Q3

International Petroleum Corporation

Management's Discussion and Analysis

For the three and nine months ended September 30, 2024

International Petroleum Corp.

Contents

Non-IFRS Measures
References are made in this MD&A to "operating cash flow" (OCF), "free cash flow" (FCF), "Earnings Before Interest, Tax, Depreciation and Amortization" (EBITDA), "operating costs" and "net debt"/"net cash" which are not generally accepted accounting measures under IFRS Accounting Standards (IFRS) and do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with definitions of OCF, FCF, EBITDA, operating costs and net debt/net cash that may be used by other public companies. Management believes that OCF, FCF, EBITDA, operating costs and net debt/net cash are useful supplemental measures that may assist shareholders and investors in assessing the cash generated by and the financial performance and position of the Corporation. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-IFRS measure is presented in this MD&A. See "Non-IFRS Measures" on page 19.

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 24.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada are effective as of December 31, 2023, and are included in the reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Sproule's December 31, 2023, price forecasts.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France and Malaysia are effective as of December 31, 2023, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2023, price forecasts.

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

INTRODUCTION

This management's discussion and analysis ("MD&A") for International Petroleum Corporation ("IPC" or the "Corporation" and, together with its subsidiaries, the "Group") is dated November 5, 2024 and is intended to provide an overview of the Group's operations, financial performance and current and future business opportunities. This MD&A should be read in conjunction with IPC's unaudited interim condensed consolidated financial statement for the three and nine months ended September 30, 2024 as well as the audited consolidated financial statements and accompanying notes for the year ended December 31, 2023 ("Financial Statements").

Group Overview
The Group is in the business of exploring for, developing and producing oil and gas. IPC holds a portfolio of oil and gas production assets and development projects in Canada, Malaysia and France with exposure to growth opportunities.

The Corporation's common shares are listed on the Toronto Stock Exchange in Canada and the Nasdaq Stockholm Exchange in Sweden. The Corporation is incorporated and domiciled in British Columbia, Canada, under the Business Corporations Act. The address of its registered office is Suite 3500, 1133 Melville Street, Vancouver, BC V6E 4E5, Canada and its business address is Suite 2800, 1055 Dunsmuir Street, Vancouver, BC V7X 1L2, Canada.

Basis of Preparation
The MD&A and the Financial Statements have been prepared in accordance with International Accounting Standard 34, Interim Financial Reporting ("IAS 34") using accounting policies consistent with IFRS Accounting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

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

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

	September 30, 2024		September 30, 2023		December 31, 2023	
	Average	Period end	Average	Period end	Average	Period end
1 EUR equals USD	1.0870	1.1196	1.0835	1.0594	1.0816	1.1050
1 USD equals CAD	1.3602	1.3516	1.3454	1.3429	1.3496	1.3251
1 USD equals MYR	4.6352	4.1235	4.5134	4.6952	4.5598	4.5950

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

HIGHLIGHTS

Q3 2024 Business Highlights

- Average net production of approximately 45,000 boepd for Q3 2024, in line with guidance (49% heavy crude oil, 17% light and medium crude oil and 34% natural gas).(1)
- Successful completion of planned maintenance shutdowns at Onion Lake Thermal (OLT) in Canada and the Bertam field in Malaysia.
- Drilling activity at the Suffield area in Canada continued with four wells drilled in Q3 2024 and completed by October 2024.
- Development activities on Phase 1 of the Blackrod project continue to progress on schedule and on budget, with forecast first oil in late 2026.
- 2.6 million IPC common shares purchased and cancelled during Q3 2024 under IPC's normal course issuer bid (NCIB), on track to complete the 2023/2024 NCIB during November 2024.
- IPC plans to seek Toronto Stock Exchange approval for the renewal of the NCIB in December 2024.

Q3 2024 Financial Highlights

- Operating costs per boe of USD 17.9 for Q3 2024, below guidance.(3)
- Operating cash flow (OCF) and Earnings Before Interest, Tax, Depreciation and Amortization (EBITDA) of MUSD 73 and MUSD 68 respectively in line with guidance for Q3 2024.(3)
- Capital and decommissioning expenditures of MUSD 102 for Q3 2024, in line with guidance.
- Free cash flow (FCF) for Q3 2024 amounted to MUSD -38 (MUSD 44 pre-Blackrod Phase 1 project funding).(3)
- Gross cash of MUSD 299 and net debt of MUSD 157 as at September 30, 2024.(3)
- Net result of MUSD 23 for Q3 2024.

Reserves and Resources

- Total 2P reserves as at December 31, 2023 of 468 MMboe, with a reserves life index (RLI) of 27 years.(1)(2)
- Contingent resources (best estimate, unrisked) as at December 31, 2023 of 1,145 MMboe.(1)(2)

2024 Annual Guidance

- Full year 2024 average net production guidance range maintained at 46,000 to 48,000 boepd.(1)
- Full year 2024 operating costs guidance revised to below USD 18 per boe.(3)
- Full year 2024 OCF guidance estimated at between MUSD 335 and 342, assuming Brent USD 70 to 80 per barrel for the remainder of 2024.(3)
- Full year 2024 capital and decommissioning expenditures guidance forecast maintained at MUSD 437.
- Full year 2024 FCF guidance estimated at between MUSD -140 and -133 (between MUSD 222 and 229 pre-Blackrod Phase 1 project funding), assuming Brent USD 70 to 80 per barrel for the remainder of 2024.(3)

	Three months ended September 30		Nine months ended September 30	
USD Thousands	2024	2023	2024	2023
Revenue	**173,200**	257,366	**598,659**	655,446
Gross profit	**39,505**	93,429	**167,397**	210,559
Net result	**22,875**	71,681	**101,804**	143,269
Operating cash flow(3)	**72,589**	119,142	**263,831**	279,414
Free cash flow(3)	**(38,269)**	34,703	**(74,021)**	67,379
EBITDA(3)	**68,313**	123,054	**259,304**	284,334
Net cash/(debt)(3)	**(157,228)**	83,097	**(157,228)**	83,097

OPERATIONS REVIEW

Business Overview

Oil prices softened in the third quarter with Brent prices averaging USD 80 per barrel compared with USD 85 per barrel in the second quarter. Volatility during the quarter was high with Brent prices ranging from USD 89 per barrel in July to USD 70 per barrel in September. Notwithstanding the volatility in prices, the crude market was in a deficit through the third quarter, aided by the proactive supply management by the OPEC+ group. The continued conflicts in the Middle East and Ukraine led to increased oil prices, though these were partially offset by concerns over global oil demand growth, in particular consumer and industrial demand in China. Despite some of these negative factors, the physical market remains tight with OECD crude stock levels below the five-year average, with oil demand expected to be at an all-time high in 2024 and continue to grow in 2025. Approximately 50% of IPC's forecast 2024 oil production is hedged at USD 80 per barrel WTI or USD 85 per barrel Dated Brent through to the end of 2024.

The third quarter 2024 WTI to Western Canadian Select (WCS) price differentials averaged just under USD 14 per barrel, in line with the second quarter and approximately USD 5 per barrel lower than the first quarter differential average of USD 19 per barrel. The Trans Mountain expansion (TMX) pipeline continues to support tighter differentials with the Western Canadian Sedimentary Basin (WCSB) now having excess spare pipeline capacity for the first time in more than a decade. Crude exports from the new TMX pipeline are flowing off the coast of British Columbia, with deliveries to the US West Coast and Asia creating new end destinations for Canadian heavy oil. Around 70% of our forecast 2024 Canadian WCS production volumes are hedged at a WTI/WCS differential of USD 15 per barrel.

Natural gas prices in Canada remained supressed in the third quarter, with AECO pricing averaging CAD 0.67 per Mcf during the period, compared to CAD 1.17 per Mcf average for the second quarter. This has led to some Canadian natural gas producers curtailing production as western Canada gas storage levels continue to sit above the five-year range. IPC implemented hedges during the third quarter for approximately 14,500 Mcf per day at CAD 1.57 per Mcf from August to year end 2024.

Third Quarter 2024 Highlights and Full Year 2024 Guidance

IPC delivered average daily production rates of 45,000 boepd for the third quarter. The average daily production for the first nine months of 2024 was 47,400 boepd and the full year Capital Markets Day (CMD) production guidance of 46,000 to 48,000 boepd is maintained. During the third quarter, planned maintenance shutdowns at the Onion Lake Thermal (OLT) asset in Canada and at the Bertam field in Malaysia were successfully completed. High uptimes were achieved across all major producing assets in our portfolio during the quarter and the business benefited from the oil wells drilled within our Southern Alberta assets and the new wells brought on stream from sustaining Pad L at the OLT asset.[1]

Operating costs in the third quarter of 2024 were below forecast at USD 17.9 per boe. The lower costs were largely driven by lower energy input costs within our Canadian asset base. Full year 2024 operating costs guidance is revised to less than USD 18 per boe, below the CMD guidance range of USD 18 to 19 per boe.[3]

Operating cash flow (OCF) for the third quarter of 2024 was USD 73 million, in line with forecast. Full year 2024 OCF guidance is revised to USD 335 to 342 million (assuming Brent USD 70 to 80 per barrel for the remainder of 2024).[3]

Capital and decommissioning expenditure for the third quarter was in line with plan at USD 102 million. Our full year 2024 capital and decommissioning expenditure guidance is unchanged at USD 437 million.

Free cash flow (FCF) was USD -38 million (or USD 44 million pre-Blackrod Phase 1 development funding) during the third quarter of 2024. Full year 2024 FCF guidance is revised to USD -140 to -133 million (or USD 222 to 229 million pre-Blackrod Phase 1 development funding) assuming Brent USD 70 to 80 per barrel for the remainder of 2024.[3]

Net debt was increased during the third quarter of 2024 by approximately USD 69 million to USD 157 million.[3] This is due to the growth capital expenditure at the Blackrod Phase 1 project and continued funding of the normal course issuer bid (NCIB) share repurchase program. The gross cash position as at September 30, 2024 was USD 299 million. In the third quarter, IPC enhanced its financing position by entering into a letter of credit facility in Canada to cover all of its existing operational letters of credit, giving full availability under IPC's undrawn CAD 180 million Revolving Credit Facility.

With a robust balance sheet and strong cashflow generation from the producing assets, IPC is strongly positioned to deliver on our three strategic pillars of organic growth, shareholder returns and pursue value-adding M&A.

Blackrod Phase 1 Project
The Blackrod asset is 100% owned by IPC and hosts the largest booked reserves and contingent resources within the IPC portfolio. After more than a decade of pilot operations, subsurface delineation and commercial engineering studies, IPC sanctioned the Phase 1 development in the first quarter of 2023. The Phase 1 development targets 218 MMboe of 2P reserves, with a multi-year forecast capital expenditure of USD 850 million to first oil planned in late 2026. The Phase 1 development is planned for plateau production of 30,000 bopd which is expected by early 2028. (1)(2)

2024 marks a peak investment year at the Blackrod Phase 1 project for IPC, with USD 362 million planned to be spent in the year. Project progress has advanced according to plan, with approximately USD 245 million spent through the first nine months of 2024. All major third-party contracts have been executed, including but not limited to, the engineering, procurement and construction (EPC) agreements for the central processing facility (CPF) and well pad facilities, midstream agreements for the input fuel gas, diluent and oil blend pipelines, and drilling rig and stakeholder agreements. All major long lead items have been procured and pre-operations onboarding continues as the asset undergoes rapid change from a pilot steam assisted gravity drainage (SAGD) operation to a commercial SAGD operation. IPC's core operational philosophy is to responsibly develop and commission projects with the staff that are going to manage and operate the asset to ensure the seamless transition from development to operations.

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

Stakeholder Returns: Normal Course Issuer Bid
Under the current 2023/2024 NCIB, IPC has the ability to repurchase up to approximately 8.3 million common shares over the period of December 5, 2023 to December 4, 2024. IPC repurchased and cancelled approximately 7.5 million common shares up to the end of September 2024. The average price of common shares purchased under the 2023/2024 NCIB was SEK 132/CAD 17 per share. IPC expects to complete the 2023/2024 NCIB during November 2024, resulting in the cancellation of 6.5% of the total number of common shares outstanding as at the beginning of December 2023.

As at September 30, 2024, IPC had a total of 120,751,038 common shares issued and outstanding and IPC held 30,000 common shares in treasury. As at October 31, 2024, IPC had a total of 120,244,638 common shares issued and outstanding and IPC held 44,400 common shares in treasury.

The IPC Board of Directors has approved, subject to acceptance by the Toronto Stock Exchange (TSX), the renewal of IPC's NCIB for a further twelve months from December 2024 to December 2025. We expect that the 2024/2025 NCIB will permit IPC to purchase on the TSX and/or Nasdaq Stockholm, and cancel, up to a further approximately 7.5 million common shares, representing approximately 6.2% of the total outstanding common shares (or 10% of IPC's "public float" under applicable TSX rules) following completion of the current 2023/2024 NCIB. IPC continues to believe that reducing the number of common shares outstanding while in parallel investing in material production growth at the Blackrod project will prove to be a winning formula for our stakeholders.

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

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

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, 2023 (AIF) available on IPC's website at www.international-petroleum.com and under IPC's profile on SEDAR+ at www.sedarplus.ca.

(2) See "Reserves and Resources Advisory" below. Further information with respect to IPC's reserves, contingent resources and estimates of future net revenue, including assumptions relating to the calculation of NPV, are described in the AIF.

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

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

Operations Overview

Q3 2024 Overview

In Q3 2024, IPC continued to successfully demonstrate its commitment to operational excellence, with strong operational performance and no material safety or environmental incidents.

In Canada, the Blackrod Phase 1 development project is progressing in line with schedule and budget. As at the end of Q3 2024, process facility fabrication is on track supporting critical equipment site installation which continues to progress in line with plan. Site civil works and access road upgrades are largely complete while production well pad drilling continues to progress ahead of schedule.

At our producing assets in Canada, strong operational performance has been maintained during a period of planned maintenance shutdown activity and lower gas production due to reduced optimization activity on the back of lower gas pricing. At the Bertam field in Malaysia, average daily production remained strong in Q3 2024, with high production uptime and a continued focus on well rate optimization activity to offset natural declines. In France, stable production performance continues at the major producing assets.

Reserves and Resources

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

In 2024, as we embarked on the peak spend year at our exciting Blackrod Phase 1 development, IPC set out a balanced base business (non-Blackrod) capital expenditure budget for the year. IPC remains focused on organic growth and continues to mature future development projects across all operated assets, with a significant portfolio of drilling and optimization opportunities ready for sanction at the discretion of the Group.

Production

Average daily net production for Q3 2024 was in line with the 2024 Capital Markets Day Guidance at 45,000 boepd.

With strong operational delivery through the first nine months of 2024, IPC is on target to deliver annual net average daily production within the guidance range of 46,000 to 48,000 boepd.

The production during Q3 2024 with comparatives is summarized below:

Production in Mboepd	Three months ended September 30		Nine months ended September 30		Year ended December 31
	2024	2023	**2024**	2023	2023
Crude oil					
Canada – Northern Assets	12.7	15.8	14.0	15.6	15.5
Canada – Southern Assets[1]	10.9	11.4	11.1	11.9	11.8
Malaysia	3.7	2.9	4.0	4.3	3.8
France	2.4	2.8	2.5	2.7	2.8
Total crude oil production	**29.7**	32.9	**31.6**	34.5	33.9
Gas					
Canada – Northern Assets	0.4	0.3	0.4	0.3	0.4
Canada – Southern Assets	14.9	17.0	15.4	16.8	16.8
Total gas production	**15.3**	17.3	**15.8**	17.1	17.2
Total production	**45.0**	50.2	**47.4**	51.6	51.1
Quantity in MMboe	**4.14**	4.62	**12.98**	14.09	18.65

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

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

CANADA

Production in Mboepd	Working Interest (WI)	Three months ended September 30		Nine months ended September 30		Year ended December 31
		2024	2023	2024	2023	2023
- Oil Onion Lake Thermal	100%	10.7	13.4	12.4	13.2	13.3
- Oil Suffield Area[1]	100%	9.2	10.0	9.7	10.3	10.2
- Oil Other	50-100%	3.7	3.8	3.0	4.0	3.8
- Gas[1]	~100%	15.3	17.3	15.8	17.1	17.2
Canada		**38.9**	44.5	**40.9**	44.6	44.5

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

Production
Net production from IPC's assets in Canada during Q3 2024 was in line with guidance at 38,900 boepd. Strong operational performance has been maintained despite lower gas production rates with a reduction in optimization activity on the back of softer gas sales pricing. The planned maintenance shutdown at Onion Lake Thermal was successfully and safely delivered in line with plan. The 2024 capital development investments continue to deliver strong results with the three new Ferguson asset wells performing ahead of expectations and positive production indications at the Mooney Phase 2 EOR project.

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

During Q3 2024, the Blackrod Phase 1 project development continued to progress in line with expectations. As at the end of Q3 2024, process facility fabrication and critical equipment site installation is progressing in line with schedule, site civil and road expansion activities are largely complete while utility well and Well Pad drilling is progressing ahead of plan.

At Ferguson, the three newly drilled oil production wells continue to deliver strong results above expectations.

During Q3 2024, on the back of positive results from the Suffield area Ellerslie well drilling to date, IPC management sanctioned three additional Ellerslie well drills increasing the 2024 Ellerslie drilling budget from the original five to eight well targets in the year. As of the end of Q3 2024, seven Ellerslie wells have been drilled with five wells online and performing in line with expectations.

At Onion Lake Thermal, daily production has remained stable with six production sustaining Pad L well pairs online. The seventh Pad L well is scheduled to be brought online in Q4 2024.

MALAYSIA

Production in Mboepd	WI	Three months ended September 30		Nine months ended September 30		Year ended December 31
		2024	2023	2024	2023	2023
Bertam	100%	**3.7**	2.9	**4.0**	4.3	3.8

Production
Net production at Bertam in Malaysia in Q3 2024 was in line with guidance at 3,700 boepd with high production uptime and a continued focus on well rate optimization activity to offset natural declines.

Organic Growth and Capital Projects
In Malaysia, field development studies have progressed in line with expectations as IPC matures the remaining undeveloped potential of the Bertam field.

FRANCE

Production in Mboepd	WI	Three months ended September 30		Nine months ended September 30		Year ended December 31
		2024	2023	2024	2023	2023
France						
- Paris Basin	100%[1]	2.1	2.5	2.2	2.3	2.4
- Aquitaine	50%	0.3	0.3	0.3	0.4	0.4
		2.4	2.8	**2.5**	2.7	2.8

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

Production
Net production in France during Q3 2024 was at 2,400 boepd with stable performance at all the major producing assets.

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

FINANCIAL REVIEW

Financial Results

Selected Annual Financial Information

Selected consolidated statement of operations is as follows:

USD Thousands	Q3-24	Q2-24	Q1-24	Q4-23	Q3-23	Q2-23	Q1-23	Q4-22
Revenue	**173,200**	219,040	206,419	198,460	257,366	205,564	192,516	254,615
Gross profit	**39,505**	72,708	55,184	39,955	93,429	52,747	64,383	95,411
Net result	**22,875**	45,210	33,719	29,710	71,681	32,025	39,563	61,183
Earnings per share – USD	**0.19**	0.36	0.27	0.23	0.56	0.24	0.29	0.45
Earnings per share fully diluted – USD	**0.18**	0.36	0.26	0.22	0.54	0.24	0.28	0.44
Operating cash flow[1]	**72,589**	101,941	89,301	73,634	119,142	84,372	75,900	113,668
Free cash flow[1]	**(38,269)**	7,559	(43,311)	(64,688)	34,703	16,415	16,259	65,288
EBITDA[1]	**68,313**	103,971	87,020	66,284	123,054	85,201	76,079	125,651
Net cash/(debt) at period end[1]	**(157,228)**	(88,220)	(60,572)	58,043	83,097	63,548	66,956	175,098

[1] *See definition on page 19 under "Non-IFRS measures"*

Summarized consolidated balance sheet information is as follows:

USD Thousands	September 30, 2024	December 31, 2023
Non-current assets	1,550,935	1,372,388
Current assets	456,253	690,597
Total assets	**2,007,188**	2,062,985
Total non-current liabilities	806,864	779,838
Current liabilities	156,318	202,888
Total liabilities	**963,182**	982,726
Net assets	**1,044,006**	1,080,259
Working capital (including cash)	**299,935**	487,709

Selected Interim Financial Information

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

	Three months ended – September 30, 2024					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	88,579	68,544	17,876	15,939	–	**190,938**
NGLs	–	243	–	–	–	**243**
Gas	26	3,863	–	–	–	**3,889**
Net sales of oil and gas	**88,605**	**72,650**	**17,876**	**15,939**	–	**195,070**
Change in under/over lift position	–	–	–	1,289	–	**1,289**
Royalties	(15,693)	(11,911)	–	(1,164)	–	**(28,768)**
Hedging settlement	2,934	2,432	–	–	–	**5,366**
Other operating revenue	–	–	–	216	27	**243**
Revenue	**75,846**	**63,171**	**17,876**	**16,280**	**27**	**173,200**
Operating costs	(20,546)	(36,412)	(9,140)	(7,823)	–	**(73,921)**
Cost of blending	(24,113)	(5,705)	–	–	–	**(29,818)**
Change in inventory position	369	(699)	3,516	(431)	–	**2,755**
Depletion and decommissioning costs	(8,204)	(12,888)	(6,285)	(3,114)	–	**(30,491)**
Depreciation of other tangible fixed assets	–	–	(2,023)	–	–	**(2,023)**
Exploration and business development costs	–	–	–	–	(197)	**(197)**
Gross profit/(loss)	**23,352**	**7,467**	**3,944**	**4,912**	**(170)**	**39,505**

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

	Nine months ended – September 30, 2024					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	308,206	209,551	75,770	49,909	–	**643,436**
NGLs	–	762	–	–	–	**762**
Gas	195	24,786	–	–	–	**24,981**
Net sales of oil and gas	**308,401**	**235,099**	**75,770**	**49,909**	–	**669,179**
Change in under/over lift position	–	–	–	6,420	–	**6,420**
Royalties	(53,565)	(32,811)	–	(3,464)	–	**(89,840)**
Hedging settlement	6,666	5,262	–	–	–	**11,928**
Other operating revenue	–	–	–	670	302	**972**
Revenue	**261,502**	**207,550**	**75,770**	**53,535**	**302**	**598,659**
Operating costs	(60,464)	(106,184)	(23,385)	(24,538)	–	**(214,571)**
Cost of blending	(97,283)	(19,416)	–	–	–	**(116,699)**
Change in inventory position	737	(1,024)	3,726	(279)	–	**3,160**
Depletion and decommissioning costs[1]	(27,413)	(39,069)	(20,208)	(9,615)	–	**(96,305)**
Depreciation of other tangible fixed assets	–	–	(6,503)	–	–	**(6,503)**
Exploration and business development costs	–	–	–	–	(344)	**(344)**
Gross profit/(loss)	**77,079**	**41,857**	**29,400**	**19,103**	**(42)**	**167,397**

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

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

Three and nine months ended September 30, 2024, Review

Revenue

Total revenue amounted to USD 173,200 thousand for Q3 2024, compared to USD 257,366 thousand for Q3 2023 and USD 598,659 thousand for the first nine months of 2024 compared to USD 655,446 thousand for the first nine months of 2023 and is analyzed as follows:

USD Thousands	Three months ended September 30		Nine months ended September 30	
	2024	2023	**2024**	2023
Crude oil sales	190,938	266,979	643,436	659,783
Gas and NGL sales	4,132	17,082	25,743	53,409
Change in under/overlift position	1,289	4,349	6,420	8,842
Royalties	(28,768)	(33,212)	(89,840)	(79,288)
Hedging settlement	5,366	1,854	11,928	11,969
Other operating revenue	243	314	972	731
Total revenue	**173,200**	257,366	**598,659**	655,446

The main components of total revenue for the three and nine months ended September 30, 2024, and September 30, 2023, respectively, are detailed below.

Crude oil sales

USD Thousands	Three months ended – September 30, 2024				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	88,579	68,544	17,876	15,939	**190,938**
- Quantity sold in bbls	1,446,627	1,107,248	221,082	198,101	**2,973,058**
- Average price realized USD per bbl	61.23	61.90	80.86	80.46	**64.22**

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

Crude oil revenue was 28% lower in Q3 2024 compared to Q3 2023 due to lower sales volumes and lower oil prices. Canadian - Northern Assets sales volumes are 20% lower in Q3 2024 compared to Q3 2023 as a result of a planned maintenance shutdown at Onion Lake Thermal in September 2024.

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

The Canadian realized sales price is based on the Western Canadian Select ("WCS") price which trades at a discount to West Texas Intermediate ("WTI"). For Q3 2024, WTI averaged USD 75 per bbl compared to USD 82 per bbl for Q3 2023 and the average discount to WCS used in IPC's pricing formula was USD 14 per bbl compared to USD 13 per bbl for Q3 2023.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices. There was one cargo lifting in Malaysia during Q3 2024 and two cargo liftings in Q3 2023. Produced unsold oil barrels from Bertam at the end of Q3 2024 amounted to 232,000 barrels, see Change in Inventory Position section below. The average Dated Brent crude oil price was USD 80 per bbl for Q3 2024 compared to USD 87 per bbl for the comparative period.

	Nine months ended – September, 2024				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	308,206	209,551	75,770	49,909	**643,436**
- Quantity sold in bbls	5,012,498	3,353,780	845,411	602,713	**9,814,402**
- Average price realized USD per bbl	61.49	62.48	89.63	82.81	**65.56**

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

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 2% during the first nine months of 2024 compared to the first nine months of 2023 mainly due to lower sales volumes partly offset by higher prices. Canadian - Northern Assets sales volumes are 9% lower during the first nine months of 2024 compared to the first nine months of 2023 mainly as a result of a planned maintenance shutdown at Onion Lake Thermal in September 2024. In addition, Canadian – Southern Assets sales volumes are 3% higher in the first nine months 2024 compared to the first nine months of 2023 as a result of the Brooks assets acquisition in March 2023.

The Canadian realized sales price is based on the WCS price which trades at a discount to WTI. For the first nine months of 2024, WTI averaged USD 77 per bbl compared to USD 77 per bbl for the comparative period and the average discount to WCS used in our pricing formula was USD 15 per bbl compared to USD 18 per bbl for the comparative period.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices and the average market Brent crude oil price was USD 83 per bbl for the first nine months of 2024 compared to USD 82 per bbl for the comparative period.

Gas and NGL sales

	Three months ended – September 30, 2024		
	Canada – Northern Assets	Canada – Southern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	26	4,106	**4,132**
- Quantity sold in Mcf	74,249	7,335,019	**7,409,268**
- Average price realized USD per Mcf	0.35	0.56	**0.56**

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

Gas and NGL sales revenue was 76% lower for Q3 2024 compared to Q3 2023 mainly due to the lower achieved gas price. IPC's achieved gas price is based on AECO pricing plus a premium. For Q3 2024, IPC realized an average price of CAD 0.72 per Mcf compared to AECO average pricing of CAD 0.67 per Mcf.

	Nine months ended – September 30, 2024		
	Canada – Northern Assets	Canada – Southern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	195	25,548	**25,743**
- Quantity sold in Mcf	208,107	22,810,152	**23,018,259**
- Average price realized USD per Mcf	0.94	1.12	**1.12**

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

Gas and NGL sales revenue was 52% lower for the first nine months of 2024 compared to the first nine months of 2023 mainly due to the lower achieved gas price.

IPC's achieved gas price is based on AECO pricing plus a premium. For the first nine months of 2024, IPC realized an average price of CAD 1.49 per Mcf compared to AECO average pricing of CAD 1.45 per Mcf.

Hedging settlement

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

The realized hedging settlement for the first nine months of 2024 amounted to a gain of USD 11,928 thousand and consisted of a gain of USD 11,255 thousand on the oil contracts and a gain of USD 673 thousand on the gas contracts. Also see the Financial Position and Liquidity and the Financial Risk Management sections below.

Production costs

Production costs including inventory movements amounted to USD 100,984 thousand for Q3 2024 compared to USD 130,765 thousand for Q3 2023 and USD 328,110 thousand for the first nine months of 2024 compared to USD 364,889 thousand for the comparative period, and is analyzed as follows:

	Three months ended – September 30, 2024					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	20,546	36,412	13,235	7,823	(4,095)	**73,921**
USD/boe[2]	17.07	15.35	39.27	34.99	n/a	**17.87**
Cost of blending	24,113	5,705	–	–	–	**29,818**
Change in inventory position	(369)	699	(3,516)	431	–	**(2,755)**
Production costs	**44,290**	**42,816**	**9,719**	**8,254**	**(4,095)**	**100,984**

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

USD Thousands	Nine months ended – September 30, 2024 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	60,464	106,184	35,670	24,538	(12,285)	**214,571**
USD/boe[2]	15.28	14.65	32.92	35.65	n/a	**16.53**
Cost of blending	97,283	19,416	–	–	–	**116,699**
Change in inventory position	(737)	1,024	(3,726)	279	–	**(3,160)**
Production costs	**157,010**	**126,624**	**31,944**	**24,817**	**(12,285)**	**328,110**

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

[1] *See definition on page 19 under "Non-IFRS measures".*
[2] *USD/boe in the tables above is calculated by dividing the cost by the production volume for each country for the period and for 2023, includes the Brooks assets from January 1, 2023.*
[3] *Included in the Malaysia operating costs is the lease cost for the FPSO Bertam which is owned by the Group. Other represents the FPSO Bertam lease fee self-to-self payment elimination. Netting the self-to-self elimination against the operating costs in Malaysia reduces the operating costs per boe for Malaysia to USD 27.12 for Q3 2024 and USD 41.06 for the comparative period and USD 21.58 and USD 22.83 for the nine months ended September 30, 2024, and September 30, 2023, respectively.*

Operating costs
Operating costs amounted to USD 73,921 thousand for Q3 2024 compared to USD 82,862 thousand for Q3 2023 and USD 214,571 thousand for the first nine months of 2024 compared to USD 238,594 thousand for the first nine months of 2023. Operating costs per boe amounted to USD 17.87 per boe in Q3 2024 below guidance for the quarter and compared with USD 17.95 per boe in Q3 2023.

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

The cost of the diluent amounted to USD 29,818 thousand for Q3 2024 compared to USD 39,836 thousand for Q3 2023 and USD 116,699 thousand for the first nine months of 2024 compared to USD 128,523 thousand for the comparative period. The decrease of the diluent in Q3 2024 compared to Q3 2023 is due mainly to lower production at Onion Lake Thermal as a consequence of a planned maintenance shutdown.

Change in inventory position
The Bertam field in Malaysia is located offshore and production is lifted and sold from the FPSO Bertam when a cargo parcel size is reached. Accordingly, the timing of a lifting varies based on the inventory level on the FPSO facility and the change in inventory position varies, both positively and negatively, from period to period. Inventories are valued at the lower of cost including depletion, and market value, and the difference in the valuation between period ends is reflected in the change in inventory position in the statement of operations. At the end of Q3 2024, IPC had crude entitlement of 232,000 barrels of oil on the FPSO Bertam facility being crude produced but not yet sold.

Depletion and decommissioning costs
The total depletion of oil and gas properties amounted to USD 30,491 thousand for Q3 2024 compared to USD 31,687 thousand for Q3 2023 and USD 96,305 thousand for the first nine months of 2024 compared to USD 71,488 thousand for the first nine months of 2023 (including an adjustment for accelerated decommissioning activities amounting to USD 24,055 thousand).

The depletion charge is analyzed in the following tables:

USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
	Three months ended – September 30, 2024				
Depletion cost in USD thousands	8,204	12,888	6,285	3,114	**30,491**
USD per boe	6.82	5.43	18.65	13.93	**7.37**

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

USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
	Nine months ended – September 30, 2024				
Depletion cost in USD thousands[1]	27,413	39,069	20,208	9,615	**96,305**
USD per boe[2]	6.93	5.39	18.65	13.97	**7.42**

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

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

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

Depreciation of other tangible fixed assets
The total depreciation of other assets amounted to USD 2,023 thousand for Q3 2024 compared to USD 1,509 thousand for Q3 2023 and USD 6,503 thousand for the first nine months of 2024 compared to USD 6,503 thousand for the first nine months of 2023. This relates to the depreciation of the FPSO Bertam, which is being depreciated to its residual value on a unit of production basis to August 2025.

Exploration and business development costs
The total exploration and business developments costs amounted to a cost of USD 344 thousand for the first nine months of 2024 and a cost of USD 2,007 thousand for the first nine months of 2023 which included the Brooks assets acquisition related costs amounting to USD 834 thousand.

Net financial items
Net financial items amounted to a charge of USD 4,124 thousand for Q3 2024, compared to a charge of USD 4,257 thousand for Q3 2023 and a charge of USD 23,942 thousand for the first nine months of 2024 compared to a charge of USD 16,227 thousand for the first nine months of 2023, and included a largely non-cash net foreign exchange gain of USD 1,743 thousand for the first nine months of 2024 compared to a net foreign exchange loss of USD 1,493 thousand for the first nine months of 2023. The foreign exchange movements 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 9,484 thousand for Q3 2024, compared to USD 5,111 thousand for Q3 2023 and a charge of USD 25,685 thousand for the first nine months of 2024 compared to a charge of 14,734 thousand for the comparative period.

The interest expense amounted to USD 9,119 thousand for Q3 2024, compared to USD 5,787 thousand for the comparative period in 2023 and USD 26,865 thousand for the first nine months of 2024 compared to USD 16,591 thousand for the first nine months of 2023 and mainly related to the bond interest at a coupon rate of 7.25% per annum. The increase compared to the comparative period is largely attributable to the additional MUSD 150 bond tap issue completed in Q3 2023. Interest income generated on cash balances held amounted to USD 4,112 thousand for Q3 2024 and USD 14,646 thousand for the first nine months of 2024 and USD 4,979 thousand for Q3 2023 and USD 14,238 thousand for the first nine months of 2023.

The unwinding of the asset retirement obligation discount rate amounted to USD 3,680 thousand for Q3 2024, compared to USD 3,479 thousand for the comparative period and USD 10,939 thousand for the first nine months of 2024 compared to USD 10,021 thousand for the first nine months of 2023.

Income tax
The corporate income tax amounted to a charge of USD 8,257 thousand for Q3 2024, compared to a charge of USD 25,451 thousand for the comparative period and a charge of USD 29,473 thousand for the first nine months of 2024 compared to a charge of USD 50,671 thousand for the comparative period.

The current income tax amounted to a credit of USD 373 thousand for Q3 2024 and a charge of USD 6,718 thousand during the first nine months of 2024 and mainly related to France and Malaysia. No corporate income tax is expected to be payable in Canada in 2024 due to the usage of historical tax pools.

Capital Expenditure

Development and exploration and evaluation expenditure incurred during the first nine months of 2024 was as follows:

USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Development	257,726	30,234	16,372	2,691	**307,023**
Exploration and evaluation	352	–	1,082	–	**1,434**
	258,078	30,234	17,454	2,691	**308,457**

Capital expenditure of USD 307,023 thousand was mainly spent in Canada on the Blackrod Phase 1 Development project, drilling on the Ferguson and Brooks assets and in Malaysia on the well workovers.

Other tangible fixed assets
Other tangible fixed assets amounted to USD 18,938 thousand as at September 30, 2024, which included USD 17,227 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated on a unit of production basis based to August 2025, being the original Bertam field PSC expiry date before the PSC extension to 2035.

Financial Position and Liquidity

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

In Q3 2023, IPC completed a tap issue of MUSD 150 under IPC's existing 7.25% bond framework issued at 7% discount to par value with proceeds amounting to MUSD 139.5 before transaction costs. For accounting purposes, the discounted amount was recognised in the balance sheet and the discount will be unwound over the period to maturity of the bond and charged to the interest expense line of the Statement of Operations using the effective interest rate methodology. As at September 30, 2024, IPC had a nominal MUSD 450 of bonds outstanding with maturity in February 2027. The bond repayment obligations as at September 30, 2024, are classified as non-current as there are no mandatory repayments within the next twelve months.

During 2023, the Group increased the Canadian RCF from MCAD 75 to MCAD 180 with a maturity to May 2025. During Q2 2024, the Group extended the maturity of the Canadian RCF to May 2026. The Canadian RCF is undrawn and fully available as at September 30, 2024. During Q3 2024, the Group entered into a letter of credit facility in Canada (the "LC Facility") to cover existing operational letters of credit. As at September 30, 2024, operational letters of credit in an aggregate of MCAD 40.2 have been issued under the LC Facility, including letters of credit issued in Q2 2024 for a total amount of MCAD 35 to support the third party pipeline construction agreements for the Blackrod project during 2024 and 2025.

As at September 30, 2024, IPC had an unsecured Euro credit facility in France (the "France Facility"), with maturity in May 2026. IPC makes quarterly repayments of the French Facility and the amount remaining outstanding under the France Facility as at September 30, 2024 was MUSD 6. An amount of MUSD 3.5 drawn under the France Facility as at September 30, 2024 is classified as current representing the repayment planned within the next twelve months.

The Group is in compliance with the covenants of the bonds and its financing facilities as at September 30, 2024.

Net debt as at September 30, 2024 amounted to MUSD 157. Cash and cash equivalents held amounted to MUSD 299 as at September 30, 2024.

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

Working Capital
As at September 30, 2024, the Group had a working capital balance including cash of USD 299,935 thousand compared to USD 487,709 thousand as at December 31, 2023. The difference as at September 30, 2024, from December 31, 2023, is mainly as a result of the decreased cash following capital expenditures on the Blackrod Phase 1 development project and the continuing NCIB program.

Non-IFRS Measures

In addition to using financial measures prescribed under IFRS, references are made in this MD&A to "operating cash flow", "free cash flow", "EBITDA", "operating costs" and "net debt"/"net cash", which are non-IFRS measures. Non-IFRS measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other public companies. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS.

The Corporation uses non-IFRS measures to provide investors with supplemental measures to assess cash generated by and the financial performance and condition of the Corporation. Management also uses non-IFRS measures internally in order to facilitate operating performance comparisons from period to period, prepare annual operating budgets and assess the Group's ability to meet its future capital expenditure and working capital requirements. Management believes these non-IFRS measures are important supplemental measures of operating performance because they highlight trends in the core business that may not otherwise be apparent when relying solely on IFRS financial measures. Management believes such measures allow for assessment of the Group's operating performance and financial condition on a basis that is more consistent and comparable between reporting periods. The Corporation also believes that securities analysts, investors and other interested parties frequently use non-IFRS measures in the evaluation of public companies. Forward-looking statements are provided for the purpose of presenting information about management's current expectations and plans relating to the future and readers are cautioned that such statements may not be appropriate for other purposes.

"Operating cash flow" is calculated as revenue less production costs less current tax. Operating cash flow is used to analyze the amount of cash that is being generated available for capital investment and servicing debt.

"Free cash flow" is calculated as operating cash flow less capital expenditures less decommissioning and farm-in expenditures less general, administration and depreciation expenses before depreciation and less cash financial items. Free cash flow is used to analyze the amount of cash that is being generated by the business and that is available for such purposes as repaying debt, funding acquisitions and returning capital to shareholders.

"EBITDA" is calculated as net result before financial items, taxes, depletion of oil and gas properties, exploration costs, impairment costs and depreciation and adjusted for non-recurring profit/loss on sale of assets and other income.

"Operating cost" is calculated as production costs excluding any change in the inventory position and the cost of blending and is used to analyze the cash cost of producing the oil and gas volumes.

"Net debt" is calculated as bank loans and bonds less cash and cash equivalents. "Net cash" is calculated as cash and cash equivalents less bank loans and bonds.

Reconciliation of Non-IFRS Measures

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

	Three months ended September 30		Nine months ended September 30	
USD Thousands	**2024**	2023	**2024**	2023
Revenue	173,200	257,366	598,659	655,446
Production costs	(100,984)	(130,765)	(328,110)	(364,889)
Current tax	373	(7,459)	(6,718)	(16,045)
Operating cash flow	**72,589**	119,142	**263,831**	274,512

The operating cash flow for the nine months ended September 30, 2023 including the operating cash flow contribution of the Brooks assets acquisition from the effective date of January 1, 2023 to the completion date of March 3, 2023 amounted to USD 279,414 thousand.

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

USD Thousands	Three months ended September 30 2024	Three months ended September 30 2023	Nine months ended September 30 2024	Nine months ended September 30 2023
Operating cash flow - see above	72,589	119,142	263,831	274,512
Capital expenditures	(99,100)	(76,844)	(308,457)	(183,904)
Abandonment and farm-in expenditures[1]	(2,575)	(2,755)	(4,938)	(7,683)
General, administration and depreciation expenses before depreciation[2]	(3,903)	(3,547)	(11,245)	(11,124)
Cash financial items[3]	(5,280)	(1,293)	(13,212)	(3,593)
Free cash flow	**(38,269)**	34,703	**(74,021)**	68,208

[1] *See note 16 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 nine months ended September 30, 2023 including the free cash flow contribution of the Brooks assets acquisition from the effective date of January 1, 2023 to the completion date of March 3, 2023 amounted to USD 67,379 thousand.

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

USD Thousands	Three months ended September 30 2024	Three months ended September 30 2023	Nine months ended September 30 2024	Nine months ended September 30 2023
Net result	22,875	71,681	101,804	143,269
Net financial items	4,124	4,257	23,942	16,227
Income tax	8,257	25,451	29,473	50,671
Depletion and decommissioning costs	30,491	31,687	96,305	71,488
Depreciation of other tangible fixed assets	2,023	1,509	6,503	6,503
Exploration and business development costs	197	(24)	344	2,007
Depreciation included in general, administration and depreciation expenses[1]	346	405	933	1,180
Sale of assets	–	(11,912)	–	(11,912)
EBITDA	**68,313**	123,054	**259,304**	279,433

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

The EBITDA for the nine months ended September 30, 2023 including the EBITDA contribution of the Brooks assets acquisition from the effective date of January 1, 2023 to the completion date of March 3, 2023 amounted to USD 284,334 thousand.

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

USD Thousands	Three months ended September 30 2024	Three months ended September 30 2023	Nine months ended September 30 2024	Nine months ended September 30 2023
Production costs	100,984	130,765	328,110	364,889
Cost of blending	(29,818)	(39,836)	(116,699)	(128,523)
Change in inventory position	2,755	(8,067)	3,160	2,228
Operating costs	**73,921**	82,862	**214,571**	238,594

The operating costs for the nine months ended September 30, 2023 including the operating costs contribution of the Brooks assets acquisition from the effective date of January 1, 2023 to the completion date of March 3, 2023 amounted to USD 245,395 thousand.

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

USD Thousands	September 30, 2024	December 31, 2023
Bank loans	(6,431)	(9,031)
Bonds[1]	(450,000)	(450,000)
Cash and cash equivalents	299,203	517,074
Net cash/(debt)	**(157,228)**	58,043

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

Off-Balance Sheet Arrangements

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

Outstanding Share Data

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

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

Over the period of January 1, 2024 to September 30, 2024, IPC purchased a total of 6,271,028 and cancelled 6,241,028 common shares under the NCIB. As at September 30, 2024, IPC had a total of 120,751,038 common shares issued and outstanding and held 30,000 common shares 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 33.7% of the outstanding common shares as at September 30, 2024.

In addition, IPC has 117,485,389 outstanding class A preferred shares, issued as a part of an internal corporate structuring to a wholly-owned subsidiary of IPC. Such preferred shares are not listed on any stock exchange and do not carry the right to vote on matters to be decided by the holders of IPC's common shares.

IPC has 3,331,566 IPC Share Unit Plan awards outstanding as at November 5, 2024 (4,333 awards granted in January 2022, 1,090,091 awards granted in March 2022, 2,391 awards granted in July 2022, 2,072 awards granted in January 2023, 1,033,326 awards granted in February 2023, 3,244 awards granted in July 2023, 2,443 awards granted in January 2024, 1,189,338 awards granted in February 2024 and 4,328 awards granted in July 2024).

Contractual Obligations and Commitments

In the normal course of business, the Group has committed to certain payments which are not recognised as liabilities. The following table summarizes the Group's commitments in Canada as at September 30, 2024:

MCAD	2024	2025	2026	2027	2028	Thereafter
Transportation service[1]	7.0	33.3	60.6	89.2	92.8	1,488.2
Power[2]	3.1	12.4	12.4	12.4	9.8	–
Total commitments	**10.1**	**45.7**	**73.0**	**101.6**	**102.6**	**1,488.2**

[1] *IPC has firm transportation commitments on oil and natural gas pipelines that expire between 2037 and 2045.*
[2] *IPC has physical delivery power hedges to purchase 15MWh at a weighted average price of CAD 74.92/MWh from October 1, 2024 to December 31, 2028 and an additional 5MWh at a weighted average price of CAD 58.31/MWh from October 1, 2024 to December 31, 2027.*

Critical Accounting Policies and Estimates

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

Transactions with Related Parties

During the nine months ended September 30, 2024, the Group paid USD 333 thousand to the Lundin Foundation in respect of sustainability advisory services provided to the Group and USD 470 thousand to Orrön Energy AB in respect of office space rental.

During the nine months ended September 30, 2024, Orrön Energy AB and ShaMaran Petroleum Corp. paid respectively USD 450 thousand and USD 147 thousand to the Group in respect of support services provided during the first nine months of 2024.

All transactions with related parties are in the normal course of business and are made on the same terms and conditions as with parties at arm's length.

Financial Risk Management

As an international oil and gas exploration and production company, IPC is exposed to financial risks such as interest rate risk, currency risk, credit risk, liquidity risks as well as the risk related to the fluctuation in oil and gas prices. The Group seeks to control these risks through sound management practice and the use of internationally accepted financial instruments, such as oil and gas, condensate and electricity price, interest rate or foreign exchange hedges as the case may be. Financial instruments will be solely used for the purpose of managing risks in the business. As at September 30, 2024, the Corporation had entered into oil, gas and electricity price hedges – see below.

Management believes that the cash resources, other current assets and cash flow from operations are sufficient to finance the Group's operations and capital expenditures program over the next year.

Capital Management

The Group's objectives when managing capital are to safeguard the Group's ability to continue as a going concern and to meet its committed financial liabilities and work program requirements in order to create shareholder value. The Group may put in place new bonds or credit facilities, repay debt, or pursue other such restructuring activities as appropriate.

Management of the Corporation will continuously monitor and manage the Group's capital, liquidity and net debt position in order to assess the requirement for changes to the capital structure to meet the objectives and to maintain flexibility.

Price of Oil and Gas

Prices of oil and gas are affected by the normal economic drivers of supply and demand as well as by financial investors and market uncertainty. Factors that influence these prices include operational decisions, prices of competing fuels, natural disasters, economic conditions, transportation constraints, political instability or conflicts or actions by major oil exporting countries. Price fluctuations will affect the Group's financial position.

Based on analysis of the circumstances, management assesses the benefits of forward hedging monthly sales contracts for the purpose of protecting cash flow. If management believes that a hedging contract will appropriately help manage cash flow then it may choose to enter into a commodity price hedge. The Group does not currently have any covenants under its current financing facilities to hedge future production.

The Group had oil price sale financial hedges outstanding as at September 30, 2024, which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
October 1, 2024 – December 31, 2024	17,700	WTI/WCS Differential	USD -15.03/bbl
October 1, 2024 – December 31, 2024	12,250	WTI Sale Swap	USD 80.26/bbl
October 1, 2024 – December 31, 2024	3,000	Brent Sale Swap	USD 85.50/bbl
January 1, 2025 - December 31, 2025	8,000	WTI/WCS Differential	USD -14.56/bbl

The Group had gas price sale financial hedges outstanding as at September 30, 2024, which are summarized as follows:

Period	Volume (Gigajoules (GJ) per day))	Type	Average Pricing
October 1, 2024 – December 31, 2024	15,000	AECO Swap	CAD 1.515/GJ
January 1, 2025 - December 31, 2025	10,000	AECO Swap	CAD 2.500/GJ

The Group had electricity financial hedges outstanding as at September 30, 2024, which are summarized as follows:

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

The above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. The hedges had a positive fair value of USD 13,830 thousand as at September 30, 2024.

In October 2024, the Group entered into the following oil price sale financial hedges in Canada:

Period	Volume (barrels per day)	Type	Average Pricing
January 1, 2025 - March 31, 2025	2,500	WTI Sale Swap	USD 70.00/bbl
January 1, 2025 - December 31, 2025	3,000	WTI/WCS Differential	USD -13.77/bbl

Currency Risk
The Group's policy on currency rate hedging is, in the case of currency exposure, to consider fixing the rate of exchange. The Group will take into account the currency exposure, current rates of exchange and market expectations in comparison to historic trends and volatility in making the decision to hedge.

In 2023, IPC entered into foreign currency hedges in Canada to buy CAD 20 million per month at CAD 1.36 (sell USD) and in Malaysia to buy MYR 11.5 million per month at MYR 4.63 (sell USD) in respect of 2024, and to buy CAD 15 million per month at CAD 1.36 (sell USD) in respect of 2025, to partially meet forecast operational expenses in those countries. In April 2024, IPC entered into currency hedge swaps from May 2024 to December 2024 to buy EUR 2.5 million per month, sell USD at an average exchange rate of 1.0705. In respect of the forecast Blackrod development capital expenditure in Canada, IPC entered into further currency hedges to purchase a total CAD 656 million for the period January 2024 to December 2025 at an average rate of CAD 1.33 (sell USD).

The outstanding portion of all of the above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. The hedges had a positive fair value of USD 3,242 thousand as at September 30, 2024.

In October 2024, in respect of the forecast operating expenditures in Canada, IPC entered into further currency hedges to purchase an additional CAD 90 million for the period January 2025 to December 2025 at an average rate of CAD 1.35 (sell USD).

Interest Rate Risk
Interest rate risk is the risk to earnings due to uncertain future interest rates on borrowings. The Group will take into account the level of external debt, current interest rates and market expectations in comparison to historic trends and volatility in making the decision to hedge.

Credit Risk
The Group may be exposed to third party credit risk through contractual arrangements with counterparties who buy the Group's hydrocarbon products. The Group's policy is to limit credit risk by only entering into oil and gas sales agreements with reputable and creditworthy oil and gas and trading companies. Where it is determined that there is a credit risk for oil and gas sales, the Group's policy is to require credit enhancement from the purchaser.

The Group's policy on joint venture parties is to rely on the provisions of the underlying joint operating agreements to take possession of the licence or the joint venture partner's share of production for non-payment of cash calls or other amounts due. In addition, cash is to be held and transacted only through major banks.

RISK FACTORS

IPC is engaged in the exploration, development and production of oil and gas and 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, 2023 ("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 Resources Advisory" in this MD&A.

DISCLOSURE CONTROLS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Disclosure Controls and Procedures
Disclosure controls and procedures have been designed to provide reasonable assurance that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation. Management, under the supervision of the Chief Executive Officer and the Chief Financial Officer, is responsible for the design and operation of disclosure controls and procedures.

Internal Controls over Financial Reporting
Management is also responsible for the design of the Group's internal controls over financial reporting in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. However, due to inherent limitations, internal control over financial reporting may not prevent or detect all misstatements and fraud.

There have been no material changes to the Groups internal control over financial reporting during the nine months period ended September 30, 2024, that have materially affected, or are reasonably likely to materially affect, the Group's internal control over financial reporting.

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

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

All statements other than statements of historical fact may be forward-looking statements. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, forecasts, guidance, budgets, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "forecast", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", "budget" and similar expressions) are not statements of historical fact and may be "forward-looking statements".

Forward-looking statements include, but are not limited to, statements with respect to:
- 2024 production ranges (including total daily average production), production composition, cash flows, operating costs and capital and decommissioning expenditure estimates;
- Estimates of future production, cash flows, operating costs and capital expenditures that are based on IPC's current business plans and assumptions regarding the business environment, which are subject to change;
- IPC's financial and operational flexibility to continue to react to recent events and navigate the Corporation through periods of volatile commodity prices;
- The ability to fully fund future expenditures from cash flows and current borrowing capacity;
- IPC's intention and ability to continue to implement strategies to build long-term shareholder value;
- The ability of IPC's portfolio of assets to provide a solid foundation for organic and inorganic growth;
- The continued facility uptime and reservoir performance in IPC's areas of operation;
- Development of the Blackrod project in Canada, including estimates of resource volumes, future production, timing, regulatory approvals, third party commercial arrangements, breakeven oil prices and net present values;
- Current and future production performance, operations and development potential of the Onion Lake Thermal, Suffield, Brooks, Ferguson and Mooney operations, including the timing and success of future oil and gas drilling and optimization programs;
- The potential improvement in the Canadian oil egress situation and IPC's ability to benefit from any such improvements;
- The ability to maintain current and forecast production in France and Malaysia;
- The intention and ability of IPC to acquire further common shares under the NCIB, including the timing of any such purchases;
- The ability of IPC to renew the NCIB and the number of common shares which may be purchased under a renewed NCIB;
- The return of value to IPC's shareholders as a result of the NCIB;
- The ability of IPC to implement further shareholder distributions in addition to the NCIB;
- IPC's ability to implement its greenhouse gas (GHG) emissions intensity and climate strategies and to achieve its net GHG emissions intensity reduction targets;
- IPC's ability to implement projects to reduce net emissions intensity, including potential carbon capture and storage;
- Estimates of reserves and contingent resources;
- The ability to generate free cash flows and use that cash to repay debt;
- IPC's continued access to its existing credit facilities, including current financial headroom, on terms acceptable to the Corporation;

- IPC's ability to maintain operations, production and business in light of any future pandemics and the restrictions and disruptions related thereto, including risks related to production delays and interruptions, changes in laws and regulations and reliance on third party operators and infrastructure;
- IPC's ability to identify and complete future acquisitions;
- Expectations regarding the oil and gas industry in Canada, Malaysia and France, including assumptions regarding future royalty rates, regulatory approvals, legislative changes, and ongoing projects and their expected completion; and
- Future drilling and other exploration and development activities.

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

The forward-looking statements are based on certain key expectations and assumptions made by IPC, including expectations and assumptions concerning: prevailing commodity prices and currency exchange rates; applicable royalty rates and tax laws; interest rates; future well production rates and reserve and contingent resource volumes; operating costs; our ability to maintain our existing credit ratings; our ability to achieve our performance targets; the timing of receipt of regulatory approvals; the performance of existing wells; the success obtained in drilling new wells; anticipated timing and results of capital expenditures; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the successful completion of acquisitions and dispositions and that we will be able to implement our standards, controls, procedures and policies in respect of any acquisitions and realize the expected synergies on the anticipated timeline or at all; the benefits of acquisitions; the state of the economy and the exploration and production business in the jurisdictions in which IPC operates and globally; the availability and cost of financing, labour and services; our intention to complete share repurchases under our normal course issuer bid program, including the funding of such share repurchases, existing and future market conditions, including with respect to the price of our common shares, and compliance with respect to applicable limitations under securities laws and regulations and stock exchange policies; and the ability to market crude oil, natural gas and natural gas liquids successfully.

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

These include, but are not limited to:
- General global economic, market and business conditions;
- The risks associated with the oil and gas industry in general such as operational risks in development, exploration and production;
- Delays or changes in plans with respect to exploration or development projects or capital expenditures;
- The uncertainty of estimates and projections relating to reserves, resources, production, revenues, costs and expenses;
- Health, safety and environmental risks;
- Commodity price fluctuations;
- Interest rate and exchange rate fluctuations;
- Marketing and transportation;
- Loss of markets;
- Environmental and climate-related risks;
- Competition;
- Innovation and cybersecurity risks related to our systems, including our costs of addressing or mitigating such risks;
- The ability to attract, engage and retain skilled employees
- Incorrect assessment of the value of acquisitions;
- Failure to complete or realize the anticipated benefits of acquisitions or dispositions;
- The ability to access sufficient capital from internal and external sources;
- Failure to obtain required regulatory and other approvals;
- Geopolitical conflicts, including the war between Ukraine and Russia and the conflict in the Middle East, and their potential impact on, among other things, global market conditions; and
- Changes in legislation, including but not limited to tax laws, royalties, environmental and abandonment regulations.

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

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, 2023, (See "Cautionary Statement Regarding Forward-Looking Information", "Reserves and Resources Advisory" and "Risk Factors") and other reports on file with applicable securities regulatory authorities, including previous financial reports, management's discussion and analysis and material change reports, which may be accessed through the SEDAR+ website (www.sedarplus.ca) or IPC's website (www.international-petroleum.com).

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

RESERVES AND RESOURCES ADVISORY

This MD&A contains references to estimates of gross and net reserves and resources attributed to the Corporation's oil and gas assets. Gross reserves/resources are the working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests. Net reserves/resources are the working interest (operating or non-operating) share after deduction of royalty obligations, plus royalty interests in reserves/resources, and in respect of PSCs in Malaysia, adjusted for cost and profit oil. Unless otherwise indicated, reserves/resource volumes are presented on a gross basis.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada are effective as of December 31, 2023, and are included in the reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Sproule's December 31, 2023 price forecasts.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France and Malaysia are effective as of December 31, 2023, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2023 price forecasts.

The price forecasts used in the Sproule and ERCE reports, are available on the website of Sproule (sproule. com) and are contained in the AIF. These price forecasts are as at December 31, 2023 and may not be reflective of current and future forecast commodity prices.

The reserve life index (RLI) is calculated by dividing the 2P reserves of 468 MMboe as at December 31, 2023, by the mid-point of the 2024 CMD production guidance of 46,000 to 48,000 boepd.

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

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

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

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

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

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

References to "unrisked" contingent resources volumes means that the reported volumes of contingent resources have not been risked (or adjusted) based on the chance of commerciality of such resources. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore, unrisked reported volumes of contingent resources do not reflect the risking (or adjustment) of such volumes based on the chance of development of such resources.

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

2P reserves and contingent resources included in the reports prepared by Sproule and ERCE have been aggregated by IPC. Estimates of reserves, resources and future net revenue for individual properties may not reflect the same level of confidence as estimates of reserves, resources and future net revenue for all properties, due to aggregation. This MD&A contains estimates of the net present value of the future net revenue from IPC's reserves and contingent resources. The estimated values of future net revenue disclosed in this MD&A do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve and resources evaluations will be attained and variances could be material.

References to "contingent resources" do not constitute, and should be distinguished from, references to "reserves".

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 thousand cubic feet (Mcf) per 1 barrel (bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a 6:1 conversion basis may be misleading as an indication of value.

Supplemental Information regarding Product Types
The following table is intended to provide supplemental information about the product type composition of IPC's net average daily production figures provided in this document:

	Heavy Crude Oil (Mbopd)	Light and Medium Crude Oil (Mbopd)	Conventional Natural Gas (per day)	Total (Mboepd)
Three months ended				
September 30, 2024	21.9	7.8	91.9 MMcf (15.3 Mboe)	45.0
September 30, 2023	25.8	7.1	103.4 MMcf (17.3 Mboe)	50.2
Nine months ended				
September 30, 2024	23.7	7.9	94.8 MMcf (15.8 Mboe)	47.4
September 30, 2023	25.9	8.6	102.4 MMcf (17.1 Mboe)	51.6
Year ended December 31, 2023				
December 31, 2023	25.8	8.1	102.8MMcf (17.1 Mboe)	51.1

This MD&A also makes reference to IPC's forecast total average daily production of 46,000 to 48,000 boepd for 2024. IPC estimates that approximately 50% of that production will be comprised of heavy oil, approximately 16% will be comprised of light and medium crude oil and approximately 34% will be comprised of conventional natural gas.

OTHER SUPPLEMENTARY INFORMATION

Abbreviations

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

Oil related terms and measurements

AECO	The daily average benchmark price for natural gas at the AECO hub in southeast Alberta
AESO	Alberta Electric System Operator
API	An indication of the specific gravity of crude oil on the API (American Petroleum Institute) gravity scale
ASP	Alkaline surfactant polymer (an EOR process)
bbl	Barrel (1 barrel = 159 litres)
boe[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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