Q3

International Petroleum Corporation

Management's Discussion and Analysis

For the three and nine months ended September 30, 2023

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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 International Financial Reporting Standards (IFRS) and do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with definitions of OCF, FCF, EBITDA, operating costs and net debt/net cash that may be used by other public companies. Management believes that OCF, FCF, EBITDA, operating costs and net debt/net cash are useful supplemental measures that may assist shareholders and investors in assessing the cash generated by and the financial performance and position of the Corporation. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-IFRS measure is presented in this MD&A. See "Non-IFRS Measures" on page 22.

Forward-Looking Statements
Certain statements contained in this MD&A constitute "forward-looking statements" or "forward-looking information" (within the meaning of applicable securities legislation). Such statements and information (together, "forward-looking statements") relate to future events, including the Corporation's future performance, business prospects or opportunities. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, forecasts, guidance, budgets, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "forecast", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", "budget" and similar expressions) are not statements of historical fact and may be "forward-looking statements". Although IPC believes that the expectations and assumptions on which such forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because IPC can give no assurances that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. For additional information underlying forward-looking statements, refer to the "Cautionary Statement Regarding Forward-Looking Information" on page 27.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada (other than the assets acquired in the Cor4 acquisition) are effective as of December 31, 2022, 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, 2022, price forecasts.

Reserve estimates and estimates of future net revenue in respect of IPC's oil and gas assets acquired in the Cor4 acquisition are effective as of December 31, 2022, and have been audited by GLJ Ltd. (GLJ), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2022, 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, 2022, 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, 2022, 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 October 31, 2023 and is intended to provide an overview of the Group's operations, financial performance and current and future business opportunities. This MD&A should be read in conjunction with IPC's unaudited interim condensed consolidated financial statements and accompanying notes for the three and nine months ended September 30, 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 International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

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

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

	September 30, 2023		September 30, 2022		December 31, 2022	
	Average	Period end	Average	Period end	Average	Year end
1 EUR equals USD	1.0835	1.0594	1.0650	0.9748	1.0539	1.0666
1 USD equals CAD	1.3454	1.3429	1.2828	1.3747	1.3015	1.3538
1 USD equals MYR	4.5134	4.6952	4.3422	4.6370	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, reserves, 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

Q3 2023 Business Highlights

- Strong quarterly average net production of approximately 50,200 barrels of oil equivalent (boe) per day (boepd) for the third quarter of 2023 (55% heavy crude oil, 14% light and medium crude oil and 31% natural gas).(1)
- Blackrod Phase 1 development progressing on schedule and budget.
- Disposal of non-core properties in Canada for MUSD 17 (0.6 MMboe of 2P reserves; approximately 400 bopd of average current production). (1)(2)
- Successfully completed planned maintenance turnaround at the Bertam Field in Malaysia on scope, schedule and budget.
- 1.31 million common shares purchased and cancelled during Q3 2023 under IPC's normal course issuer bid (NCIB); annual program 90% complete.(1)(2)
- IPC plans to seek TSX approval for the renewal of the NCIB for a further twelve months from December 2023 to December 2024, with IPC's current intention to fully complete the renewed program.
- Successfully completed USD 150 million tap issue under IPC's existing 7.25% senior unsecured bond framework.
- IPC succession plan sees William Lundin assume the role of President and CEO from January 1, 2024 as Mike Nicholson retires from executive management; Mike to continue as a Director of IPC and William to join the Board as a new Director.

Q3 2023 Financial Highlights

- Operating costs per boe of USD 17.9 for Q3 2023.(1)(3)
- Operating cash flow (OCF) generation for Q3 2023 amounted to MUSD 119.(1)(3)
- Capital and decommissioning expenditures of MUSD 80 for Q3 2023.(1)
- Free cash flow (FCF) generation for Q3 2023 amounted to MUSD 35 (MUSD 103 pre Blackrod funding).(1)(3)
- Net cash of MUSD 83 as at September 30, 2023.(3)
- Net result of MUSD 72 for Q3 2023.

Reserves and Resources

- Total 2P reserves as at December 31, 2022 of 487 million boe (MMboe), with a reserves life index (RLI) of 27 years.(1)(2)
- Contingent resources (best estimate, unrisked) as at December 31, 2022 of 1,162 MMboe.(1)(2)

2023 Annual Guidance

- Full year 2023 average net production forecast unchanged at greater than 50,000 boepd.(1)
- Full year 2023 operating costs guidance forecast remains unchanged at USD 17.5 to 18.0 per boe.(1)(3)
- Full year 2023 OCF guidance tightened to between MUSD 340 to 365 (assuming Brent USD 80 to 90 per barrel for the remainder of 2023) from previous guidance of MUSD 320 to 390 (assuming Brent USD 75 to 90 per barrel).(1)(3)
- Full year 2023 capital and decommissioning expenditures forecast reduced from MUSD 365 to MUSD 330.(1)
- Full year 2023 FCF forecast range tightened to between MUSD -15 to 5 (assuming Brent USD 80 to 90 per barrel for the remainder of 2023) from previous guidance of MUSD -65 to 5 (assuming Brent USD 75 to 90 per barrel), after taking into account MUSD 240 of proposed 2023 Blackrod capital expenditures.(1)(3)(4)

	Three months ended September 30		Nine months ended September 30	
USD Thousands	2023	2022	2023	2022
Revenue	257,366	299,361	655,446	874,683
Gross profit	93,429	140,489	210,559	421,298
Net result	71,681	90,503	143,269	276,542
Operating cash flow(3)	119,142	171,654	279,414	509,279
Free cash flow(3)	34,703	116,681	67,379	364,954
EBITDA(3)	123,054	174,328	284,334	513,829
Net Cash(3)	83,097	88,615	83,097	88,615

OPERATIONS REVIEW

Business Overview

Oil prices rebounded during the third quarter with Brent prices averaging USD 87 per barrel compared with USD 78 per barrel during the second quarter. The strength we have seen in physical markets shone through, with recessionary fears on the back of higher interest rates taking a back seat during the quarter. However, more recent talk of higher interest rates for longer by the Federal Reserve Bank, led to oil prices retreating from a push towards USD 100 per barrel in late September, back towards USD 85 per barrel in early October.

Looking forward, the decision by OPEC+ to extend their 'voluntary cuts' through the end of 2023, could set the stage for a large deficit and further draws on already below average inventories during the fourth quarter. Inventory levels now sit more than 100 million barrels below the five-year average levels. Heightened tensions, with the tragic outbreak of war in the Middle East, are exacerbating the situation and will no doubt lead to increased pricing volatility going forward.

IPC has decided to commence the hedging of its benchmark oil price exposure for 2024. Around 25% of 2024 West Texas Intermediate (WTI) exposure has been hedged at a price of USD 81 per barrel.

The third quarter 2023 WTI to Western Canadian Select (WCS) crude price differentials averaged around USD 13 per barrel, a USD 2 per barrel improvement on the second quarter. The fundamental outlook for 2024 differentials remains positive with the expansion of the Trans Mountain (TMX) pipeline (590,000 barrels per day of extra capacity linking Edmonton to the port of Vancouver) as well as a reduction in Mexican heavy oil exports to the US (due to domestic refinery capacity increases by more than 200,000 barrels per day). That being said, a possible delay in start-up of the TMX pipeline from the first quarter to the second quarter of 2024 as a result of a tunnelling issue, has seen 2024 WTI - WCS differential widen to more than USD 17 per barrel. IPC took the decision to hedge 75% of our WCS differential exposure prior to news of the TMX pipeline potential delay, when market prices were more favourable averaging USD 15 per barrel.

Gas market prices held stable during the third quarter at around CAD 2.50 per Mcf. During the third quarter, IPC continued to benefit from the AECO gas price hedges that were put in place when gas prices were much stronger in late 2022: 33.7 MMcf per day at CAD 4.10 per Mcf from April to October 2023, which represents approximately 50% of our net long exposure.

Third Quarter 2023 Highlights and Full Year 2023 Guidance
During the third quarter of 2023, our assets delivered average net production of 50,200 boepd, above our high-end guidance for the third quarter in succession. Above high-end guidance performance in Canada was partially offset by some downtime from two production wells in Malaysia that are scheduled for workover intervention activity. This work is expected to be concluded by January 2024. Given the very strong performance during the first nine months of 2023 averaging around 51,600 boepd, full year 2023 average net production guidance remains unchanged at greater than 50,000 boepd, above our original high end guidance.[1]

Our operating costs per boe for the third quarter of 2023 were USD 17.9, in line with our latest guidance. Full year 2023 operating costs per boe guidance of USD 17.5 to 18.0 per boe remains unchanged.[1][3]

Operating cash flow (OCF) generation for the third quarter of 2023 was USD 119 million, towards the high end of guidance, driven by strong production and tighter WTI to WCS differentials. Full year 2023 OCF guidance of USD 320 to 390 million (assuming Brent USD 75 to 90 per barrel) is tightened to USD 340 to 365 million (assuming Brent USD 80 to 90 per barrel for the remainder of 2023).[1][3]

Full year 2023 capital and decommissioning expenditure forecast of USD 365 million is revised down to USD 330 million largely driven by rephasing of certain Blackrod capital expenditure from 2023 into 2024 and some additions relating to the workover of two wells in Malaysia.[1]

Free cash flow (FCF) generation was USD 35 million (USD 103 million pre Blackrod funding) during the third quarter of 2023. Full year 2023 FCF guidance of USD -65 to 5 million (assumed Brent USD 75 to 90 per barrel) is tightened to USD -15 to 5 million (assuming Brent USD 80 to 90 per barrel for the remainder of 2023).[1][3][4]

IPC's transformational growth program is estimated to generate FCF post growth investment of between USD 2.6 and 4.4 billion over the next ten years assuming average Brent oil prices between USD 75 to 95 per barrel. This represents more than 2 to 3 times IPC's current market capitalisation.[1][3][4]

During the third quarter of 2023, IPC successfully completed a tap issue of USD 150 million under IPC's existing 7.25% senior unsecured bond framework issued at 7% discount to par value and therefore with net proceeds amounting to USD 139.5 million to further strengthen IPC's cash position. Following the tap issue, IPC has USD 450 million of senior unsecured bonds outstanding with maturity in February 2027.

IPC's net cash position of USD 64 million as at June 30, 2023 was increased to USD 83 million as at September 30, 2023.(3) Gross cash on the balance sheet as at September 30, 2023 amounts to USD 543 million providing a significant war chest to pursue our three strategic pillars of returning value to stakeholders, pursuing value adding M&A and focusing on organic growth. Furthermore, during Q3 2023, IPC increased its Canadian Revolving Credit Facility (RCF) from CAD 150 million to CAD 165 million. The RCF remains undrawn as at October 31, 2023.

Phase 1 Blackrod Project
Following the successful completion of FEED studies and the continued strong production performance from well pair three during 2022, IPC took the decision in Q1 2023 to advance the development of Phase 1 of the Blackrod project. Development capital expenditure to first oil is estimated at approximately USD 850 million. First oil of the Phase 1 development is estimated to be in late 2026, with forecast production of 30,000 bopd by 2028. The breakeven oil price estimated by IPC assuming a 10% discount rate is a WTI price of approximately USD 59 per barrel. Using the December 31, 2022 price forecasts of our independent qualified reserves evaluator, Sproule Associates Limited (Sproule), the net present value as at that date, at a 10% discount rate (after tax), of Phase 1 of the Blackrod project is USD 807 million. IPC intends to fund the Phase 1 development with cash on hand and forecast FCF generated by our operations.(1)(2)

During the third quarter, the Phase 1 development activities have progressed according to plan. The engineering, procurement and construction (EPC) contract for the major Phase 1 central processing facility was signed in Q2 2023 and project work continued to progress during Q3 2023 with cost levels and schedule in line with expectation. In addition, IPC has locked in more than 70% of the CAD/USD exposure through a combination of hedging and contractual arrangements to give greater certainty to the USD funding requirement for the Phase 1 project costs.

M&A
During the first nine months of 2023, IPC continued the successful integration of the acquired Brooks assets into the Group following completion of the Cor4 acquisition in March 2023. Four wells were successfully drilled and brought on production from the Ellerslie fairway since the beginning of the year and we plan to drill another four wells on this exciting play in 2023, two more than originally planned.(1)(2)

During the third quarter, IPC agreed to dispose of a small package of non-core production and land assets in the John Lake and Fishing Lake areas in Canada. Total proceeds from the disposal amounted to USD 17 million. Current production associated with the assets was around 365 bopd. 2P reserves and NPV10 value as of January 1, 2023 were 0.6 MMboe and USD 7.7 million respectively. The John Lake disposal closed in Q3 2023 and Fishing Lake early October 2023.(1)(2)

Capital Allocation Framework
Normal Course Issuer Bid
In Q4 2022, IPC announced the renewal of the NCIB, with the ability to repurchase up to approximately 9.3 million common shares over the twelve-month period to early December 2023. By the end of September 2023, IPC purchased and cancelled 8.4 million common shares under the NCIB. The average price of common shares purchased under the renewed NCIB during the period of December 2022 to September 2023 was SEK 101 / CAD 13.00 per share. IPC expects to complete the current NCIB program of 9.3 million common shares during Q4 2023.

As at September 30, 2023, IPC had a total of 129,189,220 common shares issued and outstanding, with no common shares held in treasury.

Capital Allocation Plans
IPC's capital allocation framework consists of distributing to shareholders a minimum of 40% of the Free Cash Flow generated by the business, provided that IPC's net debt to EBITDA ratio is at or below 1 time.(3) These shareholder distributions are planned to be implemented by continued share repurchases under the NCIB as well as the consideration by IPC of other forms of shareholder distributions, subject to further applicable regulatory and corporate approvals.

The IPC Board of Directors has approved, subject to acceptance by the TSX, the renewal of IPC's NCIB for a further twelve months from December 2023 to December 2024. We expect that the renewed NCIB program will permit IPC to purchase on the TSX and/or Nasdaq Stockholm, and cancel, up to a further 8.3 million common shares, representing approximately 6.5% of the total outstanding common shares (or 10% of IPC's "public float" under applicable TSX rules) following completion of the current NCIB program.

Despite the level of capital investment expected for 2024, in particular related to the Blackrod Phase 1 project, and notwithstanding the capital allocation framework described above, IPC's current intention is to complete the renewed NCIB program during 2024. We continue to believe that materially growing our 2P reserves, production and asset value whilst reducing our share count is a winning combination for shareholders.

Environmental, Social and Governance (ESG) Performance
Alongside the publication of the second quarter 2023 financial report, IPC released its fourth annual Sustainability Report and first standalone TCFD Report. 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 our operations. During the third quarter of 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. During Q1 2023, IPC extended its commitment to remain at 2025 levels of 20 kg CO_2/boe through to the end of 2027.

IPC Succession Plan
After nineteen years with the Lundin Group, Mike Nicholson, President and CEO has informed the IPC Board of his intention to step down from his executive position at the end of 2023. William Lundin, currently Chief Operating Officer of IPC (COO), will assume the role of President and CEO from January 1, 2024 and Nicki Duncan, currently Group Operations Lead, will assume the role of COO. The Board intends to increase the size of the Board to seven members and William will join as a new Director as of January 1, 2024, with Mike remaining on the Board.

Mike Nicholson said:

"IPC is generating robust cash flow from the base business, the balance sheet is stronger than ever, and our Blackrod growth project is progressing well, on schedule and budget.

I firmly believe that our production and cash flow growth, coupled with continued share buy backs and opportunistic M&A, will continue to generate superior shareholder returns in the years ahead.

I am excited to be handing over the reins to William Lundin, current COO of IPC, with such a bright future ahead of the company. Having had the pleasure of working side by side with Will for more than three years in his current role, I have been deeply impressed with his knowledge of value creation within the resource industry and the vision that we share to set the pace for our industry peers and to continue to outperform the competition. Will has amassed a vast amount of experience from working in field operations at Onion Lake Thermal and project management in the Canadian business, executive management within IPC, and strategic oversight in his various board positions across the Lundin Group. I know that Lukas Lundin would be very proud of Will's progression to CEO. The COO role will be assumed by Nicki Duncan, currently IPC's Group Operations Lead.

I am delighted to remain as a Board Director and in this capacity look forward to my continued involvement in the amazing IPC success story."

William Lundin said:

"It has been a privilege working alongside Mike. His contributions to IPC and Lundin Energy have been invaluable and we look forward to his continued support as a Director of IPC.

I take great pride in having the opportunity to represent IPC as President and CEO and look forward in continuing to maximise value alongside a highly talented team. Our strategy remains intact to deliver shareholder returns, grow organically, and opportunistically seek accretive acquisitions. With a strong balance sheet, proven portfolio of high-quality producing assets delivering robust free cashflow to the business combined with transformational production growth to come from our Blackrod asset, the outlook for IPC is extremely bright."

Notes:

(1) See "Supplemental Information regarding Product Types" in "Reserves and Resources Advisory" below. See also the annual information form for the year ended December 31, 2022 (AIF) available on IPC's website at www.international-petroleum.com and under IPC's profile on SEDAR+ at www.sedarplus.ca. IPC completed the acquisition of 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 and forecast operational and financial information included in the MD&A, including production, reserves, 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 AIF. 2P reserves as at December 31, 2022 of 487 MMboe includes 471 MMboe attributable to IPC's oil and gas assets and 15.9 MMboe attributable to the oil and gas assets acquired in the Cor4 acquisition.

(3) Non-IFRS measure, see "Non-IFRS Measures" below.

(4) Estimated FCF generation is based on IPC's current business plans over the periods of 2023 to 2027 and 2028 to 2032, including net cash of USD 175 million as at December 31, 2022 less the Cor4 acquisition consideration of USD 62 million. Assumptions include average net production of approximately 50 Mboepd over the period of 2023 to 2027, average net production of approximately 65 Mboepd over the period of 2028 to 2032, 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 AIF. IPC's market capitalization is at close on October 27, 2023 (USD 1,330 million based on 114.85 SEK/share, 129.2 million IPC shares outstanding and exchange rate of 11.15 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

Reserves and Resources

The 2P reserves attributable to IPC's oil and gas assets are 487 MMboe as at December 31, 2022, as certified by independent third party reserve auditors. The proved plus probable reserve life index (RLI) as at December 31, 2022, is approximately 27 years. Best estimate contingent resources as at December 31, 2022, are 1,162 MMboe (unrisked). See "Reserves and Resources Advisory" below.

IPC's proved plus probable reserves increased by 80% at year end 2022 relative to year end 2021. The substantial increase in 2P reserve additions for the company was largely attributed to the sanctioning of the transformational Blackrod Phase 1 development project and further complemented by a conventional asset acquisition adjacent to the Suffield property in Southern Alberta and by securing a 10 year PSC extension at the PM307 block in Malaysia.

During the third quarter in Canada, the Blackrod Phase 1 development progressed in accordance with plan. Initial construction camps have been installed and site preparations are underway to allow for drilling and equipment delivery beginning in 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. In the Suffield area, four out of the six planned Ellerslie wells have been drilled by end Q3 2023. Given the strong performance and robust pricing environment, IPC has elected to increase drilling activity by adding two more production wells to the 2023 program. At Onion Lake Thermal, the newly developed production sustaining Pad L has come on stream ahead of schedule. In France, planned drilling operations have been successfully completed with all three Villeperdue West oil wells and the Merisier side-track well online and performing ahead of forecast. In Malaysia, evaluation of a potential next phase of field development is progressing in line with schedule. IPC remains focused on organic growth and continues to mature future development projects across all operated assets, with a significant portfolio of drilling and optimisation opportunities ready for sanction at the discretion of the Group.

Production

Average daily net production for the third quarter 2023 was above the high end of our 2023 Capital Markets Day (CMD) guidance range at 50,200 boepd. In Canada, strong operational performance has been supplemented by the newly drilled Suffield Ellerslie production wells and earlier than forecast first oil from the production sustaining Pad L at Onion Lake Thermal. At Bertam in Malaysia, two production wells are offline with workovers scheduled for later in Q4 2023. The Bertam FPSO major planned maintenance shutdown was successfully executed in line with schedule and budget during September 2023.

With exceptional operational performance during the first nine months of 2023 and the production benefit from the 2023 capital expenditure investments in Canada and France, full year 2023 average net production is expected to exceed the upper end of the CMD guidance of 48,000 to 50,000 boepd.

The production during Q3 2023 with comparatives is summarized below:

Production in Mboepd	Three months ended September 30		Nine months ended September 30		Year ended December 31
	2023	2022	**2023**	2022	**2022**
Crude oil					
Canada – Northern Assets	15.8	15.8	15.6	15.4	15.6
Canada – Southern Assets[1]	11.4	8.8	11.9	8.5	8.7
Malaysia	2.9	5.8	4.3	5.3	5.3
France	2.8	2.7	2.7	2.8	2.7
Total crude oil production	**32.9**	33.1	**34.5**	32.0	32.3
Gas					
Canada – Northern Assets	0.3	0.1	0.3	0.1	0.1
Canada – Southern Assets	17.0	16.8	16.8	16.3	16.2
Total gas production	**17.3**	16.9	**17.1**	16.4	16.3
Total production	**50.2**	50.0	**51.6**	48.4	48.6
Quantity in MMboe	**4.62**	4.60	**14.09**	13.21	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 September 30		Nine months ended September 30		Year ended December 31
		2023	2022	2023	2022	2022
- Oil Onion Lake Thermal	100%	13.4	12.9	13.2	12.5	12.7
- Oil Suffield Area[1]	100%	10.0	6.9	10.3	7.2	7.1
- Oil Ferguson	100%	1.4	1.9	1.6	1.3	1.6
- Oil Other	50-100%	2.4	2.9	2.4	2.9	2.9
- Gas[1]	~100%[2]	17.3	16.9	17.1	16.4	16.3
Canada		**44.5**	41.5	**44.6**	40.3	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 Q3 2023 was above high-end CMD guidance at 44,500 boepd with continued strong operational performance at all the major producing assets. At Onion Lake Thermal, daily production has been touching the facility nameplate capacity of 14,000 boepd with the first two 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 optimisation has been supplemented by the newly drilled Suffield Ellerslie production wells which continue to exceed expectations.

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 third quarter at Blackrod, the Phase 1 development progressed in accordance with plan. Initial construction camps have been installed and site preparations are underway to allow for drilling and equipment delivery beginning in 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.

As of the end of Q3 at Suffield, four out of six of the originally planned Ellerslie play wells have been brought online with initial production ahead of expectations. Given the promising production performance and robust pricing environment, IPC has elected to increase the 2023 Ellerslie drilling program to eight wells by adding two additional production wells to the Q4 2023 drilling plan.

At Onion Lake Thermal, daily production is touching facility nameplate capacity of 14,000 boepd with the first two well pairs from production sustaining Pad L brought online ahead of schedule in Q3 2023. The third and fourth well pairs from the Pad are on steam warm up in preparation for first oil later in Q4 2023.

MALAYSIA

Production in Mboepd	WI	Three months ended September 30		Nine months ended September 30		Year ended December 31
		2023	2022	2023	2022	2022
Bertam	100%	**2.9**	5.8	**4.3**	5.3	5.3

Production
Net production at Bertam in Malaysia was below guidance at 2.9 boepd with two production wells offline and being prepared for workover later in Q4 2023. This is expected to be completed by January 2024. The Bertam FPSO planned maintenance shutdown was successfully executed in line with schedule and budget during September 2023.

Organic Growth and Capital Projects
In Malaysia, our focus is now on completing the two well workovers and studying 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 September 30		Nine months ended September 30		Year ended December 31
		2023	2022	**2023**	2022	2022
France						
- Paris Basin	100%[1]	2.5	2.4	2.3	2.5	2.4
- Aquitaine	50%	0.3	0.3	0.4	0.3	0.3
		2.8	2.7	**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 Q3 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	Q3-23	Q2-23	Q1-23	Q4-22	Q3-22	Q2-22	Q1-22	Q4-21
Revenue	**257,366**	205,564	192,516	253,921	297,952	315,540	259,782	215,296
Gross profit	**93,429**	52,747	64,383	95,411	140,489	161,709	119,100	79,469
Net result	**71,681**	32,025	39,563	61,183	90,503	105,217	80,822	66,918
Earnings per share – USD	**0.56**	0.24	0.29	0.45	0.63	0.70	0.52	0.43
Earnings per share fully diluted – USD	**0.54**	0.24	0.28	0.44	0.62	0.68	0.51	0.42
Operating cash flow[1]	**119,142**	84,372	75,900	113,668	171,654	192,515	145,110	110,687
Free cash flow[1]	**34,703**	16,415	16,259	65,288	116,681	151,792	96,479	86,960
EBITDA[1]	**123,054**	85,201	76,079	125,651	174,328	194,038	145,463	110,087
Net cash / (debt) at period end[1]	**83,097**	63,548	66,956	175,098	88,615	14,382	(42,367)	(94,312)

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

Summarized consolidated balance sheet information is as follows:

USD Thousands	September 30, 2023	December 31, 2022
Non-current assets	1,226,851	1,041,051
Current assets	727,020	638,566
Total assets	**1,953,871**	1,679,617
Total non-current liabilities	748,732	564,381
Current liabilities	180,013	149,905
Total liabilities	**928,745**	714,286
Net assets	**1,025,126**	965,331
Working capital (including cash)	**547,007**	488,661

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 – September 30, 2023					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	124,468	77,045	46,148	19,318	–	**266,979**
NGLs	–	377	–	–	–	**377**
Gas	98	16,607	–	–	–	**16,705**
Net sales of oil and gas	**124,566**	**94,029**	**46,148**	**19,318**	–	**284,061**
Change in under/over lift position	–	–	–	4,349	–	**4,349**
Royalties	(19,712)	(12,261)	–	(1,239)	–	**(33,212)**
Hedging settlement	(985)	2,839	–	–	–	**1,854**
Other operating revenue	–	–	–	229	85	**314**
Revenue	**103,869**	**84,607**	**46,148**	**22,657**	85	**257,366**
Operating costs	(22,466)	(40,330)	(11,062)	(9,004)	–	**(82,862)**
Cost of blending	(32,858)	(6,978)	–	–	–	**(39,836)**
Change in inventory position	(151)	466	(8,478)	96	–	**(8,067)**
Depletion and decommissioning costs	(9,687)	(14,906)	(3,438)	(3,656)	–	**(31,687)**
Depreciation of other tangible fixed assets	–	–	(1,509)	–	–	**(1,509)**
Exploration and business development costs	–	–	–	–	24	**24**
Gross profit/(loss)	**38,707**	**22,859**	**21,661**	**10,093**	**109**	**93,429**

	Three months ended – September 30, 2022					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	123,542	64,083	71,138	21,884	–	280,647
NGLs	–	170	–	–	–	170
Gas	173	37,224	–	–	–	37,397
Net sales of oil and gas	123,715	101,477	71,138	21,884	–	318,214
Change in under/over lift position	–	–	–	534	–	534
Royalties	(13,542)	(12,985)	–	(1,409)	–	(27,936)
Hedging settlement	6,564	1,832	–	–	–	8,396
Other operating revenue	–	10	–	143	–	153
Revenue	116,737	90,334	71,138	21,152	–	299,361
Operating costs	(23,538)	(29,867)	(9,249)	(8,349)	–	(71,003)
Cost of blending	(35,563)	(6,795)	–	–	–	(42,358)
Change in inventory position	(219)	(749)	(8,488)	162	–	(9,294)
Depletion and decommissioning costs	(8,488)	(10,965)	(9,618)	(2,868)	–	(31,939)
Depreciation of other tangible fixed assets	–	–	(2,991)	–	–	(2,991)
Exploration and business development costs	–	–	–	–	(1,287)	(1,287)
Gross profit/(loss)	48,929	41,958	40,792	10,097	(1,287)	140,489

	Nine months ended – September 30, 2023					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	324,963	196,420	85,924	52,476	–	**659,783**
NGLs	–	845	–	–	–	**845**
Gas	255	52,309	–	–	–	**52,564**
Net sales of oil and gas	**325,218**	**249,574**	**85,924**	**52,476**	–	**713,192**
Change in under/over lift position	–	–	–	8,842	–	**8,842**
Royalties	(45,495)	(30,218)	–	(3,575)	–	**(79,288)**
Hedging settlement	(1,620)	13,589	–	–	–	**11,969**
Other operating revenue	–	7	–	639	85	**731**
Revenue	**278,103**	**232,952**	**85,924**	**58,382**	85	**655,446**
Operating costs	(70,949)	(116,527)	(26,509)	(24,609)	–	**(238,594)**
Cost of blending	(108,603)	(19,920)	–	–	–	**(128,523)**
Change in inventory position	190	79	2,141	(182)	–	**2,228**
Depletion and decommissioning costs[1]	(15,804)	(30,481)	(14,818)	(10,385)	–	**(71,488)**
Depreciation of other tangible fixed assets	–	–	(6,503)	–	–	**(6,503)**
Exploration and business development costs	–	(834)	–	(9)	(1,164)	**(2,007)**
Gross profit/(loss)	**82,937**	**65,269**	**40,235**	**23,197**	**(1,079)**	**210,559**

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

	Nine months ended – September 30, 2022					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	412,222	212,295	139,782	83,284	–	847,583
NGLs	–	632	–	–	–	632
Gas	826	118,016	–	–	–	118,842
Net sales of oil and gas	413,048	330,943	139,782	83,284	–	967,057
Change in under/over lift position	–	–	–	(911)	–	(911)
Royalties	(49,347)	(37,514)	–	(4,796)	–	(91,657)
Hedging settlement	6,534	(6,994)	–	–	–	(460)
Other operating revenue	–	111	–	543	–	654
Revenue	370,235	286,546	139,782	78,120	–	874,683
Operating costs	(78,196)	(82,610)	(25,657)	(26,688)	–	(213,151)
Cost of blending	(115,881)	(26,757)	–	–	–	(142,638)
Change in inventory position	1,272	193	2,195	774	–	4,434
Depletion and decommissioning costs	(24,841)	(31,389)	(26,020)	(9,471)	–	(91,721)
Depreciation of other tangible fixed assets	–	–	(8,092)	–	–	(8,092)
Exploration and business development costs	97	–	–	–	(2,314)	(2,217)
Gross profit/(loss)	152,686	145,983	82,208	42,735	(2,314)	421,298

Three and nine months ended September 30, 2023, Review

Revenue
Total revenue amounted to USD 257,366 thousand for Q3 2023, compared to USD 299,361 thousand for Q3 2022 and USD 655,466 thousand for the first nine months of 2023 compared to USD 874,683 thousand for the first nine months of 2022 and is analyzed as follows:

USD Thousands	Three months ended September 30		Nine months ended September 30	
	2023	2022	**2023**	2022
Crude oil sales	266,979	280,647	659,783	847,583
Gas and NGL sales	17,082	37,567	53,409	119,474
Change in under/overlift position	4,349	534	8,842	(911)
Royalties	(33,212)	(27,936)	(79,288)	(91,657)
Hedging settlement	1,854	8,396	11,969	(460)
Other operating revenue	314	153	731	654
Total revenue	**257,366**	299,361	**655,446**	874,683

The main components of total revenue for the three and nine months ended September 30, 2023, and September 30, 2022, respectively, are detailed below.

Crude oil sales

USD Thousands	Three months ended – September 30, 2023				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	124,468	77,045	46,148	19,318	**266,979**
- Quantity sold in bbls	1,814,151	1,116,530	486,962	223,481	**3,641,124**
- Average price realized USD per bbl	68.61	69.00	94.77	86.44	**73.32**

USD Thousands	Three months ended – September 30, 2022				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	123,542	64,083	71,138	21,884	280,647
- Quantity sold in bbls	1,743,766	887,736	614,329	217,875	3,463,706
- Average price realized USD per bbl	70.85	72.19	115.80	100.44	81.03

Crude oil revenue was 5% lower in Q3 2023 compared to Q3 2022 mainly due to lower oil prices. Canadian - Southern Assets sales volumes are 26% higher in Q3 2023 compared to Q3 2022 as a result of the Cor4 acquisition in Q1 2023.

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 Q3 2023, WTI averaged USD 82 per bbl compared to USD 92 per bbl for Q3 2022 and the average discount to WCS used in our pricing formula was USD 13 per bbl compared to USD 20 per bbl for Q3 2022.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices. There were two cargo liftings in Malaysia during Q3 2023 and two cargo liftings in Q3 2022. Produced unsold oil barrels from Bertam at the end of Q3 2023 amounted to 146,000 barrels, see Change in Inventory Position section below. The average Dated Brent crude oil price was USD 87 per bbl for Q3 2023 compared to USD 101 per bbl for the comparative period.

USD Thousands	Nine months ended – September, 2023				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	324,963	196,420	85,924	52,476	**659,783**
- Quantity sold in bbls	5,525,405	3,248,704	932,654	640,586	**10,347,349**
- Average price realized USD per bbl	58.81	60.46	92.13	81.92	**63.76**

USD Thousands	Nine months ended – September, 2022				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	412,222	212,295	139,782	83,284	847,583
- Quantity sold in bbls	5,055,871	2,591,889	1,173,230	813,116	9,634,106
- Average price realized USD per bbl	81.53	81.91	119.14	102.43	87.98

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 22% during the first nine months of 2023 compared to the first nine months of 2022 mainly due to lower oil prices. Canadian - Southern Assets sales volumes were 25% higher in the first nine months 2023 compared to the first nine months of 2022 as a result of the Cor4 acquisition in Q1 2023.

The Canadian realized sales price is based on the WCS price which trades at a discount to WTI. For the first nine months of 2023, WTI averaged USD 77 per bbl compared to USD 98 per bbl for the comparative period and the average discount to WCS used in our pricing formula was USD 18 per bbl compared to USD 16 per bbl for the comparative period.

The realized sales price for Malaysia and France is based on Brent crude oil prices and the average market Brent crude oil price was USD 82 per bbl for the first nine months of 2023 compared to USD 106 per bbl for the comparative period.

Gas and NGL sales

	Three months ended – September 30, 2023		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	16,984	98	**17,082**
- Quantity sold in Mcf	8,541,601	55,178	**8,596,779**
- Average price realized USD per Mcf	1.99	1.77	**1.99**

	Three months ended – September 30, 2022		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	37,394	173	37,567
- Quantity sold in Mcf	8,478,728	58,742	8,537,470
- Average price realized USD per Mcf	4.41	2.95	4.40

Gas and NGL sales revenue was 55% lower for Q3 2023 compared to Q3 2022 mainly due to the lower achieved gas price. IPC's achieved gas price is based on AECO pricing plus a premium. For Q3 2023, IPC realized an average price of CAD 2.62 per Mcf compared to AECO average pricing of CAD 2.56 per Mcf.

	Nine months ended – September 30, 2023		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	53,154	255	**53,409**
- Quantity sold in Mcf	24,635,855	149,847	**24,785,702**
- Average price realized USD per Mcf	2.16	1.70	**2.15**

	Nine months ended – September 30, 2022		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	118,648	826	119,474
- Quantity sold in Mcf	24,443,007	194,580	24,637,587
- Average price realized USD per Mcf	4.85	4.24	4.85

Gas and NGL sales revenue was 55% lower for the first nine months of 2023 compared to the first nine months of 2022 mainly due to the lower achieved gas price.

IPC's achieved gas price is based on AECO pricing plus a premium. For the first nine months of 2023, IPC realized an average price of CAD 2.86 per Mcf compared to AECO average pricing of CAD 2.72 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 first nine months of 2023 amounted to a gain of USD 11,969 thousand and consisted of a gain of USD 14,357 thousand on the gas contracts and a loss of USD 2,388 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 130,765 thousand for Q3 2023 compared to USD 122,655 thousand for Q3 2022 and USD 364,889 thousand for the first nine months of 2023 compared to USD 351,355 thousand for the comparative period, and is analyzed as follows:

	Three months ended – September 30, 2023					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	40,330	22,466	14,349	9,004	(3,287)	**82,862**
USD/boe[2]	15.46	15.19	53.25	34.64	n/a	**17.95**
Cost of blending	6,978	32,858	–	–	–	**39,836**
Change in inventory position	(466)	151	8,478	(96)	–	**8,067**
Production costs	**46,842**	**55,475**	**22,827**	**8,908**	**(3,287)**	**130,765**

	Three months ended – September 30, 2022					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	29,867	23,538	13,389	8,349	(4,140)	71,003
USD/boe[2]	12.68	16.08	25.07	33.75	n/a	15.44
Cost of blending	6,795	35,563	–	–	–	42,358
Change in inventory position	749	219	8,488	(162)	–	9,294
Production costs	37,411	59,320	21,877	8,187	(4,140)	122,655

USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
	Nine months ended – September 30, 2023					
Operating costs[1]	116,527	70,949	37,941	24,609	(11,432)	**238,594**
USD/boe[2]	15.75	16.31	32.67	33.14	n/a	**17.42**
Cost of blending	19,920	108,603	–	–	–	**128,523**
Change in inventory position	(79)	(190)	(2,141)	182	–	**(2,228)**
Production costs	**136,368**	**179,362**	**35,800**	**24,791**	**(11,432)**	**364,889**

USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
	Nine months ended – September 30, 2022					
Operating costs[1]	82,610	78,196	37,942	26,688	(12,285)	213,151
USD/boe[2]	12.20	18.46	26.26	35.04	n/a	16.13
Cost of blending	26,757	115,881	–	–	–	142,638
Change in inventory position	(193)	(1,272)	(2,195)	(774)	–	(4,434)
Production costs	109,174	192,805	35,747	25,914	(12,285)	351,355

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

[2] *USD/boe in the tables above is calculated by dividing the cost by the production volume for each country for the period and 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 41.06 and USD 17.32 for Q3 2023 and Q3 2022 respectively and USD 22.83 and USD 17.76 for the nine months ended September 30, 2023 and September 30, 2022, respectively.*

Operating costs
Operating costs amounted to USD 82,862 thousand for Q3 2023 compared to USD 71,003 thousand for Q3 2022 and USD 238,594 thousand for the first nine months of 2023 compared to USD 213,151 for the first nine months of 2022. The increase in costs in Q3 2023 compared to Q3 2022 is due mainly to increased production and activity levels. Operating costs per boe amounted to USD 17.95 per boe in Q3 2023 in line with guidance for the quarter and compared with USD 15.44 per boe in Q3 2022. Operating costs per boe for Malaysia is higher in Q3 2023 compared with Q3 2022 as a result of the lower production due to two producing wells offline and the September shutdown. The full year CMD guidance of USD 17.5 to 18 per boe remains unchanged.

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 39,836 thousand for Q3 2023 compared to USD 42,358 thousand for Q3 2022 and USD 128,523 thousand for the first nine months of 2023 compared to USD 142,638 for the comparative period. The decrease versus the comparative period is largely attributable to lower commodity pricing reflected in the cost of diluent.

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 Q3 2023, IPC had crude entitlement of 146,000 barrels of oil on the FPSO Bertam facility being crude produced but not yet sold . Two crude cargo were lifted from Bertam in July and September 2023 with the next lifting scheduled for November 2023.

Depletion and decommissioning costs
The total depletion of oil and gas properties amounted to USD 31,687 thousand for Q3 2023 compared to USD 31,939 thousand for Q3 2022 and USD 71,488 thousand for the first nine months of 2023 (including an adjustment for accelerated decommissioning activities amounting to USD 24,055 thousand) compared to USD 91,721 thousand for the first nine months of 2022. The depletion charge is analyzed in the following tables:

	Three months ended – September 30, 2023				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	14,906	9,687	3,438	3,656	**31,687**
USD per boe	5.71	6.55	12.76	14.07	**6.86**

	Three months ended – September 30, 2022				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	10,964	8,488	9,618	2,868	31,939
USD per boe	4.66	5.80	18.01	11.59	6.94

	Nine months ended – September 30, 2023				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands[1]	42,225	28,115	14,818	10,385	**95,543**
USD per boe[2]	5.70	6.46	12.76	13.99	**6.96**

	Nine months ended – September 30, 2022				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	31,389	24,841	26,020	9,471	91,721
USD per boe	4.63	5.87	18.01	12.43	6.94

[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 1,509 thousand for Q3 2023 compared to USD 2,991 thousand for Q3 2022 and USD 6,503 thousand for the first nine months of 2023 compared to USD 8,092 thousand for the first nine months of 2022. 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 credit of USD 24 thousand for Q3 2023 and a cost of USD 2,007 thousand for the first nine months of 2023 including Cor4 acquisition related costs amounting to USD 834 thousand.

Sale of assets
Sale of assets amounted to USD 11,912 thousand for Q3 2023 and represents the sale of John Lake properties in Canada in September 2023 with gross proceeds of CAD 19.4 million (USD 14.4 million) and a net accounting gain on disposal of CAD 16.0 million (USD 11.9 million). IPC completed the disposal of a further non-core property, Fishing Lake, in Canada for a consideration of CAD 3.5 million, effective August 1, 2023. As this transaction completed in October 2023, the sale will be recognized in the fourth quarter of 2023.

Net financial items
Net financial items amounted to a charge of USD 4,257 thousand for Q3 2023, compared to a charge of USD 9,225 thousand for Q3 2022 and a charge of USD 16,227 thousand for the first nine months of 2023 compared to a charge of USD 31,129 thousand for the first nine months of 2022, and included a non-cash net foreign exchange loss of USD 1,493 thousand for the first nine months of 2023 compared to a net foreign exchange loss of USD 5,945 thousand for the comparative period. The foreign exchange movements during the first nine months of 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 5,111 thousand for Q3 2023, compared to USD 7,323 thousand for Q3 2022 and a charge of USD 14,734 thousand for the first nine months of 2023 compared to a charge of 25,184 thousand for the comparative period.

The interest expense amounted to USD 5,787 thousand for Q3 2023, compared to USD 5,686 thousand for the comparative period in 2022 and USD 16,591 thousand for the first nine months of 2023 compared to USD 15,201 thousand for the first nine months of 2022 and mainly related to the bond interest. Interest income generated on cash balances held in Q3 2023 amounted to USD 4,979 thousand and USD 14,238 thousand for the first nine months of 2023 and is higher than the comparative period due mainly to higher interest rates and higher cash balances.

The unwinding of the asset retirement obligation discount rate amounted to USD 3,479 thousand for Q3 2023, compared to USD 2,667 thousand for Q3 2022 and USD 10,021 thousand for the first nine months of 2023 compared to USD 8,156 thousand for the first nine months of 2022.

Income tax
The corporate income tax amounted to a charge of USD 25,451 thousand for Q3 2023, compared to a charge of USD 37,977 thousand for Q3 2022 and a charge of USD 50,671 thousand for the first nine months of 2023 compared to a charge of USD 102,927 for the comparative period.

The current income tax charge amounted to USD 7,459 thousand in Q3 2023 and USD 16,045 thousand during the first nine months of 2023 and mainly related to France and Malaysia. No corporate income tax was payable in Canada in respect of the first nine months of 2023 due to the usage of historical tax pools.

Capital Expenditure

Development and exploration and evaluation expenditure incurred during the first nine months of 2023 was as follows:

USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Development	12,664	154,200	1,803	15,228	**183,895**
Exploration and evaluation	–	–	–	9	**9**
	12,664	154,200	1,803	15,237	**183,904**

Capital expenditure of USD 183,895 thousand was mainly spent in Canada on the Blackrod Phase 1 Development project and on the Pad L completion at Onion Lake Thermal and in France on the drilling of the Villeperdue West oil wells.

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 first nine months of 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 26,697 thousand as at September 30, 2023, which included USD 24,895 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated on a unit of production basis based 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 September 30, 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 further increased the Canadian RCF to 165 million. No cash amounts were drawn under the Canadian RCF as at September 30, 2023.

As at September 30, 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 September 30, 2023 was USD 10 million (EUR 9 million).

Total net cash as at September 30, 2023 amounted to USD 83 million.

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

The bond repayment obligations as at September 30, 2023, are classified as non-current as there are no mandatory repayments within the next twelve months.

An amount of USD 3.4 million (EUR 3.2 million) drawn under the France Facility as at September 30, 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 September 30, 2023.

Cash and cash equivalents held amounted to USD 543 million as at September 30, 2023 of which USD 5.2 million was restricted.

Working Capital
As at September 30, 2023, the Group had a net working capital balance including cash of USD 547,007 thousand compared to USD 488,661 thousand as at December 31, 2022. The difference as at September 30, 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 September 30		Nine months ended September 30	
USD Thousands	2023	2022	2023	2022
Revenue	257,366	299,361	655,446	874,683
Production costs	(130,765)	(122,655)	(364,889)	(351,355)
Current tax	(7,459)	(5,052)	(16,045)	(14,049)
Operating cash flow	**119,142**	171,654	**274,512**	509,279

The operating cash flow for the first nine months of 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 279,414 thousand.

Free cash flow

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

	Three months ended September 30		Nine months ended September 30	
USD Thousands	2023	2022	2023	2022
Operating cash flow - see above	119,142	171,654	274,512	509,279
Capital expenditures	(76,844)	(46,729)	(183,904)	(114,870)
Abandonment and farm-in expenditures[1]	(2,755)	(1,517)	(7,683)	(5,877)
General, administration and depreciation expenses before depreciation[2]	(3,547)	(2,378)	(11,124)	(9,499)
Cash financial items[3]	(1,293)	(4,349)	(3,593)	(14,079)
Free cash flow	**34,703**	**116,681**	**68,208**	364,954

[1] *See note 17 to the Financial Statements*
[2] *Depreciation is not specifically disclosed in the Financial Statements*
[3] *See notes 4 and 5 to the Financial Statements.*

The free cash flow for the first nine months of 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 67,379 thousand.

EBITDA

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

	Three months ended September 30		Nine months ended September 30	
USD Thousands	2023	2022	2023	2022
Net result	71,681	90,503	143,269	276,542
Net financial items	4,257	9,225	16,227	31,129
Income tax	25,451	37,977	50,671	102,927
Depletion	31,687	31,939	71,488	91,721
Depreciation of other tangible fixed assets	1,509	2,991	6,503	8,092
Exploration and business development costs	(24)	1,287	2,007	2,217
Depreciation included in general, administration and depreciation expenses[1]	405	406	1,180	1,201
Sale of assets	(11,912)	–	(11,912)	–
EBITDA	**123,054**	174,328	**279,433**	513,829

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

The EBITDA for the first nine months of 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 284,334 thousand.

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

	Three months ended September 30		Nine months ended September 30	
USD Thousands	2023	2022	2023	2022
Production costs	130,765	122,655	364,889	351,355
Cost of blending	(39,836)	(42,358)	(128,523)	(142,638)
Change in inventory position	(8,067)	(9,294)	2,228	4,434
Operating costs	**82,862**	71,003	**238,594**	213,151

The operating costs for the first nine months of 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 245,395 thousand.

Net cash
The following table sets out how net cash is calculated:

USD Thousands	September 30, 2023	December 31, 2022
Bank loans	(9,511)	(12,142)
Bonds[1]	(450,000)	(300,000)
Cash and cash equivalents	542,608	487,240
Net cash	**83,097**	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.

As at September 30, 2023, following the cancellation during the first nine months of 2023 of a further 7,638,779 common shares repurchased under the NCIB, IPC had a total of 129,189,220 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 31.5% of the outstanding common shares as at September 30, 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 4,446,239 IPC Share Unit Plan awards outstanding as at October 31, 2023 (324,240 awards granted in March 2021, 1,716,000 awards granted in May 2021, 4,333 awards granted in January 2022, 1,247,998 awards granted in March 2022, 2,391 awards granted in July 2022, 2,072 awards granted in January 2023, 1,145,961 awards granted in March 2023 and 3,244 awards granted in July 2023).

Contractual Obligations and Commitments

In Canada, an oil pipeline from the Onion Lake Thermal field to a gathering system has been built by a third party for the exclusive use of IPC. The initial investment in the pipeline was met by the pipeline owner and is to be recovered through an agreed tariff charged to IPC. IPC has committed to a firm transportation service for 15 years from commencement of service in April 2022, with total remaining tariffs committed as shown in the table below:

	2023	2024	2025	2026	2027	Thereafter
Transportation service (MCAD)	6.9	28.0	28.4	29.0	28.2	275.2

In Malaysia, IPC has an obligation to make payments towards historic costs on Block PM307 payable on the Bertam field for every 1 MMboe gross that the field produces above 10 MMboe gross. The estimated liability based on current 2P reserves and which is capped at cumulative production of 27.5 MMboe gross, has been provided for in the Group's Balance Sheet – see Note 17 Provisions of the Financial Statements.

Critical Accounting Policies and Estimates

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

Transactions with Related Parties

During Q3 2023, the Group paid USD 273 thousand to the Lundin Foundation in respect of sustainability advisory services provided to the Group.

During Q3 2023, the Group paid USD 685 thousand to Orrön Energy (formerly Lundin Energy) in respect of office space rental for 2023. During Q3 2023, Orrön Energy paid USD 641 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 September 30, 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 gas price sale financial hedges outstanding as at September 30, 2023, which are summarized as follows:

Period	Volume (Gigajoules (GJ) per day)	Type	Average Pricing
October 1, 2023 – October 31, 2023	35,000[1]	AECO Swap	CAD 3.95/GJ

[1] *Equivalent to 33,700 Mcf per day at CAD 4.10/Mcf.*

The Group had oil price sale financial hedges outstanding as at September 30, 2023 which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
October 1, 2023 - December 31, 2023	12,000	WCS/ARV Differential	USD -10.08/bbl
January 1, 2024 - December 31, 2024	17,700	WCS/WTI Differential	USD -15.03/bbl
January 1, 2024 - December 31, 2024	2,500	WTI Sale Swap	USD 81.16/bbl

The Group had condensate financial hedges outstanding as at September 30, 2023 which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
October 31, 2023 – March 31, 2024	3,000	C5/WTI Differential	USD -1.60/bbl

The Group had electricity financial hedges outstanding as at September 30, 2023 which are summarized as follows:

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

In October 2022, IPC entered into currency hedge swaps for 2023 to buy CAD 15 million per month, sell USD at an average exchange rate of 1.36 and to buy EUR 3 million per month, sell USD at an average exchange rate of 1.00. In June 2023, IPC entered into currency hedge swaps for 2023 to buy MYR 13 million per month, sell USD at an average exchange rate of 4.54. This is to partially fund forecast operational expenditures in those currencies in Canada, France and Malaysia respectively.

In respect of the forecast Blackrod development capital expenditure in Canada, IPC had foreign currency hedge swaps outstanding at September 30, 2023 summarized as follows:

Period	Total Amount to Buy	Type	Average CAD/USD Rate
October 2023 - March 2025	Buy MCAD 436	Forward Swap	1.31

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 13,858 thousand as at September 30, 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 October 2022, IPC entered into currency hedge swaps for 2023 to buy CAD 15 million per month, sell USD at an average exchange rate of 1.36 and to buy EUR 3 million per month, sell USD at an average exchange rate of 1.00. In June 2023, IPC entered into currency hedge swaps for the second six months of 2023 to buy MYR 13 million per month, sell USD at an average exchange rate of 4.54. This is to partially fund operational expenditures in those currencies in Canada, France and Malaysia respectively.

The above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. The currency hedge swaps had a negative fair value of USD 8,857 thousand as at September 30, 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 AND UNCERTAINTIES

IPC is engaged in the exploration, development and production of oil and gas and is exposed to various operational, environmental, market and financial risks and uncertainties. For further information and discussion of these risks and uncertainties, please see IPC's Annual Information Form for the year ended December 31, 2022 ("AIF") available on SEDAR+ at www.sedarplus.ca or on IPC's website at www.international-petroleum.com. See also "Cautionary Statement Regarding Forward Looking Information" and "Reserves and Resource Advisory" in this MD&A.

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 nine month period ended September 30, 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:
- 2023 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;
- IPC's continued access to its existing credit facilities, including current financial headroom, on terms acceptable to the Corporation;
- The ability to fully fund future expenditures from cash flows and current borrowing capacity;

- IPC's ability to maintain operations, production and business in light of 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 intention and ability to continue to implement our strategies to build long-term shareholder value;
- The ability of IPC's portfolio of assets to provide a solid foundation for organic and inorganic growth;
- The continued facility uptime and reservoir performance in IPC's areas of operation;
- Future development potential of the Suffield and Ferguson operations in Canada, including the timing and success of future oil and gas drilling and optimisation programs;
- Development of the Blackrod project in Canada, including estimates of resource volumes, future production, timing, regulatory approvals, third party commercial arrangements, breakeven oil prices and net present values;
- Current and future drilling pad production 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 ability of IPC to acquire further common shares under the NCIB, including the timing of any such purchases;
- The ability of IPC to renew the NCIB and the number of common shares which may be purchased under a renewed NCIB;
- 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 ability to identify and complete future acquisitions; and
- Future drilling and other exploration and development activities.

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

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

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

These include, but are not limited to:
- 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 2023 to 2027 and 2028 to 2032. Assumptions include average net production of approximately 50 Mboepd over the period of 2023 to 2027, average net production of approximately 65 Mboepd over the period of 2028 to 2032, 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 AIF. IPC's current business plans and assumptions, and the business environment, are subject to change. Actual results may differ materially from forward-looking estimates and forecasts.

Additional information on these and other factors that could affect IPC, or its operations or financial results, are included in the Financial Statements, the Corporation's Annual Information Form (AIF) for the year ended December 31, 2022, (See "Cautionary Statement Regarding Forward-Looking Information", "Reserves and Resources Advisory" and "Risk and Uncertainties") and other reports on file with applicable securities regulatory authorities, including previous financial reports, management's discussion and analysis and material change reports, which may be accessed through the SEDAR+ website (www.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 (other than the assets acquired in the Cor4 acquisition) are effective as of December 31, 2022, 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, 2022 price forecasts.

Reserve estimates and estimates of future net revenue in respect of IPC's oil and gas assets acquired in the Cor4 acquisition are effective as of December 31, 2022, and have been audited by GLJ Ltd. (GLJ), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2022, 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, 2022, 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, 2022 price forecasts.

The price forecasts used in the Sproule, GLJ and ERCE reports, are available on the website of Sproule (sproule. com) and are contained in the AIF. These price forecasts are as at December 31, 2022 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 487 MMboe as at December 31, 2022 (including 15.9 MMboe acquired in the Cor4 acquisition), by the mid-point of the 2023 CMD production guidance of 48,000 to 50,000 boepd.

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

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

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

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

There are three classifications of contingent resources: low estimate, best estimate and high estimate. Best estimate is a classification of estimated resources described in the COGE Handbook as 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 associated with the resolution of all contingencies required for the re-classification of the contingent resources as reserves. Therefore   volumes of contingent resources do not reflect the risking (or adjustment) of such volumes based on the chance of development of such resources.

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

2P reserves and contingent resources included in the reports prepared by Sproule, GLJ 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.

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				
September 30, 2023	25.8	7.1	103.4 MMcf (17.3 Mboe)	50.2
September 30, 2022	22.7	10.4	101.5 MMcf (16.9 Mboe)	50.0
Nine months ended				
September 30, 2023	25.9	8.6	102.4 MMcf (17.1 Mboe)	51.6
September 30, 2022	22.6	9.4	98.1 MMcf (16.4 Mboe)	48.4
Year ended December 31, 2022				
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 48,000 to 50,000 boepd for 2023. IPC estimates that approximately 51% of that production will be comprised of heavy oil, approximately 16% will be comprised of light and medium crude oil and approximately 33% will be comprised of conventional natural gas.

OTHER SUPPLEMENTARY INFORMATION

Abbreviations

CAD	Canadian dollar
MCAD	Million Canadian dollar
EUR	Euro
USD	US dollar
MUSD	Million US dollar
MYR	Malaysian Ringgit
FPSO	Floating Production Storage and Offloading (facility)

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
	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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