Q1

International Petroleum Corporation

Management's Discussion and Analysis

For the three months ended March 31, 2023

International Petroleum Corp.

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Contents

Non-IFRS Measures

References are made in this MD&A to "operating cash flow" (OCF), "free cash flow" (FCF), "Earnings Before Interest, Tax, Depreciation and Amortization" (EBITDA), "operating costs" and "net debt"/"net cash" which are not generally accepted accounting measures under International Financial Reporting Standards (IFRS) and do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with definitions of OCF, FCF, EBITDA, operating costs and net debt/net cash that may be used by other public companies. Management believes that OCF, FCF, EBITDA, operating costs and net debt/net cash are useful supplemental measures that may assist shareholders and investors in assessing the cash generated by and the financial performance and position of the Corporation. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-IFRS measure is presented in this MD&A. See "Non-IFRS Measures" on page 17.

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 22.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada (other than the assets acquired in the acquisition of Cor4) are effective as of December 31, 2022, and are included in the reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Sproule's December 31, 2022, price forecasts.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France and Malaysia are effective as of December 31, 2022, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2022, price forecasts.

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

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

INTRODUCTION

This management's discussion and analysis ("MD&A") for International Petroleum Corporation ("IPC" or the "Corporation" and, together with its subsidiaries, the "Group") is dated May 2, 2023 and is intended to provide an overview of the Group's operations, financial performance and current and future business opportunities. This MD&A should be read in conjunction with IPC's audited consolidated financial statements and accompanying notes for the year ended December 31, 2022 ("Financial Statements").

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

The Corporation's common shares are listed on the Toronto Stock Exchange in Canada and the Nasdaq Stockholm Exchange in Sweden. The Corporation is incorporated and domiciled in British Columbia, Canada, under the Business Corporations Act. The address of its registered office is Suite 2600, 595 Burrard Street, P.O. Box 49314, Vancouver, BC V7X 1L3, Canada and its business address is Suite 2000, 885 West Georgia Street, Vancouver, BC V6C 3E8, Canada.

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

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

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

	March 31, 2023		March 31, 2022		December 31, 2022	
	Average	Period end	Average	Period end	Average	Year end
1 EUR equals USD	1.0730	1.0875	1.1225	1.1101	1.0539	1.0666
1 USD equals CAD	1.3521	1.3551	1.2666	1.2518	1.3015	1.3538
1 USD equals MYR	4.3865	4.4125	4.1923	4.2048	4.3995	4.4050

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

HIGHLIGHTS

Q1 2023 Business Highlights

- Record quarterly average net production of approximately 52,800 barrels of oil equivalent (boe) per day (boepd) for the first quarter of 2023 (50% heavy crude oil, 18% light and medium crude oil and 32% natural gas).
- Decision taken to advance the development of Phase 1 of the Blackrod project in Canada, maturing 218 million barrels of oil equivalent (MMboe) of 2P reserves.[1][2]
- Successful completion of the Cor4 acquisition in Canada forecast to add approximately 4,000 boepd of average production over 2023 and 15.9 MMboe of 2P reserves.[1][2]
- Ten-year extension signed for the Bertam Field, Malaysia production sharing contract (PSC) to 2035.
- 4.76 million common shares purchased and cancelled during Q1 2023 under IPC's normal course issuer bid (NCIB).

Q1 2023 Financial Highlights

- Operating costs per boe of USD 17.3 for Q1 2023 in line with CMD guidance for Q1 2023.[1][3]
- Operating cash flow (OCF) generation for Q1 2023 amounted to MUSD 76.[1][3]
- Capital and decommissioning expenditures of MUSD 55 for Q1 2023 in line with CMD guidance.[1]
- Free cash flow (FCF) generation for Q1 2023 amounted to MUSD 16.[1][3]
- Net cash of MUSD 67 as at March 31, 2023.[3]
- Increased Canadian Revolving Credit Facility (RCF) from CAD 75 to 150 million (fully committed and undrawn) and extended maturity from February 2024 to May 2025.
- Net result of MUSD 40 for Q1 2023.

Reserves and Resources

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

2023 Annual Guidance

- Full year 2023 average net production forecast expected to be at the upper end of 48,000 to 50,000 boepd guidance range.[1]
- Full year 2023 operating costs guidance forecast at USD 17.5 to 18 per boe.[1][3]
- Full year 2023 OCF guidance estimated at between MUSD 250 to 495 (assuming Brent USD 70 to 100 per barrel).[1][3]
- Full year 2023 capital and decommissioning expenditures guidance forecast at MUSD 365, including MUSD 287 relating to Phase 1 of the Blackrod project.[1]
- Full year 2023 FCF forecast ranges from approximately MUSD -145 to 105 (assuming Brent USD 70 to 100 per barrel) after taking into account MUSD 287 of proposed 2023 Blackrod capital expenditures.[1][3]

	Three months ended March 31	
USD Thousands	2023	2022
Revenue	**192,516**	259,782
Gross profit	**40,205**	119,100
Net result	**39,563**	80,822
Operating cash flow[3]	**75,900**	145,110
Free cash flow[3]	**16,259**	96,479
EBITDA[3]	**76,079**	145,463
Net Cash/(Debt)[3]	**66,956**	(42,367)

OPERATIONS REVIEW

Business Overview

During the first quarter of 2023, oil and gas prices weakened on demand concerns, as rising interest rates aimed at taming high inflation, stoked recessionary fears. This was further exacerbated by the unfolding banking crisis during the quarter. Brent prices averaged slightly over USD 80 per barrel during the quarter, down by around ten per cent compared with the fourth quarter of 2022. The surprise production cuts announced by OPEC+ in early April are a second pre-emptive move by the group, aimed at ensuring recent oil price weakness, is not sustained. While inventory levels have built back close to the five-year average levels, the OPEC+ cuts are expected by market observers to push the oil market back into deficit for the remainder of 2023.

The first quarter 2023 West Texas Intermediate (WTI) to Western Canadian Select (WCS) crude price differentials averaged around USD 25 per barrel, USD 5 per barrel wider than our base case 2023 market guidance. Those market factors that have driven differentials wider such as the US Strategic Petroleum Reserve (SPR) releases, higher natural gas prices and refinery outages have now turned to provide more favourable tailwinds to Canadian differentials going forward. In addition, the expansion of the Trans Mountain pipeline (590,000 barrels per day of extra capacity linking Edmonton to the port of Vancouver) due in service in Q1 2024 as well as a reduction in Mexican heavy oil exports to the US as domestic refinery capacity increases by more than 200,000 barrels per day is expected to provide stronger support to WTI/WCS differentials going forward. Current WTI/WCS differentials have tightened to less than USD 16 per barrel for the remainder of 2023 and the whole of 2024 as a result of these favourable market developments.

Gas markets weakened significantly during the first quarter of 2023. IPC's average realised gas price was CAD 3.10 per Mcf compared with CAD 5.90 per Mcf during the fourth quarter of 2022. The recent weakness seen in North American gas prices, was to a large extent, driven by a much milder winter in Europe and the reduced demand for US LNG as a result. IPC was partially protected by AECO gas price hedges that were put in place when gas prices were much stronger in late 2022: 33.7 MMcf per day at CAD 6.26 per Mcf in Q1 2023 and at CAD 4.10 per Mcf from April to October 2023.

First Quarter 2023 Highlights and Full Year 2023 Guidance

During the first quarter of 2023, our assets delivered average net production of 52,800 boepd, above our high-end guidance for the quarter and a record high for IPC. This was made possible by the very high uptime performance across all our assets as well as the production contribution from our recent Cor4 acquisition in Canada. Given the very strong start to the year, full year 2023 average net production is expected to be towards the upper end of the guidance range of 48,000 to 50,000 boepd.[1]

Our operating costs per boe for the first quarter of 2023 was USD 17.3, in line with our latest guidance. Full year 2023 operating costs per boe guidance of USD 17.5 to 18.0 per boe remains unchanged.[1][3]

Operating cash flow (OCF) generation for the first quarter of 2023 was USD 76 million. Full year 2023 OCF guidance of USD 250 to 495 million (assumed Brent USD 70 to 100 per barrel is unchanged).[1][3]

Capital and decommissioning expenditure for the first quarter of 2023 was USD 55 million in line with guidance. Full year 2023 capital and decommissioning expenditure of USD 365 million is unchanged.[1]

Free cash flow (FCF) generation was USD 16 million during the first quarter of 2023. Full year 2023 FCF guidance of USD -145 to 105 million (assumed Brent USD 70 to 100 per barrel) remains unchanged.[1][3]

During the first quarter of 2023, IPC's net cash position of USD 175 million was reduced to USD 67 million, largely driven by the funding of USD 62 million for the Cor4 acquisition and USD 46 million for the continuing share repurchase program (NCIB).[3] Gross cash on the balance sheet as at March 31, 2023 amounts to USD 378 million providing a significant war chest to pursue our three strategic pillars of returning value to stakeholders, pursuing value adding M&A and focusing on organic growth. In addition, IPC further strengthened its liquidity position during the first quarter by increasing its Canadian Revolving Credit Facility (RCF) from CAD 75 to 150 million.

Phase 1 Blackrod Project

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

During the first quarter, the Phase 1 development early ground works and the final facility engineering activities have progressed in line with schedule and budget. Preparations to enter in the major central processing facility build contract are on track to be finalised in the second quarter. This is expected to provide a high degree of certainty for the fixed price element of the Phase I development capital expenditure which represents close to 50% of the overall Phase I budget to first oil.

M&A
During Q1 2023, IPC announced and completed its fifth acquisition in five years. IPC acquired 15.9 MMboe of 2P reserves adjacent to our Suffield property in Alberta, Canada, through the Cor4 acquisition. This acquisition is forecast to add approximately 4,000 boepd to our Suffield area production in 2023. The producing assets are complementary to both our Suffield asset and a recent land acquisition on the same geological trend that IPC concluded in the fourth quarter of 2022. Following these acquisitions, we now have over 25 drilling inventory locations on the Ellerslie play fairway that extends from the west of our Suffield asset to our new land acquisition and into the properties acquired in the Cor4 acquisition. Three wells were successfully drilled and brought on production since the beginning of the year and we plan to drill another three wells on this exciting play in 2023. The Cor4 acquisition was completed on March 3, 2023 with the consideration funded using existing cash on hand.[1][2]

2023 Capital Allocation Framework

Normal Course Issuer Bid
In Q4 2022, IPC announced the renewal of the NCIB, with the ability to repurchase up to approximately 9.3 million common shares over the twelve-month period to December 2023. IPC repurchased in December 2022 and subsequently cancelled approximately 0.73 million common shares. By the end of March 2023, IPC purchased and cancelled a further approximately 4.76 million common shares under the NCIB. The average price of common shares purchased under the renewed NCIB during the period of December 2022 to March 2023 was SEK 102 / CAD 13.25 per share.

As at March 31, 2023, IPC had a total of 132,069,946 common shares issued and outstanding, with no common shares held in treasury.

2023 Capital Allocation Plans
IPC's capital allocation framework consists of distributing to shareholders a minimum of 40% of the FCF generated by the business, provided that IPC's net debt to EBITDA ratio is at or below 1 time.[3] These shareholder distributions are planned to be implemented by continued share repurchases under the NCIB as well as the consideration by IPC of other forms of shareholder distributions, subject to further applicable regulatory and corporate approvals.

Despite the higher level of capital investment, and notwithstanding the capital allocation framework described above, IPC plans to continue to purchase and cancel common shares under the NCIB to the remaining limit as at March 31, 2023 of 3.8 million common shares by the end of December 2023, resulting in the anticipated cancellation of 7% of shares outstanding as of December 2022. We believe a combination of materially growing our 2P reserves, production and asset value whilst reducing our share count is a winning combination for shareholders.

Environmental, Social and Governance (ESG) Performance
During the first quarter of 2023, 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 2023, IPC extended our commitment to remain at 2025 levels of 20 kg CO_2/boe through to the end of 2027.

Notes:

(1) See "Supplemental Information regarding Product Types" in "Reserves and Resources Advisory" below. See also the annual information form for the year ended December 31, 2022 (AIF) available on IPC's website at www.international-petroleum.com and under IPC's profile on SEDAR at www.sedar.com. IPC completed the acquisition of Cor4 on March 3, 2023. The Financial Statements have been prepared on that basis, with revenues and expenses related to the assets acquired in the Cor4 acquisition included in the Financial Statements from March 3, 2023. Certain historical and forecast operational and financial information included in the MD&A, including production, reserves, operating costs, OCF, FCF and EBITDA related to the assets acquired in the Cor4 acquisition, are reported based on the effective date of the Cor4 acquisition of January 1, 2023.

(2) See "Reserves and Resources Advisory" below. Further information with respect to IPC's reserves, contingent resources and estimates of future net revenue, including assumptions relating to the calculation of NPV, are described in the AIF. 2P reserves as at December 31, 2022 of 487 MMboe includes 471 MMboe attributable to IPC's oil and gas assets and 15.9 MMboe attributable to the oil and gas assets acquired in the Cor4 acquisition.

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

Operations Overview

Reserves and Resources

The 2P reserves attributable to IPC's oil and gas assets are 487 MMboe as at December 31, 2022, with 471 MMboe certified by independent third party reserve auditors and 15.9 MMboe related to the Cor4 acquisition audited by an internal qualified reserves auditor. The proved plus probable reserve life index (RLI) as at December 31, 2022, is approximately 27 years. Best estimate contingent resources as at December 31, 2022, are 1,162 MMboe (unrisked). See "Reserves and Resources Advisory" below.

With the acquisition of the Cor4 assets in the Suffield area and the major investment associated with the sanction of the Blackrod Phase 1 development in 2023, IPC has set a reduced base business capital budget for the year. In Canada, the Blackrod Phase 1 development commenced in Q1 with early works in line with schedule and budget. In the Suffield area, oil well drilling commenced with three out of the six planned Ellerslie play wells drilled in Q1 2023. In France, drilling operations that commenced in 2022 have been successfully completed with all three Villeperdue West oil wells in the early stages of clean up with results expected in Q2 2023. The planned Merisier side-track well has also been successfully completed and is expected online in Q2 2023. In Malaysia, evaluation of a potential next phase of field development is progressing in line with schedule. IPC remains focused on organic growth and continues to mature future development projects across all operated assets, with a significant portfolio of drilling and optimisation opportunities ready for sanction at the discretion of the Group.

Production

A new average daily net production record of 52,800 boepd was achieved in the first quarter of 2023. In Canada, both the Suffield oil and gas producing assets continue to deliver strong results. Production optimisation activity at Suffield Gas was supported by a more moderate freeze-off period in Q1 2023. This was supplemented by initial strong production performance at the newly acquired Suffield Cor4 assets. In addition, in Malaysia the Bertam field continued to deliver excellent results with production well rate optimisation activity and high facility uptime. In France, a short duration disruption from protestors was experienced in March that had a minor negative impact on production.

With the exceptional production performance in Q1 2023 above high end guidance, full year 2023 average net production is expected to be at the upper end of the original guidance range of 48,000 to 50,000 boepd.

The production during Q1 2023 with comparatives is summarized below:

Production in Mboepd	Three months ended March 31		Year ended December 31
	2023	2022	2022
Crude oil			
Canada – Northern Assets	15.8	14.8	15.6
Canada – Southern Assets[1]	12.7	8.4	8.7
Malaysia	5.1	4.1	5.3
France	2.5	2.9	2.7
Total crude oil production	**36.1**	30.2	32.3
Gas			
Canada – Northern Assets	0.4	0.1	0.1
Canada – Southern Assets	16.3	15.5	16.2
Total gas production	**16.7**	15.6	16.3
Total production	**52.8**	45.8	48.6
Quantity in MMboe	**4.75**	4.12	17.74

[1] *Includes production from the Cor4 assets in the Suffield area from January 1, 2023. The acquisition of Cor4 was completed on March 3, 2023.*

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

CANADA

Production in Mboepd	WI	Three months ended March 31 2023	Three months ended March 31 2022	Year ended December 31 2022
- Oil Onion Lake Thermal	100%	13.3	11.9	12.7
- Oil Suffield Area[1]	100%	10.7	7.4	7.1
- Oil Ferguson	100%	2.0	1.0	1.6
- Oil Other	50-100%	2.5	2.9	2.9
- Gas[1]	~100%[2]	16.7	15.6	16.3
Canada		**45.2**	38.8	40.6

[1] *Including the production contribution of the Cor4 acquisition from the effective date of January 1, 2023. The acquisition of Cor4 was completed on March 3, 2023.*
[2] *On a well count basis*

Production
Net production from IPC's Canadian assets during Q1 2023 was ahead of guidance at 45,200 boepd primarily due to strong performance from the Suffield area assets. Production optimisation activity at Suffield Gas was supported by a more moderate freeze off period in Q1 2023. This was supplemented by initial strong production performance at the newly acquired Cor4 assets in the Suffield area. Stable operational performance and high production uptimes continued at the Onion Lake Thermal asset in Q1 2023.

Organic Growth and Capital Projects
In Canada, the Blackrod Phase 1 development has been sanctioned with civil works and the main central processing facility build (engineering, procurement and fabrication) scheduled to commence in Q3 2023. A reduced base business budget for the remainder of the assets in Canada has been set for the year with a focus on oil well drilling in the Suffield Ellerslie formation and the completion of the next production sustaining Pad L at Onion Lake Thermal.

In Q1 2023 at Blackrod, the Phase 1 development early ground works and final facility engineering activity have progressed in line with schedule and budget. Preparations to enter into the major central processing facility build contract are on track to be finalised in Q2 2023.

At Suffield, three out of six of the planned Ellerslie play wells in 2023 have been drilled and brought online with encouraging indications as the wells clean up.

At Onion Lake Thermal, the next sustaining production Pad L completion, facility works and tie ins are progressing in line with expectations with first oil from the Pad expected in Q4 2023.

MALAYSIA

Production in Mboepd	WI	Three months ended March 31 2023	Three months ended March 31 2022	Year ended December 31 2022
Bertam	100%	**5.1**	4.1	5.3

Production
Strong performance in Q1 2023 from Bertam field on Block PM307 with average net production ahead of guidance at 5,100 boepd. Exceptional facility and well performance continued with facility uptimes registered in excess of 99%.

Organic Growth and Capital Projects
In Malaysia, a limited capital budget was set for 2023 with our focus now on studying the remaining undeveloped potential of the Bertam field following the successful results from the latest development drilling campaign in the north east of the field.

FRANCE

Production in Mboepd	WI	Three months ended March 31 2023	Three months ended March 31 2022	Year ended December 31 2022
France				
- Paris Basin	100%[1]	2.1	2.5	2.4
- Aquitaine	50%	0.4	0.4	0.3
		2.5	2.9	2.7

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

Production
Net production in France during Q1 2023 was in line with the guidance at 2,500 boepd. Production was curtailed for a short duration in March 2023 with political protests impacting oil export trucking and refining operations.

Organic Growth
In France, at the end of Q1 2023, all three planned Villeperdue West oil wells have been successfully completed and brought online. The wells are cleaning up. The planned Merisier side-track oil well has also been successfully drilled and is expected online in Q2 2023.

IPC continues to mature future development projects in France, with focus towards the undeveloped resource base within the Paris Basin.

FINANCIAL REVIEW

Financial Results

Selected Annual Financial Information

Selected consolidated statement of operations is as follows:

USD Thousands	Q1-23	Q4-22	Q3-22	Q2-22	Q1-22	Q4-21	Q3-21	Q2-21
Revenue	**192,516**	255,200	299,361	315,540	259,782	215,296	172,551	144,278
Gross profit	**64,383**	95,411	140,489	161,709	119,100	79,469	58,636	34,286
Net result	**39,563**	61,183	90,503	105,217	80,822	66,918	30,557	21,693
Earnings per share – USD	**0.29**	0.45	0.63	0.70	0.52	0.43	0.20	0.14
Earnings per share fully diluted – USD	**0.28**	0.44	0.62	0.68	0.51	0.42	0.19	0.14
Operating cash flow[1]	**75,900**	113,668	171,654	192,515	145,110	110,687	91,365	66,959
Free cash flow[1]	**16,259**	65,288	116,681	151,792	96,479	86,960	76,607	50,366
EBITDA[1]	**76,079**	125,651	174,328	194,038	145,463	110,087	89,223	65,181
Net cash / (debt) at period end[1]	**66,956**	175,098	88,615	14,382	(42,367)	(94,312)	(161,199)	(240,617)

[1] *See definition on page 17 under "Non-IFRS measures"*

Summarized consolidated balance sheet information is as follows:

USD Thousands	March 31, 2023	December 31, 2022
Non-current assets	1,172,564	1,041,051
Current assets	534,118	638,566
Total assets	**1,706,682**	1,679,617
Total non-current liabilities	603,511	564,381
Current liabilities	161,853	149,905
Total liabilities	**765,364**	714,286
Net assets	**941,318**	965,331
Working capital (including cash)	**372,265**	488,661

Selected Interim Financial Information

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

	Three months ended – March 31, 2023					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	95,829	51,902	17,671	15,131	–	**180,533**
NGLs	–	190	–	–	–	**190**
Gas	94	20,389	–	–	–	**20,483**
Net sales of oil and gas	**95,923**	**72,481**	**17,671**	**15,131**	–	**201,206**
Change in under/over lift position	–	–	–	2,670	–	**2,670**
Royalties	(10,819)	(7,846)	–	(1,474)	–	**(20,139)**
Hedging settlement	636	7,948	–	–	–	**8,584**
Other operating revenue	–	6	–	189	–	**195**
Revenue	**85,740**	**72,589**	**17,671**	**16,516**	–	**192,516**
Operating costs	(25,033)	(34,498)	(8,176)	(7,738)	–	**(75,445)**
Cost of blending	(40,740)	(7,077)	–	–	–	**(47,817)**
Change in inventory position	(461)	39	5,872	285	–	**5,735**
Depletion[1]	3,105	(582)	(5,829)	(3,133)	–	**(6,439)**
Depreciation of other assets	–	–	(2,558)	–	–	**(2,558)**
Exploration and business development costs	–	(831)	–	–	(778)	**(1,609)**
Gross profit/(loss)	**22,611**	**29,640**	**6,980**	**5,930**	**(778)**	**64,383**

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

	Three months ended – March 31, 2022					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	124,307	66,923	36,014	33,659	–	260,903
NGLs	–	227	–	–	–	227
Gas	265	29,951	–	–	–	30,216
Net sales of oil and gas	124,572	97,101	36,014	33,659	–	291,346
Change in under/over lift position	–	–	–	(6,113)	–	(6,113)
Royalties	(15,065)	(8,923)	–	(1,524)	–	(25,512)
Hedging settlement	147	(403)	–	–	–	(256)
Other operating revenue	–	101	–	216	–	317
Revenue	109,654	87,876	36,014	26,238	–	259,782
Operating costs	(25,220)	(27,216)	(9,586)	(9,439)	–	(71,461)
Cost of blending	(32,938)	(9,703)	–	–	–	(42,641)
Change in inventory position	1,323	(395)	2,136	489	–	3,553
Depletion	(7,887)	(9,972)	(6,689)	(3,404)	–	(27,952)
Depreciation of other assets	–	–	(2,080)	–	–	(2,080)
Exploration and business development costs	–	–	–	–	(101)	(101)
Gross profit/(loss)	44,932	40,590	19,795	13,884	(101)	119,100

Three months ended March 31, 2023, Review

Revenue

Total revenue amounted to USD 192,516 thousand for Q1 2023, compared to USD 259,782 thousand for Q1 2022 and is analyzed as follows:

	Three months ended March 31	
USD Thousands	**2023**	2022
Crude oil sales	180,533	260,903
Gas and NGL sales	20,673	30,443
Change in under/overlift position	2,670	(6,113)
Royalties	(20,139)	(25,512)
Hedging settlement	8,584	(256)
Other operating revenue	195	317
Total revenue	**192,516**	259,782

The main components of total revenue for Q1 2023 and Q1 2022, respectively, are detailed below.

Crude oil sales

	Three months ended – March 31, 2023				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	95,829	51,902	17,671	15,131	**180,533**
- Quantity sold in bbls	1,914,797	976,258	205,338	185,934	**3,282,327**
- Average price realized USD per bbl	50.05	53.16	86.06	81.38	**55.00**

	Three months ended – March 31, 2022				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	124,307	66,923	36,014	33,659	260,903
- Quantity sold in bbls	1,578,764	849,717	290,293	351,323	3,070,097
- Average price realized USD per bbl	78.74	78.76	124.06	95.81	84.98

Crude oil revenue was 31% lower in Q1 2023 compared to Q1 2022 mainly due to lower oil prices and a higher differential on Canadian pricing in Q1 2023 compared to Q1 2022.

The Suffield area assets and Onion Lake crude oil in Canada are blended with purchased condensate diluent volumes to meet pipeline specifications. As a result of the blended volumes, actual sales volumes are higher than produced volumes for Canada. The Canadian realized sales price is based on the Western Canadian Select ("WCS") price which trades at a discount to West Texas Intermediate ("WTI"). For Q1 2023, WTI averaged USD 76 per bbl compared to USD 95 per bbl for Q1 2022 and the average discount to WCS used in our pricing formula was USD 25 per bbl compared to USD 15 per bbl for Q1 2022.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices. There was one cargo lifting in Malaysia during Q1 2023 in March 2023 and one cargo lifting in Q1 2022. Produced unsold oil barrels from Bertam at the end of Q1 2023 amounted to 275,000 barrels, see Change in Inventory Position section below. There was no Aquitaine cargo in France lifted in Q1 2023 compared to one in Q1 2022. The average Dated Brent crude oil price was USD 81 per bbl for Q1 2023 compared to USD 102 per bbl for the comparative period.

Gas and NGL sales

	Three months ended – March 31, 2023		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	20,579	94	**20,673**
- Quantity sold in Mcf	7,645,299	53,049	**7,698,348**
- Average price realized USD per Mcf	2.69	1.76	**2.69**

	Three months ended – March 31, 2022		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	30,178	265	30,443
- Quantity sold in Mcf	7,670,925	66,189	7,737,114
- Average price realized USD per Mcf	3.93	4.00	3.93

Gas and NGL sales revenue was 32% lower for Q1 2023 compared to Q1 2022 mainly due to the lower achieved gas price. IPC's achieved gas price is based on AECO pricing plus a premium. For Q1 2023, IPC realized an average price of CAD 3.60 per Mcf compared to AECO average pricing of CAD 3.17 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 price swaps to limit pricing exposure. The oil and gas pricing contracts are not entered into for speculative purposes.

The realized hedging settlement for Q1 2023 amounted to a gain of USD 8,584 thousand and consisted of a gain of USD 1,679 thousand on the oil contracts and a gain of USD 6,905 thousand on the gas contracts. Also see the Financial Position and Liquidity and the Financial Risk Management sections below.

Other operating revenue
Other operating revenue amounted to USD 195 thousand for Q1 2023 compared to USD 317 thousand for Q1 2022 and mainly consists of tariff income and fees for strategic storage of inventory in France.

Production costs
Production costs including inventory movements amounted to USD 117,527 thousand for Q1 2023 compared to USD 110,549 thousand for Q1 2022 and is analyzed as follows:

	Three months ended – March 31, 2023					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	34,498	25,033	12,226	7,738	(4,050)	**75,445**
USD/boe[2]	15.80	17.16	26.76	34.52	n/a	**17.31**
Cost of blending	7,077	40,740	–	–	–	**47,817**
Change in inventory position	(39)	461	(5,872)	(285)	–	**(5,735)**
Production costs	**41,536**	**66,234**	**6,354**	**7,453**	**(4,050)**	**117,527**

USD Thousands	Three months ended – March 31, 2022 Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	27,216	25,220	13,636	9,439	(4,050)	71,461
USD/boe[2]	12.63	18.83	36.71	36.76	n/a	17.33
Cost of blending	9,703	32,938	–	–	–	42,641
Change in inventory position	395	(1,323)	(2,136)	(489)	–	(3,553)
Production costs	37,314	56,835	11,500	8,950	(4,050)	110,549

[1] See definition on page 17 under "Non-IFRS measures".
[2] USD/boe in the tables above is calculated by dividing the cost by the production volume for each country for the period and includes Cor4 from January 1, 2023.
[3] Included in the Malaysia operating costs is the lease cost for the FPSO Bertam which is owned by the Group. Other represents the FPSO Bertam lease fee self-to-self payment elimination. Netting the self-to-self elimination against the operating costs in Malaysia reduces the operating costs per boe for Malaysia to USD 17.90 and USD 25.80 for Q1 2023 and Q1 2022 respectively.

Operating costs
Operating costs amounted to USD 75,445 thousand for Q1 2023 compared to USD 71,461 thousand for Q1 2022. The increase in costs in Q1 2023 compared to Q1 2022 is due mainly to higher electricity prices. Operating costs per boe amounted to USD 17.31 per boe in Q1 2023 in line with CMD guidance for the quarter and compared with USD 17.33 per boe in Q1 2022. The full year CMD guidance of USD 17.5 to 18 per boe remains unchanged.

Cost of blending
For the Suffield area assets in Canada, oil production is blended with purchased condensate diluent to meet pipeline specifications. As a result of the blending, actual sales volumes are higher than produced barrels and the realized sales price of a blended barrel is higher than an unblended barrel. The majority of Onion Lake oil production is also blended and exported by pipeline since April 2022 with the commissioning of a third party export pipeline from the Onion Lake field to the gathering system.

The cost of the diluent net of proceeds from the sale of surplus diluent amounted to USD 47,817 thousand for Q1 2023 compared to USD 42,641 thousand for Q1 2022. The increase versus the comparative period is attributable to larger Onion Lake blending volumes in Q1 2023 with less volumes blended in Q1 2022 when the export pipeline for blended barrels was being commissioned.

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 Q1 2023, IPC had crude entitlement of 275,000 barrels of oil on the FPSO Bertam facility (crude produced but unsold). One crude cargo was lifted from Bertam in early March 2023 with the next lifting in April 2023.

Depletion and decommissioning costs
The total depletion of oil and gas properties amounted to USD 6,439 thousand for Q1 2023 (including an adjustment for accelerated decommissioning activities amounting to USD 24,178 thousand) compared to USD 27,952 thousand for Q1 2022. The depletion charge is analyzed in the following tables:

USD Thousands	Three months ended – March 31, 2023 Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands[1]	12,302	9,353	5,829	3,133	**30,617**
USD per boe[2]	5.65	6.41	12.76	13.98	**6.96**

USD Thousands	Three months ended – March 31, 2022 Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	9,972	7,887	6,689	3,404	27,952
USD per boe[2]	4.63	5.89	18.01	13.26	6.78

[1] In Canada, excludes the adjustment for accelerated decommissioning activities.
[2] USD/boe in the tables above is calculated by dividing the depletion cost by the production volume for each country for the period and includes Cor4 from January 1, 2023.

The depletion charge is derived by applying the depletion rate per boe to the volumes produced in the period by each field. The depletion rate in Malaysia has significantly decreased compared to the prior year following the extension to the Bertam field production sharing contract and consequent increase in field reserves announced at the end of 2022. In addition, the depletion rate in Canada has increased compared to the prior year as a result of the Cor4 acquisition.

Depreciation of other tangible fixed assets
The total depreciation of other assets amounted to USD 2,558 thousand for Q1 2023 compared to USD 2,080 thousand for Q1 2022. This relates to the depreciation of the FPSO Bertam, which is being depreciated on a unit of production basis based on the Bertam field reserves cut-off at August 2025.

Exploration and business development costs
The total exploration and business developments costs amounted to USD 1,609 thousand for Q1 2023. These costs mainly related to Cor4 acquisition related costs amounting to USD 831 thousand and to other business development costs.

General, administrative and depreciation expenses
General, administrative and depreciation expenses amounted to USD 4,194 thousand for the three months ended March 31, 2023 compared to USD 4,173 thousand for the three months ended March 31, 2022.

Net financial items
Net financial items amounted to a charge of USD 5,015 thousand for Q1 2023, compared to a charge of USD 6,607 thousand for Q1 2022, and included a non-cash net foreign exchange loss of USD 856 thousand for Q1 2023 compared to a net foreign exchange gain of USD 3,059 thousand for Q1 2022. The foreign exchange movements during Q1 2023 are mainly resulting from the revaluation of intra-group loan funding balances.

Excluding foreign exchange movements, the net financial items amounted to a charge of USD 4,159 thousand for Q1 2023, compared to a charge of USD 9,666 thousand for Q1 2022.

The interest expense amounted to USD 5,349 thousand for Q1 2023, compared to USD 4,034 thousand for the comparative period in 2022. Interest income generated on cash balances held in Q1 2023 amounted to USD 4,924 thousand.

The unwinding of the asset retirement obligation discount rate amounted to USD 3,068 thousand for Q1 2023, compared to USD 2,760 thousand for Q1 2022.

Income tax
The corporate income tax amounted to a charge of USD 15,611 thousand for Q1 2023, compared to a charge of USD 27,498 thousand for Q1 2022 and included deferred taxes of USD 11,620 thousand and USD 23,375 thousand respectively.

The current income tax charge amounted to USD 3,991 thousand in Q1 2023 and mainly related to France and Malaysia. No corporate income tax was payable in Canada in respect of Q1 2023 due to the usage of historical tax pools. On September 30, 2022, the Council of the European Union ("EU") agreed to impose an EU-wide windfall profits tax on energy companies deriving income from operations in EU countries ("Solidarity Contribution") in 2022 and potentially 2023. The current tax charge in Q1 2023 includes a Solidarity Contribution provision relating to the income in France of USD 754 thousand.

Capital Expenditure

Development and exploration and evaluation expenditure incurred in Q1 2023 was as follows:

USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Development	4,538	30,907	664	12,129	**48,238**

Capital expenditure of USD 48,238 thousand was mainly spent in Canada on the Blackrod Phase 1 Development project and on the Pad L completion at Onion Lake Thermal and in France on the drilling of the Villeperdue West oil wells.

An additional USD 5,821 thousand of capital expenditure was spent on the Cor4 assets mainly on drilling from January 1, 2023 to the completion date of March 3, 2023.

Cor4 Acquisition

On March 3, 2023, IPC completed the acquisition of all of the issued and outstanding shares of Cor4 Oil Corp. ("Cor4"). At such date, Cor4 became an indirect wholly-owned subsidiary of IPC.

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

Total cash consideration paid, after preliminary closing adjustments, amounted to USD 62.0 million (CAD 84.3 million).

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

USD Thousands	
Cash	2,792
Trade and other receivables	7,671
Prepaid expenses and deposits	2,417
Fair value of risk management assets	1,144
Deferred tax assets	19,334
Right-of-use assets	109
Property, plant and equipment	72,003
Accounts payable and accrued liabilities	(12,623)
Right-of-use liabilities	(109)
Decommissioning liabilities	(29,885)
Mark-To-Market reserve in equity	(881)
Total Consideration	**61,972**
Settled by:	
Cash payment	**61,972**

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

Acquisition-related costs of approximately USD 0.8 million have been recognized in the statement of operations during Q1 2023.

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

Other tangible fixed assets
Other tangible fixed assets amounted to USD 31,266 thousand as at March 31, 2023, which included USD 29,402 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated on a unit of production basis based on the Bertam field reserves cut-off at August 2025.

Financial Position and Liquidity

Financing
As at March 31, 2023, IPC had a EUR 13 million unsecured credit facility in France (the "France Facility"), with maturity in May 2026. IPC commenced quarterly repayments of the French Facility in August 2022. The amount remaining outstanding under the France Facility as at March 31, 2023 was USD 12 million (EUR 11 million).

In February 2022, IPC completed the issuance of USD 300 million of Bonds, which mature in February 2027 and have a fixed coupon rate of 7.25% per annum, payable in semi-annual instalments in August and February. The Group used a portion of the proceeds of the Bonds to fully repay the outstanding RBL credit facilities, which were then cancelled. At the same time, the Group entered into a revolving credit facility of CAD 75 million (the "Canadian RCF") in connection with its oil and gas assets in Canada. In Q1 2023, the Group increased the Canadian RCF to CAD 150 million and extended the maturity to May 2025. No cash amounts were drawn under the Canadian RCF as at March 31, 2023.

Total net cash as at March 31, 2023 amounted to USD 67 million.

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

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

An amount of USD 3.5 million (EUR 3.2 million) drawn under the France Facility as at March 31, 2023 is classified as current representing the repayment planned within the next twelve months.

The Group is in compliance with the covenants of the Bonds and its financing facilities as at March 31, 2023.

Cash and cash equivalents held amounted to USD 378 million as at March 31, 2023 of which USD 8.2 million was restricted.

Working Capital
As at March 31, 2023, the Group had a net working capital balance including cash of USD 372,265 thousand compared to USD 488,661 thousand as at December 31, 2022. The difference as at March 31, 2023, from December 31, 2022, is mainly a result of the lower cash balances held following the Cor4 acquisition and the continuing NCIB program.

Non-IFRS Measures

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

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

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

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

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

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

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

Reconciliation of Non-IFRS Measures

Operating cash flow

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

	Three months ended March 31	
USD Thousands	2023	2022
Revenue	192,516	259,782
Production costs	(117,527)	(110,549)
Current tax	(3,991)	(4,123)
Operating cash flow	**70,998**	**145,110**

The operating cash flow for the three months ended March 31, 2023 including the operating cash flow contribution of the Cor4 acquisition from the effective date of January 1, 2023 to the completion date of March 3, 2023 amounts to USD 75,900 thousand.

Free cash flow

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

	Three months ended March 31	
USD Thousands	2023	2022
Operating cash flow - see above	70,998	145,110
Capital expenditures	(48,238)	(38,353)
Abandonment and farm-in expenditures[1]	(1,211)	(1,925)
General, administration and depreciation expenses before depreciation[2]	(3,811)	(3,770)
Cash financial items[3]	(648)	(4,581)
Free cash flow	**17,090**	96,481

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

The free cash flow for the three months ended March 31, 2023 including the free cash flow contribution of the Cor4 acquisition from the effective date of January 1, 2023 to the completion date of March 3, 2023 amounts to USD 16,259 thousand.

EBITDA

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

	Three months ended March 31	
USD Thousands	2023	2022
Net result	39,563	80,822
Net financial items	5,015	6,607
Income tax	15,611	27,498
Depletion	6,439	27,952
Depreciation of other tangible fixed assets	2,558	2,080
Exploration and business development costs	1,609	101
Depreciation included in general, administration and depreciation expenses[1]	383	403
EBITDA	**71,178**	145,463

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

The EBITDA for the three months ended March 31, 2023 including the EBITDA contribution of the Cor4 acquisition from the effective date of January 1, 2023 to the completion date of March 3, 2023 amounts to USD 76,079 thousand.

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

	Three months ended March 31	
USD Thousands	2023	2022
Production costs	117,527	110,549
Cost of blending	(47,817)	(42,641)
Change in inventory position	5,735	3,553
Operating costs	**75,445**	71,461

The operating costs for the three months ended March 31, 2023 including the operating costs contribution of the Cor4 acquisition from the effective date of January 1, 2023 to the completion date of March 3, 2023 amounts to USD 82,246 thousand.

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

USD Thousands	March 31, 2023	December 31, 2022
Bank loans	(11,510)	(12,142)
Bonds	(300,000)	(300,000)
Cash and cash equivalents	378,466	487,240
Net cash	**66,956**	175,098

Off-Balance Sheet Arrangements

IPC, through its subsidiary IPC Canada Ltd, has issued three letters of credit as follows: (a) CAD 2.6 million in respect of its obligations to purchase diluent; (b) CAD 0.8 million in respect of its obligations related to the Ferguson asset, increasing by CAD 0.1 million annually to a maximum of CAD 1.0 million; and (c) CAD 1.3 million in respect of pipeline access.

Outstanding Share Data

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

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

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

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

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

During the Q1 2023, IPC purchased and cancelled a total of 4,758,053 common shares under the NCIB. As at March 31, 2023, IPC had a total of 132,069,946 common shares issued and outstanding, with no common shares held in treasury.

Nemesia S.à.r.l., an investment company ultimately controlled by trusts whose settlor is the late Adolf H. Lundin, holds 40,697,533 common shares in IPC, representing 30.8% of the outstanding common shares as at May 2, 2023.

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

IPC has 4,554,188 IPC Share Unit Plan awards outstanding as at May 2, 2023 (10,703 awards granted in January 2020, 25,335 awards granted in July 2020, 21,216 awards granted in January 2021, 334,566 awards granted in March 2021, 1,716,000 awards granted in May 2021, 10,067 awards granted in July 2021 and 12,543 awards granted in January 2022, 1,257,314 awards granted in March 2022, 5,487 awards granted in July 2022, 2,072 awards granted in January 2023 and 1,158,885 awards granted in March 2023).

Contractual Obligations and Commitments

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

	2023	2024	2025	2026	2027	Thereafter
Transportation service (MCAD)	20.6	28.0	28.4	29.0	28.2	275.2

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

Critical Accounting Policies and Estimates

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

Transactions with Related Parties

During Q1 2023, there were no significant cash transactions with related parties.

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 the oil price. The Group seeks to control these risks through sound management practice and the use of internationally accepted financial instruments, such as oil and gas 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 March 31, 2023, the Corporation had entered into oil and gas 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 March 31, 2023, which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
April 1, 2023 – December 31, 2023	12,000	WCS/ARV Differential	USD - 10.08/bbl

The Group had gas price sale financial hedges outstanding as at March 31, 2023, which are summarized as follows:

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

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

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 2,602 thousand as at March 31, 2023.

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

In October 2022, IPC entered into currency hedge swaps for 2023 to buy CAD 15 million per month, sell USD at an average exchange rate of 1.3619 and to buy EUR 3 million per month, sell USD at an average exchange rate of 1.0000. This is to partially fund operational expenditures in those currencies in Canada and France respectively.

The above hedge is treated as effective and changes to the fair value are reflected in other comprehensive income. The currency hedge swaps had a positive fair value of USD 3,287 thousand as at March 31, 2023.

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

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

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

RISK AND UNCERTAINTIES

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

DISCLOSURE CONTROLS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

There have been no material changes to the Groups internal control over financial reporting during the three month period ended March 31, 2023, that have materially affected, or are reasonably likely to materially affect, the Group's internal control over financial reporting.

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

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

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

Forward-looking statements include, but are not limited to, statements with respect to:
- The potential for an improved economic environment resulting from a lack of capital investment and drilling in the oil and gas industry;
- 2023 production range, 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;
- IPC's continued access to its existing credit facilities, including current financial headroom, on terms acceptable to the Corporation;
- The ability to fully fund future expenditures from cash flows and current borrowing capacity;
- IPC's ability to maintain operations, production and business in light of the current and any pandemics and the restrictions and disruptions related thereto, including risks related to production delays and interruptions, changes in laws and regulations and reliance on third-party operators and infrastructure;
- IPC's intention and ability to continue to implement our strategies to build long-term shareholder value;
- The ability of IPC's portfolio of assets to provide a solid foundation for organic and inorganic growth;
- The continued facility uptime and reservoir performance in IPC's areas of operation;
- Future development potential of the Suffield and Ferguson operations in Canada, including the timing and success of future oil and gas drilling and optimisation programs;
- Development of the Blackrod project in Canada, including estimates of resource volumes, future production, timing, regulatory approvals, third party commercial arrangements, breakeven oil prices and net present values;
- Current and future drilling pad production and timing and success of facility upgrades, tie-in work and infill drilling at Onion Lake Thermal;
- The ability of IPC to achieve and maintain current and forecast production and take advantage of production growth and development upside opportunities related to the assets acquired in the Cor4 acquisition;
- The ability of IPC to integrate the assets acquired in the Cor4 acquisition into its current operations;
- The existence of drill-ready opportunities in respect of the assets acquired in the Cor4 acquisition and their ability to add further near-term production;

- The potential improvement in the Canadian oil egress situation and IPC's ability to benefit from any such improvements;
- The timing and success of the future development projects and other organic growth opportunities in France;
- The ability to maintain current and forecast production in France;
- The ability of IPC to achieve and maintain current and forecast production in Malaysia;
- The ability to IPC to acquire further common shares under the NCIB, including the timing of any such purchases;
- The return of value to IPC's shareholders as a result of the NCIB;
- The ability of IPC to implement further shareholder distributions in addition to the NCIB;
- IPC's ability to implement its GHG emissions intensity and climate strategies and to achieve its net GHG emissions intensity reduction targets;
- Estimates of reserves and contingent resources;
- The ability to generate free cash flows and use that cash to repay debt;
- IPC's ability to identify and complete future acquisitions; and
- Future drilling and other exploration and development activities.

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

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

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

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

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

Estimated FCF generation is based on IPC's current business plans over the periods of 2023 to 2027 and 2028 to 2032. Assumptions include average net production of approximately 50 Mboepd over the period of 2023 to 2027, average net production of approximately 65 Mboepd over the period of 2028 to 2032, average Brent oil prices of USD 75 to 95 per boe escalating by 2% per year, and average Brent to Western Canadian Select differentials and average gas prices as estimated by IPC's independent reserves evaluator and as further described in the AIF. IPC's current business plans and assumptions, and the business environment, are subject to change. Actual results may differ materially from forward-looking estimates and forecasts.

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

RESERVES AND RESOURCES ADVISORY

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

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada (other than the assets acquired in the Cor4 acquisition) are effective as of December 31, 2022, and are included in the reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Sproule's December 31, 2022 price forecasts.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France and Malaysia are effective as of December 31, 2022, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2022 price forecasts.

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

The price forecasts used in the Sproule and ERCE reports, and in respect of the assets acquired in the Cor4 acquisition, are available on the website of Sproule (sproule. com) and are contained in the AIF. These price forecasts are as at December 31, 2022 and may not be reflective of current and future forecast commodity prices.

The reserve life index (RLI) is calculated by dividing the 2P reserves of 487 MMboe as at December 31, 2022 (including 15.9 MMboe acquired in the Cor4 acquisition), by the mid-point of the 2023 CMD production guidance of 48,000 to 50,000 boepd.

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

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

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

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

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

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

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

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

2P reserves and contingent resources included in the reports prepared by Sproule and ERCE in respect of IPC's oil and gas assets in Canada, France and Malaysia, and 2P reserves in respect of the oil and gas assets acquired in the Cor4 acquisition, 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				
March 31, 2023	26.6	9.5	99.9 MMcf (16.7 Mboe)	52.8
March 31, 2022	22.2	8.0	93.6 MMcf (15.6 Mboe)	45.8
Year ended December 31, 2022				
December 31, 2022	22.6	9.6	98.1MMcf (16.4 Mboe)	48.6

This document also makes reference to IPC's forecast average daily production of 48,000 to 50,000 boepd for 2023. IPC estimates that approximately 50% of that production will be comprised of heavy oil, approximately 17% will be comprised of light and medium crude oil and approximately 33% will be comprised of conventional natural gas.

OTHER SUPPLEMENTARY INFORMATION

Abbreviations

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

Oil related terms and measurements

AECO	The daily average benchmark price for natural gas at the AECO hub in southeast Alberta
API	An indication of the specific gravity of crude oil on the API (American Petroleum Institute) gravity scale
	Alkaline surfactant polymer (an EOR process)
ARV	Argus WCS Houston (a reference price for the cost of transporting WCS quality oil from Alberta to Houston)
bbl	Barrel (1 barrel = 159 litres)
boe[1]	Barrels of oil equivalents
boepd	Barrels of oil equivalents per day
bopd	Barrels of oil per day
Bcf	Billion cubic feet
Bscf	Billion standard cubic feet
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
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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