INPLAY OIL

Financial Statements

For the years ended December 31, 2021 and 2020

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Independent auditor's report

To the Shareholders of InPlay Oil Corp.

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of InPlay Oil Corp. and its subsidiaries (together the Company) as at December 31, 2021 and 2020, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards (IFRS).

What we have audited

The Company's consolidated financial statements comprise:

- the consolidated statements of financial position as at December 31, 2021 and 2020;
- the consolidated statements of profit (loss) and comprehensive income (loss) for the years then ended;
- the consolidated statements of changes in equity for the years then ended;
- the consolidated statements of cash flows for the years then ended; and
- the notes to the consolidated financial statements, which include significant accounting policies and other explanatory information.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the consolidated financial statements for the year ended December 31, 2021. These matters were addressed in the context of our audit of the consolidated financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

Key audit matter	How our audit addressed the key audit matter
The impact of oil and natural gas reserves on net property, plant and equipment (PP&E) and recoverability of deferred tax assets (DTA) *Refer to note 3 – Summary of accounting policies, note 4 – Significant accounting judgments, estimates and assumptions, note 6 – Property, plant and equipment, note 7 – Impairment loss (reversal) and note 12 – Income tax to the consolidated financial statements.* The Company has $346.4 million of PP&E as at December 31, 2021. Depletion and depreciation (D&D) expense was $27.4 million for the year then ended. PP&E is depleted using the unit-of-production method based on proved and probable oil and natural gas reserves. Oil and natural gas assets are grouped into cash generating units (CGUs) for impairment testing. At the end of each reporting date, the Company considers various external and internal sources of information when assessing whether any indication exists that a CGU may be impaired or that an impairment loss recognized in prior periods may no longer exist or may have decreased. If any such indication exists, the Company estimates the CGU's recoverable amount. A CGU's recoverable amount is the higher of its value in use and its fair value less costs of disposal. When the carrying amount of a CGU exceeds its recoverable amount, the carrying value is reduced to its recoverable amount. That reduction is an impairment loss,	Our approach to addressing the matter included the following procedures, among others: • The work of management's expert was used in performing the procedures to evaluate the reasonableness of the quantities of oil and natural gas reserves used to determine D&D expense, the recoverable amounts of the CGUs and the recoverability of the DTA. As a basis for using this work, the competence, capabilities and objectivity of management's expert were evaluated, the work performed was understood and the appropriateness of the work as audit evidence was evaluated. The procedures performed also included evaluation of the methods and key assumptions used by management's expert, tests of the data used by management's expert and an evaluation of their findings. • Tested how management determined the recoverable amounts of the Company's CGUs and D&D expense, which included the following: – Evaluated the appropriateness of the methods used by management in making these estimates. – Tested the data used in determining these estimates. – Evaluated the reasonableness of key assumptions used in developing the underlying estimates, including: ○ The discount rates, through the assistance of professionals with specialized skill and knowledge in the

Key audit matter	How our audit addressed the key audit matter
which is recognized in the statements of profit (loss) and comprehensive income (loss). When the recoverable amount exceeds the carrying amount of a CGU, and the carrying value had been reduced in a prior period due to an impairment loss, the carrying amount of the CGU is increased to the revised estimate of its recoverable amount not exceeding the carrying amount that would have been determined had no impairment loss been recognized in prior periods. On June 30, 2021 and 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 CGUs using the fair value less costs of disposal method based on the net present value of the after-tax future cash flows from the CGUs' oil and natural gas reserves prepared by the Company's independent reserves evaluator (management's expert). The impairment reversal tests resulted in impairment reversals of $61.9 million. Key assumptions developed by management used to determine the recoverable amounts of the CGUs included the discount rates, quantities of proved and probable oil and natural gas reserves, production volumes, future commodity prices, operating expenses and development costs. The Company recognizes DTA only if it is probable that future taxable amounts will be available to utilize those temporary differences and losses. The deferred tax asset is supported by the expected future utilization of tax attributes based on future cash flows derived from the Company's updated forecasts. Key assumptions developed	field of valuation. o The production volumes, operating expenses and development costs by considering the past performance of the CGUs, and whether these assumptions were consistent with evidence obtained in other areas of the audit. o Future commodity prices by comparing them to third party industry forecasts. • Recalculated the unit-of-production rates used to calculate depletion and depreciation for each of the Company's CGUs. • Tested management's assessment of the recoverability of the DTA assets by (i) evaluating whether the future cash flows, including the quantities of proved oil and natural gas reserves and production volumes, future commodity prices, operating expenses, development costs, and corporate general and administrative expenses were reasonable by considering the current and past performance of the Company and whether they were consistent with evidence obtained in other areas of the audit; and (ii) whether it is probable that the future taxable amounts will be available to utilize the Company's temporary differences and tax losses.

Key audit matter	How our audit addressed the key audit matter
by management used to determine the recoverability of the DTA included proved oil and natural gas reserves and production volumes, future commodity prices, operating expenses, development costs, and corporate general and administrative expenses. As a result of the increase in estimated future cash flows, the DTA was increased by $23.9 million as at December 31, 2021. We determined that this is a key audit matter due to (i) the significant judgment made by management, including the use of the management's expert, when developing the key assumptions used to determine the recoverable amounts of the CGUs, the D&D and the recoverability of the DTA; (ii) a high degree of auditor judgment, subjectivity and effort in performing procedures relating to the key assumptions, which included the discount rates, quantities of proved and proved and probable oil and natural gas reserves (together, oil and natural gas reserves), production volumes, future commodity prices, operating expenses, development costs and corporate and general administrative expenses; and (iii) the audit effort which involved the use of professionals with specialized skill and knowledge in the field of valuation.	
Valuation of property, plant and equipment (PP&E) assets acquired in the Prairie Storm Resources Corp. (Prairie Storm) business combination *Refer to note 3 – Summary of significant accounting policies, note 4 – Significant accounting judgments, estimates and assumptions and note 5 – Acquisitions to the consolidated financial statements.*	Our approach to addressing the matter included the following procedures, among others: • Tested how management estimated the fair value of the PP&E assets, which included the following: – Read the purchase agreement. – Professionals with specialized skill and knowledge in the field of valuation assisted in assessing the appropriateness of the discounted cash flow model and the

Key audit matter	How our audit addressed the key audit matter
On November 30, 2021, the Company acquired all of the outstanding common shares of Prairie Storm for total consideration of $57.1 million. The fair value of the identifiable assets acquired included PP&E assets of $73.8 million. Management applied significant judgment in estimating the fair value of the PP&E assets. To estimate the fair value of the PP&E assets, management used a discounted future cash flow model to determine the net present value of after-tax future cash flows from the oil and natural gas reserves prepared by the Company's independent reserves evaluator (management's expert). Key assumptions developed by management used to determine the fair value of the PP&E assets acquired included the discount rate, quantities of proved and probable oil and natural gas reserves, production volumes, future commodity prices, operating expenses and development costs. We determined that this is a key audit matter due to (i) the significant judgment made by management, including the use of management's expert, when developing the key assumptions used to determine the fair value of PP&E assets acquired; (ii) a high degree of auditor judgment, subjectivity and effort in performing procedures relating to the key assumptions, which included the discount rates, quantities of proved and probable oil and natural gas reserves, production volumes, future commodity prices, operating expenses and development costs; and (iii) the audit effort that involved the use of professionals with specialized skill and knowledge in the field of valuation.	reasonableness of the discount rate applied by management based on available data of comparable transactions. – Evaluated the reasonableness of certain key assumptions used in developing the underlying estimate, including: o Production volumes, operating expenses and development costs by considering the historical performance of the Company, and whether these assumptions were consistent with evidence obtained in other areas of the audit. o Future commodity prices by comparing them to other third party industry forecasts. – The work of management's expert was used in performing the procedures to evaluate the reasonableness of the quantities of proved and probable oil and natural gas reserves. As a basis for using this work, the competence, capabilities and objectivity of management's expert were evaluated, the work performed was understood and the appropriateness of the work as audit evidence was evaluated. The procedures performed also included evaluation of the methods and key assumptions used by management's expert, tests of the data used by management's expert and an evaluation of their findings. • Tested the underlying data used by management in the discounted cash flow model and tested the mathematical accuracy thereof.

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis.

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's consolidated financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this independent auditor’s report is Alisa Sorochan.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta
March 15, 2022

Consolidated Statements of Financial Position

AS AT DECEMBER 31,

(Thousands of Canadian dollars)	Note	2021	2020
ASSETS			
Current assets			
Accounts receivable and accrued receivables	20	**$ 16,911**	$ 6,269
Prepaid expenses and deposits		**2,971**	2,200
Inventory		**3,718**	874
Total current assets		**23,600**	9,343
Property, plant and equipment	5, 6, 7	**346,414**	180,019
Exploration and evaluation	8	**14,496**	21,136
Right-of-use asset	9	**573**	537
Deferred tax	12	**21,401**	-
Total assets		**$ 406,484**	$ 211,035
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities	20	**24,669**	19,192
Lease liability	9	**316**	455
Decommissioning obligation	11	**2,193**	796
Deferred share unit liability	14	**628**	-
Derivative contracts	20	**524**	1,316
Bank debt	10	**52,863**	38,630
Total current liabilities		**81,193**	60,389
Bank debt	10	**26,264**	25,202
Lease liability	9	**262**	98
Decommissioning obligation	11	**109,401**	79,625
Total long term liabilities		**135,927**	104,925
Total liabilities		**217,120**	165,314
Shareholders' equity			
Share capital	13	**262,524**	234,391
Contributed surplus	14	**16,580**	16,141
Deficit		**(89,740)**	(204,811)
Total shareholders' equity		**189,364**	45,721
Total liabilities and shareholders' equity		**$ 406,484**	$ 211,035
Commitments	22		

The above Consolidated Statements of Financial Position should be read in conjunction with the accompanying notes.

On behalf of the Board of Directors:

(signed) "Steve Nikiforuk"
Steve Nikiforuk
Director

(signed) "Doug Bartole"
Doug Bartole
Director

Consolidated Statements of Profit (Loss) and Comprehensive Income (Loss)

FOR THE YEARS ENDED DECEMBER 31

(Thousands of Canadian dollars, except per share amounts)	Note		**2021**		2020
Oil and natural gas sales	16	**$**	**113,854**	$	41,934
Royalties			**(11,595)**		(2,924)
Revenue			**102,259**		39,010
(Loss) on derivative contracts	16		**(12,080)**		(2,519)
			90,179		36,491
Operating expenses			**27,009**		21,043
Transportation expenses			**2,346**		1,271
Exploration and evaluation expenses	8		**8,597**		22
General and administrative expenses	17		**5,961**		4,487
Share-based compensation	14		**1,576**		569
Depletion and depreciation	6		**27,440**		20,877
Impairment loss (reversal)	7		**(61,938)**		65,710
Gain on acquisition	5		**(20,161)**		-
Finance expenses	18		**6,747**		4,844
Transaction and integration costs	5		**1,495**		-
			(928)		118,823
Profit (loss) before tax			**91,107**		(82,332)
Deferred income tax expense (recovery)	12		**(23,964)**		30,297
Profit (loss) and comprehensive income (loss)		**$**	**115,071**	$	(112,629)
PROFIT (LOSS) PER COMMON SHARE					
Basic	15	**$**	**1.65**	$	(1.65)
Diluted	15	**$**	**1.61**	$	(1.65)

The above Consolidated Statements of Profit (Loss) and Comprehensive Income (Loss) should be read in conjunction with the accompanying notes.

Consolidated Statements of Changes in Equity

(Thousands of Canadian dollars)	Note	Share capital	Contributed surplus	Deficit	Total shareholders' equity
Balance at December 31, 2019		234,391	15,399	(92,182)	157,608
Share-based compensation	14	-	742	-	742
(Loss) for the year		-	-	(112,629)	(112,629)
Balance at December 31, 2020		234,391	16,141	(204,811)	45,721
Share-based compensation	14	-	452	-	452
Option exercises	14	43	(13)	-	30
Issuance of share capital	5	28,732	-	-	28,732
Shares-issue costs, net of deferred tax	13	(642)	-	-	(642)
Profit for the year		-	-	115,071	115,071
Balance at December 31, 2021		**262,524**	**16,580**	**(89,740)**	**189,364**

The above Consolidated Statements of Changes in Equity should be read in conjunction with the accompanying notes.

Consolidated Statements of Cash Flows

FOR THE YEARS ENDED DECEMBER 31

(Thousands of Canadian dollars)			**2021**		2020
Cash flows provided by (used in):					
OPERATING ACTIVITIES					
Profit (loss) for the period		**$**	**115,071**	$	(112,629)
Non-cash items:					
Depletion and depreciation	6		**27,440**		20,877
Unrealized loss (gain) on derivative contracts	16		**(974)**		1,316
Accretion on decommissioning obligation	11		**1,133**		1,274
Share-based compensation	14		**329**		569
Exploration expense	8		**8,597**		22
Deferred income tax expense (recovery)	12		**(23,964)**		30,297
Impairment loss (reversal)	7		**(61,938)**		65,710
Gain on acquisition	5		**(20,161)**		-
Decommissioning expenditures	11		**(1,433)**		(602)
Funds flow			**44,100**		6,834
Net change in non-cash working capital	19		**(5,690)**		1,641
Net cash flow provided by operating activities			**38,410**		8,475
FINANCING ACTIVITIES					
Principal portion of finance lease payments	9	**$**	**(476)**	$	(599)
Proceeds from exercise of stock options			**30**		-
Issuance of shares, net of issue costs	13		**10,675**		-
Increase in bank debt	10		**15,295**		10,197
Net cash flow provided by financing activities			**25,524**		9,598
INVESTING ACTIVITIES					
Capital expenditures – Property, plant and equipment	6	**$**	**(33,363)**	$	(23,063)
Capital expenditures – Exploration and evaluation	8		**(71)**		(73)
Property dispositions (acquisitions)	5		**84**		(1,610)
Corporate acquisitions, net of cash acquired	5		**(29,277)**		-
Net change in non-cash working capital	19		**(1,307)**		6,673
Net cash flow (used in) investing activities			**(63,934)**		(18,073)
Increase (decrease) in cash and cash equivalents			**-**		-
Cash and cash equivalents, beginning of the year			**-**		-
Cash and cash equivalents, end of the year		**$**	**-**	$	-
Interest paid in cash		**$**	**5,614**	$	3,570

The above Consolidated Statements of Cash Flows should be read in conjunction with the accompanying notes.

Notes to the Consolidated Financial Statements

DECEMBER 31, 2021 AND DECEMBER 31, 2020

(Tabular amounts in thousands of Canadian dollars, unless otherwise stated)

1. CORPORATE INFORMATION

InPlay Oil Corp. ("**InPlay**" or the "**Company**") is actively engaged in the acquisition, exploration and development of petroleum and natural gas properties, and the production and sale of crude oil, natural gas and natural gas liquids. InPlay is a publicly traded company incorporated and domiciled in Alberta, Canada. InPlay's common shares are listed on the Toronto Stock Exchange (the "**TSX**") and trade under the symbol IPO. InPlay's corporate office is located at 2000, 350 - 7th Avenue SW, Calgary, Alberta, its registered office is located at 2400, 525 - 8th Avenue SW, Calgary, Alberta, and its petroleum and natural gas operations are located in the Province of Alberta.

2. BASIS OF PRESENTATION

2(a) Compliance with IFRS

These consolidated financial statements comply with International Financial Reporting Standards ("**IFRS**") and International Accounting Standards ("**IAS**") as issued by the International Accounting Standards Board ("**IASB**").

The consolidated financial statements were approved and authorized for issuance by the Board of Directors on March 15, 2022.

2(b) Historical cost convention

These consolidated financial statements have been prepared on the historical cost basis, except for derivative financial instruments, which are measured at fair value. The methods used to measure fair values are discussed in note 20.

2(c) Functional and presentation currency

The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency.

2(d) Function and nature of expenses

Expenses in the consolidated statements of profit (loss) and comprehensive income (loss) are presented as a combination of function and nature in conformity with industry practice. Transportation expenses, share-based compensation, depletion and depreciation, and impairment of property, plant and equipment are presented in separate lines by their nature, while operating expenses, general and administrative expenses and transaction and integration costs are presented on a functional basis. Significant general and administrative are presented by their nature in note 17.

3. SUMMARY OF ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements.

3(a) Jointly-controlled assets

Many of the Company's petroleum and natural gas operations are conducted under joint operating agreements whereby two or more parties jointly control the assets. These joint arrangements are classified as joint operations, and the financial statements include the Company's ownership-interest share of the assets, liabilities, revenue and expenses of these joint operations.

3(b) Business combinations

Business combinations are accounted for using the acquisition method. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured at their fair values at the acquisition date. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the acquisition date. The excess of the cost of the acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of the acquisition is less than the fair value of the net assets acquired, the difference is recognized immediately in profit or loss. Transaction costs associated with a business combination are expensed as incurred.

3(c) Cash and cash equivalents

Cash and cash equivalents include short-term investments with original maturities of less than 90 days.

3(d) Inventory

Inventory is primarily comprised of oil and gas field equipment. Inventories are carried at the lower of cost and net realizable value. Cost consists of the costs incurred to purchase the inventory. Net realizable value is based on current market prices as at the date of the consolidated statement of financial position.

3(e) Financial instruments

InPlay recognizes a financial asset or liability when it becomes a party to the contractual provisions of a financial instrument. Financial assets and liabilities within the scope of IFRS 9 "Financial Instruments" are classified as amortized cost, fair value through other comprehensive income or fair value through profit or loss ("**FVTPL**"). IFRS 9 uses a single approach to determine the classification of a financial asset. InPlay does not designate derivative instruments as hedges. Transaction costs are included in the initial carrying amount of financial instruments except for fair value through profit and loss items, in which case they are expensed as incurred.

(i) Financial assets and liabilities at fair value through profit or loss

The Company classifies its derivative contracts as measured at FVTPL. All of the Company's derivative contracts currently in place are derivatives not designated for hedge accounting and are therefore measured at FVTPL. Financial assets and liabilities classified as FVTPL are subsequently measured at fair value with changes in fair value charged immediately to the statements of income.

(ii) Financial assets and liabilities at amortized cost

The Company classifies its cash and cash equivalents, accounts receivable and accrued receivables and accounts payable and accrued liabilities at amortized cost. These financial instruments are measured at fair value on initial recognition, which is typically the relevant transaction price unless the transaction contains a significant financing component. The contractual cash flows received from the financial assets are solely payments of principal and interest and are held within a business model whose objective is to collect the contractual cash flows. These financial assets and financial liabilities are subsequently measured at amortized cost using the effective interest method. The carrying values of the Company's cash and cash equivalents, accounts receivable and accrued receivables, and accounts payable and accrued liabilities approximate their fair values.

(iii) Fair value

The fair value of financial instruments that are actively traded in organized financial markets is determined by reference to quoted market bid prices at the valuation date. For financial instruments that have no active market, fair value is determined using valuation techniques including the use of recent arm's length market transactions, reference to the current market value of equivalent financial instruments and discounted cash flow analysis.

(iv) Impairment of financial assets

The Company applies the IFRS 9 simplified approach to measuring expected credit losses which uses a lifetime expected loss allowance for all accounts receivable and accrued receivables. The Company's accounts receivable and accrued receivables are the only financial assets that are subject to IFRS 9's expected credit loss model. While cash and cash equivalents are also subject to the impairment requirements of IFRS 9, the identified impairment loss is immaterial given the low risk associated with its collectability.

3(f) Exploration and evaluation ("E&E") expenditures

Expenditures incurred to explore for and evaluate oil and natural gas reserves may include costs to acquire unproven oil and natural gas properties or licenses to explore, drill exploratory wells, geological and geophysical costs to evaluate the underlying resource, and directly-attributable general and administrative costs. E&E expenditures are recognized and measured as follows:

(i) Prior to obtaining the right to explore

Expenditures are recognized as an expense in profit or loss when incurred.

(ii) Subsequent to acquiring the right to explore, and before technical feasibility and commercial viability have been established

Expenditures incurred are accumulated on an area-by-area basis and are measured at cost as E&E assets. E&E assets are not subject to depletion and depreciation; however, E&E assets are assessed for impairment when facts and circumstances suggest that the carrying amount of an E&E asset may exceed its recoverable amount. Any impairment loss is recognized as an expense in profit or loss.

(iii) Upon demonstration of technical feasibility and commercial viability

An E&E asset is assessed for impairment, and any impairment loss is recognized immediately in profit or loss. The carrying amount of the E&E assets, net of any impairment loss, is reclassified to property, plant and equipment.

3(g) Property, plant and equipment

Property, plant and equipment carrying amounts are measured at cost less accumulated depreciation and depletion, and accumulated impairment losses.

(i) Development and production expenditures

All costs directly associated with the development of oil and natural gas reserves are recognized as property, plant and equipment assets if the expenditures extend or enhance the recoverable reserves of the underlying assets. Such costs include property acquisitions, carrying amounts reclassified from E&E assets to property, plant and equipment, drilling and completion costs, gathering and processing infrastructure, capitalized decommissioning obligations, and directly attributable general and administration costs.

Repairs and maintenance and operational expenditures that do not extend or enhance recoverable reserves are charged to profit or loss when incurred.

(ii) Impairment and reversals of impairment

Oil and natural gas assets are grouped into cash generating units ("**CGU**s") for impairment testing.

At the end of each reporting date, the Company considers various external and internal sources of information when assessing whether any indication exists that a CGU may be impaired or that an impairment loss recognized in prior periods may no longer exist or may have decreased. If any such indication exists, the Company estimates the CGU's recoverable amount. A CGU's recoverable amount is the higher of its value in use and its fair value less costs of disposal.

When the carrying amount of a CGU exceeds its recoverable amount, the carrying value is reduced to its recoverable amount. That reduction is an impairment loss, which is recognized immediately in profit or loss.

When the recoverable amount exceeds the carrying amount of a CGU, and the carrying value had been reduced in a prior period due to an impairment loss, the carrying amount of the CGU is increased to the revised estimate of its recoverable amount not exceeding the carrying amount that would have been determined had no impairment loss been recognized for the asset or CGU in prior periods. That increase in carrying value is a reversal of an impairment loss, which is recognized immediately in profit or loss.

3(h) Depletion and depreciation

The net carrying amount of oil and natural gas producing properties, including tangible equipment associated with these oil and natural gas properties, is depleted using the unit-of-production method based on estimated total proved and probable reserves taking into account the estimated future development and decommissioning expenditures required to produce these oil and natural gas reserves and salvage values of the tangible equipment. For other assets, depreciation is recognized in profit or loss on a straight-line or declining basis over the assets' estimated useful lives.

3(i) Leases

The Company assesses whether a contract is a lease based on whether the contract conveys the right to control the use of an underlying asset for a period of time in exchange for consideration. The Company allocates the consideration in the contract to each lease component on the basis of their relative stand-alone prices.

Leases are recognized as a right-of-use asset and a corresponding lease liability at the date on which the leased asset is available for use by the Company. Assets and liabilities arising from a lease are initially measured on a present value basis. Lease liabilities include the net present value of fixed payments, variable lease payments that are based on an index or a rate, amounts expected to be paid by the lessee under residual value guarantees, the exercise price of purchase options if the lessee is reasonably certain to exercise that option, and payments of penalties for terminating the lease, less any lease incentives receivable. These payments are discounted using the Company's incremental borrowing rate when the rate implicit in the lease is not readily available. The Company uses a single discount rate for a portfolio of leases with reasonably similar characteristics.

Lease payments are allocated between the liability and finance costs. The finance cost is charged to net income over the lease term. The lease liability is measured at amortized cost using the effective interest method. It is remeasured when there is a change in the future lease payments arising from a change in an index or rate, if there is a change in the amount expected to be payable under a residual value guarantee or if there is a change in the assessment of whether the Company will exercise a purchase, extension or termination option that is within the control of the Company. When the lease liability is remeasured, a corresponding adjustment is made to the carrying amount of the right-of-use asset or is recorded in the consolidated statements of profit and comprehensive income if the carrying amount of the right-of-use asset has been reduced to zero.

The right-of-use asset is initially measured at cost, which comprises the initial amount of the lease liability, any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or site on which it is located, less any lease payments made at or before the commencement date. The right-of-use asset is depreciated, on a straight-line basis, over the shorter of the estimated useful life of the asset or the lease term. The right-of-use asset may be adjusted for certain remeasurements of the lease liability and impairment losses. Leases that have terms of less than twelve months or leases on which the underlying asset is of low value are recognized as an expense in the consolidated statements of profit and comprehensive income on a straight-line basis over the lease term.

A lease modification will be accounted for as a separate lease if the modification increases the scope of the lease and if the consideration for the lease increases by an amount commensurate with the stand-alone price for the increase in scope. For a modification that is not a separate lease or where the increase in consideration is not commensurate, at the effective date of the lease modification, the Company will remeasure the lease liability using the Company's incremental borrowing rate, when the rate implicit to the lease is not readily available, with a corresponding adjustment to the right-of-use asset. A modification that decreases the scope of the lease will be accounted for by decreasing the carrying amount of the right-of-use asset, and recognizing a gain or loss in net income that reflects the proportionate decrease in scope.

3(j) Decommissioning obligations

The Company has regulatory obligations for the future decommissioning of the Company's oil and gas locations following the end of the assets' useful lives. Decommissioning activities include abandonment of wellbores, dismantling and decommissioning surface equipment and remediating site disturbance. Provision is made for the estimated costs of decommissioning and site restoration and capitalized in the relevant E&E asset or property, plant and equipment category.

Decommissioning obligations are measured at the present value of management's estimation of the amount and timing of expenditures. Changes in the estimated timing of decommissioning and restoration or related cost estimates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to property, plant and equipment. The accretion on the decommissioning and restoration provision is classified as a finance cost.

3(k) Income taxes

The income tax expense or credit for the period is the tax payable on the current period's taxable income based on the applicable income tax rate for each jurisdiction adjusted by changes in deferred tax assets and liabilities attributable to temporary differences and to unused tax losses. The current income tax charge is calculated on the basis of the tax laws enacted or substantively enacted at the balance sheet date.

Deferred income tax is provided, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the financial statements. However, deferred tax liabilities are not recognized if they arise from the initial recognition of goodwill, or the initial recognition of an asset or liability in a transaction other than a business combination that at the time of the acquisition affects neither accounting, nor taxable, profit or loss. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantively enacted at the end of the reporting period and are expected to apply when the deferred tax asset is realized or the deferred tax liability is settled.

Deferred tax assets are recognized only if it is probable that future taxable amounts will be available to utilize those temporary differences and losses. Given the change in market conditions as a result of the COVID-19 outbreak, management has estimated that the total proved reserves of the Company more accurately support the future utilization of the deferred tax asset as at March 31, 2020. This change in estimate has resulted in the recognition of additional deferred income tax expense of $2.7 million in the consolidated statement of profit (loss) and comprehensive income (loss) for the year ended December 31, 2020 with a corresponding reduction to deferred tax asset.

Deferred income tax relating to items recognized directly in equity is recognized in equity and not in the consolidated statement of profit (loss) and comprehensive income (loss). Deferred tax assets and liabilities are offset, if legally enforceable rights exist to set off current income tax assets against current income tax liabilities and the deferred income taxes relate to the same taxable entity and the same taxation authority.

3(l) Share capital

Shares, consisting of common shares, are classified as equity.

3(m) Profit (loss) per common share

Basic profit (loss) per common share is calculated by dividing the loss for the period by the weighted average number of common shares outstanding during the period.

Diluted profit (loss) per common share is calculated using the treasury stock method by adjusting the weighted average number of common shares outstanding for dilutive instruments.

3(n) Share-based compensation plans

The Company's share-based compensation plans include both cash-settled and equity-settled awards.

Liabilities associated with cash-settled awards are determined based on the fair value of the award at grant date and are subsequently revalued at each consolidated statement of financial position date. This valuation incorporates the share price and outstanding awards at the consolidated statement of financial position date. Share-based compensation expense is recognized in the consolidated statement of profit (loss) and comprehensive income (loss) over the vesting period with a corresponding increase or decrease in accounts payable and accrued liabilities.

Share-based compensation expense associated with equity-settled awards is determined based on the fair value of the award at grant date and is recognized over the vesting period, with a corresponding increase to contributed surplus. At the time the awards are exercised, the associated contributed surplus amount is recognized in share capital.

3(o) Revenue recognition

Revenue from the sale of oil, natural gas and NGLs is recognized when control of the product is transferred, which is, generally, when title passes to the customer in accordance with the terms of the sales contract. These sales contracts represent a series of distinct transactions. The Company considers its performance obligations under these contracts to be satisfied and control to be transferred when all the following conditions are satisfied:

- InPlay has transferred title and physical possession of the commodity to the buyer;
- InPlay has transferred the significant risks and rewards of ownership of the commodity to the buyer; and
- InPlay has the present right to payment.

Revenue is measured based on the consideration specified in the contract with the customer. Payment terms for InPlay's sales contracts are on the 25th of the month following delivery. InPlay does not have any contracts where the period between the transfer of the promised goods or services to the customer and payment by the customer exceeds one year. As a result, the Company does not adjust its revenue transactions for the time value of money.

The Company sells its production of crude oil, natural gas and NGLs pursuant to variable price contracts. The transaction price for variable price contracts is based on the commodity price, adjusted for quality, location and other factors. The amount of revenue recognized is based on the agreed transaction price with any variability in transaction price recognized in the same period. Fees associated with marketing, transportation and other items are based on fixed price contracts.

Revenue from the production of oil, natural gas and NGLs from properties in which InPlay has an ownership interest with other producers is recognized on a net working interest basis.

The Company applies a practical expedient of IFRS 15 and does not disclose information about remaining performance obligations that have an original expected duration of one year or less and it does not have any long-term contracts with unfulfilled performance obligations. In addition, the Company also applies a practical expedient of IFRS 15 that allows any incremental costs of obtaining contracts with customers to be recognized as an expense when incurred rather than being capitalized.

3(p) Government Grants

Government grants are recognized when there is reasonable assurance that the Company will comply with the conditions attached to them and the grants will be received. If a grant is received before it is certain whether compliance with all conditions will be achieved, the grant is recognized as a deferred liability until such conditions are fulfilled. When the conditions of a grant relate to income or expense, it is recognized in the consolidated statements of profit (loss) and comprehensive income (loss) in the period in which the expenditures are incurred or income is earned as a credit to the corresponding expense. When the conditions of a grant relate to an underlying asset, it is recognized as a reduction to the carrying amount of the related asset and amortized into income on a systematic basis over the expected useful life of the underlying asset through Depletion and depreciation.

3(q) Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its subsidiaries and any reference to the Company throughout these consolidated financial statements refers to the Company and its subsidiaries. All intercompany balances, transactions, revenue and expenses are eliminated on consolidation. The consolidated accounts are prepared using uniform accounting policies.

4. SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

In March 2020, the World Health Organization declared a global pandemic following the emergence and rapid spread of a novel strain of the coronavirus ("COVID-19"). The pandemic and subsequent measures intended to limit its spread, contributed to significant volatility in global financial markets. The pandemic has adversely impacted global commercial activity and has reduced worldwide demand for commodities including crude oil, natural gas and natural gas liquids. The result was significant economic uncertainty and a decline in commodity prices through most of 2020. In general, the oil and gas industry reacted with reductions to capital and other spending, as well as production shut-ins, to try to manage through this price environment. The combination of increasing worldwide demand for commodities and decreasing oil inventories has resulted in significant commodity price recoveries through most of 2021 and commodity prices are now exceeding pre-pandemic levels.

The full extent of the impact of COVID-19 on the Company's operations and future financial performance is currently unknown. It will depend on future developments that are uncertain and unpredictable, including the duration and spread of COVID-19, its continued impact on capital and financial markets on a macro-scale and any new information that may emerge concerning the severity of the virus. These uncertainties may persist beyond when it is determined how to contain the virus or treat its impact. The outbreak presents uncertainty and risk with respect to the Company, its performance, and estimates and assumptions used by management in the preparation of its financial results.

The Company's financial performance, operations and business are particularly sensitive to volatility in the demand for and prices of crude oil and natural gas. The potential direct and indirect impact of the economic volatility related to COVID-19 have been considered in management's estimates and assumptions at period end and have been reflected in the Company's results with any significant changes described in the relevant financial statement note.

The COVID-19 pandemic is an evolving situation that will continue to have widespread implications for the Company's business environment, operations and financial condition. Management cannot reasonably estimate the length or severity of this pandemic, or the extent to which the disruption may materially impact the Company's financial statements in fiscal 2022 and beyond.

The preparation of financial statements requires management to use judgment in applying its accounting policies and estimates and assumptions about the future that affect the reported amounts of assets, liabilities, revenues and expenses. Actual results may differ from these estimates.

4(a) Significant judgements in applying accounting policies

The judgements made in applying accounting policies that have the most significant effect on the amounts recognized in these financial statements are as follows:

(i) Exploration and evaluation expenditures

The application of the Company's policy for exploration and evaluation expenditures requires management to make certain judgements as to the nature of the expenditures and the technical and commercial feasibility of the underlying resource property.

E&E assets remain capitalized as long as sufficient progress is being made in assessing whether the recovery of the petroleum products is technically feasible and commercially viable. The concept of "sufficient progress" is a judgmental area, and it is possible to have E&E assets remain classified as such for several years while additional E&E activities are carried out or the Company seeks government, regulatory or internal approval for development plans. E&E assets are subject to ongoing technical, commercial and Management review to confirm the continued intent to establish the technical feasibility and commercial viability of the discovery. When Management is making this assessment, changes to project economics, expected capital expenditures and production costs, results of other operators in the region and access to infrastructure and potential infrastructure expansions are important factors.

(ii) Identification of CGUs

A CGU is defined as the smallest identifiable group of assets that generate cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The classification of assets into CGUs requires judgement with respect to similarity of sales points, shared infrastructure, geographical proximity, commodity type and similarity of exposures to market risks.

Prior to December 31, 2021, the Company had the following CGUs: Pembina, Rocky Mountain House, Pigeon Lake, Huxley and Red Deer/Minors. On December 31, 2021 and 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. InPlay's marketing and infrastructure strategy demonstrates significant interdependence of the Company's properties and effective December 31, 2021, InPlay's CGUs were realigned into one CGU: West Central Alberta.

At the time of realignment, the Company estimated the recoverable amounts of its new CGUs and compared them to the recoverable amounts of its previous CGUs and the respective carrying amounts and noted that no asset impairment or reversal of impairment would arise as a result of the realignment.

(iii) Impairment / reversal of impairment of non-financial assets

Judgement is required to select, consider and interpret various external and internal sources of information to assess when impairment or reversal of impairment indicators exist.

4(b) Major sources of estimation uncertainty

Information about assumptions and estimation uncertainties that have a significant risk of resulting in a material adjustment within the next financial year are as follows:

(i) Estimation of oil and natural gas reserves

Depletion and depreciation of property, plant and equipment costs, and amounts used in impairment calculations are based on estimates of oil and natural gas reserves. At least once per year, the Company's independent reserves evaluator prepares a reserves assessment and evaluation of the Company's oil and natural gas properties. Reserves estimates are based on engineering data, estimated future commodity prices and costs, expected future rates of production, and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. Refer to note 7 for additional information relating to this estimate.

(ii) Impairment of non-financial assets

Value in use 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.

Fair value less costs of disposal 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 Company uses a discounted future cash flow model to measure fair value of the CGUs. The future cash flows were based on level 3 fair value hierarchy inputs: the Company's reserves prepared by its independent reserves evaluator, including key assumptions regarding the discount rate, quantities of reserves and production volumes, future commodity prices, operating expenses, and development costs.

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.

Refer to note 7 for additional information relating to this estimate.

(iii) Business combinations

The amounts recorded for identifiable assets acquired, liabilities assumed, goodwill or a gain from a bargain purchase will depend on management's assumptions and estimates of future events, in particular, those assumptions and estimates used in the estimation of the fair value of oil and natural gas reserves. Key assumptions developed by management used to determine the fair value of the PP&E assets acquired included the discount rates, quantities of oil and natural gas reserves, production volumes, future commodity prices, operating expenses, and development costs. Refer to note 5 for additional information relating to this estimate.

(iv) Decommissioning obligation

The decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years, based on current legal and constructive requirements and technology. The estimated obligations and actual costs may change significantly due to changes in regulations, technology, timing of the expenditure and the discount rates used to determine the net present value of the obligations. Refer to note 11 for additional information relating to this estimate.

(v) Deferred tax

Deferred tax assets and liabilities are measured using enacted or substantively enacted tax rates at the reporting date in effect for the period in which the temporary differences are expected to be recovered or settled. The recognition of deferred tax assets is based on the significant assumptions and estimations regarding future revenues and expenses and the probability that the deductible temporary differences will reverse in the foreseeable future. The key assumptions developed by management used to determine the recoverability of the deferred tax assets included proved oil and natural gas reserves and production volumes, future commodity prices, operating expenses, development costs, and corporate general and administrative expenses. Changes in the tax rates or assumptions and estimates used in the recognition of deferred taxes may result in material adjustment to the amount recognized. Refer to note 12 for additional information relating to this estimate.

The COVID-19 outbreak and current market conditions have increased the complexity of estimates and assumptions used to prepare these financial statements, particularly related to the following key source of estimation uncertainty:

Recoverable Amounts

Determining the recoverable amount of a cash-generating unit (“CGU”) or an individual asset requires the use of estimates and assumptions, which are subject to change as new information becomes available. The severe volatility in commodity prices, due to reasons noted above, have increased the risk of measurement uncertainty in determining the recoverable amounts, especially estimating economic crude oil and natural gas reserves and estimating forward commodity prices.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

5. ACQUISITIONS

5(a) 2021 Acquisitions

On November 30, 2021, the Company completed a plan of arrangement (the "**Prairie Storm Arrangement**") whereby InPlay acquired all of the issued and outstanding common shares of Prairie Storm Resources Corp. ("**Prairie Storm**") a light-oil Cardium focused producer with operations primarily in the Willesden Green area of central Alberta, 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 valued at $2.07 per share based on the closing price of InPlay shares on November 29, 2021. The cash portion of the consideration was funded by a combination of net proceeds released to InPlay pursuant to a $11.5 million bought deal subscription receipt financing (the "**Prairie Storm Financing**") and available borrowings under InPlay's senior credit facilities (collectively, the "**Senior Credit Facility**") which have been increased from $65.0 million to $85.0 million.

The Prairie Storm Arrangement has been accounted for as a business combination under IFRS 3.

The fair value at November 30, 2021 of the total consideration transferred and the amounts recognized attributed to the assets acquired was as follows:

Consideration:	**($'000s)**
Cash consideration	**39,919**
Share consideration	**17,223**
Total Consideration	**57,142**
Recognized amounts of assets acquired and liabilities assumed:	
Cash and cash equivalents	**10,642**
Accounts receivable and accrued receivables	**2,999**
Prepaid expenses and deposits	**217**
Inventory	**544**
Property, plant and equipment	**73,769**
Exploration and evaluation	**2,037**
Right-of-use assets	**502**
Deferred tax liability	**(2,755)**
Accounts payable and accrued liabilities	**(2,604)**
Lease liability	**(502)**
Derivative contracts	**(181)**
Decommissioning obligation	**(7,365)**
Total identifiable net assets	**77,303**
Gain on acquisition	**(20,161)**
Total	**57,142**

The fair value of the decommissioning obligation at November 30, 2021 was based on the estimated future cash flows to decommission the acquired property, plant and equipment at the end of its useful life. The discount rates used to determine the net present value of the decommissioning obligation was a credit adjusted risk-free rate of 7.9%. At December 31, 2021 the decommissioning liability was revalued at a risk-free rate of 1.6%, resulting in incremental additions of $25.6 million of decommissioning obligation and corresponding additions to property, plant and equipment.

The acquired assets contributed revenues consisting of oil and natural gas sales net of royalties of approximately $2.1 million and operating income, which is defined as oil and natural gas sales net of royalties less operating and transportation costs, of $1.5 million to InPlay for the period from November 30, 2021 to December 31, 2021. Had the asset acquisition occurred on January 1, 2021, an additional pro-forma oil and natural gas sales net of royalties of approximately $22.6 million and operating income of $14.1 million would have been recognized over the year ended December 31, 2021.

Management applied significant judgment in estimating the fair value of the PP&E assets. To estimate the fair value of the PP&E assets, management used a discounted future cash flow model to determine the net present value of after tax future cash flows from the oil and natural gas reserves. The fair values of the identifiable assets and liabilities acquired as reported in the table above were estimated based on information available at the time of preparation of the financial statements and could be subject to change.

A gain on acquisition of $20.2 million was recorded with this business combination as a result of the total identifiable net assets acquired being greater than the total consideration.

For the year ended December 31, 2021 $1.5 million of transaction and integration costs were incurred for advisory and professional fees associated with the Prairie Storm Arrangement.

The Company completed other minor acquisitions during the year ended December 31, 2021.

5(b) 2020 Acquisitions

Effective October 15, 2020, the Company purchased producing assets, undeveloped lands and interests in various facilities in the Cardium area of Alberta, Canada. The transaction has been accounted for as an asset acquisition under IFRS 3.

The fair value at October 15, 2020 of the total consideration transferred (net of adjustments) and the amounts recognized attributed to the assets acquired was as follows:

Consideration:	**($'000s)**
Cash consideration	**1,875**
Total Consideration	**1,875**
Recognized amounts of assets acquired and liabilities assumed:	
Property, plant and equipment	**4,620**
Decommissioning obligation	**(2,745)**
Total identifiable net assets	**1,875**

The fair value of the decommissioning obligation at October 15, 2020 was based on the estimated future cash flows to decommission the acquired property, plant and equipment at the end of its useful life. The discount rates used to determine the net present value of the decommissioning obligation was a credit adjusted risk-free rate of 7.2%. At December 31, 2020 the decommissioning liability was revalued at a risk-free rate of 1.1%, resulting in incremental additions of $5.9 million of decommissioning obligation and corresponding additions to property, plant and equipment.

The acquired assets contributed revenues consisting of oil and natural gas sales net of royalties of approximately $0.5 million and operating income, which is defined as oil and natural gas sales net of royalties less operating and transportation costs, of $0.2 million to InPlay for the period from October 15, 2020 to December 31, 2020. Had the asset acquisition occurred on January 1, 2020, an additional pro-forma oil and natural gas sales net of royalties of approximately $1.5 million and operating income of $0.6 million would have been recognized over the year ended December 31, 2020.

Subsequent to the acquisition, the cash consideration was reduced by $0.2 million as a result of receipt of the final statement of adjustments relating to the acquisition, with a reduction in the recognized amounts of Property, plant and equipment.

The fair values of the identifiable assets and liabilities acquired as reported in the table above were estimated based on information available at the time of preparation of the financial statements and could be subject to change.

The Company completed other minor acquisitions during the year ended December 31, 2020.

6. PROPERTY, PLANT AND EQUIPMENT

Cost ($'000s)	**Total**
Balance at December 31, 2019	448,235
Additions	23,235
Additions/revisions to decommissioning obligation	5,238
Acquisitions	4,355
Balance at December 31, 2020	481,063
Additions	**33,488**
Additions/revisions to decommissioning obligation	**24,107**
Dispositions	**(84)**
Corporate acquisitions	**73,769**
Transfer from exploration and evaluations assets	**151**
Balance at December 31, 2021	**612,494**

Accumulated Depletion & Impairment ($'000s)	**Total**
Balance at December 31, 2019	215,066
Impairment loss	65,710
Depletion and depreciation[1]	20,268
Balance at December 31, 2020	301,044
Impairment reversal	**(61,938)**
Depletion and depreciation[1]	**26,974**
Balance at December 31, 2021	**266,080**

(1) Excludes $0.5 million of depreciation relating to Right-of-use assets (December 31, 2020: $0.6 million).

Net book value ($'000s)	**Total**
At December 31, 2020	180,019
At December 31, 2021	**346,414**

For the year ended December 31, 2021, additions to property, plant and equipment included capitalized general and administrative expenses of $1.2 million (December 31, 2020: $0.9 million) and costs related to share-based compensation of $0.1 million (December 31, 2020: $0.2 million). Future development costs in the amount of $474 million were included in the depletion calculation for the three months ended December 31, 2021 (December 31, 2020 - $259 million).

7. IMPAIRMENT LOSS (REVERSAL)

2021 Impairment Considerations

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 consolidated statement of profit (loss) and comprehensive income (loss) 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%. The future cash flows were based on level 3 fair value hierarchy inputs: the Company's oil and natural gas reserves prepared by its independent reserves evaluator, including key assumptions regarding the discount rate, quantities of oil and natural gas reserves and production volumes, future commodity prices, operating expenses and development costs. At December 31, 2021, a 1% change to the discount rate used would not result in a change to the impairment reversal. A 5% change to commodity prices used would not result in a change to the impairment reversal.

Refer to note 4 for further details of the Company's realignment of its CGUs effective December 31, 2021.

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 consolidated statement of profit (loss) and comprehensive income (loss) 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 future cash flows were based on level 3 fair value hierarchy inputs: the Company's oil and natural gas reserves prepared by its independent reserves evaluator, including key assumptions regarding the discount rate, quantities of oil and natural gas reserves and production volumes, future commodity prices, operating expenses and development costs. 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 June 30, 2021, a 1% change to the discount rate used would result in a decrease to the impairment reversal of approximately $3.6 million relating to the Company's Rocky ($3.4 million) and Huxley ($0.2 million) CGUs and an increase to the impairment reversal of approximately $3.6 million relating to the Company's Rocky CGU. A 5% change to commodity prices used would result in a decrease to the impairment reversal of approximately $10.8 million relating to the Company's Pigeon Lake ($2.3 million), Rocky ($8.0 million) and Huxley ($0.5 million) CGUs and an increase to the impairment reversal of approximately $3.7 million relating to the Company's Rocky CGU.

2020 Impairment Considerations

Indicators of impairment relating to Property, plant and equipment were considered to exist as at March 31, 2020 as the Company's net assets were greater than its market capitalization and due to significant decreases in estimated future commodity prices. Impairment tests were performed for each the Company's CGUs which resulted in an impairment loss of $65.7 million being recorded in the Company's consolidated statement of profit (loss) and comprehensive income (loss) relating to the Company's Pigeon Lake ($19.0 million), Pembina ($25.7 million), Rocky ($18.9 million) and Huxley ($2.1 million) CGUs. The Company 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 future cash flows were based on level 3 fair value hierarchy inputs: the Company's oil and natural gas reserves prepared by its independent reserves evaluator, including key assumptions regarding the discount rate, quantities of oil and natural gas reserves and production volumes, future commodity prices, royalties, operating expenses, development costs, and decommissioning expenditures. The Company's oil and natural gas reserves prepared by its independent reserves evaluator as at December 31, 2019 have been updated by internal qualified reserve engineers to March 31, 2020.

If the discount rate used was one percent higher, additional impairment of approximately $6.7 million would have been recorded relating to the Company's Pigeon Lake ($1.0 million), Pembina ($1.9 million), Rocky ($3.6 million) and Huxley ($0.2 million) CGUs. If the commodity prices used in the impairment tests were five percent lower, additional impairment of approximately $18.7 million would have been recorded relating to the Company's Pigeon Lake ($4.4 million), Pembina ($5.3 million), Rocky ($8.5 million) and Huxley ($0.5 million) CGUs.

The following table shows the benchmark commodity prices used in the impairment calculation of Property, plant and equipment at December 31, 2021 and June 30, 2021 of which are based on an average of independent reserve evaluator pricing estimates.

	Light, Sweet Crude Edmonton ($Cdn/bbl)			AECO Gas Price ($Cdn/MMBtu)		
Year	**Dec. 31, 2021**	June 30, 2021	Change	**Dec. 31, 2021**	June 30, 2021	Change
2022	**85.43**	76.88	8.55	**3.58**	3.09	0.49
2023	**79.36**	71.81	7.55	**3.22**	2.73	0.49
2024	**76.07**	71.37	4.70	**3.07**	2.73	0.34
2025	**77.59**	72.80	4.79	**3.14**	2.79	0.35
2026	**79.13**	74.24	4.89	**3.20**	2.85	0.35
2027	**80.73**	75.74	4.99	**3.26**	2.91	0.35
2028	**82.33**	77.25	5.08	**3.34**	2.96	0.38
2029	**83.98**	78.80	5.18	**3.40**	3.02	0.38
2030	**85.66**	80.38	5.28	**3.46**	3.08	0.38

8. EXPLORATION AND EVALUATION

($'000s)	December 31, 2021	December 31, 2020
Opening balance	**21,136**	21,085
Additions	**71**	73
Acquisitions	**2,037**	-
Transfers to property, plant and equipment	**(151)**	-
Transfers to exploration and evaluation expense	**(8,597)**	(22)
Ending balance	**14,496**	21,136

At December 31, 2021, the Company evaluated its remaining Exploration and evaluation assets for indicators of any potential impairment. As a result of this assessment, no indicators were identified and no additional impairment was recorded relating to the Company's Exploration and evaluation assets.

At March 31, 2020, the Company evaluated its remaining Exploration and evaluation assets for indicators of any potential impairment. As a result of this assessment, indicators of impairment were identified as the Company's net assets were greater than its market capitalization and the economics of development of these properties has significantly deteriorated with decreased commodity prices. Impairment tests were performed for the Company's Exploration and evaluation assets which resulted in no impairment being recorded.

9. LEASES

9(a) Right-of-use asset

Cost ($'000s)	Office Lease	Equipment	Total
Balance at December 31, 2019	805	542	1,347
Additions	-	89	89
Balance at December 31, 2020	805	631	1,436
Acquired	502	-	502
Balance at December 31, 2021	**1,307**	**631**	**1,938**

Accumulated Depreciation ($'000s)	Office Lease	Equipment	Total
Balance at December 31, 2019	60	230	290
Depreciation	358	251	609
Balance at December 31, 2020	418	481	899
Depreciation	**379**	**87**	**466**
Balance at December 31, 2021	**797**	**568**	**1,365**

Net book value ($'000s)	Office Lease	Equipment	Total
At December 31, 2020	387	150	537
At December 31, 2021	**510**	**63**	**573**

9(b) Lease liability

The following table details the movement in lease liabilities for the year ended December 31, 2021.

	($'000s)
Balance at December 31, 2019	1,063
Additions	89
Repayments	(646)
Interest	47
Balance at December 31, 2020	553
Acquired	**502**
Repayments	**(497)**
Interest	**20**
Balance at December 31, 2021	**578**
Expected to be incurred within one year	**316**
Expected to be incurred beyond one year	**262**

Payments relating to short-term leases and leases of low-value assets were $nil for the year ended December 31, 2021 (December 31, 2020: $nil).

The Company does not have any lease contracts that are entered into by a joint arrangement, or on behalf of the joint arrangement, at December 31, 2021.

10. BANK DEBT

($'000s)	**December 31, 2021**	December 31, 2020
Senior Credit Facility	**52,863**	38,630
BDC Term Facility	**26,264**	25,202
Total Bank Debt	**79,127**	63,832

10(a) Senior Credit Facility

In connection with the Prairie Storm Arrangement, on November 30, 2021 the aggregate available borrowing capacity of Company's credit facility with its syndicate of lenders (the "**Senior Credit Facility**") was increased from $65.0 million to $85.0 million. The Senior Credit Facility consists of a $55 million revolving line of credit, a $10 million operating line of credit and a $20 million syndicated term facility maturing November 30, 2022 (the "**Senior Term Facility**"). The Senior Term Facility will require mandatory repayments as follows: (i) $6 million by May 31, 2022; (ii) $7 million by August 31, 2022; and (iii) $7 million by November 30, 2022.

The revolving portion of the Senior Credit Facility has a maturity date of May 30, 2022, and if not extended, additional advances would not be permitted and any outstanding advances would become repayable at May 30, 2022. The Senior Term Facility has a maturity date of November 30, 2022 and additional advances would not be permitted and any outstanding advances would become repayable at November 30, 2022. The Senior 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, 2021 the Company had drawn $32.9 million on the revolving portion of the Senior Credit Facility and $20 million on the Senior Term Facility. There are standard reporting covenants under the Senior Credit Facility, however there are no financial covenants. The Company was in compliance with these standard reporting covenants as at December 31, 2021.

Under the Senior 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% for the revolving portion of the Senior Credit Facility and between 5.00% and 8.50% for the Senior Term Facility. Advances may also be drawn as banker's acceptances, Libor loans, and letters of credit, subject to Canadian interest benchmark rates plus margins ranging from 3.00% to 6.50% for the revolving portion of the Senior Credit Facility and 6.00% to 9.50% for the Senior Term Facility. These interest rates, fees and margins vary based on adjusted debt to earnings metrics determined at each quarter end for the preceding 12 months.

The available lending limit of the revolving portion of the Senior Credit Facility is scheduled for annual renewal on May 30, 2022, 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 Senior Credit Facility will not be adjusted at the next annual review. In the event that the lenders reduce the revolving portion of the Senior Credit Facility borrowing base 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 revolving portion of the Senior Credit Facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties.

10(b) BDC Term Facility

On October 30, 2020 the Company entered into a term loan with the Business Development Bank of Canada ("BDC") under their Business Credit Availability Program ("BCAP") which provided the Company with a non-revolving $25 million, second lien, four year term loan facility (the "BDC Term Facility"). The BDC Term Facility has a maturity date of October 30, 2024 and is secured by a floating charge debenture of $150 million and a general security agreement on the assets of the Company. At December 30, 2021 the Company had drawn the full $25.0 million on the BDC Term Facility and had accrued $1.3 million in interest that was added to the principal amount. There are standard reporting covenants under the BDC Term Facility and certain operational covenants, however there are no financial covenants.

Under the BDC Term Facility, draws incur an interest rate equal to the greater of the interest rate charged on the Company's operating line of credit or 5% for the first year and increasing by 1% at each anniversary date of the facility. Standby fees are charged on the undrawn portion of the BDC Term Facility at a rate of 0.50%. Annual renewal fees are charged on the full BDC Term Facility amount at a rate of 1.25% at inception, 1% on the first anniversary date, 1.25% on the second anniversary date and 1.5% on the third anniversary date.

The Company had letters of credit in the amount of $0.3 million outstanding at December 30, 2021 (December 31, 2020 - $0.3 million) and no additional guarantees.

11. DECOMMISSIONING OBLIGATION

($'000s)	**December 31, 2021**	December 31, 2020
Opening balance	**80,421**	71,767
Provisions incurred	**1,161**	567
Revaluation of liabilities acquired based on discount rate	**25,565**	6,161
Provisions acquired	**7,031**	2,745
Provisions settled	**(1,433)**	(602)
Change in estimates	**(1,473)**	(1,086)
Accretion expense	**1,133**	1,274
Government grants	**(811)**	(405)
Ending balance	**111,594**	80,421
Expected to be incurred within one year	**2,193**	796
Expected to be incurred beyond one year	**109,401**	79,625

The estimated future cash out flows as at December 31, 2021 are based on the current estimated costs, government regulations and industry practices to decommission the Company's exploration and production assets. The Company used an inflation rate of 1.56% per annum (December 31, 2020 – 0.92%) until settlement of the obligations, which is assumed to occur over the next 7 to 52 years, to determine the future estimated cash flows. The net present value of the future estimated cash flows have been determined using risk-free discount rates of 1.3% to 1.7% depending on the estimated timing of the future settlement of the obligations (December 31, 2020 – 0.5% to 1.2%). The total inflation adjusted undiscounted amount of estimated future cash flows required to settle the decommissioning obligation at December 31, 2021 was approximately $172.2 million (December 31, 2020 - $102.5 million). The total uninflated undiscounted amount of estimated future cash flows required to settle the decommissioning obligation at December 31, 2021 was approximately $111.6 million (December 31, 2020 - $80.4 million).

At the date of the Prairie Storm Arrangement, the acquired decommissioning obligations were recognized at fair value which was estimated using credit adjusted discount rates of 7.9%. The impact of the change in the estimated present value using risk-free discount rates is recorded as 'Revaluation of liabilities acquired based on discount rate'.

For the year ended December 31, 2021, the Company received $0.8 million (December 31, 2020 - $0.4 million) in Government grants from the Government of Alberta's Site Rehabilitation Program ("SRP") which has been recorded as a reduction to Decommissioning Obligation and a credit to Depletion and Depreciation expense.

There are material uncertainties about the amount and timing of the decommissioning obligation, which include the future market prices for services and equipment required to undertake decommissioning activities, the government regulations and industry practices that set out the relevant standards, and the life-span of the Company's portfolio of exploration and production assets.

12. INCOME TAX

The following table reconciles the income tax expense calculated using the statutory tax rates to the income tax expense (recovery) per the consolidated statement of (loss) and comprehensive (loss):

($'000s)		**December 31, 2021**		December 31, 2020
Profit (loss) before tax	**$**	**91,107**	$	(82,332)
Expected income tax rate		**23%**		24%
Expected income tax expense (recovery)		**20,954**		(19,760)
Increase (decrease) in income taxes resulting from:				
Non-taxable permanent differences – stock based comp.		**78**		142
Non-taxable permanent differences – gain on acquisition		**(4,637)**		-
Other		**5**		4
Change in opening tax pools		**(138)**		-
Change in effective tax rate		**-**		817
Change in estimate		**-**		2,746
Revaluation of deferred tax asset		**(40,226)**		46,348
Deferred income tax expense (recovery)	**$**	**(23,964)**	$	30,297

Deferred tax asset and (liability) components and continuity:

		Charged (credited)		
($'000s)	December 31, 2019	Profit or loss	Directly to balance sheet	December 31, 2020
PP&E, and E&E	$ -	$ -	$ -	$ -
Decommissioning obligation	16,505	(16,505)	-	-
Non-capital losses	13,412	(13,412)	-	-
Derivative contract	-	-	-	-
Share issue costs	380	(380)	-	-
Total	$ 30,297	$ (30,297)	$ -	$ -

		Charged (credited)		
($'000s)	December 31, 2020	Profit or loss	Directly to balance sheet	December 31, 2021
PP&E, and E&E	$ -	$ 15,084	$ (8,873)	$ 6,211
Decommissioning obligation	-	5,476	1,694	7,170
Non-capital losses	-	3,649	4,376	8,025
Derivative contract	-	(224)	42	(182)
Other	-	143	6	149
Share issue costs	-	(164)	192	28
Total	$ -	$ 23,964	$ (2,563)	$ 21,401

The following gross deductions are available for deferred income tax purposes:

($'000s)	**December 31, 2021**	December 31, 2020
Non-capital loss carryforward balances	**152,699**	117,807
Share issue costs	**1,020**	896
Canadian Exploration Expenses (CEE)	**64,773**	64,773
Canadian Development Expenses (CDE)	**68,453**	64,092
Canadian Oil and Gas Property Expenses (COGPE)	**125,542**	112,928
Undepreciated Capital Cost (UCC)	**45,207**	49,308
Total	**$ 457,694**	$ 409,804

The Company's non-capital losses will begin to expire between 2032 and 2040. The amount and timing of reversals of temporary differences will be dependent upon a number of factors, including the Company's future operating results. With the exception of the temporary differences related to the derivative contract gain, the Company does not expect any deferred tax assets or liabilities to reverse within the next twelve months.

The Company recognized deferred tax assets to the extent that it is probable that the future benefit will be realized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized. 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, the deferred tax asset was increased by $40.2 million as at December 31, 2021 (December 31, 2020: decreased $49.1 million) with a corresponding charge to deferred income tax recovery.

During the quarter ended June 30, 2019, the Government of Alberta enacted a reduction in the provincial corporate tax rate from 12% to 8% over four years. The tax rate decrease will be phased in as follows: 11% effective July 1, 2019, 10% effective January 1, 2020, 9% effective January 1, 2021, and 8% effective January 1, 2022. During the quarter ended September 30, 2020, this tax rate decrease was accelerated to 8% effective July 1, 2020. This rate change results in decreased future value attributable to the Company's unused tax losses and temporary differences. As a result, the Company recognized a reduction to its deferred tax asset and a deferred income tax expense of $1.6 million during the nine months ended September 30, 2020 due to the decrease in value of future deductibility of tax losses generated during the period.

13. SHARE CAPITAL

Outstanding share capital consists of an unlimited number of voting common shares.

	Number of Common Shares	Amount ($'000s)
Balance at December 31, 2019	68,256,616	234,391
Balance at December 31, 2020	68,256,616	234,391
Issued on exercise of options	46,800	43
Issued pursuant to acquisitions	8,320,335	17,223
Bought deal prospectus offering	9,591,000	11,509
Share issue costs, net of deferred tax	-	(642)
Balance at December 31, 2021	**86,214,751**	**262,524**

In connection with the Prairie Storm Arrangement, the Company completed a bought deal public offering on October 20, 2021 for gross proceeds of $11.5 million, pursuant to which the Company issued 9,591,000 subscription receipts of InPlay at a price of $1.20 per subscription receipt. Cash proceeds were released from escrow on November 30, 2021 upon closing of the Prairie Storm Arrangement and each subscription receipt was exchanged for one common share of InPlay for no additional consideration. Net proceeds were approximately $10.7 million after underwriting fees and other issue costs.

Also connected with the Prairie Storm Arrangement, the Company issued 8,320,335 InPlay common shares as partial consideration for the acquisition of Prairie Storm. See note 5 for additional information.

14. SHARE-BASED COMPENSATION

14(a) Stock option plan

The Company has an incentive stock option plan pursuant to which options to purchase common shares may be granted to directors, officers, employees and service providers of the Company. The aggregate number of stock options that may be granted at any time under the plan shall not exceed 10% of the aggregate number of issued and outstanding common shares. The exercise price, terms of vesting and expiry date of stock options are fixed by the directors of the Company at the time of grant. All outstanding stock options vest over a three year period, or otherwise in accordance with the stock option plan, and expire five years from the date of grant. The directors of the Company may amend, alter or revise the terms and conditions of the stock option plan or of any outstanding stock options, subject to the terms of the plan.

	Number of options	Weighted avg. remaining life (years)	Weighted avg. exercise price
Outstanding at December 31, 2019	5,242,300	4.26	0.98
Granted during the year	148,500	4.42	0.50
Forfeited during the year	(78,000)	3.44	1.29
Outstanding at December 31, 2020	5,312,800	3.29	0.96
Granted during the year	2,059,400	4.49	1.14
Exercised during the year	(46,800)	3.35	0.64
Forfeited during the year	(498,600)	1.15	1.51
Outstanding at December 31, 2021	**6,826,800**	**3.04**	**0.98**
Exercisable at December 31, 2021	**3,646,267**	**2.26**	**0.97**

	Options Outstanding			Options Exercisable		
Range of Exercise Prices ($)	Number of Options Outstanding	Weighted Average Exercise Price ($)	Weighted Average Remaining Life (Years)	Number of Options Exercisable	Weighted Average Exercise Price ($)	Weighted Average Remaining Life (Years)
0.50 – 0.99	4,216,850	0.59	3.25	2,115,967	0.67	3.00
1.00 - 1.50	1,503,450	1.35	1.36	1,440,300	1.36	1.32
1.51 - 2.00	1,106,500	1.95	4.55	90,000	1.98	0.01
	6,826,800	**0.98**	**3.04**	**3,646,267**	**0.97**	**2.26**

Share-based compensation in the amount of $0.3 million was recognized in the year ended December 31, 2021 (December 31, 2020 - $0.6 million) relating to stock options, in addition to $0.1 million (December 31, 2020 - $0.2 million) of capitalized stock based compensation recognized for year ended December 31, 2021, all with a corresponding credit to contributed surplus.

The fair value of each stock option granted in the years ended December 31, 2021 and December 31, 2020 is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions:

	2021	2020
Risk free interest rate	**0.67%**	1.12%
Expected volatility	**85%**	57%
Expected life	**3.5 years**	3.5 years
Dividend yield	**nil**	nil
Expected forfeiture rate	**nil**	nil
Stock price on grant date	**$1.10**	$0.53
Fair value per option	**$0.69**	$0.23

14(b) Deferred share unit ("DSU") plan

During the year ended December 31, 2019, the Company implemented a deferred share unit plan under which DSUs may be granted to non-employee directors of the Company. All outstanding DSUs vest evenly over a three year period. Awards are settled in cash at each vesting date and the value is determined by the Company's share price on the vesting date.

	Number of DSUs
Outstanding at December 31, 2019	500,000
Outstanding at December 31, 2020	500,000
Granted during the year	688,073
Vested during the year	(456,864)
Forfeited during the year	(190,197)
Outstanding at December 31, 2021	**541,012**

Cash payments in the amount of $0.4 million (December 31, 2020 - $nil) were made during the year ended December 31, 2021 relating to DSUs vesting during the year. Cash payments in the amount of $0.2 million were made subsequent to December 31, 2021 relating to DSUs vesting during the year ended December 31, 2021. Share-based compensation in the amount of $1.2 million was recognized in the year ended December 31, 2021 (December 31, 2020 - $nil) relating to DSUs, with a corresponding credit to Deferred share unit liability.

15. PROFIT (LOSS) PER COMMON SHARE

($'000s except per share amounts)		**December 31, 2021**		December 31, 2020
Profit (loss) for the year	**$**	**115,071**	$	(112,629)
Weighted average number of common shares (basic)		**69,798,836**		68,256,616
Weighted average number of common shares (diluted)[1]		**71,681,264**		68,256,616
Basic profit (loss) per common share	**$**	**1.65**	$	(1.65)
Diluted profit (loss) per common share		**1.61**		(1.65)

(1) A total of 2,420,500 options are excluded from the per share calculations as they are anti-dilutive. (December 31, 2020: 5,312,800 options).

16. REVENUE AND DERIVATIVE CONTRACTS

($'000s)		**December 31, 2021**		December 31, 2020
Oil sales		**85,465**		31,683
Natural Gas sales		**17,607**		6,467
NGL sales		**10,782**		3,784
Total	**$**	**113,854**	$	41,934
Changes in fair value of derivative contracts:				
Realized (loss) on derivative contracts		**(13,054)**		(1,203)
Unrealized gain (loss) on derivative contracts		**974**		(1,316)
(Loss) on derivative contracts	**$**	**(12,080)**	$	(2,519)

17. GENERAL AND ADMINISTRATIVE EXPENSES BY NATURE

($'000s)		December 31, 2021		December 31, 2020
Salaries, Benefits and Bonuses	$	4,137	$	3,152
Computer related fees		537		507
Professional Consulting Services		452		415
Legal Expenses		221		401
Other – (Office & Admin)		1,961		1,105
Capitalized Recoveries		(1,347)		(1,093)
Total General and Administrative Expense	$	5,961	$	4,487

For the year ended December 31, 2021, the Company received $0.1 million (December 31, 2020 - $0.6 million) in Government grants from the Canada Emergency Wage Subsidy ("CEWS") which has been recorded as a credit to General and administrative expense.

18. FINANCE EXPENSE

($'000s)		December 31, 2021		December 31, 2020
Interest expense (Credit Facility and other)	$	5,594	$	3,523
Interest expense (Lease liabilities)		20		47
Accretion expense on decommissioning obligation		1,133		1,274
Finance expense	$	6,747	$	4,844

19. SUPPLEMENTAL CASH FLOW INFORMATION

Net change in non-cash working capital is comprised of:

($'000s)		December 31, 2021		December 31, 2020
Source (use) of cash				
Accounts receivable and accruals	$	(10,642)	$	2,497
Prepaid expenses, deposits and inventory		(3,615)		558
Accounts payable and accruals		5,476		5,259
Deferred share unit liability		628		-
Non-cash working capital acquired		1,156		-
	$	(6,997)	$	8,314
Related to operating activities	$	(5,690)	$	1,641
Related to investing activities		(1,307)		6,673
	$	(6,997)	$	8,314

20. FINANCIAL INSTRUMENTS AND CAPITAL MANAGEMENT

The Company has exposure to credit, liquidity and market risk from its use of financial instruments. This note presents information about the Company's exposure to these risks, the Company's objectives, policies and processes for measuring and managing risk, and the Company's management of capital. Further quantitative disclosures are included throughout these financial statements.

Management of InPlay has overall responsibility for identifying the principal risks of the Company and ensuring the policies and procedures are in place to appropriately manage these risks. InPlay's management identifies, analyzes and monitors risks and considers the implication of the market condition in relation to the Company's activities.

20(a) Fair value of financial instruments

Financial instruments comprise cash and cash equivalents, accounts receivable and accrued receivables, derivative contracts, accounts payable and accrued liabilities, lease liabilities and bank debt.

The carrying amounts for cash and cash equivalents, accounts receivable and accrued receivables, and accounts payable and accrued liabilities are reasonable approximations of their respective fair values due to the short-term maturities of those instruments. Lease liabilities carrying amount is a reasonable approximation of its fair value as it is present valued at the discount rate implicit in the lease or the Company's incremental borrowing rate. Bank debt's carrying amount is also a reasonable approximation of its fair value as it is variable rate debt with similar terms to what would be available as of the consolidated statement of financial position date.

The Company classified the fair value of its financial instruments measured at fair value according to the following hierarchy based on the nature of inputs used to value the instrument:

- Level 1 – observable inputs such as quoted prices in active markets;
- Level 2 – inputs, other than the quoted market prices in active markets, which are observable, either directly and/or indirectly; and
- Level 3 – one or more of the significant inputs is not based on observable market data exists.

The fair values of the derivative contracts used for risk management as at December 31, 2021 and December 31, 2020 were measured using level 2 observable inputs, including quoted prices received from financial institutions based on published forward price curves as at the measurement date, using the remaining contracted oil and natural gas volumes.

During the years ended December 31, 2021 and December 31, 2020, there were no transfers between level 1, level 2 and level 3 classified assets and liabilities.

20(b) Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from joint operations partners and petroleum and natural gas customers.

Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production. When production is not taken in kind payment comes from the common stream operator and facility operator in which payment is typically received on the 25th day of the month following production. InPlay's approach to mitigate credit risk associated with these balances is to maintain marketing relationships with large, established and reputable customers, common stream operators and facility operators that are considered to be creditworthy. InPlay has not experienced any collection issues with its current common stream and facility operators.

Joint operations receivables are typically collected within two to three months of the joint operations billing being issued to the partner. InPlay mitigates collection risk from joint operations receivables by obtaining partner approval of significant capital and operating expenditures prior to expenditure and, in certain circumstances, may collect cash deposits in advance of incurring financial obligations on behalf of joint operations partners. Joint operations receivables are from partners in the petroleum and natural gas industry who are subject to the risks and conditions of the industry. Significant changes in industry conditions and risks that negatively impact partners' ability to generate cash flow will increase the risk of not collecting joint operations receivables.

The Company does not typically obtain collateral from oil and natural gas customers or joint interest partners; however, the Company does have the ability to withhold production from joint interest partners in the event of non-payment. In addition, the Company has approximately $1.4 million in amounts owing to oil and natural gas customers or joint interest partners that could be withheld if collection issues were to occur.

Trade and other receivables are non–interest bearing and are generally on 25 to 90 day terms. The Company's expected credit loss as at December 31, 2021 was $0.4 million (December 31, 2020 – $0.2 million). The Company has considered the impact of the COVID-19 outbreak and the resulting volatility to commodity prices on the expected credit loss of the Company and has not noted a significant impact.

In determining the recoverability of trade and other receivables, InPlay considers the type and age of the outstanding receivables, the credit risk of the counterparties, and the recourse available to InPlay. The maximum exposure to credit risk for accounts receivable and accruals, net of expected credit loss at the reporting date by type of customer was:

	Carrying Amount	
($'000s)	**December 31, 2021**	December 31, 2020
Oil and natural gas customers	**$ 11,325**	$ 4,227
Joint operations partners	**4,573**	916
Accruals & Other	**1,013**	1,126
Total	**$ 16,911**	$ 6,269

The Company applies the simplified approach to providing for expected credit losses as prescribed by IFRS 9, which permits the use of lifetime expected loss provision for all accounts receivable and accrued receivables. The expected credit losses below also incorporate forward looking information.

As of December 31, 2021 and December 31, 2020, the Company's accounts receivable and accrued receivables was aged as follows:

Aging **($'000s)**	**December 31, 2021**	December 31, 2020
0 – 30 days	**13,975**	5,093
30- 90 days	**1,507**	292
Greater than 90 days	**1,836**	1,084
Expected credit loss	**(407)**	(200)
Total	**$ 16,911**	$ 6,269

The Company considers amounts outstanding greater than 90 days to be past due. Receivables normally collectible within 30 to 60 days can take longer as information requests and timing can come into effect in dealing with receivables from joint venture partners. At December 31, 2021 $1.8 million (December 31, 2020 – $1.1 million) in receivables were over 90 days due and considered past due.

Cash and cash equivalents, when held, consist of cash bank balances and short-term deposits which all mature in less than 90 days. InPlay only invests cash and enters into short-term deposits and derivative contracts with large established Canadian banks and avoids complex investment vehicles with higher risk.

20(c) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The impacts of the COVID-19 outbreak and the resulting decreases to commodity prices has increased the liquidity risk of the Company. The Company's objective is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due.

To achieve this objective, the Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. The Company uses authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures.

To provide capital when needed, the Company has a $85 million Senior Credit Facility which is reviewed semi-annually by its lenders and a $25 million term loan with the BDC. The Senior Credit Facility and BDC Term Facility are described further in note 10.

The Company also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month.

The following are the contractual maturities of non-derivative financial liabilities at December 31, 2021:

($'000s)	Less than one year	One to two years	Two to three years
Non-derivative financial liabilities:			
Accounts payable and accrued liabilities	$ 24,669	$ -	$ -
Bank loans – principal[1]	52,863	-	25,000
Bank loans – interest[2][3]	3,540	1,882	3,015
Bank loans – fees[4]	313	375	-
Total	$ 81,385	$ 2,257	$ 28,015

(1) Assumes the revolving portion of the Senior Credit Facility is not renewed on May 30, 2022, whereby outstanding balances become due on May 30, 2022, the Senior Term Loan is payable on November 30, 2022 and the BDC Term Facility is payable on October 30, 2024.

(2) Assumes interest is incurred on bank debt outstanding on the revolving portion of the Senior Credit Facility at December 31, 2021 at the Company's effective interest rate during the current quarter and the principal of the revolving portion of the Senior Credit Facility is repaid May 30, 2022 and the principal balance of the Senior Term Facility is repaid as follows: (i) $6 million by May 31, 2022; (ii) $7 million by August 31, 2022; and (iii) $7 million by November 30, 2022.

(3) Assumes interest is incurred on the BDC Term Facility outstanding at December 31, 2021 at the interest rates prescribed in the term facility agreement, with interest in the first year added to the principal balance of the BDC Term Facility to be repaid on October 30, 2024.

(4) Annual renewal fees are charged on the full BDC Term Facility amount at a rate of 1.25% at inception, 1% on the first anniversary date, 1.25% on the second anniversary date and 1.5% on the third anniversary date.

The following table shows the break down of the Company's accounts payable and accrued liabilities:

	Carrying Amount	
($'000s)	**December 31, 2021**	December 31, 2020
Trade payables [5]	**$ 16,673**	$ 13,455
Joint operations partners	**2,291**	2,135
Accruals [6]	**5,705**	3,602
Total	**$ 24,669**	$ 19,192

(5) Includes all payables related to operations, including royalties payable.

(6) Accruals include amounts for goods and services that have been received or supplied but have not been paid, invoiced or formally agreed with the supplier as of the reporting date. These accruals relate to both operating and capital activities.

20(d) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: foreign currency risk, commodity price risk and interest rate risk. The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Derivative instruments may be used to reduce exposure to these risks.

(i) Foreign currency exchange rate risk

The Company is exposed to the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. While substantially all of the Company's sales are denominated in Canadian dollars, the market prices in Canada for oil and natural gas are impacted by changes in the exchange rate between the Canadian dollar and the United States dollar. The Company had no forward exchange rate contracts in place as at December 31, 2021.

(ii) Commodity price risk

The Company is exposed to the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. The reference price for buyers and sellers of crude oil relevant to the Company's oil sales is West Texas Intermediate at Cushing, Oklahoma, USA ("**WTI**"), and the reference price for buyers and sellers of natural gas includes deals that are conducted anywhere within TransCanada's Alberta, Canada System, otherwise known as NOVA ("**AECO**"). Commodity prices for petroleum and natural gas are impacted by not only the relationship between the Canadian and United States dollar, as outlined above, but also world economic events and North American processing and supply considerations that influence the levels of supply and demand. The impacts of the COVID-19 outbreak and the resulting decreases to commodity prices has significantly increased volatility of commodity prices and has increased the commodity price risk of the Company.

InPlay manages the risks associated with changes in commodity prices by entering into financial derivative risk management contracts. The Company does not apply hedge accounting for these contracts. The Company does not enter into commodity contracts other than to manage the risk of commodity price fluctuation from the Company's expected commodity sales.

At December 31, 2021 the following commodity-based derivative contracts were outstanding and recorded at estimated fair value.

Type of contract: put[1] (crude oil pricing WTI):

Currency denomination	Volume (bbl/day)	Bought put price	Bought put premium	Term	Fair value ($'000s CAD)
US dollar	1,700	50.00/bbl	1.00/bbl	Jan. 1, 2022 – March 31, 2022	($156)

Type of contract: three-way collar[2] (crude oil pricing WTI):

Currency denomination	Volume (bbl/day)	Sold put price	Bought put price	Sold call price	Term	Fair value ($'000s CAD)
US dollar	1,700	45.00/bbl	50.00/bbl	93.00/bbl	April 1, 2022 – June. 30, 2022	($139)
US dollar	1,400	45.00/bbl	50.00/bbl	100.00/bbl	July 1, 2022 – Nov. 30, 2022	($167)

(1) The WTI three-way collars are a combination high priced sold call, low priced sold put and a mid priced bought put. The high sold call price is the maximum price the Company will receive for the contract volumes. The mid bought put price is the minimum price InPlay will receive, unless the market price falls below the low sold put strike price, in which case InPlay receives market price plus the difference between the mid bought put price minus the low sold put price

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

Currency denomination	Volume (GJ/day)	Average swap price	Term	Fair value ($'000s CAD)
Canadian dollar	1,000	2.30/GJ	December 1, 2021 – March 31, 2022	($131)
Canadian dollar	2,750	3.19/GJ	April 1, 2022 – October 31, 2022	$166

Type of contract: costless collar[3] (natural gas pricing AECO):

Currency denomination	Volume (GJ/day)	Bought put price	Sold call price	Term	Fair value ($'000s CAD)
Canadian dollar	2,000	2.70/GJ	3.36/GJ	Nov. 1, 2021 – March 31, 2022	($92)
Canadian dollar	5,000	2.50/GJ	4.59/GJ	Jan. 1, 2022 – March 31, 2022	($17)
Canadian dollar	2,000	2.50/GJ	3.80/GJ	April 1, 2022 – June 30, 2022	$4
Canadian dollar	2,750	2.50/GJ	3.64/GJ	April 1, 2022 – Oct. 31, 2022	$13
Canadian dollar	5,500	2.25/GJ	4.93/GJ	Nov. 1, 2022 – Nov. 30, 2022	($5)

(2) 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.

The estimated fair value of the financial option contracts has been determined on the amounts the Company would receive or pay for another party to assume the contracts. At December 31, 2021, the Company estimates that it would pay $0.5 million to terminate these contracts.

An increase or decrease of $5.00 per barrel WTI of oil and $0.25 per Mcf AECO of natural gas would decrease the fair value of derivative contracts by $0.8 million and increase the fair value of derivative contracts by $0.7 million respectively as at December 31, 2021.

The fair value of the financial commodity risk management contracts at December 31, 2021 was a liability of $0.5 million (December 31, 2020: $1.3 million).

Subsequent to December 31, 2021 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	4.145/GJ	April 1, 2022 – October 31, 2022

(iii) Interest rate risk

The Company is exposed to the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company's primary exposure is related to its floating interest rate credit facility. The Company estimates that an increase or decrease of 1% in interest rates would result in a change in total annual interest expense on bank debt by approximately $0.7 million for the year ended December 31, 2021 (December 31, 2020 - $0.6 million).

20(e) Capital management

The Company's policy is to maintain a strong capital base for the objectives of maintaining financial flexibility which will allow it to execute an acquisition or to execute on its capital investment program, provide creditor and market confidence and to sustain the future development of the business.

At December 31, 2021, InPlay's capital structure includes shareholders' equity, bank debt and working capital. The Company manages its capital structure by continually monitoring its business conditions, including: changes in economic conditions, the risk profile of its drilling inventory, the efficiencies of past investments, the efficiencies of forecast investments and the timing of such investments, the forecast commodity prices and resulting cash flows.

InPlay's current capital structure is summarized below:

($'000s)		December 31, 2021		December 31, 2020
Bank debt	$	**79,127**	$	63,832
Accounts payable and accrued liabilities		**24,669**		19,192
Accounts receivable and accrued receivables, prepaid expenses and deposits and inventory		**(23,600)**		(9,343)
Net debt		**80,196**		73,681
Shareholders' equity		**189,364**		45,721
Total capitalization	$	**269,560**	$	119,402

In addition to the capital structure described above, internally generated adjusted funds flow also contributes to the Company's ability to maintain financial flexibility. Adjusted funds flow is calculated as funds flow before transaction and integration costs and decommissioning expenditures. Adjusted funds flow for the years ended December 31, 2021 and December 31, 2020 is as follows:

($'000s)		December 31, 2021		December 31, 2020
Funds flow	$	**44,100**	$	6,834
Transaction and integration costs		**1,495**		-
Decommissioning expenditures		**1,433**		602
Adjusted funds flow	$	**47,028**	$	7,436

21. RELATED PARTY TRANSACTIONS

Key management personnel are comprised of all officers and directors of the Company. Compensation of key management personnel was as follows:

($'000s)		December 31, 2021		December 31, 2020
Salaries and bonuses	$	**2,180**	$	2,094
Stock-based compensation – expensed and capitalized		**1,591**		621
Total executive compensation	$	**3,771**	$	2,715

22. COMMITMENTS

22(a) Lease commitments

The Company has the following estimated annual obligations related to various leases. The minimum future payments for these leases are as follows:

($'000s)	2022	2023	2024
Office lease payments	297	263	-
Other leases	47	17	8
Total	344	280	8

22(b) Other commitments

The Company has entered into firm service gas transportation agreements in which the Company guarantees certain minimum volumes of natural gas will be shipped on various gas transportation systems. The terms of the various agreements expire in one to five years. If no volumes were shipped pursuant to the agreements, the maximum amounts payable under the guarantees based on current tariff rates are as follows:

($'000s)	2022	2023	2024	2025	Thereafter
Firm service commitment(1)	616	400	149	84	25

(1) The Company's commitment relating to firm service transportation does not constitute a lease under IFRS 16 given the Company does not obtain substantially all of the economic benefit from the use of the relevant gas transportation systems.