Q4

International Petroleum Corporation

Management's Discussion and Analysis

For the three months ended and year ended December 31, 2023

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 24.

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 37.

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, 2023, 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, 2023, 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, 2023, 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, 2023, 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 6, 2024 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, 2023 ("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 2000, 885 West Georgia Street, Vancouver, BC V6C 3E8, Canada.

Basis of Preparation
The MD&A and the Financial Statements have been prepared in accordance with 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, 2023		December 31, 2022	
	Average	Period end	Average	Year end
1 EUR equals USD	1.0816	1.1050	1.0539	1.0666
1 USD equals CAD	1.3496	1.3251	1.3015	1.3538
1 USD equals MYR	4.5598	4.5950	4.3995	4.4050

IPC completed the acquisition of Cor4 Oil Corp. ("Cor4") on March 3, 2023. In accordance with IFRS, the Financial Statements have been prepared on that basis, with revenues and expenses related to the assets acquired in the Cor4 acquisition included in the Financial Statements from March 3, 2023. Certain historical and forecast 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 "Cor4 Acquisition", "Operations Overview – Production" and "Non-IFRS Measures" below.

HIGHLIGHTS

2023 Business Highlights

- Average net production of approximately 49,600 boepd for the fourth quarter of 2023 was in line with the high end of the guidance range for the period (52% heavy crude oil, 13% light and medium crude oil and 35% natural gas).(1)
- Full year 2023 average net production was 51,100 boepd, above the high end of annual guidance and a record high for IPC.(1)
- Following the decision in Q1 2023 to develop Phase 1 of the Blackrod project, work on the project has progressed in line within the overall schedule and budget to first oil in late 2026. Key events include signing of the engineering, procurement and fabrication contract with the Engineering Procurement and Construction (EPC) contractor for the Central Processing Facility and advancement of facility engineering and fabrication works, access road expansion and site civil preparation works, and drilling operations.
- Successfully integrated the Suffield area assets acquired from Cor4 Oil Corp. (Cor4) in March 2023 and executed the drilling program in the Ellerslie play with eight wells drilled in 2023.
- Production sustaining Pad L at Onion Lake Thermal (OLT) successfully brought online, supporting record average daily production in 2023 from the OLT asset.
- Sale of small non-core assets in Canada for MUSD 20, at a significant premium to 2P reserves net present value.(2)
- In Malaysia, successfully completed planned maintenance turnaround at the Bertam field on scope, schedule, and budget.
- In France, successfully delivered three new production wells at Villeperdue West and one side-track well at Merisier.
- 9.3 million common shares purchased and cancelled from December 5, 2022 to December 4, 2023 under IPC's 2022/2023 NCIB and a further 1.8 million common shares purchased for cancellation during December 2023 and January 2024 under the renewed 2023/2024 NCIB. 7% of IPC's common shares outstanding were reduced through the NCIB in 2023.
- In Q3 2023, published IPC's fourth annual Sustainability Report and its first stand-alone report aligned with the Task Force on Climate-Related Financial Disclosures (TCFD).
- Commitment to reduce IPC's net emissions intensity to 20 kg CO_2/boe by 2025, is extended to remain at that level through end 2028.

2023 Financial Highlights

- Operating costs per boe of USD 18.3 for the fourth quarter of 2023 and USD 17.6 for the full year in line with full year guidance of USD 17.5 to 18 per boe.(3)
- Strong operating cash flow (OCF) generation for the fourth quarter and full year 2023 amounted to MUSD 74 and MUSD 353, respectively.(3)
- Capital and decommissioning expenditures of MUSD 130 for the fourth quarter and MUSD 327 for the full year 2023, in line with most recent full year guidance of MUSD 330.
- Positive free cash flow (FCF) generation for the full year 2023 of MUSD 3, with negative FCF generation of MUSD 65 for the fourth quarter in line with expectations and taking into account the significant capital expenditures during the quarter. FCF before 2023 Blackrod capital expenditure of MUSD 240, was MUSD 243.(3)
- Net cash of MUSD 58 and gross cash of MUSD 517 as at December 31, 2023.(3)
- Net result of MUSD 30 for the fourth quarter of 2023 and MUSD 173 for the full year 2023.
- Further strengthened IPC's financial position with an increase of IPC's bonds to MUSD 450 due February 2027 and an increase of IPC's undrawn Canadian revolving credit facility to MCAD 180.

Reserves and Resources

- Total 2P reserves as at December 31, 2023 of 468 MMboe, representing a reserves replacement ratio of 78% compared to year-end 2022, with a reserves life index (RLI) of 27 years.(1)(2)
- Contingent resources (best estimate, unrisked) as at December 31, 2023 of 1,145 MMboe.(1)(2)
- 2P reserves net asset value (NAV) as at December 31, 2023 of MUSD 3,087 (10% discount rate).(1)(2)(4)(5)

2024 Annual Guidance

- Full year 2024 average net production forecast at 46,000 to 48,000 boepd.(1)
- Full year 2024 operating costs guidance forecast at USD 18 to 19 per boe.(3)
- Full year 2024 OCF guidance estimated at between MUSD 261 to 382 (assuming Brent USD 70 to 90 per boe).(3)
- Full year 2024 capital and decommissioning expenditures guidance forecast at MUSD 437, including MUSD 362 relating to continued development of Phase 1 of the Blackrod project.
- Full year 2024 FCF ranges from approximately MUSD 144 to 268 (assuming Brent USD 70 to 90 per boe) before taking into account proposed Blackrod capital expenditures, or MUSD -218 to -94 including proposed Blackrod capital expenditures.(3)

Business Plan Production and Cash Flow Guidance

- 2024 – 2028 business plan forecasts:
    - average net production forecast approximately 55,000 boepd.(1)
    - capital expenditure forecast of USD 11 per boe, including USD 6 per boe for the Blackrod Phase 1 project.
    - operating costs forecast of USD 18 per boe.(3)
    - FCF forecast of approximately MUSD 900 to 1,800 (assuming Brent USD 75 to 95 per boe).(3)(7)
- 2029 – 2033 business plan forecasts:
    - average net production forecast of approximately 65,000 boepd.(1)
    - capital expenditure forecast of USD 5 per boe.
    - operating costs forecast of USD 18 per boe.(3)
    - FCF forecast of approximately MUSD 1,750 to 2,800 (assuming Brent 75 to 95 USD per boe).(3)(7)

	Three months ended December 31		Year ended December 31	
USD Thousands	2023	2022	2023	2022
Revenue	198,460	254,615	853,906	1,129,298
Gross profit	39,955	95,411	250,514	516,709
Net result	29,710	61,183	172,979	337,725
Operating cash flow(3)	73,634	113,668	353,048	622,947
Free cash flow(3)	(64,688)	65,288	2,689	430,242
EBITDA(3)	66,284	125,651	350,618	639,480
Net Cash(3)	58,043	175,098	58,043	175,098

OPERATIONS REVIEW

Business Overview

IPC's strategy since launching IPC in April 2017 remains unchanged: to deliver operational excellence through responsible operatorship, maintain financial resilience, maximise the value of our resource base, target growth organically and through acquisitions, and deliver stakeholder returns.

IPC has followed through on this vision resulting in material value creation for all stakeholders through efficient capital allocation and operational proficiency. Since inception, IPC has sustained no material safety incidents across all operating domains, delivered within or ahead of guidance every reporting year, increased the Reserves Life Index (RLI) from 8 years to 27 years largely through 5 accretive acquisitions, and cancelled over 62.5 million common shares.

The company is strongly positioned to continue following through on our strategy supported by a strong balance sheet to start 2024 with net cash of USD 58 million and material production growth expected from the Blackrod Phase 1 development with first oil expected in late 2026.(3)

Following a year of exceptionally high oil and gas prices in 2022 with Brent prices averaging over USD 100 per barrel for the full year 2022, IPC continued to benefit in 2023 from strong oil benchmark prices, with average Brent prices over USD 82 per barrel for the full year. Quarterly average Brent prices during 2023 ranged between USD 78 to USD 87 per barrel. Strong oil and gas demand is expected to continue in 2024 which, along with such factors as OPEC+ decisions to curtail supply, potential market and transportation disruptions due to ongoing geopolitical tensions and current global observed crude inventory levels are at the bottom end of the five-year average could limit downside risks on commodity prices in 2024. These positive factors may be partially offset by increased forecast supply from countries such as the United States in a Presidential election year, which could be expected to limit price upside.

In Canada, fourth quarter 2023 West Texas Intermediate (WTI) to Western Canadian Select (WCS) crude price differentials averaged around USD 22 per barrel, with average differentials of around USD 18.5 for the full year. The Trans-Mountain (TMX) pipeline is currently expected to commence line-fill in the first half of 2024 which should benefit the WTI/WCS differentials during 2024 and into the future. IPC has hedged the WTI/WCS differential for approximately 70% of our Canadian crude production at USD 15 per barrel and hedged 25% of our WTI exposure for approximately USD 81 per barrel for 2024.

Gas markets in 2023 witnessed a substantial decrease from the 2022 average AECO benchmark prices above CAD 5 per Mcf. The average AECO gas price was CAD 2.30 per Mcf for the fourth quarter of 2023, and an average of CAD 2.60 for the full year 2023. IPC's realized prices for gas were CAD 2.55 per Mcf for the fourth quarter of 2023 and CAD 3.36 per Mcf for the full year 2023 taking into account hedges in place until October 31, 2023.

IPC benefits from a well-balanced mix of production comprising approximately 54% Canadian Crude, 33% Canadian Natural Gas and 13% Brent weighted oil, on average over 2023. With strong commodity pricing, combined with delivering operational excellence above the high end of IPC's 2023 guidance, IPC has again been able to deliver a very strong financial performance in the fourth quarter and throughout the full year 2023.

Fourth Quarter and Full Year 2023 Highlights
During the fourth quarter of 2023, IPC's assets delivered average net production of 49,600 boepd, in line with high-end guidance for the quarter. This was made possible by high operational performance across all of IPC's assets as well as the production contribution from IPC's 2023 investment program in Canada and France, notwithstanding some downtime from two production wells in Malaysia through Q4 which have now been worked over and are back on stream as of end January 2024. Full year 2023 average net production of 51,100 boepd was a record high for IPC and on target with guidance of greater than 50,000 boepd.(1)

IPC's operating costs per boe for the fourth quarter of 2023 was USD 18.3. Full year 2023 operating costs per boe was USD 17.6, in line with guidance of USD 17.5 to 18 per boe.(3)

Operating cash flow (OCF) generation for the fourth quarter of 2023 was USD 74 million. Full year 2023 OCF was USD 353 million in line with the most recent guidance of USD 340 to 365 million.(3)

Capital and decommissioning expenditure for the fourth quarter of 2023 was USD 130 million. Full year 2023 capital and decommissioning expenditure of USD 327 million was in line with guidance of USD 330 million.

Free cash flow (FCF) generation was in line with guidance at negative USD 65 million during the fourth quarter of 2023, reflecting the higher level of capital expenditure on the Blackrod Phase 1 development project. Full year 2023 FCF generation was USD 3 million, at the higher end of the most recent guidance of USD -65 to 5 million.(3)

As at December 31, 2023, IPC's net cash position was USD 58 million. IPC's gross cash on the balance sheet amounts to USD 517 million which provides IPC with significant financial strength to continue progressing its strategies in 2024, including advancing the Phase 1 Blackrod development, returning value to shareholders through the 2023/2024 NCIB, and remaining opportunistic to M&A.(3)

Blackrod Project

In Q1 2023, IPC announced the decision to advance the development of Phase 1 of the Blackrod project. Development capital expenditure to first oil is estimated at USD 850 million nominal. First oil of the Phase 1 development is estimated to be in late 2026, with forecast net production of 30,000 bopd by 2028. The Blackrod Phase 1 development targets 218 million barrels of 2P reserves and the sanction case WTI breakeven estimated as of January 1, 2023, using the December 31, 2022 price forecasts of IPC's qualified independent reserves evaluator, Sproule Associates Limited (Sproule), was USD 59 per barrel assuming a 10% discount rate. Following capital expenditure of USD 240 million invested in 2023, the project is forecast to add USD 981 million to IPC's 2P reserves net present value (NPV) as at January 1, 2024, with a WTI breakeven of USD 54.5 per barrel assuming a 10% discount rate, using Sproule's December 31, 2023 price forecasts. IPC forecasts capital expenditure in 2024 for the Blackrod project of USD 362 million, with the remainder of the estimated total project budget to be invested prior to first oil. With greater than 1 billion barrels of contingent resources (best estimate, unrisked) remaining, Blackrod presents material upside to future phase expansions beyond the initial first Phase of development.(1)(2)(4)

Project activities for the multi-year Phase 1 development have progressed in line with schedule and budget. Following the successful completion of Front-End Engineering and Design (FEED) studies through 2022, IPC formerly established a partnership with the Engineering, Procurement and Construction (EPC) contractor in 2023 through contractual commitments for the Central Processing Facility (CPF). As at the end of 2023, major long lead items have been procured, fabrication has commenced, site civil and commercial road expansion works have advanced, drilling is underway, and third-party pipeline commercial agreements are progressing according to plan.

Following significant project milestones achieved through 2023, IPC is well positioned to continue advancing responsible development of the Blackrod Phase 1 development through 2024. With a combination of contractual commitments and financial foreign exchange hedges locked in at more favourable rates than assumed at project sanction, IPC sits comfortably within the overall budget and schedule guidance to first oil. IPC intends to fund the remaining Phase 1 development costs with forecast cash flow generated by its operations and cash on hand.(3)

M&A

IPC was pleased to close the strategic acquisition of Cor4 in March 2023 for a consideration of USD 62 million. The acquisition, located in the Suffield area, brought in 15.9 MMboe of 2P reserves as at January 1, 2023 and delivered greater than 5,000 boepd through 2023. The asset holds high quality mineral rights within the Ellerslie formation, an attractive feature that crystallised through 2023 as eight wells were successfully drilled into this play supporting higher than forecast production rates. The acquired asset team has been effectively integrated within IPC and further synergies within Suffield area are of continued focus as we seek to unlock further value potential.(1)(2)

Following the strategic divestiture of small non-core production and land assets in the greater John Lake area in Canada announced in Q3 2023, IPC further sold non-producing lands in Q4 for a consideration of USD 3.5 million. The total proceeds in aggregate from the non-core dispositions in Q3 and Q4 was in excess of USD 20 million. The 2P reserves and NPV10 as of January 1, 2023 were 0.6 MMboe and USD 7.7 million respectively for the divested properties.(2)(4)

IPC continues to review potential M&A opportunities. IPC has added over USD 2.5 billion of aggregate value in FCF generation and 2P reserves NPV increases, from IPC's last 5 acquisitions.(3)(4)

Stakeholder Returns: Normal Course Issuer Bid

During the period of December 5, 2022 to December 4, 2023, IPC purchased and cancelled an aggregate of approximately 9.3 million common shares under the 2022/2023 normal course issuer bid / share repurchase program (NCIB). The average price of shares purchased under the 2022/2023 NCIB was SEK 102 / CAD 13.0 per share.

In Q4 2023, IPC announced the renewal of the NCIB, with the ability to repurchase up to approximately 8.3 million common shares over the period of December 5, 2023 to December 4, 2024. Under the 2023/2024 NCIB, IPC repurchased and cancelled approximately 1.2 million common shares in December 2023. By the end of January 2024, IPC repurchased for cancellation over 600,000 common shares under the 2023/2024 NCIB. The average price of common shares purchased under the 2023/2024 NCIB during December 2023 and January 2024 was SEK 114.5 / CAD 15 per share.

As at February 6, 2023, IPC had a total of 126,479,966 common shares issued and outstanding, of which IPC holds 102,200 common shares in treasury.

Notwithstanding the record level of capital investment forecast for 2024, IPC confirms its intention to continue to purchase and cancel common shares under the 2023/2024 NCIB to the remaining limit of 6.5 million common shares by December 4, 2024. This would result in the cancellation of 6.5% of shares outstanding as at the beginning of December 2023.

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
Responsible operatorship and ensuring that IPC adheres to the highest principles of business conduct have been integral parts of how IPC does business since it started in 2017.

With the publication of IPC's second quarter 2023 financial report, IPC was very pleased to publish its fourth Sustainability Report and its first stand-alone report aligned with the Task Force on Climate-Related Financial Disclosures. IPC is committed to the continued advancement of ESG practices in its sustainability focus areas. The Group's six sustainability priorities are:

- Ethics & Integrity
- Rewarding Workplace
- Health & Safety
- Community Engagement
- Climate Action
- Environmental Stewardship

As part of IPC's commitment to operational excellence, its objective is to reduce risk and eliminate hazards to prevent the occurrence of accidents, ill health, and environmental damage, as these are essential to the success of IPC's operations. During the fourth quarter and for the full year 2023, IPC recorded no material safety or environmental incidents.

With respect to climate action, as previously announced, IPC targets a reduction of 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. IPC has extended its commitment to remain at 2025 levels of 20 kg CO_2/boe through to the end of 2028.

Reserves, Resources and Value
As at the end of December 2023, IPC's 2P reserves are 468 MMboe. During 2023, IPC replaced 78% of the annual 2023 production. The reserves life index (RLI) as at December 31, 2023, remains at approximately 27 years.(1)(2)

The net present value (NPV) of IPC's 2P reserves as at December 31, 2023 was USD 3,023 million. IPC's net asset value (NAV) was USD 3,081 or SEK 244 / CAD 32 per share as at December 31, 2023.(1)(2)(4)(5)(6)

In addition, IPC's best estimate contingent resources (unrisked) as at December 31, 2023 are 1,145 MMboe, ofwhich 1,066 MMboe relate to future potential phases of the Blackrod project.(1)(2)

2024 Budget and Operational Guidance
IPC is pleased to announce its 2024 average net production guidance is 46,000 to 48,000 boepd. IPC forecasts operating costs for 2024 to be USD 18 to 19 per boe.(1)(3)

IPC forecasts FCF generation based on its 2P reserves base of in aggregate of more than USD 900 to 1,800 million over the period of 2024 to 2028. In addition, IPC forecasts FCF generation of USD 1,750 to 2,800 million over the period of 2029 to 2033.(2)(3)(7)

IPC's 2024 capital and decommissioning expenditure budget is USD 437 million, with USD 362 million forecast relating to the Phase 1 development of the Blackrod project. The remainder of the 2024 budget in Canada includes drilling at the Suffield and Ferguson assets, further development of the Mooney asset, and ongoing optimization work. IPC also completed well workover operations in Malaysia by January 2024 and expects to conduct technical studies for future development potential. Following the successful execution of the 2023 drilling campaign in France, the subsurface teams are maturing drilling targets within the Paris Basin.

2024 is set to be a record growth investment year for IPC, we have therefore set a limited sustaining capital expenditure plan of USD 75 million, inclusive of decommissioning, across the producing assets in the portfolio. With robust cashflow being generated from the producing assets and gross cash resources of USD 517 million, IPC intends to fully complete the remaining share buybacks available under the NCIB program through 2024.

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 2024.

Further details regarding IPC's proposed 2024 budget and operational guidance will be provided at IPC's Capital Markets Day presentation to be held on February 6, 2024 at 14:00 GMT. 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. IPC completed the acquisition of Cor4 Oil Corp. (Cor4) on March 3, 2023. The Financial Statements 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 historical 2023 operational and financial information included in the MD&A, including production, operating costs, OCF, FCF and EBITDA related to the assets acquired in the Cor4 acquisition, are reported based on the effective date of the Cor4 acquisition of January 1, 2023.

(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. Reserves replacement ratio is based on 2P reserves of 471.5 MMboe as at December 31, 2022 (not including 2P reserves related to the Brooks assets acquired in the Cor4 acquisition), sales production during 2023 of 17.7 MMboe, net additions to 2P reserves during 2023 of 16.0 MMboe, other revisions downward of 2.2 MMboe, and 2P reserves of 468 MMboe as at December 31, 2023.

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

(4) 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.

(5) NAV is calculated as NPV plus net cash of USD 58 million as at December 31, 2023.

(6) NAV per share is based on 126,992,066 IPC common shares outstanding as at December 31, 2023. NAV per share is not predictive and may not be reflective of current or future market prices for IPC common shares.

(7) Estimated FCF generation is based on IPC's current business plans over the periods of 2024 to 2028 and 2029 to 2033. Assumptions include average net production of approximately 55 Mboepd over the period of 2024 to 2028, average net production of approximately 65 Mboepd over the period of 2029 to 2033, average Brent oil prices of USD 75 to 95 per boe 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 19, 2024 (USD 1,378 million based on 113.6 SEK/share, 126.99 million IPC shares outstanding and exchange rate of 10.47 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" below.

Operations Overview

2023 Overview

In 2023, IPC successfully demonstrated its commitment to operational excellence, with record annual net average production and no material safety incidents or harm to the environment.

In Canada, the Blackrod Phase 1 development has progressed in accordance with plan. Initial construction camps have been installed and site preparations have been executed to allow for critical facility and drilling equipment delivery in Q1 2024. The major EPC contract has been signed for the central processing facility, bringing a higher degree of certainty for a significant portion of the Phase 1 capital expenditure to first oil. Drilling operations commenced in Q4 2023, with the first utility wells successfully executed in line with expectations. At Onion Lake Thermal, daily production is touching facility nameplate capacity of 14,000 boepd with the new production sustaining Pad L brought online ahead of schedule in Q3 2023. At Suffield, all eight planned new production wells in the exciting Ellerslie play have been brought online and are producing ahead of expectations. In France, all three of the budgeted Villeperdue West oil wells and the Merisier side-track oil well have been successfully brought online with production performing ahead of forecast. At Bertam in Malaysia, the two planned production well workovers have progressed in line with plan with the first well now back online and the second well expected to follow early in Q1 2024.

Reserves and Resources

The 2P reserves attributable to IPC's oil and gas assets are 468 MMboe as at December 31, 2023, as certified by independent third party reserve auditors. The proved plus probable reserve life index (RLI) as at December 31, 2023, is approximately 27 years. Best estimate contingent resources as at December 31, 2023, are 1,145 MMboe (unrisked). See "Reserves and Resources Advisory" below.

Production

Average daily net production for the fourth quarter 2023 was in line with IPC's high end guidance at 49,600 boepd. The quarter marks the end of a record production year for IPC with exceptional operational performance and the production benefit from the very successful 2023 development investment program. In Canada, strong operational performance has been supplemented by the newly drilled Suffield area Ellerslie production wells and ahead of expectations initial results from the new production sustaining Pad L at Onion Lake Thermal. In addition, IPC continues to see the benefit of 2023 development campaign in France with the three new wells at Villeperdue and the side-track well at Merisier producing above forecast.

With exceptional operational delivery through 2023, IPC exits the year with a record net average production of 51,100 boepd, 1,100 boepd above the original 2023 Capital Markets Day (CMD) high end guidance of 50,000 boepd.

The production during Q4 2023 with comparatives is summarized below:

Production in Mboepd	Three months ended December 31		Year ended December 31	
	2023	2022	**2023**	2022
Crude oil				
Canada – Northern Assets	15.5	16.0	15.5	15.6
Canada – Southern Assets[1]	11.4	9.0	11.8	8.7
Malaysia	2.5	5.2	3.8	5.3
France	2.8	2.7	2.8	2.7
Total crude oil production	**32.2**	32.9	**33.9**	32.3
Gas				
Canada – Northern Assets	0.4	0.1	0.4	0.1
Canada – Southern Assets	17.0	16.2	16.8	16.2
Total gas production	**17.4**	16.3	**17.2**	16.3
Total production	**49.6**	49.2	**51.1**	48.6
Quantity in MMboe	**4.56**	4.53	**18.65**	17.74

[1] 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	WI	Three months ended December 31		Year ended December 31	
		2023	2022	**2023**	2022
- Oil Onion Lake Thermal	100%	13.6	13.1	13.3	12.7
- Oil Suffield Area[1]	100%	10.1	6.7	10.2	7.1
- Oil Ferguson	100%	1.3	2.3	1.5	1.6
- Oil Other	50-100%	1.9	2.9	2.3	2.9
- Gas[1]	~100%[2]	17.4	16.3	17.2	16.3
Canada		**44.3**	41.3	**44.5**	40.6

[1] *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.*
[2] *On a well count basis*

Production
Net production from IPC's Canadian assets during Q4 2023 was ahead of the high-end guidance at 44,300 boepd with continued strong operational performance at all the major producing assets. At Onion Lake Thermal, daily production has been stable close to the facility nameplate capacity of 14,000 boepd with four well pairs from production sustaining Pad L online ahead of schedule. The Suffield area oil and gas producing assets continue to deliver above forecast, where base well rate optimization has been supplemented by ahead of expectations production performance from the newly drilled Ellerslie play oil wells.

Organic Growth and Capital Projects
In Canada, the Blackrod Phase 1 development was sanctioned in Q1 2023. A reduced base business budget for the remainder of the assets in Canada was set for 2023 with a focus on oil well drilling in the Suffield Ellerslie formation and the completion of the next production sustaining Pad L at Onion Lake Thermal.

During the fourth quarter, the Blackrod Phase 1 development progressed in accordance with plan. Site civil preparations and road expansion work have been completed in preparation for the key facility and drilling equipment delivery in Q1 2024. Drilling activity commenced on schedule in Q4 2023 and is progressing in line with expectations.

As of the end of Q4 2023 in the Suffield area, the six originally planned Ellerslie play wells, as well as the two additional wells announced in Q3 2023, have been drilled, brought online and are performing ahead of expectations.

At Onion Lake Thermal, daily production is stable close to the facility nameplate capacity of 14,000 boepd with four well pairs from production sustaining Pad L online.

MALAYSIA

Production in Mboepd	WI	Three months ended December 31		Year ended December 31	
		2023	2022	**2023**	2022
Bertam	100%	**2.5**	5.2	**3.8**	5.3

Production
Net production at Bertam in Malaysia in Q4 2023 was below guidance at 2.5 boepd, with two production wells offline awaiting workover intervention in the quarter. The two workovers were completed and both wells were back on-stream as of end January 2024.

Organic Growth and Capital Projects
In Malaysia, field development studies have progressed in line with expectations as IPC matures the remaining undeveloped potential of the Bertam field following the successful results from the latest development drilling campaign in the north east of the field.

FRANCE

Production in Mboepd	WI	Three months ended December 31		Year ended December 31	
		2023	2022	**2023**	2022
France					
- Paris Basin	100%[1]	2.5	2.3	2.4	2.4
- Aquitaine	50%	0.3	0.4	0.4	0.3
		2.8	2.7	**2.8**	2.7

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

Production
Net production in France during Q4 2023 was in line with the guidance at 2,800 boepd.

Organic Growth
In France, all three Villeperdue West oil wells and the Merisier side-track oil well have been drilled, completed and brought online with production performing ahead of forecast.

IPC continues to mature future development projects in France, with focus towards the undeveloped resource base within the Paris Basin supported by the positive results following the 2023 development campaign.

FINANCIAL REVIEW

Financial Results

Selected Annual Financial Information

Selected consolidated statement of operations is as follows:

USD Thousands	2023	2022	2021
Revenue	**853,906**	1,129,298	666,409
Gross profit	**250,514**	516,709	210,321
Net result	**172,979**	337,725	146,059
Earnings per share – USD	**1.31**	2.30	0.94
Earnings per share fully diluted – USD	**1.28**	2.25	0.92
Operating cash flow[1]	**353,048**	622,947	336,732
Free cash flow[1]	**2,689**	430,242	262,884
EBITDA[1]	**350,618**	639,480	330,754
Net cash / (debt) at period end[1]	**58,043**	175,098	(94,312)

[1] *See definition on page 24 under "Non-IFRS measures"*

Summarized consolidated balance sheet information is as follows:

USD Thousands	December 31, 2023	December 31, 2022	December 31, 2021
Non-current assets	1,372,388	1,041,051	1,122,514
Current assets	690,597	638,566	151,160
Total assets	**2,062,985**	1,679,617	1,273,674
Total non-current liabilities	779,838	564,381	331,152
Current liabilities	202,888	149,905	94,979
Total liabilities	**982,726**	714,286	426,131
Net assets	**1,080,259**	965,331	847,543
Working capital (including cash)	487,709	488,661	56,181

Selected Interim Financial Information

Selected interim condensed consolidated statement of operations is as follows:

USD Thousands	2023	Q4-23	Q3-23	Q2-23	Q1-23	2022	Q4-22	Q3-22	Q2-22	Q1-22
Revenue	**853,906**	198,460	257,366	205,564	192,516	**1,129,298**	254,615	299,361	315,540	259,782
Gross profit	**250,514**	39,955	93,429	52,747	64,383	**516,709**	95,411	140,489	161,709	119,100
Net result	**172,979**	29,710	71,681	32,025	39,563	**337,725**	61,183	90,503	105,217	80,822
Earnings per share – USD	**1.31**	0.23	0.56	0.24	0.29	**2.30**	0.45	0.63	0.70	0.52
Earnings per share fully diluted – USD	**1.28**	0.22	0.54	0.24	0.28	**2.25**	0.44	0.62	0.68	0.51
Operating cash flow[1]	**353,048**	73,634	119,142	84,372	75,900	**622,947**	113,668	171,654	192,515	145,110
Free cash flow[1]	**2,689**	(64,688)	34,703	16,415	16,259	**430,242**	65,288	116,681	151,792	96,479
EBITDA[1]	**350,618**	66,284	123,054	85,201	76,079	**639,480**	125,651	174,328	194,038	145,463
Net cash / (debt) at period end[1]	**58,043**	58,043	83,097	63,548	66,956	**175,098**	175,098	88,615	14,382	(42,367)

[1] *See definition on page 24 under "Non-IFRS measures"*

Selected Interim Financial Information

The Group operates within several geographical areas. Operating segments are reported at a country level, with Canada being further analyzed by main areas: (i) Canada – Northern Assets (comprising mainly of the Onion Lake Thermal asset) and (ii) Canada – Southern Assets (comprising of the Suffield assets (including the Brooks assets acquired as part of the Cor4 acquisition) and the Ferguson asset). This is consistent with the internal reporting provided to IPC management. The following tables present certain segment information.

	Three months ended – December 31, 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**

USD Thousands	Three months ended – December 31, 2022 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	101,127	52,721	44,361	29,095	–	227,304
NGLs	–	142	–	–	–	142
Gas	256	35,656	–	–	–	35,912
Net sales of oil and gas	101,383	88,519	44,361	29,095	–	263,358
Change in under/over lift position	–	–	–	(7,642)	–	(7,642)
Royalties	(10,006)	(8,989)	–	(1,864)	–	(20,859)
Hedging settlement	12,308	7,277	–	–	–	19,585
Other operating revenue	–	–	–	173	–	173
Revenue	103,685	86,807	44,361	19,762	–	254,615
Operating costs	(23,247)	(32,964)	(9,394)	(8,900)	–	(74,505)
Cost of blending	(39,494)	(7,040)	–	–	–	(46,534)
Change in inventory position	(551)	124	(4,111)	(54)	–	(4,592)
Depletion and decommissioning costs	(8,256)	(10,591)	(8,667)	(2,806)	–	(30,320)
Depreciation of other tangible fixed assets	–	–	(2,695)	–	–	(2,695)
Exploration and business development costs	–	–	–	–	(558)	(558)
Gross profit/(loss)	32,137	36,336	19,494	8,002	(558)	95,411

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	(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**

USD Thousands	Year ended – December 31, 2022					
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	513,349	265,016	184,143	112,379	–	1,074,887
NGLs	–	774	–	–	–	774
Gas	1,082	153,672	–	–	–	154,754
Net sales of oil and gas	514,431	419,462	184,143	112,379	–	1,230,415
Change in under/over lift position	–	–	–	(8,553)	–	(8,553)
Royalties	(59,353)	(46,503)	–	(6,660)	–	(112,516)
Hedging settlement	18,842	283	–	–	–	19,125
Other operating revenue	–	111	–	716	–	827
Revenue	473,920	373,353	184,143	97,882	–	1,129,298
Operating costs	(101,443)	(115,574)	(35,051)	(35,588)	–	(287,656)
Cost of blending	(155,375)	(33,797)	–	–	–	(189,172)
Change in inventory position	721	317	(1,916)	720	–	(158)
Depletion and decommissioning costs	(33,097)	(41,980)	(34,687)	(12,277)	–	(122,041)
Depreciation of other tangible fixed assets	–	–	(10,787)	–	–	(10,787)
Exploration and business development costs	97	–	–	–	(2,872)	(2,775)
Gross profit/(loss)	184,823	182,319	101,702	50,737	(2,872)	516,709

Three months and year ended December 31, 2023, Review

Revenue

Total revenue amounted to USD 198,460 thousand for Q4 2023, compared to USD 254,615 thousand for Q4 2022 and USD 853,906 thousand for the year ended December 31, 2023 compared to USD 1,129,298 thousand for the year ended December 31, 2022 and is analyzed as follows:

USD Thousands	Three months ended December 31		Year ended December 31	
	2023	2022	**2023**	2022
Crude oil sales	211,438	227,304	871,221	1,074,887
Gas and NGL sales	15,101	36,054	68,510	155,528
Change in under/overlift position	(8,442)	(7,642)	400	(8,553)
Royalties	(27,009)	(20,859)	(106,297)	(112,516)
Hedging settlement	6,959	19,585	18,928	19,125
Other operating revenue	413	173	1,144	827
Total revenue	**198,460**	254,615	**853,906**	1,129,298

The main components of total revenue for the three months and year ended December 31, 2023, and December 31, 2022, respectively, are detailed below.

Crude oil sales

	Three months ended – December 31, 2023				
USD Thousands	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**

	Three months ended – December 31, 2022				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	101,127	52,721	44,361	29,095	227,304
- Quantity sold in bbls	1,824,392	900,832	473,071	330,014	3,528,309
- Average price realized USD per bbl	55.43	58.52	93.77	88.16	64.42

Crude oil revenue was 7% lower in Q4 2023 compared to Q4 2022 mainly due to lower oil prices. Canadian - Southern Assets sales volumes are 21% higher in Q4 2023 compared to Q4 2022 as a result of the Cor4 acquisition in Q1 2023 and Malaysia sales volume are 62% lower in Q4 2023 compared to Q4 2022 as a result of two production wells offline awaiting workover intervention.

The Suffield area assets and Onion Lake crude oil in Canada are blended with purchased condensate diluent volumes to meet pipeline specifications. As a result of the blended volumes, actual sales volumes are higher than produced volumes for Canada. The Canadian realized sales price is based on the Western Canadian Select ("WCS") price which trades at a discount to West Texas Intermediate ("WTI"). For Q4 2023, WTI averaged USD 79 per bbl compared to USD 83 per bbl for Q4 2022 and the average discount to WCS used in IPC's pricing formula was USD 22 per bbl compared to USD 26 per bbl for Q4 2022.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices. There was one cargo lifting in Malaysia during Q4 2023 and two cargo liftings in Q4 2022. Produced unsold oil barrels from Bertam at the end of Q4 2023 amounted to 163,000 barrels, see Change in Inventory Position section below. The average Dated Brent crude oil price was USD 84 per bbl for Q4 2023 compared to USD 89 per bbl for the comparative period.

	Year ended – December 31, 2023				
USD Thousands	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**

	Year ended – December 31, 2022				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	513,349	265,016	184,143	112,379	1,074,887
- Quantity sold in bbls	6,880,263	3,492,721	1,646,301	1,143,130	13,162,415
- Average price realized USD per bbl	74.61	75.88	111.85	98.31	81.66

The Suffield area assets and Onion Lake crude oil in Canada are blended with purchased condensate diluent volumes to meet pipeline specifications. As a result of the blended volumes, actual sales volumes are higher than produced volumes for Canada.

Crude oil revenue was lower by 19% during the year ended December 31, 2023 compared to the year ended December 31, 2022 mainly due to lower oil prices despite higher sales volumes driven by the Cor4 acquisition and Onion Lake performance.

The Canadian realized sales price is based on the WCS price which trades at a discount to WTI. WTI averaged USD 78 per bbl for the year ended December 31, 2023 compared to USD 94 per bbl for the comparative period and the average discount to WCS used in IPC's pricing formula was USD 19 per bbl compared to USD 18 per bbl for the comparative period.

The realized sales price for Malaysia and France is based on Brent crude oil prices and the average market Brent crude oil price was USD 83 per bbl for the year ended December 31, 2023 compared to USD 101 per bbl for the comparative period.

Gas and NGL sales

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

	Three months ended – December 31, 2022		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	35,798	256	36,054
- Quantity sold in Mcf	8,256,010	70,093	8,326,103
- Average price realized USD per Mcf	4.34	3.65	4.33

Gas and NGL sales revenue was 58% lower for Q4 2023 compared to Q4 2022 mainly due to the lower achieved gas price. IPC's achieved gas price is based on AECO pricing plus a premium. For Q4 2023, IPC realized an average price of CAD 2.33 per Mcf compared to AECO average pricing of CAD 2.29 per Mcf.

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

	Year ended – December 31, 2022		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	154,446	1,082	155,528
- Quantity sold in Mcf	32,699,017	264,673	32,963,690
- Average price realized USD per Mcf	4.72	4.09	4.72

Gas and NGL sales revenue was 56% lower for the year ended December 31, 2023 compared to the year ended December 31, 2022 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, 2023, IPC realized an average price of CAD 2.73 per Mcf compared to AECO average pricing of CAD 2.61 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. The oil and gas pricing contracts are not entered into for speculative purposes.

The realized hedging settlement for the year ended December 31, 2023 amounted to a gain of USD 18,928 thousand and consisted of a gain of USD 15,664 thousand on the gas contracts and a gain of USD 3,264 thousand on the oil 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 126,414 thousand for Q4 2023 compared to USD 125,631 thousand for Q4 2022 and USD 491,303 thousand for the year ended December 31, 2023 compared to USD 476,987 thousand for the comparative period, and is analyzed as follows:

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

	Three months ended – December 31, 2022					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	32,964	23,247	13,534	8,900	(4,140)	74,505
USD/boe[2]	14.21	15.72	28.12	33.75	n/a	16.45
Cost of blending	7,040	39,494	–	–	–	46,534
Change in inventory position	(124)	551	4,111	54	–	4,592
Production costs	39,880	63,292	17,645	8,954	(4,140)	125,631

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

USD Thousands	Year ended – December 31, 2022 Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	115,574	101,443	51,476	35,589	(16,425)	287,657
USD/boe[2]	12.71	17.75	26.72	35.04	n/a	16.21
Cost of blending	33,797	155,375	–	–	–	189,172
Change in inventory position	(317)	(721)	1,916	(720)	–	158
Production costs	149,054	256,097	53,392	34,869	(16,425)	476,987

[1] See definition on page 24 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 includes Cor4 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 39.24 and USD 19.52 for Q4 2023 and Q4 2022 respectively and USD 25.58 and USD 18.20 for the year ended December 31, 2023 and December 31, 2022, respectively.

Operating costs
Operating costs amounted to USD 83,368 thousand for Q4 2023 compared to USD 74,505 thousand for Q4 2022 and USD 321,962 thousand for the year ended December 31, 2023 compared to USD 287,657 for the year ended December 31, 2022. The increase in costs in 2023 compared to 2022 is due mainly to the Cor4 acquisition in Q1 2023, increased production and activity levels. Operating costs per boe amounted to USD 18.28 per boe in Q4 2023 below guidance for the quarter and compared with USD 16.45 per boe in Q4 2022. The operating cost per boe in Malaysia is higher in Q4 2023 compared with Q4 2022 as a result of the lower production due to two producing wells offline. Operating costs per boe for the year ended December 31, 2023 amounted to USD 17.63 per boe which was within the full year operating cost guidance of between USD 17.5 to 18 per boe.

Cost of blending
For the Suffield area 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 majority of Onion Lake oil production has also been blended and exported by pipeline since April 2022 with the commissioning of a third party export pipeline from the Onion Lake field to the gathering system.

The cost of the diluent amounted to USD 44,473 thousand for Q4 2023 compared to USD 46,534 thousand for Q4 2022 and USD 172,996 thousand for the year ended December 31, 2023 compared to USD 189,172 thousand for the comparative period. The decrease versus the comparative period is largely attributable to lower commodity pricing reflected in the cost of diluent partly offset by increased blending at Onion Lake following the commissioning of the pipeline in April 2022.

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 2023, IPC had crude entitlement of 163,000 barrels of oil on the FPSO Bertam facility being crude produced but not yet sold. The next Bertam lifting scheduled for February 2024.

Depletion and decommissioning costs
The total depletion of oil and gas properties amounted to USD 30,434 thousand for Q4 2023 compared to USD 30,320 thousand for Q4 2022 and USD 126,010 thousand for the year ended December 31, 2023 (including an adjustment for accelerated decommissioning activities amounting to USD 24,088 thousand) compared to USD 122,041 thousand for the year ended December 31, 2023. The depletion charge is analyzed in the following tables:

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

USD Thousands	Three months ended – December 31, 2022 Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	10,591	8,256	8,667	2,806	30,320
USD per boe	4.57	5.58	18.01	11.22	6.69

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

USD Thousands	Year ended – December 31, 2022 Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	41,980	33,097	34,687	12,277	122,041
USD per boe	4.62	5.79	18.01	12.13	6.88

[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 includes Cor4 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 decreased compared to the prior year following the extension to the Bertam field production sharing contract and consequent increase in field reserves announced at the end of 2022. In addition, the depletion rate in Canada - Southern Assets has increased compared to the prior year as a result of the Cor4 acquisition.

Depreciation of other tangible fixed assets
The total depreciation of other assets amounted to USD 1,309 thousand for Q4 2023 compared to USD 2,695 thousand for Q4 2022 and USD 7,812 thousand for the year ended December 31, 2023 compared to USD 10,787 thousand for the comparative period. This relates to the depreciation of the FPSO Bertam, which is being depreciated on a unit of production basis to August 2025, being the original Bertam field production sharing contract (PSC) expiry date, before the PSC extension to 2035.

Exploration and business development costs
The total exploration and business developments costs amounted to a cost of USD 348 thousand for Q4 2023 and a cost of USD 2,355 thousand for the year ended December 31, 2023 including Cor4 acquisition related costs amounting to USD 834 thousand.

Sale of assets
Sale of assets amounted to USD 19,018 thousand for the year ended December 31, 2023 and represents the sale of John Lake properties in Canada with gross proceeds of CAD 28.1 million (USD 20.8 million) and a net accounting gain on disposal of CAD 25.7 million (USD 19.0 million).

Net financial items
Net financial items amounted to a charge of USD 22,736 thousand for the year ended December 31, 2023, compared to a charge of USD 37,131 thousand for the year ended December 31, 2022, and included a non-cash net foreign exchange loss of USD 1,911 thousand for 2023 compared to a net foreign exchange loss of USD 7,872 thousand for 2022. The foreign exchange movements during the year ended December 31, 2023 are mainly resulting from the revaluation of intra-group loan funding balances.

Excluding foreign exchange movements, the net financial items amounted to a charge of USD 20,825 thousand for the year ended December 31, 2023, compared to USD 29,259 thousand for the year ended December 31, 2022.

The interest expense amounted to USD 25,635 thousand for the year ended December 31, 2023, compared to USD 20,689 thousand for the comparative period in 2022 and mainly related to the bond interest at a coupon rate of 7.25% per annum. Interest income generated on cash balances held in 2023 amounted to USD 21,774 thousand for the year ended December 31, 2023 and is higher than the comparative period of USD 6,966 thousand due mainly to higher interest rates and higher cash balances.

The unwinding of the asset retirement obligation discount rate amounted to USD 13,408 thousand for year ended December 31, 2023, compared to USD 10,758 thousand for the year ended December 31, 2022.

Income tax
The corporate income tax amounted to a charge of USD 55,362 thousand for the year ended December 31, 2023, compared to a charge of USD 127,413 thousand for the year ended December 31, 2022 and has decreased due to the lower net financial result before tax.

The current income tax charge amounted to USD 14,457 thousand in 2023 compared to USD 29,365 thousand in 2022 and mainly related to France and Malaysia. The current income tax charge included a windfall profits tax in France amounting to USD 10,915 thousand. No corporate income tax was payable in Canada in respect of the year ended December 31, 2023 due to the usage of historical tax pools.

Capital Expenditure

Development and exploration and evaluation expenditure incurred during the year ended December 31, 2023 was as follows:

USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Development	23,454	255,159	17,873	16,204	**312,690**
Exploration and evaluation	–	–	–	39	**39**
	23,454	255,159	17,873	16,243	**312,729**

Capital expenditure of USD 312,729 thousand was mainly spent in Canada on the Blackrod Phase 1 Development project and on the Pad L completion at Onion Lake Thermal, in France on the drilling of the Villeperdue West oil wells and in Malaysia on the well workovers.

In addition, USD 5,821 thousand of capital expenditure was spent on the Brooks assets mainly on drilling from January 1, 2023 to the completion date of March 3, 2023.

Cor4 Acquisition

On March 3, 2023, IPC completed the acquisition of all of the issued and outstanding shares of Cor4 Oil Corp. ("Cor4"). Cor4 owned assets in the Brooks area, Alberta. At such date, Cor4 became an indirect wholly-owned subsidiary of IPC. On June 1, 2023, Cor4 was amalgamated into IPC Canada Ltd.

The Cor4 acquisition has been accounted for as a business combination with IPC being the acquirer, and in accordance with IFRS 3 Business Combinations, the assets acquired and liabilities assumed have been recorded at their fair values.

Total cash consideration paid, after preliminary closing adjustments, amounted to USD 62.2 million (CAD 84.7 million).

The amounts recognized in respect of the identifiable assets acquired and liabilities assumed are as set out in the table below.

USD Thousands	
Cash	2,792
Trade and other receivables	7,671
Prepaid expenses and deposits	2,417
Fair value of risk management assets	1,144
Deferred tax assets	19,334
Right-of-use assets	109
Property, plant and equipment	72,242
Accounts payable and accrued liabilities	(12,623)
Right-of-use liabilities	(109)
Decommissioning liabilities	(29,885)
Mark-To-Market reserve in equity	(881)
Total Consideration	**62,211**
Settled by:	
Cash payment	**62,211**

The Corporation performed a preliminary purchase price allocation for the Cor4 acquisition. The amounts disclosed above were determined provisionally pending the finalization of the valuation for those assets and liabilities. Up to twelve months from the effective date of the Cor4 acquisition, further adjustments may be made to the fair values assigned to the identifiable assets acquired and liabilities assumed.

Acquisition-related costs of approximately USD 0.8 million have been recognized in the statement of operations during the year ended December 31, 2023.

Decommissioning liabilities
The fair value of the decommissioning liability at the acquisition date was based on the estimated future cash flows to decommission the acquired oil and natural gas properties at the end of their useful life. The discount rate used to determine the net present value of the decommissioning obligation was a credit risk adjusted rate of 8%.

Other tangible fixed assets
Other tangible fixed assets amounted to USD 25,438 thousand as at December 31, 2023, which included USD 23,730 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated on a unit of production basis based to August 2025, being the original Bertam field PSC expiry date before the PSC extension to 2035.

Financial Position and Liquidity

Financing
As at January 2022, the Group had a reserve-based lending (RBL) credit facility of USD 140 million in connection with its oil and gas assets in France and Malaysia and a RBL credit facility of CAD 300 million in connection with its oil and gas assets in Canada.

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

In Q3 2023, IPC completed a tap issue of USD 150 million under IPC's existing 7.25% bond framework issued at 7% discount to par value with proceeds amounting to USD 139.5 million 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, 2023, IPC had a nominal USD 450 million of bonds outstanding with maturity in February 2027.

In Q1 2023, the Group increased the Canadian RCF from CAD 75 to CAD 150 million and extended the maturity to May 2025. In Q3 2023, the Group increased the Canadian RCF to CAD 165 million and in Q4 2023, the Group further increased the Canadian RCF to CAD 180 million. No cash amounts were drawn under the Canadian RCF as at December 31, 2023.

As at December 31, 2023, IPC had a EUR 13 million unsecured credit facility in France (the "France Facility"), with maturity in May 2026. IPC commenced quarterly repayments of the French Facility in August 2022. The amount remaining outstanding under the France Facility as at December 31, 2023 was USD 9 million (EUR 8 million).

Total net cash as at December 31, 2023 amounted to USD 58 million.

IPC intends to fund the Blackrod Phase 1 development with cash on hand, forecast FCF generated by its operations and available credit facilities.

The bond repayment obligations as at December 31, 2023, are classified as non-current as there are no mandatory repayments within the next twelve months.

An amount of USD 3.6 million (EUR 3.2 million) drawn under the France Facility as at December 31, 2023 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, 2023.

Cash and cash equivalents held amounted to USD 517 million as at December 31, 2023.

Working Capital
As at December 31, 2023, the Group had a net working capital balance including cash of USD 487,709 thousand compared to USD 488,661 thousand as at December 31, 2022. The difference as at December 31, 2023, from December 31, 2022 is mainly as a result of the increased cash following the tap issue offset by the payment for the Cor4 acquisition 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 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	**2023**	2022	**2023**	2022
Revenue	198,460	254,615	853,906	1,129,298
Production costs	(126,414)	(125,631)	(491,303)	(476,986)
Current tax	1,588	(15,316)	(14,457)	(29,365)
Operating cash flow	**73,634**	113,668	**348,146**	622,947

The operating cash flow for the year ended December 31, 2023 including the operating cash flow contribution of the Cor4 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:

USD Thousands	Three months ended December 31		Year ended December 31	
	2023	2022	2023	2022
Operating cash flow - see above	73,634	113,668	348,146	622,947
Capital expenditures	(128,825)	(42,792)	(312,729)	(157,662)
Abandonment and farm-in expenditures[1]	(1,516)	(1,085)	(9,199)	(6,962)
General, administration and depreciation expenses before depreciation[2]	(5,762)	(3,333)	(16,886)	(12,832)
Cash financial items[3]	(2,219)	(1,170)	(5,812)	(15,249)
Free cash flow	**(64,688)**	65,288	**3,520**	430,242

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

The free cash flow for the year ended December 31, 2023 including the free cash flow contribution of the Cor4 acquisition from the effective date of January 1, 2023 to the completion date of March 3, 2023 amounted to USD 2,689 thousand.

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

USD Thousands	Three months ended December 31		Year ended December 31	
	2023	2022	2023	2022
Net result	29,710	61,183	172,979	337,725
Net financial items	6,509	6,002	22,736	37,131
Income tax	4,691	24,486	55,362	127,413
Depletion	30,434	30,320	101,922	122,041
Depreciation of other tangible fixed assets	1,309	2,695	7,812	10,787
Exploration and business development costs	348	558	2,355	2,775
Depreciation included in general, administration and depreciation expenses[1]	389	407	1,569	1,608
Sale of assets	(7,106)	–	(19,018)	–
EBITDA	**66,284**	125,651	**345,717**	639,480

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

The EBITDA for the year ended December 31, 2023 including the EBITDA contribution of the Cor4 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:

USD Thousands	Three months ended December 31		Year ended December 31	
	2023	2022	2023	2022
Production costs	126,414	127,495	491,303	483,646
Cost of blending	(44,473)	(46,534)	(172,996)	(189,172)
Change in inventory position	1,427	(4,592)	3,655	(158)
Operating costs	**83,368**	76,369	**321,962**	294,316

The operating costs for the year ended December 31, 2023 including the operating costs contribution of the Cor4 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

The following table sets out how net cash is calculated:

USD Thousands	December 31, 2023	December 31, 2022
Bank loans	(9,031)	(12,142)
Bonds[1]	(450,000)	(300,000)
Cash and cash equivalents	517,074	487,240
Net cash	**58,043**	175,098

[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 four letters of credit as follows: (a) CAD 2.6 million in respect of its obligations to purchase diluent; (b) CAD 0.8 million in respect of its obligations related to the Ferguson asset, increasing by CAD 0.1 million annually to a maximum of CAD 1.0 million; (c) CAD 1.3 million in respect of pipeline access; and (d) CAD 0.5 million in relation to the hedging of electricity prices.

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, 2022, IPC had a total of 155,198,105 common shares issued and outstanding, of which IPC held 1,160,651 common shares in treasury. All common shares held in treasury as at January 1, 2022 were cancelled during January 2022.

During 2022, under the normal course issuer bid/share repurchase program announced in December 2021 and renewed in December 2022 (NCIB), IPC purchased and cancelled an aggregate of 8,951,391 common shares.

During Q2 2022, IPC commenced an offer to repurchase common shares under the substantial issuer bid (SIB). Under the SIB, IPC purchased and cancelled an aggregate of 8,258,064 common shares.

As at December 31, 2022, IPC had a total of 136,827,999 common shares issued and outstanding, with no common shares held in treasury.

Over the period of December 5, 2022 to December 4, 2023, IPC purchased and cancelled a total of 9,333,479 common shares under the NCIB (8,603,179 common shares purchased and cancelled in 2023). The NCIB was further renewed in Q4 2023 and IPC is entitled to purchase up to 8,342,119 common shares over the period of December 5, 2023 to December 4, 2024. During December 2023, IPC purchased and cancelled a total of 1,232,754 common shares under the renewed NCIB.

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.

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 32.0% of the outstanding common shares as at December 31, 2023.

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 4,440,062 IPC Share Unit Plan awards outstanding as at February 6, 2024 (321,512 awards granted in March 2021, 1,716,000 awards granted in May 2021, 4,333 awards granted in January 2022, 1,244,359 awards granted in March 2022, 2,391 awards granted in July 2022, 2,072 awards granted in January 2023, 1,143,708 awards granted in March 2023, 3,244 awards granted in July 2023 and 2,443 awards granted in January 2024).

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, 2023:

CAD Millions	2024	2025	2026	2027	2028	Thereafter
Transportation service [1]	27.9	29.2	38.4	43.4	46.4	555.6
Power[2]	9.8	9.8	9.8	9.8	9.8	–
Total commitments	**37.7**	**39.0**	**48.2**	**53.2**	**56.2**	**555.6**

[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 15MW at a weighted average price of CAD 74.92/MWH from January 1, 2024 - December 31, 2028.*

Critical Accounting Policies and Estimates

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

Transactions with Related Parties

During the year 2023, the Group paid USD 365 thousand to the Lundin Foundation in respect of sustainability advisory services provided to the Group and USD 685 thousand to Orrön Energy in respect of office space rental for 2023.

During the year 2023, Orrön Energy paid USD 657 thousand to the Group in respect of support services provided to Orrön Energy during 2023.

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, 2023, the Corporation had entered into oil and gas, condensate 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, 2023, which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
January 1, 2024 – December 31, 2024	17,700	WTI/WCS Differential	USD -15.03/bbl
January 1, 2024 – December 31, 2024	6,250	WTI Sale Swap	USD 80.94/bbl

The Group had condensate financial hedges outstanding as at December 31, 2023, which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
January 1, 2024 – March 31, 2024	3,000	C5/WTI Differential	USD -1.60/bbl

The Group had no gas price sale financial hedges outstanding as at December 31, 2023.

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 28,291 thousand as at December 31, 2023.

The Group had electricity financial hedges outstanding as at December 31, 2023, which are summarized as follows:

Period	Volume (MW)	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 long term negative fair value of USD 202 thousand as at December 31, 2023.

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.

In 2023, IPC entered into foreign currency hedges in Canada to buy CAD 20 million per month at CAD 1.36 (sell USD) and in Malaysia to buy MYR 11.5 million per month at MYR 4.63 (sell USD) in respect of 2024, and to buy CAD 15 million per month at CAD 1.36 (sell USD) in respect of 2025, to partially meet forecast operational expenses in those countries. In respect of the forecast Blackrod development capital expenditure in Canada, IPC entered into further currency hedges to purchase a total CAD 556 million for the period January 2024 to December 2025 at an average rate of CAD 1.33 (sell USD).

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 12,934 thousand as at December 31, 2023.

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 the IPC's common shares to decline. If any of the following risks actually occur, the Group's business may be harmed and the financial condition and results of operations may suffer significantly.

See also "Cautionary Statement Regarding Forward-Looking Information" and "Reserves and Resources 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. 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.

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

Volatility in Oil and Gas Commodity Prices and Price Differentials: The marketability and price of oil and gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and gas may depend upon its ability to access space on pipelines that deliver oil and gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities, 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 (SPR) management by the United States, the conflict in Ukraine, the impact of pandemics (including Covid19), 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.

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 a lighter hydrocarbon (commonly referred to as diluent) to increase its flow characteristics. The cost of diluent is generally correlated to crude oil prices. A shortfall in the supply of diluent may cause its price to increase which would adversely affect the Group's financial position and cash flow.

Climate Change: 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.

Emission and carbon tax regulations in Canada federally and regionally are evolving and as these regulations are established or amended, they may have an impact on organizations involved in oil and gas production. Canada has taken steps to address climate change by establishing the Canadian Net-Zero Emissions Accountability Act that enshrines in law the Government of Canada's commitment to achieve net-zero GHG emissions by 2050. In December 2023, the Government of Canada introduced draft regulations to cap oil and gas emissions by 2030 at levels 20% to 23% below 2019 levels (with the use of offsets) and 35% to 38% (without the use of offsets). The draft regulations are expected to be released in mid-2024 with final regulations in 2025. The regulations would be effective January 1, 2026. It is difficult to assess the overall impact these regulations will have on the Group at this time but it could result in increased costs to comply, delays in having projects approved and potentially a reduction in demand for oil from these regions, all of which could have a material negative impact on the Group's business.

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.

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.

Reputational Risks: Reputational risks arise from the surge of 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.

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.

Change in governments or policies in the countries in which the Group operates may have an impact on the decisions taken and regulations made by such governments on matters that may impact the oil and gas industry including the balance between economic development and environmental policy. The oil and gas industry has become an increasingly political topic, which has resulted in a rise in activism and criticism surrounding oil and gas development, particularly with respect to infrastructure projects. Protests, blockades and demonstrations 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 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 majority of the Group's interests at Onion Lake are situated on traditional reserve lands and are subject to the federal rules and regulations of Indian Oil and Gas Canada as well as of the Onion Lake Cree Nation of Saskatchewan/Alberta. There are risks associated with the management of the Group's interests on these lands, including access and lease terms.

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.

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 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 reductions 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.

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.

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.

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 32 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.

In 2022, the EU imposed tax on energy companies deriving income from operations in EU countries ("Solidarity Contribution"). The Solidarity Contribution was applicable to the Group in France for the 2022 fiscal year. Such tax could be extended or increased in the future, and similar taxes may 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, 2023, that have materially affected, or are reasonably likely to materially affect, the Group's internal control over financial reporting.

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

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

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:

- 2024 production range, operating costs, operating cash flow, free cash flow, and capital and decommissioning expenditure estimates;
- Estimates of future production, cash flows, operating costs and capital expenditures that are based on IPC's current business plans and assumptions regarding the business environment, which are subject to change;
- IPC's financial and operational flexibility to continue to react to recent events and navigate the Corporation through periods of volatile commodity prices;
- The ability to fully fund future expenditures from cash flows and current borrowing capacity;
- IPC's intention and ability to continue to implement its 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;
- Future development potential of the Suffield, Brooks, Ferguson and Mooney operations, including the timing and success of future oil and gas drilling and optimization programs;
- Current and future operations and production performance at Onion Lake Thermal;
- The potential improvement in the Canadian oil egress situation and IPC's ability to benefit from any such improvements;
- The ability of IPC to achieve and 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 GHG emissions intensity and climate strategies and to achieve its net GHG emissions intensity reduction targets;
- Estimates of reserves and contingent resources;
- The ability to generate free cash flows and use that cash to repay debt;
- IPC's continued access to its existing credit facilities, including current financial headroom, on terms acceptable to the Corporation;
- IPC's ability to maintain operations, production and business in light of any future pandemics and the restrictions and disruptions related thereto, including risks related to production delays and interruptions, changes in laws and regulations and reliance on third party operators and infrastructure;
- IPC's ability to identify and complete future acquisitions; and
- Future drilling and other exploration and development activities.

Statements relating to "reserves" and "contingent resources" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated and that the reserves and resources can be profitably produced in the future. Ultimate recovery of reserves or resources is based on forecasts of future results, estimates of amounts not yet determinable and assumptions of management. See also "Reserves and 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; the timing of receipt of regulatory approvals; the performance of existing wells; the success obtained in drilling new wells; anticipated timing and results of capital expenditures; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the successful completion of acquisitions and dispositions; the benefits of acquisitions;

the state of the economy and the exploration and production business in the jurisdictions in which IPC operates and globally; the availability and cost of financing, labour and services; and the ability to market crude oil, natural gas and natural gas liquids successfully.

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

These include, but are not limited to:
- 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;
- Incorrect assessment of the value of acquisitions;
- Failure to complete or realize the anticipated benefits of acquisitions or dispositions;
- The ability to access sufficient capital from internal and external sources;
- Failure to obtain required regulatory and other approvals; and
- Changes in legislation, including but not limited to tax laws, royalties, environmental and abandonment regulations.

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

Estimated FCF generation is based on IPC's current business plans over the periods of 2024 to 2028 and 2029 to 2033. Assumptions include average net production of approximately 55 Mboepd over the period of 2024 to 2028, average net production of approximately 65 Mboepd over the period of 2029 to 2033, average Brent oil prices of USD 75 to 95 per boe 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 6, 2024, the Corporation's Annual Information Form (AIF) for the year ended December 31, 2022, (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 release. 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, 2023, 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, 2023 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, 2023, 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, 2023 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, 2023 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 468 MMboe as at December 31, 2023, by the mid-point of the 2024 CMD production guidance of 46,000 to 48,000 boepd.

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

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

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

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

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

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

References to "unrisked" contingent resources volumes means that the reported volumes of contingent resources have not been risked (or adjusted) based on the chance of commerciality of such resources. In accordance with the COGE Handbook guidance 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 in respect of IPC's oil and gas assets in Canada, France and Malaysia have been aggregated by IPC. Estimates of reserves, resources and future net revenue for individual properties may not reflect the same level of confidence as estimates of reserves, resources and future net revenue for all properties, due to aggregation. This MD&A contains estimates of the net present value of the future net revenue from IPC's reserves and contingent resources. The estimated values of future net revenue disclosed in this MD&A do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve and resources evaluations will be attained and variances could be material.

The reserves and resources information and data provided in this MD&A 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, 2023, which will be filed on SEDAR+ (accessible at www.sedarplus.ca) on or before April 1, 2024. 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, 2023	25.7	6.6	103.8 MMcf (17.3 Mboe)	49.6
December 31, 2022	22.6	10.3	98.1 MMcf (16.4 Mboe)	49.2
Year ended December 31, 2023				
December 31, 2023	25.8	8.1	102.8MMcf (17.1 Mboe)	51.1
December 31, 2022	22.6	9.6	98.1MMcf (16.4 Mboe)	48.6

This document also makes reference to IPC's forecast average daily production of 46,000 to 48,000 boepd for 2024. IPC estimates that approximately 51% of that production will be comprised of heavy oil, approximately 15% will be comprised of light and medium crude oil and approximately 34% 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)

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)
ARV	Argus WCS Houston (a reference price for the cost of transporting WCS quality oil from Alberta to Houston)
bbl	Barrel (1 barrel = 159 litres)
boe[1]	Barrels of oil equivalents
boepd	Barrels of oil equivalents per day
bopd	Barrels of oil per day
Bcf	Billion cubic feet
Bscf	Billion standard 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)

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

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