# Q4

## International Petroleum Corporation

# *Management's Discussion and Analysis*

*For the three months ended and year ended December 31, 2021*

International Petroleum Corp.

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## For the three months ended and year ended December 31, 2021

## 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 21.

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 33.

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, 2021, 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, 2021, 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, 2021, 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, 2021, 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 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. Although demand, commodity prices and share prices have recovered, there can be no assurance that these effects will not resume 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 February 8, 2022, 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 audited consolidated financial statements and accompanying notes for the year ended December 31, 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:

| | December 31, 2021 | | December 31, 2020 | |
|---|---|---|---|---|
| | Average | Period end | Average | Year end |
| 1 EUR equals USD | 1.1835 | 1.1326 | 1.1413 | 1.2271 |
| 1 USD equals CAD | 1.2536 | 1.2708 | 1.3412 | 1.2740 |
| 1 USD equals MYR | 4.1433 | 4.1660 | 4.2026 | 4.0209 |

## HIGHLIGHTS

### 2021 Business and Financial Highlights

- Average net production of approximately 46,800 barrels of oil equivalent (boe) per day (boepd) for the fourth quarter of 2021 was above the high end of the third quarter of 2021 guidance range for the period (46% heavy crude oil, 18% light and medium crude oil and 36% natural gas)[1].
- Full year 2021 average net production was 45,500 boepd above the high end of guidance and year end exit rate was above 46,000 boepd.
- Production from the new sustaining Pad D' at Onion Lake Thermal, Canada successfully brought online in the third quarter of 2021, with initial performance ahead of expectations and five production infill wells drilled at Onion Lake Thermal during the fourth quarter of 2021.
- Increased working interest in the Bertam Field, Malaysia from 75% to 100% in April 2021.
- Exceptional operational performance at the Bertam Field during 2021, with greater than 99% uptime and the successful increase of Bertam FPSO water handling capacity from 17,000 to 24,000 barrels of water per day in Q3 2021.
- Drilling operations on the A15 sidetrack well at the Bertam Field commenced in December 2021.
- Second annual Sustainability Report published in Q2 2021.
- Proved plus probable (2P) reserves as at December 31, 2021 of 270 million boe (MMboe), with a reserves life index (RLI) of 16 years[1][2].
- Contingent resources (best estimate, unrisked) as at December 31, 2021 of 1,410 MMboe[1][2].
- Operating costs per boe of USD 15.1 for the fourth quarter of 2021 and USD 15.0 for the full year compared to full year guidance of USD 15.5 per boe.[3]
- Record high operating cash flow (OCF) generation for the fourth quarter and full year 2021 amounted to MUSD 111 and MUSD 337 respectively.[3]
- Capital and decommissioning expenditures of MUSD 48 for the full year 2021, slightly below guidance of MUSD 50 following the re-phasing of drilling projects in Malaysia into the first quarter of 2022.
- Record high free cash flow (FCF) generation for the fourth quarter and full year 2021 amounted to MUSD 87 and MUSD 263 respectively.[3]
- Net debt of MUSD 94 as at December 31, 2021, down from MUSD 161 at the end of the third quarter of 2021 and down from MUSD 321 as at December 31, 2020.[3]
- Net debt to 12 month rolling EBITDA ratio as at December 31, 2021 was 0.3 times.[3]
- Net result of MUSD 67 for the fourth quarter of 2021 and MUSD 146 for the full year 2021.

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| USD Thousands | 2021 | 2020 | 2021 | 2020 |
| Revenue | 215,296 | 103,353 | 666,409 | 324,164 |
| Gross profit / (loss) | 79,469 | (60,570) | 210,321 | (83,986) |
| Net result | 66,918 | (45,250) | 146,059 | (77,941) |
| Operating cash flow[3] | 110,687 | 46,019 | 336,732 | 119,423 |
| Free cash flow[3] | 86,960 | 28,571 | 262,884 | 9,342 |
| EBITDA[3] | 110,087 | 43,004 | 330,754 | 108,451 |
| Net Debt[3] | 94,312 | 321,193 | 94,312 | 321,193 |

### 2022 Business Plan Highlights

- Forecast cumulative FCF for 2022 to 2026 of approximately MUSD 900 to MUSD 1,800 (Brent USD 65 to 95 per barrel) generating estimated average annual free cash flow yield over the five year period of between 18% and 36%.[3][7]
- Approved new capital allocation plan where, from and including 2022, IPC intends to distribute to shareholders up to 40% of the FCF generated by IPC above achieved average Brent oil prices of USD 55 per barrel.
- IPC's inaugural USD 300 million bond issued on February 1, 2022, with a portion of the bond proceeds used to fully repay and cancel IPC's existing reserve-based lending credit facilities.

## OPERATIONS REVIEW

### Business Overview

Market conditions for oil and gas producers rebounded strongly in 2021 from the lows experienced in 2020, finishing on a high in the final quarter of 2021 with an average Brent oil price of USD 80 per barrel. Full year 2021 average Brent prices averaged USD 71 per barrel, well in excess of the full year 2020 Brent oil prices average of USD 42 per barrel.

Proactive supply management by the OPEC+ group, led by Saudi Arabia, has more than rebalanced the market. Excess oil inventory levels are reported to have drawn back down well below pre-pandemic levels, and now sit below the five year average. The recovery in oil demand remains on track and it now feels like we are approaching the beginning of the end of the pandemic. Covid-19 defences are incomparable to this time last year with the vaccination and testing programs we now have in place. This should bode well for oil demand going forward as the final wave of mobility restrictions eases and OPEC+ production curtailment fully unwind, noting that some producers are facing challenges in meeting their increased quotas.

In Canada, fourth quarter 2021 Western Canadian Select (WCS) crude price differentials averaged below USD 15 per barrel and forward markets into 2022 and 2023 are pricing the WCS differential at below USD 14 per barrel. Completion and placement into service of Enbridge's Line 3 replacement pipeline in the fourth quarter of 2021 as well as the positive construction progress on 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 several years. IPC has positioned itself well to benefit from this fundamental improvement in market conditions and has decided to take advantage of this by hedging approximately 60% of our WTI/WCS differential exposure at approximately USD 13 per barrel for the remainder of 2022. No other oil hedges are in place providing full exposure to the strength we are seeing in both the Brent and WTI benchmarks.

Gas markets have also strengthened driven by a combination of increasing demand, lower supply and warmer than average summer temperatures that diverted gas supply away from injecting into storage. Fourth quarter 2021 average Empress gas prices were CAD 5.00 per Mcf and forward 2022 prices sit above CAD 3.50 per Mcf. IPC has hedged AECO gas prices, 19,000 Mcf per day at CAD 4.40 CAD per Mcf in Q1 2022 and 33,000 Mcf per day at CAD 3.60 per Mcf in Q2 and Q3 2022.

IPC benefits from a well balanced mix of production comprising approximately 48% Canadian crude oil, 36% Canadian gas and 16% Brent weighted oil. With synchronized strength in pricing across the entire energy complex, combined with IPC delivering operational excellence above the high end of our forecasts, IPC has been able to deliver our best ever quarterly and annual financial performance since our launch in 2017.

We were very pleased with IPC's first USD 300 million bond, issued on February 1, 2022, accessing the debt capital markets at a favourable time. We used a portion of the proceeds of the bond to fully repay and cancel our existing reserve-based lending facilities and at the same time, we put in place a new CAD 75 million revolving credit facility for financial flexibility in Canada. We strongly believe that the winners in the next phase of the energy transition in the upstream oil and gas industry will be the companies able to access diverse sources of funding. Whilst we do not have an imminent acquisition, we believe that being able to demonstrate to sellers that IPC has the financial strength on its balance sheet, will enable IPC to access a greater universe of opportunities whilst differentiating us from our peers in terms of certainty of being able to close transactions.

We have created significant value from acquisition for all of our stakeholders having concluded four acquisitions in the past four years and will remain opportunistic in our approach with respect to further M&A activity focusing on securing additional high quality resources.

**Fourth Quarter and Full Year 2021 Highlights**
During the fourth quarter of 2021, our assets delivered average net production of 46,800 boepd.[1] Production for the full year 2021 averaged 45,500 boepd.[1] In all four quarters of 2021, IPC has delivered production above our original high end guidance. This was made possible by the very high uptime performance across all our assets as well as the earlier than forecast production contribution from the newly commissioned Pad D' at Onion Lake Thermal.

Our operating costs per boe for the fourth quarter of 2021 was USD 15.1.[3] Full year operating costs per boe of 15.0 was below our latest guidance of USD 15.50 per boe, largely driven by the production outperformance.

Operating cash flow generation for the fourth quarter of 2021 was USD 111 million, a record high for IPC.[3] Full year operating cash flow amounts to USD 337 million, above our high end guidance and a record for IPC.

Capital and decommissioning expenditures for the full year was USD 48 million, USD 2 million below guidance largely the result of re-phasing into 2022.

Free cash flow generation was exceptionally strong at USD 87 million during the fourth quarter of 2021 and USD 263 million for the full year, a record quarterly and full year result for IPC and above our latest high end guidance.[3] This represents close to 26% of IPC's current market capitalization.

Net debt reduced more than 70% during 2021 to USD 94 million as at December 31, 2021.[3] Net debt to EBITDA drops to 0.3 times at year-end 2021 from 3 times at the year-end 2020 (trailing 12 months).

**Capital Allocation Plans**
We are also pleased to announce IPC's 2022 capital allocation plans, given our strong forecast liquidity position resulting from continued operational performance and strong commodity prices. Based on our current business plans and assumptions, IPC plans to distribute to shareholders up to 40% of the free cash flow generated by IPC above achieved average Brent oil prices of USD 55 per barrel, provided that IPC's net debt to EBITDA ratio is at or below 1 time.[3][7] These shareholder distributions are planned to be implemented by continued share repurchases under the previously announced share repurchase program as well as the consideration by IPC of other forms of shareholder distributions, subject to further applicable regulatory and corporate approvals.

**Share Repurchase Program**
In Q4 2021, IPC announced a share repurchase program, with the ability to repurchase up to approximately 11.1 million IPC common shares over the twelve month period to December 2022. IPC repurchased in December 2021 and subsequently cancelled approximately 1.3 million IPC shares, at an average purchase price of approximately SEK 49.5 (or around CAD 6.95) per share. By the end of January 2022, IPC repurchased a further approximately 1.0 million IPC shares of which 726,676 shares have been cancelled.

**Environmental, Social and Governance ("ESG") Performance**
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. Over the past five years, IPC has rapidly grown our business with the completion of three acquisitions in Canada, an acquisition in Malaysia in addition to significant organic investments into those businesses. In parallel, we have made a concerted effort to further develop and improve our sustainability strategy. An important part of this 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 were very pleased to publish our second Sustainability Report that was fully GRI compliant. We encourage everyone to read it and see first-hand the good work that is being done within our company. As previously announced, IPC targets a reduction of our net GHG emissions intensity by the end of 2025 to 50% of the Corporation's 2019 baseline.

During the fourth quarter of 2021 and for the full year 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. Throughout 2021, IPC continued the health protocols implemented across the organization.

**Reserves and Resources**
As at the end of December 2021, IPC's 2P reserves are 270 MMboe.[1][2] During 2021, IPC replaced 91% of production through a combination of reserve additions and the acquisition of an additional 25% working interest in the Bertam field, Malaysia. The reserves life index (RLI) as at December 31, 2021, is approximately 16 years.[2]

Based on independent qualified reserve auditor reports, the net present value (NPV)[2][4] of IPC's 2P reserves as at December 31, 2021 was USD 2,522 million. IPC's net asset value (NAV)[2][5] as at December 31, 2021 was USD 2,428 million. IPC's NAV per share[2][6] was SEK 143 as at December 31, 2021.

In addition, IPC's best estimate contingent resources (unrisked) as at end December 2021 have increased by more than 300 MMboe to 1,410 MMboe.[1][2]

The biggest single contributor to the increase in contingent resource estimates comes from the Blackrod project in Canada.[1][2] IPC commissioned a third party independent qualified reserves evaluator report from Sproule Associates Ltd. (Sproule) on the contingent resources at Blackrod Phase I as at December 31, 2021. Full field best estimate contingent resources (unrisked) increased from 987 MMboe as at end December 2020 to 1,283 MMboe as at end December 2021. Phase I best estimate contingent resources (unrisked) increased from 178 MMboe to 217 MMboe as at end December 2021. Development capital expenditure to first oil is estimated at USD 540 million (unrisked). The Phase I development concept has been further optimised to include initial production capacity of 20,000 bopd rising to 30,000 bopd. First oil is assumed to be four to five years after final investment decision with production ramping up to 30,000 bopd thereafter. The breakeven oil price estimated by IPC assuming a 10% discount rate is a WTI price of approximately USD 50 per barrel. Using Sproule's price forecasts as at December 31, 2021, the net present value at a 10% discount rate (after tax, unrisked) of Blackrod Phase I as at December 31, 2021 is USD 609 million. IPC plans to mature the Blackrod Phase I project during 2022 through FEED studies in parallel with the continuation of production from well pair three.

**2022 Budget and Production Guidance**

We are pleased to announce our 2022 average net production guidance is 46,000 to 48,000 boepd.[1] We forecast operating costs for 2022 to be USD 15.2 per boe.[3]

We also forecast significant free cash flow generation based on our 2P reserves base of an aggregate of more than USD 900 million to USD 1,800 million over the period of 2022 to 2026, without taking into account development of our contingent resources or any further potential acquisitions.[2][3][7]

Our 2022 capital expenditure budget is USD 127 million, as IPC focuses our 2022 strategy on strong free cash flow generation whilst growing our production and maturing our significant contingent resource base. The 2022 budget includes the commencement of investment at Onion Lake Thermal on the next sustaining Pad L as well as further infill drilling, Suffield oil N2N drilling, Phase I development at the Ferguson asset and Blackrod FEED studies as well as continued production from well pair three in Canada. We plan to complete the A15 sidetrack and ESP pump upsizing campaign in Malaysia as well as to start the Phase I development of the Villeperdue West project in France. Given that IPC operates 100% of these projects, significant flexibility is retained to amend our plans based on the development of commodity prices.

Notes:

(1) See "Supplemental Information regarding Product Types" in "Reserves and Resources Advisory" below. See also the material change report dated February 8, 2022 (MCR) available on IPC's website at www.international-petroleum.com and filed on the date of this press release under IPC's profile on SEDAR at www.sedar.com.
(2) See "Reserves and Resources Advisory" below. Further information with respect to IPC's reserves, contingent resources and estimates of future net revenue, including assumptions relating to the calculation of NPV, are further described in the MCR.
(3) Non-IFRS measure, see "Non-IFRS Measures" below and in the MD&A.
(4) NPV is after tax, discounted at 8% and based upon the forecast prices and other assumptions further described in the MCR. See "Reserves and Resources Advisory" below.
(5) NAV is calculated as NPV less net debt of USD 94 million as at December 31, 2021.
(6) NAV per share is based on 155,037,454 IPC common shares, being 155,198,105 IPC common shares outstanding as at December 31, 2021 less 1,160,651 IPC common shares held in treasury for cancellation in early January 2022.
(7) Estimated free cash flow generation is based on IPC's current business plans over the period of 2022 to 2026. Assumptions include average net production over that period of approximately 47 Mboepd, average Brent oil prices of USD 65 to 95 per boe escalating by 2% per year, average gas prices of CAD 3.00 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 MCR. Free cash flow yield is based on IPC's market capitalization at close February 4, 2022 (60.0 SEK/share, 9.1 SEK/USD, USD 1,014 million). 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. See "Cautionary Statement Regarding Forward-Looking Information" below.

## Operations Overview

**Reserves and Resources**

The 2P reserves attributable to IPC oil and gas assets are 270 MMboe as at December 31, 2021, as certified by independent third party reserves auditors. The reserves life index (RLI) as at December 31, 2021, is approximately 16 years. Best estimate contingent resources as at December 31, 2021, are 1,410 MMboe (unrisked). See "Reserves and Resources Advisory" below.

IPC remains focused on organic growth, maturing and executing opportunities across all our operated assets. IPC initially set a limited capital budget for 2021, with the focus on free cash flow delivery to the business. At the end of the second quarter in 2021, with strong production performance and improved market conditions strengthening free cash flow generation, IPC increased the capital expenditure budget to allow for infill drilling and optimisation projects in both Malaysia and Canada. In Canada, production sustaining Pad D' and five infill wells have been successfully delivered and brought online at Onion Lake Thermal. In Malaysia, the A15 sidetrack and Electric Submersible Pump (ESP) upsizing campaign commenced in Q4 2021; drilling operations are ongoing with first production from the project expected in the first quarter of 2022. IPC remains focused on free cash flow generation and, notwithstanding the inclusion of the incremental capital expenditure projects in 2021, IPC delivered free cash flow well in excess of our original high end Capital Markets Day 2021 guidance.

**Production**

The average net production during Q4 2021 was 46,800 boepd. This is the fourth quarter in succession of delivering production above our high end CMD guidance. In Canada, the exceptional production performance continued with high levels of production optimisation activity driving our gas production to the high end of guidance. All five new production infill wells have been brought online at Onion Lake Thermal. In addition, strong performance from the Malaysian and French assets continued in Q4 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.

With the exceptional operational performance through 2021, IPC achieved a net annual average production of 45,500 boepd, a 500 boepd increase from our previous guidance of above 45,000 boepd and six percent above our original high end CMD guidance.

The production during Q4 2021 with comparatives is summarized below:

| Production in Mboepd | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | 2021 | 2020 | 2021 | 2020 |
| Crude oil | | | | |
| Canada – Northern Assets | 14.2 | 12.0 | 12.8 | 10.6 |
| Canada – Southern Assets | 8.5 | 8.4 | 8.6 | 7.1 |
| Malaysia | 4.5 | 4.2 | 4.4 | 4.4 |
| France | 2.9 | 2.9 | 3.0 | 2.8 |
| Total crude oil production | **30.1** | 27.5 | **28.8** | 24.9 |
| Gas | | | | |
| Canada – Northern Assets | 0.1 | 0.1 | 0.1 | 0.1 |
| Canada – Southern Assets | 16.6 | 17.3 | 16.6 | 17.1 |
| Total gas production | **16.7** | 17.4 | **16.7** | 17.2 |
| Total production | **46.8** | 44.9 | **45.5** | 42.1 |
| Quantity in MMboe | **4.31** | 4.13 | **16.61** | 15.42 |

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

## CANADA

| Production in Mboepd | WI | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|---|
| | | 2021 | 2020 | 2021 | 2020 |
| - Oil Onion Lake Thermal | 100% | 11.5 | 10.6 | 10.6 | 9.5 |
| - Oil Suffield | 100% | 7.5 | 7.2 | 7.5 | 5.9 |
| - Oil Ferguson | 100% | 1.0 | 1.2 | 1.1 | 1.2 |
| - Oil Other | 50-100% | 2.7 | 1.4 | 2.2 | 1.1 |
| - Gas | 99.7%[1] | 16.7 | 17.4 | 16.7 | 17.2 |
| Canada | | **39.4** | 37.8 | **38.1** | 34.9 |

[1] *On a well count basis*

**Production**
Net production from the Canadian assets during Q4 2021 was above the high end of CMD guidance at 39,400 boepd with continued strong performance and high production uptime at all the oil and gas producing assets. In Q4 2021, high levels of production optimisation activity pushed Suffield Gas production to the high end of our guidance range.

**Organic Growth and Capital Projects**
In Canada, IPC had originally set a limited capital budget for 2021. At the end of Q2 2021, IPC increased the capital expenditure budget to allow the 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, new production sustaining Pad D' was brought online in Q3 2021. As of the end of Q4 2021, all six production wells have been successfully brought online with initial production in line with pre sanction expectations. During Q4 2021, the five well infill drilling campaign was successfully completed at Onion Lake Thermal. All five production wells have been brought online with positive initial indications as the wells clean up.

The production ramp up and testing of the third well pair at the Blackrod SAGD pilot project continued through Q4 2021. Heat conformance and production performance remain ahead of expectation.

## MALAYSIA

| Production in Mboepd | WI | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|---|
| | | 2021 | 2020 | 2021 | 2020 |
| Bertam | 100% [1] | 4.5 | 4.2 | 4.4 | 4.4 |

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

**Production**
Net production from the Bertam field on Block PM307 during Q4 2021 was ahead of CMD guidance at 4,500 boepd with continued excellent operational performance and facility uptime close to 100%.

**Organic Growth and Capital Projects**
In Malaysia, IPC originally set a limited capital budget for 2021. In April 2021, IPC increased its working interest in the Bertam field from 75% to 100%. At the end of Q2 2021, IPC 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 the end of Q4 2021, A15 sidetrack drilling operations have commenced with first oil from the well planned to be delivered in the first quarter of 2022. The production well pump rate optimisation project is scheduled to follow in Q1 2022.

### FRANCE

| Production in Mboepd | WI | Three months ended December 31 2021 | Three months ended December 31 2020 | Year ended December 31 2021 | Year ended December 31 2020 |
|---|---|---|---|---|---|
| France | | | | | |
| - Paris Basin | 100%[1] | 2.5 | 2.5 | 2.6 | 2.4 |
| - Aquitaine | 50% | 0.4 | 0.4 | 0.4 | 0.4 |
| | | **2.9** | 2.9 | **3.0** | 2.8 |

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

**Production**
Net production in France during Q4 2021 was ahead of CMD guidance at 2,900 boepd with stable production and good uptime at the major producing fields. In Q4 2021, strong reservoir performance continued at the Vert-la-Gravelle field supported by increased water injection.

**Organic Growth**
In France, IPC 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 Annual Financial Information*

Selected consolidated statement of operations is as follows:

| USD Thousands | 2021 | 2020 | 2019 |
|---|---|---|---|
| Revenue | **666,409** | 324,164 | 553,749 |
| Gross profit | **210,321** | (83,986) | 152,904 |
| Net result | **146,059** | (77,941) | 103,588 |
| Earnings per share – USD | **0.94** | (0.50) | 0.63 |
| Earnings per share fully diluted – USD | **0.92** | (0.49) | 0.62 |
| Operating cash flow[1] | **336,732** | 119,423 | 307,944 |
| Free cash flow[1] | **262,884** | 9,342 | 89,308 |
| EBITDA[1] | **330,754** | 108,451 | 302,513 |
| Net debt at period end[1] | **94,312** | 321,193 | 231,503 |

[1] *See definition on page 21 under "Non-IFRS measures"*

Summarized consolidated balance sheet information is as follows:

| USD Thousands | December 31, 2021 | December 31, 2020 | December 31, 2019 |
|---|---|---|---|
| Non-current assets | 1,122,514 | 1,240,653 | 1,252,600 |
| Current assets | 151,160 | 92,467 | 112,041 |
| **Total assets** | **1,273,674** | 1,333,120 | 1,364,641 |
| Total non-current liabilities | 331,152 | 527,530 | 474,200 |
| Current liabilities | 94,979 | 97,137 | 99,632 |
| **Total liabilities** | **426,131** | 624,667 | 573,832 |
| **Net assets** | **847,543** | 708,453 | 790,809 |
| | | | |
| **Working capital (including cash)** | **56,181** | (4,670) | 12,409 |

### *Selected Interim Financial Information*

Selected interim condensed consolidated statement of operations is as follows:

| USD Thousands | 2021 | Q4-21 | Q3-21 | Q2-21 | Q1-21 | 2020 | Q4-20 | Q3-20 | Q2-20 | Q1-20 |
|---|---|---|---|---|---|---|---|---|---|---|
| Revenue | **666,409** | **215,296** | 172,551 | 144,278 | 134,284 | **324,164** | 103,353 | 95,346 | 44,929 | 80,536 |
| Gross profit | **210,321** | **79,469** | 58,636 | 34,286 | 37,930 | **(83,986)** | (60,570) | 5,557 | (16,537) | (12,436) |
| Net result | **146,059** | **66,918** | 30,557 | 21,693 | 26,891 | **(77,941)** | (45,250) | 8,850 | (1,472) | (40,069) |
| Earnings per share – USD | **0.94** | **0.43** | 0.20 | 0.14 | 0.17 | **(0.50)** | (0.29) | 0.06 | (0.01) | (0.25) |
| Earnings per share fully diluted – USD | **0.92** | **0.42** | 0.19 | 0.14 | 0.17 | **(0.49)** | (0.29) | 0.06 | (0.01) | (0.25) |
| Operating cash flow[1] | **336,732** | **110,687** | 91,365 | 66,959 | 67,721 | **119,423** | 46,019 | 37,181 | 14,742 | 21,481 |
| Free cash flow[1] | **262,884** | **86,960** | 76,607 | 50,366 | 48,951 | **9,342** | 28,571 | 22,766 | 717 | (42,712) |
| EBITDA[1] | **330,754** | **110,087** | 89,223 | 65,181 | 66,263 | **108,451** | 43,004 | 34,251 | 12,187 | 19,009 |
| Net debt at period end[1] | **94,312** | **94,312** | 161,199 | 240,617 | 286,132 | **321,193** | 321,193 | 322,092 | 341,367 | 302,473 |

[1] *See definition on page 21 under "Non-IFRS measures"*

### *Selected Interim Financial 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 – December 31, 2021 | | | | | |
|---|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia[1] | France | Other | Total |
| Crude oil | 84,039 | 53,940 | 47,166 | 18,863 | – | **204,008** |
| NGLs | – | 172 | – | – | – | **172** |
| Gas | 212 | 33,076 | – | – | – | **33,288** |
| **Net sales of oil and gas** | **84,251** | **87,188** | **47,166** | **18,863** | – | **237,468** |
| Change in under/over lift position | – | – | – | 2,958 | – | **2,958** |
| Royalties | (7,968) | (7,095) | – | – | – | **(15,063)** |
| Hedging settlement | (7,109) | (3,323) | – | – | – | **(10,432)** |
| Other operating revenue | – | 171 | – | 194 | – | **365** |
| **Revenue** | **69,174** | **76,941** | **47,166** | **22,015** | – | **215,296** |
| Production costs (including inventory movements) | (36,585) | (34,998) | (19,984) | (10,994) | – | **(102,561)** |
| Depletion | (8,121) | (10,758) | (7,843) | (3,571) | – | **(30,293)** |
| Depreciation of other tangible fixed assets | – | – | (2,628) | – | – | **(2,628)** |
| Exploration and business development costs | (4) | – | – | – | (341) | **(345)** |
| **Gross profit/(loss)** | **24,464** | **31,185** | **16,711** | **7,450** | **(341)** | **79,469** |

| | Three months ended – December 31, 2020 | | | | | |
|---|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia[1] | France | Other | Total |
| Crude oil | 31,835 | 28,352 | 18,569 | 10,333 | – | 89,089 |
| NGLs | – | 72 | – | – | – | 72 |
| Gas | 97 | 18,528 | – | – | – | 18,625 |
| **Net sales of oil and gas** | **31,932** | **46,952** | **18,569** | **10,333** | – | **107,786** |
| Change in under/over lift position | – | – | – | 2,430 | – | 2,430 |
| Royalties | (2,954) | (2,596) | – | – | – | (5,550) |
| Hedging settlement | (1,867) | (3,866) | – | – | – | (5,733) |
| Other operating revenue | – | – | 3,910 | 384 | 126 | 4,420 |
| **Revenue** | **27,111** | **40,490** | **22,479** | **13,147** | **126** | **103,353** |
| Production costs (including inventory movements) | (16,589) | (24,106) | (8,803) | (7,724) | – | (57,222) |
| Depletion | (7,381) | (11,262) | (6,553) | (4,597) | – | (29,793) |
| Depreciation of other tangible fixed assets | – | – | (2,751) | – | – | (2,751) |
| Exploration and business development costs | (24) | – | (829) | (33) | (128) | (1,014) |
| Impairment costs of oil and gas properties | – | – | – | (73,143) | – | (73,143) |
| **Gross profit/(loss)** | **3,117** | **5,122** | **3,543** | **(72,350)** | **(2)** | **(60,570)** |

| | Year ended – December 31, 2021 | | | | | |
|---|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia[1] | France | Other | Total |
| Crude oil | 268,403 | 190,287 | 100,436 | 75,949 | – | 635,075 |
| NGLs | – | 570 | – | – | – | 570 |
| Gas | 630 | 99,389 | – | – | – | 100,019 |
| **Net sales of oil and gas** | **269,033** | **290,246** | **100,436** | **75,949** | – | **735,664** |
| Change in under/over lift position | – | – | – | 5,391 | – | 5,391 |
| Royalties | (25,179) | (21,245) | – | – | – | (46,424) |
| Hedging settlement | (22,272) | (11,320) | – | – | – | (33,592) |
| Other operating revenue | – | 171 | 4,208 | 927 | 64 | 5,370 |
| **Revenue** | **221,582** | **257,852** | **104,644** | **82,267** | **64** | **666,409** |
| Production costs (including inventory movements) | (131,700) | (128,016) | (25,243) | (40,048) | – | (325,007) |
| Depletion | (29,667) | (43,097) | (30,156) | (16,093) | – | (119,013) |
| Depreciation of other tangible fixed assets | – | – | (10,108) | – | – | (10,108) |
| Exploration and business development costs | (8) | – | (259) | (7) | (1,686) | (1,960) |
| **Gross profit/(loss)** | **60,207** | **86,739** | **38,878** | **26,119** | **(1,622)** | **210,321** |

| | Year ended – December 31, 2020 | | | | | |
|---|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia[1] | France | Other | Total |
| Crude oil | 89,206 | 78,146 | 60,465 | 35,700 | – | 263,517 |
| NGLs | – | 214 | – | – | – | 214 |
| Gas | 334 | 59,616 | – | – | – | 59,950 |
| **Net sales of oil and gas** | 89,540 | 137,976 | 60,465 | 35,700 | – | 323,681 |
| Change in under/over lift position | – | – | – | (630) | – | (630) |
| Royalties | (8,202) | (5,862) | – | – | – | (14,064) |
| Hedging settlement | 1,351 | (3,334) | – | – | – | (1,983) |
| Other operating revenue | – | – | 15,555 | 1,164 | 441 | 17,160 |
| **Revenue** | 82,689 | 128,780 | 76,020 | 36,234 | 441 | 324,164 |
| Production costs (including inventory movements) | (64,623) | (88,759) | (24,793) | (26,453) | – | (204,628) |
| Depletion | (26,255) | (40,555) | (27,759) | (17,327) | – | (111,896) |
| Depreciation of other tangible fixed assets | – | – | (11,681) | – | – | (11,681) |
| Exploration and business development costs | (3,011) | – | (741) | (2,389) | (661) | (6,802) |
| Impairment costs of oil and gas properties | – | – | – | (73,143) | – | (73,143) |
| **Gross profit/(loss)** | (11,200) | (534) | 11,046 | (83,078) | (220) | (83,986) |

*[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 months and year ended December 31, 2021, Review*

**Revenue**

Total revenue amounted to USD 215,296 thousand for Q4 2021 compared to USD 103,353 thousand for Q4 2020 and USD 666,409 thousand for the year ended December 31, 2021, compared to USD 324,164 thousand for the year ended December 31, 2020, and is analyzed as follows:

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| USD Thousands | 2021 | 2020 | 2021 | 2020 |
| Crude oil sales | 204,008 | 89,089 | 635,075 | 263,517 |
| Gas and NGL sales | 33,460 | 18,697 | 100,589 | 60,164 |
| Change in under/overlift position | 2,958 | 2,430 | 5,391 | (630) |
| Royalties | (15,063) | (5,550) | (46,424) | (14,064) |
| Hedging settlement | (10,432) | (5,733) | (33,592) | (1,983) |
| Other operating revenue | 365 | 4,420 | 5,370 | 17,160 |
| **Total revenue** | **215,296** | 103,353 | **666,409** | 324,164 |

The main components of total revenue for the three months and year ended December 31, 2021, and December 31, 2020, respectively are detailed below.

**Crude oil sales**

| | Three months ended – December 31, 2021 | | | | |
|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia[1] | France | Total |
| Crude oil sales | | | | | |
| - Revenue in USD thousands | 84,039 | 53,940 | 47,166 | 18,863 | **204,008** |
| - Quantity sold in bbls | 1,405,654 | 873,890 | 577,258 | 235,921 | **3,092,723** |
| - Average price realized USD per bbl | 59.79 | 61.72 | 81.71 | 79.96 | **65.96** |

| | Three months ended – December 31, 2020 | | | | |
|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia[1] | France | Total |
| Crude oil sales | | | | | |
| - Revenue in USD thousands | 31,835 | 28,352 | 18,569 | 10,333 | **89,089** |
| - Quantity sold in bbls | 1,113,135 | 860,551 | 395,244 | 225,974 | **2,594,904** |
| - Average price realized USD per bbl | 28.60 | 32.95 | 46.98 | 45.73 | **34.33** |

Crude oil revenue was more than double for Q4 2021 compared to Q4 2020 mainly due to higher oil prices. Q4 2020 was impacted by the global Covid-19 outbreak causing a decrease in oil demand and prices.

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 Q4 2021, WTI averaged USD 77 per bbl compared to USD 43 per bbl for Q4 2020 and the average discount to WCS used in our pricing formula was USD 15 per bbl (USD 9 per bbl for Q4 2020).

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices. There were two cargo liftings in Malaysia during Q4 2021 compared to two cargo liftings in Q4 2020. Produced unsold oil barrels from Bertam at the end of Q4 2021 amounted to 103,000 barrels, see Change in Inventory Position section below. There was no Aquitaine cargo lifted in Q4 2021. The average Dated Brent crude oil price was USD 80 per bbl for Q4 2021 compared to USD 44 per bbl for the comparative period.

| USD Thousands | Year ended – December 31, 2021 Canada – Northern Assets | Canada – Southern Assets | Malaysia[1] | France | Total |
|---|---|---|---|---|---|
| Crude oil sales | | | | | |
| - Revenue in USD thousands | 268,403 | 190,287 | 100,436 | 75,949 | **635,075** |
| - Quantity sold in bbls | 5,118,726 | 3,505,698 | 1,337,346 | 1,069,276 | **11,031,046** |
| - Average price realized USD per bbl | 52.44 | 54.28 | 75.10 | 71.03 | **57.57** |

| USD Thousands | Year ended – December 31, 2020 Canada – Northern Assets | Canada – Southern Assets | Malaysia[1] | France | Total |
|---|---|---|---|---|---|
| Crude oil sales | | | | | |
| - Revenue in USD thousands | 89,206 | 78,146 | 60,465 | 35,700 | **263,517** |
| - Quantity sold in bbls | 4,000,485 | 2,821,549 | 1,358,097 | 998,700 | **9,178,831** |
| - Average price realized USD per bbl | 22.30 | 27.70 | 44.52 | 35.75 | **28.71** |

Crude oil sales revenues were 141% higher for the year ended December 31, 2021, compared to the year ended December 31, 2020, mainly due to a 101% 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 WCS price which trades at a discount to WTI. WTI averaged USD 68 per bbl and the average discount from WTI to WCS was approximately USD 13 per bbl for the year ended December 31, 2021, compared to an average WTI of USD 40 per bbl and an average discount from WTI to WCS of USD 13 per bbl for the comparative period in 2020.

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 71 per bbl for the year ended December 31, 2021, compared to USD 42 per bbl for the comparative period in 2020.

**Gas and NGL sales**

| | Three months ended – December 31, 2021 Canada – Southern Assets | Canada – Northern Assets | Total |
|---|---|---|---|
| Gas and NGL sales | | | |
| - Revenue in USD thousands | 33,248 | 212 | **33,460** |
| - Quantity sold in Mcf | 8,536,894 | 69,643 | **8,606,537** |
| - Average price realized USD per Mcf | 3.89 | 3.05 | **3.89** |

| | Three months ended – December 31, 2020 Canada – Southern Assets | Canada – Northern Assets | Total |
|---|---|---|---|
| Gas and NGL sales | | | |
| - Revenue in USD thousands | 18,600 | 97 | **18,697** |
| - Quantity sold in Mcf | 8,922,304 | 54,072 | **8,976,376** |
| - Average price realized USD per Mcf | 2.08 | 1.79 | **2.08** |

Gas and NGL sales revenue was 79% higher for Q4 2021 compared to Q4 2020 mainly due to the higher achieved gas price. Approximately 98% of the Suffield gas production was physically sold on the Alberta/Saskatchewan border with the remainder being delivered in Alberta based on AECO pricing plus a premium. For Q4 2021, IPC realized an average price of CAD 4.87 per Mcf compared to AECO average pricing of CAD 4.66 per Mcf and Empress average pricing of CAD 4.99 per Mcf for Q4 2021.

| | Year ended – December 31, 2021 | | |
|---|---|---|---|
| | Canada – Southern Assets | Canada – Northern Assets | Total |
| Gas and NGL sales | | | |
| - Revenue in USD thousands | 99,959 | 630 | **100,589** |
| - Quantity sold in Mcf | 33,731,280 | 237,489 | **33,968,769** |
| - Average price realized USD per Mcf | 2.96 | 2.65 | **2.96** |

| | Year ended – December 31, 2020 | | |
|---|---|---|---|
| | Canada – Southern Assets | Canada – Northern Assets | Total |
| Gas and NGL sales | | | |
| - Revenue in USD thousands | 59,830 | 334 | **60,164** |
| - Quantity sold in Mcf | 35,113,522 | 224,252 | **35,337,774** |
| - Average price realized USD per Mcf | 1.70 | 1.49 | **1.70** |

Gas and NGL sales revenue was 67% higher for the year ended December 31, 2021, compared to the comparative period in 2020 mainly due to the higher achieved gas price. For the year ended December 31, 2021, IPC realized an average price of CAD 3.70 per Mcf compared CAD 2.28 per Mcf for the comparative period in 2020. The AECO average pricing was CAD 3.63 per Mcf and the Empress average pricing was CAD 3.90 per Mcf for 2021.

**Hedging settlement**
IPC enters into risk management contracts in order to ensure a certain level of cashflow. It 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.

The realized hedging settlements for Q4 2021 amounted to a loss of USD 10,432 thousand and for the year ended December 31, 2021, amounted to a loss of USD 33,592 thousand, consisting of USD 5,410 thousand on the gas contracts and USD 28,182 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 365 thousand for Q4 2021 compared to USD 4,420 thousand for Q4 2020 and USD 5,370 thousand for the year ended December 31, 2021, compared to USD 17,160 thousand for the year ended December 31, 2020. 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 Carigali 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 102,561 thousand for Q4 2021 compared to USD 57,222 thousand for Q4 2020 and USD 325,007 thousand for the year ended December 31, 2021, compared to USD 204,628 thousand for the year ended December 31, 2020, and is analyzed as follows:

| | Three months ended – December 31, 2021 | | | | | |
|---|---|---|---|---|---|---|
| USD Thousands | Canada – Southern Assets | Canada – Northern Assets | Malaysia | France | Other[3] | Total |
| Operating costs[1] | 27,412 | 20,956 | 10,104 | 10,610 | (4,140) | 64,942 |
| USD/boe[2] | 11.89 | 15.90 | 24.27 | 39.37 | n/a | 15.07 |
| Cost of blending | 6,884 | 15,439 | – | – | – | 22,323 |
| Change in inventory position | 702 | 190 | 14,020 | 384 | – | 15,296 |
| Production costs | 34,998 | 36,585 | 24,124 | 10,994 | (4,140) | 102,561 |

| | Three months ended – December 31, 2020 | | | | | |
|---|---|---|---|---|---|---|
| USD Thousands | Canada – Southern Assets | Canada – Northern Assets | Malaysia | France | Other[3] | Total |
| Operating costs[1] | 20,367 | 14,176 | 18,621 | 7,597 | (11,730) | 49,031 |
| USD/boe[2] | 8.60 | 12.71 | 48.62 | 28.70 | n/a | 11.87 |
| Cost of blending | 3,106 | 3,677 | – | – | – | 6,783 |
| Change in inventory position | 62 | (693) | 1,912 | 127 | – | 1,408 |
| Production costs | 24,106 | 16,589 | 20,533 | 7,724 | (11,730) | 57,222 |

| | Year ended – December 31, 2021 | | | | | |
|---|---|---|---|---|---|---|
| USD Thousands | Canada – Southern Assets | Canada – Northern Assets | Malaysia | France | Other[3] | Total |
| Operating costs[1] | 102,084 | 79,213 | 51,420 | 39,852 | (24,340) | 248,229 |
| USD/boe[2] | 11.11 | 16.74 | 32.13 | 36.57 | n/a | 14.95 |
| Cost of blending | 25,579 | 52,855 | – | – | – | 78,434 |
| Change in inventory position | 353 | (368) | (1,837) | 196 | – | (1,656) |
| Production costs | 128,016 | 131,700 | 49,583 | 40,048 | (24,340) | 325,007 |

| | Year ended – December 31, 2020 | | | | | |
|---|---|---|---|---|---|---|
| USD Thousands | Canada – Southern Assets | Canada – Northern Assets | Malaysia | France | Other[3] | Total |
| Operating costs[1] | 75,054 | 57,616 | 72,152 | 25,639 | (46,665) | 183,796 |
| USD/boe[2] | 8.48 | 14.69 | 44.47 | 25.14 | n/a | 11.92 |
| Cost of blending | 13,334 | 7,357 | – | – | – | 20,691 |
| Change in inventory position | 371 | (350) | (694) | 814 | – | 141 |
| Production costs | 88,759 | 64,623 | 71,458 | 26,453 | (46,665) | 204,628 |

[1] *See definition on page 21 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 14.33 and USD 17.99 for Q4 2021 and Q4 2020, respectively, and USD 16.92 and USD 15.71 for the year ended December 31, 2021, and the year ended December 31, 2020, respectively.*

**Operating costs**
Operating costs amounted to USD 64,942 thousand for Q4 2021 compared to USD 49,031 thousand for Q4 2020 and USD 248,229 thousand for the year ended December 31, 2021, compared to USD 183,796 thousand for the year ended December 31, 2020. The increase in costs in 2021 compared to 2020 is due to increased activity and higher energy costs. Operating costs per boe amounted to USD 15.07 per boe in Q4 2021 compared with USD 11.87 per boe in Q4 2020 and to USD 14.95 per boe for the full year 2021 which was below CMD guidance of USD 15.5 per boe mainly as a result of higher production volumes.

**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 22,323 thousand for Q4 2021 compared to USD 6,783 thousand for Q4 2020 and USD 78,434 thousand for the year ended December 31, 2021, compared to USD 20,691 thousand for the year ended December 31, 2020. The increase is attributable to larger Onion Lake blending volumes 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 net gain of USD 214 thousand and a gain of USD 11 thousand was recognized relating to the difference between the cost and sale proceeds of the surplus diluent for Q4 2021 and Q4 2020 respectively. A gain of USD 421 thousand and a cost of USD 1,258 thousand were recognized for the year ended December 31, 2021, and December 31, 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 year 2021, IPC had crude entitlement of 103,000 barrels of oil on the FPSO Bertam facility (crude produced but unsold).

**Depletion and decommissioning costs**
The total depletion and decommissioning costs amounted to USD 30,293 thousand for Q4 2021 compared to USD 29,793 thousand for Q4 2020 and USD 119,013 thousand for the year ended December 31, 2021, compared to USD 111,896 thousand for the year ended December 31, 2020. The depletion charge is analyzed in the following tables:

| | Three months ended – December 31, 2021 | | | | |
|---|---|---|---|---|---|
| USD Thousands | Canada – Southern Assets | Canada – Northern Assets | Malaysia | France | Total |
| Depletion cost in USD thousands | 10,758 | 8,121 | 7,843 | 3,571 | **30,293** |
| USD per boe | 4.67 | 6.16 | 18.84 | 13.25 | **7.03** |

| | Three months ended – December 31, 2020 | | | | |
|---|---|---|---|---|---|
| USD Thousands | Canada – Southern Assets | Canada – Northern Assets | Malaysia | France | Total |
| Depletion cost in USD thousands | 11,262 | 7,381 | 6,553 | 4,597 | **29,793** |
| USD per boe | 4.76 | 6.62 | 17.11 | 17.37 | **7.21** |

| | Year ended – December 31, 2021 | | | | |
|---|---|---|---|---|---|
| USD Thousands | Canada – Southern Assets | Canada – Northern Assets | Malaysia | France | Total |
| Depletion cost in USD thousands | 43,097 | 29,667 | 30,156 | 16,093 | **119,013** |
| USD per boe | 4.69 | 6.27 | 18.84 | 14.77 | **7.17** |

| | Year ended – December 31, 2020 | | | | |
|---|---|---|---|---|---|
| USD Thousands | Canada – Southern Assets | Canada – Northern Assets | Malaysia | France | Total |
| Depletion cost in USD thousands | 40,555 | 26,255 | 27,759 | 17,327 | **111,896** |
| USD per boe | 4.58 | 6.70 | 17.11 | 16.99 | **7.26** |

The depletion charge is derived by applying the depletion rate per boe to the volumes produced in the period by each field.

**Depreciation of other tangible fixed assets**
The total depreciation of other tangible fixed assets amounted to USD 2,628 thousand for Q4 2021 compared to USD 2,751 thousand for Q4 2020 and USD 10,108 thousand for the year ended December 31, 2021, compared to USD 11,681 thousand for the year ended December 31, 2020. This related to the depreciation of the FPSO Bertam, which is being depreciated on a unit of production basis based on the Bertam field 2P reserves.

**Exploration and business development costs**
The total exploration and business developments costs amounted to USD 345 thousand for Q4 2021 and USD 1,960 thousand for the year ended December 31, 2021. These costs mainly related to business development costs.

**General, administrative and depreciation expenses**
General, administrative and depreciation expenses amounted to USD 12,364 thousand for the year ended December 31, 2021, compared to USD 12,788 thousand for the year ended December 31, 2020.

**Net financial items**
Net financial items amounted to a charge of USD 30,214 thousand for the year ended December 31, 2021, compared to a charge of USD 14,987 thousand for the year ended December 31, 2020, and included a non-cash net foreign exchange loss of USD 1,994 thousand for 2021 compared to a net foreign exchange gain of USD 13,028 thousand for 2020. The foreign exchange movements mainly result from the revaluation of intra-group loan funding balances.

Excluding foreign exchange movements, the net financial items amounted to a charge of USD 28,220 thousand for the year ended December 31, 2021, compared to USD 28,015 thousand for the year ended December 31, 2020.

The interest expense amounted to USD 12,867 thousand for the year ended December 31, 2021, compared to interest expense USD 13,401 thousand for the comparative period in 2020. Despite the lower borrowings, the cost of financing remained at similar level as 2020 following the refinancing of the credit facilities during 2020.

The unwinding of the asset retirement obligation discount rate amounted to USD 11,488 thousand for the year ended December 31, 2021, compared to USD 10,837 thousand for year ended December 31, 2020.

**Income tax**
The corporate income tax amounted to a charge of USD 21,684 thousand for the year ended December 31, 2021, compared to a credit of USD 33,820 thousand for the year ended December 31, 2020. The income tax movements in 2021 mainly relate to deferred taxes with low cash taxes reflected. No corporate income tax is payable in Canada and Malaysia in 2021 due to the historical tax pools.

## Capital Expenditure

Development and exploration and evaluation expenditure incurred in the year ended December 31, 2021, was as follows:

| USD Thousands | Canada – Southern Assets | Canada – Northern Assets | Malaysia | France | Total |
|---|---|---|---|---|---|
| Development | 14,805 | 18,645 | 10,333 | 2,451 | **46,234** |
| Exploration and evaluation | – | (2,723) | 472 | 7 | **(2,244)** |
| | 14,805 | 15,922 | 10,805 | 2,458 | **43,990** |

Capital expenditure of USD 43,990 thousand was mainly in Canada including completion of the Pad D' project and start of the infill drilling program on the Onion Lake Thermal field, additional field optimisation activities and commencement of the drillling in Malaysia.

**Other tangible fixed assets**
Other tangible fixed assets amounted to USD 46,363 thousand as at December 31, 2021, which included USD 43,649 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated on a unit of production basis 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 December 31, 2021, and as at February 8, 2022.

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 was required, and 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 November 2021 at approximately USD 100 million of which USD 4 million was drawn as at December 31, 2021. The borrowing base availability under the Canadian RBL was CAD 300 million of which CAD 120 million was drawn as at December 31, 2021.

Total net debt as at December 31, 2021 amounted to USD 94 million.

The amounts drawn under the International RBL and the Canadian RBL as at December 31, 2021, are classified as non-current as there are no mandatory repayments within the next twelve months.

In February 2022, IPC completed the issuance of USD 300 million of senior unsecured bonds (the "Bonds"), which mature in February 2027 and have a fixed coupon rate of 7.25 percent per annum, payable in semi-annual instalments. The Group used a portion of the proceeds of the Bonds to fully repay the Canadian RBL and the International RBL, which were then cancelled. At the same time, the Group entered into a revolving credit facility of CAD 75 million (the "Canadian RCF") in connection with its oil and gas assets in Canada. The Canadian RCF has a maturity of February 2024.

An amount of USD 1.8 million drawn under the France Facility as at December 31, 2021 is classified as current representing the repayment planned within the next twelve months.

The Group is in compliance with the covenants of the financing facilities as at December 31, 2021.

Cash and cash equivalents held amounted to USD 18.8 million as at December 31, 2021. The Corporation holds cash to meet imminent operational funding requirements in the different countries.

### Working Capital

As at December 31, 2021, the Group had a net working capital balance including cash of USD 56,181 thousand compared to USD (4,670) thousand as at December 31, 2020. The difference as at December 31, 2021, from December 31, 2020, is mainly a result of higher trade receivables due to the higher oil price, 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 December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| USD Thousands | 2021 | 2020 | 2021 | 2020 |
| Revenue | 215,296 | 103,353 | 666,409 | 324,164 |
| Production costs | (102,561) | (57,222) | (325,007) | (204,628) |
| Current tax | (2,048) | (112) | (4,670) | (113) |
| Operating cash flow | **110,687** | 46,019 | **336,732** | 119,423 |

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

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| USD Thousands | 2021 | 2020 | 2021 | 2020 |
| Operating cash flow - see above | 110,687 | 46,019 | 336,732 | 119,423 |
| Capital expenditures | (17,441) | (7,732) | (43,990) | (77,659) |
| Abandonment and farm-in expenditures[1] | (1,282) | (2,109) | (4,546) | (6,138) |
| General, administration and depreciation expenses before depreciation[2] | (2,648) | (3,127) | (10,648) | (11,085) |
| Cash financial items[3] | (2,356) | (4,480) | (14,664) | (15,199) |
| Free cash flow | **86,960** | 28,571 | **262,884** | 9,342 |

*[1] See note 20 to the financial statements*
*[2] Depreciation is not specifically disclosed in the Financial Statements*
*[3] See notes 5 and 6 to the financial statements.*

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

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| USD Thousands | 2021 | 2020 | 2021 | 2020 |
| Net result | 66,918 | (45,250) | 146,059 | (77,941) |
| Net financial items | 4,079 | (6,731) | 30,214 | 14,987 |
| Income tax | 5,408 | (12,139) | 21,684 | (33,820) |
| Depletion | 30,293 | 29,793 | 119,013 | 111,896 |
| Depreciation of other tangible fixed assets | 2,628 | 2,751 | 10,108 | 11,681 |
| Impairment | – | 73,143 | – | 73,143 |
| Exploration and business development costs | 345 | 1,014 | 1,960 | 6,802 |
| Depreciation included in general, administration and depreciation expenses[1] | 416 | 423 | 1,716 | 1,703 |
| EBITDA | **110,087** | 43,004 | **330,754** | 108,451 |

[1] *Item is not shown in the Financial Statements*

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

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| USD Thousands | 2021 | 2020 | 2021 | 2020 |
| Production costs | 102,561 | 57,222 | 325,007 | 204,628 |
| Cost of blending[1] | (22,323) | (6,783) | (78,434) | (20,691) |
| Change in inventory position | (15,296) | (1,408) | 1,656 | (141) |
| Operating costs | **64,942** | 49,031 | **248,229** | 183,796 |

[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 | December 31, 2021 | December 31, 2020 |
|---|---|---|
| Bank loans | 113,122 | 327,691 |
| Cash and cash equivalents | (18,810) | (6,498) |
| Net debt | **94,312** | 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; 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.

### 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 increased by 25,000 to 155,367,757 common shares. On December 1, 2021, IPC announced the commencement of a share repurchase program. During the period up to December 31, 2021, IPC repurchased an aggregate of 1,330,303 common shares. A number of 169,652 shares were cancelled at December 31, 2021. The remaining 1,160,651 shares have been cancelled in January 2022. As at December 31, 2021, IPC had a total of 155,198,105 common shares issued and outstanding with voting rights.

As at February 8, 2022, following the cancellation of a further 726,676 common shares repurchased, IPC has a total of 153,310,778 common shares issued and outstanding with no par value.

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 26.5% of the outstanding common shares as at February 8, 2022.

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 5,279,308 IPC Share Unit Plan awards (992,491 awards granted in July 2019, 10,703 awards granted in January 2020, 1,421,515 awards granted in March 2020, 25,335 awards granted in July 2020, 45,781 awards granted in January 2021, 1,036,773 awards granted in March 2021, 1,716,000 awards granted in May 2021, 18,167 awards granted in July 2021 and 12,543 awards granted in January 2022) outstanding as at February 8, 2022.

### Contractual Obligations and Commitments

In Canada, an oil pipeline from the Onion Lake Thermal field to the Husky Alberta Gathering System has been built by Husky Midstream ("Husky") for the exclusive use of IPC. Onion Lake Thermal oil production is blended with condensate before being transported via the pipeline and is therefore expected to attract improved realised prices as a result of the blended oil. The pipeline is also expected to improve the reliability and uptime of the transportation and production at Onion Lake Thermal. The initial investment in the pipeline was met by Husky and is to be recovered through an agreed tariff charged to IPC. IPC has committed to a firm transportation service for 15 years from commencement of service, with total tariffs committed as shown in the table below:

| | 2022[1] | 2023 | 2024 | 2025 | 2026 | Thereafter |
|---|---|---|---|---|---|---|
| Transportation service (MCAD) | 22.5 | 27.3 | 28.0 | 28.4 | 29.0 | 300.9 |

[1] *Assuming commissioning of the pipeline and commencement of the service occurs during the first quarter of 2022.*

The initial tariffs escalate at 2% per annum and approximately 65% of the forecast cost for 2022 is reflected in the 2022 Capital Markets Day (CMD) guidance of operating costs of USD 15.2/boe which is in line with the actual 2021 operating costs of USD 15.0/boe. The remaining 35% of the forecast cost for 2022 is also reflected in the CMD cost of blending guidance.

In Malaysia, IPC has an obligation to make payments towards historic costs on Block PM307 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 21 Provisions of the Financial Statements.

### 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 636 thousand in respect of office space rental and USD 1,508 thousand in respect of shared services provided during the year 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 December 31, 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 December 31, 2021, which are summarized as follows:

| Period | Volume (Gigajoules (GJ) per day) | Type | Average Pricing |
|---|---|---|---|
| January 1, 2022 – March 31, 2022 | 20,000 | AECO Swap | CAD 4.15/GJ |
| April 1, 2022 – September 30, 2022 | 20,000 | AECO Swap | CAD 3.14/GJ |

The Group had no oil price sale financial hedges outstanding as at December 31, 2021.

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 fair value of USD 1,159 thousand at December 31, 2021.

**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 its operations are subject to various risks and uncertainties which include but are not limited to those listed below. The risks and uncertainties below are not the only ones that the Group faces. Additional risks and uncertainties not presently known to the Group or that the Group currently considers immaterial may also impair the business and operations of the Group and cause the price of the IPC's shares to decline. If any of the following risks actually occur, the Group's business may be harmed and the financial condition and results of operations may suffer significantly.

See also "Cautionary Statement Regarding Forward-Looking Information" and "Reserves and Resource Advisory" in this MD&A.

**Pandemic:** The Covid-19 virus and the restrictions and disruptions related to it 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. 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.

The current and any future Covid-19 outbreaks may increase IPC's exposure to, and magnitude of, each of the risks and uncertainties identified below that result from, for example, a reduction in demand for oil and gas consumption, lower or volatile commodity prices, reliance on third parties, operational risks and costs and changes in government regulation. 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 any 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 of the pandemic.

### Non Financial Risks

**Exploration, Development and Production Risks:** Oil and gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Group depends on its ability to find, acquire, develop and commercially produce oil and gas reserves. Without the continual addition of new reserves, any existing reserves associated with the Group's oil and gas assets at any particular time, and the production therefrom, will decline over time as such existing reserves are exploited. There is a risk that additional commercial quantities of oil and gas will not be discovered or acquired by the Group. Production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Future oil and gas development may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. Production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees. In addition, the Covid-19 virus, and the restrictions and disruptions related to it, may cause production delays and interruptions which could have adverse effects on the Corporation, its revenues and cash flows and the market price of the Common Shares.

Oil and gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, hydrocarbon releases and spills, each of which could result in substantial damage to oil and gas wells, production facilities, other property and the environment or personal injury. In accordance with industry practice, the Group will not fully insure against all of these risks, nor are all such risks insurable. The Group maintains liability insurance in an amount that it considers consistent with industry practice. Due to the nature of these risks, however, there is a risk that such liabilities could exceed policy limits, in which event the Group could incur significant costs.

**Volatility in Oil and Gas Commodity Prices and Price Differentials:** The marketability and price of oil and gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and gas may depend upon its ability to access space on pipelines that deliver oil and gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and gas and many other aspects of the oil and gas business.

Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions in Europe, Asia, the United States, Canada and elsewhere, the actions of OPEC and OPEC+, governmental regulation, political instability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports, the availability of alternative fuel sources and the potential for increased supply of oil and gas for unconventional shale oil and shale gas and other services.

Oil and gas prices have fluctuated widely during recent years and may continue to be volatile in the future. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the carrying value of the reserves and resources, borrowing capacity, revenues, profitability and cash flows associated with operation of the Group's assets and may have a material adverse effect on the business, financial condition, results of operations and prospects associated with the Group's assets.

The Group's financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials in Canada between the Group's heavy crude oil (in particular the heavy crude oil differential) and quoted market prices. The market price for heavy crude oil and bitumen in Canada is generally lower than market prices for light oil, due principally to the higher costs associated with refining a barrel of heavy crude oil and higher transportation costs (diluent is required to be purchased and blended with heavy crude oil to transport on most pipelines). Heavy crude oil differentials are also influenced by other factors such as capacity and interruptions, refining demand and the quality of the oil produced, all of which are beyond the Group's control. It is difficult to predict future price differentials and any increase in heavy crude oil differentials could have an adverse effect on the Group's business, financial condition, results of operations and cash flows.

In order to transport crude oil production in Canada to sales markets, the Group is required to meet certain pipeline specifications. Heavy crude oil and bitumen is usually blended with a lighter hydrocarbon (commonly referred to as diluent) to increase its flow characteristics. The cost of diluent is generally correlated to crude oil prices. A shortfall in the supply of diluent may cause its price to increase which would adversely affect the Group's financial position and cash flow.

**Climate Change:** Physical climate change related risks can be event-driven with increased severity of extreme weather events, such as cyclones, hurricanes, or floods, or long-term shifts in climate patterns with sustained higher temperatures or sea level rise. These physical risks may have financial and operational implications for the Corporation, such as direct damage to assets and indirect impacts from supply chain disruption.

Reputational risks arise from the surge of societal pressure on the fossil fuel industry in relation to its contribution to global greenhouse gas (GHG) emissions. Maintaining a positive reputation in the eyes of investors, regulators, communities, employees and the general public is an important aspect for the success of the Corporation. Negative impact on the industry and the Corporation's reputation could result in the long term delays in obtaining regulatory approvals, increased operating costs, lower shareholder confidence, or availability of insurance and financing.

Regulatory climate change related risks arise from increased environmental regulation. A breach of such regulations may result in the imposition of fines or issuance of clean up orders in respect of the Group or the Group's assets, some of which may be material. Furthermore, management of the Corporation believes the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions or emissions intensity. There is a risk that any such programs, laws or regulations, if proposed and enacted, may contain emission reduction targets which will require substantial capital investments to adapt processes in place or lead to financial penalties or charges as a result of the failure to meet such targets.

The Group's facilities and operations, and the oil and gas that the Group markets, result in the emission of GHGs which makes the Group subject to GHG emissions legislation and regulation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. Implementation of strategies by any level of government within the countries in which the Corporation operates, and whether to meet international agreed limits, or as otherwise determined, for reducing GHGs could have a material impact on the operations and financial condition of the Corporation.

In addition, concerns about climate change and public discussion that climate change may be associated with extreme weather conditions have resulted in a number of environmental activists and members of the public opposing the continued exploitation, transportation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHGs and resulting requirements, it is not possible to predict the impact on the Group and its operations and financial condition.

Emission and carbon tax regulations in Canada federally and regionally are evolving and as these regulations are established or amended, they may have an impact on organizations involved in heavy oil production. As a signatory to the United Nations Framework Convention on Climate Change and a party to the Paris Agreement, the Government of Canada committed to a 30% reduction in GHG emissions below 2005 levels by 2030; one of the policies announced to date by the Government of Canada to reduce GHG emission is the implementation of a nation-wide price on carbon emissions. It is difficult to assess the overall impact these regulations will have on the Group at this time but it could result in increased costs to comply, delays in having projects approved and potentially a reduction in demand for oil from these regions, all of which could have a material negative impact on the Group's business.

**Operational Risks Relating to Facilities and Pipelines:** The pipelines and facilities associated with the Group's assets, including the FPSO Bertam, are exposed to operational risks that can lead to hydrocarbon releases, production interruptions and unplanned outages. Other operating risks relating to the facilities and pipelines associated with the Group's assets include: the breakdown or failure of equipment; issues and failures affecting the FPSO Bertam; breakdown or malicious attacks on information systems or processes; the performance of equipment at levels below those originally intended; operator error; disputes and other issues with interconnected facilities; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs and other similar events, many of which will be beyond the control of the Group. In addition, the Covid-19 virus, and the restrictions and disruptions related to it, may cause production delays and interruptions which could have adverse effects on the Corporation, its revenues and cash flows and the market price of the Common Shares. The occurrence or continuance of any of these or other operational events could curtail sales or production or materially increase the cost of operating the facilities and pipelines associated with the Group's oil and gas assets and reduce revenues accordingly.

The Group's financial performance is significantly affected by the cost of operating and the capital costs associated with its assets. Operating and capital costs are affected by a number of factors including, but not limited to inflationary price pressure, scheduling delays, failure to maintain quality construction standards and supply chain disruptions. Electricity, chemicals, supplies, abandonment, reclamation and labour costs are examples of operating costs that are susceptible to significant fluctuations. Fluctuations in operating and capital costs could negatively impact the Group's business, financial condition, results of operations, cash flows and value of it oil and gas reserves.

**Uncertainties Associated with Estimating Reserves and Resources Volumes:** There are numerous uncertainties inherent in estimating quantities of oil and gas reserves and resources (contingent and prospective) and the future cash flows attributed to such reserves and resources. The cash flow information associated with reserves and resources set forth in this MD&A are estimates only. The actual production, revenues, taxes and development and operating expenditures with respect to the reserves and resources associated with the Group's assets will vary from estimates thereof and such variations could be material. Estimates of reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources.

In accordance with applicable securities laws, the Corporation and the Corporation's independent reserves auditors have used forecast prices and costs in estimating the reserves, resources and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and gas, curtailments or increases in consumption by oil and gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

References to "contingent resources" do not constitute, and should be distinguished from, references to "reserves". References to "prospective resources" do not constitute, and should be distinguished from, references to "contingent resources" and "reserves". 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. See also "Reserves and Resource Advisory" below.

**SAGD Recovery Process:** The Group has implemented a SAGD recovery process at the Onion Lake Thermal project and would use the SAGD process at the Blackrod project. The SAGD recovery process requires a significant amount of gas or other fuels to produce steam for use in the recovery process. The amount of steam required in the production process can vary and impact costs significantly. The quality and performance of the reservoir can impact the timing, cost and levels of production using this technology. There can be no assurance that the Group's operations will produce at the expected levels or on schedule. In addition, a significant amount of water is used in SAGD operations. Government regulations apply to access to and use of water. Any shortages in water supplies could lead to increased costs and have a material adverse effect on results of operation and financial condition.

**Regulatory Approvals and Compliance and Changes in Legislation and the Regulatory Environment:** Oil and gas operations (including exploration, development, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. Governments may regulate or intervene with respect to exploration, production and abandonment activities, price, taxes, royalties and the exportation of oil and gas. The implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could reduce demand for crude oil and gas and increase the costs associated with the Group's oil and gas assets, any of which may have a material adverse effect on the business, financial condition, results of operations and prospects of the Group's oil and gas assets. In order to conduct oil and gas operations, the Group will require regulatory permits, licences, registrations, approvals, authorizations and concessions from various governmental authorities. There is a risk that the permits, licences, registrations, approvals, authorizations and concessions currently granted to the Group (including, for example, the Malaysian flagging status for the FPSO Bertam) will not be renewed or that the Group will be unable to obtain all of the permits, licences, registrations, approvals, authorizations and concessions that may be required to conduct operations that it may wish to undertake.

The French government has enacted legislation to cease granting new petroleum exploration licences in France and to restrict the production of oil and gas under existing production licences in France from 2040. There is a risk that France could implement further legislative changes and that the licence regime in France could become more onerous. In Canada, the oil and gas regulatory authorities have implemented regulations regarding the ability to transfer leases, licences, permits, wells and facilities between parties. These authorities have increased the minimum abandonment liability rating of the buyer before they will accept a transfer of oil and gas assets. These regulations may make it difficult and costly for producers, such as IPC, to transfer or sell assets to other parties.

**Aboriginal Land Claims in Canada:** In Canada, aboriginal groups have filed claims in respect of their aboriginal and treaty rights against the federal and certain provincial governments as well as private individuals and companies. The Group is not aware of any claims made with respect to its properties or assets; however; if a claim arose and was successful, it may have a material adverse effect on the Group's business, financial condition, results of operation and prospects. The majority of the Group's interests at Onion Lake are situated on traditional reserve lands and are subject to the federal rules and regulations of Indian Oil and Gas Canada as well as of the Onion Lake Cree Nation of Saskatchewan/Alberta. There are risks associated with the management of the Group's interests on these lands, including access and lease terms.

**Change of Control under Licences:** Certain of the licence areas associated with the Group's oil and gas assets, including in France and in Canada, require government consent or compliance with regulations imposed by oil and gas regulatory authorities to effect a change of control of the owner or an assignment of the ownership interest in the licence area. There may also be contractual restrictions on assignment and change of control, including in the Suffield area of Canada where certain operations are conducted within a Canadian Forces Base under access agreements with Canadian federal government and the Alberta provincial government. Accordingly, should the ownership interest in these licence areas be reduced or if there is a change of control of the Corporation, consent may be required in order to remain in compliance with the applicable licences and concessions. The failure to obtain such consent may have a material adverse effect on the Corporation. Further, the requirement to obtain such consent may limit the ability of a third party to effect a change of control transaction with the Corporation.

**Failure to Realize Anticipated Benefits of Acquisitions and Dispositions:** The Group may make acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Group's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Group. In addition, non-core assets may be periodically disposed of, so that the Group can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Group, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Group.

**Reliance on Third-Party Operators:** The Group has partners in many of the licence, lease and PSC areas associated with the Group's assets. In some cases, including in the Aquitaine Basin in France, the Group is not the operator of the licence and concession areas and must depend on the competence, expertise, judgment and financial resources (in addition to those of its own and, where relevant, other partnership and joint venture companies) of the partner operator and the operator's compliance with the terms of the licences, leases, PSCs and contractual arrangements. Mismanagement of licence areas by the Group's partner operators or defaults by them in meeting required obligations may result in significant exploration, production or development delays, losses or increased costs to the Group. In addition, the Covid-19 virus, and the restrictions and disruptions related to it, may adversely affect third-party operators which could have adverse effects on the Corporation, its revenues and cash flows and the market price of the Common Shares.

**Reliance on Third-Party Infrastructure:** The Group delivers the products associated with the Group's assets by gathering, processing and pipeline systems, most of which it does not own. The amount of oil and gas that the Group is able to produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities (for example, Total is ceasing crude oil transportation and storage operations at the Grandpuits refinery in the Paris Basin, France), could ceased refining and result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production or increased operating or transportation costs. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Group's business financial condition, results of operations, cash flows and future prospects. In addition, the Covid-19 virus, and the restrictions and disruptions related to it, may adversely affect third-party infrastructure which could have adverse effects on the Corporation, its revenues and cash flows and the market price of the Common Shares.

**Credit Facilities and Bonds:** The Group is, and may in the future become, party to credit facilities with international financial institutions. The Corporation has also issued bonds and may issue further bonds in the future. The terms of these facilities and bonds may contain operating and financial covenants and restrictions on the ability of the Group to, among other things, incur or lend additional debt, pay dividends and make restricted payments, encumber its assets, sell assets and enter into certain merger or consolidation transactions. The failure of the Group to comply with the covenants contained in these facilities and bonds could result in an event of default, which could, through acceleration of debt, enforcement of security or otherwise, materially and adversely affect the operating results and financial condition of the Group.

In addition, the maximum amount that the Group is permitted to borrow under its credit facilities may be subject to periodic review by the lenders. The Group's lenders generally review its oil and gas production and reserves, forecast oil and gas prices, general business environment and other factors to establish the amount which the Group is entitled to borrow. In the event the lenders decide to reduce the amount of credit available under the credit facilities, the Group may be required to repay all or a portion of the amounts owing thereunder.

If the Group fails to comply with the covenants in these facilities and bonds, is unable to repay or refinance amounts owned at maturity or pay the debt service charges or otherwise commit an event of default, such as bankruptcy, it could result in the seizure and/or sale of the Group's assets by the creditors. The proceeds from any sale of our assets would be applied to satisfy amounts owed to the secured creditors and then unsecured creditors. Only after the proceeds of that sale were applied towards the Group's debt would the remainder, if any, be available for the benefit of shareholders.

**Credit Ratings:** Credit ratings affect the Corporation's ability to obtain short term and long term financing and the cost of such financing. A reduction in the current rating or a negative change in the rating outlook could adversely affect the cost of financing and access to sources of liquidity and capital. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

**Competition for Resources and Markets:** The international petroleum industry is competitive in all its phases. The Group competes with numerous other organizations in the search for, and the acquisition of, oil and gas properties and in the marketing of oil and gas. The Corporation's competitors include oil and gas companies that may have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves and resources in the future depends not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory and development drilling. Competitive factors in the distribution and marketing of oil and gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources and renewable energies.

**Marketing:** A decline in the Group's ability to market oil and gas production could have a material adverse effect on its production levels or on the price that the Group receives for production, which in turn may affect the financial condition of the Corporation and the market price of the Common Shares. IPC's business depends in part upon the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities (for example, the Total-operated Grandpuits facility which ceased refining and is ceasing crude oil transportation and storage operations) as well as, potentially, rail loading facilities and railcars. Applicable regulation of oil and gas production, processing and transportation, tax and energy policies, general economic conditions, and changes in supply and demand could adversely affect IPC's ability to produce and market oil and gas. If market factors change and inhibit the marketing of production, overall production or realized prices may decline, which may affect the financial condition of the Corporation and the market price of the Common Shares.

**Hedging Strategies:** From time to time, the Group may enter into agreements to receive fixed prices on its oil and gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Group will not benefit from such increases. Similarly, from time to time, the Group may enter into agreements to fix the exchange rate of certain currencies. However, if a currency declines in value compared to another currency, the operation of the Group's assets will not benefit from the fluctuating exchange rate if an agreement has fixed such exchange rate.

**Fraud, Bribery and Corruption:** The operations relating to the Group's oil and gas assets are governed by the laws of many jurisdictions, which generally prohibit bribery and other forms of corruption. While the Corporation has implemented an anti-corruption compliance program across the Group, the Corporation cannot guarantee that the Group's employees, officers, directors, agents, or business partners have not in the past or will not in the future engage in conduct undetected by the processes and procedures to be adopted by the Corporation and for which the Corporation might be held liable under applicable anti-corruption laws. Despite the Corporation's compliance program and other related training initiatives, it is possible that the Corporation, or some of its subsidiaries, employees or contractors, could be subject to an investigation related to charges of bribery or corruption as a result of the unauthorized actions of its employees or contractors, which could result in significant corporate disruption, onerous penalties and reputational damage.

**Decommissioning, Abandonment and Reclamation Costs:** The Group is responsible for compliance with all applicable laws, regulations and contractual requirements regarding the decommissioning, abandonment and reclamation of the Group's assets at the end of their economic life, the costs of which may be substantial. It is not possible to predict these costs with certainty since they will be a function of requirements at the time of decommissioning, abandonment and reclamation and the actual costs may exceed current estimates. Laws, regulations and contractual requirements with regard to abandonment and decommissioning may be implemented or amended in the future.

**Third-Party Credit Risk:** The Group may be exposed to third party credit risk through the contractual arrangements associated with the Group's assets with its current or future joint venture partners, marketers of its petroleum and gas production, third party uses of its facilities and other parties. In the event such entities fail to meet their contractual obligations in respect of the Group's assets, such failures may have a material adverse effect on the Group's business, financial condition, results of operations and prospects.

**Repatriation of Earnings:** A portion of the revenue-generating operations of the Group's assets is located in Malaysia. In December 2016, the Central Bank of Malaysia implemented measures to facilitate its management of foreign exchange risk. These rules to date have not had a material adverse effect on the Group, but there is a risk that the Central Bank of Malaysia or another authority may implement further measures that will restrict the future repatriation of earnings.

**Expiration and Renewal of Licences, Leases and Production Sharing Contracts:** Certain properties constituting the Group's oil and gas assets are held in the form of licences, leases and production sharing contracts (PSCs). If the holder of the licence, lease or PSC or the operator of the licence, lease or PSC fails to meet the specific requirement of a licence, lease or PSC, including compliance with environmental, health and safety requirements, the licence, lease or PSC may terminate or expire. There is a risk that the obligations required to maintain each licence, lease or PSC will not be met. The termination or expiration of the licence, lease or PSC, or the working interests relating to a licence may have a material adverse effect on the business, financial condition, results of operations and prospects associated with the Group's oil and gas assets. From time to time, the licences and leases may, in accordance with their terms, become due for renewal; there is a risk that these licences, leases and PSCs associated with the Group's oil and gas assets will not be renewed by the relevant government authorities, on terms that will be acceptable to the Corporation. There also can be significant delay in obtaining licence renewals which may already affect the operations associated with the Group's oil and gas assets.

**Litigation:** In the normal course of the Group's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Group and as a result, could have a material adverse effect on the Group's assets, liabilities, business, financial condition and results of operations.

**Economic and Political Developments in Countries in which the Group Operates:** International operations are subject to political, economic and other uncertainties. The Group's assets could also be adversely affected by changes in applicable laws and policies of Canada, Malaysia and France (including relating to the Covid-19 virus), which could have a negative impact on the Group.

In response to the Covid-19 virus, there are public health restrictions and other related disruptions which could have adverse effects on the business and operations of the Corporation, including production delays or interruptions. 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 the 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.

**Terrorism and Sabotage:** If any of the properties, wells or facilities comprising the Group's assets is the subject of terrorist attack or sabotage, it may have a material adverse effect on the Group's business, financial condition, results of operations, cash flows and future prospects.

**Information Security:** The Group is dependent on its information systems and computer based programs. Failure, malfunction or security breaches by computer hackers and cyberterrorists of any such systems or programs may have a material adverse effect on the Group's business and systems, potentially affecting network assets and people's privacy. The Group manages cyber security risk by ensuring appropriate technologies, processes and practices are effectively designed and implemented to help prevent, detect and respond to threats as they emerge and evolve. The primary risks to the Group include, loss of data, destruction or corruption of data, compromising of confidential customer or employee information, leaked information, disruption of business, theft or extortion of funds, regulatory infractions, loss of competitive advantage and reputational damage.

**Potential Conflicts of Interest:** Certain of the individuals who are directors of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions.

**Significant Shareholder:** Nemesia S.à.r.l. and Zebra Holdings and Investments S.à.r.l., investment companies wholly owned by a Lundin family trust (the "Trust Entities"), own approximately 26 percent of the aggregate voting shares of the Corporation. The Trust Entities' holdings may allow them to significantly affect substantially all the actions taken by the shareholders of the Corporation, including the election of directors. As long as the Trust Entities maintain a significant interest in the Corporation, it is likely that the Trust Entities will exercise significant influence on the ability of the Corporation to, among other things, amend the articles of the Corporation, enter into a change in control transaction of the Corporation that might otherwise be beneficial to its shareholders and may also discourage acquisition bids for the Corporation. There is a risk that the interests of the Trust Entities will not be aligned with the interests of other shareholders.

### Financial Risks

**Management Estimates and Assumptions:** In preparing consolidated financial statements in conformity with IFRS, estimates and assumptions are used by management in determining the reported amounts of assets and liabilities, revenues and expenses recognized during the periods presented and disclosures of contingent assets and liabilities known to exist as of the date of the financial statements. These estimates and assumptions must be made because certain information that is used in the preparation of such financial statements is dependent on future events, cannot be calculated with a high degree of precision from data available, or is not capable of being readily calculated based on generally accepted methodologies. In some cases, these estimates are particularly difficult to determine and the Corporation must exercise significant judgment. Actual results for all estimates could differ materially from the estimates and assumptions used by the Corporation, which could have a material adverse effect on the Group's business, financial condition, results of operations, cash flows and future prospects.

**Disclosure Controls and Procedures and Internal Controls over Financial Reporting:** Effective disclosure controls and procedures and internal controls over financial reporting are necessary for the Corporation to provide reliable financial and other disclosures and to help prevent fraud. The Corporation cannot be certain that the procedures it undertakes to help ensure the reliability of its financial reports and other disclosures, including those imposed on it under Canadian securities laws, will ensure that it maintains adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm the Group's results of operations or cause it to fail to meet its reporting obligations. If the Corporation or its independent auditor discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Corporation's consolidated financial statements and harm the trading price of the common shares.

**Income Taxes:** Income tax laws relating to the oil and gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Group's assets. Furthermore, there is a risk that the relevant tax authorities will not agree with management's calculation of the income for tax purposes associated with the Group's assets or that such tax authorities will change their administrative practices to the detriment of the Corporation. In the event of a successful reassessment of the Corporation's income tax returns, such reassessment may have an impact on current and future taxes payable.

**Additional Funding Requirements:** The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's funds from operations is not sufficient to satisfy its capital expenditure requirements, there is a risk that debt or equity financing will be unavailable to meet these requirements or, if available, will be on terms unacceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects and also negatively impact the market price of the Common Shares.

**Variations in Foreign Exchange Rates and Interest Rates:** World oil and gas prices are quoted in United States dollars and are therefore affected by exchange rates, which will fluctuate over time. Future exchange rates could accordingly impact the future value of the Corporation's reserves and resources as determined by independent evaluators. To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there will be a credit risk associated with counterparties of the Corporation. An increase in interest rates could result in a significant increase in the amount the Corporation pays to service any debt that it may incur, which could negatively impact the market price of the Common Shares.

**Issuance of Further Debt:** From time to time, the Corporation may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may create debt or increase the Corporation's then-existing debt levels above industry standards for oil and gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional equity and/or debt financing that may not be available or, if available, may not be available on favorable terms. The level of the indebtedness that the Corporation may have from time to time could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

**Common Share Price Volatility:** The market price for Common Shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond the Corporation's control, including the following:

- Actual or anticipated fluctuations in the Corporation's results of operations;
- Recommendations by securities research analysts;
- Changes in the economic performance or market valuations of other companies that investors deem comparable to the Corporation;
- The loss of executive officers and other key personnel of the Corporation;
- Sales or perceived sales of additional Common Shares;
- Significant acquisitions or business combinations, strategic partnerships, joint ventures or capital;
- Commitments by or involving the Corporation or its competitors; and
- Trends, concerns, technological or competitive developments, regulatory changes and other related issues in the Corporation's business segments or target markets.

Financial markets can experience significant price and volume fluctuations that may particularly affect the market prices of equity securities of companies and that may be unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the Common Shares may decline even if the Corporation's operating results, underlying asset values or prospects have not changed. These factors, as well as other related factors, may cause decreases in asset values, which may result in impairment losses.

## 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 and twelve month periods ended December 31, 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 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. Although demand, commodity prices and share prices have recovered, there can be no assurance that these effects will not resume 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;
- The potential for an improved economic environment resulting from a lack of capital investment and drilling in the oil and gas industry;
- 2022 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 volatile commodity prices;
- IPC's continued access to its existing credit facilities, including current financial headroom, on terms acceptable to the Corporation;
- The ability to fully fund future 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 in Canada, including the timing and success of future oil and gas drilling and optimization programs;
- Development of the Blackrod project in Canada, including estimates of resource volumes, future production, timing, breakeven oil prices and net present values;
- Current and future drilling pad production and timing and success of facility upgrades, tie-in work and infill drilling at Onion Lake Thermal;
- The potential improvement in the Canadian oil egress situation and IPC's ability to benefit from any such improvements;
- The timing and success of the future development projects and other organic growth opportunities in France;
- The ability to maintain current and forecast production in France;
- The ability of IPC to achieve and maintain current and forecast production in Malaysia;
- The success of the drilling of the A15 sidetrack well and of the production well pump rate optimisation project in Malaysia;
- The ability to IPC to acquire further common shares under the share repurchase program, including the timing of any such purchases;
- The return of value to IPC's shareholders as a result of the share repurchase program;
- The ability of IPC to implement further shareholder distributions in addition to the share repurchase program;
- 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;
- IPC's ability to identify and complete future acquisitions; 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 abandonment regulations.

Readers are cautioned that the foregoing list of factors is not exhaustive. See also "Risk and Uncertainties"

Estimated free cash flow generation is based on IPC's current business plans over the period of 2022 to 2026. Assumptions include average net production of approximately 47 Mboepd, average Brent oil prices of USD 65 to 95 per boe escalating by 2% per year, average gas prices of CAD 3.00 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 MCR. 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 material change report dated February 8, 2022 (MCR), 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 and Uncertainties") 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 RESOURCES 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, 2021, 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, 2021 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, 2021, 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 MCR. These price forecasts are as at December 31, 2021 and may not be reflective of current and future forecast commodity prices.

The reserve life index (RLI) is calculated by dividing the 2P reserves of 270 MMboe as at December 31, 2021, by the mid-point of the 2022 CMD production guidance of 46,000 to 48,000 boepd.

The product types comprising the 2P reserves 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 and contingent resources. 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 and resources evaluations will be attained and variances could be material.

The reserves and resources information and data provided in this MD&A presents only a portion of the disclosure required under NI 51-101. All of the required information will be contained in the Corporation's Annual Information Form for the year ended December 31, 2021, which will be filed on SEDAR (accessible at www.sedar.com) on or before April 1, 2022. Further information with respect to IPC's reserves, contingent resources and estimates of future net revenue, including assumptions relating to the calculation of net present value and other relevant information related to the contingent resources disclosed, is disclosed in the MCR available under IPC's profile on www.sedar.com and on IPC's website at www.international-petroleum.com.

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 | | | | |
| December 31, 2021 | 21.7 | 8.5 | 100.2 MMcf (16.7 Mboe) | 46.8 |
| December 31, 2020 | 19.2 | 8.2 | 104.4 MMcf (17.4 Mboe) | 44.9 |
| Year ended | | | | |
| December 31, 2021 | 20.4 | 8.4 | 99.9 MMcf (16.7 Mboe) | 45.5 |
| December 31, 2020 | 16.5 | 8.5 | 103.1 MMcf (17.2 Mboe) | 42.1 |

This document also makes reference to IPC's forecast total average daily production of 46,000 to 48,000 boepd for 2022. IPC estimates that approximately 46% of that production will be comprised of heavy oil, approximately 21% will be comprised of light and medium crude oil and approximately 33% 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 |
| GJ | Gigajoules |
| 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 |
| MMcf | Million 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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