# Q4

## International Petroleum Corporation

### *Management's Discussion and Analysis*

*For the three months ended and year ended December 31, 2024*

International Petroleum Corp.

## Contents



Non-IFRS Measures
References are made in this MD&A to "operating cash flow" (OCF), "free cash flow" (FCF), "Earnings Before Interest, Tax, Depreciation and Amortization" (EBITDA), "operating costs" and "net debt"/"net cash" which are not generally accepted accounting measures under IFRS Accounting 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/net cash that may be used by other public companies. Management believes that OCF, FCF, EBITDA, operating costs and net debt/net cash 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 22.

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 38.

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, 2024, 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, 2024, 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, 2024, 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, 2024, price forecasts.

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

## 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 11, 2025 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, 2024 ("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 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 3500, 1133 Melville Street, Vancouver, BC V6E 4E5, Canada and its business address is Suite 2800, 1055 Dunsmuir Street, Vancouver, BC V7X 1L2, Canada.

**Basis of Preparation**
The MD&A and the Financial Statements have been prepared in accordance with IFRS Accounting 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, 2024 | | December 31, 2023 | |
|---|---|---|---|---|
| | Average | Year end | Average | Year end |
| 1 EUR equals USD | 1.0821 | 1.0389 | 1.0816 | 1.1050 |
| 1 USD equals CAD | 1.3698 | 1.4388 | 1.3496 | 1.3251 |
| 1 USD equals MYR | 4.5759 | 4.4715 | 4.5598 | 4.5950 |

IPC completed the acquisition of Cor4 Oil Corp. ("Cor4") on March 3, 2023. In accordance with IFRS, the Financial Statements for periods in 2023 have been prepared on that basis, with revenues and expenses related to the Brooks assets acquired in the Cor4 acquisition included in the Financial Statements from March 3, 2023. Certain 2023 operational and financial information included in the MD&A, including production, operating costs, OCF, FCF and EBITDA related to the Brooks assets acquired in the Cor4 acquisition, are reported based on the effective date of the Cor4 acquisition of January 1, 2023. See also "Operations Overview – Production" and "Non-IFRS Measures" below.

## HIGHLIGHTS

**2024 Business Highlights**

- Average net production of approximately 47,400 boepd for the fourth quarter of 2024 was in line with the guidance range for the period (51% heavy crude oil, 15% light and medium crude oil and 34% natural gas).(1)
- Full year 2024 average net production was 47,400 boepd, above the mid-point of the 2024 annual guidance of 46,000 to 48,000 boepd.(1)
- Development activities on Phase 1 of the Blackrod project progressed in 2024 on schedule and on budget, with forecast first oil in late 2026. All major third-party contracts have been executed and construction is advancing according to plan, including construction of the central processing facility (CPF) and well pad facilities, finalization of the midstream agreements for the input fuel gas, diluent and oil blend pipelines, and advancement of drilling operations. As at the end of 2024, over two-thirds of the forecast Blackrod Phase 1 development capital expenditure of USD 850 million has been spent since project sanction in early 2023.
- Drilling activity at the Southern Alberta assets in Canada continued with a total of thirteen wells drilled during 2024.
- Successful completion of planned maintenance shutdowns at Onion Lake Thermal (OLT) in Canada and the Bertam field in Malaysia during 2024.
- 8.3 million common shares purchased and cancelled from December 2023 to early December 2024 under IPC's 2023/2024 NCIB and a further 2.2 million common shares purchased for cancellation during December 2024 and January 2025 under the renewed 2024/2025 NCIB.
- In Q3 2024, published IPC's fifth annual Sustainability Report.

**2024 Financial Highlights**

- Operating costs per boe of USD 18.2 for the fourth quarter of 2024 and USD 17.0 for the full year, in line with the most recent 2024 guidance of less than USD 18 per boe for the full year.(3)
- Strong operating cash flow (OCF) generation for the fourth quarter and full year 2024 amounted to MUSD 78 and MUSD 342, respectively.(3)
- Capital and decommissioning expenditures of MUSD 129 for the fourth quarter and MUSD 442 for the full year 2024, in line with the full year guidance of MUSD 437.
- Free cash flow (FCF) generation for the full year 2024 of negative MUSD 135, with negative FCF generation of MUSD 61 for the fourth quarter in line with expectations and taking into account the significant capital expenditures during the quarter in respect of the Blackrod project. FCF for the full year 2024, before 2024 Blackrod Phase 1 development expenditure of MUSD 351, was MUSD 216.(3)
- Net debt of MUSD 209 and gross cash of MUSD 247 as at December 31, 2024.(3)
- Net result of MUSD 0.4 for the fourth quarter of 2024 and MUSD 102 for the full year 2024.
- Entered into a letter of credit facility in Canada during 2024 to cover operational letters of credit, giving full availability under IPC's undrawn CAD 180 million Revolving Credit Facility.

**Reserves and Resources**

- Total 2P reserves as at December 31, 2024 of 493 MMboe, with a reserve life index (RLI) of 31 years.(1)(2)
- Contingent resources (best estimate, unrisked) as at December 31, 2024 of 1,107 MMboe.(1)(2)
- 2P reserves net asset value (NAV) as at December 31, 2024 of MUSD 3,083 (10% discount rate).(1)(2)(5)(6)

**2025 Annual Guidance**

- Full year 2025 average net production forecast at 43,000 to 45,000 boepd.(1)
- Full year 2025 operating costs forecast at USD 18 to 19 per boe.(3)
- Full year 2025 OCF guidance estimated at between MUSD 210 and 280 (assuming Brent USD 65 to 85 per barrel).(3)
- Full year 2025 capital and decommissioning expenditures guidance forecast at MUSD 320, including MUSD 230 relating to Blackrod capital expenditure.
- Full year 2025 FCF ranges from approximately MUSD 80 to 150 (assuming Brent USD 65 to 85 per barrel) before taking into account proposed Blackrod capital expenditures, or negative MUSD 150 to 80 including proposed Blackrod capital expenditures.(3)

**Business Plan Production and Cash Flow Guidance**

- 2025 – 2029 business plan forecasts:
  - average net production forecast approximately 57,000 boepd.(1)(8)
  - capital expenditure forecast of USD 8 per boe, including USD 3 per boe for growth expenditures.(8)
  - operating costs forecast of USD 18 to 19 per boe.(3)(8)
  - FCF forecast of approximately MUSD 1,200 to 2,000 (assuming Brent USD 75 to 95 per barrel).(3)(8)
- 2030 – 2034 business plan forecasts:
  - average net production forecast of approximately 63,000 boepd.(1)(8)
  - capital expenditure forecast of USD 5 per boe.(8)
  - operating costs forecast of USD 18 to 19 per boe.(3)(8)
  - FCF forecast of approximately MUSD 1,600 to 2,600 (assuming Brent USD 75 to 95 per barrel).(3)(8)

| USD Thousands | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2024** | 2023 | **2024** | 2023 |
| Revenue | **199,124** | 198,460 | **797,783** | 853,906 |
| Gross profit | **42,774** | 39,955 | **210,171** | 250,514 |
| Net result | **415** | 29,710 | **102,219** | 172,979 |
| Operating cash flow(3) | **78,158** | 73,634 | **341,989** | 353,048 |
| Free cash flow(3) | **(61,476)** | (64,688) | **(135,497)** | 2,689 |
| EBITDA(3) | **76,184** | 66,284 | **335,488** | 350,618 |
| Net cash/(debt)(3) | **(208,528)** | 58,043 | **(208,528)** | 58,043 |

## OPERATIONS REVIEW

### Business Overview

IPC was launched in 2017 by way of spinning off the non-Norwegian assets from Lundin Energy. The strategy and vision from the outset was to be the international E&P growth vehicle for the Lundin Group by pursuing growth organically and through acquisitions. The foundation of this strategy was and is predicated on maximising long-term stakeholder value through responsible business operations focused on operational excellence and financial resilience to underpin optimal capital allocation decision-making.

We are very pleased with the track record of value creation achieved by the company to date. IPC's production, reserves, resources and cash flow exposure has increased materially through accretive acquisitions supplemented by base business investment. Excluding the growth capital expenditure assigned to the Blackrod Phase 1 development, over USD 1.5 billion in free cash flow (FCF) has been generated and over USD 0.5 billion has been returned to shareholders in the form of share buybacks since inception. IPC's current shares outstanding are less than 5% higher than the original shares outstanding upon the formation of the company. IPC is determined to build on the historical success and the growth outlook has never been brighter.[3]

2024 was a milestone year for the company through successfully delivering the largest capital investment campaign in its history. The record investment was accompanied by strong safety, operational and financial performance. IPC returned USD 102 million of value to shareholders in the year through share repurchases, whilst maintaining a strong balance sheet.

Oil prices were rangebound in 2024 between Brent USD 70 to 90 per barrel, with a full year Brent average of USD 81 per barrel, in line with our original oil price sensitivities guided at CMD. The fourth quarter 2024 Brent price averaged USD 75 per barrel, the lowest quarterly price average in the year. The downward trend in benchmark oil prices through the second half of 2024 has been slightly reversed in current time as continuous crude inventory draws, strong demand, underwhelming non-OPEC production growth and continued OPEC production curtailments have supported the market balance. A new administration in the White House presents uncertainty for the oil market, as looming tariffs and sanctions pose a risk to global supply chain systems and trade flows. Around 40% of our 2025 Dated Brent and WTI exposure is hedged at USD 76 per barrel and USD 71 per barrel respectively.

The fourth quarter 2024 WTI to WCS price differentials averaged less than USD 13 per barrel, around USD 2 per barrel lower than the full year average of USD 15 per barrel. The fourth quarter differential was the lowest quarterly average since the Covid pandemic in 2020 when benchmark oil prices were more than USD 30 per barrel less than current levels. The TMX pipeline is driving the tighter differentials with excess take-away capacity in the Western Canadian Sedimentary Basin (WCSB) relative to supply. Close to 50% of our 2025 WCS to WTI differential exposure is hedged at USD 14 per barrel, which should assist in mitigating adverse effects of potential US tariffs on Canadian production.

Natural gas prices averaged CAD 1.5 per Mcf for 2024 and in the fourth quarter. Western Canada gas storage levels continue to sit above the five-year range. This is in part due to delays of the LNG Canada start-up project which was supposed to be onstream at end 2024, start-up is now anticipated for mid-2025. IPC has around 9,600 Mcf per day hedged at CAD 2.6 per Mcf for 2025.

**Fourth Quarter and Full Year 2024 Highlights**
During the fourth quarter of 2024, IPC's assets delivered average net production of 47,400 boepd, in line with guidance for the quarter. Full year 2024 average net production of 47,400 boepd was above the 2024 mid-point guidance range of 46,000 to 48,000 boepd.[1]

IPC's operating costs per boe for the fourth quarter of 2024 was USD 18.2. Full year 2024 operating costs per boe was USD 17.0, in line with the most recent 2024 annual guidance of less than USD 18 per boe.[3]

Operating cash flow (OCF) generation for the fourth quarter of 2024 was USD 78 million. Full year 2024 OCF was USD 342 million in line with the most recent guidance of USD 335 to 342 million.[3]

Capital and decommissioning expenditure for the fourth quarter of 2024 was USD 129 million. Full year 2024 capital and decommissioning expenditure of USD 442 million was in line with guidance of USD 437 million.

Free cash flow (FCF) generation was in line with guidance at negative USD 61 million during the fourth quarter of 2024, reflecting the higher level of capital expenditure on the Blackrod Phase 1 development project. Full year 2024 FCF generation was negative USD 135 million, in line with the most recent guidance of negative USD 140 to 133 million.[3]

As at December 31, 2024, IPC's net debt position was USD 209 million. IPC's gross cash on the balance sheet amounts to USD 247 million which provides IPC with significant financial strength to continue progressing its strategies in 2025, including advancing the Blackrod development project, returning value to shareholders through the 2024/2025 NCIB, and remaining opportunistic to mergers and acquisitions activity.[3]

**Blackrod Project**
The Blackrod asset is 100% owned by IPC and hosts the largest booked reserves and contingent resources within the IPC portfolio. After more than a decade of pilot operations, subsurface delineation and commercial engineering studies, IPC sanctioned the Phase 1 Steam Assisted Gravity Drainage (SAGD) development in the first quarter of 2023. The Phase 1 development targets 259 MMboe of 2P reserves, with a multi- year forecast capital expenditure of USD 850 million to first oil planned in late 2026. The Phase 1 development is planned for plateau production of 30,000 bopd which is expected by early 2028.(1)(2)

As at the end of 2024, USD 591 million of cumulative growth capital, has been spent on the Blackrod Phase 1 development since sanction with a peak annual investment of USD 351 million incurred in 2024. Significant progress has been made across all key scopes of the project including but not limited to: detailed engineering, procurement, fabrication, drilling, construction, third party transport pipelines, commissioning and operations planning. Site health and safety control has been excellent with zero lost time incidents since commercial development activities commenced.

Looking forward, USD 230 million is planned to be spent in 2025 mainly relating to advancing the remaining fabrication, construction and substantial completion of the Central Processing Facility (CPF) for the Phase 1 development. The remaining growth capital expenditure to first oil is forecast to be spent in 2026 on drilling, completions and commissioning of the CPF with first steam anticipated by end Q1 2026.

IPC is strongly positioned to deliver within plan with a clear line of sight to start-up. The Blackrod Phase 1 project is expected to generate significant value for all our stakeholders. And with over 1 billion barrels of best estimate contingent resources (unrisked) beyond Phase 1, IPC is pleased to announce a resource maturation plan that sees significant volume maturation into reserves through low cost of less than USD 0.15 per barrel. The 2P reserves attributable to Phase 1 has increased by 40 MMboe to 259 MMboe from year end 2023 to year end 2024.(2)

As at the end of 2024, 70% of the Blackrod Phase 1 development capital had been spent since the project sanction in early 2023. All major work streams are progressing as planned and the focus continues to be on executing the detailed sequencing of events as facility modules are safely delivered and installed at site. The total Phase 1 project guidance of USD 850 million capital expenditure to first oil in late 2026 is unchanged. IPC intends to fund the remaining Blackrod Phase 1 development costs with forecast cash flow generated by its operations and cash on hand**.**

**Stakeholder Returns: Normal Course Issuer Bid**
During the period of December 5, 2023 to December 4, 2024, IPC purchased and cancelled an aggregate of approximately 8.3 million common shares under the 2023/2024 NCIB. The average price of shares purchased under the 2023/2024 NCIB was SEK 131 / CAD 17 per share.

In Q4 2024, IPC announced the renewal of the NCIB, with the ability to repurchase up to approximately 7.5 million common shares over the period of December 5, 2024 to December 4, 2025. Under the 2024/2025 NCIB, IPC repurchased and cancelled approximately 0.8 million common shares in December 2024. By the end of January 2025, IPC repurchased for cancellation over 1.4 million common shares under the 2024/2025 NCIB. The average price of common shares purchased under the 2024/2025 NCIB during December 2024 and January 2025 was SEK 135 / CAD 17.5 per share.

As at February 7, 2025, IPC had a total of 117,781,927 common shares issued and outstanding, of which IPC holds 508,853 common shares in treasury.

Under the 2024/2025 NCIB, IPC may purchase and cancel a further 5.3 million common shares by December 4, 2025. This would result in the cancellation of 6.2% of shares outstanding as at the beginning of December 2024. IPC continues to believe that reducing the number of shares outstanding while in parallel investing in material production growth at Blackrod will prove to be a winning formula for our stakeholders.

**Environmental, Social and Governance (ESG) Performance**
As part of IPC's commitment to operational excellence and responsible development, IPC's objective is to reduce risk and eliminate hazards to prevent occurrence of accidents, ill health, and environmental damage, as these are essential to the success of our business operations. During the fourth quarter and for the full year 2024, IPC recorded no material safety or environmental incidents.

As previously announced, IPC targets a reduction of our net GHG emissions intensity by the end of 2025 to 50% of IPC's 2019 baseline and IPC remains on track to achieve this reduction. During 2024, IPC announced the commitment to remain at end 2025 levels of 20 kg $CO_2$/boe through to the end of 2028.(4)

**Reserves, Resources and Value**
As at the end of December 2024, IPC's 2P reserves are 493 MMboe. During 2024, IPC replaced 251% of the annual 2024 production. The reserve life index (RLI) as at December 31, 2024, is approximately 31 years.(1)(2)

The net present value (NPV) of IPC's 2P reserves as at December 31, 2024 was USD 3.3 billion. IPC's net asset value (NAV) was USD 3.1 billion or SEK 287 / CAD 37 per share as at December 31, 2024.(1)(2)(5)(6)(7)

In addition, IPC's best estimate contingent resources (unrisked) as at December 31, 2024 are 1,107 MMboe, of which 1,025 MMboe relate to future potential phases of the Blackrod project.(1)(2)

**2025 Budget and Operational Guidance**
IPC is pleased to announce its 2025 average net production guidance is 43,000 to 45,000 boepd. IPC forecasts operating costs for 2025 between USD 18 and 19 per boe.(1)(3)

IPC's 2025 capital and decommissioning expenditure budget is USD 320 million, with USD 230 million forecast relating to Blackrod capital expenditure. The remainder of the 2025 budget in Canada includes drilling and ongoing optimization work at Onion Lake Thermal and Suffield Area assets. IPC also plans to advance the next phase of infill drilling and complete well maintenance works at the Bertam field in Malaysia. IPC expects to conduct technical studies for future development potential in France. In all of IPC's areas of operation, IPC has significant flexibility to control its pace of spend based on the development of commodity prices during 2025.

Notwithstanding a modest production decline expected in 2025, IPC's production per share metric remains largely unchanged relative to 2024 and 2023. IPC has prioritised capital allocation to the transformational Blackrod Phase 1 development and share buybacks as opposed to further increasing its base business investment to preserve balance sheet strength and maximise long-term shareholder value.

Further details regarding IPC's proposed 2025 budget and operational guidance will be provided at IPC's Capital Markets Day presentation to be held on February 11, 2025 at 15:00 CET. A copy of the Capital Markets Day presentation will be available on IPC's website at www.international-petroleum.com.

Notes:

(1) See "Supplemental Information regarding Product Types" in "Reserves and Resources Advisory" below. See also the material change report (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.sedarplus.ca.

(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 described in the MCR. The reserve life index (RLI) is calculated by dividing the 2P reserves of 493 MMboe as at December 31, 2024, by the mid-point of the 2025 CMD production guidance of 43,000 to 45,000 boepd. Reserves replacement ratio is based on 2P reserves of 468 boe as at December 31, 2024, sales production during 2024 of 16.6 MMboe, net additions to 2P reserves during 2024 of 41.7 MMboe, and 2P reserves of 493 MMboe as at December 31, 2024.

(3) Non-IFRS measure, see "Non-IFRS Measures" below and in the MD&A.

(4) Emissions intensity is the ratio between oil and gas production and the associated carbon emissions, and net emissions intensity reflects gross emissions less operational emission reductions and carbon offsets.

(5) Net present value (NPV) is after tax, discounted at 10% and based upon the forecast prices and other assumptions further described in the MCR. See "Reserves and Resources Advisory" below.

(6) Net asset value (NAV) is calculated as NPV less net debt of USD 209 million as at December 31, 2024.

(7) NAV per share is based on 119,059,315 IPC common shares as at December 31, 2024, being 119,169,471 common shares outstanding less 110,156 common shares held in treasury and cancelled in January 2025. NAV per share is not predictive and may not be reflective of current or future market prices for IPC common shares.

(8) Estimated FCF generation is based on IPC's current business plans over the periods of 2025 to 2029 and 2030 to 2034, including net debt of USD 209 million as at December 31, 2024, with assumptions based on the reports of IPC's independent reserves evaluators, and including certain corporate adjustments relating to estimated general and administration costs and hedging, and excluding shareholder distributions and financing costs. Assumptions include average net production of approximately 57 Mboepd over the period of 2025 to 2029, average net production of approximately 63 Mboepd over the period of 2030 to 2034, average Brent oil prices of USD 75 to 95 per bbl escalating by 2% per year, and average Brent to Western Canadian Select differentials and average gas prices as estimated by IPC's independent reserves evaluator and as further described in the MCR. IPC's market capitalization is at close on January 31, 2025 (USD 1,557 million based on 146.8 SEK/share, 117.7 million IPC shares outstanding (net of treasury shares) and exchange rate of 11.10 SEK/USD). 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 "Forward-Looking Statements" and "Non-IFRS Measures" below.

## Operations Overview

**2024 Overview**
In 2024, IPC continued to successfully demonstrate its commitment to operational excellence, delivering annual net average daily production above the mid-point of our Capital Markets Day (CMD) guidance with no material safety or environmental incidents recorded in the year.

In Canada, the Blackrod Phase 1 development project is progressing in line with schedule and budget. Process facility fabrication is on track supporting critical equipment site installation which continues to progress in line with plan. Access road upgrades have been completed and third-party transport pipeline installation is progressing on schedule. Production well pad drilling continues and is ahead of schedule. At Onion Lake Thermal, daily production has remained stable with three additional production sustaining Pad L well pairs brought online in 2024. A total of seven Pad L well pairs are now online. At Suffield, all eight budgeted Ellerslie play production wells have been brought online and are producing in line with expectations. At Ferguson, the three new oil production wells continue to deliver above expectations. During Q4, on the back of the positive results, IPC sanctioned and drilled two additional Ferguson production wells. The wells are expected to be online early in Q1 2025.

In Malaysia and France, field development studies have progressed as planned.

**Reserves and Resources**
The 2P reserves attributable to IPC's oil and gas assets are 493 MMboe as at December 31, 2024, as certified by independent third party reserve auditors. The proved plus probable reserve life index (RLI) as at December 31, 2024, is approximately 31 years. Best estimate contingent resources as at December 31, 2024, are 1,107 MMboe (unrisked). See "Reserves and Resources Advisory" below.

**Production**
Average daily net production for Q4 2024 was in line with the CMD guidance at 47,400 boepd. In Canada, strong operational performance has been supported by increased gas production rates with re-initiation of base gas optimization activity. At the Bertam field in Malaysia, average daily production remained strong in Q4 2024, with high production uptime and a continued focus on well rate optimization activity to offset natural declines. In France, stable production performance continued through Q4 2024.

With strong operational delivery through 2024, IPC's exits the year with a net average daily production for 2024 above the mid-point of our CMD guidance at 47,400 boepd.

The production during Q4 2024 with comparatives is summarized below:

| Production in Mboepd | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2024** | 2023 | **2024** | 2023 |
| **Crude oil** | | | | |
| Canada – Northern Assets | 14.6 | 15.5 | 14.2 | 15.5 |
| Canada – Southern Assets[1] | 11.2 | 11.4 | 11.1 | 11.8 |
| Malaysia | 3.5 | 2.5 | 3.8 | 3.8 |
| France | 2.1 | 2.8 | 2.4 | 2.8 |
| **Total crude oil production** | **31.4** | 32.2 | **31.5** | 33.9 |
| **Gas** | | | | |
| Canada – Northern Assets | 0.5 | 0.4 | 0.5 | 0.4 |
| Canada – Southern Assets | 15.5 | 17.0 | 15.4 | 16.8 |
| **Total gas production** | **16.0** | 17.4 | **15.9** | 17.2 |
| **Total production** | **47.4** | 49.6 | **47.4** | 51.1 |
| **Quantity in MMboe** | **4.36** | 4.56 | **17.34** | 18.65 |

*[1] In respect of 2023 production, includes production from the Brooks assets acquired in the Cor4 acquisition in the Suffield area from January 1, 2023 being the effective date of the Cor4 acquisition. The acquisition of Cor4 was completed on March 3, 2023.*

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

## CANADA

| Production in Mboepd | Working Interest (WI) | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|---|
| | | 2024 | 2023 | 2024 | 2023 |
| - Oil Onion Lake Thermal | 100% | 12.2 | 13.6 | 12.3 | 13.3 |
| - Oil Suffield Area[1] | 100% | 9.8 | 10.1 | 9.7 | 10.2 |
| - Oil Other | 50-100% | 3.8 | 3.2 | 3.3 | 3.8 |
| - Gas[1] | ~100% | 16.0 | 17.4 | 15.9 | 17.2 |
| Canada | | **41.8** | 44.3 | **41.2** | 44.5 |

[1] *In respect of 2023 production, includes production from the Brooks assets acquired in the Cor4 acquisition in the Suffield area from January 1, 2023 being the effective date of the Cor4 acquisition. The acquisition of Cor4 was completed on March 3, 2023.*

**Production**
Net production from IPC's assets in Canada during Q4 2024 was in line with guidance at 41,800 boepd. Strong operational performance has been supplemented by base gas optimization activity recommencing and positive results from the recent oil well drilling in the Southern Alberta assets. At the Mooney asset, the Phase 2 enhanced oil recovery polymer flood project has performed ahead of expectations. Production remains stable at Onion Lake Thermal as the production wells from the latest production sustaining Pad L are phased in.

**Organic Growth and Capital Projects**
In Canada, with the Blackrod Phase 1 project development in its most capital-intensive phase, IPC announced a minimum non-Blackrod capital expenditure budget for 2024. At our Southern assets, the focus remains on the high performing Suffield Ellerslie play and is supplemented with the next phase of development well drilling at our Ferguson asset. At Onion Lake Thermal, production rate optimization is the priority with a continued phased ramp up of the latest production sustaining Pad L.

The Blackrod Phase 1 development project is progressing in line with schedule and budget. As at the end of Q4 2024, process facility fabrication is on track supporting critical equipment site installation which continues to progress in line with plan. Access road upgrades have been completed and third-party transport pipeline installation is progressing on schedule. Production well pad drilling continues and remains ahead of schedule.

At Ferguson, the three 2024 drilled oil production wells continue to deliver ahead of expectations. On the back of the positive results, IPC sanctioned drilling of an additional two Ferguson wells in Q4 2024. The wells have been drilled and are expected to be online in Q1 2025.

During Q4 2024, IPC completed drilling of the final Suffield area Ellerslie well target in the year. As of the end of Q4 2024, all eight 2024 sanctioned Ellerslie wells have been drilled and are online and performing in line with expectations.

At Onion Lake Thermal, daily production has remained stable with the seventh production sustaining Pad L well pair brought online in the quarter.

## MALAYSIA

| Production in Mboepd | WI | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|---|
| | | 2024 | 2023 | 2024 | 2023 |
| Bertam | 100% | **3.5** | 2.5 | **3.8** | 3.8 |

**Production**
Net production at Bertam in Malaysia in Q4 2024 was in line with guidance at 3,500 boepd with one production well offline late in December awaiting workover intervention.

**Organic Growth and Capital Projects**
In Malaysia, field development studies have progressed in line with expectations. During 2025, IPC plans to advance the next phase of infill drilling and complete well maintenance works at the Bertam field.

**FRANCE**

| Production in Mboepd | WI | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|---|
| | | **2024** | 2023 | **2024** | 2023 |
| France | | | | | |
| - Paris Basin | 100%[1] | 1.8 | 2.5 | 2.1 | 2.4 |
| - Aquitaine | 50% | 0.3 | 0.3 | 0.3 | 0.4 |
| | | **2.1** | 2.8 | **2.4** | 2.8 |

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

**Production**
Net production in France during Q4 2024 was at 2,100 boepd with stable performance at all the major producing assets.

**Organic Growth**
IPC continues to mature future development projects in France, with the next phase of production well targets matured and ready for sanction decision at the company's discretion.

## FINANCIAL REVIEW

### Financial Results

#### *Selected Annual Financial Information*

Selected consolidated statement of operations is as follows:

| USD Thousands | 2024 | 2023 | 2022 |
|---|---|---|---|
| Revenue | **797,783** | 853,906 | 1,129,298 |
| Gross profit | **210,171** | 250,514 | 516,709 |
| Net result | **102,219** | 172,979 | 337,725 |
| Earnings per share – USD | **0.82** | 1.31 | 2.30 |
| Earnings per share fully diluted – USD | **0.81** | 1.28 | 2.25 |
| Operating cash flow[1] | **341,989** | 353,048 | 622,947 |
| Free cash flow[1] | **(135,497)** | 2,689 | 430,242 |
| EBITDA[1] | **335,488** | 350,618 | 639,480 |
| Net cash / (debt) at period end[1] | **(208,528)** | 58,043 | 175,098 |

[1] *See definition on page 22 under "Non-IFRS measures"*

Summarized consolidated balance sheet information is as follows:

| USD Thousands | December 31, 2024 | December 31, 2023 | December 31, 2022 |
|---|---|---|---|
| Non-current assets | 1,554,833 | 1,372,388 | 1,041,051 |
| Current assets | 398,849 | 690,597 | 638,566 |
| **Total assets** | **1,953,682** | 2,062,985 | 1,679,617 |
| Total non-current liabilities | 806,134 | 779,838 | 564,381 |
| Current liabilities | 208,078 | 202,888 | 149,905 |
| **Total liabilities** | **1,014,212** | 982,726 | 714,286 |
| **Net assets** | **939,470** | 1,080,259 | 965,331 |
| **Working capital (including cash)** | **190,771** | 487,709 | 488,661 |

### Selected Interim Financial Information

Selected interim condensed consolidated statement of operations is as follows:

| USD Thousands | 2024 | Q4-24 | Q3-24 | Q2-24 | Q1-24 | 2023 | Q4-23 | Q3-23 | Q2-23 | Q1-23 |
|---|---|---|---|---|---|---|---|---|---|---|
| Revenue | **797,783** | 199,124 | 173,200 | 219,040 | 206,419 | **853,906** | 198,460 | 257,366 | 205,564 | 192,516 |
| Gross profit | **210,171** | 42,774 | 39,505 | 72,708 | 55,184 | **250,514** | 39,955 | 93,429 | 52,747 | 64,383 |
| Net result | **102,219** | 415 | 22,875 | 45,210 | 33,719 | **172,979** | 29,710 | 71,681 | 32,025 | 39,563 |
| Earnings per share – USD | **0.82** | 0.00 | 0.19 | 0.36 | 0.27 | **1.31** | 0.23 | 0.56 | 0.24 | 0.29 |
| Earnings per share fully diluted – USD | **0.81** | 0.00 | 0.18 | 0.36 | 0.26 | **1.28** | 0.22 | 0.54 | 0.24 | 0.28 |
| Operating cash flow[1] | **341,989** | 78,158 | 72,589 | 101,941 | 89,301 | **353,048** | 73,634 | 119,142 | 84,372 | 75,900 |
| Free cash flow[1] | **(135,497)** | (61,476) | (38,269) | 7,559 | (43,311) | **2,689** | (64,688) | 34,703 | 16,415 | 16,259 |
| EBITDA[1] | **335,488** | 76,184 | 68,313 | 103,971 | 87,020 | **350,618** | 66,284 | 123,054 | 85,201 | 76,079 |
| Net cash/(debt) at period end[1] | **(208,528)** | (208,528) | (157,228) | (88,220) | (60,572) | **58,043** | 58,043 | 83,097 | 63,548 | 66,956 |

[1] *See definition on page 22 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 mainly of the Suffield assets, including the Brooks assets). This is consistent with the internal reporting provided to the CEO, who is the chief operating decision maker. The following tables present certain segment information.

| | Three months ended – December 31, 2024 | | | | | |
|---|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Other | Total |
| Crude oil | 96,884 | 63,453 | 29,675 | 21,039 | – | **211,051** |
| NGLs | – | 165 | – | – | – | **165** |
| Gas | 69 | 8,990 | – | – | – | **9,059** |
| **Net sales of oil and gas** | **96,953** | **72,608** | **29,675** | **21,039** | – | **220,275** |
| Change in under/over lift position | – | – | – | (6,379) | – | **(6,379)** |
| Royalties | (14,048) | (10,690) | – | (821) | – | **(25,559)** |
| Hedging settlement | 5,430 | 5,012 | – | – | – | **10,442** |
| Other operating revenue | – | – | – | 244 | 101 | **345** |
| **Revenue** | **88,335** | **66,930** | **29,675** | **14,083** | **101** | **199,124** |
| Operating costs | (23,554) | (35,573) | (9,386) | (10,926) | – | **(79,439)** |
| Cost of blending | (29,653) | (6,383) | – | – | – | **(36,036)** |
| Change in inventory position | (741) | 434 | (4,750) | 424 | – | **(4,633)** |
| Depletion and decommissioning costs | (9,141) | (12,960) | (7,273) | (2,713) | – | **(32,087)** |
| Depreciation of other tangible fixed assets | – | – | (2,430) | – | – | **(2,430)** |
| Exploration and business development costs | – | – | (1,407) | (12) | (306) | **(1,725)** |
| **Gross profit/(loss)** | **25,246** | **12,448** | **4,429** | **856** | **(205)** | **42,774** |

| | Three months ended – December 31, 2023 | | | | | |
|---|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Other | Total |
| Crude oil | 105,268 | 62,240 | 15,313 | 28,617 | – | 211,438 |
| NGLs | – | 327 | – | – | – | 327 |
| Gas | 118 | 14,656 | – | – | – | 14,774 |
| Net sales of oil and gas | 105,386 | 77,223 | 15,313 | 28,617 | – | 226,539 |
| Change in under/over lift position | – | – | – | (8,442) | – | (8,442) |
| Royalties | (14,657) | (10,807) | – | (1,545) | – | (27,009) |
| Hedging settlement | 3,205 | 3,754 | – | – | – | 6,959 |
| Other operating revenue | – | – | – | 228 | 185 | 413 |
| Revenue | 93,934 | 70,170 | 15,313 | 18,858 | 185 | 198,460 |
| Operating costs | (23,868) | (38,651) | (9,170) | (11,679) | – | (83,368) |
| Cost of blending | (37,601) | (6,872) | – | – | – | (44,473) |
| Change in inventory position | (638) | 873 | 1,217 | (25) | – | 1,427 |
| Depletion and decommissioning costs | (9,165) | (14,654) | (2,982) | (3,633) | – | (30,434) |
| Depreciation of other tangible fixed assets | – | – | (1,309) | – | – | (1,309) |
| Exploration and business development costs | – | – | – | (30) | (318) | (348) |
| Gross profit/(loss) | 22,662 | 10,866 | 3,069 | 3,491 | (133) | 39,955 |

| | Year ended – December 31, 2024 | | | | | |
|---|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Other | Total |
| Crude oil | 405,090 | 273,004 | 105,445 | 70,948 | – | **854,487** |
| NGLs | – | 927 | – | – | – | **927** |
| Gas | 264 | 33,776 | – | – | – | **34,040** |
| **Net sales of oil and gas** | **405,354** | **307,707** | **105,445** | **70,948** | – | **889,454** |
| Change in under/over lift position | – | – | – | 41 | – | **41** |
| Royalties | (67,613) | (43,501) | – | (4,285) | – | **(115,399)** |
| Hedging settlement | 12,096 | 10,274 | – | – | – | **22,370** |
| Other operating revenue | – | – | – | 914 | 403 | **1,317** |
| **Revenue** | **349,837** | **274,480** | **105,445** | **67,618** | **403** | **797,783** |
| Operating costs | (84,018) | (141,757) | (32,771) | (35,464) | – | **(294,010)** |
| Cost of blending | (126,936) | (25,799) | – | – | – | **(152,735)** |
| Change in inventory position | (4) | (590) | (1,024) | 145 | – | **(1,473)** |
| Depletion and decommissioning costs | (36,554) | (52,029) | (27,481) | (12,328) | – | **(128,392)** |
| Depreciation of other tangible fixed assets | – | – | (8,933) | – | – | **(8,933)** |
| Exploration and business development costs | – | – | (1,407) | (12) | (650) | **(2,069)** |
| **Gross profit/(loss)** | **102,325** | **54,305** | **33,829** | **19,959** | **(247)** | **210,171** |

| USD Thousands | Year ended – December 31, 2023 Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Other | Total |
|---|---|---|---|---|---|---|
| Crude oil | 430,231 | 258,660 | 101,237 | 81,093 | – | 871,221 |
| NGLs | – | 1,172 | – | – | – | 1,172 |
| Gas | 373 | 66,965 | – | – | – | 67,338 |
| Net sales of oil and gas | 430,604 | 326,797 | 101,237 | 81,093 | – | 939,731 |
| Change in under/over lift position | – | – | – | 400 | – | 400 |
| Royalties | (60,152) | (41,025) | – | (5,120) | – | (106,297) |
| Hedging settlement | 1,585 | 17,343 | – | – | – | 18,928 |
| Other operating revenue | – | 7 | – | 867 | 270 | 1,144 |
| Revenue | 372,037 | 303,122 | 101,237 | 77,240 | 270 | 853,906 |
| Operating costs | (94,817) | (155,178) | (35,679) | (36,288) | – | (321,962) |
| Cost of blending | (146,204) | (26,792) | – | – | – | (172,996) |
| Change in inventory position | (448) | 952 | 3,358 | (207) | – | 3,655 |
| Depletion and decommissioning costs[1] | (24,969) | (45,135) | (17,800) | (14,018) | – | (101,922) |
| Depreciation of other tangible fixed assets | – | – | (7,812) | – | – | (7,812) |
| Exploration and business development costs | – | (834) | – | (39) | (1,482) | (2,355) |
| Gross profit/(loss) | 105,599 | 76,135 | 43,304 | 26,688 | (1,212) | 250,514 |

[1] *In Canada, includes an adjustment for accelerated decommissioning activities funded by a non cash site rehabilitation program.*

### *Three months and year ended December 31, 2024, Review*

**Revenue**

Total revenue amounted to USD 199,124 thousand for Q4 2024, compared to USD 198,460 thousand for Q4 2023 and USD 797,783 thousand for the year ended December 31, 2024 compared to USD 853,906 thousand for the year ended December 31, 2023 and is analyzed as follows:

| USD Thousands | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2024** | 2023 | **2024** | 2023 |
| Crude oil sales | 211,051 | 211,438 | 854,487 | 871,221 |
| Gas and NGL sales | 9,224 | 15,101 | 34,967 | 68,510 |
| Change in under/overlift position | (6,379) | (8,442) | 41 | 400 |
| Royalties | (25,559) | (27,009) | (115,399) | (106,297) |
| Hedging settlement | 10,442 | 6,959 | 22,370 | 18,928 |
| Other operating revenue | 345 | 413 | 1,317 | 1,144 |
| **Total revenue** | **199,124** | 198,460 | **797,783** | 853,906 |

The main components of total revenue for the three months and year ended December 31, 2024, and December 31, 2023, respectively, are detailed below.

**Crude oil sales**

| USD Thousands | Three months ended – December 31, 2024 | | | | |
|---|---|---|---|---|---|
| | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total |
| **Crude oil sales** | | | | | |
| - Revenue in USD thousands | 96,884 | 63,453 | 29,675 | 21,039 | **211,051** |
| - Quantity sold in bbls | 1,715,195 | 1,088,790 | 379,569 | 284,053 | **3,467,607** |
| - Average price realized USD per bbl | 56.49 | 58.28 | 78.18 | 74.07 | **60.86** |

| USD Thousands | Three months ended – December 31, 2023 | | | | |
|---|---|---|---|---|---|
| | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total |
| Crude oil sales | | | | | |
| - Revenue in USD thousands | 105,268 | 62,240 | 15,313 | 28,617 | 211,438 |
| - Quantity sold in bbls | 1,901,026 | 1,085,848 | 179,754 | 349,216 | 3,515,844 |
| - Average price realized USD per bbl | 55.37 | 57.32 | 85.19 | 81.95 | 60.14 |

Crude oil revenue was in line in Q4 2024 compared to Q4 2023 with slightly lower sales volumes and slightly higher oil prices. Malaysia sales are higher in Q4 2024 compared to Q4 023 as a result of two liftings in Q4 2024 versus one lifting in Q4 2023.

The Suffield area assets and Onion Lake Thermal crude oil in Canada is 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 2024, WTI averaged USD 70 per bbl compared to USD 79 per bbl for Q4 2023 and the average discount to WCS used in IPC's pricing formula was USD 13 per bbl compared to USD 22 per bbl for Q4 2023.

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 2024 and one cargo lifting in Q4 2023. Produced unsold oil barrels from Bertam at the end of Q4 2024 amounted to 124,000 barrels, see Change in Inventory Position section below. The average Dated Brent crude oil price was USD 75 per bbl for Q4 2024 compared to USD 84 per bbl for the comparative period.

| USD Thousands | Year ended – December 31, 2024 | | | | |
|---|---|---|---|---|---|
| | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total |
| **Crude oil sales** | | | | | |
| - Revenue in USD thousands | 405,090 | 273,004 | 105,445 | 70,948 | **854,487** |
| - Quantity sold in bbls | 6,727,693 | 4,442,570 | 1,224,980 | 886,766 | **13,282,009** |
| - Average price realized USD per bbl | 60.21 | 61.45 | 86.08 | 80.01 | **64.33** |

| USD Thousands | Year ended – December 31, 2023 | | | | |
|---|---|---|---|---|---|
| | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total |
| Crude oil sales | | | | | |
| - Revenue in USD thousands | 430,231 | 258,660 | 101,237 | 81,093 | 871,221 |
| - Quantity sold in bbls | 7,426,431 | 4,334,552 | 1,112,408 | 989,802 | 13,863,193 |
| - Average price realized USD per bbl | 57.93 | 59.67 | 91.01 | 81.93 | 62.84 |

Crude oil revenue was lower by 2% during the year ended December 31, 2024 compared to the year ended December 31, 2023 mainly due to lower sales volumes partly offset by higher prices.

The Suffield area assets and Onion Lake Thermal crude oil in Canada is 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 WCS price which trades at a discount to WTI. For the year ended December 31, 2024, WTI averaged USD 76 per bbl compared to USD 78 per bbl for the comparative period and the average discount to WCS used in our pricing formula was USD 15 per bbl compared to USD 19 per bbl for the comparative period.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices and the average market Brent crude oil price was USD 81 per bbl for the year ended December 31, 2024 compared to USD 83 per bbl for the comparative period.

**Gas and NGL sales**

| | Three months ended – December 31, 2024 | | |
|---|---|---|---|
| | Canada – Northern Assets | Canada – Southern Assets | Total |
| Gas and NGL sales | | | |
| - Revenue in USD thousands | 69 | 9,155 | **9,224** |
| - Quantity sold in Mcf | 76,102 | 7,791,291 | **7,867,393** |
| - Average price realized USD per Mcf | 0.91 | 1.18 | **1.17** |

| | Three months ended – December 31, 2023 | | |
|---|---|---|---|
| | Canada – Northern Assets | Canada – Southern Assets | Total |
| Gas and NGL sales | | | |
| - Revenue in USD thousands | 118 | 14,983 | 15,101 |
| - Quantity sold in Mcf | 77,185 | 8,585,805 | 8,662,990 |
| - Average price realized USD per Mcf | 1.53 | 1.75 | 1.74 |

Gas and NGL sales revenue was 39% lower for Q4 2024 compared to Q4 2023 mainly due to the lower achieved gas price. IPC's achieved gas price is based on AECO pricing plus a premium. For Q4 2024, IPC realized an average price of CAD 1.61 per Mcf compared to AECO average pricing of CAD 1.44 per Mcf.

| | Year ended – December 31, 2024 | | |
|---|---|---|---|
| | Canada – Northern Assets | Canada – Southern Assets | Total |
| Gas and NGL sales | | | |
| - Revenue in USD thousands | 264 | 34,703 | **34,967** |
| - Quantity sold in Mcf | 284,209 | 30,601,443 | **30,885,652** |
| - Average price realized USD per Mcf | 0.93 | 1.13 | **1.13** |

| | Year ended – December 31, 2023 | | |
|---|---|---|---|
| | Canada – Northern Assets | Canada – Southern Assets | Total |
| Gas and NGL sales | | | |
| - Revenue in USD thousands | 373 | 68,137 | 68,510 |
| - Quantity sold in Mcf | 227,032 | 33,221,660 | 33,448,692 |
| - Average price realized USD per Mcf | 1.64 | 2.05 | 2.05 |

Gas and NGL sales revenue was 49% lower for the year ended December 31, 2024 compared to the year ended December 31, 2023 mainly due to the lower achieved gas price.

IPC's achieved gas price is based on AECO pricing plus a premium. For the year ended December 31, 2024, IPC realized an average price of CAD 1.51 per Mcf compared to AECO average pricing of CAD 1.45 per Mcf.

**Hedging settlement**
IPC enters into risk management contracts in order to ensure a certain level of cash flow. It focuses mainly on oil and gas price swaps to limit pricing exposure. Oil and gas pricing contracts are not entered into for speculative purposes.

The realized hedging settlement for the year ended December 31, 2024 amounted to a gain of USD 22,370 thousand and consisted of a gain of USD 21,587 thousand on the oil contracts and a gain of USD 783 thousand on the gas contracts. Also see the Financial Position and Liquidity and the Financial Risk Management sections below.

**Production costs**
Production costs including inventory movements amounted to USD 100,984 thousand for Q4 2024 compared to USD 126,414 thousand for Q4 2023 and USD 328,110 thousand for the year ended December 31, 2024 compared to USD 491,303 thousand for the comparative period, and is analyzed as follows:

| | Three months ended – December 31, 2024 | | | | | |
|---|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Other[3] | Total |
| **Operating costs[1]** | 23,554 | 35,573 | 13,418 | 10,926 | (4,032) | **79,439** |
| USD/boe[2] | 17.04 | 14.47 | 41.31 | 55.91 | n/a | **18.21** |
| **Cost of blending** | 29,653 | 6,383 | – | – | – | **36,036** |
| **Change in inventory position** | 741 | (434) | 4,750 | (424) | – | **4,633** |
| **Production costs** | **53,948** | **41,522** | **18,168** | **10,502** | **(4,032)** | **120,108** |

| | Three months ended – December 31, 2023 | | | | | |
|---|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Other[3] | Total |
| Operating costs[1] | 23,868 | 38,651 | 12,091 | 11,679 | (2,921) | 83,368 |
| USD/boe[2] | 16.39 | 14.80 | 51.74 | 45.26 | n/a | 18.28 |
| Cost of blending | 37,601 | 6,872 | – | – | – | 44,473 |
| Change in inventory position | 638 | (873) | (1,217) | 25 | – | (1,427) |
| Production costs | 62,107 | 44,650 | 10,874 | 11,704 | (2,921) | 126,414 |

| | Year ended – December 31, 2024 | | | | | |
|---|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Other[3] | Total |
| **Operating costs[1]** | 84,018 | 141,757 | 49,089 | 35,464 | (16,318) | **294,010** |
| USD/boe[2] | 15.74 | 14.60 | 34.85 | 40.13 | n/a | **16.96** |
| **Cost of blending** | 126,936 | 25,799 | – | – | – | **152,735** |
| **Change in inventory position** | 4 | 590 | 1,024 | (145) | – | **1,473** |
| **Production costs** | **210,958** | **168,146** | **50,113** | **35,319** | **(16,318)** | **448,218** |

| USD Thousands | Year ended – December 31, 2023 | | | | | |
|---|---|---|---|---|---|---|
| | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Other[3] | Total |
| Operating costs[1] | 94,817 | 155,178 | 50,032 | 36,288 | (14,353) | 321,962 |
| USD/boe[2] | 16.33 | 15.51 | 35.87 | 36.27 | n/a | 17.63 |
| Cost of blending | 146,204 | 26,792 | – | – | – | 172,996 |
| Change in inventory position | 448 | (952) | (3,358) | 207 | – | (3,655) |
| Production costs | 241,469 | 181,018 | 46,674 | 36,495 | (14,353) | 491,303 |

*[1] See definition on page 22 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 and for 2023, includes the Brooks assets from January 1, 2023.*
*[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 costs per boe for Malaysia to USD 28.89 for Q4 2024 and USD 39.24 for the comparative period and USD 23.27 and USD 25.58 for the year ended December 31, 2024, and December 31, 2023, respectively.*

**Operating costs**
Operating costs amounted to USD 79,439 thousand for Q4 2024 compared to USD 83,368 thousand for Q4 2023 and USD 294,010 thousand for the year ended December 31, 2024 compared to USD 321,962 thousand for the year ended December 31, 2023. Operating costs per boe amounted to USD 16.96 per boe for 2024 below the guidance and compared with USD 17.63 per boe for 2023.

**Cost of blending**
For the Suffield area and Onion Lake Thermal assets in Canada, oil production is blended with purchased condensate diluent to meet pipeline specifications. As a result of the blending, actual sales volumes are higher than produced barrels and the realized sales price of a blended barrel is higher than an unblended barrel.

The cost of the diluent amounted to USD 36,036 thousand for Q4 2024 compared to USD 44,473 thousand for Q4 2023 and USD 152,735 thousand for the year ended December 31, 2024 compared to USD 172,996 thousand for the comparative period.

**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 Q4 2024, IPC had crude entitlement of 124,000 bbl of oil on the FPSO Bertam facility being crude produced but not yet sold.

**Depletion and decommissioning costs**
The total depletion of oil and gas properties amounted to USD 30,491 thousand for Q4 2024 compared to USD 30,434 thousand for Q4 2023 and USD 96,305 thousand for the year ended December 31, 2024 compared to USD 126,010 thousand the year ended December 31, 2023 (including an adjustment for accelerated decommissioning activities amounting to USD 24,088 thousand).

The depletion charge is analyzed in the following tables:

| USD Thousands | Three months ended – December 31, 2024 | | | | |
|---|---|---|---|---|---|
| | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total |
| **Depletion cost in USD thousands** | 9,141 | 12,960 | 7,273 | 2,713 | **32,087** |
| **USD per boe** | 6.61 | 5.27 | 22.39 | 13.88 | **7.36** |

| USD Thousands | Three months ended – December 31, 2023 | | | | |
|---|---|---|---|---|---|
| | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total |
| Depletion cost in USD thousands | 9,165 | 14,654 | 2,982 | 3,633 | 30,434 |
| USD per boe | 6.30 | 5.61 | 12.76 | 14.08 | 6.67 |

| USD Thousands | Year ended – December 31, 2024 Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total |
|---|---|---|---|---|---|
| **Depletion cost in USD thousands** | 36,554 | 52,029 | 27,481 | 12,328 | **128,392** |
| **USD per boe** | 6.85 | 5.36 | 19.51 | 13.95 | **7.40** |

| USD Thousands | Year ended – December 31, 2023 Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total |
|---|---|---|---|---|---|
| Depletion cost in USD thousands[1] | 37,295 | 56,897 | 17,800 | 14,018 | 126,010 |
| USD per boe | 6.42 | 5.68 | 12.76 | 14.01 | 6.89 |

[1] *In Canada, excludes the adjustment for accelerated decommissioning activities.*
[2] *USD/boe in the tables above is calculated by dividing the depletion cost by the production volume for each country for the period and for 2023, includes the Brooks assets from January 1, 2023.*

The depletion charge is derived by applying the depletion rate per boe to the volumes produced in the period by each field. The depletion rate in Malaysia has significantly increased compared to the prior year following the capitalization of the workover costs incurred in Q4 2023 and Q1 2024.

**Depreciation of other tangible fixed assets**
The total depreciation of other assets amounted to USD 2,430 thousand for Q4 2024 compared to USD 1,309 thousand for Q4 2023 and USD 8,933 thousand for the year ended December 31, 2024 compared to USD 7,812 thousand for the year ended December 31, 2023. This relates to the depreciation of the FPSO Bertam, which is being depreciated to its residual value on a unit of production basis to August 2025.

**Exploration and business development costs**
The total exploration and business developments costs amounted to a cost of USD 2,069 thousand for the year ended December 31, 2024 and mainly relates to the write-off of exploration costs in Malaysia.

**Net financial items**
Net financial items amounted to a charge of USD 59,709 thousand for the year ended December 31, 2024, compared to a charge of USD 22,736 thousand for the year ended December 31, 2023 and included a net foreign exchange loss of USD 23,427 thousand for 2024 compared to a net foreign exchange loss of USD 1,911 thousand for the year ended December 31, 2023. The foreign exchange movements are mainly resulting from the revaluation of intra-group loan funding balances and the settlement of currency hedging.

Excluding foreign exchange movements, the net financial items amounted to a charge of USD 36,282 thousand for the year ended December 31, 2024, compared to USD 20,825 thousand for the year ended December 31,2023.

The interest expense amounted to USD 35,905 thousand for the year ended December 31, 2024, compared to USD 25,635 thousand for the comparative period in 2023 and mainly related to the bond interest at a coupon rate of 7.25% per annum. The increase compared to the comparative period is largely attributable to the additional MUSD 150 bond tap issue completed in Q3 2023. Interest income generated on cash balances held amounted to USD 17,721 thousand for the year ended December 31, 2024 and USD 21,774 thousand for the year ended December 31, 2023.

The unwinding of the asset retirement obligation discount rate amounted to USD 14,568 thousand for the year ended December 31, 2024, compared to USD 13,408 thousand for the year ended December 31, 2023.

**Income tax**
The corporate income tax amounted to a charge of USD 33,325 thousand for the year ended December 31, 2024, compared to a charge of USD 55,362 thousand for the year ended December 31, 2023.

The current income tax amounted to a charge of USD 8,313 thousand for the year ended December 31, 2024 and mainly related to France and Malaysia. No corporate income tax is expected to be payable in Canada in 2024 due to the usage of historical tax pools.

## Capital Expenditure

Development and exploration and evaluation expenditure incurred during the year ended December 31, 2024 was as follows:

| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total |
|---|---|---|---|---|---|
| Development | 369,465 | 42,819 | 17,035 | 3,475 | **432,794** |
| Exploration and evaluation | 500 | – | 1,407 | 12 | **1,919** |
| | 369,965 | 42,819 | 18,442 | 3,487 | **434,713** |

Capital expenditure of USD 434,713 thousand was mainly spent in Canada on the Blackrod Phase 1 Development project, drilling on the Southern Alberta assets and in Malaysia on the well workovers.

**Other tangible fixed assets**
Other tangible fixed assets amounted to USD 16,425 thousand as at December 31, 2024, which included USD 14,797 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated to its residual value on a unit of production basis to August 2025.

## Financial Position and Liquidity

**Financing**
As at January 2023, IPC had MUSD 300 of bonds outstanding, issued in February 2022 and maturing in February 2027 with a fixed coupon rate of 7.25% per annum, payable in semi-annual instalments in August and February. The Group also had a revolving credit facility of MCAD 75 (the "Canadian RCF") in connection with its oil and gas assets in Canada.

In Q3 2023, IPC completed a tap issue of MUSD 150 under IPC's existing 7.25% bond framework issued at 7% discount to par value with proceeds amounting to MUSD 139.5 before transaction costs. For accounting purposes, the discounted amount was recognised in the balance sheet and the discount will be unwound over the period to maturity of the bond and charged to the interest expense line of the Statement of Operations using the effective interest rate methodology. As at December 31, 2024, IPC had a nominal MUSD 450 of bonds outstanding with maturity in February 2027. The bond repayment obligations as at December 31, 2024, are classified as non-current as there are no mandatory repayments within the next twelve months.

During 2023, the Group increased the Canadian RCF from MCAD 75 to MCAD 180 with a maturity to May 2025. During Q2 2024, the Group extended the maturity of the Canadian RCF to May 2026. The Canadian RCF is undrawn and fully available as at December 31, 2024. During Q3 2024, the Group entered into a letter of credit facility in Canada (the "LC Facility") to cover existing operational letters of credit. As at December 31, 2024, operational letters of credit in an aggregate of MCAD 40.2 have been issued under the LC Facility, including letters of credit issued in Q2 2024 for a total amount of MCAD 35 to support the third party pipeline construction agreements for the Blackrod project during 2024 and 2025.

As at December 31, 2024, IPC had an unsecured Euro credit facility in France (the "France Facility"), with maturity in May 2026. IPC makes quarterly repayments of the French Facility and the amount remaining outstanding under the France Facility as at December 31, 2024 was MUSD 5.1 million. An amount of MUSD 3.4 drawn under the France Facility as at December 31, 2024 is classified as current representing the repayment planned within the next twelve months.

The Group is in compliance with the covenants of the bonds and its financing facilities as at December 31, 2024.

Net debt as at December 31, 2024 amounted to MUSD 209. Cash and cash equivalents held amounted to MUSD 247 as at December 31, 2024.

IPC intends to fund the remaining Blackrod Phase 1 project development costs with cash on hand and forecast cash flow generated by its operations.

**Working Capital**
As at December 31, 2024, the Group had a working capital balance including cash of USD 190,771 thousand compared to USD 487,709 thousand as at December 31, 2023. The difference as at December 31, 2024, from December 31, 2023, is mainly as a result of the decreased cash following capital expenditures on the Blackrod Phase 1 development project and the continuing NCIB program.

## 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"/"net cash", 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 including net sales of diluent 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 and bonds less cash and cash equivalents. "Net cash" is calculated as cash and cash equivalents less bank loans and bonds.

### 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 | 2024 | 2023 | 2024 | 2023 |
| Revenue | 199,124 | 198,460 | 797,783 | 853,906 |
| Production costs and net sales of diluent to third party[1] | (119,371) | (126,414) | (447,481) | (491,303) |
| Current tax | (1,595) | 1,588 | (8,313) | (14,457) |
| Operating cash flow | **78,158** | 73,634 | **341,989** | 348,146 |

[1] *Include net sales of diluent to third party amounting to USD 737 thousand for the fourth quarter of 2024 and the year ended December 31, 2024.*

The operating cash flow for the year ended December 31, 2023 including the operating cash flow contribution of the Brooks assets acquisition from the effective date of January 1, 2023 to the completion date of March 3, 2023 amounted to USD 353,048 thousand.

**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 | 2024 | 2023 | 2024 | 2023 |
| Operating cash flow - see above | 78,158 | 73,634 | 341,989 | 348,146 |
| Capital expenditures | (126,256) | (128,825) | (434,713) | (312,729) |
| Abandonment and farm-in expenditures[1] | (3,364) | (1,516) | (8,302) | (9,199) |
| General, administration and depreciation expenses before depreciation[2] | (3,569) | (5,762) | (14,814) | (16,886) |
| Cash financial items[3] | (6,445) | (2,219) | (19,657) | (5,812) |
| Free cash flow | **(61,476)** | (64,688) | **(135,497)** | 3,520 |

[1] *See note 19 to the Financial Statements*
[2] *Depreciation is not specifically disclosed in the Financial Statements*
[3] *See notes 5 and 6 to the Financial Statements.*

The free cash flow for the year ended December 31, 2023 including the free cash flow contribution of the Brooks assets acquisition from the effective date of January 1, 2023 to the completion date of March 3, 2023 amounted to USD 2,689 thousand. Free cash flow is before shareholder distributions and financing costs.

**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 | 2024 | 2023 | 2024 | 2023 |
| Net result | 415 | 29,710 | 102,219 | 172,979 |
| Net financial items | 35,767 | 6,509 | 59,709 | 22,736 |
| Income tax | 3,852 | 4,691 | 33,325 | 55,362 |
| Depletion and decommissioning costs | 32,087 | 30,434 | 128,392 | 101,922 |
| Depreciation of other tangible fixed assets | 2,430 | 1,309 | 8,933 | 7,812 |
| Exploration and business development costs | 1,725 | 348 | 2,069 | 2,355 |
| Depreciation included in general, administration and depreciation expenses[1] | 308 | 389 | 1,241 | 1,569 |
| Sale of assets[2] | (400) | (7,106) | (400) | (19,018) |
| EBITDA | **76,184** | 66,284 | **335,488** | 345,717 |

[1] *Item is not shown in the Financial Statements.*
[2] *Sale of assets is included under "Other income/(expense)" but not specifically disclosed in the Financial Statements*

The EBITDA for the year ended December 31, 2023 including the EBITDA contribution of the Brooks assets acquisition from the effective date of January 1, 2023 to the completion date of March 3, 2023 amounted to USD 350,618 thousand.

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

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| USD Thousands | 2024 | 2023 | 2024 | 2023 |
| Production costs | 120,108 | 126,414 | 448,218 | 491,303 |
| Cost of blending | (36,036) | (44,473) | (152,735) | (172,996) |
| Change in inventory position | (4,633) | 1,427 | (1,473) | 3,655 |
| Operating costs | **79,439** | 83,368 | **294,010** | 321,962 |

The operating costs for the year ended December 31, 2023 including the operating costs contribution of the Brooks assets acquisition from the effective date of January 1, 2023 to the completion date of March 3, 2023 amounted to USD 328,763 thousand.

**Net cash/(debt)**
The following table sets out how net cash/(debt) is calculated:

| USD Thousands | December 31, 2024 | December 31, 2023 |
|---|---|---|
| Bank loans | (5,121) | (9,031) |
| Bonds[1] | (450,000) | (450,000) |
| Cash and cash equivalents | 246,593 | 517,074 |
| Net cash/(debt) | **(208,528)** | 58,043 |

[1] *The bond amount represents the redeemable value at maturity (February 2027).*

## Off-Balance Sheet Arrangements

IPC, through its subsidiary IPC Canada Ltd, has issued six letters of credit as follows: (a) MCAD 2.6 in respect of its obligations to purchase diluent; (b) MCAD 0.9 in respect of its obligations related to the Ferguson asset, increasing by MCAD 0.1 annually to a maximum of MCAD 1.0; (c) MCAD 1.3 in respect of pipeline access; (d) MCAD 0.5 in relation to the hedging of electricity prices; (e) and (f) MCAD 24.5 and MCAD 10.5 respectively in respect of its obligations related to Blackrod pipelines.

## Outstanding Share Data

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

As at January 1, 2023, IPC had a total of 136,827,999 common shares issued and outstanding, with no common shares held in treasury.

During 2023, under the normal course issuer bid (NCIB) announced in December 2022 and renewed in December 2023, IPC purchased and cancelled an aggregate of 9,835,933 common shares.

As at December 31, 2023, IPC had a total of 126,992,066 common shares issued and outstanding, with no common shares held in treasury.

From January 1, 2024 to December 4, 2024, IPC purchased and cancelled a total of 7,109,365 common shares under the NCIB.

The NCIB was further renewed in Q4 2024 and IPC is entitled to purchase up to 7,465,356 common shares over the period of December 5, 2024 to December 4, 2025. During December 2024, IPC purchased 823,386 and cancelled 713,230 common shares under the renewed NCIB, for an aggregate of 7,822,595 common shares cancelled in 2024.

As at December 31, 2024, IPC had a total of 119,169,471 common shares issued and outstanding and held 110,156 common shares held in treasury.

Nemesia S.à.r.l., an investment company ultimately controlled by trusts whose settlor is the late Adolf H. Lundin, holds 40,697,533 common shares in IPC, representing 34.2% of the outstanding common shares as at December 31, 2024.

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 3,325,568 IPC Share Unit Plan awards outstanding as at February 11, 2025 (4,333 awards granted in January 2022, 1,088,035 awards granted in March 2022, 2,391 awards granted in July 2022, 2,072 awards granted in January 2023, 1,030,080 awards granted in February 2023, 3,244 awards granted in July 2023, 2,443 awards granted in January 2024, 1,183,035 awards granted in February 2024, 4,328 awards granted in July 2024 and 5,607 awards granted in January 2025).

The Corporation is authorized to issue an unlimited number of common shares without par value. The Corporation is also authorized to issue an unlimited number of class A preferred shares and an unlimited number of class B preferred shares, issuable in series.

## Contractual Obligations and Commitments

In the normal course of business, the Group has committed to certain payments which are not recognised as liabilities. The following table summarizes the Group's commitments in Canada as at December 31, 2024:

| MCAD | 2025 | 2026 | 2027 | 2028 | 2029 | Thereafter |
|---|---|---|---|---|---|---|
| Transportation service[1] | 33.3 | 60.6 | 89.2 | 92.8 | 96.7 | 1,391.6 |
| Power[2] | 14.5 | 12.4 | 12.4 | 9.8 | – | – |
| **Total commitments** | **47.8** | **73.0** | **101.6** | **102.6** | **96.7** | **1,391.6** |

*[1] IPC has firm transportation commitments on oil and natural gas pipelines that expire between 2037 and 2045.*
*[2] IPC has physical delivery power hedges to purchase 15MWh at a weighted average price of CAD 74.92/MWh from January 1, 2025 to December 31, 2028, an additional 5MWh at a weighted average price of CAD 58.31/MWh from January 1, 2025 to December 31, 2027, and an additional 5MWh at a weighted average price of CAD 46.85/MWh from January 1, 2025 to December 31, 2025.*

## Material Accounting Policies and Estimates

In connection with the preparation of the consolidated financial statements, the Group's 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. The assumptions, estimates and judgments are based on historical experience, current trends and other factors that management believes to be relevant at the time the consolidated financial statements are prepared. On a regular basis, management reviews the accounting policies, assumptions, estimates and judgments to ensure that the consolidated financial statements are presented fairly in accordance with IFRS Accounting Standards. 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.

Management believes the following critical accounting policies affect the more significant judgments and estimates used in the preparation of the consolidated financial statements:

### *Estimates of oil and gas reserves*
Estimates of oil and gas reserves are used in the calculations for impairment tests and accounting for depletion and asset retirement obligation. Standard recognized evaluation techniques are used to estimate the proved and probable reserves. These techniques take into account the future level of development required to produce the reserves. An independent qualified reserves auditor reviews these estimates. Changes in estimates in oil and gas reserves, resulting in different future production profiles, will affect the discounted cash flows used in impairment testing, the anticipated date of site decommissioning and restoration and the depletion charges in accordance with the unit of production method. Changes in estimates in oil and gas reserves could for example result from additional drilling, observation of long-term reservoir performance or changes in economic factors such as oil price and inflation rates. Significant assumptions developed by management used to determine estimates of proved and probable oil and gas reserves include expected production volumes, future oil and gas prices, future development costs and future production costs.

### *Impairment of oil and gas properties*
Impairment tests are performed when there are indicators of impairment. Key assumptions in the impairment models relate to prices and costs that are based on forward curves and the long-term corporate assumptions. The impairment test requires the use of estimates. For the purpose of determining a potential impairment, the significant assumptions developed by management used to determine the recoverable amount include the estimates of oil an gas reserves and the discount rate. These assumptions and judgements of management that are based on them are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates and the discount rate applied is reviewed throughout the year.

### *Provision for asset retirement obligations*
Amounts used in recording a provision for asset retirement obligations are estimates based on current legal and constructive requirements and current technology and price levels for the removal of facilities and decommissioning. Due to changes in relation to these items, the future actual cash outflows in relation to the site decommissioning and restoration can be different. To reflect the effects due to changes in legislation, requirements and technology and price levels, the carrying amounts of asset retirement obligation provisions are reviewed on a regular basis.

### *Deferred income tax assets*
The Group accounts for differences that arise between the carrying amount of assets and liabilities and their tax bases in accordance with IAS 12, Income Taxes, which requires deferred income tax assets only to be recognized to the extent that is probable that future taxable profits will be available against which the temporary differences can be utilized. Management estimates future taxable profits based on the financial models used to value its oil and gas properties. Any change to the estimates and assumptions used for the key operational and financial variables used within the business models could affect the amount of deferred income tax assets recognized.

The effects of changes in estimates do not give rise to prior year adjustments and are treated prospectively over the estimated remaining commercial reserves of each field. While the Group uses its best estimates and judgement, actual results could differ from these estimates.

***Fair value of assets acquired and liabilities assumed in a business combination***
The fair value of assets acquired and liabilities assumed in a business combination, including contingent consideration and any goodwill, is estimated based on information available at the date of acquisition. Various valuation techniques are applied for measuring fair value including market comparables and discounted cash flows which rely on assumptions such as forward commodity prices, reserves and resources estimates, production costs and discount rates. Changes in these variables could significantly impact the carrying value of the net assets.

## Transactions with Related Parties

During the year 2024, the Group paid USD 444 thousand to the Lundin Foundation in respect of sustainability advisory services provided to the Group and USD 834 thousand to Orrön Energy in respect of office space rental.

During the year ended December 31, 2024, Orrön Energy AB and ShaMaran Petroleum Corp. paid respectively USD 546 thousand and USD 186 thousand to the Group in respect of support services provided during the year 2024.

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 oil and gas prices. The Group seeks to control these risks through sound management practice and the use of internationally accepted financial instruments, such as oil and gas, condensate and electricity 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, 2024, the Corporation had entered into oil, gas and electricity 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 bonds or 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, 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. The Group does not currently have any covenants under its current financing facilities to hedge future production.

The Group had oil price sale financial hedges outstanding as at December 31, 2024, which are summarized as follows:

| Period | Volume (barrels per day) | Type | Average Pricing |
|---|---|---|---|
| January 1, 2025 - December 31, 2025 | 11,700 | WTI/WCS Differential | USD -14.26/bbl |
| January 1, 2025 - March 31, 2025 | 5,000 | WTI Sale Swap | USD 70.00/bbl |
| April 1, 2025 - June 30, 2025 | 2,500 | WTI Sale Swap | USD 70.00/bbl |

The Group had gas price sale financial hedges outstanding as at December 31, 2024, which are summarized as follows:

| Period | Volume (Gigajoules (GJ) per day)) | Type | Average Pricing |
|---|---|---|---|
| January 1, 2025 - December 31, 2025 | 10,000 | AECO Swap | CAD 2.500/GJ |

The Group had electricity financial hedges outstanding as at December 31, 2024, which are summarized as follows:

| Period | Volume (MWh) | Type | Average Pricing |
|---|---|---|---|
| October 1, 2025 - September 30, 2040 | 3 | AESO | CAD 75.00/MWh |

The above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. The hedges had a positive fair value of USD 3,219 thousand as at December 31, 2024.

In January 2025, the Group entered into the following oil price sale financial hedges:

| Period | Volume (barrels per day) | Type | Average Pricing |
|---|---|---|---|
| January 1, 2025 - January 31, 2025 | 2,000 | WTI Sale Swap | USD 72.00/bbl |
| February 1, 2025 - March 31, 2025 | 5,000 | WTI Sale Swap | USD 72.60/bbl |
| April 1, 2025 - June 30, 2025 | 7,500 | WTI Sale Swap | USD 71.73/bbl |
| July 1, 2025 - December 31, 2025 | 10,000 | WTI Sale Swap | USD 71.30/bbl |
| January 1, 2025 - January 31, 2025 | 1,000 | Brent Sale Swap | USD 75.00/bbl |
| February 1, 2025 - December 31, 2025 | 2,000 | Brent Sale Swap | USD 75.78/bbl |

**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.

The Group entered into currency hedges to purchase:
(i) a total CAD 520 million for the period January 2025 to December 2025 at an average rate of CAD 1.36 (sell USD);
(ii) a total EUR 27 million for the period January 2025 to December 2025 at an average rate of EUR 1.07 (sell USD);
(iii) a total MYR 138 million for the period January 2025 to December 2025 at an average rate of MYR 4.40 (sell USD).

The outstanding portion of all of the above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. The hedges had a negative fair value of USD 19,869 thousand as at December 31, 2024.

**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 FACTORS

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 IPC's common shares ("Common Shares") to decline. If any of the following risks actually occur, the Group's business may be adversely affected, and the Group's financial condition and results of operations may suffer significantly.

See also "Cautionary Statement Regarding Forward-Looking Information" and "Reserves and Resource Advisory" below.

### 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. While diligent well supervision, effective maintenance operations and the development of EOR technologies can contribute to maximizing production rates over time, it is not possible to eliminate 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.

IPC uses multi-well pad drilling in certain situations where practicable. Wells drilled on a pad may not be placed on production until all wells on the pad are drilled and completed. In addition, problems affecting a single well could adversely affect production from all of the wells on the pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production, or interruption in ongoing production. These delays or interruptions may cause volatility in operating results.

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 demand for energy, including oil and gas, is generally linked to broad-based economic activities. If there was a slowdown in economic growth, an economic downturn or recession, or other adverse economic or political developments in the U.S., Europe, Asia or elsewhere, there could be a significant adverse effect on global financial markets and commodity prices. In addition, hostilities in the Middle East, Ukraine and elsewhere and the occurrence or threat of terrorist attacks in the U.S. or other countries could adversely affect the global economy.

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, the capacity of such pipelines and 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+, strategic petroleum reserve management and imposition of tariffs by the United States, the conflict in Ukraine, the impact of pandemics, 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 and the availability of alternative fuel sources.

In February 2025, the United States threatened to impose tariffs on Canadian imports to the US, including oil and gas produced in Canada. It is uncertain whether these tariffs will be implemented and, if implemented, how long they will remain in place and what the impact will be on the prices of Canadian oil and gas.
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 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 addition, there has not been, at times, sufficient pipeline capacity to export all Canadian crude oil and the availability of alternative transport capacity is more expensive and variable, therefore, the price for Canadian crude oil is very sensitive to pipeline and refinery outages. This has resulted in significantly lower prices being realized by Canadian producers compared with the WTI price and the Brent price for crude oil. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and gas from Canada. There can be no certainty that current investment in pipelines will provide sufficient long-term export capacity or that currently operating systems will remain in service. There is also no certainty that short-term operational constraints on pipeline systems, arising from pipeline interruption, refinery outages and/or increased supply of crude oil, will not occur.

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 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:** Climate change issues are an important factor for the oil and gas industry.

*Transition Risks*

The Group's facilities and operations, and the oil and gas that the Group markets, result in the emission of greenhouse gas ("GHG") which makes the Group subject to GHG emissions legislation and regulation. Governments continue to evaluate and implement policy, legislation, and regulations focused on restricting GHG emissions commonly and promoting adaptation to climate change and the transition to a low-carbon economy. It is not possible to predict what measures governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented. Given the evolving nature of climate change policy and the control of GHG emissions and resulting requirements, including carbon taxes and carbon pricing schemes implemented by varying levels of government, it is expected that current and future climate change regulations will have the effect of increasing the Group's operating expenses, and, in the long-term, potentially reducing the value of oil and gas assets.

Regulatory climate change related risks arise from increased or amended 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, or limitations on, GHG 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.

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. Increased scrutiny of applications for oil and gas licenses, permits and authorizations to develop assets and projects could lead to delay, limit or prevent future development of assets or affect the productivity of assets and the costs associated.

In addition, concerns about climate change and public discussion that oil and gas operations may be associated with climate change 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.

Claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. Individuals, governmental authorities, or other organizations may make claims against oil and natural gas companies, including us, for alleged personal injury, property damage, or other potential liabilities. While IPC is not a party to any such litigation or proceedings, IPC could be named in actions making similar allegations. An unfavourable ruling in any such case could adversely affect the demand for and price of the Common Shares, impact the Group's operations and have an adverse impact on IPC's 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 companies involved in oil production in Canada. The federal Government of Canada has taken steps to address climate change by establishing the Canadian Net-Zero Emissions Accountability Act that brings into law the commitment to achieve net-zero GHG emissions by 2050 and issuing the 2030 Emissions Reduction Plan that describes the measures Canada is undertaking to reduce emissions to 40 to 45 percent below 2005 levels by 2030. In November 2024, the Government of Canada commenced a consultation process with respect to draft Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations, under which specific limits on emissions from the oil and gas sector would be imposed with the intention to reduce the carbon intensity of oil and gas production in Canada, with a focus on improving energy efficiency, fostering the adoption of cleaner technologies, and accelerating the transition to more sustainable practices. It is difficult to assess the overall impact all of 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.

The International Sustainability Standards Board ("ISSB") was created on November 3, 2021 with the aim to develop globally consistent, comparable and reliable sustainability disclosure standards. On June 26, 2023, the ISSB issued IFRS S1 "General Requirements for Disclosure of Sustainability-related Financial Information" and IFRS S2 "Climate-related Disclosures". The Corporation is actively evaluating the potential effects of the ISSB issued sustainability standards; however, at this time, the Corporation is not able to determine the impact on future financial statements, nor the potential costs to comply with these sustainability standards.

In December 2024, the Canadian Sustainability Standards Board released its voluntary and non-binding Canadian Sustainability Disclosure Standards: CSDS 1 – General Requirements for Disclosure of Sustainability-related Financial Information and CSDS 2 – Climate-related Disclosures, which are effective for annual reporting periods beginning on or after January 1, 2025. CSDS 1 and CSDS 2 establish a set of sustainability and climate-related disclosure standards for Canadian companies that are modelled on those developed by the ISSB. While these Canadian standards are non-binding, they could influence the development by securities regulators of sustainability and climate-related reporting obligations for Canadian public companies under applicable Canadian law.

The Corporate Sustainability Reporting Directive ("CSRD") entered into force in 2023 introducing requirements for certain companies in the EU, to include disclosures related to climate, the environment and wider sustainability issues. The CSRD requirements may become applicable to the Group for the financial years commencing January 1, 2025. The EU authorities are expected to provide further guidance on the CSRD requirements in Q1 2025.

In 2024, Malaysia announced plans to introduce a carbon tax on the Malaysian energy industry commencing in 2026. The Group will continue to monitor this situation and, when further details are provided by the Malaysian authorities, will assess the potential effects of this proposed tax on the Group's business in Malaysia.

If the Group is not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, IPC's business and ability to attract and retain skilled employees, obtain regulatory permits, licences, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected.

*Physical Risks*

Physical climate change related risks can be event-driven with increased severity of extreme weather events, such as cyclones, hurricanes, wildfires, droughts or floods, or long-term shifts in climate patterns with sustained higher temperatures, water stress or sea level rise. These physical risks may have financial and operational implications for the Group, such as direct damage to assets and indirect impacts from supply chain disruption to the delivery of goods and services. Certain of IPC's oil and gas assets are in locations that are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage.

**Sustainability Targets and Disclosures:** IPC is targeting to reduce its net GHG emissions intensity. IPC's ability to achieve these targets is subject to numerous risks and uncertainties, and actions taken in implementing these objectives may also expose the Group to certain additional and/or heightened financial and operational risks. In addition, the cost associated with achieving emissions reductions targets and other climate and sustainability targets could be significant, and could require significant capital expenditures and resources, potentially including the acquisition of technology, with the potential that the costs required to achieve targets could differ from original estimates and expectations, which differences may be material. Failure to achieve emissions, climate or sustainability targets could have a negative impact on IPC's reputation, business, cash flows, results of operations, and on the Group's access to, and cost of, capital.

In June 2024, the Canadian federal government amended the Competition Act (Canada) with respect to how companies communicate about environmental goals and performance. There is uncertainty regarding how this new legislation will be interpreted and applied. Statements made in this MD&A in respect of activities undertaken or to be undertaken by IPC with respect to protecting or restoring the environment or mitigating environmental and ecological causes or effects of climate change, including the provision of emissions figures and forecasts, the acquisition and use of carbon offsets, activities to potentially reduce emissions, and activities to provide for environmental stewardship, including water management and biodiversity, should not be relied upon for the purposes of investing in securities of IPC or otherwise be considered as promoting IPC's products or business interests.

**Reputational Risks:** Reputational risks arise from societal pressure on the fossil fuel industry in relation to its contribution to global 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.

Oil and gas operations may be subject to public opposition. Such public opposition could result in higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental groups and other organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses, and direct legal challenges, including the possibility of climate-related litigation.

**Project Risks:** The Group is undertaking various projects, including Phase 1 of the Blackrod project. Project interruptions may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. IPC's ability to execute projects depends upon numerous factors beyond its control, including: processing, pipeline and storage capacity, availability of water, electricity, gas, diluent and other operational supplies, effects of weather, availability of personnel and equipment, unexpected cost increases, accidents, regulatory and third party approvals and commercial arrangements, stakeholder consultations (including Indigenous consultation) and regulatory changes (including carbon tax). As a result of these and other factors, the Group may be unable to execute projects on time, on budget, or at all.

**Inflationary Pressures and Costs:** The Group's operating costs could escalate and make operations unprofitable due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention. Labour costs, abandonment, reclamation, gas, electricity, water, diluent and chemicals are examples of some of the operating and other costs that are susceptible to significant fluctuation. The inability to manage costs may impact project returns and future development decisions, which could have an adverse effect on financial performance. The cost or availability of oil and gas field equipment may adversely affect IPC's ability to undertake projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services. These materials and services may not be available when required at reasonable prices. A failure to secure the services and equipment necessary to operations or projects for the expected price, on the expected timeline, or at all, may have an adverse effect on financial performance.

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. Fluctuations in operating and capital costs could negatively impact the Group's business, financial condition, results of operations, cash flows and value of its oil and gas reserves.

**Operational Risks Relating to Facilities and Pipelines:** The pipelines and facilities associated with the Group's assets, 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; 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, acts of terrorists and saboteurs and other similar events, many of which will be beyond the control of the Group. 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.

**Reductions in Demand for Oil and Gas:** Increasing consumer demand for alternatives to oil and gas, conservation measures, alternative fuel requirements, and technological advances in fuel economy and renewable energy generation systems, could reduce the demand for oil and gas. Some jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and to encourage the use of renewable fuel alternatives, which could reduce the demand for oil and gas. Advancements in energy efficient products have a similar effect on the demand for oil and gas. The Corporation cannot predict the impact of changing demand for oil and gas products, and any major changes may have an adverse effect on IPC's business, financial condition, results of operations and cash flow from operations by decreasing increasing costs, limiting access to capital and decreasing the value of oil and gas assets.

**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 and 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 reserves and resource evaluations will be attained and variances could be material. See also "Reserves and Resources Advisory" below.

**SAGD Recovery Process:** The Group has implemented a SAGD recovery process at the Onion Lake Thermal project and 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.

**Hydraulic Fracturing:** Hydraulic fracturing involves the injection of water, sand, and small amounts of additives under high pressure into tight rock formations that were previously unproductive to stimulate the production of oil and gas. Concerns about seismic activity, including earthquakes, caused by hydraulic fracturing has resulted in regulatory authorities implementing additional protocols for areas that are prone to seismic activity or completely banning hydraulic fracturing in other areas. Any new laws, regulations, or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third-party or governmental claims, and could increase costs of compliance, as well as delay development of certain oil and gas resources. Restrictions or bans on hydraulic fracturing could result in restricting the economic recovery of oil and gas reserves. In addition, the Group may need to dispose of the fluids produced from oil and gas production operations, including produced water. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities.

**Water:** Water is an essential component of IPC's drilling and hydraulic fracturing processes. Limitations or restrictions on IPC's ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact IPC's operations. Severe drought conditions can result in local water authorities taking steps to restrict the use of water in their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If the Group is unable to obtain water to use in IPC's operations from local sources, water may need to be obtained from new sources and transported to drilling sites, resulting in increased costs. Cost increases could have a material adverse effect on drilling economics resulting in delays or suspensions of drilling which ultimately would have a detrimental effect on IPC's financial condition, results of operations, and funds flow.

**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 (including carbon taxes), GHG emission restrictions, royalties and the export 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 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 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.

IPC may be adversely impacted by political, legal, or regulatory developments in Canada and elsewhere that affect local operations and local and international markets. Changes in government, government policy or regulations, changes in law or interpretation of settled law, third-party opposition to industrial activity generally or projects specifically, and duration of regulatory reviews could impact IPC's existing operations and planned projects. This includes actions by regulators or other political actors to delay or deny necessary licences and permits for activities or restrict the operation of third-party infrastructure on which the Group relies. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact results. Other government and political factors that could adversely affect financial results include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements. Further, the adoption of regulations mandating efficiency standards and mandating the sale of electric vehicles, and the use of alternative fuels or uncompetitive fuel components, could affect the demand for oil and gas. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels, technologies or electric vehicles. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources. The success of these initiatives may decrease demand for oil and gas. A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. The oil and natural gas industry has become an increasingly politically polarizing topic resulting in a rise in civil disobedience surrounding oil and natural gas development, particularly with respect to infrastructure projects such as pipelines. Protests, blockades, demonstrations and vandalism have the potential to delay and disrupt the Group's activities.

**Indigenous Land and Rights Claims:** In Canada, Indigenous groups have filed claims in respect of their Indigenous and treaty rights against the federal and certain provincial governments as well as private individuals and companies. Consultation delays, claims or objections related to Indigenous rights may disrupt or delay third-party operations, new development or new project approvals on the Group's properties. 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 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.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of litigation. The fulfilment of the duty to consult Indigenous people and any associated accommodations may adversely affect the Group's ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals, or to advance project development, including Phase 1 of the Blackrod project.

In addition, the Canadian federal government has introduced legislation to implement the United Nations Declaration of the Rights of Indigenous Peoples ("UNDRIP"). Other Canadian jurisdictions have introduced or passed similar legislation and have begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by government are uncertain. Additional processes may be created and legislation associated with project development and operations may be amended or introduced, further increasing uncertainty with respect to project regulatory approval timelines and requirements.

**Change of Control under Licences:** The licence areas associated with the Group's oil and gas assets 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 Group propose to dispose of assets 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 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, 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.

**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 or distributions 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 not have the ability to borrow funds under such facilities or 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 the Group's 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. Credit ratings are not recommendations to buy, sell or hold any of the Corporation's securities.

**Competition for Resources and Markets:** The international oil and gas 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 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 reduction 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 Group may 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.

Certain jurisdictions in Canada, including Alberta, have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines if a licensee or permit holder is unable to satisfy its regulatory obligations. The implementation of or changes to the requirements of liability management programs may result in significant increases to the security that must be posted by licensees, increased and more frequent financial disclosure obligations or the denial of licence or permit transfers, which could impact the availability of capital to be spent by the Group, which could in turn materially adversely affect IPC's business and financial condition. In addition, these liability management programs may prevent or interfere with IPC's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets.

**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:** Jurisdictions in which the Group operates may implement measures to facilitate management of foreign exchange risk. Such measures could restrict the Group's ability to repatriate earning or other funds.

**Expiration and Renewal of Licences, Leases and Production Sharing Contracts:** : Certain of 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.

**Reliance on Third Party Operators:** The Group has partners in some of the licence 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 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.

**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.

**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 disrupting operations and 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 Chief Operating Officer of the Corporation is principally responsible for overseeing cybersecurity risk management and for reporting such risks to other members of executive management and to the Board. 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.

Further, the Group is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to business activities. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, credit card and banking details (and money), or approval of wire transfer requests, by disguising themselves as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If IPC were to become a victim to a cyber phishing attack it could result in a loss or theft of financial resources or critical data and information, or could result in a loss of control of the Group's technological infrastructure or financial resources. IPC maintains policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts regular cyber-security risk assessments. Despite efforts to mitigate such cyber phishing attacks through education and training, cyber phishing activities remain a serious problem that may damage the Group's information technology infrastructure. The controls implemented by the Group may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on performance and earnings, as well as IPC's reputation, and any damages sustained may not be adequately covered by current insurance coverage, or at all. The significance of any such event is difficult to quantify but may in certain circumstances be material and could have a material adverse effect on the Group's business, financial condition and results of operations. The protection of customer, employee, and company data is also critical to IPC's business. The regulatory environment surrounding information security and privacy is increasingly demanding, with the frequent imposition of new and constantly changing requirements. A significant breach of employee or company data could attract a substantial amount of media attention, damage relationships and reputation, and result in fines or lawsuits. In addition, an increasing number of countries have introduced and/or increased enforcement of comprehensive privacy laws or are expected to do so. The continued emphasis on information security as well as increasing concerns about government surveillance may lead to the Group being required to take additional measures to enhance security and/or assume higher liability.

**Insurance:** Although the Group maintains insurance in accordance with industry standards to address certain risks related to oil and gas operations, such insurance has limitations on liability and may not be sufficient to cover the full extent of potential liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Group may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to IPC. The occurrence of a significant event that IPC is not fully insured against, or the insolvency of the insurer of such event, may have an adverse effect on IPC's business, financial condition, results of operations and prospects. The Group's insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, policy limits and/or deductibles for certain insurance policies can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage.

**Forced or Child Labour in Supply Chains:** The *Fighting Against Forced Labour and Child Labour in Supply Chains Act* came into force in Canada in 2024. Pursuant to this legislation, any company that is subject to the reporting requirements, including IPC, is required to conduct certain due diligence on its supply chains and to file an annual report accordingly. While IPC is currently unaware of any forced or child labour in any of the Group's supply chains, the increased scrutiny on the supply chains of Canadian companies could uncover the risk or existence of forced or child labour in a supply chain to which IPC has a connection, which could negatively impact IPC's reputation.

**Pandemics:** 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 resume or that commodity prices will not decrease or remain volatile in the future due to Covid-19 or other pandemics. 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.

**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.

**Key Personnel:** IPC's success is in part dependent upon management, leadership capabilities and the quality and competency of key personnel. If IPC is unable to retain key personnel and critical talent or to attract and retain new talent with the necessary leadership, professional and technical competencies, it could have an adverse effect on the Group's financial condition, results of operations and prospects.

**Change in Investors:** Some institutional and other investors have announced that they no longer are willing to fund or invest in oil and gas assets or companies, or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Corporation. Failing to implement the policies and practices, as requested by institutional investors, may result in such investors reducing their investment in the Corporation, or not investing in IPC at all.

**Significant Shareholder:** Nemesia S.à.r.l., an investment company wholly owned by trusts whose settlor is the late Adolf H. Lundin ("Nemesia"), owns approximately 34 percent of the aggregate Common Shares of the Corporation. Nemesia's holdings may allow it to significantly affect substantially all the actions taken by the shareholders of the Corporation, including the election of directors. As long as Nemesia maintains a significant interest in the Corporation, it is likely that Nemesia will exercise significant influence on the ability of the Corporation to, among other things, enter into a change in control transaction of the Corporation and may also discourage acquisition bids for the Corporation. There is a risk that the interests of Nemesia may 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 and the imposition of carbon taxes, 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.

The EU previously imposed a tax on energy companies deriving income from operations in EU countries, which tax was applicable to the Group in France in 2022. Such tax could be reinstated in the future or similar taxes could be levied in other jurisdictions in which the Group operates or proposes to operate.

**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 reserve auditors. 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;
- Issuances or perceived issuances 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 year ended December 31, 2024, 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). Management concluded that the Corporation's internal control over financial reporting was effective as of December 31, 2024.

## 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.

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:

- 2025 production ranges (including total daily average production), production composition, cash flows, 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 navigate the Corporation through periods of volatile commodity prices;
- The ability to fully fund future expenditures from cash flows and current borrowing capacity;
- IPC's intention and ability to continue to implement 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;
- Development of the Blackrod project in Canada, including estimates of resource volumes, future production, timing, regulatory approvals, third party commercial arrangements, breakeven oil prices and net present values;
- Current and future production performance, operations and development potential of the Onion Lake Thermal, Suffield, Brooks, Ferguson and Mooney operations, including the timing and success of future oil and gas drilling and optimization programs;
- The potential improvement in the Canadian oil egress situation and IPC's ability to benefit from any such improvements;
- The ability to maintain current and forecast production in France and Malaysia;
- The intention and ability of IPC to acquire further common shares under the NCIB, including the timing of any such purchases;
- The return of value to IPC's shareholders as a result of the NCIB;
- The ability of IPC to implement further shareholder distributions in addition to the NCIB;
- IPC's ability to implement its greenhouse gas (GHG) emissions intensity and climate strategies and to achieve its net GHG emissions intensity reduction targets;
- IPC's ability to implement projects to reduce net emissions intensity, including potential carbon capture and storage;
- Estimates of reserves and contingent resources;
- The ability to generate free cash flows and use that cash to repay debt;
- IPC's continued access to its existing credit facilities, including current financial headroom, on terms acceptable to the Corporation;
- IPC's ability to identify and complete future acquisitions;

- Expectations regarding the oil and gas industry in Canada, Malaysia and France, including assumptions regarding future royalty rates, regulatory approvals, legislative changes, and ongoing projects and their expected completion; 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 Resources 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; our ability to maintain our existing credit ratings; our ability to achieve our performance targets; 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 and that we will be able to implement our standards, controls, procedures and policies in respect of any acquisitions and realize the expected synergies on the anticipated timeline or at all; 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; our intention to complete share repurchases under our normal course issuer bid program, including the funding of such share repurchases, existing and future market conditions, including with respect to the price of our common shares, and compliance with respect to applicable limitations under securities laws and regulations and stock exchange policies; 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:
- General global economic, market and business conditions;
- 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 and climate-related risks;
- Competition;
- Innovation and cybersecurity risks related to our systems, including our costs of addressing or mitigating such risks;
- The ability to attract, engage and retain skilled employees
- 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;
- Geopolitical conflicts, including the war between Ukraine and Russia and the conflict in the Middle East, and their potential impact on, among other things, global market conditions; 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 Factors"

Estimated FCF generation is based on IPC's current business plans over the periods of 2025 to 2029 and 2030 to 2034, including net debt of USD 209 million as at December 31, 2024, with assumptions based on the reports of IPC's independent reserves evaluators, and including certain corporate adjustments relating to estimated general and administration costs and hedging, and excluding shareholder distributions and financing costs. Assumptions include average net production of approximately 57 Mboepd over the period of 2025 to 2029, average net production of approximately 63 Mboepd over the period of 2030 to 2034, average Brent oil prices of USD 75 to 95 per bbl escalating by 2% per year, and average Brent to Western Canadian Select differentials and average gas prices 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 (MCR) dated February 11, 2025, the Corporation's Annual Information Form (AIF) for the year ended December 31, 2023, (See "Cautionary Statement Regarding Forward-Looking Information", "Reserves and Resources Advisory" and "Risk Factors") and other reports on file with applicable securities regulatory authorities, including previous financial reports, management's discussion and analysis and material change reports, which may be accessed through the SEDAR+ website (www.sedarplus.ca) or IPC's website (www. international-petroleum.com).

Management of IPC approved the production, operating costs, operating cash flow, capital and decommissioning expenditures and free cash flow guidance and estimates contained herein as of the date of this MD&A. The purpose of these guidance and estimates is to assist readers in understanding IPC's expected and targeted financial results, and this information may not be appropriate for other purposes.

## 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, 2024, 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, 2024 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, 2024, 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, 2024 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, 2024 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 493 MMboe as at December 31, 2024, by the mid-point of the 2025 CMD production guidance of 43,000 to 45,000 boepd. Reserves replacement ratio is based on 2P reserves of 468 boe as at December 31, 2024, sales production during 2024 of 16.6 MMboe, net additions to 2P reserves during 2024 of 41.7 MMboe, and 2P reserves of 493 MMboe as at December 31, 2024.

The product types comprising the 2P reserves and contingent resources described in this MD&A are contained in the MCR. See also "Supplemental Information regarding Product Types" below. Light, medium and heavy crude oil and bitumen 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 percent 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 commercial contingencies can be clearly defined. Chance of development is the probability of a project being commercially viable. Where risked resources are presented, they have been adjusted based on the chance of development by multiplying the unrisked values by the chance of development.

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 this 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 this MD&A. 2P reserves and contingent resources included in the reports prepared by Sproule and ERCE 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 present 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, 2024, which will be filed on SEDAR+ (accessible at www.sedarplus.ca) on or before April 1, 2025. Further information with respect to IPC's reserves, contingent resources and estimates of future net revenue is disclosed in the MCR available under IPC's profile on www.sedarplus.ca 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 (Mbopd) | Light and Medium Crude Oil (Mbopd) | Conventional Natural Gas (per day) | Total (Mboepd) |
|---|---|---|---|---|
| Three months ended | | | | |
| December 31, 2024 | 24.3 | 7.1 | 95.9 MMcf (16.0 Mboe) | 47.4 |
| December 31, 2023 | 25.7 | 6.6 | 103.8 MMcf (17.3 Mboe) | 49.6 |
| Year ended | | | | |
| December 31, 2024 | 23.9 | 7.7 | 95.1MMcf (15.8 Mboe) | 47.4 |
| December 31, 2023 | 25.8 | 8.1 | 102.8 MMcf (17.1 Mboe) | 51.1 |

This MD&A also makes reference to IPC's forecast total average daily production of 43,000 to 45,000 boepd for 2025. IPC estimates that approximately 55% of that production will be comprised of heavy oil, approximately 12% will be comprised of light and medium crude oil and approximately 33% will be comprised of conventional natural gas.

## OTHER SUPPLEMENTARY INFORMATION

### Abbreviations

| | |
|---|---|
| CAD | Canadian dollar |
| MCAD | Million Canadian dollar |
| EUR | Euro |
| USD | US dollar |
| MUSD | Million US dollar |
| MYR | Malaysian Ringgit |
| FPSO | Floating Production Storage and Offloading (facility) |
| OECD | Organisation for Economic Co-operation and Development |

### Oil related terms and measurements

| | |
|---|---|
| AECO | The daily average benchmark price for natural gas at the AECO hub in southeast Alberta |
| AESO | Alberta Electric System Operator |
| 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 | Barrels of oil equivalents |
| boepd | Barrels of oil equivalents per day |
| bopd | Barrels of oil per day |
| Bcf | Billion cubic feet |
| C5 | Condensate |
| $CO_2e$ | Carbon dioxide equivalents, including carbon dioxide, methane and nitrous oxide |
| 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 |
| Mcfpd | Thousand cubic feet per day |
| MMcf | Million cubic feet |
| MW | Mega watt |
| MWh | Mega watt per hour |
| 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) |

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