated Annual Guidance	3,535	1,495	22,170	8,750[2]
2025 Annual Guidance	3,425	1,510	23,790	8,900[3]

1. *This reflects the mid-point of the Company's 2024 previous production guidance range of 8,700 to 9,000 boe/d.*
2. *This reflects the mid-point of the Company's 2024 updated production guidance range of 8,700 to 8,750 boe/d.*
3. *This reflects the mid-point of the Company's 2025 production guidance range of 8,650 to 9,150 boe/d.*
4. *With respect to forward-looking production guidance, product type breakdown is based upon management's expectations based on reasonable assumptions but are subject to variability based on actual well results.*

Non-GAAP and Other Financial Measures

Throughout this document and other materials disclosed by the Company, InPlay uses 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 GAAP and therefore may not be comparable to similar measures presented by other entities. The non-GAAP and other financial measures should not be considered alternatives to, or more meaningful than, financial measures that are determined in accordance with GAAP as indicators of the Company performance. Management believes that the presentation of these non-GAAP and other financial measures provides useful information to shareholders and investors in understanding and evaluating the Company's ongoing operating performance, and the measures provide increased transparency and the ability to better analyze InPlay's business performance against prior periods on a comparable basis.

Non-GAAP Financial Measures and Ratios

Included in this document are references to the terms "free adjusted funds flow", "free adjusted funds flow yield", "operating income", "operating netback per boe", "operating income profit margin" and "Net Debt to EBITDA". Management believes these measures and ratios are helpful supplementary measures of financial and operating performance and provide users with similar, but potentially not comparable, information that is commonly used by other oil and natural gas companies. These terms do not have any standardized meaning prescribed by GAAP and should not be considered an alternative to, or more meaningful than "profit before taxes", "profit and comprehensive income", "adjusted funds flow", "capital expenditures", "net debt", or assets and liabilities as determined in accordance with GAAP as a measure of the Company's performance and financial position.

Free Adjusted Funds Flow ("FAFF") - Management considers FAFF an important measure to identify the Company's ability to improve its financial condition through debt repayment and its ability to provide returns to shareholders. FAFF should not be considered as an alternative to or more meaningful than AFF as determined in accordance with GAAP as an indicator of the Company's performance. FAFF is calculated by the Company as AFF less exploration and development capital expenditures and property dispositions (acquisitions) and is a measure of the cashflow remaining after capital expenditures before corporate acquisitions that can be used for additional capital activity, corporate acquisitions, repayment of debt or decommissioning expenditures or potentially return of capital to shareholders. Refer to the "Forward Looking Information and Statements" section for a calculation of forecast FAFF.

Free Adjusted Funds Flow Yield - InPlay uses "free adjusted funds flow yield" as a key performance indicator. Free adjusted funds flow is calculated by the Company as free adjusted funds flow divided by the market capitalization of the Company. Management considers FAFF yield to be an important performance indicator as it demonstrates a Company's ability to generate cash to pay down debt and provide funds for potential distributions to shareholders. Refer to the "Forward Looking Information and Statements" section for a calculation of free adjusted funds flow yield.

Operating Income/Operating Netback per boe/Operating Income Profit Margin - InPlay uses "operating income", "operating netback per boe" and "operating income profit margin" as key performance indicators. Operating income is calculated by the Company as oil and natural gas sales less royalties, operating expenses and transportation expenses and is a measure of the profitability of operations before administrative, share-based compensation, financing and other non-cash items. Management considers operating income an important measure to evaluate its operational performance as it demonstrates its field level profitability. Operating income should not be considered as an alternative to or more meaningful than net income as determined in accordance with GAAP as an indicator of the Company's performance. Operating netback per boe is calculated by the Company as operating income divided by average production for the respective period. Management considers operating netback per boe an important measure to evaluate its operational performance as it demonstrates its field level profitability per unit of production. Operating income profit margin is calculated by the Company as operating income as a percentage of oil and natural gas sales. Management considers operating income profit margin an important measure to evaluate its operational performance as it demonstrates how efficiently the Company generates field level profits from its sales revenue. Refer below for a calculation of operating income, operating netback per boe and operating income profit margin. Refer to the "Forward Looking Information and Statements" section for a calculation of forecast operating income, operating netback per boe and operating income profit margin.

Reader Advisories (continued)

Non-GAAP and Other Financial Measures (cont'd)

		3 mos. Ended Sep 30/2024	3 mos. Ended Sep 30/2023	9 mos. Ended Sep 30/2024	9 mos. Ended Sep 30/2023
Revenue	$000's	**34,217**	46,672	**113,674**	131,735
Royalties	$000's	**(5,122)**	(5,387)	**(14,711)**	(16,178)
Operating expenses	$000's	**(12,085)**	(12,677)	**(35,786)**	(36,343)
Transportation expenses	$000's	**(667)**	(698)	**(2,296)**	(2,190)
Operating income	$000's	**16,343**	27,910	**60,881**	77,024
Sales volumes	Mboe	**755.0**	828.3	**2,325.9**	2,411.2
Revenue	$/boe				
Royalties	$/boe	**45.32**	56.35	**48.87**	54.63
Operating expenses	$/boe	**(6.78)**	(6.50)	**(6.33)**	(6.71)
Transportation expenses	$/boe	**(16.01)**	(15.31)	**(15.39)**	(15.07)
Operating netback	$/boe	**(0.88)**	(0.85)	**(0.99)**	(0.90)
Operating income profit margin	%	**21.65**	33.69	**26.16**	31.95

Net Debt to EBITDA - Management considers Net Debt to EBITDA an important measure as it is a key metric to identify the Company's ability to fund financing expenses, net debt reductions and other obligations. EBITDA is calculated by the Company as adjusted funds flow before interest expense. When this measure is presented quarterly, EBITDA is annualized by multiplying by four. When this measure is presented on a trailing twelve month basis, EBITDA for the twelve months preceding the net debt date is used in the calculation. This measure is consistent with the EBITDA formula prescribed under the Company's Senior Credit Facility. Net Debt to EBITDA is calculated as Net Debt divided by EBITDA. Refer to the "Forward Looking Information and Statements" section for a calculation of forecast Net Debt to EBITDA.

Capital Management Measures

Adjusted Funds Flow - Management considers adjusted funds flow to be an important measure of InPlay's ability to generate the funds necessary to finance capital expenditures. Adjusted funds flow is a GAAP measure and is disclosed in the notes to the Company's financial statements for the three and nine months ended September 30, 2024. All references to adjusted funds flow throughout this document are calculated as funds flow adjusting for decommissioning expenditures. Decommissioning expenditures are adjusted from funds flow as they are incurred on a discretionary and irregular basis and are primarily incurred on previous operating assets. The Company also presents adjusted funds flow per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of profit per common share.

Net debt - Net debt is a GAAP measure and is disclosed in the notes to the Company's financial statements for the three and nine months ended September 30, 2024. The Company closely monitors its capital structure with the goal of maintaining a strong balance sheet to fund the future growth of the Company. The Company monitors net debt as part of its capital structure. The Company uses net debt (bank debt plus accounts payable and accrued liabilities less accounts receivables and accrued receivables, prepaid expenses and deposits and inventory) as an alternative measure of outstanding debt. Management considers net debt an important measure to assist in assessing the liquidity of the Company.

Supplementary Measures

"Average realized crude oil price" is comprised of crude oil commodity sales from production, as determined in accordance with IFRS, divided by the Company's crude oil volumes. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

"Average realized NGL price" is comprised of NGL commodity sales from production, as determined in accordance with IFRS, divided by the Company's NGL volumes. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

"Average realized natural gas price" is comprised of natural gas commodity sales from production, as determined in accordance with IFRS, divided by the Company's natural gas volumes. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

"Average realized commodity price" is comprised of commodity sales from production, as determined in accordance with IFRS, divided by the Company's volumes. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

"Adjusted funds flow per weighted average basic share" is comprised of adjusted funds flow divided by the basic weighted average common shares.

"Adjusted funds flow per weighted average diluted share" is comprised of adjusted funds flow divided by the diluted weighted average common shares.

"Adjusted funds flow per boe" is comprised of adjusted funds flow divided by total production.

Forward Looking Information and Statements

This document contains certain forward–looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "project", "should", "believe", "plans", "intends", "forecast" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this news release contains forward-looking information and statements pertaining to the following: the Company's business strategy, milestones and objectives; all estimates and guidance related to the year ended 2024 results; the Company's planned 2025 capital program including wells to be drilled and completed and the timing of the same including, without limitation, the timing of wells coming on production and the anticipated benefits therefrom; 2025 guidance based on the planned capital program and all associated underlying assumptions set forth in this news release including, without limitation, forecasts of 2025 annual average production levels, adjusted funds flow, free adjusted funds flow, Net Debt/EBITDA ratio, operating income profit margin, net debt and Management's belief that the Company can grow some or all of these attributes and specified measures; light crude oil and NGLs weighting estimates; expectations regarding future commodity prices; future oil and natural gas prices; future liquidity and financial capacity; future results from operations and operating metrics; future costs, expenses and royalty rates; future interest costs; the exchange rate between the $US and $Cdn; future development, exploration, acquisition, development and infrastructure activities and related capital expenditures, including our planned 2025 capital program; the amount and timing of capital projects;; and methods of funding our capital program.

The internal projections, expectations, or beliefs underlying our Board approved 2025 capital budget and associated guidance are subject to change in light of, among other factors, changes to U.S. economic, regulatory and/or trade policies (including tariffs), the impact of world events including the Russia/Ukraine conflict and war in the Middle East, ongoing results, prevailing economic circumstances, volatile commodity prices, and changes in industry conditions and regulations. InPlay's 2025 financial outlook and revised guidance provides shareholders with relevant information on management's expectations for results of operations, excluding any potential acquisitions or dispositions, for such time periods based upon the key assumptions outlined herein. Readers are cautioned that events or circumstances could cause capital plans and associated results to differ materially from those predicted and InPlay's revised guidance for 2025 may not be appropriate for other purposes. Accordingly, undue reliance should not be placed on same.

Forward-looking statements or information are based on a number of material factors, expectations or assumptions of InPlay which have been used to develop such statements and information but which may prove to be incorrect. Although InPlay believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because InPlay can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified herein, assumptions have been made regarding, among other things: the current U.S. economic, regulatory and/or trade policies; the impact of increasing competition; the general stability of the economic and political environment in which InPlay operates; the timely receipt of any required regulatory approvals; the ability of InPlay to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects in which InPlay has an interest in to operate the field in a safe, efficient and effective manner; the ability of InPlay to obtain debt financing on acceptable terms; the anticipated tax treatment of the monthly base dividend; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and cost of pipeline, storage and facility construction and the ability of InPlay to secure adequate product transportation; future commodity prices; that various conditions to a shareholder return strategy can be satisfied; the ongoing impact of the Russia/Ukraine conflict and war in the Middle East; currency, exchange and interest rates; regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which InPlay operates; and the ability of InPlay to successfully market its oil and natural gas products.

Without limitation of the foregoing, readers are cautioned that the Company's future dividend payments to shareholders of the Company, if any, and the level thereof will be subject to the discretion of the Board of Directors of InPlay. The Company's dividend policy and funds available for the payment of dividends, if any, from time to time, is dependent upon, among other things, levels of FAFF, leverage ratios, financial requirements for the Company's operations and execution of its growth strategy, fluctuations in commodity prices and working capital, the timing and amount of capital expenditures, credit facility availability and limitations on distributions existing thereunder, and other factors beyond the Company's control. Further, the ability of the Company to pay dividends will be subject to applicable laws, including satisfaction of solvency tests under the Business Corporations Act (Alberta), and satisfaction of certain applicable contractual restrictions contained in the agreements governing the Company's outstanding indebtedness.

The forward-looking information and statements included herein are not guarantees of future performance and should not be unduly relied upon. Such information and statements, including the assumptions made in respect thereof, involve known and unknown risks, uncertainties and other factors that may cause actual results or events to defer materially from those anticipated in such forward-looking information or statements including, without limitation: changes in industry regulations and legislation (including, but not limited to, tax laws, royalties, and environmental regulations); the risk that the U.S. government imposes tariffs on Canadian goods, including crude oil and natural gas, and that such tariffs (and/or the Canadian government's response to such tariffs) adversely affect the demand and/or market price for InPlay's products and/or otherwise adversely affects InPlay; the continuing impact of the Russia/Ukraine conflict and war in the Middle East; potential changes to U.S. economic, regulatory and/or trade policies as a result of a change in government; inflation and the risk of a global recession; changes in our planned 2025 capital program; changes in our approach to shareholder returns; changes in commodity prices and other assumptions outlined herein; the risk that dividend payments may be reduced, suspended or cancelled; the potential for variation in the quality of the reservoirs in which we operate; changes in the demand for or supply of our products; unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans or strategies of InPlay or by third party operators of our properties; changes in our credit structure, increased debt levels or debt service requirements; inaccurate estimation of our light crude oil and natural gas reserve and resource volumes; limited, unfavorable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; and certain other risks detailed from time-to-time in InPlay's continuous disclosure documents filed on SEDAR+ including our Annual Information Form and our MD&A.

This document contains future-oriented financial information and financial outlook information (collectively, "FOFI") about InPlay's financial and leverage targets and objectives, potential dividends, and beliefs underlying our Board approved 2025 capital budget and associated guidance, all of which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth in the above paragraphs. The actual results of operations of InPlay and the resulting financial results will likely vary from the amounts set forth in this document and such variation may be material. InPlay and its management believe that the FOFI has been prepared on a reasonable basis, reflecting management's reasonable estimates and judgments. However, because this information is subjective and subject to numerous risks, it should not be relied on as necessarily indicative of future results. Except as required by applicable securities laws, InPlay undertakes no obligation to update such FOFI. FOFI contained in this document was made as of the date of this document and was provided for the purpose of providing further information about InPlay's anticipated future business operations and strategy. Readers are cautioned that the FOFI contained in this document should not be used for purposes other than for which it is disclosed herein.

The forward-looking information and statements contained in this document speak only as of the date hereof and InPlay does not assume any obligation to publicly update or revise any of the included forward-looking statements or information, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

In addition, this document contains certain forward-looking information relating to economics for drilling opportunities in the areas that InPlay has an interest. Such information includes, but is not limited to, anticipated payout rates, rates of return, profit to investment ratios and recycle ratios which are based on additional various forward looking information such as production rates, anticipated well performance and type curves, the estimated net present value of the anticipated future net revenue associated with the wells, anticipated reserves, anticipated capital costs, anticipated finding and development costs, estimated ultimate recoverable volumes, anticipated future royalties, operating expenses, and transportation expenses.

Risk Factors to FLI

Risk factors that could materially impact successful execution and actual results of the Company's 2024 and 2025 capital program and associated guidance and estimates include:

- the risk that the U.S. government imposes tariffs on Canadian goods, including crude oil and natural gas, and that such tariffs (and/or the Canadian government's response to such tariffs) adversely affect the demand and/or market price for the Company's products and/or otherwise adversely affects the Company;
- volatility of petroleum and natural gas prices and inherent difficulty in the accuracy of predictions related thereto;
- the extent of any unfavourable impacts of wildfires in the province of Alberta;
- changes in Federal and Provincial regulations;
- the Company's ability to secure financing for the Board approved 2025 capital program and longer-term capital plans sourced from AFF, bank or other debt instruments, asset sales, equity issuance, infrastructure financing or some combination thereof; and
- those additional risk factors set forth in the Company's MD&A and most recent Annual Information Form filed on SEDAR+.

Reader Advisories (continued)

Key Budget and Underlying Material Assumptions to FLI

The key budget and underlying material assumptions used by the Company in the development of its 2024 guidance are as follows:

		Actuals FY 2023	Updated Guidance FY 2024	Previous Guidance FY 2024(1)	Guidance FY 2025
WTI	US$/bbl	$77.62	$75.72	$76.10	$72.00
NGL Price	$/boe	$36.51	$32.90	$33.10	35.40
AECO	$/GJ	$2.50	$1.39	$1.33	$1.90
Foreign Exchange Rate	CDN$/US$	0.74	0.73	0.73	0.70
MSW Differential	US$/bbl	$3.25	$4.50	$4.55	$4.50
Production	Boe/d	9,025	8,700 – 8,750	8,700 – 9,000	8,650 – 9,150
Revenue	$/boe	54.45	47.75 – 48.75	46.00 – 51.00	46.00 – 51.00
Royalties	$/boe	6.84	6.00 – 6.50	5.75 – 7.25	5.50 – 7.00
Operating Expenses	$/boe	15.05	14.50 – 15.50	13.50 – 15.50	13.00 – 15.00
Transportation	$/boe	0.95	0.90 – 1.05	0.85 – 1.10	0.90 – 1.15
Interest	$/boe	1.65	2.00 – 2.25	1.90 – 2.50	1.30 – 1.90
General and Administrative	$/boe	3.13	2.90 – 3.20	2.50 – 3.25	3.00 – 3.75
Hedging loss (gain)	$/boe	(1.10)	(0.75 – (1.00)	(0.50) – (1.00)	0.00 – 0.25
Decommissioning Expenditures	$ millions	$3.3	$3.2 – $3.4	$3.0 – $3.5	$3.0 – $3.5
Adjusted Funds Flow	$ millions	$92	$68 – $70	$70 – $73	$69 – $75
Dividends	$ millions	$16	$16	$16 – $17	$16.5

		Actuals FY 2023	Updated Guidance FY 2024	Previous Guidance FY 2024(1)	Guidance FY 2025
Adjusted Funds Flow	$ millions	$92	$68 – $70	$70 – $73	$69 – $75
Capital Expenditures	$ millions	$84.5	$63	$63	$41 – $44
Free Adjusted Funds Flow	$ millions	$7	$5 – $7	$7 – $10	$25 – $34
Shares outstanding, end of year	# millions	90.3	90.1	90.1	90.4
Assumed share price	$/share	$2.21	$1.73	$1.73	$1.65
Market capitalization	$ millions	$200	$156	$156	$150
FAFF Yield	%	4%	3% – 4%	4% – 6%	17% – 23%

		Actuals FY 2023	Updated Guidance FY 2024	Previous Guidance FY 2024(1)	Guidance FY 2025
Revenue	$/boe	54.45	47.75 – 48.75	46.00 – 51.00	46.00 – 51.00
Royalties	$/boe	6.84	6.00 – 6.50	5.75 – 7.25	5.50 – 7.00
Operating Expenses	$/boe	15.05	14.50 – 15.50	13.50 – 15.50	13.00 – 15.00
Transportation	$/boe	0.95	0.90 – 1.05	0.85 – 1.10	0.90 – 1.15
Operating Netback	$/boe	31.61	25.50 – 26.50	24.00 – 29.00	24.75 – 29.75
Operating Income Profit Margin		58%	54%	55%	56%

Reader Advisories (continued)

		Actuals FY 2023	Updated Guidance FY 2024	Previous Guidance FY 2024(1)	Guidance FY 2025
Adjusted Funds Flow	$ millions	$92	$68 – $70	$70 – $73	$69 – $75
Interest	$/boe	1.65	2.00 – 2.25	1.90 – 2.50	1.30 – 1.90
EBITDA	$ millions	$98	$75 – $77	$77 – $81	$74 – $80
Net Debt	$ millions	$46	$59 – $61	$56 – $59	$52 – $58
Net Debt/EBITDA		0.5	0.8	0.7 – 0.8	0.6 – 0.8

(1) As previously released November 14, 2024.

- See "Production Breakdown by Product Type" below
- Quality and pipeline transmission adjustments may impact realized oil prices in addition to the MSW Differential provided above
- Changes in working capital are not assumed to have a material impact between the years presented above.

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