InPlay Oil Corp. Announces its 2018 Financial, Operating and Reserves Results Highlighted by a 22% Increase in Light Oil and Liquids Growth over 2017

March 20, 2019 - Calgary Alberta – InPlay Oil Corp. (TSX: IPO) (OTCQX: IPOOF) ("InPlay" or the "Company") announces its financial and operating results for the three and twelve months ended December 31, 2018, and the results of its independent oil and gas reserves evaluation effective December 31, 2018 (the "Sproule Report") prepared by Sproule Associates Limited ("Sproule"). InPlay's audited annual financial statements and notes, as well as management's discussion and analysis ("MD&A") for the year ended December 31, 2018 will be available shortly on the System for Electronic Document Analysis and Retrieval ("SEDAR") and our website ("www.inplayoil.com").

Message to Shareholders:

InPlay had a strong year in 2018 pursuing a focused light oil growth strategy which also included increasing our land base in both short and long term premier light oil assets. This was achieved without share dilution while maintaining financial flexibility. InPlay achieved organic drill bit light oil and liquids production growth of 22% over 2017 with a capital efficiency of $14,770 per boe/d which we believe is in the top tier among our light oil peers. We successfully grew our Willesden Green land base by adding over 50 net tier one locations effectively replacing five years of drilling inventory. InPlay also added 7,680 acres, a 34% increase, to our land base in the longer term East Duvernay light oil shale play where we have now spent the required capital extending our land tenure four to five years. These long tenured Crown lands allow us to continue to evaluate increasingly positive results from industry delineating the play. InPlay disposed of $27.3 million of non-core facilities and infrastructure as well as non-core, non-operated assets that were producing approximately 250 boe/d in 2018. These dispositions enabled us to increase our position in our top tier plays while also maintaining our strong balance sheet.

Production results and drilling and completion costs continue to exceed our expectations and budget. This was accomplished through strong execution of an efficient, cost effective development program (including drilling pacesetter wells), evolving and optimizing completions utilizing new technology, and smart facility enhancements. This resulted in two increases to our annual production guidance in the second half of 2018 achieving exceptional financial and operational results with a 25% year over year increase in annual operating income to $39.8 million.

The strong performance of the Company's assets, specifically in Willesden Green, resulted in increased year end reserves (volumes and values) across all categories, including reserves sold during the year and the removal of legacy undeveloped gas locations held by InPlay's predecessor entity prior to going public in November 2016. The performance is highlighted by proved developed producing reserves ("PDP") that increased 6% to 8,348 mboe and before tax net present values of future net revenue discounted at 10% ("NPV10 BT") that increased 7% to $139.2 million. The net result is PDP net asset value ("NAV") increased 9% to $2.17 per share while generating solid finding, development, and acquisition ("FD&A") costs of $9.49 per boe, with a recycle ratio of 2.5 times. Total proved plus probable reserves ("TPP") increased 4% and associated NPV10 BT increased 11% to 27,063 mboe and $387.7 million respectively, resulting in a TPP NAV that increased 11% to $5.81 per share. (See section "Net Asset Value" for these NAV calculations).

These results were achieved in light of the extreme negative market factors that affected Canada's crude oil pricing market in the fourth quarter of 2018. Revenues were impacted by reduced West Texas Intermediate ("WTI") pricing, with the peak lows in December at $42.53 per bbl (USD) coupled with significantly widening Edmonton light oil differentials which settled at $34.80 per bbl (USD) in December and averaged $26.30 per bbl (USD) for the quarter. These differentials exacerbated for most of the Canadian oil weighted production companies due to the activities of some large producers who have upstream and downstream operations as well as refiners from the United States, all of whom have the majority of terminal storage, and firm service on pipelines tied up, and in most cases are nominating pipeline volumes above and beyond their producing capacity. InPlay prudently reacted to these deteriorating pricing scenarios by delaying the completions and tie-in of two horizontal wells that were drilled in 2018 to the first quarter of 2019 when we saw the crude oil pricing and differential situation start to improve.

Commodity pricing has quickly corrected positively in the first quarter of 2019 with WTI prices currently at approximately $59.00 per bbl (USD) and Edmonton differentials settling back to more normalized levels in the $4.00-$6.00 per bbl (USD) range. The result for InPlay is that we expect the first quarter of 2019 to be one of our best financial and operational quarters in our history. The solid start to 2019 with pricing and operational results from our capital program has us confirming guidance for the year, which we anticipate will result in top tier organic light oil and liquids growth among our light oil peers of 6 to 10 percent on annual production and 10 to 14 percent on exit production while spending approximately adjusted funds flow from operations.

The Company has continued to evolve by increasing our exposure to two high quality and focused plays. The current high return, quick payout light oil Cardium growth play, and the evolving longer term light oil East Basin Duvernay shale play. This transformation has put us in a much stronger position than when InPlay went public in November of 2016 and places us in an enviable position as a sustainable Canadian Junior Light Oil Exploration & Production ("E&P") producer with the ability to show top tier growth in this current volatile environment.

Financial and Operating Results:

(CDN$) (000's)	**Three months ended Dec 31**		**Year ended Dec 31**	
	2018	**2017**	**2018**	**2017**
Financial (CDN $)				
Petroleum and natural gas revenue	12,716	18,017	76,419	62,239
Cashflow provided by operating activities	4,536	6,460	30,411	22,552
Per share – basic and diluted	0.07	0.10	0.45	0.36
Per boe	9.82	16.78	17.91	15.56
Adjusted Funds flow from operations(1)	1,721	8,043	27,040	24,974
Per share – basic and diluted(1)	0.03	0.13	0.40	0.40
Per boe(1)	3.73	20.90	15.92	17.23
Comprehensive (Loss)	(7,887)	(6,939)	(8,598)	(7,701)
Per share – basic and diluted	(0.12)	(0.11)	(0.13)	(0.12)
Exploration and Development Capital expenditures	6,954	26,992	50,206	49,224
Property Acquisitions (Dispositions)	(17,305)	(152)	(21,470)	1,067
(Net Debt) (1)	(53,670)	(51,266)	(53,670)	(51,266)
Shares outstanding	68,256,616	67,886,619	68,256,616	67,886,619
Basic & Diluted weighted-average shares	67,987,162	63,875,582	67,911,962	62,688,280

(CDN$) (000's)	Three months ended Dec 31		Year ended Dec 31	
	2018	**2017**	**2018**	**2017**
Daily production volumes				
Crude oil (bbls/d)	2,937	2,503	2,756	2,310
Natural gas liquids (bbls/d)	573	371	492	352
Natural gas (Mcf/d)	9,065	7,866	8,431	7,857
Total (boe/d)	5,021	4,185	4,653	3,972
Realized prices				
Crude Oil & NGLs ($/bbls)	35.09	62.81	60.49	57.02
Natural gas ($/Mcf)	1.66	1.95	1.53	2.38
Total ($/boe)	27.53	46.79	45.00	42.93
Operating netbacks ($/boe) (1)				
Oil and Gas sales	27.53	46.79	45.00	42.93
Royalties	(2.43)	(4.58)	(4.72)	(4.32)
Transportation expense	(1.00)	(0.50)	(0.83)	(0.62)
Operating costs	(15.26)	(15.40)	(16.02)	(16.10)
Operating Netback (prior to realized derivative contracts)	8.84	26.31	23.43	21.89
Realized gain (loss) on derivative contracts	(0.66)	0.43	(2.42)	0.77
Operating Netback (including realized derivative contracts)	8.18	26.74	21.01	22.66

(1) "Adjusted funds flow from operations", "Net Debt" and "Operating netback per boe" do not have a standardized meaning under International Financial Reporting standards (IFRS) and GAAP. "Adjusted funds flow from operations" adjusts for decommissioning obligation expenditures and net change in operating non-cash working capital from net cash flow provided by operating activities. Please refer to "Non-GAAP Financial Measures" and "BOE equivalent" at the end of this news release and to the section entitled "Non-GAAP Measures" in our MD&A for details of calculations, rationale for use and applicable reconciliation to the nearest IFRS measure.

2018 Financial & Operating Highlights:

- The transformation of InPlay continued with strategic acquisitions and dispositions activity throughout the year. Premier lands were added to our focused light oil core asset base while maintaining a strong balance sheet. This effective activity was the driver that allowed us to increase our production guidance twice in the second half of 2018 and includes the following:

    - Acquired 6,059 net acres in Q1/2018 in Willesden Green for consideration of $5.5 million which added an additional 50 net tier one drilling locations. 12 (8.6 net) wells have been drilled to date with results that have exceeded our expectations.
    - Sold our 100% interest in a non-core natural gas facility and associated infrastructure for $10 million in the Q1/2018 of which InPlay was only using 14% of the throughput capacity.
    - Disposed of predominantly non-operated, non-core assets in West Pembina producing 250 boe/d for premium market valuation proceeds of $16.6 million in Q4/2018.

- Capital efficiencies of $14,770 per boe/d were achieved on exploration and development capital spent on drilling, completions, equipping and facilities. The majority of capital was spent in Willesden Green where we drilled 16 (11.2 net) horizontal wells, and in the Duvernay where a 100% vertical stratigraphic test well was drilled (that has been abandoned) and completion of the horizontal well drilled in 2017.

- Annual 2018 light oil and liquids growth is up 22% to 3,248 bbl/day over 2017 reflecting the focused development of our light oil and liquids assets. Annual average 2018 production is up 17% over 2017 to 4,653 boe/day exceeding corporate guidance of 4,600 boe/d day. Production per weighted average basic share increased 8% in 2018 over 2017 and all of the growth was achieved while disposing of 250 boe/d on October 1, 2018 and with the deferral of completions of two horizontal wells drilled in the fourth quarter of 2018 to first quarter of 2019.

- Average fourth quarter 2018 light oil and liquids production is up 22% over fourth quarter 2017 to 3,510 bbl/day, reflecting our focus on our light oil weighted Cardium assets. Fourth quarter 2018 production was up 20% over the fourth quarter 2017 to 5,021 boe/day representing per weighted average share growth of 13%.

- Significant growth occurred in production and reserves in our core Willesden Green area.
  - Production grew 107% to over 3,000 boe/day for Q4/2018 compared to just over 1,400 boe/day in Q4/2017 with light oil and liquids weighting of 73%.
  - Year end PDP, TP and TPP reserves grew 54%, 59% and 50% to 4,124 mboe, 9,035 mboe and 12,055 mboe respectively.

- Annual revenues increased by 23% to $76.4 million (94% derived from crude oil and natural gas liquids) resulting in operating income profit margins(1) of 52% in 2018.

- Operating income(1) increased by 25% to $39.8 million in 2018 and operating netbacks per boe(1) increased by 7% to $23.43 per boe in 2018 backed by increased oil and liquid weightings, stronger prices and reduced operating costs. This was accomplished even with the extreme market factors affecting crude commodity pricing in the fourth quarter which resulted in operating netbacks of $8.84 per boe versus $28.88 per boe achieved in the first three quarters of 2018.

- Adjusted funds flow from operations(1) increased by 8% to $27.0 million year over year in 2018. This would have increased by 31% to $31.2 million without hedging gains and losses on derivative contracts over the years and results would have been much higher without the severe crude commodity price environment in the fourth quarter.

- Strategic Crown land holdings in the East Duvernay light oil shale play increased by 12 sections for consideration of $1.4 million in the year. The Company now has a significant land position in one of the most exciting new Canadian light oil plays with 30,640 net acres (48.25 net sections). An independent report was prepared for InPlay on this land by qualified land evaluators, Seaton-Jordan & Associates, which resulted in a value of $49.6 million at year-end. (See the section entitled "Net Asset Value").

(1) Non-GAAP term. See "Non-GAAP Financial Measures" section.

2018 Capital and Operating Overview:

InPlay executed a $50.2 million capital program during 2018, focused on the Willesden Green bioturbated Cardium formation. The Company drilled 12 (8.6 net) extended reach horizontal ("ERH") wells and 4 (2.6 net) one-mile horizontal wells. The final two Cardium completions were deferred from October of 2018 into 2019 to avoid the poor fourth quarter 2018 Canadian oil prices and add value by selling the flush production period into a time frame with improved pricing. In aggregate, InPlay drilled an equivalent of 23.0 (16.5 net) horizontal miles. The Company completed one Duvernay horizontal well during the second quarter of 2018 and drilled one vertical stratigraphic Duvernay test well in the fourth quarter. By drilling these wells our land tenure has been extended between four to five years. The Company also acquired an additional 12 sections of undeveloped Crown land in the Duvernay area.

InPlay's focus on developing the Willesden Green bioturbated Cardium assets continued to deliver exceptional results with production volumes and rates consistently exceeding internal estimates. We believe InPlay is delivering top tier capital efficiencies with its capital program where we have managed to achieve some of the shortest spud to rig release days for ERH wells seen to date in the area. Our most recent six 1.5 mile ERH wells have averaged 9.7 drilling days. We have also achieved very consistent drilling performance whereby the maximum deviation from average drilling time of the six 1.5 mile ERH wells has been +/- 0.7 days. Our 1.5 mile ERH wells allow us to access approximately 60% more reservoir while incurring only 20% more in additional capital expenditures compared to a one mile horizontal well. These factors drove improved capital efficiencies on our 2018 capital program to approximately $14,770 per boe/d.

2018 Reserve Highlights:

InPlay's strong operational results translated into growth in 2018 year-end reserves across all three categories: proved developed producing reserves ("PDP"), total proved reserves ("TP") and total proved plus probable reserves ("TPP"). These results were achieved even with the reduction of reserves following the October 1, 2018 non-core asset disposition of 579 mboe ($12.0 mm NPV 10 BT) of PDP, 1,817 mboe ($24.5 mm NPV 10 BT) of TP and 2,290 mboe ($34.4 mm NPV 10 BT) of TPP. There was also the elimination of 1,453 mmcf of TP and 2,503 mmcf of TPP respectively associated with legacy undeveloped gas reserves held over from InPlay's predecessor company.

The Company increased year end net present reserve values resulting in higher year end corporate net asset values ("NAV") across all categories: Total PDP NPV 10 BT NAV increased 9% year over year to $2.17 per basic share, TP NPV 10 BT NAV increased 16% to $3.83 per basic share and TPP NPV 10 BT NAV increased 11% year over year to $5.81 per basic share. These increases materialized inclusive of a significant reduction in year-end natural gas price deck and with the previously mentioned dispositions. Following are the yearend reserve highlights:

Reserve Increases:

- PDP Increased 6% to 8,348 mboe (oil & liquids 66%)
- TP increased 8% to 18,859 mboe (oil & liquids 71%)
- TPP increased 4% to 27,063 mboe (oil & liquids 73%)

  **Year end reserves include Proved developed non-producing reserves ("PDNP") of 436.2 mboe attributable to the two deferred Willesden Green wells completed in January 2019.*

Finding and Development ("FD") and Finding Development & Acquisition ("FD&A") Costs per boe[1]:

- PDP FD&A costs were $9.49 and F&D costs were $17.80
- TP FD&A costs were $16.94 and F&D costs were $16.58
- TPP FD&A costs were $15.96 and F&D costs were $14.88

Recycle Ratios[1]:

- PDP was 2.5 times
- TP was 1.4 times
- TPP was 1.5 times

Reserve Values (BT discounted at 10%):

- PDP value increases 7% to $139 mm and per share net asset value increased 9% to $2.17[2].
- TP value increases 16% to $252 mm and per share net asset value increased 16% to $3.83[2].
- TPP value increases 11% to $388 mm and per share net asset value increased 11% to $5.81[2].
- Results accomplished with Sproule's overall AECO spot gas price deck dropping 37%, 33% and 21% in years 1, 2 and 3 respectively and 18% for the remaining years thereafter, compared to its 2017 year-end price deck, as well as the significant disposition in reserves, and revisions of the legacy gas assets that will not be drilled.
  **Year end reserves include PDNP NPV 10 BT reserve values of $9.4 mm attributable to the two deferred Willesden Green wells completed in January 2019.*

Reserve Replacement[1]:

- PDP replacement was 126%
- TP replacement was 182%
- TPP replacement was 158%

Sustainability[1]:

- PDP reserve life index of 4.9 years
- TP reserve life index of 11.1 years
- TPP reserve life index of 15.9 years

Strong Willesden Green Reserves Results:

- PDP increased 54% to 4,124 mboe with 66% liquids content
- TP increased 59% to 9,035 mboe with 71% liquids content
- TPP increased 50% to 12,055 mboe with 71% liquids content
- PDP NPV 10 BT reserves value increased 60% to $78.9 mm
- TP NPV 10 BT reserve value increased 68% to $128.8 mm
- TPP NPV 10 BT reserve value increased 56% to $180.0 mm
- Reserve Replacement was 269% (PDP), 489% (TP) and 571% (TPP)

Notes:

1. *Refer to section "Performance Measures" for the determination of these measures' calculations*
2. *Refer to section "Net Asset Value" for the determination of these values.*

Corporate Reserves Information:

The following summarizes certain information contained in the Sproule Report. The Sproule Report was prepared in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") and National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Additional reserve information as required under NI 51-101 will be included in the Company's Annual Information Form ("AIF") which will be filed on SEDAR by the end of March 2019.

December 31, 2018 **Reserves Category(2)(3)(4)(5)**	**Crude Oil & NGLs(1) Mbbl**	**Conventional Natural Gas MMcf**	**Oil Equivalent MBOE**	**BTAX NPV 10% ($000's)**	**Future Development Capital ($000's)**	**Net Undeveloped Wells Booked**
Proved developed producing	5,477.7	17,222	8,348.0	139,214	-	-
Proved developed non-producing	380.6	334	436.2	9,430	-	-
Proved undeveloped	7,541.9	15,195	10,074.5	103,810	185,656	88.1
Total proved	13,400.3	32,751	18,858.8	252,454	185,656	88.1
Probable developed producing	1,429.9	4,351	2,155.1	25,467	-	-
Probable developed non-producing	96.4	130	117.9	2,374	-	-
Probable undeveloped	4,717.1	7,287	5,931.6	107,387	53,918	25.2
Total probable	6,243.4	11,767	8,204.6	135,228	53,918	25.2
Total proved plus probable(6)	19,643.7	44,518	27,063.4	387,682	239,574	113.3

Notes:

1. *"Oil & NGL" reserves include all light crude oil & medium crude oil volumes, and natural gas liquids volumes.*
2. *Reserves have been presented on gross basis which are the Company's total working interest (operating and non-operating) share before the deduction of any royalties and without including any royalty interests of the Company.*
3. *Based on Sproule's December 31, 2018, escalated price forecast as outlined in the table herein entitled "Pricing Assumptions".*
4. *It should not be assumed that the net present value of estimated future net revenue ("NPV") presented in the tables above represents the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of InPlay's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.*
5. *All future net revenues are stated prior to provision for interest, general and administrative expenses and after deduction of royalties, operating costs, estimated well abandonment and reclamation costs and estimated future capital expenditures. Future net revenues have been presented on a before tax basis.*
6. *Totals may not add due to rounding.*

Net Asset Value:

December 31, 2018

	BTAX NPV 5%		BTAX NPV 10%	
	($000's)	**$/share[5]**	**($000's)**	**$/share[5]**
PDP NPV[1][2]	164,259	2.41	139,214	2.04
Undeveloped acreage[3]	62,515	0.92	62,515	0.92
Net debt[4]	(53,671)	(0.79)	(53,671)	(0.79)
Net Asset Value (basic)	173,103	2.54	148,058	2.17

December 31, 2018

	BTAX NPV 5%		BTAX NPV 10%	
	($000's)	**$/share[5]**	**($000's)**	**$/share[5]**
TP NPV[1][2]	326,610	4.79	252,454	3.70
Undeveloped acreage[3]	62,515	0.92	62,515	0.92
Net debt[4]	(53,671)	(0.79)	(53,671)	(0.79)
Net Asset Value (basic)	335,454	4.91	261,298	3.83

December 31, 2018

	BTAX NPV 5%		BTAX NPV 10%	
	($000's)	**$/share[5]**	**($000's)**	**$/share[5]**
TPP NPV[1][2]	515,075	7.55	387,682	5.68
Undeveloped acreage[3]	62,515	0.92	62,515	0.92
Net debt[4]	(53,671)	(0.79)	(53,671)	(0.79)
Net Asset Value (basic)	523,919	7.68	396,526	5.81

Notes:

1. *Evaluated by Sproule as at December 31, 2018. The estimated net present value of future net revenue ("NPV") does not represent fair market value of the reserves.*
2. *Based on Sproule's forecast prices and costs as of December 31, 2018.*
3. *Duvernay land holdings evaluated by independent third party firm Seaton-Jordan Partners effective December 31, 2018 attributed a value of $49.6 mm ($1,619/acre) for 30,720 net acres. The remaining undeveloped acreage is based on an internal valuation totaling $12.9 mm ($256/acre) for 50,522 net acres.*
4. *Net debt as at December 31, 2018..*
5. *Based upon 68,256,616 total common shares outstanding as at December 31, 2018.*

Future Development Costs ("FDCs"):

FDCs increased by $32.0 million on a proved basis and $22.5 million on a proved plus probable basis due to the addition of 10.9 (TP) and 4.9 (TPP) locations as well as a shift to more extended reach drilling locations. Following is a summary of the estimated FDC required to bring InPlay's undeveloped reserves on production.

Future Development Capital Costs (amounts in $000,000's)

	Total Proved	Total Proved + Probable
2019	39.7	40.6
2020	58.5	67.0
2021	42.9	57.5
2022	44.6	56.9
Remainder	-	17.6
Total undiscounted FDC	185.7	239.6
Total discounted FDC at 10% per year	155.2	194.4

Note: FDC as per Sproule Report based on Sproule forecast pricing as at December 31, 2018

Performance Measures:

	2016	2017	2018	3 Year Avg
Average crude oil price WTI US$/bbl	43.32	50.95	64.76	53.00
E&D Capital ($000's)(2)	10,251	40,679	20,251	-
Production boe/day – Full Year	1,940	3,972	4,653	3,522
Production boe/day – Q4	2712	4,185	5,021	3,973
Operating netback $/boe – FY(1)	17.57	21.89	23.43	21.79
Proved Developed Producing				
Total Reserves mboe	7,304	7,911	8,348	7,854
Reserves additions mboe	4,907	2,057	2,135	3,033
FD&A (including FDCs) $/boe(2)	18.12	19.77	9.49	16.47
FD&A (excluding FDCs) $/boe(2)	18.12	19.77	9.49	16.47
Recycle Ratio(3)	1.0	1.1	2.5	1.3
Reserves Replacement(4)	691%	142%	126%	236%
RLI (years)(5)	7.3	5.2	4.9	5.6
Total Proved				
Total Reserves mboe	16,579	17,473	18,859	17,637
Reserves additions mboe	11,512	2,345	3,084	5,647
FD&A (including FDCs) $/boe(2)	14.13	27.88	16.94	16.54
FD&A (excluding FDCs) $/boe(2)	7.72	17.35	6.57	8.84
Recycle Ratio(3)	1.2	0.8	1.4	1.3
Reserves Replacement(4)	1,622%	162%	182%	439%
RLI (years)(5)	16.6	11.4	11.1	12.5
Proved Plus Probable				
Total Reserves mboe	24,486	26,084	27,063	25,878
Reserves additions mboe	16,456	3,048	2,678	7,394
FD&A (including FDCs) $/boe(2)	11.54	26.17	15.96	14.08
FD&A (excluding FDCs) $/boe(2)	5.40	13.35	7.56	6.75
Recycle Ratio(3)	1.5	0.8	1.5	1.6
Reserves Replacement(4)	2,318%	210%	158%	575%
RLI (years)(5)	24.5	17.1	15.9	18.4

In 2018, InPlay's successful exploration, development and acquisition/disposition capital program achieved a capital efficiency of $14,770 per boe/d.[6]

Notes:

1. *Operating Netback per boe excludes realized gains/ (losses) on commodity derivative contracts. See "Non-GAAP Financial Measures".*
2. *Finding, Development & Acquisition ("FD&A") costs are used as a measure of capital efficiency. The calculation includes the period's capital expenditures, including Exploration and Development ("E&D") expenditures less capitalized G&A expenses adjusted to exclude undeveloped Duvernay land expenditures acquired with no reserves adjusting for "Acquisition Capital" to exclude in 2018, (and include in 2017) capital expended for acquisitions with effective dates in 2017 but which closed post December 31, 2017 and are included in December 31, 2017 reserves. This total of capital expenditures, including the change in the FDC over the period, is then divided by the change in reserves, other than from production, for the period incorporating additions/reductions from extensions, infill drilling, technical revisions, acquisitions/dispositions and economic factors. For example: 2018 TPP = ($50.2 mm E&D - $1.3 mm capitalized G&A - $1.4 mm of Duvernay Crown land acquisitions – $21.5 mm net acquisition/disposition capital -$5.7 mm post December 31, 2017 acquisition capital +$22.5 mm FDC) / (27,063 mboe – 26,084 mboe + 1,698 mboe) = $15.96 per boe. Finding and Development Costs ("F&D") are calculated the same as FD&A costs, however adjusted to exclude the capital expenditures and reserve additions/reductions from acquisition/disposition activity. The -$21.5 mm and -$5.7 of acquisition/disposition capital mentioned above is excluded as well as the corresponding 2,021 mboe of TPP net reserves reduced through acquisitions/dispositions is excluded from the change in reserves in the calculation. See "Non-GAAP Measures".*
3. *Recycle Ratio is calculated by dividing the year's operating netback per boe by the FD&A costs for that period. For example: 2018 TPP = ($23.43/$15.96) = 1.5. The recycle ratio compares netback from existing reserves to the cost of finding new reserves and may not accurately indicate the investment success unless the replacement reserves are of equivalent quality as the produced reserves. See Non-GAAP Measures.*
4. *The reserves replacement ratio is calculated by dividing the yearly change in reserves before production by the actual annual production for that year. For example: 2018 TPP = (27,063 mboe -26,084 mboe + 1,698 mboe) / 1,698 mboe = 158%, which reflects the extent to which the Company was able to replace production and add reserves throughout the year. See Non-GAAP Measures.*
5. *RLI is calculated by dividing the reserves in each category by the 2018 average annual production. For example 2018 TPP = (27,063 mboe) / (4,653 boe\day) = 15.9 years. See Non-GAAP Measures.*
6. *Capital Efficiency is calculated as the total annual exploration & development and acquisition and disposition capital expended in the year, less capitalized G&A and land acquisition costs divided by production additions comparing the fourth quarter of 2018 to 2017 using a decline rate of 22% over the course of the year, calculated as follows: ($50.2 mm E&D capital - $21.5 mm acquisition/disposition capital - $1.3 mm capitalized G&A - $1.4 mm of Duvernay Crown land acquisitions) / (Q4/2018 production of 5,021 boe/d – Q4/2017 production of 4,185 boe/d + 2018 declined production at 22% of 921 boe/d).*

Pricing Assumptions:

The following tables set forth the benchmark reference prices, as at December 31, 2018, reflected in the Sproule Report. These price assumptions were provided to InPlay by Sproule and were Sproule's then current forecast at the effective date of the Sproule Report.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS [1]
as of December 31, 2018
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/Bbl)	Canadian Light Sweet 40º API ($Cdn/Bbl)	Cromer LSB 35º API ($Cdn/Bbl)	Natural Gas AECO-C Spot ($Cdn/ MMBtu)	NGLs Edmonton Propane ($Cdn/Bbl)	NGLs Edmonton Butanes ($Cdn/Bbl)	Edmonton Pentanes Plus ($Cdn/Bbl)	Operating Cost Inflation Rates %/Year	Capital Cost Inflation Rates %/Year	Exchange Rate [2] ($Cdn/$US)
Forecast[3]										
2019	63.00	75.27	75.27	1.95	30.27	40.91	75.32	0.0%	0.0%	0.770
2020	67.00	77.89	76.89	2.44	34.51	50.25	80.00	2.0%	2.0%	0.800
2021	70.00	82.25	81.25	3.00	38.15	56.88	83.75	2.0%	2.0%	0.800
2022	71.40	84.79	83.79	3.21	39.64	58.01	85.50	2.0%	2.0%	0.800
2023	72.83	87.39	86.39	3.30	40.62	59.17	87.29	2.0%	2.0%	0.800
2024	74.28	89.14	88.14	3.39	41.62	60.36	89.11	2.0%	2.0%	0.800
2025	75.77	90.92	89.92	3.49	42.64	61.56	90.96	2.0%	2.0%	0.800
2026	77.29	92.74	91.74	3.58	43.68	62.79	92.86	2.0%	2.0%	0.800
2027	78.83	94.60	93.60	3.68	44.75	64.05	94.79	2.0%	2.0%	0.800
2028	80.41	96.49	95.49	3.78	45.83	65.33	96.76	2.0%	2.0%	0.800
2029	82.02	98.42	97.42	3.88	46.94	66.64	98.77	2.0%	2.0%	0.800

Thereafter Escalation rate of 2.0%

Notes:

1. *This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.*
2. *The exchange rate used to generate the benchmark reference prices in this table.*
3. *As at December 31, 2018.*

Outlook:

Following the improvements in crude oil price differentials seen at the beginning of 2019, InPlay initiated its 2019 capital program beginning with the completions of the two ERH horizontal Willesden Green wells that were drilled in 2018. We commenced drilling 2.7 net ERH wells in the first quarter of our estimated 9 net horizontal well drilling program budgeted for 2019. All wells drilled in the first quarter have been completed with initial results in line with previous wells which have exceeded our forecasted type curves.

The Company is on track with our focused capital budget of $36 million for the year drilling approximately 9 net ERH wells with the majority being Cardium wells in Willesden Green. The remaining ERH wells are expected to be drilled and brought on production in the second half of 2019. Our 2019 guidance is maintained with annual average production estimated at 4,900 to 5,100 boe/d (approximately 70% oil & liquids) with growth between 6 and 10 percent for oil and liquids, and on a total boe basis, exit production of 5,400 to 5,600 boe/d (70% oil & liquids) with growth between 10 and 14 percent. This guidance is based on realizing an annual average WTI price of $54.00 per bbl (USD), $1.50 per mcf AECO, a foreign exchange ratio of 0.75 CDN/USD and an Edmonton light sweet differential of ($7.50) per bbl (USD). Strengthening WTI crude oil pricing currently at $59 (USD), above our forecast pricing, in addition to the narrowing of Edmonton light sweet differentials to more normalized levels of $4-$6 (USD) are supportive to our capital program matching estimated adjusted funds flow from operations. This program is expected to continue to yield strong returns with anticipated top quartile light oil production growth amongst our light oil weighted peers.

We thank our employees and directors for their ongoing commitment and dedication and we thank all of our shareholders for their continued interest and support. We are excited about the strong operational results we have achieved to date and look forward to reporting our first quarter 2019 financial and operating results from our ongoing development program in May.

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Reader Advisories

Non-GAAP Financial Measures

InPlay uses certain terms within this news release that do not have a standardized prescribed meaning under GAAP and these measurements may not be comparable with the calculation of similar measurements of other entities. The terms "Adjusted funds flow from operations", "Adjusted funds flow from operations per share", "Adjusted funds flow from operations per boe", "operating income" , "operating netback per boe" and "Operating income profit margin" in this news release are not defined measures under GAAP and do not have standardized meanings or standardized methods of calculation and therefore may not be comparable to similar measures presented by other companies. Management believes that in addition to net earnings and cash flow provided by operating activities as defined by GAAP, these terms are useful supplemental measures to evaluate operating performance as it demonstrates its field level of profitability relative to current commodity prices and to assess leverage. "Adjusted funds flow from operations" should not be considered as an alternative to or more meaningful than cash flow provided by operating activities as determined in accordance with GAAP as an indicator of the Company's performance. InPlay's determination of adjusted funds flow from operations may not be comparable to that reported by other companies. Adjusted funds flow from operations is calculated by adjusting for changes in operating non-cash working capital and decommissioning expenditures from cash flow provided by operating activities. These items are adjusted from cash flow provided by operating activities as these expenditures are primarily incurred on previous operating assets and there is uncertainty with the timing and payment of these items and they are incurred on a discretionary basis making them less useful in the evaluation InPlay's operating performance. Adjusted funds flow from operations per share is calculated using the same weighted average number of shares outstanding used in calculating earnings per share. For a detailed description of InPlay's method of the calculation of adjusted funds flow from operations and its reconciliation to its nearest GAAP term, see "Non-IFRS Measures" in the Company's MD&A filed on Sedar. The term "net debt" is not recognized under GAAP and is calculated as bank debt plus working capital deficiency adjusted for risk management derivative contract fair values, deferred lease credits, flow-through share premiums and current portion of decommissioning obligation. Net debt is used by management to analyze the financial position and leverage of InPlay. InPlay monitors working capital and net debt as part of its capital structure. Such terms do not have a standardized meaning prescribed by GAAP and, therefore, may not be comparable with the calculation of similar measures for other entities. InPlay also uses "operating income" and "operating netback per boe" as a key performance indicator. Operating income is calculated by the Company as oil and natural gas sales less royalties, operating expenses and transportation expenses and is a measure of the profitability of operations before administrative, share-based compensation, financing and other non-cash items. Management considers operating income an important measure to evaluate its operational performance as it demonstrates its field level profitability. Operating netback per boe is calculated by the Company as operating income divided by average production for the respective period. Management considers operating netback per boe an important measure to evaluate its operational performance as it demonstrates its field level profitability per unit of production. Operating income profit margin is calculated as operating netback as a percentage of oil and natural gas sales. This measure demonstrates the Company's ability to generate field level profitability in relation to sales revenue.

Information Regarding Disclosure on Oil and Gas Reserves and Operational Information

Our oil and gas reserves statement for the year ended December 31, 2017, which will include complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, will be contained within our Annual Information Form which will be available on our SEDAR profile at www.sedar.com on or before March 29, 2019. The recovery and reserve estimates contained herein are estimates only and there is no guarantee that the estimated reserves will be recovered. In relation to the disclosure of estimates for individual properties, such estimates may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. The Company's belief that it will establish additional reserves over time with conversion of probable undeveloped reserves into proved reserves is a forward-looking statement and is based on certain assumptions and is subject to certain risks, as discussed below under the heading "Forward-Looking Information and Statements".

This press release contains metrics commonly used in the oil and natural gas industry, such as "finding, development and acquisition costs", "finding and development costs", "operating netbacks", "recycle ratios" and "recycle ratio", "reserve replacement" and "reserve life index or "RLI". Each of these terms are calculated by InPlay as described in this press release. These terms do not have standardized meanings or standardized methods of calculation and therefore may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included herein to provide readers with additional information to evaluate the Company's performance, however such metrics should not be unduly relied upon.

Finding, development and acquisition costs take into account reserves revisions during the year on a per boe basis. The aggregate of the costs incurred in the financial year and changes during that year in estimated future development costs may not reflect total finding and development costs related to reserves additions for that year. Finding, development and acquisition costs have been presented in this press release because acquisitions and dispositions can have a significant impact on our ongoing reserves replacement costs and excluding these amounts could result in an inaccurate portrayal of our cost structure. Exploration & development capital means the aggregate exploration and development costs incurred in the financial year on exploration and on reserves that are categorized as development. Exploration & development capital excludes capitalized administration costs and exploration costs incurred acquiring Duvernay lands with no reserves assigned Acquisition capital amounts to the total amount of cash and share consideration net of any working capital balances assumed with an acquisition on closing.

Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare InPlay's operations over time, however such measures are not reliable indicators of InPlay's future performance and future performance may not be comparable to the performance in prior periods.. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this press release, should not be relied upon for investment or other purposes, however such measures are not reliable indicators on InPlay's future performance and future performance may not be comparable to the performance in prior periods.

Test results and initial or short term production rates disclosed herein may not necessarily be indicative of long term performance of ultimate recovery. Initial production rates disclosed herein, particularly those short in duration, may not be indicative of long term performance or of ultimate recovery.

Forward-Looking Information and Statements

This news release contains certain forward–looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "project", "should", "believe", "plans", "intends" "forecast" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this news release contains forward-looking information and statements pertaining to the following: the recognition of significant additional reserves under the heading "Corporate Reserves Information", the future net value of InPlay's reserves, the future development capital and costs, the life of InPlay's reserves and the net asset values disclosed under the heading "Net Asset Value" including the value ascribed to undeveloped acreage; the volume and product mix of InPlay's oil and gas production; production estimates including 2019 annualized and exit forecasts; targeted production growth; future oil and natural gas prices and InPlay's commodity risk management programs; future liquidity and financial capacity; future results from operations and operating metrics including forecasts of operating netbacks, adjusted funds flow and net debt ratios; future costs, expenses and royalty rates; future interest costs; the exchange rate between the $US and $Cdn; future development, exploration, acquisition, development and infrastructure activities and related capital expenditures, including our 2019 capital budget, and the timing thereof; the number of wells to be drilled, completed and tied-in and the timing thereof; the amount and timing of capital projects; the resource potential of our Duvernay play and the land value ascribed therto; and methods of funding our capital program. Forward-looking statements or information are based on a number of material factors, expectations or assumptions of InPlay which have been used to develop such statements and information but which may prove to be incorrect. Although InPlay believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because InPlay can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified herein, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which InPlay operates; the timely receipt of any required regulatory approvals; the ability of InPlay to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects in which InPlay has an interest in to operate the field in a safe, efficient and effective manner; the ability of InPlay to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and cost of pipeline, storage and facility construction and the ability of InPlay to secure adequate product transportation; future commodity prices; currency, exchange and interest rates; regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which InPlay operates; the ability of InPlay to successfully market its oil and natural gas products.

The forward-looking information and statements included herein are not guarantees of future performance and should not be unduly relied upon. Such information and statements, including the assumptions made in respect thereof, involve known and unknown risks, uncertainties and other factors that may cause actual results or events to defer materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; the potential for variation in the quality of the reservoirs in which we operate; changes in the demand for or supply of our products; unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans of InPlay or by third party operators of our properties, increased debt levels or debt service requirements; inaccurate estimation of our oil and gas reserve and resource volumes; limited, unfavorable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; and certain other risks detailed from time-to-time in InPlay's disclosure documents.

The internal projections, expectation or beliefs underlying InPlay's 2019 capital budget and guidance for 2019 is subject to change based on ongoing results, prevailing economic circumstances, commodity prices and industry conditions. InPlay's outlook for 2019 and beyond provides shareholders with relevant information on management's expectations for results of operations, excluding any potential acquisitions, dispositions or other strategic transactions that may be completed in 2019 or beyond. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted and InPlay's guidance may not be appropriate for other purposes.

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

BOE equivalent

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