Q1

International Petroleum Corporation

Management's Discussion and Analysis

For the three months ended March 31, 2025

International Petroleum Corp.

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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, 2024, 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, 2024, 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, 2024, 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, 2024, 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 6, 2025 and is intended to provide an overview of the Group's operations, financial performance and current and future business opportunities. This MD&A should be read in conjunction with IPC's unaudited interim condensed consolidated financial statement for the period ended March 31, 2025 as well as the audited consolidated financial statements and accompanying notes for the year ended December 31, 2024 ("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, 2025		March 31, 2024		December 31, 2024	
	Average	Period end	Average	Period end	Average	Year end
1 EUR equals USD	1.0807	1.0815	1.0857	1.0811	1.0821	1.0389
1 USD equals CAD	1.4352	1.4362	1.3484	1.3571	1.3698	1.4388
1 USD equals MYR	4.4475	4.4375	4.7234	4.7330	4.5759	4.4715

HIGHLIGHTS

Q1 2025 Business Highlights

- Average net production of approximately 44,400 boepd for the first quarter of 2025, within the guidance range for the period (52% heavy crude oil, 15% light and medium crude oil and 33% natural gas).[1]
- Continued progressing Phase 1 development activity as well as future phase resource maturation works at the Blackrod asset.
- At Onion Lake Thermal, all four planned production infill wells and the final Pad L well pair have been successfully drilled.
- 3.9 million IPC common shares purchased and cancelled during Q1 2025 and continuing with target to complete the full 2024/2025 NCIB this year.

Q1 2025 Financial Highlights

- Operating costs per boe of USD 17.3 for Q1 2025, in line with guidance.[3]
- Operating cash flow (OCF) generation of MUSD 75 for Q1 2025, in line with guidance.[3]
- Capital and decommissioning expenditures of MUSD 99 for Q1 2025, in line with guidance.
- Free cash flow (FCF) generation for Q1 2025 amounted to MUSD -43 (MUSD 37 pre-Blackrod capital expenditure).[3]
- Gross cash of MUSD 140 and net debt of MUSD 314 as at March 31, 2025.[3]
- Net result of MUSD 16 for Q1 2025.

Reserves and Resources

- Total 2P reserves as at December 31, 2024 of 493 MMboe, with a reserve life index (RLI) of 31 years.[1][2]
- Contingent resources (best estimate, unrisked) as at December 31, 2024 of 1,107 MMboe.[1][2]
- 2P reserves net asset value (NAV) as at December 31, 2024 of MUSD 3,083 (10% discount rate).[1][2]

2025 Annual Guidance

- Full year 2025 average net production guidance range forecast maintained at 43,000 to 45,000 boepd.[1]
- Full year 2025 operating costs guidance range forecast maintained at USD 18 to 19 per boe.[3]
- Full year 2025 OCF revised guidance estimated at between MUSD 240 and 270 (assuming Brent USD 60 to 75 per barrel for the remainder of 2025) from previous guidance of between MUSD 210 and 280 (assuming Brent USD 65 to 85 per barrel).[3][4]
- Full year 2025 capital and decommissioning expenditures guidance forecast maintained at MUSD 320.
- Full year 2025 FCF revised guidance estimated at between MUSD -135 and -110 (assuming Brent USD 60 to 75 per barrel for the remainder of 2025) from previous guidance of between MUSD -150 and -80 (assuming Brent USD 65 to 85 per barrel), after taking into account MUSD 230 of forecast full year 2025 capital expenditures relating to the Blackrod asset.[3][4]

	Three months ended March 31	
USD Thousands	2025	2024
Revenue	178,492	206,419
Gross profit	44,149	55,184
Net result	16,231	33,719
Operating cash flow[3]	74,790	89,301
Free cash flow[3]	(43,172)	(43,311)
EBITDA[3]	70,946	87,020
Net cash/(debt)[3]	(314,255)	(60,572)

OPERATIONS REVIEW

Business Overview

During the first quarter of 2025, oil prices were relatively stable, with Brent prices averaging just below USD 76 per barrel. Following the quarter, commodity prices pulled back with spot Brent rates falling to USD 60 per barrel in April 2025. The physical crude market remained tight throughout the first quarter, prompting OPEC and the OPEC+ group to increase supply ahead of expectations. The timing of the supply increases coincided with the United States proposing harsh tariffs to countries deemed in a trade surplus of US goods. These two events have impacted future crude supply and demand outlooks, in turn weighing on spot and future oil benchmark prices. Despite the poor market sentiment, global inventories remain below the 5-year average, high geopolitical tensions persist, non-OPEC 2025 oil production (namely, in the US) is unlikely to grow at current prices, and US Federal Reserve Bank rate cuts are likely to occur in the near future. IPC prudently supplemented downside protection measures at the beginning of the first quarter of 2025 through financial swap hedging arrangements which in total represent nearly 40% of our forecast 2025 oil production at around USD 76 and USD 71 per barrel for Dated Brent and West Texas Intermediate (WTI), respectively, for the remainder of 2025.

In Canada, WTI to Western Canadian Select (WCS) crude price differentials during the first quarter of 2025 averaged just under USD 13 per barrel, with spot differentials decreasing to around USD 9 per barrel in April 2025. The Western Canadian Sedimentary Basin (WCSB) petroleum producers have greatly benefited from the TMX pipeline expansion with differentials tightening to levels not seen since 2020. There are currently no tariffs on Canadian crude exports to the United States, which remain covered by the US Mexico Canada free trade agreement. IPC has hedged the WTI/WCS differential for approximately 50% of our forecast 2025 Canadian oil production at USD 14 per barrel for 2025.

Natural gas markets in Canada for the first quarter of 2025 remained weak, given the softer than average winter weather conditions and high natural gas storage levels. The average AECO gas price was CAD 2.1 per Mcf for the first quarter of 2025. The forward strip implies improved pricing for Canadian gas benchmark prices, driven by the pending startup of the West Coast LNG Canada project later this year. Approximately 50% of our net long exposure is hedged at CAD 2.4 per Mcf to end October 2025, dropping to around 15% for November and December at CAD 2.6 per mcf.

First Quarter 2025 Highlights and Full Year 2025 Guidance
During the first quarter of 2025, our portfolio delivered average net production of 44,400 boepd, in line with guidance. Operational performance from our producing assets was strong to start the year as high facility and well uptimes were achieved. Drilling activity commenced in the first quarter of 2025 at Onion Lake Thermal, which aims to sustain production levels at the asset for 2025. In Malaysia, drilling and well maintenance works are planned to start in the second quarter of 2025, in line with plan. We maintain the full year 2025 average net production guidance range of 43,000 to 45,000 boepd.[(1)]

Our operating costs per boe for the first quarter of 2025 was USD 17.3, in line with guidance. Full year 2025 operating expenditure guidance of USD 18.0 to 19.0 per boe remains unchanged.[(3)]

Operating cash flow (OCF) generation for the first quarter of 2025 was MUSD 75. Full year 2025 OCF guidance is tightened to MUSD 240 to 270 (assuming Brent USD 60 to 75 per barrel for the remainder of 2025).[(3)(4)]

Capital and decommissioning expenditure for the first quarter of 2025 was MUSD 99 in line with guidance. Full year 2025 capital and decommissioning expenditure of MUSD 320 is maintained.

Free cash flow (FCF) generation was MUSD -43 (MUSD 37 pre-Blackrod capital expenditure) during the first quarter of 2025. Full year 2025 FCF guidance is tightened to MUSD -135 to -110 (assuming Brent USD 60 to 75 per barrel for the remainder of 2025) after taking into account MUSD 320 of forecast full year 2025 capital expenditures (including MUSD 230 relating to the Blackrod asset).[(3)(4)]

As at March 31, 2025, IPC's net debt position was MUSD 314, from a net debt position of MUSD 209 as at December 31, 2024, mainly driven by the funding of forecast capital expenditures and the continuing share repurchase program (NCIB). Gross cash on the balance sheet as at March 31, 2025 amounts to MUSD 140 and IPC has access to an undrawn Canadian credit facility of greater than 130 MUSD. The access to liquidity supports IPC to follow through on its key strategic objectives of enhancing stakeholder value through organic growth, stakeholder returns, and pursuing value adding M&A.[(3)]

Blackrod
During the first quarter of 2025, IPC continued to advance the Phase 1 development of the Blackrod asset. Growth capital expenditure to first oil is maintained at MUSD 850. First oil of the Phase 1 development is estimated to be in late 2026, with forecast net production of 30,000 boepd by 2028. IPC forecasts capital expenditure in 2025 at the Blackrod asset of MUSD 230, of which MUSD 77 was invested in the Phase 1 development project during Q1 2025. Since the transformational organic growth project was sanctioned in early 2023, MUSD 669, or approximately 80% of the total multi-year project capital budget has been incurred.[(1)]

Project activities for the multi-year Blackrod Phase 1 development have progressed according to plan. Engineering, procurement and fabrication is substantially complete with greater than 90% of all facility modules delivered to site. Equipment installation, piping inter-connects, electrical and instrumentation are the key areas of focus for construction at the Central Processing Facility (CPF) and well pad facilities.

Resource maturation drilling for future phase expansion considerations took place during Q1 2025. Commercial operational readiness planning has ramped up in line with our progressive turnover strategy to ensure a seamless transition from build to start-up. IPC intends to fund the remaining Blackrod capital expenditure with forecast cash flow generated by its operations, cash on hand and drawing under the existing Canadian credit facility if needed.[3]

Stakeholder Returns: Normal Course Issuer Bid

In Q4 2024, IPC announced the renewal of the NCIB, with the ability to repurchase up to approximately 7.5 million common shares over the period of December 5, 2024 to December 4, 2025. Under the 2024/2025 NCIB, IPC repurchased and cancelled approximately 0.8 million common shares in December 2024, 3.7 million common shares during Q1 2025, and a further 0.2 million common shares purchased under other exemptions in Canada. The average price of common shares purchased under the 2024/2025 NCIB during Q1 2025 was SEK 146 / CAD 20 per share.

As at March 31, 2025, IPC had a total of 115,176,514 common shares issued and outstanding and IPC held no common shares in treasury. As at April 30, 2025, IPC had a total of 114,248,119 common shares issued and outstanding and IPC held no common shares in treasury.

Notwithstanding the final major capital investment year at Blackrod in 2025, IPC had purchased and cancelled 73% of the maximum 7.5 million common shares allowed under the 2024/2025 NCIB by the end of April 2025 and intends to purchase and cancel the remaining 2.0 million common shares under that program in 2025. This would result in the cancellation of 6.2% of common shares outstanding as at the beginning of December 2024. IPC continues to believe that reducing the number of shares outstanding in combination with investing in long-life 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 2025, 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. IPC has also made a commitment to maintain 2025 levels of 20 kg CO_2/boe through to the end of 2028.[5]

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, 2024 (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 net present value (NPV), are described in the AIF. NAV is calculated as NPV less net debt of USD 209 million as at December 31, 2024.

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

(4) OCF and FCF forecasts at Brent USD 60 and 70 per barrel assume Brent to WTI differential of USD 3 and 5 per barrel, respectively, and WTI to WCS differential of USD 10 and 15 per barrel, respectively, for the remainder of 2025. OCF and FCF forecasts assume gas price on average of CAD 2.25 per Mcf for the remainder of 2025.

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

Operations Overview

Q1 2025 Overview
In Q1 2025, IPC continued to successfully demonstrate its commitment to operational excellence, delivering annual net average daily production in line with our Capital Markets Day (CMD) guidance with no material safety or environmental incidents recorded in the quarter.

Budgeted capital expenditure activity started in Q1 2025 and is progressing in line with expectations.

In Canada, the Blackrod Phase 1 development continues to progress in line with schedule and budget. Engineering, procurement and fabrication is substantially complete with greater than 90% of all facility modules delivered to site. Equipment installation, piping inter-connects, electrical and instrumentation are the key areas of focus for construction in the Central Processing Facility (CPF) and well pad facilities. Third-party transport pipeline installation is progressing on schedule while production well pad drilling is ahead of schedule. At Onion Lake Thermal, all four planned production infill wells and the final Pad L well pair have been successfully drilled with completion activity ongoing. The new wells will be brought online through the year, with a phased well heat conformance and production start-up plan initiated.

In Malaysia, preparations for the planned infill well drilling and well maintenance activity have continued and remain on track to commence in Q2 2025.

In France, field development studies continue with the next phase of production well targets matured and ready for sanction at the Corporation's discretion.

Reserves and Resources
The 2P reserves attributable to IPC's oil and gas assets are 493 MMboe as at December 31, 2024, as certified by independent third party reserve auditors. The proved plus probable reserve life index (RLI) as at December 31, 2024, is approximately 31 years. Best estimate contingent resources as at December 31, 2024, are 1,107 MMboe (unrisked). See "Reserves and Resources Advisory" below.

Production
Average daily net production for Q1 2025 was in line with our CMD guidance at 44,400 boepd. In Canada, strong operational performance at the major oil and gas assets has been supplemented by a continued positive production response at the Mooney Phase 2 enhanced oil recovery (EOR) polymer flood. At the Bertam field in Malaysia, average daily production remained strong in Q1 2025, with high production uptime and a continued focus on well rate optimization activity to offset natural declines. In France, stable production performance continues at all the major producing assets.

With strong operational delivery during the first quarter 2025, and a strong production outlook for the remainder of the year, IPC remains well positioned to deliver an annual net average daily production within the guidance range of 43,000 to 45,000 boepd.

The production during Q1 2025 with comparatives is summarized below:

Production in Mboepd	Three months ended March 31 2025	Three months ended March 31 2024	Year ended December 31 2024
Crude oil			
Canada – Northern Assets	13.9	15.0	14.2
Canada – Southern Assets	10.8	11.2	11.1
Malaysia	2.9	4.1	3.8
France	2.1	2.5	2.4
Total crude oil production	**29.7**	32.8	31.5
Gas			
Canada – Northern Assets	0.5	0.3	0.5
Canada – Southern Assets	14.2	15.7	15.4
Total gas production	**14.7**	16.0	15.9
Total production	**44.4**	48.8	47.4
Quantity in MMboe	**4.00**	4.44	17.34

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

CANADA

Production in Mboepd	Working Interest (WI)	Three months ended March 31		Year ended December 31
		2025	2024	2024
- Oil Onion Lake Thermal	100%	11.5	13.3	12.3
- Oil Suffield Area	100%	9.3	10.0	9.7
- Oil Other	50-100%	3.9	2.9	3.3
- Gas	~100%	14.7	16.0	15.9
Canada		**39.4**	42.2	**41.2**

Production
Net production from IPC's assets in Canada during Q1 2025 was in line with guidance at 39,400 boepd with continued strong operational performance at the major oil and gas producing assets. At Mooney, the Phase 2 EOR polymer flood project is performing ahead of expectations. Stable performance continued at Onion Lake Thermal during the planned drilling campaign.

Organic Growth and Capital Projects
In Canada, with the forecast final major spend year at the Blackrod Phase 1 project development, IPC announced a balanced non-Blackrod capital expenditure budget for 2025. IPC retains the ability to increase capital expenditure levels in Canada as we continue to mature opportunities across all the major assets.

The Blackrod Phase 1 development project is progressing in line with schedule and budget. As at the end of Q1 2025, process facility fabrication is substantially complete supporting critical equipment site installation which continues to progress in line with plan. Third-party transport pipeline installation is progressing on schedule while production well pad drilling remains ahead of schedule.

Future phase resource maturation work at the Blackrod asset continued in Q1 2025, with all five planned appraisal wells drilled and results in line with expectations.

At Onion Lake Thermal, all four planned production infill wells and the final Pad L well pair have been successfully drilled with completion activity ongoing. The new wells will be brought online through the year, with a phased well steam conformance optimization and production startup plan initiated. A total of seven out of nine Pad L production wells are currently online with the eighth well expected online in Q2 2025.

During Q1 2025 at Ferguson, the two final 2024 drilled oil production wells have been brought online and are delivering in line with expectations.

MALAYSIA

Production in Mboepd	WI	Three months ended March 31		Year ended December 31
		2025	2024	2024
Bertam	100%	**2.9**	4.1	3.8

Production
Net production at Bertam in Malaysia in Q1 2025 was in line with guidance at 2,900 boepd with one production well offline awaiting workover intervention.

Organic Growth and Capital Projects
In Malaysia, preparations for the planned infill well drilling and well maintenance activity continued in Q1 2025 and remain on track to commence in Q2 2025.

FRANCE

Production in Mboepd	WI	Three months ended December 31 2025	Three months ended December 31 2024	Year ended December 31 2024
France				
- Paris Basin	100%[1]	1.9	2.1	2.1
- Aquitaine	50%	0.2	0.4	0.3
		2.1	2.5	2.4

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

Production
Net production in France during Q1 2025 was in line with guidance at 2,100 boepd with stable performance at all the major producing assets.

Organic Growth
In France, field development studies continued in Q1 2025 with the next phase of production well targets matured and ready for sanction decision at the company's discretion.

FINANCIAL REVIEW

Financial Results

Selected Annual Financial Information

Selected consolidated statement of operations is as follows:

USD Thousands	Q1-25	Q4-24	Q3-24	Q2-24	Q1-24	Q4-23	Q3-23	Q2-23
Revenue	**178,492**	199,124	173,200	219,040	206,419	198,460	257,366	205,564
Gross profit	**44,149**	42,774	39,505	72,708	55,184	39,955	93,429	52,747
Net result	**16,231**	415	22,875	45,210	33,719	29,710	71,681	32,025
Earnings per share – USD	**0.14**	0.00	0.19	0.36	0.27	0.23	0.56	0.24
Earnings per share fully diluted – USD	**0.13**	0.00	0.18	0.36	0.26	0.22	0.54	0.24
Operating cash flow[1]	**74,790**	78,158	72,589	101,941	89,301	73,634	119,142	84,372
Free cash flow[1]	**(43,172)**	(61,476)	(38,269)	7,559	(43,311)	(64,688)	34,703	16,415
EBITDA[1]	**70,946**	76,184	68,313	103,971	87,020	66,284	123,054	85,201
Net cash/(debt) at period end[1]	**(314,255)**	(208,528)	(157,228)	(88,220)	(60,572)	58,043	83,097	63,548

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

Summarized consolidated balance sheet information is as follows:

USD Thousands	March 31, 2025	December 31, 2024
Non-current assets	1,627,403	1,554,833
Current assets	273,612	398,849
Total assets	**1,901,015**	1,953,682
Total non-current liabilities	817,350	806,134
Current liabilities	189,882	208,078
Total liabilities	**1,007,332**	1,014,212
Net assets	**893,783**	939,470
Working capital (including cash)	**83,730**	190,771

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 the CEO, who is the chief operating decision maker. The following tables present certain segment information.

	Three months ended – March 31, 2025					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	98,236	63,786	15,376	12,814	–	**190,212**
NGLs	–	191	–	–	–	**191**
Gas	107	11,515	–	–	–	**11,622**
Net sales of oil and gas	**98,343**	**75,492**	**15,376**	**12,814**	–	**202,025**
Change in under/over lift position	–	–	–	1,141	–	**1,141**
Royalties	(13,120)	(9,668)	–	(840)	–	**(23,628)**
Hedging settlement	(843)	(373)	–	–	–	**(1,216)**
Other operating revenue	–	–	–	170	–	**170**
Revenue	**84,380**	**65,451**	**15,376**	**13,285**	–	**178,492**
Operating costs	(19,180)	(33,325)	(8,581)	(8,067)	–	**(69,153)**
Cost of blending	(32,391)	(5,335)	–	–	–	**(37,726)**
Change in inventory position	864	(536)	3,339	(167)	–	**3,500**
Depletion	(8,797)	(12,302)	(5,751)	(2,166)	–	**(29,016)**
Depreciation of other assets	–	–	(1,917)	–	–	**(1,917)**
Exploration and business development costs	–	–	–	–	(31)	**(31)**
Gross profit	**24,876**	**13,953**	**2,466**	**2,885**	**(31)**	**44,149**

	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, 2025, Review

Revenue
Total revenue amounted to USD 178,492 thousand for Q1 2025, compared to USD 206,419 thousand for Q1 2024 and is analyzed as follows:

	Three months ended March 31	
USD Thousands	2025	2024
Crude oil sales	190,212	204,886
Gas and NGL sales	11,813	14,661
Change in under/overlift position	1,141	2,916
Royalties	(23,628)	(25,622)
Hedging settlement	(1,216)	9,206
Other operating revenue	170	372
Total revenue	**178,492**	206,419

The main components of total revenue for Q1 2025 and Q1 2024 respectively, are detailed below.

Crude oil sales

	Three months ended – March 31, 2025				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	98,236	63,786	15,376	12,814	**190,212**
- Quantity sold in bbls	1,688,646	1,082,087	195,131	169,022	**3,134,886**
- Average price realized USD per bbl	58.17	58.95	78.80	75.81	**60.68**

	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

Crude oil revenue was 7% lower in Q1 2025 compared to Q1 2024 with lower sales volumes. Prices were slightly higher in Canada, and lower in Malaysia and France in Q1 2025 compared to Q1 2024.

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

The Canadian realized sales price is based on the Western Canadian Select ("WCS") price which trades at a discount to West Texas Intermediate ("WTI"). For Q1 2025, WTI averaged USD 71 per bbl compared to USD 77 per bbl for Q1 2024 and the average discount to WCS used in IPC's pricing formula was USD 13 per bbl compared to USD 19 per bbl for Q1 2024.

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 2025 and one cargo lifting in Q1 2024. Produced unsold oil barrels from Bertam at the end of Q1 2025 amounted to 146,000 barrels, see Change in Inventory Position section below. The average Dated Brent crude oil price was USD 76 per bbl for Q1 2025 compared to USD 83 per bbl for the comparative period.

Gas and NGL sales

	Three months ended – March 31, 2025		
	Canada – Northern Assets	Canada – Southern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	107	11,706	**11,813**
- Quantity sold in Mcf	78,835	6,885,845	**6,964,680**
- Average price realized USD per Mcf	1.36	1.70	**1.70**

	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

Gas and NGL sales revenue was 19% lower for Q1 2025 compared to Q1 2024 mainly due to the lower achieved gas price.

IPC's achieved gas price is based on AECO pricing plus a premium. For the year Q1 2025, IPC realized an average price of CAD 2.44 per Mcf compared to AECO average pricing of CAD 2.13 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 hedging contracts are not entered into for speculative purposes.

The realized hedging settlement for Q1 2025 amounted to a loss of USD 1,216 thousand and consisted of a loss of USD 1,500 thousand on the oil contracts and a gain of USD 284 thousand on the gas contracts. Also see the Financial Position and Liquidity and the Financial Risk Management sections below.

Production costs
Production costs including inventory movements amounted to USD 103,379 thousand for Q1 2025 compared to USD 115,745 thousand for Q1 2024 and is analyzed as follows:

	Three months ended – March 31, 2025					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	19,180	33,325	11,802	8,067	(3,221)	**69,153**
USD/boe[2]	14.81	14.76	45.80	43.08	n/a	**17.30**
Cost of blending	32,391	5,335	–	–	–	**37,726**
Change in inventory position	(864)	536	(3,339)	167	–	**(3,500)**
Production costs	**50,707**	**39,196**	**8,463**	**8,234**	**(3,221)**	**103,379**

USD Thousands	Three months ended – March 31, 2024					
	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

[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 2024.
[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 33.30 for Q1 2025 and USD 18.61 for the comparative period.

Operating costs
Operating costs amounted to USD 69,153 thousand for Q1 2025 compared to USD 75,816 thousand for Q1 2024. Operating costs per boe amounted to USD 17.30 per boe in Q1 2025 below the guidance and compared with USD 17.09 per boe in Q1 2024. Operating costs per boe in Malaysia increased in Q1 2025 compared to Q1 2024 due to lower production with one production well offline awaiting workover intervention planned in Q2 2025.

Cost of blending
For the Suffield area and Onion Lake Thermal assets in Canada, oil production is blended with purchased 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 37,726 thousand for Q1 2025 compared to USD 45,206 thousand for Q1 2024.

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 2025, IPC had crude entitlement of 146,000 bbl of oil on the FPSO Bertam facility being crude produced but not yet sold.

Depletion costs
The total depletion of oil and gas properties amounted to USD 29,016 thousand for Q1 2025 compared to USD 33,153 thousand for Q1 2024.

The depletion charge is analyzed in the following tables:

USD Thousands	Three months ended – March 31, 2025				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Depletion cost in USD thousands	8,797	12,302	5,751	2,166	**29,016**
USD per boe[2]	6.79	5.45	22.32	11.57	**7.26**

USD Thousands	Three months ended – March 31, 2024				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
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

[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.

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 period due to lower production with one production well offline awaiting workover intervention planned in Q2 2025.

Depreciation of other tangible fixed assets
The total depreciation of other assets amounted to USD 1,917 thousand for Q1 2025 compared to USD 2,262 thousand for Q1 2024. This relates to the depreciation of the FPSO Bertam, which is being depreciated to its residual value on a unit of production basis to August 2025.

Exploration and business development costs
The total exploration and business developments costs amounted to a cost of USD 31 thousand for Q1 2025.

Net financial items
Net financial items amounted to a charge of USD 18,855 thousand for Q1 2025, compared to a charge of USD 9,770 thousand for Q1 2024, and included a realized currency hedge loss and a net foreign exchange gain of respectively USD 6,858 thousand and USD 18 thousand for Q1 2025 compared to no realized currency hedges and a net foreign exchange loss of USD 2,061 thousand for Q1 2024. The foreign exchange movements are mainly resulting from the revaluation of intra-group loan funding balances.

Excluding foreign exchange movements and realized currency cashflow hedges, the net financial items amounted to a charge of USD 12,015 thousand for Q1 2025, compared to USD 7,709 thousand for Q1 2024.

The interest expense amounted to USD 8,761 thousand for Q1 2025, compared to USD 8,818 thousand for the comparative period in 2024 and mainly related to the bond interest at a coupon rate of 7.25% per annum. Interest income generated on cash balances held amounted to USD 1,634 thousand for Q1 2025 and USD 5,617 thousand for Q1 2024.

The unwinding of the asset retirement obligation discount rate amounted to USD 3,957 thousand for Q1 2025 compared to USD 3,618 thousand for Q1 2024.

Income tax
The corporate income tax amounted to a charge of USD 4,679 thousand for Q1 2025, compared to a charge of USD 7,746 thousand for Q1 2024.

The current income tax amounted to a charge of USD 514 thousand for Q1 2025 and mainly related to France. No corporate income tax is expected to be payable in Canada in 2025 due to the usage of historical tax pools.

Capital Expenditure

Development and exploration and evaluation expenditure incurred for the first three months of 2025 was as follows:

USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Development	90,342	3,035	592	3,099	**97,068**
Exploration and evaluation	1,818	–	–	–	**1,818**
	92,160	3,035	592	3,099	**98,886**

Capital expenditure of USD 98,886 thousand was mainly spent in Canada on the Blackrod Phase 1 Development project and on infill well drilling at Onion Lake Thermal.

Other tangible fixed assets
Other tangible fixed assets amounted to USD 14,492 thousand as at March 31, 2025, which included USD 12,880 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated to its residual value on a unit of production basis to August 2025.

Financial Position and Liquidity

Financing
As at March 31, 2025, IPC had MUSD 450 of bonds outstanding, maturing in February 2027 with a fixed coupon rate of 7.25% per annum, payable in semi-annual instalments in August and February. The bond repayment obligations as at March 31, 2025, are classified as non-current as there are no mandatory repayments within the next twelve months.

In addition, as at March 31, 2025, the Group had a revolving credit facility of MCAD 180 (the "Canadian RCF") in connection with its oil and gas assets in Canada. The Canadian RCF has a maturity in May 2026 and is undrawn and fully available as at March 31, 2025. During Q3 2024, the Group entered into a letter of credit facility in Canada (the "LC Facility") to cover existing operational letters of credit. As at March 31, 2025, operational letters of credit in an aggregate of MCAD 40.2 have been issued under the LC Facility, including letters of credit of MCAD 35 to support the third party pipeline construction agreements for the Blackrod project which are expected to be released when these pipelines become operational, in the course of 2025.

As at March 31, 2025, IPC had an unsecured Euro credit facility in France (the "France Facility"), with maturity in May 2026. IPC makes quarterly repayments of the France Facility and the amount remaining outstanding under the France Facility as at March 31, 2025 was MUSD 4.4. An amount of MUSD 3.5 under the France Facility as at March 31, 2025 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, 2025.

Net debt as at March 31, 2025 amounted to MUSD 314. Cash and cash equivalents held amounted to MUSD 140 as at March 31, 2025.

IPC intends to fund the remaining Blackrod capital expenditure with forecast cash flow generated by its operations, cash on hand and Canadian RCF loan drawing if needed.

Working Capital
As at March 31, 2025, the Group had a working capital balance including cash of USD 83,730 thousand compared to USD 190,771 thousand as at December 31, 2024. The difference as at March 31, 2025, from December 31, 2024, is mainly 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 including net sales of diluent 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	2025	2024
Revenue	178,492	206,419
Production costs and net sales of diluent to third party[1]	(103,188)	(115,745)
Current tax	(514)	(1,373)
Operating cash flow	**74,790**	89,301

[1] *Includes net sales of diluent to third party amounting to USD 191 thousand for the first quarter of 2025.*

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	2025	2024
Operating cash flow - see above	74,790	89,301
Capital expenditures	(98,886)	(125,256)
Abandonment and farm-in expenditures[1]	(321)	(122)
General, administration and depreciation expenses before depreciation[2]	(4,358)	(3,653)
Cash financial items[3]	(14,397)	(3,581)
Free cash flow	**(43,172)**	(43,311)

[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.*

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	2025	2024
Net result	16,231	33,719
Net financial items	18,855	9,770
Income tax	4,679	7,746
Depletion and decommissioning costs	29,016	33,153
Depreciation of other tangible fixed assets	1,917	2,262
Exploration and business development costs	31	75
Sale of assets[1]	(94)	–
Depreciation included in general, administration and depreciation expenses[2]	311	295
EBITDA	**70,946**	87,020

[1] *Sale of assets is included under "Other income/(expense)" but not specifically disclosed in the Financial Statements*
[2] *Item is not shown in the Financial Statements.*

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

	Three months ended March 31	
USD Thousands	2025	2024
Production costs	103,379	115,745
Cost of blending	(37,726)	(45,206)
Change in inventory position	3,500	5,277
Operating costs	**69,153**	75,816

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

USD Thousands	March 31, 2025	December 31, 2024
Bank loans	(4,449)	(5,121)
Bonds[1]	(450,000)	(450,000)
Cash and cash equivalents	140,194	246,593
Net cash/(debt)	**(314,255)**	(208,528)

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

Off-Balance Sheet Arrangements

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

Outstanding Share Data

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

As at January 1, 2024, IPC had a total of 126,992,066 common shares issued and outstanding, with no common shares held in treasury. From January 1, 2024 to December 4, 2024, IPC purchased and cancelled a total of 7,109,365 common shares under the normal course issuer bid/share repurchase program (NCIB). The NCIB was further renewed in Q4 2024 and IPC is entitled to purchase up to 7,465,356 common shares over the period of December 5, 2024 to December 4, 2025. During December 2024, IPC purchased 823,386 and cancelled 713,230 common shares under the renewed NCIB, for an aggregate of 7,822,595 common shares cancelled in 2024.

As at December 31, 2024, IPC had a total of 119,169,471 common shares issued and outstanding and held 110,156 common shares held in treasury.

Over the period of January 1, 2025 to March 31, 2025, IPC purchased 3,670,983 common shares under the NCIB and 211,818 common shares under certain other exemptions in Canada. All of these purchased common shares, including the common shares held in treasury as at December 31, 2024, were cancelled during Q1 2025. As at March 31, 2025, IPC had a total of 115,176,514 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 35.3% of the outstanding common shares as at March 31, 2025.

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 2,944,382 IPC Share Unit Plan awards outstanding as at May 6, 2025 (4,333 awards granted in January 2022, 2,391 awards granted in July 2022, 2,072 awards granted in January 2023, 919,911 awards granted in February 2023, 3,244 awards granted in July 2023, 2,443 awards granted in January 2024, 1,057,235 awards granted in February 2024, 4,328 awards granted in July 2024, 5,607 awards granted in January 2025 and 942,818 awards granted in February 2025).

The Corporation is authorized to issue an unlimited number of common shares without par value. The Corporation is also authorized to issue an unlimited number of class A preferred shares and an unlimited number of class B preferred shares, issuable in series.

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, 2025:

MCAD	2025	2026	2027	2028	2029	Thereafter
Transportation service[1]	24.6	59.3	88.2	92.8	96.6	1,395.7
Power[2]	10.9	12.4	12.4	9.8	–	–
Total commitments	**35.5**	**71.7**	**100.6**	**102.6**	**96.6**	**1,395.7**

[1] IPC has firm transportation commitments on oil and natural gas pipelines that expire between 2037 and 2045.
[2] IPC has physical delivery power hedges to purchase 15MWh at a weighted average price of CAD 74.92/MWh from April 1, 2025 to December 31, 2028, an additional 5MWh at a weighted average price of CAD 58.31/MWh from April 1, 2025 to December 31, 2027, and an additional 5MWh at a weighted average price of CAD 46.85/MWh from April 1, 2025 to December 31, 2025.

Material Accounting Policies and Estimates

In connection with the preparation of the consolidated financial statements, the Group's 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. The assumptions, estimates and judgments are based on historical experience, current trends and other factors that management believes to be relevant at the time the consolidated financial statements are prepared. On a regular basis, management reviews the accounting policies, assumptions, estimates and judgments to ensure that the consolidated financial statements are presented fairly in accordance with IFRS Accounting Standards. 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.

Management believes the following critical accounting policies affect the more significant judgments and estimates used in the preparation of the consolidated financial statements:

Estimates of oil and gas reserves
Estimates of oil and gas reserves are used in the calculations for impairment tests and accounting for depletion and asset retirement obligation. Standard recognized evaluation techniques are used to estimate the proved and probable reserves. These techniques take into account the future level of development required to produce the reserves. An independent qualified reserves auditor reviews these estimates. Changes in estimates in oil and gas reserves, resulting in different future production profiles, will affect the discounted cash flows used in impairment testing, the anticipated date of site decommissioning and restoration and the depletion charges in accordance with the unit of production method. Changes in estimates in oil and gas reserves could for example result from additional drilling, observation of long-term reservoir performance or changes in economic factors such as oil price and inflation rates. Significant assumptions developed by management used to determine estimates of proved and probable oil and gas reserves include expected production volumes, future oil and gas prices, future development costs and future production costs.

Impairment of oil and gas properties
Impairment tests are performed when there are indicators of impairment. Key assumptions in the impairment models relate to prices and costs that are based on forward curves and the long-term corporate assumptions. The impairment test requires the use of estimates. For the purpose of determining a potential impairment, the significant assumptions developed by management used to determine the recoverable amount include the estimates of oil and gas reserves and the discount rate. These assumptions and judgements of management that are based on them are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates and the discount rate applied is reviewed throughout the year.

Provision for asset retirement obligations
Amounts used in recording a provision for asset retirement obligations are estimates based on current legal and constructive requirements and current technology and price levels for the removal of facilities and decommissioning. Due to changes in relation to these items, the future actual cash outflows in relation to the site decommissioning and restoration can be different. To reflect the effects due to changes in legislation, requirements and technology and price levels, the carrying amounts of asset retirement obligation provisions are reviewed on a regular basis.

Deferred income tax assets
The Group accounts for differences that arise between the carrying amount of assets and liabilities and their tax bases in accordance with IAS 12, Income Taxes, which requires deferred income tax assets only to be recognized to the extent that is probable that future taxable profits will be available against which the temporary differences can be utilized. Management estimates future taxable profits based on the financial models used to value its oil and gas properties. Any change to the estimates and assumptions used for the key operational and financial variables used within the business models could affect the amount of deferred income tax assets recognized.

The effects of changes in estimates do not give rise to prior year adjustments and are treated prospectively over the estimated remaining commercial reserves of each field. While the Group uses its best estimates and judgement, actual results could differ from these estimates.

Transactions with Related Parties

The Group recognises the following related parties: associated companies, jointly controlled entities, key management personnel and members of their close family or other parties that are partly, directly or indirectly controlled by key management personnel or of its family or of any individual that controls, or has joint control or significant influence over the entity.

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.

During the first quarter of 2025, the Group has not entered into material transactions with related parties.

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, 2025, the Corporation had entered into oil, gas, electricity and currency 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, 2025, which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
April 1, 2025 - December 31, 2025	11,700	WTI/WCS Differential	USD -14.26/bbl
April 1, 2025 - December 31, 2025	10,000	WTI Sale Swap	USD 71.30/bbl
April 1, 2025 - December 31, 2025	2,000	Brent Sale Swap	USD 75.78/bbl

The Group had gas price sale financial hedges outstanding as at March 31, 2025, which are summarized as follows:

Period	Volume (Gigajoules (GJ) per day))	Type	Average Pricing
April 1, 2025 - October 31, 2025	20,000	AECO Swap	CAD 2.25/GJ
April 1, 2025 - December 31, 2025	10,000	AECO Swap	CAD 2.50/GJ

The Group had electricity financial hedges outstanding as at March 31, 2025, which are summarized as follows:

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

The above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. The hedges had a negative fair value of USD 1,815 thousand as at March 31, 2025.

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.

The Group entered into currency hedges to purchase:
(i) a total CAD 357.5 million for the period April 2025 to December 2025 at an average rate of CAD 1.36 (sell USD);
(ii) a total EUR 20.25 million for the period April 2025 to December 2025 at an average rate of EUR 1.07 (sell USD);
(iii) a total MYR 102 million for the period April 2025 to December 2025 at an average rate of MYR 4.39 (sell USD).

The outstanding portion of all of the above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. The hedges had a negative fair value of USD 12,484 thousand as at March 31, 2025.

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. There are currently no interest rate hedges.

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, 2024 ("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, 2025, 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). Management concluded that the Corporation's internal control over financial reporting was effective as of March 31, 2025.

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:
- 2025 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 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 its strategies to build long-term shareholder value;
- The ability of IPC's portfolio of assets to provide a solid foundation for organic and inorganic growth;
- The continued facility uptime and reservoir performance in IPC's areas of operation;
- Development of the Blackrod project in Canada, including estimates of resource volumes, future production, timing, regulatory approvals, third party commercial arrangements, breakeven oil prices and net present values;
- Current and future production performance, operations and development potential of the Onion Lake Thermal, Suffield, Brooks, Ferguson and Mooney operations, including the timing and success of future oil and gas drilling and optimization programs;
- The potential improvement in the Canadian oil egress situation and IPC's ability to benefit from any such improvements;
- The ability to maintain current and forecast production in France and Malaysia;
- The intention and ability of IPC to acquire further common shares under the NCIB, including the timing of any such purchases;
- The return of value to IPC's shareholders as a result of the NCIB;
- IPC's ability to implement its greenhouse gas (GHG) emissions intensity and climate strategies and to achieve its net GHG emissions intensity reduction targets;
- IPC's ability to implement projects to reduce net emissions intensity, including potential carbon capture and storage;
- Estimates of reserves and contingent resources;
- The ability to generate free cash flows and use that cash to repay debt;
- IPC's continued access to its existing credit facilities, including current financial headroom, on terms acceptable to the Corporation;
- IPC's ability to 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: the potential impact of tariffs implemented in 2025 by the U.S. and Canadian governments and that other than the tariffs that have been implemented, neither the U.S. nor Canada (i) increases the rate or scope of such tariffs, or imposes new tariffs, on the import of goods from one country to the other, including on oil and natural gas, and/or (ii) imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas; 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
- Political or economic developments, including, without limitation, the risk that (i) one or both of the U.S. and Canadian governments increases the rate or scope of tariffs implemented in 2025, or imposes new tariffs on the import of goods from one country to the other, including on oil and natural gas, (ii) the U.S. and/or Canada imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas, and (iii) the tariffs imposed by the U.S. on other countries and responses thereto could have a material adverse effect on the Canadian, U.S. and global economies, and by extension the Canadian oil and natural gas industry and the Corporation; 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 production and FCF generation are based on IPC's current business plans over the periods of 2025 to 2029 and 2030 to 2034, less net debt of USD 209 million as at December 31, 2024, with assumptions based on the reports of IPC's independent reserves evaluators, and including certain corporate adjustments relating to estimated general and administration costs and hedging, and excluding shareholder distributions and financing costs. Assumptions include average net production of approximately 57 Mboepd over the period of 2025 to 2029, average net production of approximately 63 Mboepd over the period of 2030 to 2034, average Brent oil prices of USD 75 to 95 per bbl 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, 2024 (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, 2024, 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, 2024 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, 2024, 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, 2024 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, 2024 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 493 MMboe as at December 31, 2024, by the mid-point of the 2025 CMD production guidance of 43,000 to 45,000 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, 2025	23.2	6.5	88.2 MMcf (14.7 Mboe)	44.4
March 31, 2024	24.9	7.9	96.0 MMcf (16.0 Mboe)	48.8
Year ended December 31, 2024				
December 31, 2024	23.9	7.7	95.1MMcf (15.8 Mboe)	47.4

This MD&A also makes reference to IPC's forecast total average daily production of 43,000 to 45,000 boepd for 2025. IPC estimates that approximately 52% of that production will be comprised of heavy oil, approximately 15% will be comprised of light and medium crude oil and approximately 33% will be comprised of conventional natural gas.

OTHER SUPPLEMENTARY INFORMATION

Abbreviations

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

Oil related terms and measurements

AECO	The daily average benchmark price for natural gas at the AECO hub in southeast Alberta
AESO	Alberta Electric System Operator
API	An indication of the specific gravity of crude oil on the API (American Petroleum Institute) gravity scale
ASP	Alkaline surfactant polymer (an EOR process)
bbl	Barrel (1 barrel = 159 litres)
boe	Barrels of oil equivalents
boepd	Barrels of oil equivalents per day
bopd	Barrels of oil per day
Bcf	Billion 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
WTI	West Texas Intermediate
WCS	Western Canadian Select

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

William Lundin
President and Chief Executive Officer
Coppet, Switzerland

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

International Petroleum Corporation
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