Q2

International Petroleum Corporation

Management's Discussion and Analysis

For the three and six months ended June 30, 2023

International Petroleum Corp.

Contents

Non-IFRS Measures
References are made in this MD&A to "operating cash flow" (OCF), "free cash flow" (FCF), "Earnings Before Interest, Tax, Depreciation and Amortization" (EBITDA), "operating costs" and "net debt"/"net cash" which are not generally accepted accounting measures under 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 21.

Forward-Looking Statements
Certain statements contained in this MD&A constitute "forward-looking statements" or "forward-looking information" (within the meaning of applicable securities legislation). Such statements and information (together, "forward-looking statements") relate to future events, including the Corporation's future performance, business prospects or opportunities. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, forecasts, guidance, budgets, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "forecast", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", "budget" and similar expressions) are not statements of historical fact and may be "forward-looking statements". Although IPC believes that the expectations and assumptions on which such forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because IPC can give no assurances that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. For additional information underlying forward-looking statements, refer to the "Cautionary Statement Regarding Forward-Looking Information" on page 26.

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 August 1, 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 six months ended June 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 2600, 595 Burrard Street, P.O. Box 49314, Vancouver, BC V7X 1L3, Canada and its business address is Suite 2000, 885 West Georgia Street, Vancouver, BC V6C 3E8, Canada.

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

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

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

	June 30, 2023		June 30, 2022		December 31, 2022	
	Average	Period end	Average	Period end	Average	Year end
1 EUR equals USD	1.0811	1.0866	1.0940	1.0387	1.0539	1.0666
1 USD equals CAD	1.3477	1.3266	1.2712	1.2925	1.3015	1.3538
1 USD equals MYR	4.4564	4.6675	4.2715	4.4075	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. See also "Cor4 Acquisition" below. 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. See also "Operations Overview – Production" and "Non-IFRS Measures" below.

HIGHLIGHTS

Q2 2023 Business Highlights

- Strong quarterly average net production of approximately 51,800 barrels of oil equivalent (boe) per day (boepd) for the second quarter of 2023 (49% heavy crude oil, 18% light and medium crude oil and 33% natural gas).[1]
- Blackrod Phase 1 engineering, procurement and construction (EPC) contract for the Central Processing Facility (CPF) signed in Canada.
- Successfully integrated the assets acquired in the Cor4 acquisition in Canada.[1][2]
- 1.57 million common shares purchased and cancelled during Q2 2023 under IPC's normal course issuer bid (NCIB).
- Published IPC's fourth annual Sustainability Report (2022) and first standalone TCFD Report.

Q2 2023 Financial Highlights

- Operating costs per boe of USD 17.0 for Q2 2023.[1][3]
- Operating cash flow (OCF) generation for Q2 2023 amounted to MUSD 84.[1][3]
- Capital and decommissioning expenditures of MUSD 62 for Q2 2023.[1]
- Free cash flow (FCF) generation for Q2 2023 amounted to MUSD 16 (MUSD 65 pre Blackrod funding).[1][3]
- Net cash of MUSD 64 as at June 30, 2023.[3]
- Net result of MUSD 32 for Q2 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 expected to exceed the upper end of 48,000 to 50,000 boepd guidance range.[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 320 to 390 (assuming Brent USD 75 to 90 per barrel for the remainder of 2023) from previous guidance of MUSD 250 to 495 (assuming Brent USD 70 to 100 per barrel).[1][3]
- Full year 2023 capital and decommissioning expenditures guidance forecast unchanged at MUSD 365, including MUSD 287 relating to Phase 1 of the Blackrod project.[1]
- Full year 2023 FCF forecast range tightened to between MUSD -65 to 5 (assuming Brent USD 75 to 90 per barrel for the remainder of 2023) from previous guidance of MUSD -145 to 105 (assuming Brent USD 70 to 100 per barrel), after taking into account MUSD 287 of proposed 2023 Blackrod capital expenditures.[1][3][4]

	Three months ended June 30		Six months ended June 30	
USD Thousands	2023	2022	2023	2022
Revenue	**205,564**	315,540	**398,080**	575,322
Gross profit	**52,747**	161,709	**117,130**	280,809
Net result	**32,025**	105,217	**71,588**	186,039
Operating cash flow[3]	**84,372**	192,515	**160,272**	337,625
Free cash flow[3]	**16,415**	151,792	**32,674**	248,273
EBITDA[3]	**85,201**	194,038	**161,280**	339,501
Net Cash[3]	**63,548**	14,382	**63,548**	14,382

OPERATIONS REVIEW

Business Overview

The pull back that we saw in oil and gas prices during the first quarter of 2023 stabilised during the second quarter with Brent prices averaging USD 78 per barrel compared with just over USD 80 per barrel during the first quarter. Demand concerns continue to weigh on oil markets, as rising interest rates aimed at taming high inflation, raise recessionary fears. The surprise production cuts announced by OPEC+ in early April were followed up with additional 'voluntary cuts' implemented by Saudi Arabia through July and August, a fourth pre-emptive move by the group, aimed at ensuring recent oil price weakness is not sustained. Inventory levels have moved back below the five-year average levels and market observers expect a deficit in the oil market for the remainder of 2023. Strategic Petroleum Reserve (SPR) releases in the US have come to an end and up to 12 million barrels are expected to be repurchased to begin refilling the SPR by the end of the year. The physical market certainly seems tighter than that priced in by the financial markets and many commentators believe oil prices will increase from the recent market trading range. We saw Brent prices trade in July occasionally over the USD 80 per barrel mark which had not been the case since April.

The second quarter 2023 West Texas Intermediate (WTI) to Western Canadian Select (WCS) crude price differentials averaged around USD 15 per barrel, USD 10 per barrel tighter than first quarter levels and USD 5 per barrel tighter than our base case 2023 market guidance. Those market factors that have driven differentials wider such as the SPR releases, higher natural gas prices and refinery outages have now turned to provide more favourable tailwinds to the WTI/WCS differentials going forward. In addition, the expansion of the Trans Mountain pipeline (590,000 barrels per day of extra capacity linking Edmonton to the port of Vancouver) due in service in Q1 2024, 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) is expected to provide stronger support to WTI/WCS differentials going forward. Current WTI/WCS differentials have tightened to less than USD 15 per barrel for the remainder of 2023 and the whole of 2024 as a result of these favourable market developments. IPC has taken the opportunity to lock in a WTI/WCS differential of approximately USD 14 per barrel for close to 50% of our forecast 2024 Canadian WCS forecast production volumes. Leveraging on the traditional lower costs for condensate in the summer season, we also locked in approximately 50%, or 3,000 barrels per day, of our Q3 2023 and Q1 2024 average daily condensate purchase forecast at WTI minus USD 1.60 per barrel.

Gas market prices remained below our 2023 base case price guidance of CAD 3.50 per Mcf during the second quarter. IPC's average realised gas price was CAD 2.44 per Mcf during the quarter, compared with CAD 3.60 per Mcf during the first quarter of 2023. The recent weakness seen in North American gas prices was to a large extent driven by a much milder winter in Europe and the resulting reduced demand for US LNG. IPC was partially protected by 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.

Second Quarter 2023 Highlights and Full Year 2023 Guidance

During the second quarter of 2023, our assets delivered average net production of 51,800 boepd, above our high-end guidance for the second quarter in succession. This was made possible by the very high uptime performance across all our assets as well as the production contribution from our recent Cor4 acquisition in Canada and our successful four well drilling program in France. Given the very strong first half performance averaging around 52,000 boepd, full year 2023 average net production is now expected to exceed the upper end of the guidance range of 48,000 to 50,000 boepd.(1)

Our operating costs per boe for the second quarter of 2023 were USD 17.0, 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 second quarter of 2023 was USD 84 million, ahead of guidance as a result of the strong production performance and tighter WCS/WTI differentials. Full year 2023 OCF guidance of USD 250 to 495 million (assuming Brent USD 70 to 100 per barrel) is tightened to USD 320 to 390 million (assuming Brent USD 75 to 90 per barrel for the remainder of 2023).(1)(3)

Full year 2023 capital and decommissioning expenditure forecast of USD 365 million is unchanged.(1)

Free cash flow (FCF) generation was USD 16 million (USD 65 million pre Blackrod funding) during the second quarter of 2023. Full year 2023 FCF guidance of USD -145 to 105 million (assumed Brent USD 70 to 100 per barrel) is tightened to USD -65 to 5 million (assuming Brent USD 75 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 second quarter of 2023, IPC's net cash position of USD 67 million was reduced to USD 64 million, largely driven by the funding of USD 14 million for the continuing share repurchase program (NCIB) and other working capital movements.(3) Gross cash on the balance sheet as at June 30, 2023 amounts to USD 374 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, IPC's CAD 150 million Canadian Revolving Credit Facility (RCF) remains undrawn.

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 (including inflation and contingencies). 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 second 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 with cost levels and schedule in line with expectation. This contract provides a high degree of certainty for the largely fixed price element of the Phase 1 development capital expenditure which represents close to 65% of the overall Phase 1 capital expenditure budget to first oil. In addition, IPC has decided to lock in approximately 65% 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. Following these actions, more than 85% of the overall Phase 1 contingency (USD 110 million) remains available, a comfortable position to be in.

However, we believe it is prudent to retain the total Phase 1 capital expenditure estimate to first oil of USD 850 million given the early stages in the project's execution.

M&A
During Q2 2023, IPC successfully integrated the acquired Cor4 assets into the Group following completion of the 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 two wells on this exciting play in 2023.[(1)(2)]

2023 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 June 2023, IPC purchased and cancelled 7.1 million common shares under the NCIB. The average price of common shares purchased under the renewed NCIB during the period of December 2022 to June 2023 was SEK 101 / CAD 13.00 per share.

As at June 30, 2023, IPC had a total of 130,497,085 common shares issued and outstanding, with no common shares held in treasury.

2023 Capital Allocation Plans
IPC's capital allocation framework consists of distributing to shareholders a minimum of 40% of the FCF 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.

Despite the higher level of capital investment, and notwithstanding the capital allocation framework described above, IPC plans to continue to purchase and cancel common shares under the NCIB to the remaining limit as at June 30, 2023 of 2.2 million common shares by the end of November 2023, resulting in the anticipated cancellation of 7% of shares outstanding as of December 2022. We believe a combination of 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
IPC is committed to the continued advancement of our ESG practices in our 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 our commitment to operational excellence, our objective is to reduce risk and eliminate hazards to prevent the occurrence of accidents, ill health and environmental damage, as these are essential to the success of our operations. During the second quarter of 2023, IPC recorded no material safety or environmental incidents.

With respect to climate action, IPC has made notable progress over the past years. Our operational emission reduction efforts have resulted in a reduction of greater than 125,000 tonnes of CO_2e emissions since announcing IPC's climate strategy in 2020. IPC also signed its first virtual green power purchase agreement in 2022, contributing to a greater share of green energy in the Alberta electricity grid. In addition, IPC expanded carbon compensation efforts by offsetting a substantial share of the Group's 2022 CO_2e emissions, offsetting a total of 330,000 tonnes of CO_2e for the year 2022. These initiatives put IPC on track to achieve a 50% reduction in our net emissions intensity by 2025, and the company announced this year at the 2023 Capital Markets Day (CMD) a commitment to extend the reduced net emissions intensity level through 2027.

Sustainability Reporting and Climate disclosures

Alongside the publication of this second quarter 2023 financial report, IPC releases its fourth annual Sustainability Report and its first standalone TCFD Report. The Sustainability Report provides details on IPC's approach to sustainability, highlighting specific initiatives, and measurable goals and targets related to the key focus areas set by the Group. The TCFD Report aligns with the recommendations of the Task Force on Climate-Related Financial Disclosures (TCFD) and demonstrates our commitment to addressing climate-related risks and opportunities to our business.

The Sustainability Report and the TCFD Report, including additional information on IPC's efforts and performance across its sustainability priorities, are available on our website at www.international-petroleum.com.

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 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 July 28, 2023 (USD 1,190 million based on 95.92 SEK/share, 130.5 million IPC shares outstanding and exchange rate of 10.55 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.

With the acquisition of the Cor4 assets in the Suffield area and the growth investment associated with the sanction of the Blackrod Phase 1 development in 2023, IPC has set a reduced base business capital budget for the year. In Canada, the Blackrod Phase 1 development is progressing in line with schedule and budget. The major facility EPC contract has been signed, bringing a higher degree of cost certainty on a significant portion of the Phase 1 project. In the Suffield area, four out of the six planned Ellerslie play wells have been drilled by end Q2 2023. 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 second quarter 2023 was above the high end of our CMD guidance range at 51,800 boepd. In Canada, strong performance and high production uptimes have been supplemented by the newly drilled Suffield Ellerslie production wells which continue to exceed expectations. In addition, in Malaysia, the Bertam field continued to deliver excellent results with production well rate optimisation activity and high facility uptime during the quarter. In France, all four planned 2023 production wells are online and delivering ahead of forecast.

With exceptional operational performance during the first six 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 original CMD guidance of 48,000 to 50,000 boepd.

The production during Q2 2023 with comparatives is summarized below:

Production in Mboepd	Three months ended June 30		Six months ended June 30		Year ended December 31
	2023	2022	**2023**	2022	**2022**
Crude oil					
Canada – Northern Assets	15.1	15.6	15.5	15.2	15.6
Canada – Southern Assets[1]	11.7	8.5	12.2	8.5	8.7
Malaysia	4.8	5.9	4.9	5.0	5.3
France	2.8	2.8	2.7	2.8	2.7
Total crude oil production	**34.4**	32.8	**35.3**	31.5	32.3
Gas					
Canada – Northern Assets	0.4	0.1	0.4	0.1	0.1
Canada – Southern Assets	17.0	16.5	16.6	16.0	16.2
Total gas production	**17.4**	16.6	**17.0**	16.1	16.3
Total production	**51.8**	49.4	**52.3**	47.6	48.6
Quantity in MMboe	**4.72**	4.49	**9.47**	8.61	17.74

[1] *Includes production from the Cor4 assets in the Suffield area from January 1, 2023. 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 June 30		Six months ended June 30		Year ended December 31
		2023	2022	**2023**	2022	2022
- Oil Onion Lake Thermal	100%	12.9	12.8	13.1	12.3	12.7
- Oil Suffield Area[1]	100%	10.1	7.4	10.4	7.4	7.1
- Oil Ferguson	100%	1.6	1.1	1.8	1.1	1.6
- Oil Other	50-100%	2.2	2.8	2.4	2.9	2.9
- Gas[1]	~100%[2]	17.4	16.6	17.0	16.1	16.3
Canada		**44.2**	40.7	**44.7**	39.8	40.6

[1] *Including the production contribution of the Cor4 acquisition from the effective date of January 1, 2023. 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 Q2 2023 was ahead of guidance at 44,200 boepd. 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. Stable operations and high production uptimes have continued at the Onion Lake Thermal asset in Q2 2023.

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 has been 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.

As of the end of Q2 2023 at Blackrod, the Phase 1 development early ground works, detailed engineering, procurement of long lead items, and fabrication of facility modules has progressed in line with schedule and budget. The EPC contract for the major central processing facility (CPF) has been signed as planned with cost levels and schedule in line with expectation. This contract includes a significant fixed price element and provides a higher degree of spend certainty representing close to 65% of the Phase 1 development capital expenditure.

At Suffield, four out of six of the planned Ellerslie play wells in 2023 have been drilled and brought online with encouraging initial results.

At Onion Lake Thermal, the next sustaining production Pad L completions have progressed ahead of schedule with steam injection started up at the first two Pad L production wells in July. A period of steam injection optimisation and well conformance testing will be completed prior to first oil production from the Pad. First oil remains on track for Q4 2023.

MALAYSIA

Production in Mboepd	WI	Three months ended June 30		Six months ended June 30		Year ended December 31
		2023	2022	**2023**	2022	2022
Bertam	100%	**4.8**	5.9	**4.9**	5.0	5.3

Production
Strong performance in Q2 2023 from Bertam field on Block PM307 with average net production ahead of guidance at 4,800 boepd. Exceptional facility and well performance continued with facility uptimes registered in excess of 99%.

Organic Growth and Capital Projects
In Malaysia, a limited capital budget was set for 2023 with our focus now on 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 June 30		Six months ended June 30		Year ended December 31
		2023	2022	2023	2022	2022
France						
- Paris Basin	100%[1]	2.5	2.5	2.3	2.5	2.4
- Aquitaine	50%	0.3	0.3	0.4	0.3	0.3
		2.8	2.8	**2.7**	2.8	2.7

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

Production
Net production in France during Q2 2023 was in line with the guidance at 2,800 boepd.

Organic Growth
In France, all three Villeperdue West oil wells and the planned 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	Q2-23	Q1-23	Q4-22	Q3-22	Q2-22	Q1-22	Q4-21	Q3-21
Revenue	**205,564**	192,516	253,921	297,952	315,540	259,782	215,296	172,551
Gross profit	**52,747**	64,383	95,411	140,489	161,709	119,100	79,469	58,636
Net result	**32,025**	39,563	61,183	90,503	105,217	80,822	66,918	30,557
Earnings per share – USD	**0.24**	0.29	0.45	0.63	0.70	0.52	0.43	0.20
Earnings per share fully diluted – USD	**0.24**	0.28	0.44	0.62	0.68	0.51	0.42	0.19
Operating cash flow[1]	**84,372**	75,900	113,668	171,654	192,515	145,110	110,687	91,365
Free cash flow[1]	**16,415**	16,259	65,288	116,681	151,792	96,479	86,960	76,607
EBITDA[1]	**85,201**	76,079	125,651	174,328	194,038	145,463	110,087	89,223
Net cash / (debt) at period end[1]	**63,548**	66,956	175,098	88,615	14,382	(42,367)	(94,312)	(161,199)

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

Summarized consolidated balance sheet information is as follows:

USD Thousands	June 30, 2023	December 31, 2022
Non-current assets	1,201,668	1,041,051
Current assets	518,263	638,566
Total assets	**1,719,931**	1,679,617
Total non-current liabilities	598,798	564,381
Current liabilities	142,334	149,905
Total liabilities	**741,132**	714,286
Net assets	**978,799**	965,331
Working capital (including cash)	**375,929**	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 Cor4 acquisition assets) and the Ferguson asset). This is consistent with the internal reporting provided to IPC management. The following tables present certain segment information.

	Three months ended June 30, 2023					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	104,666	67,473	22,105	18,027	–	**212,271**
NGLs	–	278	–	–	–	**278**
Gas	63	15,313	–	–	–	**15,376**
Net sales of oil and gas	**104,729**	**83,064**	**22,105**	**18,027**	–	**227,925**
Change in under/over lift position	–	–	–	1,823	–	**1,823**
Royalties	(14,964)	(10,111)	–	(862)	–	**(25,937)**
Hedging settlement	(1,271)	2,802	–	–	–	**1,531**
Other operating revenue	–	1	–	221	–	**222**
Revenue	**88,494**	**75,756**	**22,105**	**19,209**	–	**205,564**
Operating costs	(23,450)	(41,699)	(7,271)	(7,867)	–	**(80,287)**
Cost of blending	(35,005)	(5,865)	–	–	–	**(40,870)**
Change in inventory position	802	(426)	4,747	(563)	–	**4,560**
Depletion	(9,222)	(14,993)	(5,551)	(3,596)	–	**(33,362)**
Depreciation of other assets	–	–	(2,436)	–	–	**(2,436)**
Exploration and business development costs	–	(3)	–	(9)	(410)	**(422)**
Gross profit/(loss)	**21,619**	**12,770**	**11,594**	**7,174**	**(410)**	**52,747**

	Three months ended June 30, 2022					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	164,373	81,289	32,630	27,741	–	306,033
NGLs	–	235	–	–	–	235
Gas	388	50,841	–	–	–	51,229
Net sales of oil and gas	164,761	132,365	32,630	27,741	–	357,497
Change in under/over lift position	–	–	–	4,668	–	4,668
Royalties	(20,740)	(15,606)	–	(1,863)	–	(38,209)
Hedging settlement	(177)	(8,423)	–	–	–	(8,600)
Other operating revenue	–	–	–	184	–	184
Revenue	143,844	108,336	32,630	30,730	–	315,540
Operating costs	(29,438)	(25,526)	(6,822)	(8,901)	–	(70,687)
Cost of blending	(47,380)	(10,259)	–	–	–	(57,639)
Change in inventory position	168	1,337	8,547	123	–	10,175
Depletion	(8,466)	(10,452)	(9,713)	(3,199)	–	(31,830)
Depreciation of other assets	–	–	(3,021)	–	–	(3,021)
Exploration and business development costs	97	–	–	–	(926)	(829)
Gross profit/(loss)	58,825	63,436	21,621	18,753	(926)	161,709

USD Thousands	Six months ended June 30, 2023 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	200,495	119,375	39,776	33,158	–	**392,804**
NGLs	–	468	–	–	–	**468**
Gas	157	35,702	–	–	–	**35,859**
Net sales of oil and gas	**200,652**	**155,545**	**39,776**	**33,158**	–	**429,131**
Change in under/over lift position	–	–	–	4,493	–	**4,493**
Royalties	(25,783)	(17,957)	–	(2,336)	–	**(46,076)**
Hedging settlement	(635)	10,750	–	–	–	**10,115**
Other operating revenue	–	7	–	410	–	**417**
Revenue	**174,234**	**148,345**	**39,776**	**35,725**	–	**398,080**
Operating costs	(48,483)	(76,197)	(15,447)	(15,605)	–	**(155,732)**
Cost of blending	(75,745)	(12,942)	–	–	–	**(88,687)**
Change in inventory position	341	(387)	10,619	(278)	–	**10,295**
Depletion[1]	(6,117)	(15,575)	(11,380)	(6,729)	–	**(39,801)**
Depreciation of other assets	–	–	(4,994)	–	–	**(4,994)**
Exploration and business development costs	–	(834)	–	(9)	(1,188)	**(2,031)**
Gross profit/(loss)	**44,230**	**42,410**	**18,574**	**13,104**	**(1,188)**	**117,130**

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

USD Thousands	Six months ended June 30, 2022 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	288,680	148,212	68,644	61,400	–	566,936
NGLs	–	462	–	–	–	462
Gas	653	80,792	–	–	–	81,445
Net sales of oil and gas	289,333	229,466	68,644	61,400	–	648,843
Change in under/over lift position	–	–	–	(1,445)	–	(1,445)
Royalties	(35,805)	(24,529)	–	(3,387)	–	(63,721)
Hedging settlement	(30)	(8,826)	–	–	–	(8,856)
Other operating revenue	–	101	–	400	–	501
Revenue	253,498	196,212	68,644	56,968	–	575,322
Operating costs	(54,658)	(52,743)	(16,408)	(18,339)	–	(142,148)
Cost of blending	(80,318)	(19,962)	–	–	–	(100,280)
Change in inventory position	1,491	942	10,683	612	–	13,728
Depletion	(16,353)	(20,424)	(16,402)	(6,603)	–	(59,782)
Depreciation of other assets	–	–	(5,101)	–	–	(5,101)
Exploration and business development costs	97	–	–	–	(1,027)	(930)
Gross profit/(loss)	103,757	104,025	41,416	32,638	(1,027)	280,809

Three and six months ended June 30, 2023, Review

Revenue

Total revenue amounted to USD 205,564 thousand for Q2 2023, compared to USD 315,540 thousand for Q2 2022 and USD 398,080 thousand for the first six months of 2023 compared to USD 575,322 thousand for the first six months of 2022 and is analyzed as follows:

	Three months ended June 30		Six months ended June 30	
USD Thousands	**2023**	2022	**2023**	2022
Crude oil sales	212,271	306,033	392,804	566,936
Gas and NGL sales	15,654	51,464	36,327	81,907
Change in under/overlift position	1,823	4,668	4,493	(1,445)
Royalties	(25,937)	(38,209)	(46,076)	(63,721)
Hedging settlement	1,531	(8,600)	10,115	(8,856)
Other operating revenue	222	184	417	501
Total revenue	**205,564**	315,540	**398,080**	575,322

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

Crude oil sales

	Three months ended June 30, 2023				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	104,666	67,473	22,105	18,027	**212,271**
- Quantity sold in bbls	1,796,457	1,155,916	240,354	231,171	**3,423,898**
- Average price realized USD per bbl	58.26	58.37	91.97	77.98	**62.00**

	Three months ended June 30, 2022				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	164,373	81,289	32,630	27,741	306,033
- Quantity sold in bbls	1,733,341	854,436	268,608	243,918	3,100,303
- Average price realized USD per bbl	94.83	95.14	121.48	113.73	98.71

Crude oil revenue was 31% lower in Q2 2023 compared to Q2 2022 mainly due to lower oil prices. Canadian - Southern Assets sales volumes are 35% higher in Q2 2023 compared to Q2 2022 as a result of the Cor4 acquistion 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 Q2 2023, WTI averaged USD 73 per bbl compared to USD 109 per bbl for Q2 2022 and the average discount to WCS used in our pricing formula was USD 15 per bbl compared to USD 13 per bbl for Q2 2022.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices. There was one cargo lifting in Malaysia during Q2 2023 and one cargo lifting in Q2 2022. Produced unsold oil barrels from Bertam at the end of Q2 2023 amounted to 404,000 barrels, see Change in Inventory Position section below. The average Dated Brent crude oil price was USD 78 per bbl for Q2 2023 compared to USD 114 per bbl for the comparative period.

USD Thousands	Six months ended June 30, 2023 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	200,495	119,375	39,776	33,158	**392,804**
- Quantity sold in bbls	3,711,254	2,132,174	445,692	417,105	**6,706,225**
- Average price realized USD per bbl	54.02	55.99	89.25	79.50	**58.57**

USD Thousands	Six months ended June 30, 2022 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	288,680	148,212	68,644	61,400	566,936
- Quantity sold in bbls	3,312,105	1,704,153	558,901	595,241	6,170,400
- Average price realized USD per bbl	87.16	86.97	122.82	103.15	91.88

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 were lower by 31% during the first six months of 2023 compared to the first six months of 2022 mainly due to lower oil prices. Canadian - Southern Assets sales volumes are 25% higher in the first six months 2023 compared to the first six months of 2022 as a result of the Cor4 acquistion in Q1 2023.

The Canadian realized sales price is based on the WCS price which trades at a discount to WTI. For the first six months of 2023, WTI averaged USD 75 per bbl compared to USD 102 per bbl for the comparative period and the average discount to WCS used in our pricing formula was USD 20 per bbl compared to USD 14 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 80 per bbl for the first six months of 2023 compared to USD 108 per bbl for the comparative period.

Gas and NGL sales

	Three months ended – June 30, 2023 Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	15,591	63	**15,654**
- Quantity sold in Mcf	8,448,955	41,620	**8,490,575**
- Average price realized USD per Mcf	1.85	1.52	**1.84**

	Three months ended – June 30, 2022 Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	51,076	388	51,464
- Quantity sold in Mcf	8,293,354	69,649	8,363,003
- Average price realized USD per Mcf	6.16	5.57	6.15

Gas and NGL sales revenue was 70% lower for Q2 2023 compared to Q2 2022 mainly due to the lower achieved gas price. IPC's achieved gas price is based on AECO pricing plus a premium. For Q2 2023, IPC realized an average price of CAD 2.44 per Mcf compared to AECO average pricing of CAD 2.41 per Mcf.

	Six months ended June 30, 2023		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	36,170	157	**36,327**
- Quantity sold in Mcf	16,094,254	94,669	**16,188,923**
- Average price realized USD per Mcf	2.25	1.66	**2.24**

	Six months ended June 30, 2022		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	81,254	653	81,907
- Quantity sold in Mcf	15,964,279	135,838	16,100,117
- Average price realized USD per Mcf	5.09	4.80	5.09

Gas and NGL sales revenue was 56% lower for the first six months of 2023 compared to the first six 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 six months of 2023, IPC realized an average price of CAD 3.00 per Mcf compared to AECO average pricing of CAD 2.80 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 six months of 2023 amounted to a gain of USD 10,115 thousand and consisted of a gain of USD 10,776 thousand on the gas contracts and a loss of USD 661 thousand on the oil contracts. Also see the Financial Position and Liquidity and the Financial Risk Management sections below.

Other operating revenue
Other operating revenue amounted to USD 222 thousand for Q2 2023 compared to USD 184 thousand for Q2 2022 and USD 417 thousand for the first six months of 2023 compared to USD 501 thousand for the comparative period and mainly consists of tariff income and fees for strategic storage of inventory in France.

Production costs
Production costs including inventory movements amounted to USD 116,597 thousand for Q2 2023 compared to USD 118,151 thousand for Q2 2022 and USD 234,124 thousand for the first six months of 2023 compared to USD 228,700 thousand for the comparative period, and is analyzed as follows:

	Three months ended June 30, 2023					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	41,699	23,450	11,366	7,867	(4,095)	**80,287**
USD/boe[2]	15.96	16.62	26.12	30.44	n/a	**17.02**
Cost of blending	5,865	35,005	–	–	–	**40,870**
Change in inventory position	426	(802)	(4,747)	563	–	**(4,560)**
Production costs	**47,990**	**57,653**	**6,619**	**8,430**	**(4,095)**	**116,597**

	Three months ended June 30, 2022					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	25,526	29,438	10,917	8,900	(4,095)	70,687
USD/boe[2]	11.28	20.55	20.24	34.55	n/a	15.74
Cost of blending	10,259	47,380	–	–	–	57,639
Change in inventory position	(1,337)	(168)	(8,547)	(123)	–	(10,175)
Production costs	34,448	76,650	2,370	8,777	(4,095)	118,151

	Six months ended – June 30, 2023					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	76,197	48,483	23,592	15,605	(8,145)	**155,732**
USD/boe[2]	15.54	16.89	26.45	32.34	n/a	**17.03**
Cost of blending	12,942	75,745	–	–	–	**88,687**
Change in inventory position	387	(341)	(10,619)	278	–	**(10,295)**
Production costs	**89,526**	**123,887**	**12,973**	**15,883**	**(8,145)**	**234,124**

	Six months ended – June 30, 2022					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	52,743	54,658	24,553	18,339	(8,145)	142,148
USD/boe[2]	11.94	19.72	26.95	35.66	n/a	16.50
Cost of blending	19,962	80,318	–	–	–	100,280
Change in inventory position	(942)	(1,491)	(10,683)	(612)	–	(13,728)
Production costs	71,763	133,485	13,870	17,727	(8,145)	228,700

[1] *See definition on page 21 under "Non-IFRS measures".*
[2] *USD/boe in the tables above is calculated by dividing the cost by the production volume for each country for the period 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 16.71 and USD 12.65 for Q2 2023 and Q2 2022 respectively and USD 17.32 and USD 18.01 for the six months ended June 30, 2023, and June 30, 2022, respectively.*

Operating costs
Operating costs amounted to USD 80,287 thousand for Q2 2023 compared to USD 70,687 thousand for Q2 2022 and USD 155,732 thousand for the first six months of 2023 compared to USD 142,148 for the first six months of 2022. The increase in costs in Q2 2023 compared to Q2 2022 is due mainly to increased production and activity levels and higher electricity prices. Operating costs per boe amounted to USD 17.02 per boe in Q2 2023 in line with guidance for the quarter and compared with USD 15.74 per boe in Q2 2022. 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 is also 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 net of proceeds from the sale of surplus diluent amounted to USD 40,870 thousand for Q2 2023 compared to USD 57,639 thousand for Q2 2022 and USD 88,687 thousand for the first six months of 2023 compared to USD 100,280 for the comparative period. The decrease versus the comparative period is 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 Q2 2023, IPC had crude entitlement of 404,000 barrels of oil on the FPSO Bertam facility (crude produced but unsold). One crude cargo was lifted from Bertam in April 2023 with the next lifting in July 2023.

Depletion and decommissioning costs
The total depletion of oil and gas properties amounted to USD 33,362 thousand for Q2 2023 compared to USD 31,830 thousand for Q2 2022 and USD 39,801 thousand for the first six months of 2023 (including an adjustment for accelerated decommissioning activities amounting to USD 24,123 thousand) compared to USD 59,782 thousand for the first six months of 2022. The depletion charge is analyzed in the following tables:

	Three months ended June 30, 2023				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	14,993	9,222	5,551	3,596	**33,362**
USD per boe[2]	5.74	6.53	12.76	13.92	**7.07**

	Three months ended June 30, 2022				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	10,452	8,466	9,713	3,199	31,830
USD per boe[2]	4.62	5.91	18.01	12.42	7.09

	Six months ended June 30, 2023				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands[1]	27,267	18,548	11,380	6,729	**63,924**
USD per boe[2]	5.69	6.46	12.76	13.94	**7.01**

	Six months ended June 30, 2022				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	20,424	16,353	16,402	6,603	59,782
USD per boe[2]	4.62	5.90	18.01	12.84	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 2,436 thousand for Q2 2023 compared to USD 3,021 thousand for Q2 2022 and USD 4,994 thousand for the first six months of 2023 compared to USD 5,101 thousand for the first six 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 PSC extension to 2035.

Exploration and business development costs
The total exploration and business developments costs amounted to USD 422 thousand for Q2 2023 and USD 2,031 thousand for the first six months of 2023. These costs included Cor4 acquisition related costs amounting to USD 831 thousand.

General, administrative and depreciation expenses
General, administrative and depreciation expenses amounted to USD 4,158 thousand for Q2 2023, compared to USD 3,743 thousand for Q2 2022 and USD 8,352 thousand for the first six months of 2023 compared to USD 7,916 thousand for the first six months of 2022.

Net financial items
Net financial items amounted to a charge of USD 6,955 thousand for Q2 2023, compared to a charge of USD 15,297 thousand for Q2 2022 and a charge of USD 11,970 thousand for the first six months of 2023 compared to a charge of USD 21,904 thousand for the first six months of 2022, and included a largely non-cash net foreign exchange loss of USD 2,347 thousand for the first six months of 2023 compared to a net foreign exchange loss of USD 4,043 thousand for the first six months of 2022. The foreign exchange movements during the first six 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 5,464 thousand for Q2 2023, compared to USD 8,195 thousand for Q2 2022 and a charge of USD 9,623 thousand for the first six months of 2023 compared to a charge of 17,861 thousand for the comparative period.

The interest expense amounted to USD 5,455 thousand for Q2 2023, compared to USD 5,481 thousand for the comparative period in 2022 and USD 10,804 thousand for the first six months of 2023 compared to USD 9,515 thousand for the first six months of 2022 and mainly related to the bond interest. Interest income generated on cash balances held in Q2 2023 amounted to USD 4,335 thousand and USD 9,259 thousand for the first six months of 2023 and is higher than the comparative period due mainly to higher interest rates.

The unwinding of the asset retirement obligation discount rate amounted to USD 3,474 thousand for Q2 2023, compared to USD 2,729 thousand for Q2 2022 and USD 6,542 thousand for the first six months of 2023 compared to USD 5,489 thousand for the first six months of 2022.

Income tax
The corporate income tax amounted to a charge of USD 9,609 thousand for Q2 2023, compared to a charge of USD 37,452 thousand for Q2 2022 and a charge of USD 25,220 thousand for the first six months of 2023 compared to a charge of USD 64,950 for the comparative period.

The current income tax charge amounted to USD 4,595 thousand in Q2 2023 and USD 8,586 thousand during the first six months of 2023 and mainly related to France and Malaysia. No corporate income tax was payable in Canada in respect of the first six months of 2023 due to the usage of historical tax pools.

Capital Expenditure

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

USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Development	8,489	82,701	1,262	14,599	**107,051**
Exploration and evaluation	–	–	–	9	**9**
	8,489	82,701	1,262	14,608	**107,060**

Capital expenditure of USD 107,060 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 Cor4 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"). 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 six 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 28,895 thousand as at June 30, 2023, which included USD 26,948 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 before 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 Q1 2023, the Group increased the Canadian RCF to CAD 150 million and extended the maturity to May 2025. No cash amounts were drawn under the Canadian RCF as at June 30, 2023.

As at June 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 June 30, 2023 was USD 11 million (EUR 10 million).

Total net cash as at June 30, 2023 amounted to USD 64 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 June 30, 2023, are classified as non-current as there are no mandatory repayments within the next twelve months.

An amount of USD 3.5 million (EUR 3.2 million) drawn under the France Facility as at June 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 June 30, 2023.

Cash and cash equivalents held amounted to USD 374 million as at June 30, 2023 of which USD 5.2 million was restricted.

Working Capital
As at June 30, 2023, the Group had a net working capital balance including cash of USD 375,929 thousand compared to USD 488,661 thousand as at December 31, 2022. The difference as at June 30, 2023, from December 31, 2022, is mainly a result of the lower cash balances held following 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 June 30		Six months ended June 30	
USD Thousands	**2023**	2022	**2023**	2022
Revenue	205,564	315,540	398,080	575,322
Production costs	(116,597)	(118,151)	(234,124)	(228,700)
Current tax	(4,595)	(4,874)	(8,586)	(8,997)
Operating cash flow	**84,372**	192,515	**155,370**	337,625

The operating cash flow for the first six 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 amounts to USD 160,272 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 June 30		Six months ended June 30	
USD Thousands	2023	2022	2023	2022
Operating cash flow - see above	84,372	192,515	155,370	337,625
Capital expenditures	(58,822)	(29,788)	(107,060)	(68,141)
Abandonment and farm-in expenditures[1]	(3,717)	(2,435)	(4,928)	(4,360)
General, administration and depreciation expenses before depreciation[2]	(3,766)	(3,351)	(7,577)	(7,121)
Cash financial items[3]	(1,652)	(5,149)	(2,300)	(9,730)
Free cash flow	**16,415**	151,792	**33,505**	248,273

[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 six 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 amounts to USD 32,674 thousand.

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

	Three months ended June 30		Six months ended June 30	
USD Thousands	2023	2022	2023	2022
Net result	32,025	105,217	71,588	186,039
Net financial items	6,955	15,297	11,970	21,904
Income tax	9,609	37,452	25,220	64,950
Depletion	33,362	31,830	39,801	59,782
Depreciation of other tangible fixed assets	2,436	3,021	4,994	5,101
Exploration and business development costs	422	829	2,031	930
Depreciation included in general, administration and depreciation expenses[1]	392	392	775	795
EBITDA	**85,201**	194,038	**156,379**	339,501

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

The EBITDA for the first six 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 amounts to USD 161,280 thousand.

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

	Three months ended June 30		Six months ended June 30	
USD Thousands	2023	2022	2023	2022
Production costs	116,597	118,151	234,124	228,700
Cost of blending	(40,870)	(57,639)	(88,687)	(100,280)
Change in inventory position	4,560	10,175	10,295	13,728
Operating costs	**80,287**	70,687	**155,732**	142,148

The operating costs for the first six 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 amounts to USD 162,533 thousand.

Net cash

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

USD Thousands	June 30, 2023	December 31, 2022
Bank loans	(10,629)	(12,142)
Bonds	(300,000)	(300,000)
Cash and cash equivalents	374,177	487,240
Net cash	**63,548**	175,098

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 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 June 30, 2023, following the cancellation during the first six months of 2023 of a further 6,330,914 common shares repurchased under the NCIB, IPC had a total of 130,497,085 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 31.2% of the outstanding common shares as at June 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 4,528,333 IPC Share Unit Plan awards outstanding as at August 1, 2023 (10,703 awards granted in January 2020, 25,335 awards granted in July 2020, 21,216 awards granted in January 2021, 324,811 awards granted in March 2021, 1,716,000 awards granted in May 2021, 10,067 awards granted in July 2021 and 12,543 awards granted in January 2022, 1,248,434 awards granted in March 2022, 5,487 awards granted in July 2022, 2,072 awards granted in January 2023, 1,148,421 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)	13.8	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 Q2 2023, Lundin Foundation has charged the Group USD 182 thousand in respect of sustainability advisory services provided to the Group.

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 June 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 June 30, 2023, which are summarized as follows:

Period	Volume (Gigajoules (GJ) per day)	Type	Average Pricing
July 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 June 30, 2023 which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
July 1, 2023 - December 31, 2023	12,000	WCS/ARV Differential	USD -10.08/bbl
January 1, 2024 - December 31, 2024	8,500	WCS/WTI Differential	USD -13.91/bbl

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

Period	Volume (MW)	Type	Pricing
July 1, 2023 – July 31, 2023	5	AESO	CAD 72.95/MWh
October 1, 2025 - September 1, 2040	3	AESO	CAD 75.00/MWh

The above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. The hedges had a positive fair value of USD 5,920 thousand as at June 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 1.3619 and to buy EUR 3 million per month, sell USD at an average exchange rate of 1.0000. 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 4.5. 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 positive fair value of USD 3,292 thousand as at June 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 six month period ended June 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 and timing and success of facility upgrades, tie-in work and infill drilling at Onion Lake Thermal;
- The ability of IPC to achieve and maintain current and forecast production and take advantage of production growth and development upside opportunities related to the assets acquired in the Cor4 acquisition;
- The potential improvement in the Canadian oil egress situation and IPC's ability to benefit from any such improvements;
- The timing and success of the future development projects and other organic growth opportunities in France;
- The ability to maintain current and forecast production in France;
- The ability of IPC to achieve and maintain current and forecast production in Malaysia;
- The ability to IPC to acquire further common shares under the NCIB, including the timing of any such purchases;

- The return of value to IPC's shareholders as a result of the NCIB;
- The ability of IPC to implement further shareholder distributions in addition to the NCIB;
- IPC's ability to implement its GHG emissions intensity and climate strategies and to achieve its net GHG emissions intensity reduction targets;
- Estimates of reserves and contingent resources;
- The ability to generate free cash flows and use that cash to repay debt;
- IPC's 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				
June 30, 2023	25.3	9.2	104.0 MMcf (17.3 Mboe)	51.8
June 30, 2022	22.9	9.9	99.6 MMcf (16.6 Mboe)	49.4
Six months ended				
June 30, 2023	26.0	9.4	102.0 MMcf (17.0 Mboe)	52.3
June 30, 2022	22.6	8.9	96.6 MMcf (16.1 Mboe)	47.6
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 50% of that production will be comprised of heavy oil, approximately 17% 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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