Q2

International Petroleum Corporation

Management's Discussion and Analysis

For the three and six months ended June 30, 2021

International Petroleum Corp.

Contents

Non-IFRS Measures
References are made in this MD&A to "operating cash flow" (OCF), "free cash flow" (FCF), "Earnings Before Interest, Tax, Depreciation and Amortization" (EBITDA), "operating costs" and "net debt" which are not generally accepted accounting measures under International Financial Reporting Standards (IFRS) and do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with definitions of OCF, FCF, EBITDA, operating costs and net debt that may be used by other public companies. Management believes that OCF, FCF, EBITDA, operating costs and net debt are useful supplemental measures that may assist shareholders and investors in assessing the cash generated by and the financial performance and position of the Corporation. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-IFRS measure is presented in this MD&A. See "Non-IFRS Measures" on page 20.

Forward-Looking Statements
Certain statements contained in this MD&A constitute "forward-looking statements" or "forward-looking information" (within the meaning of applicable securities legislation). Such statements and information (together, "forward-looking statements") relate to future events, including the Corporation's future performance, business prospects or opportunities. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, forecasts, guidance, budgets, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "forecast", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", "budget" and similar expressions) are not statements of historical fact and may be "forward-looking statements". Although IPC believes that the expectations and assumptions on which such forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because IPC can give no assurances that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. For additional information underlying forward-looking statements, refer to the "Cautionary Statement Regarding Forward-Looking Information" on page 25.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada are effective as of December 31, 2020, and are included in the reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Sproule's December 31, 2020, price forecasts.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France and Malaysia are effective as of December 31, 2020, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2020, price forecasts.

Certain abbreviations and technical terms used in this MD&A are defined or described under the heading "Other Supplementary Information".

The Covid-19 virus and the restrictions and disruptions related to it have had a material effect on the world demand for, and prices of, oil and gas as well as the market price of the shares of oil and gas companies generally, including the Corporation's common shares. There can be no assurance that these effects will not continue or that commodity prices will not decrease or remain volatile in the future. These factors are beyond the control of the Corporation and it is difficult to assess how these, and other factors, will continue to affect the Corporation and the market price of IPC's common shares. In light of the current situation, as at the date of this MD&A, the Corporation continues to review and assess its business plans and assumptions regarding the business environment, as well as its estimates of future production, cash flows, operating costs and capital expenditures. See "Risks and Uncertainties".

INTRODUCTION

This management's discussion and analysis ("MD&A") for International Petroleum Corporation ("IPC" or the "Corporation" and, together with its subsidiaries, the "Group") is dated August 3, 2021, and is intended to provide an overview of the Group's operations, financial performance and current and future business opportunities. This MD&A should be read in conjunction with IPC's unaudited interim condensed consolidated financial statements and accompanying notes for the three and six months ended June 30, 2021 ("Financial Statements").

Group Overview

The Group is in the business of exploring for, developing and producing oil and gas. IPC holds a portfolio of oil and gas production assets and development projects in Canada, Malaysia and France with exposure to growth opportunities.

The Corporation's common shares are listed on the Toronto Stock Exchange ("TSX") in Canada and the Nasdaq Stockholm Exchange in Sweden. The Corporation is incorporated and domiciled in British Columbia, Canada under the Business Corporations Act. The address of its registered office is Suite 2600, 595 Burrard Street, P.O. Box 49314, Vancouver, BC V7X 1L3, Canada and its business address is Suite 2000, 885 West Georgia Street, Vancouver, BC V6C 3E8, Canada.

Basis of Preparation

The MD&A and the Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

Financial information is presented in United States Dollars ("USD"). However, as the Group operates in Europe and in Canada, certain financial information prepared by subsidiaries has been reported in Euros ("EUR") and in Canadian Dollars ("CAD"). In addition, certain costs relating to the operations in Malaysia, which are reported in USD, are incurred in Malaysian Ringgit ("MYR").

Exchange rates for the relevant currencies of the Group with respect to the US Dollar are as follows:

	June 30, 2021		June 30, 2020		December 31, 2020	
	Average	Period end	Average	Year end	Average	Year end
1 EUR equals USD	1.2057	1.1884	1.1015	1.1198	1.1413	1.2271
1 USD equals CAD	1.2474	1.2388	1.3648	1.3685	1.3412	1.2740
1 USD equals MYR	4.1345	4.1515	4.2519	4.2855	4.2026	4.0209

Q2 2021 HIGHLIGHTS

Business Highlights

- Average net production of approximately 44,600 barrels of oil equivalent (boe) per day (boepd) for the second quarter of 2021 is above the high end of the 2021 Capital Markets Day (CMD) guidance range for the period (42% heavy crude oil, 20% light and medium crude oil and 38% natural gas)[1].
- Full year 2021 average net production forecast revised upwards to above 44,000 boepd[1].
- Operating costs[2] per boe of USD 15.6 for the second quarter of 2021, in line with CMD guidance. Full year guidance revised to USD 15.5 per boe from USD 14.6 per boe.
- Capital and decommissioning expenditures of MUSD 21 for the first six months of 2021, in line with CMD guidance. Full year guidance has been increased to MUSD 73 from MUSD 37 following the addition of drilling projects in Malaysia and Canada in the second half of 2021.
- Exceptionally strong free cash flow (FCF)[2] generation of MUSD 50 for the second quarter of 2021. FCF[2] generation of MUSD 99 for the first six months of 2021, represents close to 13% of IPC's market capitalization as at July 30, 2021.
- Increased working interest in the Bertam field, Malaysia from 75% to 100% from April 10, 2021.
- Production commenced at the new Pad D' at Onion Lake Thermal, Canada ahead of schedule and within budget.
- Proved plus probable (2P) reserves as at December 31, 2020 of 272 million boe (MMboe), with a reserves life index (RLI) of 18 years[1].
- Contingent resources (best estimate, unrisked) as at December 31, 2020 of 1,102 MMboe[1].
- Forecast cumulative FCF[2] for 2021 to 2025 of approximately MUSD 600 to MUSD 1,200 (Brent USD 55 to 75 per barrel) generating estimated average annual free cash flow yield over the five year period of between 16% and 32%[3].

Financial Highlights

	Three months ended - June 30		Six months ended - June 30	
USD Thousands	**2021**	2020	**2021**	2020
Revenue	**144,278**	44,929	**278,562**	125,465
Gross profit / (loss)	**34,286**	(16,537)	**72,216**	(28,973)
Net result	**21,693**	(1,472)	**48,584**	(41,541)
Operating cash flow[2]	**66,959**	14,742	**134,680**	36,223
Free cash flow[2]	**50,366**	717	**99,317**	(41,995)
EBITDA[2]	**65,181**	12,187	**131,444**	31,196
Net Debt[2]	**240,617**	341,367	**240,617**	341,367

- Operating cash flow (OCF)[2] and FCF[2] generation for the second quarter of 2021 amounted to MUSD 67 and MUSD 50 respectively, above the high end of the CMD guidance.
- Full year OCF[2] guidance is revised upwards to between USD 235 million to USD 290 million (actual realized prices for the first half of 2021 and Brent USD 55 to 75 per barrel for the second half of 2021) from USD 165 million to USD 220 million (Brent USD 55 to 65 per barrel).
- Full year FCF[2] guidance is revised upwards to between USD 135 million to USD 195 million (actual realized prices for the first half of 2021 and Brent USD 55 to 75 per barrel for the second half of 2021) from USD 100 million to USD 155 million (Brent USD 55 to 65 per barrel).
- Net debt[2] of MUSD 241 as at June 30, 2021, down from MUSD 286 at the end of the first quarter of 2021.
- Net debt[2] to 12 month rolling EBITDA[2] ratio as at June 30,2021 was below 1.2 times.
- Canadian reserve-based lending facility (RBL) amended and extended until the end of May 2023.
- Net result of MUSD 22 for the second quarter of 2021.

[1] See "Supplemental Information regarding Product Types" in the "Reserves and Resources Advisory" below and the Corporation's annual information form for the year ended December 31, 2020 (AIF), available on the SEDAR website (www.sedar.com) or IPC's website (www.international-petroleum.com).
[2] See definition on page 20 under "Non-IFRS measures".
[3] Free cash flow yield based on IPC market capitalization at July 30, 2021 (41.4 SEK/share, 8.6 SEK/USD, 750 MUSD). Assumptions described below in "Cautionary Statement Regarding Forward-Looking Information" on page 25.

OPERATIONS REVIEW

Business Overview

Market conditions for oil and gas producers have continued to improve during the first half of 2021. Second quarter 2021 average Brent oil price was USD 69 per barrel, in excess of the first quarter 2021 price that averaged just above USD 60 per barrel.

Proactive supply management by the OPEC+ group, led by Saudi Arabia, is rebalancing the market. The International Energy Agency ("IEA") is forecasting a net supply deficit during the second half of 2021 and excess oil inventory levels are reported to have drawn back down below pre-pandemic levels.

The pace of recovery in oil demand is accelerating as we see the easing of restrictions on mobility following the continued roll-out of Covid-19 vaccination programs to the wider population. With demand still not expected to fully recover to pre-Covid-19 levels until next year, and new variants on the rise, continued proactive supply management on the part of OPEC+ members remains crucial. It is encouraging to see the OPEC+ cooperation agreement extended until the end of 2022.

In Canada, second quarter 2021 Western Canadian Select ("WCS") crude price differential averaged below USD 12 per barrel and forward markets into 2022 and 2023 are pricing the WCS differential at around USD 13 per barrel. Clearly the positive construction progress on both Enbridge's Line 3 replacement as well as the TransMountain pipeline expansion project is providing a much more constructive outlook for Canadian oil market egress relative to the tightness we have witnessed over the past five years. IPC has positioned itself well to benefit from this situation.

Gas markets have also been much stronger driven by a combination of increasing demand, lower supply and warmer than average temperatures diverting gas supply away from injecting into storage which could lead to further tightness during winter if cold temperatures prevail.

Given the very strong start to the year, IPC is well placed to deliver results above our high case free cash flow guidance and as a result, we plan to add some additional capital expenditure activities that are expected to enable us to grow production as we move into 2022. Details are set out below in our revised guidance.

In addition, IPC remains opportunistic in our approach with respect to further Mergers and Acquisitions ("M&A") activity and we have witnessed an uptick in activity levels that we anticipate will continue in the months ahead.

Second Quarter 2021 Highlights

During the second quarter of 2021, our assets delivered average net production of 44,600 boepd. This sits above the top end of our guidance range for the second quarter in succession and was largely driven by the very high uptime performance across all our assets as well as increasing our working interest in the Bertam field from 75% to 100% in April 2021. The decision was taken to defer the Bertam turnaround to the third quarter 2021 in order to optimize the planned maintenance activities. Production would have remained above high end guidance had we adjusted for the original second quarter turnaround timing. First half of 2021 production averaged 44,200 boepd.

As a result of the robust production performance in the first half, we are revising upwards our full year guidance to above 44,000 boepd which represents a 1,000 boepd increase above our previous high case guidance. With Pad D' production ramping up at Onion Lake Thermal during the second half of 2021, we expect IPC to exit 2021 with production in excess of 45,000 boepd, some 2,000 boepd higher than our previous guidance.

Our operating costs per boe for the second quarter of 2021 was USD 15.6, in line with guidance. Full year operating costs per boe are expected to increase from USD 14.6 per boe to USD 15.5 per boe to take account of higher energy costs (gas and electricity) and the restart of some higher cost production in Canada.

Operating cash flow generation for the second quarter of 2021 amounted to USD 67 million, stronger than our February 2021 Capital Markets Day ("CMD") high case (Brent USD 65 per barrel) forecast as a result of stronger than forecast production, tighter Canadian crude price differentials and stronger realized Canadian gas prices. This takes our first half operating cash flow generation to USD 135 million or more than 60% of our full year CMD high case.

Full year operating cash flow guidance is now revised upwards to between USD 235 million to USD 290 million (actual realized prices for the the first half of 2021 and Brent USD 55 to 75 per barrel for the second half of 2021) from USD 165 million to USD 220 million (Brent USD 55 to 65 per barrel).

Capital and decommissioning expenditures during the first half of 2021 of MUSD 21 was in line with forecast, representing just below 60% of our originally guided full year expenditure program of USD 37 million.

Following the improved oil and gas prices in 2021, we now believe it is prudent to expand the 2021 program to position IPC to capture some additional high return, quick payback opportunities that are forecast to add production growth as we move into 2022.

As a result, we are increasing our full year 2021 capital expenditure budget by USD 36 million to USD 73 million. In Malaysia, we now plan to drill the A15 sidetrack well in the Bertam field during the fourth quarter 2021. We have also elected to take advantage of having a rig on location to upgrade the size of three Electrical Submersible Pumps ("ESPs") on existing producing Bertam field wells to be able to operate at higher liquid rates as well as to execute other well maintenance activities. In Canada, we plan to drill five infill wells at Onion Lake Thermal as well as to perform optimization work at the Suffield Oil property. Undertaking this activity in the fourth quarter of 2021 is expected to add more than 2,500 boepd of production potential in 2022 which will assist in achieving our forecast five year average production level of 45,000 boepd.

Free cash flow generation was exceptionally strong at USD 50 million during the second quarter 2021 and just below USD 100 million for the first half 2021. This represents close to 13% of IPC's current market capitalization.

Full year 2021 free cash flow guidance is now revised upwards to between USD 135 million to USD 195 million (actual realized prices for the the first half of 2021 and Brent USD 55 to 75 per barrel for the second half of 2021) from USD 100 million to USD 155 million (Brent USD 55 to 65 per barrel). The increased capital program is more than fully funded from excess free cash flow generation. This revised guidance translates into a full year free cash flow yield of between 18 to 26%.

Over the 2021 to 2025 period, we retain our longer term guidance of generating between USD 600 and 900 million of free cash flow with average Brent prices between USD 55 to 65 per barrel. In a more bullish world, with Brent at USD 75 per barrel, our five year cumulative free cash flow would increase to approximately USD 1,200 million. At this level, the entire enterprise value of IPC would be liquidated in less than five years.

Net debt was reduced during the second quarter of 2021 by MUSD 45 to MUSD 241. Net debt to EBITDA drops to below 1.2 times from 3 times at the year-end 2020 (trailing 12 months) or to below 1.0 times on an annualized basis. We have continued to delever through the first half of 2021 and the momentum should continue into next year with the second half of 2021 increased capital program providing additional production growth as we enter 2022.

Environmental, Social and Governance ("ESG") Performance
Health, Safety & Environmental performance remains a priority for all operational assets. Our objective is to reduce risk and eliminate hazards to prevent the occurrence of accidents, ill health and environmental damage, as these are essential to the success of our operations. During the second quarter of 2021, IPC recorded no material safety or environmental incidents.
In response to the Covid-19 pandemic, we remain focused on protecting the health and safety of our employees, contractors and other stakeholders, while also working to ensure business continuity. In the second quarter of 2021, IPC continued the health protocols implemented throughout the organization.

Sustainability Reporting
Responsible operatorship and ensuring that we adhere to the highest principles of business conduct have been an integral part of how we do business since the creation of IPC in 2017. An important part of our sustainability journey involves the measurement and transparent reporting of a broad range of ESG metrics. Alongside the publication of our second quarter 2021 financial report, we are very pleased that IPC is today presenting to our stakeholders our second Sustainability Report.

The Sustainability Report 2020 details the Corporation's ESG performance. The Sustainability Report 2020 advances the Corporation's non-financial sustainability disclosures and provides stakeholders with relevant operational and sustainability context in which IPC operates, as well as the Corporation's management approach and performance with respect to these areas. The report is available on IPC's website at www.international-petroleum.com.

Highlights of IPC's sustainability performance for 2020 include:
- Zero severe incidents
- Lost time incident rate of 0.6 in 2020 vs 1.8 in 2019
- Proactive COVID-19 health and safety management
- On track with our commitment to reducing net GHG emissions intensity by 50% by the end of 2025
- 35,000 tonnes of CO_2e credits generated through emission reduction initiatives
- Doubled carbon offsets compared to 2019 with 100,000 tonnes of CO_2e
- Workforce drawn 99% from local hiring and composed of 29% women
- Meaningful support and engagement with the Onion Lake Cree Nation (OLCN) community and MUSD 12.7 contracted with First Nations businesses
- Support to local communities' mental health programs, including by partnering with the United Way in Canada
- Participation in community projects in Malaysia, including youth internships and coral reef preservation.

We encourage everyone to read the IPC's second Sustainability Report and see first-hand the good work that is being done within our company.

Operations Overview

Reserves and Resources

The 2P reserves attributable to IPC oil and gas assets are 272 MMboe as at December 31, 2020, as certified by independent third party reserves auditors. The reserves life index ("RLI") as at December 31, 2020, is approximately 18 years. Best estimate contingent resources as at December 31, 2020, are 1,102 MMboe (unrisked). See "Reserves and Resources Advisory" below.

IPC initially set a limited capital budget for 2021, with the focus on free cash flow delivery to the business.

At the end of Q2 2021, with strong production performance and improved market conditions strengthening free cash flow, IPC has increased the capital expenditure budget to allow for the planned 2021 execution of the A15 sidetrack well and the production well pump rate optimisation project at Bertam field in Malaysia. In Canada, a five infill well campaign at the Onion Lake Thermal asset is planned for 2021 as well as an oil optimisation project at Suffield. The combined incremental activities are expected to add more than 2,500 boepd of production potential in 2022. IPC remains focused on free cash flow generation and, notwithstanding the inclusion of the incremental capital projects and expenditure, IPC remains on target for free cash flow delivery in excess of our original high end CMD guidance.

Production

The average net production during the second quarter of 2021 was above the high end CMD guidance at 44,600 boepd. Production delivery in Canada was underpinned by strong reservoir performance and high production uptime across all the major producing assets and the successful, on schedule, execution of the planned maintenance shutdown at Onion Lake Thermal. In addition, strong performance from our international assets continued in Q2 2021 with excellent operational performance and facility uptime at the Bertam field in Malaysia and stable production performance in France with optimisation activity continuing to offset natural production declines. The planned maintenance shutdown at the Bertam field in Malaysia was deferred to Q3 2021 to optimise the activities.

With the very strong production performance year to date, and the ramp up of the oil assets in Canada as a result of strengthening Canadian crude oil prices, IPC now expects our 2021 net average production to be above 44,000 boepd, exceeding the high end of our previous guidance range of 41,000 to 43,000 boepd. First half 2021 production averaged 44,200 boepd.

The production during Q2 2021 with comparatives are summarized below:

Production in Mboepd	Three months ended - June 30		Six months ended - June 30		Year ended December 31
	2021	2020	2021	2020	2020
Crude oil					
Canada – Northern Assets	11.2	7.2	11.5	10.3	10.6
Canada – Southern Assets	8.6	5.0	8.7	6.4	7.1
Malaysia	4.8	4.6	4.4	4.6	4.4
France	3.0	1.9	3.0	2.6	2.8
Total crude oil production	**27.6**	18.7	**27.6**	23.9	24.9
Gas					
Canada – Northern Assets	0.1	0.1	0.1	0.1	0.1
Canada – Southern Assets	16.9	16.9	16.5	16.9	17.1
Total gas production	**17.0**	17.0	**16.6**	17.0	17.2
Total production	**44.6**	35.7	**44.2**	40.9	42.1
Quantity in MMboe	**4.06**	3.25	**7.99**	7.44	15.42

See "Supplemental Information regarding Product Types" in "Reserves and Resource Advisory".

CANADA

Production in Mboepd	WI	Three months ended - June 30 2021	Three months ended - June 30 2020	Six months ended - June 30 2021	Six months ended - June 30 2020	Year ended December 31 2020
- Oil Onion Lake Thermal	100%	9.1	7.0	9.6	9.1	9.5
- Oil Suffield	100%	7.5	3.8	7.6	5.1	5.9
- Oil Ferguson	100%	1.1	1.2	1.1	1.3	1.2
- Oil Other	50-100%	2.1	0.2	1.9	1.2	1.1
- Gas	99.7%[1]	17.0	17.0	16.6	17.0	17.2
Canada		**36.8**	29.2	**36.8**	33.7	34.9

[1] *On a well count basis*

Production
Net production from the Canadian assets during Q2 2021 was above the high end of CMD guidance at 36,800 boepd. The strong production performance was underpinned by ahead of expectation production recovery from the N2N Enhanced Oil Recovery ASP (Alkaline Surfactant Polymer) project at the Suffield asset, increased well counts and production ramp up at the Onion Lake Primary and Mooney assets and the on schedule execution of the planned maintenance shutdown at Onion Lake Thermal.

Organic Growth and Capital Projects
In Canada, IPC had originally set a limited capital budget for 2021. IPC continues to mature future development projects, with a significant portfolio of drilling and optimisation opportunities ready for sanction at the discretion of the Group. At the end of Q2 2021, with the strong production performance and improved market conditions strengthening free cash flow, IPC has increased the capital expenditure budget to allow the planned 2021 execution of a five infill well project at the Onion Lake Thermal asset and an oil optimisation project at the Suffield asset.

At Onion Lake Thermal, the production sustaining Pad D' development project was completed ahead of schedule and in line with the approved budget. Three production wells have been brought online with positive initial results. Steam conformance optimisation and production start-up of the remaining three production wells at the Pad D' is expected to be completed ahead of forecast in Q3 2021.

During Q2 2021, production ramp up and testing of the third well pair at the Blackrod SAGD pilot project continued. Heat conformance and production performance remains ahead of expectations.

MALAYSIA

Production in Mboepd	WI	Three months ended - June 30 2021	Three months ended - June 30 2020	Six months ended - June 30 2021	Six months ended - June 30 2020	Year ended December 31 2020
Bertam	100% [1]	4.8	4.6	4.4	4.6	4.4

[1] *100% from April 10, 2021 (75% previously)*

Production
Net production from the Bertam field on Block PM307 during Q2 2021 was ahead of CMD guidance at 4,800 boepd with continued excellent operational performance and facility uptime close to 100%. The Bertam planned maintenance shutdown has been deferred to Q3 2021.

Organic Growth and Capital Projects
In Malaysia, IPC originally set a limited capital budget for 2021. At the end of Q2 2021, with the strong production performance and improved market conditions strengthening free cash flow, IPC has increased the capital expenditure budget to allow the planned 2021 execution of the A15 sidetrack well and the production well pump rate optimisation project. As part of the Bertam maintenance scheduled for Q3 2021, IPC plans to upgrade the FPSO Bertam liquid handling capacity from 17,000 to 24,000 barrels of liquids per day.

FRANCE

Production in Mboepd	WI	Three months ended - June 30		Six months ended - June 30		Year ended December 31
		2021	2020	2021	2020	2020
- Paris Basin	100%[1]	2.6	1.5	2.6	2.2	2.4
- Aquitaine	50%	0.4	0.4	0.4	0.4	0.4
France		3.0	1.9	3.0	2.6	2.8

[1] *Except for the working interest in the Dommartin Lettree field of 43%*

Production

Net production in France during Q2 2021 was ahead of CMD guidance at 3,000 boepd with steady production and good uptime at the major producing fields. In Q2 2021, strong reservoir performance continued at the Vert-la-Gravelle field supported by increased water injection.

Organic Growth

In France, IPC has set a limited capital budget for 2021. IPC continues to mature future development projects in France, with drilling and optimisation opportunities ready for sanction at the discretion of the Group.

FINANCIAL REVIEW

Financial Results

Selected Interim Financial Information

Selected interim condensed consolidated statement of operations is as follows:

USD Thousands	Q2-21	Q1-21	Q4-20	Q3-20	Q2-20	Q1-20	Q4-19	Q3-19
Revenue	**144,278**	134,284	103,353	95,346	44,929	80,536	145,535	131,437
Gross profit	**34,286**	37,930	(60,570)	5,557	(16,537)	(12,436)	43,245	23,487
Net result	**21,693**	26,891	(45,250)	8,850	(1,472)	(40,069)	38,372	6,330
Earnings per share – USD	**0.14**	0.17	(0.29)	0.06	(0.01)	(0.25)	0.23	0.04
Earnings per share fully diluted – USD	**0.14**	0.17	(0.29)	0.06	(0.01)	(0.25)	0.23	0.04
Operating cash flow[1]	**66,959**	67,721	46,019	37,181	14,742	21,481	78,888	69,504
EBITDA[1]	**65,181**	66,263	43,004	34,251	12,187	19,009	77,353	68,885
Net debt at period end[1]	**240,617**	286,132	321,193	322,092	341,367	302,473	231,503	207,778

[1] *See definition on page 20 under "Non-IFRS measures"*

Summarized interim consolidated balance sheet information is as follows:

USD Thousands	June 30, 2021	December 31, 2020
Non-current assets	1,229,390	1,240,653
Current assets	141,494	92,467
Total assets	**1,370,884**	1,333,120
Total non-current liabilities	501,011	527,530
Current liabilities	112,921	97,137
Total liabilities	**613,932**	624,667
Net assets	**756,952**	708,453
Working capital (including cash)	**28,573**	(4,670)

Segment Information

The Group operates within several geographical areas. Operating segments are reported at a country level, with Canada being further analyzed by main areas: (i) Canada – Northern Assets (comprising mainly of the Onion Lake Thermal asset) and (ii) Canada – Southern Assets (comprising of the Suffield Assets and the Ferguson asset). This is consistent with the internal reporting provided to IPC management. The following tables present certain segment information.

	Three months ended – June 30, 2021					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	58,901	46,761	18,031	16,580	–	**140,273**
NGLs	–	149	–	–	–	**149**
Gas	122	21,250	–	–	–	**21,372**
Net sales of oil and gas	**59,023**	**68,160**	**18,031**	**16,580**	–	**161,794**
Change in under/over lift position	–	–	–	3,124	–	**3,124**
Royalties	(5,141)	(5,219)	–	–	–	**(10,360)**
Hedging settlement	(6,121)	(4,632)	–	–	–	**(10,753)**
Other operating revenue	–	–	383	242	(152)	**473**
Revenue	**47,761**	**58,309**	**18,414**	**19,946**	**(152)**	**144,278**
Production costs (including inventory movements)	(32,562)	(33,053)	(385)	(10,213)	–	**(76,213)**
Depletion of oil and gas properties	(6,586)	(11,065)	(8,256)	(4,290)	–	**(30,197)**
Depreciation of other assets	–	–	(2,768)	–	–	**(2,768)**
Exploration and business development costs	(4)	–	(259)	–	(551)	**(814)**
Gross profit/(loss)	**8,609**	**14,191**	**6,746**	**5,443**	**(703)**	**34,286**

	Three months ended – June 30, 2020					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	5,997	7,690	7,080	5,952	–	26,719
NGLs	–	11	–	–	–	11
Gas	79	12,007	–	–	–	12,086
Net sales of oil and gas	6,076	19,708	7,080	5,952	–	38,816
Change in under/over lift position	–	–	–	(707)	–	(707)
Royalties	(527)	(238)	–	–	–	(765)
Hedging settlement	1,835	1,613	–	–	–	3,448
Other operating revenue	–	–	3,867	177	93	4,137
Revenue	7,384	21,083	10,947	5,422	93	44,929
Production costs (including inventory movements)	(10,605)	(16,398)	460	(3,532)	–	(30,075)
Depletion of oil and gas properties	(4,361)	(8,937)	(7,097)	(2,903)	–	(23,298)
Depreciation of other assets	–	–	(2,989)	–	–	(2,989)
Exploration and business development costs	(3,033)	–	68	(2,220)	81	(5,104)
Gross profit/(loss)	(10,615)	(4,252)	1,389	(3,233)	174	(16,537)

[1] The segment Malaysia includes the FPSO Bertam which is owned by the Group. The self-to-self payment of the lease fee for the FPSO Bertam has been eliminated from the revenue and the production costs.

	Six months ended – June 30, 2021					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	109,455	85,440	31,064	39,751	–	**265,710**
NGLs	–	265	–	–	–	**265**
Gas	253	40,839	–	–	–	**41,092**
Net sales of oil and gas	**109,708**	**126,544**	**31,064**	**39,751**	–	**307,067**
Change in under/over lift position	–	–	–	(1,006)	–	**(1,006)**
Royalties	(9,263)	(8,378)	–	–	–	**(17,641)**
Hedging settlement	(8,355)	(6,298)	–	–	–	**(14,653)**
Other operating revenue	–	–	4,208	523	64	**4,795**
Revenue	**92,090**	**111,868**	**35,272**	**39,268**	**64**	**278,562**
Production costs (including inventory movements)	(61,917)	(62,025)	2,191	(20,084)	–	**(141,835)**
Depletion of oil and gas properties	(13,426)	(21,471)	(15,025)	(8,345)	–	**(58,267)**
Depreciation of other assets	–	–	(5,037)	–	–	**(5,037)**
Exploration and business development costs	(4)	–	(259)	(7)	(937)	**(1,207)**
Gross profit/(loss)	**16,743**	**28,372**	**17,142**	**10,832**	**(873)**	**72,216**

	Six months ended – June 30, 2020					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	28,122	25,572	23,935	14,685	–	92,314
NGLs	–	88	–	–	–	88
Gas	151	26,721	–	–	–	26,872
Net sales of oil and gas	28,273	52,381	23,935	14,685	–	119,274
Change in under/over lift position	–	–	–	(4,064)	–	(4,064)
Royalties	(2,815)	(1,674)	–	–	–	(4,489)
Hedging settlement	4,165	2,136	–	–	–	6,301
Other operating revenue	–	–	7,735	453	255	8,443
Revenue	29,623	52,843	31,670	11,074	255	125,465
Production costs (including inventory movements)	(29,235)	(43,415)	(5,801)	(10,765)	–	(89,216)
Depletion of oil and gas properties	(12,591)	(18,761)	(14,304)	(7,916)	–	(53,572)
Depreciation of other assets	–	–	(6,024)	–	–	(6,024)
Exploration and business development costs	(3,033)	–	68	(2,220)	(441)	(5,626)
Gross profit/(loss)	(15,236)	(9,333)	5,609	(9,827)	(186)	(28,973)

[1] *The segment Malaysia includes the FPSO Bertam which is owned by the Group. The self-to-self payment of the lease fee for the FPSO Bertam has been eliminated from the revenue and the production costs.*

Three and six months ended June 30, 2021 Review

Revenue

Total revenue amounted to USD 144,278 thousand for Q2 2021, compared to USD 44,929 thousand for Q2 2020 and USD 278,562 thousand for the first six months of 2021 compared to USD 125,465 thousand for the first six months of 2020 and is analyzed as follows:

	Three months ended - June 30		Six months ended - June 30	
USD Thousands	**2021**	2020	**2021**	2020
Crude oil sales	140,273	26,719	265,710	92,314
Gas and NGL sales	21,521	12,097	41,357	26,960
Change in under/overlift position	3,124	(707)	(1,006)	(4,064)
Royalties	(10,360)	(765)	(17,641)	(4,489)
Hedging settlement	(10,753)	3,448	(14,653)	6,301
Other operating revenue	473	4,137	4,795	8,443
Total revenue	**144,278**	44,929	**278,562**	125,465

The main components of total revenue for the three and six months ended June 30, 2021, and June 30, 2020, respectiviely, are detailed below.

Crude oil sales

	Three months ended – June 30, 2021				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	58,901	46,761	18,031	16,580	**140,273**
- Quantity sold in bbls	1,140,762	869,422	256,256	238,156	**2,504,596**
- Average price realized USD per bbl	51.63	53.78	70.36	69.62	**56.01**

	Three months ended – June 30, 2020				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	5,997	7,690	7,080	5,952	26,719
- Quantity sold in bbls	658,117	527,562	224,001	247,169	1,656,849
- Average price realized USD per bbl	9.11	14.58	31.61	24.08	16.13

Crude oil revenue was more than 5 times higher for Q2 2021 compared to Q2 2020 mainly due to higher oil prices and higher produced volumes. Q2 2020 was impacted by the global Covid-19 outbreak causing a decrease in oil prices and the consequential decision by IPC to partially curtail production.

The Suffield area assets and part of the Onion Lake crude oil in Canada are blended with purchased condensate diluent volumes to meet pipeline specifications. As a result of the blended volumes, actual sales volumes are higher than produced volumes for Canada. The Canadian realized sales price is based on the Western Canadian Select ("WCS") price which trades at a discount to West Texas Intermediate ("WTI"). For Q2 2021, WTI averaged USD 66 per bbl compared to USD 28 per bbl for Q2 2020 and the average discount to WCS used in our pricing formula was USD 11 per bbl in line with Q2 2020.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices. There was one cargo lifting in Malaysia during Q2 2021 compared to two cargo liftings in Q2 2020. Produced unsold oil barrels from Bertam at the end of Q2 2021 amounted to 301,000 barrels, see Change in Inventory Position section below. There was no Aquitaine cargo lifted in Q2 2021. The average Dated Brent crude oil price was USD 69 per bbl for Q2 2021 compared to USD 30 per bbl for the comparative period.

USD Thousands	Six months ended – June 30, 2021 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	109,455	85,440	31,064	39,751	**265,710**
- Quantity sold in bbls	2,328,895	1,736,591	457,388	596,998	**5,119,872**
- Average price realized USD per bbl	47.00	49.20	67.92	66.58	**51.90**

USD Thousands	Six months ended – June 30, 2020 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	28,122	25,572	23,935	14,685	92,314
- Quantity sold in bbls	1,868,024	1,205,057	568,562	507,174	4,148,817
- Average price realized USD per bbl	15.05	21.22	42.10	28.96	22.25

Crude oil revenue was 187% higher for the first six months of 2021 compared to the first six months of 2020 mainly due to a 133% increase in achieved oil prices resulting from the improvement of market conditions as well as IPC's increased production.

The Canadian realized sales price is based on the Western Canadian Select ("WCS") price which trades at a discount to West Texas Intermediate ("WTI"). For the first six months of 2021, WTI averaged USD 62 per bbl compared to USD 37 per bbl for the comparative period and the average discount to WCS used in our pricing formula was USD 12 per bbl compared to USD 16 per bbl for the comparative period.

The realized sales price for Malaysia and France is based on Brent crude oil prices and the average market Brent crude oil price was USD 65 per bbl for the first six months of 2021 compared to USD 40 per bbl for the comparative period.

Gas and NGL sales

	Three months ended – June 30, 2021 Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	21,399	122	**21,521**
- Quantity sold in Mcf	8,581,489	51,221	**8,632,710**
- Average price realized USD per Mcf	2.49	2.38	**2.49**

	Three months ended – June 30, 2020 Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	12,018	79	12,097
- Quantity sold in Mcf	8,669,351	54,514	8,723,865
- Average price realized USD per Mcf	1.39	1.44	1.39

Gas and NGL sales revenue was 78% higher for Q2 2021 compared to Q2 2020 mainly due to the higher achieved gas price. Approximately 98% of the Suffield gas production was sold on the Alberta/Saskatchewan border at Empress with the remainder being delivered in Alberta based on AECO pricing. For Q2 2021, IPC realized an average price of CAD 3.05 per Mcf which was in line with Empress average pricing for Q2 2021 of CAD 3.10 per Mcf.

	Six months ended – June 30, 2021		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	41,104	253	**41,357**
- Quantity sold in Mcf	16,581,658	106,300	**16,687,958**
- Average price realized USD per Mcf	2.48	2.38	**2.48**

	Six months ended – June 30, 2020		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	26,809	151	26,960
- Quantity sold in Mcf	17,326,824	113,198	17,440,022
- Average price realized USD per Mcf	1.55	1.33	1.55

Gas and NGL sales revenue was 53% higher for the first six months of 2021 compared to the first six months of 2020 mainly due to the higher achieved gas price. For the first six months of 2021, IPC realized an average price of CAD 3.08 per Mcf which was in line with Empress average pricing of CAD 3.15 per Mcf for the first six months of 2021.

Hedging settlement
IPC enters into risk management contracts in order to ensure a certain level of cashflow and to comply with covenants of its financing facilities. IPC's hedging strategy focuses mainly on oil price swaps and collars to limit pricing exposure. IPC also uses natural gas at the Onion Lake Thermal project and the Blackrod SAGD pilot project to generate steam and manages the pricing risk by entering into fixed price swaps. The oil and gas pricing contracts are not entered into for speculative purposes. Also see the Financial Position and Liquidity and the Financial Risk Management sections below.

The realized hedging settlement for the first six months of 2021 amounted to a loss of USD 14,653 thousand and consisted of a loss of USD 993 thousand on the gas contracts and a loss of USD 13,660 thousand on the oil contracts. Also see the Financial Position and Liquidity and the Financial Risk Management sections below.

Other operating revenue
Other operating revenue amounted to USD 473 thousand for Q2 2021 compared to USD 4,137 thousand for Q2 2020 and USD 4,795 thousand for the first six months of 2021 compared to USD 8,443 for the comparative period. Other operating revenue consists of lease fee income, tariff income and fees for strategic storage of inventory in France. The significant part of other operating revenue was third party lease fee income received by the Group for the leasing of the owned FPSO Bertam to the Bertam field in Malaysia until April 10, 2021. Following the withdrawal of Petronas Carigli Sdn Bhd from the Production Sharing Contract for the Bertam Field, and its interest being assigned to IPC, there is no such third party lease fee income after April 10, 2021. From this date, 100% of the lease income is eliminated from other operating revenue and the corresponding self-to-self lease fee is eliminated from operating costs, and IPC reports additional oil sales revenues associated with the assigned 25% working interest in the Bertam field.

Production costs
Production costs including inventory movements amounted to USD 76,213 thousand for Q2 2021 compared to USD 30,075 thousand for Q2 2020 and is analyzed as follows:

USD Thousands	Three months ended – June 30, 2021 Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	26,129	19,929	12,062	10,157	(4,838)	**63,439**
USD/boe[2]	11.30	19.32	27.52	36.71	n/a	**15.63**
Cost of blending	6,795	12,797	–	–	–	**19,592**
Change in inventory position	129	(164)	(6,839)	56	–	**(6,818)**
Production costs	**33,053**	**32,562**	**5,223**	**10,213**	**(4,838)**	**76,213**

USD Thousands	Three months ended – June 30, 2020 Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	14,767	10,605	16,443	4,467	(11,602)	34,680
USD/boe[2]	7.42	15.89	39.64	25.38	n/a	10.67
Cost of blending	2,051	–	–	–	–	2,051
Change in inventory position	(420)	–	(5,301)	(935)	–	(6,656)
Production costs	16,398	10,605	11,142	3,532	(11,602)	30,075

USD Thousands	Six months ended – June 30, 2021 Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	49,748	37,137	29,198	20,310	(16,313)	**120,080**
USD/boe[2]	10.93	17.68	36.61	37.29	n/a	**15.02**
Cost of blending	12,723	25,313	–	–	–	**38,036**
Change in inventory position	(446)	(533)	(15,076)	(226)	–	**(16,281)**
Production costs	**62,025**	**61,917**	**14,122**	**20,084**	**(16,313)**	**141,835**

USD Thousands	Six months ended – June 30, 2020 Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	37,047	29,235	33,251	10,910	(23,205)	87,238
USD/boe[2]	8.73	15.41	39.77	23.25	n/a	11.72
Cost of blending	6,169	–	–	–	–	6,169
Change in inventory position	199	–	(4,245)	(145)	–	(4,191)
Production costs	43,415	29,235	29,006	10,765	(23,205)	89,216

[1] See definition on page 20 under "Non-IFRS measures".
[2] USD/boe in the tables above is calculated by dividing the cost by the production volume for each country for the period.
[3] Included in the Malaysia operating costs is the lease cost for the FPSO Bertam which is owned by the Group. Other represents the FPSO Bertam lease fee self-to-self payment elimination. Netting the self-to-self elimination against the operating costs in Malaysia reduces the operating cost per boe for Malaysia to USD 16.48 and USD 11.67 for Q2 2021 and Q2 2020 respectively and USD 16.16 and USD 12.02 for the six months ended June 30, 2021, and June 30, 2020, respectively.

Operating costs
Operating costs amounted to USD 63,439 thousand for Q2 2021 compared to USD 34,680 thousand for Q2 2020 and USD 120,080 thousand for the first six months of 2021 compared to USD 87,238 for the first six months of 2020. Operating costs in Q2 2020 were significantly lower than for Q2 2021 as a consequence of the curtailment of higher cost production and the deferral and cancellation of discretionary expenditures in response to the lower oil prices seen in Q2 2020. In addition, energy costs in Q2 2021, both electricity and gas, were also higher. Operating costs per boe amounted to USD 15.63 per boe in Q2 2021 in line with guidance, compared with USD 10.67 per boe in Q2 2020. Full year operating costs per boe are expected to increase from USD 14.6 per boe to USD 15.5 per boe to take account of higher energy costs and the restart of some higher cost production in Canada.

Cost of blending
For the Suffield area assets in Canada, oil production is blended with purchased condensate diluent to meet pipeline specifications. Since July 2020, a portion of Onion Lake oil production is also blended and exported by pipeline. The cost of the diluent net of proceeds from the sale of surplus diluent amounted to USD 19,592 thousand for Q2 2021 compared to USD 2,051 thousand for Q2 2020 and USD 38,036 thousand for the first six months of 2021 compared to USD 6,169 thousand for the first six months of 2020. The increase is attributable to Onion Lake blending and higher diluent prices in line with higher oil prices.

As a result of the blending, actual sales volumes are higher than produced barrels. A cost of USD 140 thousand and USD 962 thousand were recognized relating to the difference between the cost and sale proceeds of the surplus diluent for Q2 2021 and Q2 2020 respectively. A cost of USD 70 thousand and USD 732 thousand were recognized for the six months ended June 30, 2021, and June 30, 2020, respectively.

Change in inventory position
The Bertam field in Malaysia is located offshore and production is lifted and sold from the FPSO Bertam when a cargo parcel size is reached. Accordingly, the timing of a lifting varies based on the inventory level on the FPSO facility and the change in inventory position varies, both positively and negatively, from period to period. Inventories are valued at the lower of cost including depletion, and market value, and the difference in the valuation between period ends is reflected in the change in inventory position in the statement of operations. At the end of Q2 2021, IPC had crude entitlement of 301,000 barrels of oil on the FPSO Bertam facility (crude produced but unsold).

Depletion of oil and gas properties
The total depletion of oil and gas properties amounted to USD 30,197 thousand for Q2 2021 compared to USD 23,298 thousand for Q2 2020 and USD 58,267 thousand for the first six months of 2021 compared to USD 53,572 thousand for the first six months of 2020. The depletion charge is analyzed in the following tables:

	Three months ended – June 30, 2021				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	11,065	6,586	8,256	4,290	**30,197**
USD per boe	4.78	6.39	18.84	15.50	**7.44**

	Three months ended – June 30, 2020				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	8,937	4,361	7,097	2,903	23,298
USD per boe	4.49	6.54	17.11	16.50	7.17

	Six months ended – June 30, 2021				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	21,471	13,426	15,025	8,345	**58,267**
USD per boe	4.72	6.39	18.84	15.32	**7.29**

	Six months ended – June 30, 2020				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	18,761	12,591	14,304	7,916	53,572
USD per boe	4.42	6.64	17.11	16.87	7.20

The depletion charge is derived by applying the depletion rate per boe to the volumes produced in the period by each field. The depletion rate for each field was updated for 2021 to align with the annual reserves report process at the end of 2020.

Depreciation of other assets
The total depreciation of other assets amounted to USD 2,768 thousand for Q2 2021 compared to USD 2,989 thousand for Q2 2020 and USD 5,037 thousand for the first six months of 2021 compared to USD 6,024 thousand for the first six months of 2020. This related to the depreciation of the FPSO Bertam, which is being depreciated on a unit of production basis over the 2P reserves of the Bertam field.

Exploration and business development costs
The total exploration and business developments costs amounted to USD 814 thousand for Q2 2021 and USD 1,207 thousand for the first six months of 2021. These costs mainly related to business development costs.

General, administrative and depreciation expenses
General, administrative and depreciation expenses amounted to USD 3,351 thousand for Q2 2021, compared to USD 3,095 thousand for Q2 2020 and USD 6,169 thousand for the first six months of 2021 compared to USD 5,905 thousand for the first six months of 2020.

Net financial items
Net financial items amounted to a charge of USD 4,683 thousand for Q2 2021, compared to a credit of USD 6,411 thousand for Q2 2020 and a charge of USD 13,175 thousand for the first six months of 2021 compared to a charge of USD 22,751 thousand for the first six months of 2020, and included a largely non-cash net foreign exchange loss of USD 3,066 thousand for the first six months of 2021 compared to a net foreign exchange loss of USD 9,492 thousand for the first six months of 2020. The foreign exchange movements during the first six months of 2021 are mainly resulting from the revaluation of intra-group funding loans.

Excluding foreign exchange movements, the net financial items amounted to a charge of USD 8,427 thousand for Q2 2021, compared to a charge of USD 5,954 thousand for Q2 2020 and a charge of USD 16,241 thousand for the first six months of 2021 compared to a charge of USD 13,259 thousand for the first six months of 2020.

The interest expense amounted to USD 4,331 thousand for Q2 2021, compared to USD 2,563 thousand for the comparative period in 2020 and USD 8,330 thousand for the first six months of 2021 compared to USD 6,350 thousand for the first six months of 2020. Despite the lower borrowings, the cost of financing was higher in the first six months of 2021 compared to the first six months of 2020 following the refinancing of the credit facilities in the summer of 2020. Cost of financing is expected to reduce during the second half year of 2021.

The unwinding of the asset retirement obligation discount rate amounted to USD 2,941 thousand for Q2 2021, compared to USD 2,646 thousand for Q2 2020 and USD 5,798 thousand for the first six months of 2021 compared to USD 5,289 thousand for the first six months of 2020.

Income tax
The corporate income tax amounted to a charge of USD 4,559 thousand for Q2 2021, compared to a credit of USD 11,749 thousand for Q2 2020 and a charge of USD 4,288 thousand for the first six months of 2021 compared to a credit of USD 16,088 thousand for the first six months of 2020. The income tax movements in the first six months of 2021 relate to deferred taxes with minimal cash taxes reflected.

Capital Expenditure

Development and exploration and evaluation expenditure incurred in the first six months of 2021, was as follows:

USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Development	5,771	10,509	1,255	1,278	**18,813**
Exploration and evaluation	–	(299)	365	7	**73**
	5,771	10,210	1,620	1,285	**18,886**

Capital expenditure of USD 18,886 thousand was mainly in Canada including completion of the Pad D' project on the Onion Lake Thermal field.

Other tangible fixed assets
Other tangible fixed assets amounted to USD 52,996 thousand as at June 30, 2021, which included USD 49,838 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated on a unit of production basis from July 2019 based on the Bertam field 2P reserves.

Financial Position and Liquidity

Financing

As at January 1, 2020, the Group had a reserve-based lending credit facility of USD 175 million (the "International RBL") with a maturity to end of June 2022 in connection with its oil and gas assets in France and Malaysia. In addition, the Group had a reserve-based lending credit facility of CAD 375 million (the "Canadian RBL") with a maturity date in May 2021, in connection with its oil and gas assets in Canada.

In May 2020, IPC entered into a EUR 13 million unsecured credit facility in France (the "France Facility") under a financial assistance program instituted by the French government. In April 2021, IPC extended the France Facility until May 2026, with quarterly repayments commencing in August 2022. The France Facility amount was fully drawn as at June 30, 2021, and as at August 3, 2021.

In June 2020, the Group amended and extended the International RBL to a facility size of USD 125 million, with a maturity at the end of December 2024. In July 2020, the facility size was further increased to USD 140 million.

In March 2020, in connection with the completion of the acquisition of Granite Oil Corp. ("Granite"), the Group assumed the bank debt of Granite consisting of a revolving credit facility of CAD 42.5 million (the "Granite Facility"). In July 2020, the Group amended and extended the Canadian RBL to a facility size of CAD 350 million with a maturity extended until the end of May 2022. In December 2020, the Granite Facility was amended to a CAD 30 million revolving credit facility.

In June 2021, the Group consolidated the amounts outstanding under the Granite Facility into the Canadian RBL and the Granite Facility was terminated. As of June 30, 2021, the Canadian RBL was amended to a facility size of CAD 300 million with a maturity extended until the end of May 2023. Under the Canadian RBL, the Group is required, and has satisfied the requirement, to hedge 40% of forecast Canadian oil production from June 30, 2021, to December 31, 2021. There are currently no mandatory hedging requirements beyond the end of 2021.

The borrowing base availability under the International RBL was agreed in June 2021 at USD 105 million of which USD 41 million was drawn as at June 30, 2021. The borrowing base availability under the Canadian RBL was CAD 300 million of which CAD 255 million was drawn as at June 30, 2021.

As at June 30, 2021, total net debt amounted to USD 241 million and the net debt to 12 month rolling EBITDA ratio was below 1.2 times.

The amounts drawn under the International RBL, the France Facility and the Canadian RBL as at June 30, 2021, are classified as non-current as there are no mandatory repayments within the next twelve months.

The Group is in compliance with the covenants under the financing facilities as at June 30, 2021.

Cash and cash equivalents held amounted to USD 21,262 thousand as at June 30, 2021. The Corporation holds cash to meet imminent operational funding requirements in the different countries.

Working Capital

As at June 30, 2021, the Group had a net working capital balance including cash of USD 28,573 thousand compared to USD (4,670) thousand as at December 31, 2020. The difference as at June 30, 2021, from December 31, 2020, is mainly as a result of higher trade receivables due to the higher oil price, the higher hydrocarbon stocks in Malaysia as only one cargo was lifted during Q2 2021, the higher cash balances held and the reclassification of borrowings to long term following the refinancing in Canada, partly offet by the higher trade payables.

Non-IFRS Measures

In addition to using financial measures prescribed under IFRS, references are made in this MD&A to "operating cash flow", "free cash flow", "EBITDA", "operating costs" and "net debt", which are non-IFRS measures. Non-IFRS measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other public companies. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS.

The Corporation uses non-IFRS measures to provide investors with supplemental measures to assess cash generated by and the financial performance and condition of the Corporation. Management also uses non-IFRS measures internally in order to facilitate operating performance comparisons from period to period, prepare annual operating budgets and assess the Group's ability to meet its future capital expenditure and working capital requirements. Management believes these non-IFRS measures are important supplemental measures of operating performance because they highlight trends in the core business that may not otherwise be apparent when relying solely on IFRS financial measures. Management believes such measures allow for assessment of the Group's operating performance and financial condition on a basis that is more consistent and comparable between reporting periods. The Corporation also believes that securities analysts, investors and other interested parties frequently use non-IFRS measures in the evaluation of public companies. Forward-looking statements are provided for the purpose of presenting information about management's current expectations and plans relating to the future and readers are cautioned that such statements may not be appropriate for other purposes.

"Operating cash flow" is calculated as revenue less production costs less current tax. Operating cash flow is used to analyze the amount of cash that is being generated available for capital investment and servicing debt.

"Free cash flow" is calculated as operating cash flow less capital expenditures less decommissioning and farm-in expenditures less general, administration and depreciation expenses before depreciation and less cash financial items. Free cash flow is used to analyze the amount of cash that is being generated by the business and that is available for such purposes as repaying debt, funding acquisitions and returning capital to shareholders.

"EBITDA" is calculated as net result before financial items, taxes, depletion of oil and gas properties, exploration costs, impairment costs and depreciation and adjusted for non-recurring profit/loss on sale of assets and other income.

"Operating cost" is calculated as production costs excluding any change in the inventory position and the cost of blending and is used to analyze the cash cost of producing the oil and gas volumes.

"Net debt" is calculated as bank loans less cash and cash equivalents.

Reconciliation of Non-IFRS Measures

Operating cash flow
The following table sets out how operating cash flow is calculated from figures shown in the Financial Statements:

	Three months ended - June 30		Six months ended - June 30	
USD Thousands	2021	2020	2021	2020
Revenue	144,278	44,929	278,562	125,465
Production costs	(76,213)	(30,075)	(141,835)	(89,216)
Current tax	(1,106)	(112)	(2,047)	(26)
Operating cash flow	**66,959**	14,742	**134,680**	36,223

Free cash flow
The following table sets out how free cash flow is calculated from figures shown in the Financial Statements:

USD Thousands	Three months ended - June 30 2021	Three months ended - June 30 2020	Six months ended - June 30 2021	Six months ended - June 30 2020
Operating cash flow - see above	66,959	14,742	134,680	36,223
Capital expenditures	(7,215)	(6,422)	(18,886)	(62,612)
Abandonment and farm-in expenditures[1]	(1,555)	(2,002)	(1,888)	(3,342)
General, administration and depreciation expenses before depreciation[2]	(2,884)	(2,667)	(5,283)	(5,053)
Cash financial items[3]	(4,939)	(2,934)	(9,306)	(7,211)
Free cash flow	**50,366**	717	**99,317**	(41,995)

[1] See note 16 to the Financial Statements
[2] Depreciation is not specifically disclosed in the Financial Statements
[3] See notes 4 and 5 to the Financial Statements

EBITDA
The following table sets out the reconciliation from net result from the consolidated statement of operations to EBITDA:

USD Thousands	Three months ended - June 30 2021	Three months ended - June 30 2020	Six months ended - June 30 2021	Six months ended - June 30 2020
Net result	21,693	(1,472)	48,584	(41,541)
Net financial items	4,683	(6,411)	13,175	22,751
Income tax	4,559	(11,749)	4,288	(16,088)
Depletion of oil and gas properties	30,197	23,298	58,267	53,572
Depreciation of other assets	2,768	2,989	5,037	6,024
Exploration and business development costs	814	5,104	1,207	5,626
Depreciation included in general, administration and depreciation expenses[1]	467	428	886	852
EBITDA	**65,181**	12,187	**131,444**	31,196

[1] Item is not shown in the Financial Statements

Operating costs
The following table sets out how operating costs is calculated:

USD Thousands	Three months ended - June 30 2021	Three months ended - June 30 2020	Six months ended - June 30 2021	Six months ended - June 30 2020
Production costs	76,213	30,075	141,835	89,216
Cost of blending[1]	(19,592)	(2,051)	(38,036)	(6,169)
Change in inventory position	6,818	6,656	16,281	4,191
Operating costs	**63,439**	34,680	**120,080**	87,238

[1] Item is shown in the Financial Statements. See production costs section above.

Net debt
The following table sets out how net debt is calculated from figures shown in the Financial Statements:

USD Thousands	June 30, 2021	December 31, 2020
Bank loans	261,879	327,691
Cash and cash equivalents	(21,262)	(6,498)
Net debt	**240,617**	321,193

Off-Balance Sheet Arrangements

IPC, through its subsidiary IPC Canada Ltd, has issued two letters of credit as follows: (a) CAD 2.6 million in respect of its obligations to purchase diluent, outstanding until October 2021; and (b) CAD 600,000 in respect of its obligations related to the Ferguson asset, increasing by CAD 100,000 annually to a maximum of CAD 1,000,000.

IPC has also guaranteed the obligations of its subsidiary, IPC Canada Ltd, in respect of its pipeline gathering and transportation of crude oil for a maximum amount of CAD 3.6 million and its electricity supply for a maximum amount of CAD 1.0 million.

Outstanding Share Data

The common shares of IPC trade on both the Toronto Stock Exchange and the Nasdaq Stockholm.

As at January 1, 2020, the total number of common shares issued and outstanding in IPC was 159,790,869. In 2020, IPC repurchased 4,448,112 common shares under a share repurchase program and all of these shares were cancelled. IPC suspended further share repurchases under the program which expired in early November 2020. As at December 31, 2020, IPC had a total of 155,342,757 common shares issued and outstanding.

Following the exercise of stock options during February 2021, the number of issued and outstanding common shares of the Corporation has increased by 25,000 to 155,367,757 common shares. As at June 30, 2021, and as at August 3, 2021, IPC had a total of 155,367,757 common shares issued and outstanding with voting rights.

Nemesia S.à.r.l. and Zebra Holdings and Investments S.à.r.l., investment companies wholly owned by a Lundin family trust, own 40,697,533 common shares in IPC, representing 26.2% of the outstanding common shares as at August 3, 2021.

In addition, IPC has 117,485,389 outstanding class A preferred shares, issued as a part of an internal corporate structuring to a wholly-owned subsidiary of IPC. Such preferred shares are not listed on any stock exchange and do not carry the right to vote on matters to be decided by the holders of IPC's common shares.

IPC has 5,540,140 IPC Share Unit Plan awards (82,815 awards granted in March 2019, 1,042,799 awards granted in July 2019, 25,349 awards granted in January 2020, 1,507,078 awards granted in March 2020, 25,335 awards granted in July 2020, 45,781 awards granted in January 2021, 1,076,816 awards granted in March 2021, 1,716,000 awards granted in May 2021 and 18,167 awards granted in July 2021) outstanding as at August 3, 2021.

Contractual Obligations and Commitments

IPC has an obligation to make payments towards historic costs on Block PM307 in Malaysia payable on the Bertam field for every 1 MMboe gross that the field produces above 10 MMboe gross. The estimated liability based on current 2P reserves has been provided for in the Group's Balance Sheet – see Note 16 to the Financial Statements.

The Bertam field has leased the FPSO Bertam from another Group company for a period up to April 2022, with three further one-year options to extend such lease up to April 2025.

Critical Accounting Policies and Estimates

In connection with the preparation of the Corporation's consolidated financial statements, management has made assumptions and estimates about future events and applied judgments that affect the reported values of assets, liabilities, revenues, expenses and related disclosures. These assumptions, estimates and judgments are based on historical experience, current trends and other factors that they believe to be relevant at the time the financial statements are prepared. The management reviews the accounting policies, assumptions, estimates and judgments to ensure that the financial statements are presented fairly in accordance with IFRS. However, because future events and their effects cannot be determined with certainty, actual results could differ from these assumptions and estimates, and such differences could be material.

Transactions with Related Parties

Lundin Energy has charged the Group USD 320 thousand in respect of office space rental and USD 750 thousand in respect of shared services provided during the first six months of 2021.

All transactions with related parties are in the normal course of business and are made on the same terms and conditions as with parties at arm's length.

Financial Risk Management

As an international oil and gas exploration and production company, IPC is exposed to financial risks such as interest rate risk, currency risk, credit risk, liquidity risks as well as the risk related to the fluctuation in the oil price. The Group seeks to control these risks through sound management practice and the use of internationally accepted financial instruments, such as oil and gas price, interest rate or foreign exchange hedges as the case may be. Financial instruments will be solely used for the purpose of managing risks in the business. As at June 30, 2021, the Corporation had entered into oil and gas price hedges – see below.

Management believes that the cash resources, other current assets and cash flow from operations are sufficient to finance the Group's operations and capital expenditures program over the next year.

Capital Management
The Group's objectives when managing capital are to safeguard the Group's ability to continue as a going concern and to meet its committed financial liabilities and work program requirements in order to create shareholder value. The Group may put in place new credit facilities, repay debt, or pursue other such restructuring activities as appropriate.

Management of the Corporation will continuously monitor and manage the Group's capital, liquidity and net debt position in order to assess the requirement for changes to the capital structure to meet the objectives and to maintain flexibility.

Price of Oil and Gas
Prices of oil and gas are affected by the normal economic drivers of supply and demand as well as by financial investors and market uncertainty. Factors that influence these prices include operational decisions, prices of competing fuels, natural disasters, economic conditions, transportation constraints, political instability or conflicts or actions by major oil exporting countries. Price fluctuations will affect the Group's financial position.

Based on analysis of the circumstances, the management assesses the benefits of forward hedging monthly sales contracts for the purpose of protecting cash flow. If management believes that a hedging contract will appropriately help manage cash flow then it may choose to enter into a commodity price hedge. In addition, see the Financial Position and Liquidity section above regarding applicable credit facility covenants to hedge future production.

The Group had gas price sale financial hedges outstanding as at June 30, 2021, which are summarized as follows:

Period	Volume (Gigajoules (GJ) per day)	Type	Average Pricing
July 1, 2021 – September 30, 2021	45,000	AECO Swap	CAD 2.57/GJ
October 1, 2021 – December 31, 2021	15,000	AECO Swap	CAD 2.88/GJ

The Group had oil price sale financial hedges outstanding as at June 30, 2021, which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
July 1, 2021 - September 30, 2021	5,350	WCS Swap	USD 45.46/bbl
October 1, 2021 - December 31, 2021	5,000	WCS Swap	USD 44.16/bbl
July 1, 2021 – December 31, 2021	3,300	WTI Collar	USD 57.94/bbl - 77.26/bbl
July 1, 2021 – September 30, 2021	3,133	WCS/WTI Differential	USD -13.91/bbl
October 1, 2021 - December 31, 2021	3,300	WCS/WTI Differential	USD -13.94/bbl

All of the above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income.

These hedges had a net negative fair value of USD 15,934 thousand as at June 30, 2021.

In July 2021, the Group also entered into the following gas price sale financial hedges in Canada:

Period	Volume (Gigajoules (GJ) per day)	Type	Average Pricing
November 1, 2021 – March 31, 2022	10,000	AECO Swap	CAD 4.045/GJ

Currency Risk
The Group's policy on currency rate hedging is, in the case of currency exposure, to consider fixing the rate of exchange. The Group will take into account the currency exposure, current rates of exchange and market expectations in comparison to historic trends and volatility in making the decision to hedge.

Interest Rate Risk
Interest rate risk is the risk to earnings due to uncertain future interest rates on borrowings. The Group will take into account the level of external debt, current interest rates and market expectations in comparison to historic trends and volatility in making the decision to hedge.

Credit Risk
The Group may be exposed to third party credit risk through contractual arrangements with counterparties who buy the Group's hydrocarbon products. The Group's policy is to limit credit risk by only entering into oil and gas sales agreements with reputable and creditworthy oil and gas and trading companies. Where it is determined that there is a credit risk for oil and gas sales, the Group's policy is to require credit enhancement from the purchaser.

The Group's policy on joint venture parties is to rely on the provisions of the underlying joint operating agreements to take possession of the licence or the joint venture partner's share of production for non-payment of cash calls or other amounts due. In addition, cash is to be held and transacted only through major banks.

RISK AND UNCERTAINTIES

IPC is engaged in the exploration, development and production of oil and gas and is exposed to various operational, environmental, market and financial risks and uncertainties. For further information and discussion of these risks and uncertainties, please see IPC's Annual Information Form for the year ended December 31, 2020 ("AIF") available on SEDAR at www.sedar.com or on IPC's website at www.international-petroleum.com. See also "Cautionary Statement Regarding Forward-Looking Information" and "Reserves and Resource Advisory" in this MD&A.

The current and any future Covid-19 outbreaks may increase IPC's exposure to, and magnitude of, each of the risks and uncertainties identified in the AIF or this MD&A that result from a reduction in demand for oil and gas consumption and/or lower commodity prices and/or reliance on third parties. The extent to which Covid-19 impacts IPC's business, results of operations and financial condition will depend on future developments, which are highly uncertain and are difficult to predict, including, but not limited to, the duration and spread of the current and any future Covid-19 outbreaks, their severity, the actions taken to contain such outbreaks or treat their impact, and how quickly and to what extent normal economic and operating conditions resume and their impacts to IPC's business, results of operations and financial condition which could be more significant in upcoming periods as compared with previous periods. Even after the Covid-19 outbreaks have subsided, IPC may continue to experience materially adverse impacts to IPC's business as a result of the global economic impact.

The Covid-19 virus and the restrictions and disruptions related to it have had a material effect on the world demand for, and prices of, oil and gas as well as the market price of the shares of oil and gas companies generally, including the Corporation's common shares. There can be no assurance that these effects will not continue or that commodity prices will not decrease or remain volatile in the future. These factors are beyond the control of the Corporation and it is difficult to assess how these, and other factors, will continue to affect the Corporation and the market price of IPC's common shares. In light of the current situation, as at the date of this MD&A, the Corporation continues to review and assess its business plans and assumptions regarding the business environment, as well as its estimates of future production, cash flows, operating costs and capital expenditures.

DISCLOSURE CONTROLS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Disclosure Controls and Procedures
Disclosure controls and procedures have been designed to provide reasonable assurance that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation. Management, under the supervision of the Chief Executive Officer and the Chief Financial Officer, is responsible for the design and operation of disclosure controls and procedures.

Internal Controls over Financial Reporting
Management is also responsible for the design of the Group's internal controls over financial reporting in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. However, due to inherent limitations, internal control over financial reporting may not prevent or detect all misstatements and fraud.

There have been no material changes to the Groups internal control over financial reporting during the three month period ended June 30, 2021, that have materially affected, or are reasonably likely to materially affect, the Group's internal control over financial reporting.

Control Framework
Management assesses the effectiveness of the Corporation's internal control over financial reporting using the Internal Control – Integrated Framework (2013 Framework) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This MD&A contains statements and information which constitute "forward-looking statements" or "forward-looking information" (within the meaning of applicable securities legislation). Such statements and information (together, "forward-looking statements") relate to future events, including the Corporation's future performance, business prospects or opportunities. Actual results may differ materially from those expressed or implied by forward-looking statements. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement. Forward-looking statements speak only as of the date of this MD&A, unless otherwise indicated. IPC does not intend, and does not assume any obligation, to update these forward-looking statements, except as required by applicable laws.

The Covid-19 virus and the restrictions and disruptions related to it have had a material effect on the world demand for, and prices of, oil and gas as well as the market price of the shares of oil and gas companies generally, including the Corporation's common shares. There can be no assurance that these effects will not continue or that commodity prices will not decrease or remain volatile in the future. These factors are beyond the control of the Corporation and it is difficult to assess how these, and other factors, will continue to affect the Corporation and the market price of IPC's common shares. In light of the current situation, as at the date of this MD&A, the Corporation continues to review and assess its business plans and assumptions regarding the business environment, as well as its estimates of future production, cash flows, operating costs and capital expenditures.

All statements other than statements of historical fact may be forward-looking statements. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, forecasts, guidance, budgets, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "forecast", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", "budget" and similar expressions) are not statements of historical fact and may be "forward-looking statements".

Forward-looking statements include, but are not limited to, statements with respect to:

- IPC's ability to maximize liquidity and financial flexibility in connection with the current and any future Covid-19 outbreaks and reductions in commodity prices;
- The potential for an improved economic environment resulting from a lack of capital investment and drilling in the oil and gas industry;
- 2021 production range, operating costs and capital and decommissioning expenditure estimates;
- Estimates of future production, cash flows, operating costs and capital expenditures that are based on IPC's current business plans and assumptions regarding the business environment, which are subject to change;
- IPC's financial and operational flexibility to continue to react to recent events and navigate the Corporation through periods of low or volatile commodity prices;
- IPC's ability, as market conditions evolve and if determined necessary from time to time, to reduce expenditures and curtail production, and then to resume such production;
- IPC's continued access to its existing credit facilities, including current financial headroom, on terms acceptable to the Corporation;
- The ability to fully fund 2021 expenditures from cash flows and current borrowing capacity;
- IPC's ability to maintain operations, production and business in light of the current and any future Covid-19 outbreaks and the restrictions and disruptions related thereto, including risks related to production delays and interruptions, changes in laws and regulations and reliance on third-party operators and infrastructure;
- IPC's intention and ability to continue to implement our strategies to build long-term shareholder value;
- The ability of IPC's portfolio of assets to provide a solid foundation for organic and inorganic growth;
- The continued facility uptime and reservoir performance in IPC's areas of operation;
- Future development potential of the Suffield and Ferguson operations, including the timing and success of future oil and gas optimization programs;
- Development of the Blackrod project in Canada;
- Current and future drilling pad production and timing and success of facility upgrades and tie-in work at Onion Lake Thermal;
- The timing and success of the planned five well infill drilling program at Onion Lake Thermal;
- The ability to maintain current and forecast production in France;
- The ability of IPC to implement alternative transportation arrangements for Paris Basin production in connection with the closure of the Total-operated Grandpuits refinery, including at costs estimated by the Corporation;
- The ability to maintain current and forecast production in Malaysia;
- The timing and success of the drilling of the A15 sidetrack well and of the production well pump rate optimisation project in Malaysia;
- IPC's ability to implement its GHG emissions intensity and climate strategies and to achieve its net GHG emissions intensity reduction targets;
- Estimates of reserves and contingent resources;
- The ability to generate free cash flows and use that cash to repay debt; and
- Future drilling and other exploration and development activities.

Statements relating to "reserves" and "contingent resources" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated and that the reserves and resources can be profitably produced in the future. Ultimate recovery of reserves or resources is based on forecasts of future results, estimates of amounts not yet determinable and assumptions of management. See also "Reserves and Resource Advisory".

The forward-looking statements are based on certain key expectations and assumptions made by IPC, including expectations and assumptions concerning: prevailing commodity prices and currency exchange rates; applicable royalty rates and tax laws; interest rates; future well production rates and reserve and contingent resource volumes; operating costs; the timing of receipt of regulatory approvals; the performance of existing wells; the success obtained in drilling new wells; anticipated timing and results of capital expenditures; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the successful completion of acquisitions and dispositions; the benefits of acquisitions; the state of the economy and the exploration and production business in the jurisdictions in which IPC operates and globally; the availability and cost of financing, labour and services; and the ability to market crude oil, natural gas and natural gas liquids successfully.

Although IPC believes that the expectations and assumptions on which such forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because IPC can give no assurances that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks.

These include, but are not limited to:

- The risks associated with the oil and gas industry in general such as operational risks in development, exploration and production;
- Delays or changes in plans with respect to exploration or development projects or capital expenditures;
- The uncertainty of estimates and projections relating to reserves, resources, production, revenues, costs and expenses;
- Health, safety and environmental risks;
- Commodity price fluctuations;
- Interest rate and exchange rate fluctuations;
- Marketing and transportation;
- Loss of markets;
- Environmental risks;
- Competition;
- Incorrect assessment of the value of acquisitions;
- Failure to complete or realize the anticipated benefits of acquisitions or dispositions;
- The ability to access sufficient capital from internal and external sources;
- Failure to obtain required regulatory and other approvals; and
- Changes in legislation, including but not limited to tax laws, royalties, environmental and decommissioning regulations.

Readers are cautioned that the foregoing list of factors is not exhaustive.

Estimated free cash flow generation is based on IPC's current business plans over the period of 2021 to 2025. Assumptions include average net production of approximately 45 Mboepd, average Brent oil prices of USD 55 to 75 per boe escalating by 2% per year, average gas prices of CAD 2.50 per thousand cubic feet, and average Brent to Western Canadian Select differentials as estimated by IPC's independent reserves evaluator and as further described in the AIF. IPC's current business plans and assumptions, and the business environment, are subject to change. Actual results may differ materially from forward-looking estimates and forecasts. Additional information on these and other factors that could affect IPC, or its operations or financial results, are included in the Financial Statements, the Corporation's Annual Information Form (AIF) for the year ended December 31, 2020, (See "Cautionary Statement Regarding Forward-Looking Information", "Reserves and Resources Advisory" and "Risk Factors") and other reports on file with applicable securities regulatory authorities, including previous financial reports, management's discussion and analysis and material change reports, which may be accessed through the SEDAR website (www.sedar.com) or IPC's website (www.international-petroleum.com).

RESERVES AND RESOURCE ADVISORY

This MD&A contains references to estimates of gross and net reserves and resources attributed to the Corporation's oil and gas assets. Gross reserves / resources are the working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests. Net reserves / resources are the working interest (operating or non-operating) share after deduction of royalty obligations, plus royalty interests in reserves/resources, and in respect of PSCs in Malaysia, adjusted for cost and profit oil. Unless otherwise indicated, reserves / resource volumes are presented on a gross basis.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada are effective as of December 31, 2020, and are included in the reports prepared by Sproule Associates Limited ("Sproule"), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Sproule's December 31, 2020, price forecasts.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France and Malaysia are effective as of December 31, 2020, and are included in the report prepared by ERC Equipoise Ltd. ("ERCE"), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2020, price forecasts.

The price forecasts used in the Sproule and ERCE reports are available on the website of Sproule (sproule.com) and are contained in the AIF.

The reserve life index ("RLI") is calculated by dividing the 2P reserves of 272 MMboe as at December 31, 2020, by the midpoint of the initial 2021 average net daily production guidance of 41,000 to 43,000 boepd.

The product types comprising the 2P reserves and the contingent resources described in this MD&A are contained in the AIF. See also "Supplemental Information regarding Product Types" below. Light, medium and heavy crude oil reserves/resources disclosed in this MD&A include solution gas and other by-products.

"2P reserves" means proved plus probable reserves. "Proved reserves" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. "Probable reserves" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Each of the reserves categories reported (proved and probable) may be divided into developed and undeveloped categories. "Developed reserves" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing. "Developed producing reserves" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty. "Developed non-producing reserves" are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown. "Undeveloped reserves" are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies are conditions that must be satisfied for a portion of contingent resources to be classified as reserves that are: (a) specific to the project being evaluated; and (b) expected to be resolved within a reasonable timeframe. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on a project maturity and/or characterized by their economic status.

There are three classifications of contingent resources: low estimate, best estimate and high estimate. Best estimate is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will be actually recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.

Contingent resources are further classified based on project maturity. The project maturity subclasses include development pending, development on hold, development unclarified and development not viable. All of the Corporation's contingent resources are classified as either development on hold or development unclarified. Development on hold is defined as a contingent resource where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator. Development unclarified is defined as a contingent resource that requires further appraisal to clarify the potential for development and has been assigned a lower chance of development until contingencies can be clearly defined. Chance of development is the probability of a project being commercially viable.

References to "unrisked" contingent resources volumes means that the reported volumes of contingent resources have not been risked (or adjusted) based on the chance of commerciality of such resources. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore unrisked reported volumes of contingent resources do not reflect the risking (or adjustment) of such volumes based on the chance of development of such resources.

The contingent resources reported in the MD&A are estimates only. The estimates are based upon a number of factors and assumptions each of which contains estimation error which could result in future revisions of the estimates as more technical and commercial information becomes available. The estimation factors include, but are not limited to, the mapped extent of the oil and gas accumulations, geologic characteristics of the reservoirs, and dynamic reservoir performance. There are numerous risks and uncertainties associated with recovery of such resources, including many factors beyond the Corporation's control. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources referred to in the MD&A.

2P reserves and contingent resources included in the reports prepared by Sproule and ERCE in respect of IPC's oil and gas assets in Canada, France and Malaysia have been aggregated by IPC. Estimates of reserves, resources and future net revenue for individual properties may not reflect the same level of confidence as estimates of reserves, resources and future net revenue for all properties, due to aggregation. This MD&A contains estimates of the net present value of the future net revenue from IPC's reserves. The estimated values of future net revenue disclosed in this MD&A do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material.

References to "contingent resources" do not constitute, and should be distinguished from, references to "reserves".

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 thousand cubic feet (Mcf) per 1 barrel (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. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a 6:1 conversion basis may be misleading as an indication of value.

Supplemental Information regarding Product Types

The following table is intended to provide supplemental information about the product type composition of IPC's net average daily production figures provided in this document:

	Heavy Crude Oil (Mboepd)	Light and Medium Crude Oil (Mboepd)	Conventional Natural Gas (per day)	Total (Mboepd)
Three months ended				
June 30, 2021	18.6	8.9	102.0 Mcf (17.0 Mboe)	44.6
June 30, 2020	11.0	7.7	102.0 Mcf (17.0 Mboe)	35.7
Six months ended				
June 30, 2021	19.0	8.5	100.2 Mcf (16.7 Mboe)	44.2
June 30, 2020	15.4	8.5	102.0Mcf (17.0 Mboe)	40.9
Year ended				
December 31, 2020	16.5	8.5	103.1 Mcf (17.2 Mboe)	42.1

This document also makes reference to IPC's forecast average net daily production of above 44,000 boepd for 2021. IPC estimates that approximately 45% of that production will be comprised of heavy oil, approximately 18% will be comprised of light and medium crude oil and approximately 37% will be comprised of conventional natural gas.

OTHER SUPPLEMENTARY INFORMATION

Abbreviations

CAD or CA$	Canadian dollar
EUR or €	Euro
USD or US$	US dollar
MYR	Malaysian Ringgit
FPSO	Floating Production Storage and Offloading (facility)

Oil related terms and measurements

AECO	The daily average benchmark price for natural gas at the AECO hub in southeast Alberta
API	An indication of the specific gravity of crude oil on the API (American Petroleum Institute) gravity scale
ASP	Alkaline surfactant polymer (an EOR process)
bbl	Barrel (1 barrel = 159 litres)
boe[1]	Barrels of oil equivalents
boepd	Barrels of oil equivalents per day
bopd	Barrels of oil per day
Bscf	Billion standard cubic feet
Empress	The benchmark price for natural gas at the Empress point at the Alberta/Saskatchewan border
EOR	Enhanced Oil Recovery
Mbbl	Thousand barrels
MMbbl	Million barrels
Mboe	Thousand barrels of oil equivalents
Mboepd	Thousand barrels of oil equivalents per day
Mbopd	Thousand barrels of oil per day
MMboe	Million barrels of oil equivalents
MMbtu	Million British thermal units
Mcf	Thousand cubic feet
NGL	Natural gas liquid
SAGD	Steam assisted gravity drainage (a thermal recovery process)
WTI	West Texas Intermediate (a light oil reference price)
WCS	Western Canadian Select (a heavy oil reference price)

[1] All volume references to boe are calculated on the basis of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 Mcf: 1 bbl) unless otherwise indicated. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, particularly if used in isolation. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

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