Management's Discussion and Analysis

For the years ended December 31, 2022 and 2021

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEARS ENDED DECEMBER 31, 2022 AND DECEMBER 31, 2021

The following management's discussion and analysis ("**MD&A**") is dated March 14, 2023 and should be read in conjunction with the audited financial statements of InPlay Oil Corp. ("**InPlay**" or the "**Company**") for the years ended December 31, 2022 and December 31, 2021. The financial statements have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") and interpretations of the IFRS Interpretations Committee.

In addition to generally accepted accounting principles ("**GAAP**") measures, this MD&A contains additional conversion measures, non-GAAP measures, and forward-looking statements. Readers are cautioned that the MD&A should be read in conjunction with InPlay's disclosure under the headings "Conversion Measures and Short-Term Production Rates", "Non-GAAP and Other Financial Measures", and "Forward-Looking Information" included at the end of this MD&A.

All references to dollar values are to Canadian dollars unless otherwise stated. Production volumes are measured upon sale unless otherwise noted. Definitions of the abbreviations used in this discussion and analysis are located on the last page of this document.

DESCRIPTION OF BUSINESS

InPlay is a crude oil and natural gas exploration, development and production company with operations in Alberta. InPlay's strategic plan is to build a sustainable long-term oil and natural gas company. The plan is based on acquiring low decline, high operating netback producing properties with drilling development and enhanced oil recovery potential as well as undeveloped lands with exploration and development upside.

REVIEW OF FINANCIAL RESULTS

Production

Average production volumes for the three months and years ended December 31, 2022 and December 31, 2021 were as follows:

	Three months Ended December 31		Year Ended December 31	
	2022	2021	**2022**	2021
Crude oil (bbls/d)	**3,909**	3,156	**3,766**	2,981
NGL (boe/d)	**1,532**	933	**1,402**	782
Natural gas (Mcf/d)	**25,090**	15,590	**23,623**	12,030
Total (boe/d)(1)(2)(3)	**9,623**	6,687	**9,105**	5,768
Crude oil and NGLs	**57%**	61%	**57%**	65%

(1) Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. Refer to the section entitled "Conversion Measures and Short Term Production Rates" at the end of this MD&A.

(2) References to crude oil, NGLs or natural gas production in this MD&A refer to the light and medium crude oil, natural gas liquids and conventional natural gas product types, respectively, as defined in National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities ("Nl 51-101").

(3) See "Production Breakdown by Product Type" at the end of this MD&A.

Production for the three months and year ended December 31, 2022 was 44% and 58% higher respectively compared to the three months and year ended December 31, 2021, primarily as a result of the added volumes from the 2021 and 2022 drilling programs and the acquisition of Prairie Storm Resources Corp. ("Prairie Storm") which closed November 30, 2021. The reduced light oil and liquids weighting to 57% and 61% respectively in the three months and year ended December 31, 2022 compared to the same periods in 2021 is primarily a result of the higher gas weighting on the acquired Prairie Storm volumes.

InPlay's capital program for 2022 consisted of $77.6 million of development capital. The Company drilled, completed and brought on production six (6.0 net) extended reach horizontal ("ERH") wells in Pembina, ten (9.3 net) ERH wells on our Prairie Storm assets, two (2.0 net) Belly River wells and one (0.2 net) non-operated Willesden Green ERH well. Other capital activity for the year ended December 31, 2022 consisted of construction of a modular multi-well facility in Willesden Green during the year to accommodate current and future drilling in the area and construction of two Vapor Recovery Units to increase gas conservation and reduce greenhouse gas emissions. This activity amounted to the drilling of 19 gross (17.5 net) wells for an equivalent of 29.0 gross horizontal miles (26.7 net horizontal miles). InPlay accelerated the start of its 2023 capital program at the end of 2022 initiating drilling activities on a two well pad in Willesden Green and proactively starting facility and pipeline construction in the fourth quarter of 2022 to bring on production promptly after the completion of wells drilled in the first quarter of 2023.

Crude oil and natural gas sales

(thousands of dollars)	Three Months Ended December 31		Year Ended December 31	
	2022	2021	**2022**	2021
Crude oil	**38,896**	26,124	**163,474**	85,465
NGLs	**6,266**	3,904	**25,653**	10,782
Natural gas	**12,999**	7,227	**49,463**	17,607
Total crude oil and natural gas sales	**58,161**	37,255	**238,590**	113,854

Prices

	Three Months Ended December 31		Year Ended December 31	
Average Realized Price(1)	**2022**	2021	**2022**	2021
Crude oil ($/bbl)	**108.15**	89.97	**118.92**	78.55
NGLs ($/boe)	**44.45**	45.51	**50.14**	37.79
Natural gas ($/Mcf)	**5.63**	5.04	**5.74**	4.01
Total ($/boe)	**65.69**	60.56	**71.79**	54.08
WTI ($USD/bbl)	**82.64**	77.19	**94.23**	67.91
AECO ($/GJ)	**4.85**	4.41	**5.04**	3.44

(1) Supplementary financial measure. See "Non-IFRS and Other Financial Measures" contained within this MD&A.

Throughout the later part of 2021 and through 2022, global economies continued to recover from the COVID-19 pandemic with the easing of COVID restrictions, resulting in global crude oil demand recovering to near pre-pandemic levels. Supply has grown at a more gradual pace due to lower levels of capital spending and discipline among producers. As a result, commodity prices in the three months and year ended December 31, 2022 have significantly improved compared to the same periods in 2021.

West Texas Intermediate ("WTI") prices improved in the three months and year ended December 31, 2022 compared to average prices during the three months and year ended December 31, 2021. In the fourth quarter of 2022, WTI oil prices increased 7% averaging $82.64 US per bbl compared to $77.19 US per bbl in the fourth quarter of 2021. Throughout 2022, WTI oil prices increased 39% averaging $94.23 US per bbl compared to $67.91 US per bbl during 2021.

Differentials between WTI oil prices and prices received in Alberta strengthened in the three months and year ended December 31, 2022 and compared to the same periods in 2021. These differentials can be volatile due to factors including refining demand and pipeline capacity. InPlay sells oil at monthly average Edmonton Par prices less quality differentials, transportation and marketing fees. Light, sweet oil differentials between

Cushing, Oklahoma and Edmonton, Alberta are affected by pipeline apportionment, refinery turnarounds, rail capacity and market supply/demand conditions. Strong demand for Alberta crude oil resulted in substantial improvements to monthly index differentials averaged $1.76 US per barrel discount for the fourth quarter of 2022 compared to $3.10 US per barrel discount for the fourth quarter of 2021. Monthly index differentials averaged $1.82 US per barrel discount for the year ended December 31, 2022 compared to $3.88 US per barrel discount for the same period in 2021.

Realized oil prices are adjusted for the Canada/US exchange rate which decreased averaging 0.74 for the fourth quarter of 2022 compared to 0.79 during the fourth quarter of 2021. The Canada/US exchange rate also decreased over the year ended December 31, 2022 to 0.77 compared to 0.80 throughout 2021.

Due to the items noted above, and specifically the weakening Canadian dollar, realized oil prices for the three months and year ended December 31, 2022 increased compared to the three months and year ended December 31, 2021. The Company's average net realized price for crude oil was $108.15 per bbl for the fourth quarter of 2021, 20% higher than the fourth quarter 2021 realized price of $89.97 per bbl. The Company's average net realized price for crude oil was $118.92 per bbl for year ended December 31, 2022, 51% higher than the realized price of $78.55 per bbl for the same period during 2021.

Increases in demand for natural gas in 2022 resulted in significant improvements to natural gas benchmark prices. In the fourth quarter of 2022, natural gas AECO daily index prices increased 10% averaging $4.85 per GJ compared to $4.41 per GJ in the fourth quarter of 2021. During the year ended December 31, 2022, natural gas AECO daily index prices increased 47% averaging $5.04 per GJ compared to $3.44 per GJ in the year ended December 31, 2021.

The Company's average realized natural gas sales price was $5.63 per Mcf for the fourth quarter of 2022, 12% higher than the fourth quarter of 2021 realized price of $5.04 per Mcf on improved natural gas markets. The Company's average realized natural gas sales price was $5.74 per Mcf for the year ended December 31, 2022, 43% higher than the realized price of $4.01 per Mcf for the year ended December 31, 2021, also on improved natural gas markets.

Realized NGL pricing were relatively flat for the three months ended December 31, 2022 compared to the same period in 2021. The Company's average realized NGL price was $44.45 per boe for the fourth quarter of 2022, 2% lower than the fourth quarter of 2021 realized price of $45.51 per boe. The Company's average realized NGL sales price was $50.14 per boe for the year ended December 31, 2022, 33% higher than the realized price of $37.79 per boe for the same period in 2021 as a result of improved ethane, propane and butane markets and higher condensate and pentane prices which track WTI pricing.

Royalties

Production coming from new wells drilled by the Company on Crown lands qualify for royalty incentives that reduce average Crown royalties for periods of up to 48 months from initial production depending on commodity prices. After this period, the Crown royalties from these wells will come off this incentive period and be subject to the regular Alberta royalty structure. Recent increases to commodity prices have resulted in wells coming off of this incentive period in shorter time frames, resulting in increasing royalty rates.

Royalties as a percentage of total oil and natural gas sales are highly sensitive to commodity prices and adjustments to gas cost allowance. Thus, royalty rates can fluctuate from quarter-to-quarter and year-to-year. Royalties, as a percentage of crude oil and natural gas sales and royalties per boe are as follows:

	Three Months Ended December 31		Year Ended December 31	
	2022	2021	**2022**	2021
Total royalties ($'000s)	**10,375**	4,632	**38,392**	11,595
Total royalties (% of sales)	**17.8%**	12.4%	**16.1%**	10.2%
Total royalties ($/boe)	**11.72**	7.53	**11.55**	5.51

Royalties as a percentage of revenue and on a per boe basis increased during the three months and year ended December 31, 2022 compared to the same periods in 2021 due to the effect of shorter royalty incentive periods for recently drilled wells in the improved pricing environment and the sliding scale nature of oil royalties which increases the percentage during periods of high commodity prices.

Derivative contracts

The Company's production is usually sold using near-term contracts with complementary spot sales as needed, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Company may selectively enter into commodity derivative contracts in order to hedge a portion of oil and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts. The Company does not apply hedge accounting for these contracts.

At December 31, 2022 the Company had the following commodity-based derivative contracts outstanding.

Type of contract: swap (natural gas pricing AECO):

Currency denomination	Volume (GJ/day)	Average swap price	Term
Canadian dollar	10,000	3.96/GJ	April 1, 2023 – October 31, 2023

The statements of profit and comprehensive income for the year ended December 31, 2022 reflected the following gains (losses) related to derivative contracts that were outstanding during 2022 and the comparative period for 2021.

(thousands of dollars)	Three Months Ended December 31		Year Ended December 31	
	2022	2021	**2022**	2021
Realized gain (loss)	**147**	(3,490)	**(6,555)**	(13,054)
Unrealized gain	**2,222**	3,023	**2,400**	974
Total gain (loss) on derivative contracts	**2,369**	(467)	**(4,155)**	(12,080)

Subsequent to December 31, 2022 the Company entered into commodity-based derivative contracts as follows:

Type of contract: swap (natural gas pricing AECO):

Currency denomination	Volume (GJ/day)	Average swap price	Term
Canadian dollar	2,500	2.81/GJ	April 1, 2023 – October 31, 2023

Type of contract: costless collar(1) (natural gas pricing AECO):

Currency denomination	Volume (GJ/day)	Bought put price	Sold call price	Term
Canadian dollar	2,500	2.75/GJ	4.68/GJ	Nov. 1, 2023 – March 31, 2024

(1) Costless collar indicates 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.

Operating expenses

	Three Months Ended December 31		Year Ended December 31	
	2022	2021	**2022**	2021
Total operating expenses ($'000s)	**13,081**	7,695	**43,740**	27,009
Total operating expenses ($/boe)	**14.78**	12.51	**13.16**	12.83

Operating expenses include expenses incurred to operate wells, gather and treat production volumes as well as costs to perform well and facility repairs and maintenance. For the three months ended December 31, 2022, operating expenses per boe increased 18% to $14.78 per boe compared to $12.51 per boe for the same period in 2021. For the year ended December 31, 2022, operating expenses per boe increased 3% to $13.16 per boe compared to $12.83 per boe in 2021. Increases to operating expenses in the fourth quarter of 2022 compared to the fourth quarter of 2021 were due to more significant repairs and maintenance and well servicing costs incurred during the quarter. Increases to operating expenses in 2022 compared to 2021 on a total basis were due to additional variable costs incurred on higher production volumes.

Transportation expenses

	Three Months Ended December 31		Year Ended December 31	
	2022	2021	**2022**	2021
Total transportation expenses ($'000s)	**1,118**	673	**3,920**	2,346
Total transportation expenses ($/boe)	**1.26**	1.09	**1.18**	1.11

Transportation expenses include costs incurred to transport processed crude oil, liquids and natural gas products to the point of sale, as well as firm-service take or pay contracts that InPlay has secured directly to transport its natural gas. Expenses incurred to transport production that is not yet in a suitable condition to be shipped on a common-carrier pipeline from the well or battery to a cleaning facility or fractionation plant are included within operating expenses.

For the quarter ended December 31, 2022, transportation expenses were $1.26 per boe and were higher in comparison to $1.09 per boe for the quarter ended December 31, 2021. For the year ended December 31, 2022, transportation expenses were $1.18 per boe compared and were slightly higher in comparison to $1.11 per boe for the year ended December 31, 2021. Increases to oil production resulted in higher transportation rates on a per boe basis tracking increased trucking requirements for new production from wells drilled during 2022.

Operating Income and Netback

(thousands of dollars)	Three Months Ended December 31		Year Ended December 31	
	2022	2021	**2022**	2021
Revenue[(1)]	**58,161**	37,255	**238,590**	113,854
Royalties	**(10,375)**	(4,632)	**(38,392)**	(11,595)
Operating expenses	**(13,081)**	(7,695)	**(43,740)**	(27,009)
Transportation expenses	**(1,118)**	(673)	**(3,920)**	(2,346)
Operating income [(2)]	**33,587**	24,255	**152,538**	72,904

Sales volume (Mboe)	**885.3**	615.2	**3,323.4**	2,105.1
Per boe				
Revenue[1]	**65.69**	60.56	**71.79**	54.08
Royalties	**(11.72)**	(7.53)	**(11.55)**	(5.51)
Operating expenses	**(14.78)**	(12.51)	**(13.16)**	(12.83)
Transportation expenses	**(1.26)**	(1.09)	**(1.18)**	(1.11)
Operating netback per boe [2]	**37.93**	39.43	**45.90**	34.63
Operating income profit margin [2]	**58%**	65%	**64%**	64%

(1) Includes royalty and other income classified with oil and natural gas sales.

(2) Non-IFRS financial measure or ratio that does not have a standardized meaning under International Financial Reporting Standards (IFRS) and GAAP and therefore may not be comparable with the calculations of similar measures for other companies. Please refer to "Non-GAAP and Other Financial Measures" within this MD&A.

Operating income and operating netback per boe in year ended December 31, 2022 increased dramatically compared to the year ended December 31, 2021 reflecting the higher production volumes and significant increases to realized prices over these periods. Operating income in the three months ended December 31, 2022 increased dramatically compared to the three months ended December 31, 2021 reflecting the higher production volumes and significant increases to realized prices over these periods. Operating netback per boe in the three months ended December 31, 2022 remained flat compared to the three months ended December 31, 2021.

General and administrative expenses

The following table is a reconciliation of the Company's gross general and administrative ("**G&A**") expenditures to general and administrative expenses:

(thousands of dollars)	Three Months Ended December 31		Year Ended December 31	
	2022	2021	**2022**	2021
Gross G&A expenditures	**3,039**	2,102	**11,826**	7,308
Capitalized and recoveries	**(570)**	(374)	**(2,315)**	(1,347)
General and administrative expenses	**2,469**	1,728	**9,511**	5,961
G&A expenses ($/boe)	**2.79**	2.81	**2.86**	2.83
% Capitalized and recoveries	**19%**	18%	**20%**	18%

For the quarter ended December 31, 2022, G&A expenses were $2.5 million ($2.79 per boe) compared to $1.7 million ($2.81 per boe) for the same period in 2021. For the year ended December 31, 2022, G&A expenses were $9.5 million ($2.86 per boe) compared to $6.0 million ($2.83 per boe) for the same period in 2021. G&A expenses remained relatively flat on a per boe basis in comparison to the three months and year ended December 31, 2021. Total G&A expenses increased in the three months and year ended December 31, 2022 in comparison to the same periods in 2021 as a result of higher compensation, marketing and other public company related costs due to the increased size of the Company following the Prairie Storm acquisition.

Share-based compensation expenses

The Company accounts for share-based compensation using the fair value method of accounting, and share-based compensation (net of amounts capitalized) is included in the determination of profit and comprehensive income.

(thousands of dollars)	Three Months Ended December 31		Year Ended December 31	
	2022	2021	**2022**	2021
Share-based compensation	**1,114**	803	**2,790**	1,699
Capitalized portion	**(321)**	(34)	**(649)**	(123)
Share-based compensation expense	**793**	769	**2,141**	1,576

For the quarter ended December 31, 2022, share-based compensation expense was $0.8 million compared to $0.8 million for the same period in 2021. For the year ended December 31, 2022, share-based compensation expense was $2.1 million compared to $1.6 million for the same period in 2021. Share-based compensation expenses were higher in the three months and year ended December 31, 2022 due to significant improvements in the Company's share price in the later portion of 2021 and into 2022, resulting in additional expenses incurred from the vesting and revaluation of deferred share units and additional share-based compensation as a result of the implementation of the Company's restricted and performance award incentive plan.

During the year ended December 31, 2022, 590,200 options were granted, 935,550 options were exercised, 63,000 options were forfeited and 90,000 options expired.

At December 31, 2022, the maximum number of stock options available for grant was 8,695,260.

During 2022, the Company implemented a Restricted and Performance Award Incentive Plan under which Restricted Awards ("RAs") and Performance Awards ("PAs") may be granted to directors, officers, employees, consultants or other service providers of the Company. Each RA and PA entitles the holder to an award value vesting evenly over a three year period. The award value of PAs is adjusted for a payout multiplier which can range from 0.0 to 2.0 and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. The Company is eligible to settle the award value of vesting RAs and PAs either in cash or in common shares acquired by an independent trustee in the open market.

During the year ended December 31, 2022, 735,749 RAs were granted and 428,710 PAs were granted.

Depletion and depreciation

	Three Months Ended December 31		Year Ended December 31	
	2022	2021	**2022**	2021
Depletion and depreciation ($'000s)	**11,957**	7,691	**43,293**	27,440
Depletion and depreciation ($/boe)	**13.51**	12.50	**13.03**	13.03

The carrying costs for property, plant and equipment directly associated with crude oil and natural gas operations, including estimated future development costs, are recognized as depletion expense in the statements of profit and comprehensive income on a unit of production basis over proved plus probable reserves. The carrying costs of office and computer equipment are recognized as depreciation expense in the statements of profit and comprehensive income on a straight-line or declining-balance basis.

Depletion and depreciation was $12.0 million ($13.51 per boe) for the quarter ended December 31, 2022 compared to $7.7 million ($12.50 per boe) for the same period in 2021. Depletion and depreciation was $43.3 million ($13.03 per boe) for the year ended December 31, 2022 compared to $27.4 million ($13.03 per boe) for the same period in 2021. The increase on a total basis is due the higher production volumes in the three months and year ended December 31, 2021 compared to the same periods in 2020 and the impact of the impairment reversal recorded in 2021.

Impairment loss

At December 31, 2022 there were no indicators of impairment or impairment reversal relating to the Company's Property, plant and equipment assets.

At December 31, 2021 there were indicators of impairment reversal due to significant increases in estimated future commodity prices. Impairment reversal tests were performed for the Company's West Central Alberta CGU which resulted in an impairment reversal of historical impairment charges of $3.6 million being recorded in the Company's statement of profit and comprehensive income relating to the Company's West Central Alberta CGU. The Company used a discounted future cash flow model to measure fair value of the CGUs whereby the net present value of the after tax future cash flows were calculated using a discount rate of 12%.

Prior to December 31, 2021, the Company had the following CGUs: Pembina, Rocky Mountain House, Pigeon Lake, Huxley and Red Deer/Minors. Following the acquisition of Prairie Storm Resources Corp., the Company conducted an analysis of its CGUs to determine if their composition was still reflective of InPlay's core asset base and internal asset management. Following the analysis, it was determined that the previous CGUs no longer appropriately reflect InPlay's current asset base for purposes of determining impairment. Recent acquisitions and continued growth and development in concentrated areas has resulted in the Company's asset base primarily comprising liquids weighted assets in west central Alberta. Effective December 31, 2021, InPlay's CGUs were realigned into one CGU: West Central Alberta.

At June 30, 2021 there were indicators of impairment reversal due to significant increases in estimated future commodity prices. Impairment reversal tests were performed for each of the Company's CGUs which resulted in an impairment reversal of historical impairment charges of $58.3 million being recorded in the Company's statement of profit and comprehensive income relating to the Company's Pigeon Lake ($18.3 million), Pembina ($24.1 million), Rocky ($13.8 million) and Huxley ($2.1 million) CGUs. The Company used a discounted future cash flow model to measure fair value of the CGUs whereby the net present value of the after tax future cash flows were calculated using a discount rate of 13% for Huxley and 12% for all other CGUs. The Company's oil and natural gas reserves prepared by its independent reserves evaluator as at December 31, 2020 have been updated by internal qualified reserve engineers to June 30, 2021.

At December 31, 2022 there were no indicators of impairment relating to the Company's Exploration and evaluation assets.

Finance expenses

(thousands of dollars)	Three Months Ended December 31		Year Ended December 31	
	2022	2021	**2022**	2021
Interest expense (Credit Facility and other)	**919**	1,216	**4,918**	5,594
Interest expense (Lease liabilities)	**5**	4	**25**	20
Accretion on decommissioning obligations	**239**	342	**1,516**	1,133
Finance expense	**1,163**	1,562	**6,459**	6,747

Finance expenses were $1.2 million for the fourth quarter of 2022, compared to $1.6 million in the fourth quarter of 2021. Finance expenses were $6.5 million for the year ended December 31, 2022, compared to $6.7 million during the same period in 2021. These decreases are due to lower outstanding debt levels in the year ended December 31, 2022 compared to 2021 offset by the impact of higher interest rates incurred on the Senior Credit Facility interest rate grid caused by higher prime interest rates.

Income taxes

The Company has recognized a deferred tax asset of $19.7 million at December 31, 2022. The Company recognized deferred income tax expense of $1.7 million during the year ended December 31, 2022.

The deferred tax asset is supported by the expected future utilization of tax attributes based upon future cashflows derived from the Company's updated forecasts and independent year end reserve report using the total proved cashflows and expenditures and factoring in expected corporate general and administrative and interest expenses. As a result of the increase in these future cashflows, deferred income tax expense (recovery) was credited by $18.4 million during the year ended December 31, 2022 (December 31, 2021 - $40.2 million) with a corresponding impact to the deferred tax asset.

InPlay is not currently cash taxable and had the following estimated Canadian federal income tax pool balances at December 31, 2022.

(thousands of dollars)		
Non-capital loss carryforward balances	$	103,705
Share issue costs		675
Canadian Exploration Expenses (CEE)		64,773
Canadian Development Expenses (CDE)		83,381
Canadian Oil and Gas Property Expenses (COGPE)		113,296
Undepreciated Capital Cost (UCC)		42,989
Total	$	408,819

ADJUSTED FUNDS FLOW

(thousands of dollars)	Three Months Ended December 31		Year Ended December 31	
	2022	2021	**2022**	2021
Funds flow	**29,305**	14,634	**127,502**	44,100
Transactions and integration costs	**-**	1,495	**291**	1,495
Decommissioning expenditures	**966**	1,020	**3,012**	1,433
Adjusted funds flow(1)	**30,271**	17,149	**130,805**	47,028

(1) Capital management measure. See "Non-IFRS and Other Financial Measures" contained within this MD&A.

Adjusted funds flow for the three months ended December 31 2022 was $30.3 million compared to $17.1 million for the same period in 2021. Adjusted funds flow for the year ended December 31, 2022 was $130.8 million compared to $47.0 million for the same period in 2021. These significant increases are reflective of the higher sales volumes and increases in benchmark prices realized during the respective periods.

CAPITAL EXPENDITURES

Capital expenditures for the three months and year ended December 31, 2022 were $13.3 million and $77.8 million, respectively. The breakdown of capital expenditures is shown below:

(thousands of dollars)	Three Months Ended December 31		Year Ended December 31	
	2022	2021	**2022**	2021
Land and lease	**31**	29	**288**	71
Drilling & completions	**9,026**	4,779	**60,796**	26,538
Facilities and equipping costs	**4,159**	896	**14,643**	5,580
Total exploration and development capital	**13,216**	5,704	**75,727**	32,189
Office and Capitalized G&A	**431**	320	**1,876**	1,245
Capital expenditures – PP&E and E&E	**13,647**	6,024	**77,603**	33,434
Property (dispositions)	**-**	-	**(2)**	(84)
Net Corporate acquisitions(1)(2)(3)	**(321)**	38,287(1)	**180**	38,287(1)
Total capital expenditures(2)	**13,326**	44,311	**77,781**	71,637

(1) Reflects the acquisition of Prairie Storm. This amount consists of total gross consideration of $49.9, net of $11.6 million in net working capital balances assumed on closing.

(2) Non-IFRS financial measure or ratio that does not have a standardized meaning under International Financial Reporting Standards (IFRS) and GAAP and therefore may not be comparable with the calculations of similar measures for other companies. Please refer to "Non-GAAP and Other Financial Measures" within this MD&A.

(3) During the year ended December 31, 2022, the acquired amount of Property, plant and equipment was adjusted by $0.2 million as a result of adjustments relating to the acquisition of Prairie Storm, with a corresponding increase in the recognized amounts of Accounts payable and accrued liabilities.

InPlay's capital program for 2022 consisted of $77.6 million of development capital. The Company drilled, completed and brought on production six (6.0 net) extended reach horizontal ("ERH") wells in Pembina, ten (9.3 net) ERH wells on our Prairie Storm assets, two (2.0 net) Belly River wells and one (0.2 net) non-operated Willesden Green ERH well. Other capital activity for the year ended December 31, 2022 consisted of construction of a modular multi-well facility in Willesden Green during the year to accommodate current and future drilling in the area and construction of two Vapor Recovery Units to increase gas conservation and reduce greenhouse gas emissions. This activity amounted to the drilling of 19 gross (17.5 net) wells for an equivalent of 29.0 gross horizontal miles (26.7 net horizontal miles). InPlay accelerated the start of its 2023 capital program at the end of 2022 initiating drilling activities on a two well pad in Willesden Green and proactively starting facility and pipeline construction in the fourth quarter of 2022 to bring on production promptly after the completion of wells drilled in the first quarter.

Drilling statistics are shown below:

	Three months ended December 31				Year ended December 31			
	2022		2021		**2022**		2021	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Oil	**3**	**2.9**	2	1.6	**19**	**17.5**	12	10.0
Natural gas	**-**	**-**	-	-	**-**	**-**	-	-
Dry	**-**	**-**	-	-	**-**	**-**	-	-
Total	**3**	**2.9**	2	1.6	**19**	**17.5**	12	10.0
Success rate	**100%**	**100%**	100%	100%	**100%**	**100%**	100%	100%

SHARE INFORMATION

The Company's common shares are listed on the Toronto Stock Exchange under the symbol IPO.

As of March 14, 2023, there were 89,098,401 common shares outstanding, which includes 312,600 common shares held in trust for the potential future settlement of awards issued under the Company's Restricted and Performance Award Incentive Plan, and an additional 4,279,950 stock options that, subject to vesting, are convertible into, or exercisable or exchangeable for, an equivalent number of common shares of the Company. In addition, there were 748,249 RAs and 428,710 PAs outstanding.

The Company periodically provide funds to an independent trustee to acquire common shares in the open market, which are held in trust for the potential future settlement of Restricted and Performance award values. The common shares held in trust are netted out of share capital, including the cumulative purchase cost, until they are distributed for future settlements. For the year ended December 31, 2022, the independent trustee purchased 97,300 common shares for a total cost of $0.3 million and as at December 31, 2022, the independent trustee held 97,300 common shares in trust. Subsequent to December 31, 2022, the independent trustee purchased an additional 215,300 common shares for a total cost of $0.6 million.

On October 13, 2022, the Company announced that the Toronto Stock Exchange ("**TSX**") had accepted the notice of the Company's intention to commence a Normal Course Issuer Bid ("**NCIB**"). Pursuant to the NCIB, the Company is permitted to purchase up to 6,467,875 common shares representing approximately 10% of its public float as at October 7, 2022 over a twelve month period commencing October 17, 2022. During the year ended December 31, 2022, the Company purchased 100,400 common shares for cancellation at an average price of $2.98 per common share.

The Company's Board of Directors approved the implementation of a monthly base cash dividend of $0.015 per share commencing in November 2022 which resulted in the payment of $2.6 million in dividends during the year ended December 31, 2022.

Subsequent to December 31, 2022, the Board of Directors approved and declared monthly cash dividends of $0.015 per share, designated as an eligible dividend, payable to shareholders of record on January 16, 2023, February 15, 2023 and March 15, 2023 respectively. The dividend payment dates for these dividends are January 31, 2023, February 28, 2023 and March 31, 2023 respectively.

RELATED PARTY TRANSACTIONS

InPlay had no related party transactions that were entered into under the normal course of business for the three months and years ended December 31, 2022 and December 31, 2021.

LIQUIDITY AND CAPITAL RESOURCES

The Company's policy is to maintain a strong capital base which provides the financial flexibility to fund its ongoing capital expenditure program, provide creditor and market confidence and sustain the future development of the business. The Company is able to maintain high operating netbacks even while facing low commodity prices which, in turn, provides strong cash flows that assist in managing its working capital and capital requirements.

On August 10, 2022, the Company amended its first lien credit facilities and entered into an amended and restated senior secured credit facility with a borrowing base of $110 million (the "**Credit Facility**"). At this time, the second lien $25 million term facility with the Business Development Bank of Canada ("**BDC**") and the remaining $14 million term facility within the pre-amended senior credit facility were repaid. The Credit Facility consists of a $100 million revolving line of credit and a $10 million operating line of credit.

The Credit Facility has a term out date of May 30, 2023, and if not extended, additional advances would not be permitted and any outstanding advances would become repayable one year later on May 30, 2024. The Credit Facility is secured by a floating charge debenture of $150 million and a general security agreement on the assets of the Company. At December 31, 2022, the Company had drawn $29.2 million on the Credit Facility. There are standard reporting covenants under the Credit Facility and no financial covenants. The Company was in compliance with these standard reporting covenants as at December 31, 2022.

Under the Credit Facility, advances can be drawn as prime rate loans and bear interest at the bank's prime lending rate plus interest rates between 2.00% and 5.50%. Advances may also be drawn as banker's acceptances, SOFR loans, and letters of credit, subject to Canadian interest benchmark rates plus margins ranging from 3.00% to 6.50%. These interest rates, fees and margins varied based on adjusted debt to earnings metrics determined at each quarter end for the preceding 12 months.

The available lending limit of the Credit Facility is scheduled for annual renewal on or before May 30, 2023, and is based on the Lenders' interpretation of the Company's oil and natural gas reserves and future commodity prices. There can be no assurance that the amount or terms of the Credit Facility will not be adjusted at the next annual review. In the event that the lenders reduce the borrowing base under the Credit Facility below the amount drawn at the time of the redetermination, the Company would have 60 days to eliminate any borrowing base shortfall by repaying the amount drawn in excess of the re-determined borrowing base or by providing additional security or other consideration satisfactory to the lenders. Repayments of principal are not required provided that the borrowings under the Credit Facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties.

The Company had letters of credit in the amount of $nil outstanding at December 31, 2022 (December 31, 2021 - $0.3 million) and no additional guarantees.

In addition to the amount drawn on the Credit Facility at December 31, 2022 the Company had a working capital deficit of $3.8 million.

OFF-BALANCE SHEET ARRANGEMENTS

The Company had no guarantees or off-balance sheet arrangements other than as described below under "Contractual Obligations."

CONTRACTUAL OBLIGATIONS

The Company enters into various contractual obligations in the course of conducting its operations. At December 31, 2022, these obligations include:

- **Loan agreements** – The Credit Facility has a term out date of May 30, 2023 and, if not extended, any outstanding balances would have become repayable one year later on May 30, 2024. Refer to the "Liquidity and Capital Resources" section for more information.
- **Firm service transportation commitments** – The Company has entered into firm service transportation agreements. Fees related to transportation periods subsequent to December 31, 2022 were not recognized as a liability at December 31, 2022.

As at December 31, 2022 the Company had the following minimum contractual obligations:

Contractual obligations (in thousands of dollars)	2023	2024	2025	2026
Accounts payable	37,509	-	-	-
Bank debt - principal[1]	-	29,210	-	-
Bank debt - interest[2]	2,528	1,053	-	-
Leases	355	-	-	-
Firm service	765	511	133	25
Total	41,157	30,774	133	25

(1) Assumes the Credit Facility is not renewed on May 30, 2023, whereby outstanding balances become due on May 30, 2024.

(2) Assumes interest is incurred on bank debt outstanding on the Credit Facility at December 31, 2022 at the Company's effective interest rate during the current quarter and the principal of the Credit Facility is repaid May 30, 2024.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

The Company is a plaintiff or defendant in various legal actions and other disputes arising from time to time in the normal course of business. The Company believes that any liabilities that may arise pertaining to these matters will not have a material effect on its financial position.

CRITICAL ACCOUNTING ESTIMATES

The Company's significant accounting policies are disclosed in note 3 to the Company's audited financial statements for the years ended December 31, 2022 and December 31, 2021. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. These accounting policies are discussed below and are included to aid the reader in assessing the critical accounting policies and practices of the Company and the likelihood of materially different results than reported. The Company's management reviews its estimates regularly. The emergence of new information and changed circumstances may result in actual results that differ materially from current estimates.

Oil and natural gas reserves

Proved and probable reserves, as defined by the Canadian Securities Administrators in NI 51-101 with reference to the COGE Handbook, are estimated using independent reserves evaluator reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50% statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proved and probable and a 50% statistical probability that it will be less. The equivalent statistical probabilities for the proved component of proved and probable reserves are 90% and 10%, respectively. Determination of reserves is a complex process involving judgments, estimates and decisions based on available geological, engineering, production and any other relevant data. These estimates are subject to material change as economic conditions change and ongoing production and development activities provide new information.

Purchase price allocations and calculations of depletion and depreciation, impairment loss and deferred income tax assets are based on estimates of oil and natural gas reserves. Reserves estimates are based on engineering data, estimated future commodity prices and operating costs, expected future rates of production and timing and amount of future capital expenditures. By their nature, these estimates are subject to measurement uncertainties and interpretations and the impact on the financial statements could be material. The Company expects that over time, its reserves estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels and may be affected by changes in commodity prices.

Recoverable amounts of CGUs

The recoverable amount of a CGU used in the assessment of impairment is the greater of its value-in-use ("**VIU**") and its fair value less costs to sell ("**FVLCTS**"). VIU is determined by estimating the present value of the future net cash flows from the continued use of the CGU, and is subject to the risks associated with estimating the value of reserves. FVLCTS refers to the amount obtainable from the sale of a CGU in an arm's length transaction between knowledgeable, willing parties, less costs of disposal. The criteria used in the estimation of this amount are discussed in note 4 to the audited annual financial statements for the years ended December 31, 2022 and December 31, 2021.

Both VIU and FVLCTS estimates include the estimated reserves values in their determination. The key assumptions and estimates of the value of oil and natural gas reserves and the existing and potential markets for the Company's oil and natural gas assets are made at the time of reserves estimation and market assessment and are subject to change as new information becomes available. Changes in international and regional factors, including supply and demand of commodities, inventory levels, drilling activity, currency exchange rates, weather, geopolitical and general economic environment factors, may result in significant changes to the estimated recoverable amounts of CGUs.

Decommissioning obligations

The Company is required to set up a provision for future removal and site restoration costs. The Company must estimate these costs in accordance with existing laws, contracts or other policies. These estimated costs are charged to property, plant and equipment and the appropriate liability account over the expected service life of the asset. The estimate of future removal and site restoration costs involves a number of estimates related to timing of abandonment, determination of the economic life of the asset, costs associated with abandonment and site restoration, discount rates and review of potential abandonment methods.

Income taxes

The determination of the Company's income and other tax assets and liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax asset or liability may differ from that estimated and recorded by management. The Company estimates its future income tax rate in calculating its future income tax asset or liability. Various assumptions are made in assessing when temporary differences will reverse and this may impact the rate used.

CHANGES IN ACCOUNTING POLICIES

The following accounting policies were adopted during the year ended December 31, 2022.

Amendments to IAS 16 Property, Plant and Equipment

On January 1, 2022, the Company adopted Property, Plant and Equipment - Proceeds before Intended Use issued by the IASB which made amendments to IAS 16 Property, Plant and Equipment. The amendments prohibit a company from deducting from the cost of PP&E amounts received from selling items produced while the company is preparing the asset for its intended use. Instead, a company will recognize such sales proceeds and related cost in profit or loss. There was not a material impact to the Company's financial statements.

Amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets

On January 1, 2022, the Company adopted Onerous Contracts - Cost of Fulfilling a Contract issued by the IASB which made amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets. The amendments specify which costs an entity includes in determining the cost of fulfilling a contract for the purpose of assessing whether the contract is onerous. There was not a material impact to the Company's financial statements.

The Company has reviewed the following reporting and accounting standards that have been issued, but are not yet effective:

IAS 12 "Income Taxes"

In May 2021, the IASB issued amendments to IAS 12 Income Taxes, which require entities to recognize deferred tax on transactions that, on initial recognition, give rise to equal amounts of taxable and deductible temporary differences. This will be effective on January 1, 2023. The impact of this amendment is not expected to have a material impact on the Company's financial statements.

IAS 1 "Presentation of Financial Statements"

In January 2020, the IASB issued amendments to IAS 1 Presentation of Financial Statements ("IAS 1"), to clarify its requirements for the presentation of liabilities as current or non-current in the statement of financial position. This will be effective on January 1, 2024. The impact of this amendment is not expected to have a material impact on the Company's financial statements.

In October 2022, the IASB issued amendments to IAS 1, which specify the classification and disclosure of a liability with covenants. This will be effective on January 1, 2024. The impact of this amendment is not expected to have a material impact on the Company's financial statements.

CONTROLS AND PROCEDURES

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures at the financial year end of the Company and have concluded that the Company's disclosure controls and procedures are effective at the financial year end of the Company.

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Utilizing the Committee of Sponsoring Organizations of the Treadway Commission ("**COSO**") Internal Control – Integrated Framework (2013), such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal controls over financial reporting at the financial year end of the Company and concluded that the Company's internal controls over financial reporting are effective, at the financial year end of the Company. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on October 1, 2022 and ended on December 31, 2022 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

BUSINESS RISKS

The emergence of COVID-19 has resulted in emergency actions by governments worldwide, and has impacted the Company's results, business, financial and operating conditions, and has negatively impacted the Canadian, U.S., and global economies; disrupted Canadian, U.S., and global supply chains; disrupted financial markets; contributed to volatility in interest rates; resulted in ratings downgrades, credit deterioration and defaults in many industries; forced the closure of many businesses, led to loss of revenues, increased unemployment and bankruptcies; and necessitated the imposition of quarantines, physical distancing, business closures, travel restrictions, and sheltering-in-place requirements in Canada, the U.S., and other countries. If the pandemic is prolonged, including through subsequent waves, or if additional variants of COVID-19 continue to emerge which are more transmissible or cause more severe disease, or if other diseases emerge with similar effects, the adverse impact on the economy could worsen. Moreover, it remains uncertain how the macroeconomic environment, and societal and business norms will be impacted following this COVID-19 pandemic. As a result, the Company's business, financial and operational conditions, cash flows, reputation, access to capital, cost of borrowing, access to liquidity, and/or business plans may, in particular, and without limitation, may be adversely impacted as a result of the pandemic and/or decline in commodity prices. The full extent of the risks surrounding the severity and continuance of the COVID-19 pandemic is continually evolving and is not fully known at this time. Therefore, there is significant risk and uncertainty which may have a material and adverse effect on the Company's operations.

The extent to which the COVID-19 pandemic continues to impact the Company's financial results and condition or liquidity will depend on future developments in Canada, the U.S. and globally, including the widespread availability of efficient and accurate testing options, and effective treatment options or vaccines. Despite the approval of certain vaccines by the regulatory bodies in Canada and the U.S., the ongoing evolution of the efficiency of widespread distribution of an effective vaccine against COVID-19 and new variants thereof also continues to raise uncertainty.

Oil and natural gas exploration and production is capital intensive and involves a number of business risks including, without limitation, the uncertainty of finding new reserves, the instability of commodity prices, weather, and various operational risks. Commodity prices are influenced by local and worldwide supply and demand, OPEC actions, ongoing global economic concerns, aggression by Russia towards Ukraine and other neighboring nations and the actions, including sanctions, taken by NATO nations against this aggression, the US dollar exchange rate, transportation costs, political stability, Indigenous land claims, inflation and rising interest rates, the continuing impact of COVID-19 and travel bans and seasonal and weather-related changes to demand. The concern over increasing US natural gas production, driven primarily by the US shale gas plays, continues to depress the natural gas futures market. Oil prices declined sharply in the latter part of 2015 and continue to remain volatile as oil is a geopolitical commodity, affected by concerns about global economic markets, continued instability in oil producing countries and increases in production from US tight oil plays. Current areas of geopolitical risk include: global uncertainty and market repercussions due to the spread of COVID-19; Russia's military invasion of Ukraine; and rising civil unrest and activism globally. Differentials between WTI oil prices and prices received in Alberta are volatile. The industry is subject to extensive governmental regulation with respect to the environment. Over the past number of years, several new environmental regulations at both the Federal and Provincial level were announced, though the details of how some of the regulations will be implemented have yet to be released. Operational risks include well performance, uncertainties inherent in estimating reserves, timing of/ability to obtain and maintain drilling licenses and other regulatory approvals, ability to obtain equipment, expiration of licenses and leases, competition from other producers, third-party transportation and processing disruption issues, sufficiency of insurance, ability to manage growth, reliance on key personnel, third party credit risk and appropriateness of accounting estimates. These additional risks are described in more detail in the Company's most recent AIF filed with certain Canadian securities regulatory authorities on SEDAR at www.sedar.com.

The Company makes substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves. As the Company's revenues may decline as a result of decreased commodity pricing, it may be required to reduce capital expenditures. In addition, uncertain levels of near-term industry activity coupled with the present global economic concerns exposes the Company to additional access-to-capital risk. There can be no assurance that debt or equity financing, or funds generated by operations, will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

InPlay manages these risks by employing competent and professional staff, following sound operating practices and using capital prudently. The Company generates its exploration and development prospects internally and performs extensive geological, geophysical, engineering, and environmental analysis before committing to the drilling of new prospects. InPlay seeks out and employs new technologies where possible. With the Company's extensive potential drilling opportunities and advance planning, the Company believes it can manage the slower pace of regulatory approvals and the requirements for extensive landowner consultation.

The Company has a formal emergency response plan which details the procedures employees and contractors will follow in the event of an operational emergency. The emergency response plan is designed to respond to emergencies in an organized and timely manner so that the safety of employees, contractors, residents in the vicinity of field operations, the general public and the environment are protected. A corporate safety program covers hazard identification and control on the jobsite, establishes Company policies, rules and work procedures and outlines training requirements for employees and contract personnel.

The Company currently deals with a small number of buyers and sales contracts, and endeavors to ensure that those buyers are an appropriate credit risk. The Company continuously evaluates the merits of entering into fixed price or financial hedge contracts for price management.

The oil and natural gas business is subject to regulation and intervention by governments in such matters as the awarding of exploration and production interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields (including restrictions on production) and possibly expropriation or cancellation of contract rights. As well, governments may regulate or intervene with respect to prices, taxes, royalties, transportation and the exportation of oil and natural gas. Such regulation may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for oil and natural gas, increase the Company's costs, impact the Company's ability to get its product to market, or affect its future opportunities.

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and natural gas industry operations. Such legislation may also impose restrictions and prohibitions on water use or processing in connection with certain oil and natural gas operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in, amongst other things, suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social and governance ("**ESG**") and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators have issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters. The cost to comply with these standards, and others that may be developed or evolve over time, is not quantifiable at this time.

Based on the Company's current understanding, the potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding timing, scope, and severity of potential impacts. Many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall, and wildfires may restrict the Company's ability to access its properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of the Company's assets are located in locations that are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage to the Company's assets or cause disruptions to the production and transport of its products or the delivery of goods and services in its supply chain.

Our exploration and production facilities and other operations and activities emit greenhouse gasses ("**GHG**") which may require us to comply with federal and/or provincial GHG emissions legislation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate our effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, climate change has been linked to long-term shifts in climate patterns and extreme weather conditions both of which pose the risk of causing operational difficulties.

Upon the occurrence of a natural disaster, or upon an incident of war, riot or civil unrest, the impacted country, province, or region may not efficiently and quickly recover from such event, which could have a materially adverse effect on the Company, its customers, and/or either of their businesses or operations. Terrorist attacks, public health crises including epidemics, pandemics or outbreaks of new infectious disease or viruses (including, most recently, COVID-19), civil unrest and related events can result in volatility and disruption to local and global supply chains, operations, mobility of people and the financial markets, which could affect interest rates, credit ratings, credit risk, inflation, business, financial conditions, results of operations and other factors relevant to the Company, its customers, and/or either of their businesses or operations.

OUTLOOK

InPlay's capital program for the first quarter of 2023 was initiated late in December 2022 with the drilling of the first of two (1.6 net) Extended Reach Horizontal ("ERH") Willesden Green wells on a single pad to take advantage of the availability of services and get ahead of what is expected to be the busiest quarter of activity for the industry in years. These wells were brought on production in early February.

The Company also drilled another two (1.6 net) ERH Willesden Green wells which were recently brought on production in early March.

These four wells were drilled in close proximity and have delivered initial production rates significantly above internal expectations despite being somewhat curtailed due to the high fluid rates and high back pressure in the gathering system in the area, which has also backed out production from older lower pressured offsetting wells. Our first of two upgraded gas facilities in the area is expected to come online in late March which will alleviate back pressure on the gas gathering system. This new facility coupled with natural declines and lower fluid rates as water cuts drop are expected to allow all wells to flow at more optimal levels. This is expected to reduce decline rates throughout the second quarter.

Two (0.3 net) non-operated ERH wells in Willesden Green were brought on production in February. Drilling operations have begun on an additional two (2.0 net) ERH well pad in Pembina which is expected to be brought on production in early April.

InPlay's capital program for the first half of 2023 includes plans to upgrade two operated gas facilities in Willesden Green, including the first project discussed above, providing InPlay with operated facility capacity that it controls to facilitate production growth and reduce field pressures in the current and upcoming years.

In the first quarter of 2023, the Company had natural gas production curtailments of approximately 4.5 mmcf/d starting February 15th from a third party natural gas facility due to capacity constraints. The impact of this curtailment is not expected to be significant to InPlay as the Company had previously shifted drilling plans away from this area in 2023 due to its higher gas weighted production and the high gas processing fees being charged compared to other regions. The Company responded by shutting in wells with the highest gas weighting, maximizing oil production and AFF in the strong oil pricing environment. Natural decline of production in this field, limited drilling plans from the Company and other operators in the area as well as alternative options currently being finalized are expected to alleviate the impact of this production curtailment. Our estimates of impacted production due to this curtailment is approximately 475 boe/d (68% natural gas) in the first quarter of 2023.

InPlay anticipates that the exceptional well results to date in 2023 and its upcoming drilling program will fully offset the impact of the temporary gas production curtailments and as a result, InPlay continues to reiterate its 2023 annual average production guidance of 9,500 – 10,500 boe/d(1)(3). When considering the impacted production is predominantly gas, and the outperforming new drills have a high oil weighting, the net impact to AFF(2) is anticipated to be minimal. With the continued value add from our high return asset base, a pristine balance sheet and a very low leverage ratio, the Company is optimistic about the potential for continued value add opportunities and increasing returns to shareholders in the upcoming year and beyond.

Notes:

1. *See "Production Breakdown by Product Type"*
2. *Non-IFRS measure or ratio that does not have a standardized meaning under International Financial Reporting Standards (IFRS) and GAAP and therefore may not be comparable with the calculations of similar measures for other companies. Please refer to "Non-GAAP and Other Financial Measures" within this MD&A for details of calculations, rationale for use and applicable reconciliation to the nearest IFRS measure.*
3. *See table in the Reader Advisories for key budget and underlying material assumptions related to the Company's 2023 capital program and associated guidance.*

SELECTED QUARTERLY INFORMATION

The following table provides financial and operating results for the last eight quarters. Commodity prices remain volatile, affecting adjusted funds flow and profit (loss) throughout those quarters.

SELECTED QUARTERLY INFORMATION

($ amounts in thousands, except per share amounts)	**Q4 2022**	Q3 2022	Q2 2022	Q1 2022
Oil and natural gas sales	**58,161**	56,985	71,287	52,156
Oil and natural gas sales, net of royalties	**47,786**	46,378	61,476	44,557
Profit	**20,736**	15,352	29,032	18,774
Profit per share, basic	**0.24**	0.18	0.33	0.22
Profit per share, diluted	**0.23**	0.17	0.32	0.21
Capital expenditures – PP&E and E&E	**13,647**	24,542	17,850	21,562
Property (dispositions)	**-**	-	-	(1)
Net Corporate acquisitions(1)	**(321)**	89	(20)	432
Adjusted funds flow(2)	**30,271**	30,232	40,922	29,379
Adjusted funds flow per share, basic(3)	**0.35**	0.35	0.47	0.34
Adjusted funds flow per share, diluted(3)	**0.33**	0.33	0.45	0.33
Adjusted funds flow per boe(3)	**34.19**	34.61	49.62	39.71
Net debt(2)	**32,963**	45,615	50,473	73,392

	Q4 2021	Q3 2021	Q2 2021	Q1 2021
Oil and natural gas sales	37,255	31,331	25,267	20,001
Oil and natural gas sales, net of royalties	32,623	27,979	22,901	18,756
Profit (loss)	55,191	8,289	59,127	(7,536)
Profit (loss) per share, basic	0.74	0.12	0.87	(0.11)
Profit (loss) per share, diluted	0.71	0.12	0.85	(0.11)
Capital expenditures – PP&E and E&E	6,024	10,457	4,744	12,209
Property acquisitions/(dispositions)	-	(2)	(101)	19
Net Corporate acquisitions(1)	38,287	-	-	-
Adjusted funds flow(2)	17,149	15,555	8,219	6,105
Adjusted funds flow per share, basic(3)	0.23	0.23	0.12	0.09
Adjusted funds flow per share, diluted(3)	0.22	0.22	0.12	0.09
Adjusted funds flow per boe(3)	27.87	28.13	16.77	13.66
Net debt(2)	80,196	71,331	76,113	79,780

(1) Non-IFRS financial measure or ratio that does not have a standardized meaning under International Financial Reporting Standards (IFRS) and GAAP and therefore may not be comparable with the calculations of similar measures for other companies. Please refer to "Non-GAAP and Other Financial Measures" within this MD&A for details of calculations, rationale for use and applicable reconciliation to the nearest IFRS measure.

(2) Capital management measure. See "Non-IFRS and Other Financial Measures" contained within this MD&A.

(3) Supplementary financial measure. See "Non-IFRS and Other Financial Measures" contained within this MD&A

An impairment reversal of $58.3 million was recognized in the quarter ended June 30, 2021 due to increases in estimated future commodity prices and the recoverable amount of the Company's CGUs.

An impairment reversal of $3.6 million was recognized in the quarter ended December 31, 2021 due to increases in estimated future commodity prices and the recoverable amount of the Company's CGUs.

On November 30, 2021, the Company completed the Prairie Storm Arrangement for consideration of: (a) the payment of an aggregate of approximately $39.9 million in cash; and (b) the issuance of an aggregate of 8,320,335 common shares of InPlay at $1.20 per share, for total gross consideration of $49.9 million. For accounting purposes in accordance with IFRS 3, the shares issued as consideration have been valued at $2.07 per share, based on the closing price of InPlay shares on November 29, 2021.

InPlay's capital program for 2021 consisted of $33.4 million of development capital, drilling 12 (10.0 net) wells during the year. This activity amounted to the drilling 12 gross (10.0 net) wells for an equivalent of 20.5 gross horizontal miles (15.4 net horizontal miles). This capital spending also included the construction of a multi-well battery in Pembina which is anticipated to accommodate all of our future development of the area over the next three years. InPlay accelerated the start of its 2022 capital program at the end of 2021 initiating lease construction and drilling activities on a three well pad in Pembina due to optimal conditions and availability of services.

InPlay's capital program for 2022 consisted of $77.6 million of development capital. The Company drilled, completed and brought on production six (6.0 net) extended reach horizontal ("ERH") wells in Pembina, ten (9.3 net) ERH wells on our Prairie Storm assets, two (2.0 net) Belly River wells and one (0.2 net) non-operated Willesden Green ERH well.

During 2022, InPlay reduced its net debt by 59% to $32.9 million at December 31, 2022 from $80.2 million at December 31, 2021.

SELECTED ANNUAL INFORMATION

Years ended December 31

(in thousands, except per share amounts)	**2022**	2021	2020
Total oil and natural gas sales[(1)]	**238,590**	113,854	41,934
Oil and natural gas sales, net of royalties[(1)]	**200,198**	102,259	39,010
Profit (loss)	**83,896**	115,071	(112,629)
Profit (loss) per share, basic	**0.97**	1.65	(1.65)
Profit (loss) per share, diluted	**0.92**	1.61	(1.65)
Total assets	**430,911**	406,484	211,035
Total bank loans	**29,210**	79,127	63,832
Total net debt[(2)]	**32,963**	80,196	73,681

(1) The oil and natural gas sales exclude realized and unrealized gains (losses) on risk management derivative contracts: 2022 excludes ($6.6 million) realized loss and $2.4 million unrealized gain; 2021 excludes ($13.1 million) realized loss and $1.0 million unrealized gain; and 2020 excludes ($1.2 million) realized loss and ($1.3) million unrealized loss.

(2) Capital management measure. See "Non-IFRS and Other Financial Measures" contained within this MD&A.

ADDITIONAL INFORMATION

Additional information regarding InPlay and its business and operation, including its most recently filed annual information form, is available on the Company's profile on SEDAR at www.sedar.com. This information is also available on the Company's website at www.inplayoil.com.

CONVERSION MEASURES AND SHORT-TERM PRODUCTION RATES

Production volumes and reserves are commonly expressed on a boe basis whereby natural gas volumes are converted at the ratio of 6 thousand cubic feet to 1 barrel of oil. Although the intention is to sum oil and natural gas measurement units into one basis for improved analysis of results and comparisons with other industry participants, boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 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. In recent years, the value ratio based on the price of crude oil as compared to natural gas has been significantly higher than the energy equivalency of 6:1, and utilizing a conversion of natural gas volumes on a 6:1 basis may be misleading as an indication of value.

Short-term production rates can be influenced by flush production effects from fracture stimulations in horizontal wellbores and may not be indicative of longer-term production performance or ultimate recovery of reserves. Individual well performance may vary.

NON-GAAP AND OTHER FINANCIAL MEASURES

Throughout this MD&A 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", "operating income", "operating netback per boe", "operating income profit margin", "Net corporate acquisitions", "Total capital expenditures" and "Debt adjusted production per share". Management believes these measures 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 (loss) before taxes", "profit (loss) and comprehensive income (loss)", "adjusted funds flow", "capital expenditures", "corporate acquisitions, net of cash acquired", "net debt", "weighted average number of common shares (basic)" 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 below for a calculation of free adjusted funds flow and a reconciliation to the nearest GAAP measure, adjusted funds flow.

(thousands of dollars)	Three Months Ended December 31		Year Ended December 31	
	2022	2021	**2022**	2021
Adjusted funds flow	**30,271**	17,149	**130,805**	47,028
Exploration and dev. capital expenditures	**(13,647)**	(6,024)	**(77,603)**	(33,434)
Property dispositions (acquisitions)	**-**	-	**2**	84
Free adjusted funds flow	**16,624**	11,125	**53,204**	13,678

Operating Income

Management considers operating income an important measure to evaluate its operational performance as it demonstrates its field level profitability. 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. Refer to the section entitled "Operating income and netback" within this MD&A for a calculation of this measure and a reconciliation to the nearest GAAP measure.

Operating Netback per BOE

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 netback per boe is calculated by the Company as operating income divided by average production for the respective period. Refer to the section entitled "Operating income and netback" within this MD&A for a calculation of this measure.

Operating Income Profit Margin

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. Operating income profit margin is calculated by the Company as operating income as a percentage of oil and natural gas sales. Refer to the section entitled "Operating income and netback" within this MD&A for a calculation of this measure.

Net Corporate Acquisitions

Management considers Net corporate acquisitions an important measure as it is a key metric to evaluate the corporate acquisition in comparison to other transactions using the negotiated consideration value and ignoring changes to the fair value of the share consideration between the signing of the definitive agreement and the closing of the transaction. Net corporate acquisitions should not be considered as an alternative to or more meaningful than "Corporate acquisitions, net of cash acquired" as determined in accordance with GAAP as an indicator of the Company's performance. Net corporate acquisitions is calculated as total consideration with share consideration adjusted to the value negotiated with the counterparty, less working capital balances assumed on the corporate acquisition. Refer below for a calculation of Net corporate acquisitions and reconciliation to the nearest GAAP measure, "Corporate acquisitions, net of cash acquired".

(thousands of dollars)	Three Months Ended December 31		Year Ended December 31	
	2022	2021	**2022**	2021
Corporate acquisitions, net of cash acquired	**(321)**	29,277	**180**	29,277
Share consideration[(1)]	**-**	9,985	**-**	9,985
Non-cash working capital acquired	**-**	(1,156)	**-**	(1,156)
Derivative contracts	**-**	181	**-**	181
Net Corporate acquisitions	**(321)[(3)]**	38,287	**180[(3)]**	38,287

(1) For purposes of the corporate acquisition, the share consideration had a negotiated value of $1.20 per share. For accounting purposes in accordance with IFRS 3, the shares issued as consideration have been valued at $2.07 per share, based on the closing price of InPlay shares on November 29, 2021.

(2) Net working capital acquired equals the fair value of cash and cash equivalents, accounts receivable and accrued liabilities, prepaid expenses and deposits, inventory, accounts payable and accrued liabilities and derivative contracts acquired as disclosed in note 5 of the Company's financial statements.

(3) During the year ended December 31, 2022, the acquired amount of Property, plant and equipment was adjusted by $0.2 million as a result of adjustments relating to the acquisition, with a corresponding increase in the recognized amounts of Accounts payable and accrued liabilities.

Total Capital Expenditures

Management considers Total capital expenditures an important metric to measure its total capital investment compared to the Company's annual budgeted capital expenditures. Total capital expenditures is calculated as exploration and development capital expenditures plus net property acquisitions (dispositions) and net corporate acquisitions. Net corporate acquisitions should not be considered as an alternative to or more meaningful than "Capital expenditures – PP&E and E&E" as determined in accordance with GAAP as an indicator of the Company's performance. Refer to the section entitled "Capital expenditures" within this MD&A for a calculation of this measure and reconciliation to the nearest GAAP measure, "Capital expenditures – PP&E and E&E".

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. 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.

Production per Debt Adjusted Share

InPlay uses "Production per debt adjusted share" as a key performance indicator. Debt adjusted shares should not be considered as an alternative to or more meaningful than common shares as determined in accordance with GAAP as an indicator of the Company's performance. Debt adjusted shares is a non-GAAP measure used in the calculation of Production per debt adjusted share and is calculated by the Company as common shares outstanding plus the change in net debt divided by the Company's current trading price on the TSX, converting net debt to equity. Debt adjusted shares should not be considered as an alternative to or more meaningful than weighted average number of common shares (basic) as determined in accordance with GAAP as an indicator of the Company's performance. Management considers Debt adjusted share is a key performance indicator as it adjusts for the effects of capital structure in relation to the Company's peers. Production per debt adjusted share is calculated by the Company as production divided by debt adjusted shares. Management considers Production per debt adjusted share is a key performance indicator as it adjusts for the effects of changes in annual production in relation to the Company's capital structure. Refer below for a calculation of Production per debt adjusted share.

		Year Ended December 31	
		2022	2021
Production	Boe/d	**9,105**	5,768
Net Debt	$ millions	**32.9**	80.2
Weighted average outstanding shares	# millions	**86.9**	69.8
Assumed Share price(2)	$	**3.39**	
Production per debt adjusted share growth(2)		**51%**	

(1) Production per debt adjusted share is calculated by the Company as production divided by debt adjusted shares. Debt adjusted shares is calculated by the Company as common shares outstanding plus the change in net debt divided by the Company's current trading price on the TSX, converting net debt to equity.

(2) Weighted average share price throughout 2022.

EV / DAAFF

InPlay uses "enterprise value to debt adjusted AFF" or "EV/DAAFF" as a key performance indicator. EV/DAAFF is calculated by the Company as enterprise value divided by debt adjusted AFF for the relevant period. Debt adjusted AFF ("DAAFF") is calculated by the Company as adjusted funds flow plus financing costs. Enterprise value is a capital management measures that is used in the calculation of EV/DAAFF. Enterprise value is calculated as the Company's market capitalization plus working capital (net debt). Management considers enterprise value a key performance indicator as it identifies the total capital structure of the Company. Management considers EV/DAAFF a key performance indicator as it is a key metric used to evaluate the sustainability of the Company relative to other companies while incorporating the impact of differing capital structures. Refer to the "Forward Looking Information and Statements" section for a calculation of forecast EV/DAAFF.

<u>Capital Management Measures</u>

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 year ended December 31, 2022. All references to adjusted funds flow throughout this MD&A are calculated as funds flow adjusting for decommissioning expenditures and transaction and integration costs. 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. Transaction costs are non-recurring costs for the purposes of an acquisition, making the exclusion of these items relevant in Management's view to the reader in the evaluation of InPlay's operating performance. 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 / Working Capital

Net debt / working capital is a GAAP measure and is disclosed in the notes to the Company's financial statements for year ended December 31, 2022. The Company closely monitors its capital structure with a goal of maintaining a strong balance sheet to fund the future growth of the Company. The Company monitors net debt / working capital as part of its capital structure. The Company uses net debt / working capital (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 / working capital an important measure to assist in assessing the liquidity of the Company.

<u>Supplementary Measures</u>

"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 MD&A contains certain forward-looking statements and forward-looking information (collectively referred to herein as "**FLI**" or "**forward-looking statements**") within the meaning of applicable Canadian securities laws. All statements other than statements of present or historical fact are forward-looking statements. Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "believe", "plan", "intend", "objective", "continuous", "ongoing", "estimate", "expect", "may", "will", "project", "targets", "should", or similar words suggesting future outcomes. In particular, this MD&A contains forward-looking statements relating, but not limited, to:

- 2023 guidance based on the planned capital program of $75 - $80 million including forecasts of 2023 annual average production levels, light oil and liquids weightings, adjusted funds flow, free adjusted funds flow, Net Debt/EBITDA ratio, operating income profit margin and growth rates;
- the information contained within the "Outlook" section;
- the possible refinement of our 2023 capital program and anticipated changes resulting therefrom;
- management's assessment of the potential and uncertain continuing impacts of COVID-19 and the Russian/Ukraine conflict on the Company's operations and results;
- the expectation that the gas production curtailments in the first quarter of 2023 is not expected to be significant and that the exceptional well results to date in 2023 and the upcoming drilling program will fully offset the impact of the curtailments;
- the expectation that the gas production curtailments in the first quarter of 2023 will have a minimal impact on AFF;
- the expectation that the first of two upgraded gas facilities is expected to come online in late March which will alleviate back pressure on the gas gathering system in the curtailed area;
- the expectation that the new facility coupled with natural declines and lower fluid rates as water cuts drop are expected to allow all wells to flow at more optimal levels, resulting in reduced decline rates throughout the second quarter of 2023;
- expectations regarding InPlay's multi-well battery at Pembina being able to accommodate all of our future development in the area over the next three years;
- the estimated time to payout of wells;
- production estimates;
- expectations regarding the business environment, industry conditions and future commodity prices;
- InPlay's business strategy, goals and management focus;
- sources of funds for the Company's operations, capital expenditures and decommissioning obligations;
- future liquidity and the Company's access to sufficient debt and equity capital;
- the resource potential of InPlay's asset base and future prospects for development and growth;
- future costs, expenses and royalty rates;
- the volume and product mix of InPlay's oil and gas production;
- future exchange rate between the $US and $Cdn
- expectations regarding InPlay's tax horizon;
- capital management strategies;
- the anticipated continuation of the Company's monthly dividend program and the amounts of dividends;
- the timing and impact of new accounting policies and standards; and
- treatment under governmental and other regulatory regimes and tax, environmental and other laws.

Forward-looking statements regarding InPlay are based on certain key expectations and assumptions of InPlay concerning anticipated financial performance, business prospects, strategies, regulatory developments, current commodity prices and exchange rates, applicable royalty rates, tax laws, future well production rates and reserve volumes, future operating costs, the performance of existing wells, the success of its exploration and development activities, the sufficiency and timing of budgeted capital expenditures in carrying out planned activities, the availability and cost of labor and services, the impact of increasing competition, conditions in general economic and financial markets, availability of drilling and related equipment effects of regulation by governmental agencies, the ability to obtain financing on acceptable terms which are subject to change based on commodity prices, world events, market conditions, drilling success and potential timing delays.

These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond InPlay's control. Such risks and uncertainties include, without limitation: the impact of general economic conditions; volatility in market prices for crude oil and natural gas; the impact of COVID-19 and the Russia/Ukraine conflict; industry conditions; currency fluctuations; imprecision of reserve estimates; liabilities inherent in crude oil and natural gas operations; environmental risks; incorrect assessments of the value of acquisitions and exploration and development programs; competition from other producers; the lack of availability of qualified personnel, drilling rigs or other services; changes in income tax laws or changes in royalty rates and incentive programs relating to the oil and natural gas industry; hazards such as fire, explosion, blowouts, and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury; and ability to access sufficient capital from internal and external sources.

Management has included the above summary of assumptions and risks related to forward-looking statements provided in this MD&A in order to provide readers with a more complete perspective on InPlay's future operations and such information may not be appropriate for other purposes. InPlay's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that InPlay will derive there from. Readers are cautioned that the foregoing lists of factors are not exhaustive. These forward-looking statements are made as of the date of this MD&A and InPlay disclaims any intent or obligation to update publicly any forward looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws. Additional information on these and other factors and risks that could affect InPlay's operations and financial results are included in the Company's public disclosure documents on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or at InPlay's website (www.inplayoil.com).

Any financial outlook or future oriented financial information contained in this MD&A regarding prospective financial position, including, but not limited to: beliefs underlying our Board approved 2023 capital budget and associated guidance, as well as management's preliminary estimates and targets in respect of plans for 2024, 2025 and beyond, is based on reasonable assumptions about future events, including those described above, based on an assessment by management of the relevant information that is currently available.

The internal projections, expectations, or beliefs underlying our Board approved 2023 capital budget and associated guidance, as well as management's preliminary estimates and targets in respect of plans for 2024, 2025 and beyond, are subject to change in light of, among other factors, the impact of the COVID-19 pandemic, and any related actions taken by businesses and governments, ongoing results, prevailing economic circumstances and world events, volatile commodity prices, and industry conditions and regulations. InPlay's financial outlook and 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. In this document reference is made to the Company's longer range 2024, 2025 and beyond internal plan and associated economic model. Such information reflects internal targets used by management for the purposes of making capital investment decisions and for internal long range planning and budget preparation. Readers are cautioned that events or circumstances could cause capital plans and associated results to differ materially from those predicted and InPlay's guidance for 2023, and more particularly, preliminary estimated for 2024, 2025 and beyond, may not be appropriate for other purposes. Accordingly, undue reliance should not be placed on same.

The key budget and underlying material assumptions used by the Company in the development of its 2023 guidance and preliminary estimates and plans for 2024 and 2025 are as follows:

		Actuals FY 2022	Guidance FY 2023[1]	Preliminary Plan FY 2024[1][5]	Preliminary Plan FY 2025[1][5]
WTI	US$/bbl	$94.23	$80.00	$75.00	$70.00
NGL Price	$/boe	$50.14	$45.80	$43.00	$40.00
AECO	$/GJ	$5.04	$3.40	$4.50	$4.65
Foreign Exchange Rate	CDN$/US$	0.77	0.73	0.73	0.73
MSW Differential	US$/bbl	$1.82	$3.20	$3.00	$3.00
Production	Boe/d	9,105	9,500 – 10,500	10,250 – 11,250	10,950 – 11,950
Revenue	$/boe	71.79	60.25 – 65.25	58.50 – 63.50	55.25 – 60.25
Royalties	$/boe	11.55	8.75 – 10.25	7.50 – 9.00	6.00 – 7.50
Operating Expenses	$/boe	13.16	11.75 – 14.75	11.00 – 14.00	10.50 – 13.50
Transportation	$/boe	1.18	1.10 – 1.35	1.00 – 1.25	0.90 – 1.15
Interest	$/boe	1.49	0.35 – 0.85	0.00 – 0.10	0.00 – 0.10
General and Administrative	$/boe	2.86	2.25 – 2.95	2.15 – 2.85	2.05 – 2.75
Hedging loss (gain)	$/boe	1.97	(0.50) – (0.75)	–	–
Decommissioning Expenditures	$ millions	$3.0	$3.5 – $4.0	$5.0 – $5.5	$5.0 – $5.5
Adjusted Funds Flow	$ millions	$131	$126 – $138	$138 – $150	$144 – $154
Dividends	$ millions	$3	$15 – $16	$15 – $16	$15 – $16

		Actuals FY 2022	Guidance FY 2023[1]	Preliminary Plan FY 2024[1][5]	Preliminary Plan FY 2025[1][5]
Adjusted Funds Flow	$ millions	$131	$126 – $138	$138 – $150	$144 – $154
Capital Expenditures	$ millions	$77.6	$75 – $80	$76 – $81	$77 – $82
Free Adjusted Funds Flow	$ millions	$53	$46 – $63	$57 – $74	$62 – $77

		Actuals FY 2022	Guidance FY 2023[1]	Preliminary Plan FY 2024[1][5]	Preliminary Plan FY 2025[1][5]
Adjusted Funds Flow	$ millions	$131	$126 – $138	$138 – $150	$144 – $154
Interest	$/boe	1.49	0.35 – 0.85	0.00 – 0.10	0.00 – 0.10
EBITDA	$ millions	$136	$128 – $140	$138 – $150	$144 – $154
Working Capital (Net Debt)	$ millions	($33)	($2) – $10	$38 – $50	$81 – $92
Net Debt/EBITDA		0.2	(0.1) – 0.1	(0.2) – (0.4)	(0.5) – (0.6)

		Actuals FY 2022	Guidance FY 2023[1]	Preliminary Plan FY 2024[1][5]	Preliminary Plan FY 2025[1][5]
Production	Boe/d	9,105	9,500 – 10,500	10,250 – 11,250	10,950 – 11,950
Opening Working Cap. (Net Debt)	$ millions	($80.2)	($33)	($2) – $10	$38 – $50
Ending Working Cap. (Net Debt)	$ millions	($33)	($2) – $10	$38 – $50	$81 – $92
Weighted avg. outstanding shares	# millions	86.9	88.6	89.1	89.1
Assumed Share price	$	3.39[3]	3.00	3.00	3.00
Prod. per debt adj. share growth[2]		51%	16% – 36%	17% – 36%	18% – 37%

		Actuals FY 2022	Guidance FY 2023[1]	Preliminary Plan FY 2024[1][5]	Preliminary Plan FY 2025[1][5]
Share outstanding, end of year	# millions	87.0	89.1	89.1	89.1
Assumed Share price	$	3.03[4]	3.00	3.00	3.00
Market capitalization	$ millions	$263	$267	$267	$267
Working Capital (Net Debt)	$ millions	($33)	($2) – $10	$38 – $50	$81 – $92
Enterprise value	$millions	$296	$257 – $269	$217 – $229	$175 – $186
Adjusted Funds Flow	$ millions	$131	$126 – $138	$138 – $150	$144 – $154
Interest	$/boe	1.49	0.35 – 0.85	0.00 – 0.10	0.00 – 0.10
Debt Adjusted AFF	$ millions	$136	$128 – $140	$138 – $150	$144 – $154
EV/DAAFF		2.2	2.1 – 1.8	1.7 – 1.4	1.3 – 1.1

(1) As previously released January 18, 2023.

(2) Production per debt adjusted share is calculated by the Company as production divided by debt adjusted shares. Debt adjusted shares is calculated by the Company as common shares outstanding plus the change in working capital (net debt) divided by the

Company's current trading price on the TSX, converting working capital (net debt) to equity. Future share prices assumed to be consistent with the current share price.

(3) Weighted average share price throughout 2022.

(4) Ending share price at December 31, 2022.

(5) InPlay's plans and estimates for 2024 and beyond remain preliminary in nature and do not, at this time, reflect a Board approved capital expenditures budget. Accordingly, undue reliance should not be placed on the same.

- 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 (net debt) are not assumed to have a material impact between the years presented above.
- The assumptions above do not include potential future purchases through the Company's NCIB.

PRODUCTION BREAKDOWN BY PRODUCT TYPE

Disclosure of production on a per boe basis in this press release 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 (bbls/d)	NGLs (boe/d)	Conventional Natural gas (Mcf/d)	Total (boe/d)
Q4 2021 Average Production	3,156	933	15,590	6,687
2021 Average Production	2,981	782	12,030	5,768
Q4 2022 Average Production	3,909	1,532	25,090	9,623
2022 Average Production	3,766	1,402	23,623	9,105
2023 Annual Guidance	4,520	1,385	24,570	10,000(1)
2024 Annual Preliminary Plan	4,655	1,565	27,180	10,750(2)
2025 Annual Preliminary Plan	4,900	1,685	29,190	11,450(2)

Notes:

1. *This reflects the mid-point of the Company's 2023 production guidance range of 9,500 to 10,500 boe/d.*
2. *This reflects the mid-point of the Company's updated annual production forecast range.*
3. *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.*

ABBREVIATIONS USED

bbl	Barrel	AECO	intra-Alberta Nova inventory transfer price
bpd	barrels per day	GJ	gigajoule
boe	barrel of oil equivalent	Mcf	thousand cubic feet
boed	barrels of oil equivalent per day	Mcfd	thousand cubic feet per day
bopd	barrels of oil per day	MMBtu	million British thermal units
Mbbls	thousand barrels	MMcf	million cubic feet
Mboe	thousand barrels of oil equivalent	MMcfd	million cubic feet per day
MMboe	million barrels of oil equivalent	Bcf	billion cubic feet
Mstb	thousand stock tank barrels	NGL	natural gas liquids
m3	cubic metres	Cdn	Canadian
WTI	West Texas Intermediate	US	United States