Q1

International Petroleum Corporation

Management's Discussion and Analysis

For the three months ended March 31, 2024

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 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 16.

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 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 May 7, 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 interim condensed consolidated financial statement for the period ended March 31, 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 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:

	March 31, 2024		March 31, 2023		December 31, 2023	
	Average	Period end	Average	Period end	Average	Period end
1 EUR equals USD	1.0857	1.0811	1.0730	1.0875	1.0816	1.1050
1 USD equals CAD	1.3484	1.3571	1.3521	1.3551	1.3496	1.3251
1 USD equals MYR	4.7234	4.7330	4.3865	4.4125	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

Q1 2024 Business Highlights

- Average net production of approximately 48,800 boepd for the first quarter of 2024 was above the high end of the guidance range for the period (51% heavy crude oil, 16% light and medium crude oil and 33% natural gas).[1]
- Progressing development activities on Phase 1 of the Blackrod project which remains on schedule and on budget.
- Successfully drilled, completed and tied-in three out of five 2024 budgeted Ellerslie wells within the Suffield area.
- 1.6 million IPC common shares purchased and cancelled during Q1 2024 under IPC's normal course issuer bid (NCIB) and continuing with target to complete the full 2023/2024 NCIB this year.

Q1 2024 Financial Highlights

- Operating costs per boe of USD 17.1 for Q1 2024, below guidance.[3]
- Operating cash flow (OCF) generation of MUSD 89 for Q1 2024, ahead of the guidance range.[3]
- Capital and decommissioning expenditures of MUSD 125 for Q1 2024, in line with guidance.
- Free cash flow (FCF) generation for Q1 2024 amounted to MUSD -43 (MUSD 53 pre-Blackrod Phase 1 project funding).[3]
- Gross cash of MUSD 397 and net debt of MUSD 61 as at March 31, 2024.[3]
- Net result of MUSD 34 for Q1 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 range maintained at USD 18 to 19 per boe.[3]
- Full year 2024 OCF guidance estimated at between MUSD 323 and 363 (assuming Brent USD 70 to 90 per boe 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 -154 and -114 (assuming Brent USD 70 to 90 per boe for the remainder of 2024), after taking into account MUSD 362 of forecast full year 2024 capital expenditures relating to the continued development of Phase 1 of the Blackrod project and the additional oil hedges executed in March and April 2024.[3]

	Three months ended March 31	
USD Thousands	2024	2023
Revenue	**206,419**	192,516
Gross profit	**55,184**	64,383
Net result	**33,719**	39,563
Operating cash flow[3]	**89,301**	75,900
Free cash flow[3]	**(43,311)**	16,259
EBITDA[3]	**87,020**	76,079
Net cash/(debt)[3]	**(60,572)**	66,956

OPERATIONS REVIEW

Business Overview

During the first quarter of 2024, oil prices remained strong, with Brent prices averaging USD 83 per barrel. Following the quarter, Brent prices increased to spot rates over USD 91 per barrel in April 2024. Increased global crude demand revisions in combination with downward supply adjustments largely influenced by extended OPEC+ curtailments and rising geopolitical tension in the Middle East are some of the key factors that have lead to higher oil prices. Global crude inventories were largely unchanged in the first quarter and are below the 5 year average. Current consensus is that the oil market will be in a deficit for the remainder of 2024.

IPC has taken advantage of the favourable pricing outlook by increasing our benchmark hedged volumes to around 50% of our oil production at approximately USD 80.3 and USD 85.5 per barrel for West Texas Intermediate (WTI) and Dated Brent, respectively, for the remainder of 2024. Despite a favourable outlook for crude prices, 2024 is an election year in the United States and with recent inflation data impacting rate cut decisions, IPC took prudent action to protect the business in a downside pricing scenario given the record investment year for the Corporation.

In Canada, first quarter 2024 WTI to Western Canadian Select (WCS) crude price differentials averaged around USD 19 per barrel, with differentials decreasing to around USD 12 per barrel in April 2024. The Trans-Mountain (TMX) pipeline began commercial operations in May 2024 which should benefit future WTI/WCS differentials. Another positive catalyst for WCS is the reduced Mexican heavy oil exports to the US. IPC has hedged the WTI/WCS differential for approximately 70% of our Canadian crude production at USD 15 per barrel for 2024.

Gas markets in the first quarter of 2024 were relatively weak, given the warmer than average weather conditions and high gas storage levels in North America. The average AECO gas price was CAD 2.50 per Mcf for the first quarter of 2024.

First Quarter 2024 Highlights and Full Year 2024 Guidance

During the first quarter of 2024, our assets delivered average net production of 48,800 boepd, ahead of guidance for the quarter. High uptime performance was achieved across all our assets, including resumed production in Malaysia following the completion of the previously announced well maintenance work. IPC also benefited from short cycle investment activities, mainly within Southern Alberta assets in Canada where three out of five 2024 budgeted Ellerslie wells have been successfully drilled. We maintain the full year 2024 average net production guidance range of 46,000 to 48,000 boepd.(1)

Our operating costs per boe for the first quarter of 2024 was USD 17.1, below guidance. Full year 2024 operating costs per boe guidance of USD 18.0 to 19.0 per boe remains unchanged.(3)

Operating cash flow (OCF) generation for the first quarter of 2024 was MUSD 89. Full year 2024 OCF guidance is tightened to MUSD 323 to 363 (assuming Brent USD 70 to 90 per boe for the remainder of 2024).(3)

Capital and decommissioning expenditure for the first quarter of 2024 was MUSD 125 in line with guidance. Full year 2024 capital and decommissioning expenditure of MUSD 437 is unchanged.

Free cash flow (FCF) generation was MUSD -43 (MUSD 53 pre-Blackrod Phase 1 project funding) during the first quarter of 2024. Full year 2024 FCF guidance is tightened to MUSD -154 to -114(assuming Brent USD 70 to 90 per boe for the remainder of 2024) after taking into account MUSD 362 of forecast full year 2024 capital expenditures relating to the continued development of Phase 1 of the Blackrod project and the additional oil hedges executed in March and April 2024.(3)

As at March 31, 2024, IPC's net debt position was MUSD 61, from a net cash position of MUSD 58 as at December 31, 2023, largely driven by the funding of forecast capital expenditures and the continuing share repurchase program (NCIB).(3) Gross cash on the balance sheet as at March 31, 2024 amounts to MUSD 397 providing a significant war chest to pursue our three strategic pillars of organic growth, returning value to stakeholders, and pursuing value adding M&A.

Blackrod Project

In Q1 2024, IPC continued to advance the development of Phase 1 of the Blackrod project. Development capital expenditure to first oil is estimated at MUSD 850. First oil of the Phase 1 development is estimated to be in late 2026, with forecast net production of 30,000 bopd by 2028. IPC forecasts development capital expenditure in 2024 for the Blackrod Phase 1 project of MUSD 362, of which MUSD 96 was invested in Q1 2024.(1)

Project activities for the multi-year Blackrod Phase 1 development have progressed in line with expectations. As at the end of Q1 2024, fabrication and installation have commenced, site civil and commercial road expansion works continue to advance, drilling is progressing, and third-party pipeline commercial agreements are moving forward according to plan. IPC intends to fund the remaining Blackrod Phase 1 development costs with forecast cash flow generated by its operations and cash on hand.(3)

Stakeholder Returns: Normal Course Issuer Bid
In Q4 2023, IPC announced the renewal of the NCIB, with the ability to repurchase up to approximately 8.3 million common shares over the period of December 5, 2023 to December 4, 2024. Under the 2023/2024 NCIB, IPC repurchased and cancelled approximately 1.2 million common shares in December 2023 and a further 1.6 million common shares during Q1 2024. The average price of common shares purchased under the 2023/2024 NCIB during Q1 2024 was SEK 115 / CAD 15 per share.

As at March 31, 2024, IPC had a total of 125,438,160 common shares issued and outstanding and IPC held no common shares in treasury. As at April 30, 2024, IPC had a total of 125,151,742 common shares issued and outstanding and IPC held no common shares in treasury.

Notwithstanding the record level of capital investment forecast for 2024, IPC confirms its intention to continue to purchase and cancel common shares under the 2023/2024 NCIB to the remaining limit as at April 1, 2024 of 5.5 million common shares by early December 2024. This would result in the cancellation of 6.5% of shares outstanding as at the beginning of December 2023. IPC continues to believe that reducing the number of shares outstanding while in parallel investing in material production growth at the Blackrod project will prove to be a winning formula for our stakeholders.

Environmental, Social and Governance (ESG) Performance
During the first 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 2025 levels of 20 kg CO_2/boe through to the end of 2028.

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.

Operations Overview

Q1 2024 Overview
In Q1 2024, IPC continued to successfully demonstrate its commitment to operational excellence, with higher than forecasted net average daily production and no material safety incidents or harm to the environment.

In Canada, the Blackrod Phase 1 project development continues to progress in line with expectations. As at the end of Q1 2024, process facility fabrication and critical equipment site installation has commenced, site civil and commercial road expansion works continue to advance, utility well and well Pad drilling is progressing ahead of plan, and third-party pipeline commercial agreements are moving forward. At Onion Lake Thermal, daily production remained strong through the quarter as we gradually phase in the new wells from the latest production sustaining Pad L. At Suffield, three new production wells in the exciting Ellerslie play have been brought online in the quarter and are producing in line with expectations. At Bertam in Malaysia, the previously announced well maintenance workovers have been completed with both wells returning to production in Q1 2024. In France, the focus remains on maturing the next round of development targets with field development studies progressing in line with expectations.

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 embark 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 optimisation opportunities ready for sanction at the discretion of the Group.

Production
Average daily net production for the first quarter 2024 was ahead of IPC's high end guidance at 48,800 boepd with continued strong performance at our major producing assets. In Canada, exceptional operational performance has been supplemented by recent Suffield area Ellerslie production well drilling and continued ahead of expectations results from production sustaining Pad L at Onion Lake Thermal. In addition, IPC continues to benefit from high facility uptime and strong production well performance post the planned maintenance workovers at Bertam in Malaysia.

With exceptional operational delivery through the first quarter of 2024, and a strong production outlook for the remainder of the year, IPC is well positioned to deliver an annual net average daily production within the guidance range of 46,000 to 48,000 boepd.

The production during Q1 2024 with comparatives is summarized below:

Production in Mboepd	Three months ended March 31		Year ended December 31
	2024	2023	2023
Crude oil			
Canada – Northern Assets	15.0	15.8	15.5
Canada – Southern Assets[1]	11.2	12.7	11.8
Malaysia	4.1	5.1	3.8
France	2.5	2.5	2.8
Total crude oil production	**32.8**	36.1	33.9
Gas			
Canada – Northern Assets	0.3	0.4	0.4
Canada – Southern Assets	15.7	16.3	16.8
Total gas production	**16.0**	16.7	17.2
Total production	**48.8**	52.8	51.1
Quantity in MMboe	**4.44**	4.75	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 March 31 2024	Three months ended March 31 2023	Year ended December 31 2023
- Oil Onion Lake Thermal	100%	13.3	13.3	13.3
- Oil Suffield Area[1]	100%	10.0	10.7	10.2
- Oil Other	50-100%	2.9	4.5	3.8
- Gas[1]	~100%	16.0	16.7	17.2
Canada		**42.2**	45.2	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 Canadian assets during Q1 2024 was in line with guidance at 42,200 boepd with continued strong operational performance at all the major producing assets. At Onion Lake Thermal, daily production remained high through the quarter as we continue to phase in new wells from the latest production sustaining Pad L. The Suffield area oil and gas producing assets continue to deliver above forecast, where base well rate optimization has been supplemented with three newly drilled Ellerslie play oil wells.

Organic Growth and Capital Projects
In Canada, as the Blackrod Phase 1 project development enters its most capital-intensive phase, IPC announced a reduced base business budget set 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 optimisation is the priority with a continued phased ramp up of the latest production sustaining Pad L planned.

During the first quarter of 2024, the Blackrod Phase 1 project development continues to progress in line with expectations. As at the end of Q1 2024, process facility fabrication and critical equipment site installation has commenced, site civil and commercial road expansion works continue to advance, utility well and well Pad drilling is progressing ahead of plan, and third-party pipeline commercial agreements are moving forward.

As of the end of Q1 2024 in the Suffield area, three out of five budgeted Ellerslie play wells have been drilled and brought online with performance in line with expectations. The drilling rig has relocated to the Ferguson asset to undertake a planned three well program prior to returning to Suffield to drill the final two budgeted Ellerslie play wells in 2024.

At Onion Lake Thermal, daily production is close to the facility nameplate capacity of 14,000 boepd with the fifth well pair from production sustaining Pad L brought online in the quarter. The sixth and seventh Pad L wells are planned to be brought online in Q2 and Q3 2024 respectively.

MALAYSIA

Production in Mboepd	WI	Three months ended March 31 2024	Three months ended March 31 2023	Year ended December 31 2023
Bertam	100%	**4.1**	5.1	3.8

Production
Net production at Bertam in Malaysia in Q1 2024 was above guidance at 4.1 boepd, with IPC benefiting from high facility uptime and strong production performance post completion of the two planned well workovers earlier in the quarter.

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

FRANCE

Production in Mboepd	WI	Three months ended March 31 2024	Three months ended March 31 2023	Year ended December 31 2023
France				
- Paris Basin	100%[1]	2.1	2.1	2.4
- Aquitaine	50%	0.4	0.4	0.4
		2.5	2.5	2.8

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

Production
Net production in France during Q1 2024 was slightly below guidance at 2,500 boepd due to well maintenance activity. Well maintenance has been completed and production is now in line with forecast.

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	Q1-24	Q4-23	Q3-23	Q2-23	Q1-23	Q4-22	Q3-22	Q2-22
Revenue	**206,419**	198,460	257,366	205,564	192,516	254,615	299,361	315,540
Gross profit	**55,184**	39,955	93,429	52,747	64,383	95,411	140,489	161,709
Net result	**33,719**	29,710	71,681	32,025	39,563	61,183	90,503	105,217
Earnings per share – USD	**0.27**	0.23	0.56	0.24	0.29	0.45	0.63	0.70
Earnings per share fully diluted – USD	**0.26**	0.22	0.54	0.24	0.28	0.44	0.62	0.68
Operating cash flow[1]	**89,301**	73,634	119,142	84,372	75,900	113,668	171,654	192,515
Free cash flow[1]	**(43,311)**	(64,688)	34,703	16,415	16,259	65,288	116,681	151,792
EBITDA[1]	**87,020**	66,284	123,054	85,201	76,079	125,651	174,328	194,038
Net cash/(debt) at period end[1]	**(60,572)**	58,043	83,097	63,548	66,956	175,098	88,615	14,382

[1] *See definition on page 16 under "Non-IFRS measures"*

Summarized consolidated balance sheet information is as follows:

USD Thousands	March 31, 2024	December 31, 2023
Non-current assets	1,426,489	1,372,388
Current assets	534,004	690,597
Total assets	**1,960,493**	2,062,985
Total non-current liabilities	772,402	779,838
Current liabilities	181,698	202,888
Total liabilities	**954,100**	982,726
Net assets	**1,006,393**	1,080,259
Working capital (including cash)	**352,306**	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 – March 31, 2024					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	104,145	65,471	18,553	16,717	–	**204,886**
NGLs	–	244	–	–	–	**244**
Gas	125	14,292	–	–	–	**14,417**
Net sales of oil and gas	**104,270**	**80,007**	**18,553**	**16,717**	–	**219,547**
Change in under/over lift position	–	–	–	2,916	–	**2,916**
Royalties	(15,495)	(8,988)	–	(1,139)	–	**(25,622)**
Hedging settlement	5,255	3,951	–	–	–	**9,206**
Other operating revenue	–	–	–	217	155	**372**
Revenue	**94,030**	**74,970**	**18,553**	**18,711**	155	**206,419**
Operating costs	(20,658)	(39,231)	(7,016)	(8,911)	–	**(75,816)**
Cost of blending	(38,294)	(6,912)	–	–	–	**(45,206)**
Change in inventory position	368	(229)	5,039	99	–	**5,277**
Depletion	(9,744)	(13,160)	(7,030)	(3,219)	–	**(33,153)**
Depreciation of other assets	–	–	(2,262)	–	–	**(2,262)**
Exploration and business development costs	–	–	–	–	(75)	**(75)**
Gross profit	**25,702**	**15,438**	**7,284**	**6,680**	**80**	**55,184**

	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 March 31, 2024, Review

Revenue

Total revenue amounted to USD 206,419 thousand for Q1 2024, compared to USD 192,516 thousand for Q1 2023 and is analyzed as follows:

	Three months ended March 31	
USD Thousands	2024	2023
Crude oil sales	204,886	180,533
Gas and NGL sales	14,661	20,673
Change in under/overlift position	2,916	2,670
Royalties	(25,622)	(20,139)
Hedging settlement	9,206	8,584
Other operating revenue	372	195
Total revenue	**206,419**	192,516

The main components of total revenue for Q1 2024 and Q1 2023 respectively, are detailed below.

Crude oil sales

	Three months ended – March 31, 2024				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	104,145	65,471	18,553	16,717	**204,886**
- Quantity sold in bbls	1,826,774	1,127,014	202,519	201,604	**3,357,911**
- Average price realized USD per bbl	57.01	58.09	91.61	82.92	**61.02**

	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

Crude oil revenue was 13% higher in Q1 2024 compared to Q1 2023 mainly due to higher oil prices. Canadian - Southern Assets sales volumes are 15% higher in Q1 2024 compared to Q1 2023 as a result of the Brooks assets acquired in March 2023.

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 Q1 2024, WTI averaged USD 77 per bbl compared to USD 76 per bbl for Q1 2023 and the average discount to WCS used in IPC's pricing formula was USD 19 per bbl compared to USD 25 per bbl for Q1 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 Q1 2024 and one cargo lifting in Q1 2023. Produced unsold oil barrels from Bertam at the end of Q1 2024 amounted to 279,000 barrels, see Change in Inventory Position section below. The average Dated Brent crude oil price was USD 83 per bbl for Q1 2024 compared to USD 81 per bbl for the comparative period.

Gas and NGL sales

	Three months ended – March 31, 2024		
	Canada – Northern Assets	Canada – Southern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	125	14,536	**14,661**
- Quantity sold in Mcf	70,491	7,668,608	**7,739,099**
- Average price realized USD per Mcf	1.77	1.90	**1.89**

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

Gas and NGL sales revenue was 29% lower for Q1 2024 compared to Q1 2023 mainly due to the lower achieved gas price. IPC's achieved gas price is based on AECO pricing plus a premium. For Q1 2024, IPC realized an average price of CAD 2.52 per Mcf compared to AECO average pricing of CAD 2.49 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 Q1 2024 amounted to a gain of USD 9,206 thousand on the oil contracts and there were no gas financial hedges. Also see the Financial Position and Liquidity and the Financial Risk Management sections below.

Production costs
Production costs including inventory movements amounted to USD 115,745 thousand for Q1 2024 compared to USD 117,527 thousand for Q1 2023 and is analyzed as follows:

	Three months ended – March 31, 2024					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	20,658	39,231	11,066	8,911	(4,050)	**75,816**
USD/boe[2]	14.89	16.05	29.36	38.89	n/a	**17.09**
Cost of blending	38,294	6,912	–	–	–	**45,206**
Change in inventory position	(368)	229	(5,039)	(99)	–	**(5,277)**
Production costs	58,584	46,372	6,027	8,812	(4,050)	115,745

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

[1] See definition on page 16 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 18.61 for Q1 2024 and USD 17.90 for the comparative period.

Operating costs
Operating costs amounted to USD 75,816 thousand for Q1 2024 compared to USD 75,445 thousand for Q1 2023. Operating costs per boe amounted to USD 17.09 per boe in Q1 2024 below guidance for the quarter and compared with USD 17.31 per boe in Q1 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 45,206 thousand for Q1 2024 compared to USD 47,817 thousand for Q1 2023. The decrease versus the comparative period is largely attributable to lower diluent pricing.

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 2024, IPC had crude entitlement of 279,000 barrels of oil on the FPSO Bertam facility being crude produced but not yet sold. The next Bertam lifting occurred in April 2024.

Depletion and decommissioning costs
The total depletion of oil and gas properties amounted to USD 33,153 thousand for Q1 2024 compared to USD 6,439 thousand for Q1 2023 (including an adjustment for accelerated decommissioning activities amounting to USD 24,178 thousand). The depletion charge is analyzed in the following tables:

USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
	Three months ended – March 31, 2024				
Depletion cost in USD thousands	9,744	13,160	7,030	3,219	**33,153**
USD per boe[2]	7.02	5.38	18.65	14.05	**7.47**

USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
	Three months ended – March 31, 2023				
Depletion cost in USD thousands[1]	9,353	12,302	5,829	3,133	30,617
USD per boe[2]	6.41	5.65	12.76	13.98	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 2,262 thousand for Q1 2024 compared to USD 2,558 thousand for Q1 2023. This relates to the depreciation of the FPSO Bertam, which is being depreciated on a unit of production basis to August 2025, being the original Bertam field production sharing contract (PSC) expiry date, before the PSC extension to 2035.

Exploration and business development costs
The total exploration and business developments costs amounted to a cost of USD 75 thousand for Q1 2024 and a cost of USD 1,609 thousand for the year ended December 31, 2023 which included the Brooks assets acquisition related costs amounting to USD 831 thousand.

Net financial items
Net financial items amounted to a charge of USD 9,770 thousand for Q1 2024, compared to a charge of USD 5,015 thousand for Q1 2023, and included a non-cash net foreign exchange loss of USD 2,061 thousand for Q1 2024 compared to a net foreign exchange loss of USD 856 thousand for Q1 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 7,709 thousand for Q1 2024, compared to USD 4,159 thousand for Q1 2023.

The interest expense amounted to USD 8,818 thousand for Q1 2024, compared to USD 5,349 thousand for the comparative period in 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 5,617 thousand for Q1 2024 and is higher than the comparative period of USD 4,924 thousand due mainly to higher interest rates and higher cash balances.

The unwinding of the asset retirement obligation discount rate amounted to USD 3,618 thousand for Q1 2024, compared to USD 3,068 thousand for the comparative period and has increased mainly as a result of the inclusion of the Brooks assets acquired in March 2023.

Income tax
The corporate income tax amounted to a charge of USD 7,746 thousand for Q1 2024, compared to a charge of USD 15,611 thousand for the comparative period.

The current income tax charge amounted to USD 1,373 thousand for Q1 2024 compared to USD 3,991 thousand for Q1 2023 and mainly related to France and Malaysia. The current income tax charge for the comparative period included a provision for a windfall profits tax amounting to USD 754 thousand in Q1 2023. 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 year ended December 31, 2023 was as follows:

USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Development	99,809	10,295	14,200	790	**125,094**
Exploration and evaluation	–	–	162	–	**162**
	99,809	10,295	14,362	790	**125,256**

During the first quarter of 2024, capital expenditure of USD 125,256 thousand was mainly spent in Canada on the Blackrod Phase 1 Development project and in Malaysia on the well workovers.

Other tangible fixed assets
Other tangible fixed assets amounted to USD 23,117 thousand as at March 31, 2024, which included USD 21,468 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 March 31, 2024, IPC had a nominal MUSD 450 of bonds outstanding with maturity in February 2027. The bond repayment obligations as at March 31, 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 and extended the maturity to May 2025. No cash amounts were drawn under the Canadian RCF as at March 31, 2024.

As at March 31, 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 March 31, 2024 was MUSD 8. An amount of MUSD 3.5 drawn under the France Facility as at March 31, 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 March 31, 2024.

Total net debt as at March 31, 2024 amounted to MUSD 61. Cash and cash equivalents held amounted to MUSD 397 as at March 31, 2024.

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

Working Capital

As at March 31, 2024, the Group had a working capital balance including cash of USD 352,306 thousand compared to USD 487,709 thousand as at December 31, 2023. The difference as at March 31, 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 March 31	
USD Thousands	2024	2023
Revenue	206,419	192,516
Production costs	(115,745)	(117,527)
Current tax	(1,373)	(3,991)
Operating cash flow	**89,301**	70,998

The operating cash flow for the three months ended March 31, 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 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	2024	2023
Operating cash flow - see above	89,301	70,998
Capital expenditures	(125,256)	(48,238)
Abandonment and farm-in expenditures[1]	(122)	(1,211)
General, administration and depreciation expenses before depreciation[2]	(3,653)	(3,811)
Cash financial items[3]	(3,581)	(648)
Free cash flow	**(43,311)**	17,090

[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 three months ended March 31, 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 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	2024	2023
Net result	33,719	39,563
Net financial items	9,770	5,015
Income tax	7,746	15,611
Depletion and decommissioning costs	33,153	6,439
Depreciation of other tangible fixed assets	2,262	2,558
Exploration and business development costs	75	1,609
Depreciation included in general, administration and depreciation expenses[1]	295	383
EBITDA	**87,020**	71,178

[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 Brooks assets acquisition from the effective date of January 1, 2023 to the completion date of March 3, 2023 amounted to USD 76,079 thousand.

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

	Three months ended March 31	
USD Thousands	2024	2023
Production costs	115,745	117,527
Cost of blending	(45,206)	(47,817)
Change in inventory position	5,277	5,735
Operating costs	**75,816**	75,445

The operating costs for three months ended March 31, 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 82,246 thousand.

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

USD Thousands	March 31, 2024	December 31, 2023
Bank loans	(7,962)	(9,031)
Bonds[1]	(450,000)	(450,000)
Cash and cash equivalents	397,390	517,074
Net cash/(debt)	**(60,572)**	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 four 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; and (d) MCAD 0.5 in relation to the hedging of electricity prices.

Outstanding Share Data

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

As at January 1, 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, 2023 to December 4, 2023, IPC purchased and cancelled a total of 8,603,179 common shares under the normal course issuer bid/share repurchase program (NCIB). The NCIB was renewed in Q4 2023 and IPC is entitled to purchase up to 8,342,119 common shares over the period of December 5, 2023 to December 4, 2024. During December 2023, IPC purchased and cancelled a total of 1,232,754 common shares under the renewed NCIB. As at December 31, 2023, IPC had a total of 126,992,066 common shares issued and outstanding, with no common shares held in treasury.

Over the period of January 1, 2024 to March 31, 2024, IPC purchased and cancelled a total of 1,553,906 common shares under the NCIB. As at March 31, 2024, IPC had a total of 125,438,160 common shares issued and outstanding, with no 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 32.4% of the outstanding common shares as at March 31, 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 3,327,463 IPC Share Unit Plan awards outstanding as at May 7, 2024 (4,333 awards granted in January 2022, 1,090,117 awards granted in March 2022, 2,391 awards granted in July 2022, 2,072 awards granted in January 2023, 1,033,384 awards granted in February 2023, 3,244 awards granted in July 2023, 2,443 awards granted in January 2024 and 1,189,479 awards granted in February 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 March 31, 2024:

MCAD	2024	2025	2026	2027	2028	Thereafter
Transportation service [1]	21.0	29.2	38.4	43.4	46.4	555.6
Power[2]	8.7	12.4	12.4	12.4	9.8	–
Total commitments	**29.7**	**41.6**	**50.8**	**55.8**	**56.2**	**555.6**

[1] IPC has firm transportation commitments on oil and natural gas pipelines that expire between 2037 and 2045.
[2] IPC has physical delivery power hedges to purchase 15MW at a weighted average price of CAD 74.92/MWh from April 1, 2024 to December 31, 2028 and an additional 5MW at a weighted average price of CAD 58.31/MWh from July 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 three months ended March 31, 2024, the Group paid USD 111 thousand to the Lundin Foundation in respect of sustainability advisory services provided to the Group and USD 193 thousand to Orrön Energy in respect of office space rental for the first quarter 2024.

During the three months ended March 31, 2024, Orrön Energy paid USD 168 thousand to the Group in respect of support services provided to Orrön Energy during the first quarter 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 March 31, 2024, the Corporation had entered into oil 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 March 31, 2024, which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
April 1, 2024 – December 31, 2024	17,700	WTI/WCS Differential	USD -15.03/bbl
April 1, 2024 – December 31, 2024	8,250	WTI Sale Swap	USD 80.01/bbl

The Group had electricity financial hedges outstanding as at March 31, 2024, which are summarized as follows:

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

The Group had no gas price sale financial hedges outstanding as at March 31, 2024.

The above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. The hedges had a negative fair value of USD 11,496 thousand as at March 31, 2024.

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

Period	Volume (barrels per day)	Type	Average Pricing
April 1, 2024 - December 31, 2024	4,000	WTI Sale Swap	USD 80.76/bbl
April 1, 2024 - December 31, 2024	3,000	Brent Sale Swap	USD 85.50/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 MCAD 20 per month at CAD 1.36 (sell USD) and in Malaysia to buy MMYR 11.5 per month at MYR 4.63 (sell USD) in respect of 2024, and to buy MCAD 15 per month at CAD 1.36 (sell USD) in respect of 2025, to partially meet forecast operational expenses in those countries. In respect of the forecast Blackrod Phase 1 development capital expenditure in Canada, IPC entered into further currency hedges to purchase a total MCAD 556 for the period January 2024 to December 2025 at an average rate of CAD 1.33 (sell USD).

The above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. The hedges had a negative fair value of USD 2,574 thousand as at March 31, 2024.

In April 2024, IPC entered into currency hedge swaps from May 2024 to December 20024 to buy MEUR 2.5 per month, sell USD at an average exchange rate of 1.0705.

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 three months period ended March 31, 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;
- Future development potential of the Suffield, Brooks, Ferguson and Mooney operations, including the timing and success of future oil and gas drilling and optimization programs;
- Current and future operations and production performance at Onion Lake Thermal;
- The potential improvement in the Canadian oil egress situation and IPC's ability to benefit from any such improvements;
- The ability 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 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;
- 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"

Estimated FCF generation is based on IPC's current business plans over the periods of 2024 to 2028 and 2029 to 2033. Assumptions include average net production of approximately 55 Mboepd over the period of 2024 to 2028, average net production of approximately 65 Mboepd over the period of 2029 to 2033, average Brent oil prices of USD 75 to 95 per boe escalating by 2% per year, and average Brent to Western Canadian Select differentials and average gas prices as estimated by IPC's independent reserves evaluator and as further described in the 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, 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				
March 31, 2024	24.9	7.9	96.0 MMcf (16.0 Mboe)	48.8
March 31, 2023	26.6	9.5	99.9 MMcf (16.7 Mboe)	52.8
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)

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.*

DIRECTORS

C. Ashley Heppenstall
Director, Chair
London, England

William Lundin
Director, President and Chief Executive Officer
Coppet, Switzerland

Chris Bruijnzeels
Director
Abcoude, The Netherlands

Donald K. Charter
Director
Toronto, Ontario, Canada

Lukas (Harry) H. Lundin
Director
Toronto, Ontario, Canada

Emily Moore
Director
Toronto, Ontario, Canada

Mike Nicholson
Director
Monaco

Deborah Starkman
Director
Toronto, Ontario, Canada

OFFICERS

Christophe Nerguararian
Chief Financial Officer
Geneva, Switzerland

Nicki Duncan
Chief Operating Officer
Geneva, Switzerland

Jeffrey Fountain
General Counsel and Corporate Secretary
Geneva, Switzerland

Rebecca Gordon
Senior Vice President Corporate Planning and Investor Relations
Geneva, Switzerland

Chris Hogue
Senior Vice President, Canada
Calgary, Alberta, Canada

Ryan Adair
Vice President Asset Management and Corporate Planning, Canada
Calgary, Alberta, Canada

Curtis White
Vice President Commercial, Canada
Calgary, Alberta, Canada

MEDIA AND INVESTOR RELATIONS

Robert Eriksson
Stockholm, Sweden

CORPORATE OFFICE

Suite 2800, 1055 Dunsmuir Street Vancouver,
British Columbia
V7X 1L2 Canada
Telephone: +1 604 689 7842
Website: www.international-petroleum.com

OPERATIONS OFFICE

5 Chemin de la Pallanterie
1222 Vésenaz
Switzerland
Telephone: +41 22 595 10 50
E-mail: info@international-petroleum.com

REGISTERED AND RECORDS OFFICE

Suite 3500 - 1133 Melville Street
Vancouver, British Columbia
V6E 4E5 Canada

INDEPENDENT AUDITORS

PricewaterhouseCoopers LLP, Canada

TRANSFER AGENT

Computershare Trust Company of Canada
Calgary, Alberta, and Toronto, Ontario

STOCK EXCHANGE LISTINGS

Toronto Stock Exchange and NASDAQ Stockholm
Trading Symbol: IPCO

Corporate Office
International Petroleum Corp
Suite 2800
1055 Dunsmuir Street
Vancouver, British Columbia
V7X 1L2, Canada

Tel: +1 604 689 7842
E-mail: info@international-petroleum.com
Web: international-petroleum.com