

# Q1

**International Petroleum Corporation**

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*Management's Discussion  
and Analysis*

*For the three months ended March 31, 2026*



**International  
Petroleum  
Corp.**

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

### Contents

<b>INTRODUCTION</b>	<b>3</b>
<b>HIGHLIGHTS</b>	<b>4</b>
<b>OPERATIONS REVIEW</b>	<b>5</b>
• Business Overview	5
• Operations Overview	7
<b>FINANCIAL REVIEW</b>	<b>9</b>
• Financial Results	9
• Capital Expenditure	14
• Financial Position and Liquidity	14
• Non-IFRS Measures	15
• Off-Balance Sheet Arrangements	17
• Outstanding Share Data	17
• Contractual Obligations and Commitments	17
• Material Accounting Policies and Estimates	18
• Transactions with Related Parties	18
• Financial Risk Management	18
<b>RISK FACTORS</b>	<b>20</b>
<b>DISCLOSURE CONTROLS AND INTERNAL CONTROL OVER FINANCIAL REPORTING</b>	<b>20</b>
<b>CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION</b>	<b>20</b>
<b>RESERVES AND RESOURCES ADVISORY</b>	<b>23</b>
<b>OTHER SUPPLEMENTARY INFORMATION</b>	<b>25</b>

#### 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 15.

#### 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 20.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada and France/Malaysia are effective as of December 31, 2025, and are included in the reports prepared by Sproule International Limited and ERC Equipoise Ltd., respectively (collectively, Sproule ERCE), an independent qualified reserves evaluator and auditor, 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 ERCE's December 31, 2025, price forecasts.

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

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

### 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 5, 2026 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, 2026 as well as the audited consolidated financial statements and accompanying notes for the year ended December 31, 2025 ("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, 2026		March 31, 2025		December 31, 2025	
	Average	Period end	Average	Period end	Average	Year end
1 EUR equals USD	1.1707	1.1498	1.0807	1.0815	1.1293	1.1750
1 USD equals CAD	1.3724	1.3935	1.4352	1.4362	1.3975	1.3692
1 USD equals MYR	3.9638	4.0490	4.4475	4.4375	4.2791	4.0580

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

### HIGHLIGHTS

#### Q1 2026 Business Highlights

- Average net production of approximately 43,000 boepd for the first quarter of 2026, at the high end of the guidance range for the period (52% heavy crude oil, 15% light and medium crude oil and 33% natural gas).<sup>(1)</sup>
- Blackrod Phase 1 development activity nears completion as final construction activities and commissioning of the Central Processing Facility (CPF) advance, with first oil forecast for Q3 2026.
- Following the increase in commodity prices in Q1 2026, decision taken to increase 2026 planned capital activities, with an additional MUSD 41 of forecast capital expenditures over the remainder of 2026.

#### Q1 2026 Financial Highlights

- Operating costs per boe of USD 17.6 for Q1 2026, ahead of guidance.<sup>(3)</sup>
- Operating cash flow (OCF) generation of MUSD 68 for Q1 2026, ahead of guidance.<sup>(3)</sup>
- Capital and decommissioning expenditures of MUSD 71 for Q1 2026, in line with guidance.
- Free cash flow (FCF) generation for Q1 2026 amounted to MUSD -17.<sup>(3)</sup>
- Net result of MUSD 13 for Q1 2026.
- Amended and extended the credit facility in Canada in Q2 2026 to increase the committed facility size to CAD 348.5 million (approximately USD 250 million), with maturity extended to May 2028.

#### Reserves and Resources

- Total 2P reserves as at December 31, 2025 of 521 MMboe, with a reserve life index (RLI) of 31 years.<sup>(1)(2)</sup>
- Contingent resources (best estimate, unrisked) as at December 31, 2025 of 1,224 MMboe.<sup>(1)(2)</sup>

#### 2026 Annual Guidance

- Full year 2026 average net production guidance range maintained at 44,000 to 47,000 boepd.<sup>(1)</sup>
- Full year 2026 operating costs guidance range maintained at USD 18 to 20 per boe.<sup>(3)</sup>
- Full year 2026 OCF revised guidance estimated at between MUSD 220 and 340 (assuming Brent USD 70 to 90 per barrel for the remainder of 2026) from previous guidance of between MUSD 100 and 250 (assuming Brent USD 55 to 75 per barrel).<sup>(3)(4)</sup>
- Full year 2026 capital and decommissioning expenditures guidance forecast increased to MUSD 163, as a result of additional planned capital activities.
- Full year 2026 FCF revised guidance estimated at between MUSD 0 and 120 (assuming Brent USD 70 to 90 per barrel for the remainder of 2026) from previous guidance of between negative MUSD 70 and positive MUSD 85 (assuming Brent USD 55 to 75 per barrel).<sup>(3)(4)</sup>

USD Thousands	Three months ended March 31	
	2026	2025
Revenue	173,010	178,492
Gross profit	37,175	44,149
Net result	12,762	16,231
Operating cash flow <sup>(3)</sup>	67,735	74,790
Free cash flow <sup>(3)</sup>	(17,086)	(43,172)
EBITDA <sup>(3)</sup>	64,289	70,946
Net cash/(debt) <sup>(3)</sup>	(513,413)	(314,255)

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

### OPERATIONS REVIEW

#### Business Overview

During the first quarter of 2026, commodity prices increased materially compared to the prior quarter, with Brent oil prices averaging over USD 80 per barrel. During the quarter and into the second quarter, commodity prices continued to be high and volatile mainly in response to uncertainties with respect to the conflict in the Middle East and the corresponding effects on supply of oil and gas from the region. As a result of the constrained flows through the Strait of Hormuz from the end of February, one of the largest supply disruptions on record has taken place with an estimated net 10 million barrels per day shortfall. This has prompted coordinated Strategic Petroleum Reserves releases, increased OPEC spare capacity unwinds, and relief on previously sanctioned Russian and Iranian barrels to combat high crude and crude product prices. Prompt spreads between physical spot and Brent futures month contracts have seen all time high price separation signalling extreme physical market tightness due to the supply disruption. The profound effect of this crisis is likely to be much longer lasting as consumers and producers alike reshape their thinking around access to resources and security of supply. Prior to the commencement of hostilities in Iran, IPC hedged 2,000 barrels per day of Dated Brent from April to June 2026 at around USD 68 per barrel and 9,000 barrels per day of West Texas Intermediate (WTI) from April to June 2026 at around USD 62 per barrel. IPC remains fully exposed to benchmark oil prices from the beginning of July 2026 onwards.

The first quarter 2026 WTI to Western Canadian Select (WCS) price differential averaged USD 14 per barrel, in line with the 2026 forecast. The WTI to WCS differential continues to benefit from the TMX pipeline expansion, driving up competitive tension for Canadian oil and increased buying from Asia. The outlook of the WTI to WCS differential remains tight with excess egress capacity relative to the supply in the Western Canadian Sedimentary Basin (WCSB), balanced against the potential of Venezuelan heavy oil barrels to the US Gulf Coast PADD III refineries. There are currently no tariffs on Canadian crude oil exports to the United States, which remain covered by the US Mexico Canada trade agreement. For 2026, IPC has implemented WTI to WCS differential hedges for 5,000 barrels per day at USD -12.50 per barrel. In addition, IPC has hedged from July to year end 2027, 5,000 barrels per day of the differential between the WCS price in Hardisty, Canada and the WCS price in Houston, USA, effectively hedging the transportation cost between the locations, at USD -7.55 per barrel. In addition, 2,000 barrels per day of quality differential between the WCS in Houston and the WTI were hedged from July to December 2026 at USD -3.65 per barrel.

The average Canadian gas benchmark price, AECO, was CAD 1.98 per Mcf for the first quarter of 2026, with WCSB gas inventory levels remaining elevated above the historical average. There is an expectation that the ramp up of the LNG Canada project in 2026 should drive higher natural gas prices in Canada. IPC has implemented hedges for 15,000 GJ (approximately 14,500 Mcf) per day at CAD 2.73 per GJ (approximately CAD 2.84 per Mcf) for 2026 from April to October 2026.

#### First Quarter 2026 Highlights and Full Year 2026 Guidance

During the first quarter of 2026, our portfolio delivered average net production of 43,000 boepd, at the high end of the guidance range for the quarter. Operational performance from our producing assets was strong to start the year as high facility and well uptimes were achieved. We maintain the full year 2026 average net production guidance range of 44,000 to 47,000 boepd.<sup>(1)</sup>

Our operating costs per boe for the first quarter of 2026 was USD 17.6, ahead of guidance. Full year 2026 operating expenditure guidance of USD 18.0 to 20.0 per boe remains unchanged.<sup>(3)</sup>

Operating cash flow (OCF) generation for the first quarter of 2026 was USD 68 million. Full year 2026 OCF guidance is increased to USD 220 to 340 million (assuming Brent USD 70 to 90 per barrel for the remainder of 2026).<sup>(3)(4)</sup>

Capital and decommissioning expenditure for the first quarter of 2026 was USD 71 million in line with guidance. Full year 2026 capital and decommissioning expenditure is increased to USD 163 million following the decision to accelerate capital activities following the 2026 commodity price increases.

Free cash flow (FCF) generation was USD -17 million during the first quarter of 2026, ahead of guidance. Full year 2026 FCF guidance is increased to USD 0 to 120 million (assuming Brent USD 70 to 90 per barrel for the remainder of 2026).<sup>(3)(4)</sup>

As at March 31, 2026, IPC's net debt position was USD 513 million, from a net debt position of USD 484 million as at December 31, 2025, mainly driven by the funding of Blackrod project capital expenditures.

In April 2026, IPC increased the facility size of its Canadian credit facility to CAD 348.5 million (approximately USD 250 million) and extended the maturity of the facility to May 2028. IPC previously announced the 2025 refinancing of its USD 450 million of unsecured bonds, with maturity in October 2030. This enhanced liquidity position for the company, combined with the better than forecast cash flow generation to date and forecast for 2026, supports IPC in following through on its key strategic objectives to maximize stakeholder value.

IPC maintains the ability to repurchase up to approximately 6.5 million common shares up to early December 2026 under the renewed normal course issuer bid (NCIB) announced in Q4 2025. IPC has not purchased any common shares under the 2025/2026 NCIB to date. As at March 31, 2026 and May 5, 2026, IPC had a total of 112,826,752 common shares issued and outstanding and IPC held no common shares in treasury.

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

### Blackrod

The Blackrod asset is 100% owned by IPC and hosts the largest booked reserves and contingent resources within the IPC portfolio. After more than a decade of pilot operations, subsurface delineation and commercial engineering studies, IPC sanctioned the Phase 1 SAGD development in the first quarter of 2023. The Phase 1 development targets 311 MMboe of 2P reserves, with first oil planned in Q3 2026 and a plateau production of 30,000 bopd by the end of 2027.<sup>(1)(2)</sup>

As previously announced, IPC achieved first steam at the Blackrod Phase 1 project in December 2025, a quarter earlier than originally guided at the time of project sanction. By the end of the first quarter of 2026, approximately USD 842 million of cumulative growth capital has been spent on the Blackrod Phase 1 development since sanction. Construction is nearing completion at the Central Processing Facility (CPF) and well pad facilities, commissioning activities are progressing in line with schedule, and drilling plus completions have been completed in line with plan. Site health and safety control has been excellent with no lost time incidents since commercial development activities commenced.

IPC remains well-positioned to responsibly deliver the Phase 1 project in line with the multi-year budget of USD 850 million to first oil. The total growth capital expenditure comprises the total installed costs for the facilities and associated 40 well pairs needed to fill the plant capacity of 30,000 bopd and has remained unchanged since the time of sanction in 2023.<sup>(1)</sup>

Blackrod is a multi-generational asset that is being unlocked through the first phase of commercial development. More than 1.45 billion barrels of recoverable resource lies within the contiguous reservoir wholly owned by IPC. The company remains laser focused on achieving the production start and ramp up targets as previously disclosed on the Phase 1 project and in parallel is maturing future phase expansion concepts. Blackrod has regulatory approval for up to 80,000 bopd.<sup>(1)(2)</sup>

### Environmental, Social and Governance (ESG) Performance

As part of IPC's commitment to operational excellence and responsible development, IPC's objective is to reduce risk and eliminate hazards to prevent occurrence of accidents, ill health, and environmental damage, as these are essential to the success of our business operations. During the first quarter of 2026, IPC recorded no material safety or environmental incidents.

#### 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, 2025 (AIF) available on IPC's website at [www.international-petroleum.com](http://www.international-petroleum.com) and under IPC's profile on SEDAR+ at [www.sedarplus.ca](http://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.
- (3) Non-IFRS measures, see "Non-IFRS Measures" below and in the MD&A.
- (4) OCF and FCF forecasts at Brent USD 70 to 90 per barrel assume Brent to WTI differential of USD 5 per barrel and WTI to WCS differential of USD 14 per barrel for the remainder of 2026. OCF and FCF forecasts assume gas price on average of approximately CAD 2.17 per Mcf for the remainder of 2026.

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

### Operations Overview

#### Q1 2026 Overview

In Q1 2026, IPC continued to successfully demonstrate its commitment to operational excellence, delivering high end production performance with strong cost discipline resulting in operating expenditure at the low end of our Capital Markets Day (CMD) guidance. No material safety or environmental incidents were recorded in the quarter.

At the end of Q1 2026, on the back of the strong pricing environment and the strong operational performance year to date, IPC has increased the 2026 capital expenditure budget by MUS\$ 41 to allow additional production well drilling activities in France and Canada. In France, three sidetrack wells are planned to be drilled as part of the first phase of development of the Fontaine-au-Bron field, in addition to one sidetrack well planned at the Villeperdue field. In Canada, oil production well drilling in the Suffield Basal Quartz formation is expected to recommence with the sanction of four additional production wells planned to be executed in 2026. The incremental activity is forecast to raise 2026 exit rates and support higher production levels into 2027. The planned 4D seismic activity has been acquired at Onion Lake Thermal with reprocessing ongoing in preparation for the potential next phase of infill production well drilling.

At the Blackrod Phase 1 development, the remaining project scope and overall project budget continued to progress in line with guidance. By the end of Q1 2026, project construction activities are near completion, while commissioning has entered its final stages, with activities expected to ramp down towards the summer. The production and injection well pair warm-up process, through steam circulation, is ongoing, with a total of 30 well pairs brought onto steam circulation by the end of Q1 2026. To take advantage of economies of scale and provide additional well capacity, IPC accelerated the drilling of sixteen well pairs on the final pad starting in Q4 2025, delivering six additional sustaining well pairs beyond the original Phase 1 development budget. Drilling operations were completed ahead of schedule in Q1 2026, and commissioning of the final well pad facilities is currently ongoing, with completion expected in Q3 2026. Final third-party export pipeline commissioning was completed as planned in Q1 2026 and, at quarter-end, all three third party utility and export lines were operational.

#### Reserves and Resources

The 2P reserves attributable to IPC's oil and gas assets are 521 MMboe as at December 31, 2025, as certified by IPC's independent third-party reserve auditor and evaluator. The 2P reserve life index (RLI) as at December 31, 2025, is approximately 31 years. Best estimate contingent resources as at December 31, 2025, are 1,224 MMboe (unrisked). See "Reserves and Resources Advisory" below.

#### Production

Average daily net production for Q1 2026 was in line with IPC's CMD guidance at 43,000 boepd with strong operational performance in all regions.

With the first quarter 2026 operational delivery, and a robust 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 44,000 to 47,000 boepd.

The production during Q1 2026 with comparatives is summarized below:

Production in Mboepd	Three months ended March 31		Year ended December 31
	2026	2025	2025
<b>Crude oil</b>			
Canada – Northern Assets	14.2	13.9	14.7
Canada – Southern Assets	9.2	10.8	10.2
Malaysia	3.3	2.9	3.0
France	2.0	2.1	2.1
<b>Total crude oil production</b>	<b>28.7</b>	29.7	30.0
<b>Gas</b>			
Canada – Northern Assets	0.5	0.5	0.4
Canada – Southern Assets	13.8	14.2	14.5
<b>Total gas production</b>	<b>14.3</b>	14.7	14.9
<b>Total production</b>	<b>43.0</b>	44.4	44.9
<b>Quantity in MMboe</b>	<b>3.87</b>	4.00	16.38

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

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

### CANADA

Production in Mboepd	Working Interest (WI)	Three months ended March 31		Year ended December 31
		2026	2025	2025
- Oil Onion Lake Thermal	100%	11.8	11.5	12.2
- Oil Suffield Area	100%	8.2	9.3	8.9
- Oil Other	50-100%	3.4	3.9	3.8
- Gas	~100%	14.3	14.7	14.9
Canada		<b>37.7</b>	39.4	39.8

#### Production

Net production from IPC's assets in Canada during Q1 2026 was in line with guidance at 37.7 Mboepd with continued strong operational performance at the major oil and gas producing assets.

#### Organic Growth and Capital Projects

In Canada, with the forecast final development spend year at the Blackrod Phase 1 project, IPC announced a balanced non-Blackrod capital expenditure budget for 2026. In response to the improved commodities pricing environment, IPC intends to take advantage of operatorship across its assets by increasing short cycle production activities.

At Suffield, drilling of the Basal Quartz formation is planned to recommence with an additional four production wells scheduled to commence drilling in Q3 2026.

At Onion Lake Thermal, the 4D seismic data is being reprocessed as IPC looks to mature the potential next phase of infill well targets and to optimize future sustaining pad well locations.

At Blackrod Phase 1, remaining scope and total project budget continued to progress in line with guidance. By the end of Q1 2026, construction activities were nearing completion, and commissioning was in the final stages, with activity levels expected to reduce toward the summer. Steam circulation warm-up of the production and injection well pairs were ongoing, with 30 well pairs on steam circulation at quarter end. Drilling of the final well pad was completed ahead of schedule in Q1 2026, with commissioning ongoing and expected to be completed in Q3 2026. Commissioning of the third party export pipeline was completed as planned in Q1 2026, and all utility and export lines were operational at quarter end.

### MALAYSIA

Production in Mboepd	WI	Three months ended March 31		Year ended December 31
		2026	2025	2025
Bertam	100%	<b>3.3</b>	2.9	3.0

#### Production

Net production in Malaysia during Q1 2026 was in line with guidance at 3.3 Mboepd.

#### Organic Growth and Capital Projects

Limited planned well maintenance at the Bertam field is scheduled for execution early in Q3 2026.

### FRANCE

Production in Mboepd	WI	Three months ended March 31		Year ended December 31
		2026	2025	2025
France				
- Paris Basin	100%	1.7	1.9	1.8
- Aquitaine	50%	0.3	0.2	0.3
		<b>2.0</b>	2.1	2.1

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

### Production

Net production in France during Q1 2026 was in line with guidance at 2.0 Mboepd with stable performance across all the major producing fields.

### Organic Growth

In France, three sidetrack wells are planned to be drilled as part of the first phase of development of the Fontaine-au-Bron field, in addition to one sidetrack well planned at the Villeperdue field. Drilling operations are on track to commence in Q2.

## FINANCIAL REVIEW

### Financial Results

#### Selected Annual Financial Information

Selected consolidated statement of operations is as follows:

USD Thousands	Q1-26	Q4-25	Q3-25	Q2-25	Q1-25	Q4-24	Q3-24	Q2-24
Revenue	173,010	176,207	172,297	158,892	178,492	199,124	173,200	219,040
Gross profit	37,175	28,242	32,066	23,663	44,149	42,774	39,505	72,708
Net result	12,762	(4,942)	3,802	13,850	16,231	415	22,875	45,210
Earnings per share – USD	0.11	(0.04)	0.03	0.12	0.14	0.00	0.19	0.36
Earnings per share fully diluted – USD	0.11	(0.04)	0.03	0.12	0.13	0.00	0.18	0.36
Operating cash flow <sup>1</sup>	67,735	63,138	66,102	54,873	74,790	78,158	72,589	101,941
Free cash flow <sup>1</sup>	(17,086)	(28,627)	(23,083)	(58,252)	(43,172)	(61,476)	(38,269)	7,559
EBITDA <sup>1</sup>	64,289	58,966	62,106	51,519	70,946	76,184	68,313	103,971
Net cash/(debt) at period end <sup>1</sup>	(513,413)	(483,615)	(434,822)	(374,977)	(314,255)	(208,528)	(157,228)	(88,220)

<sup>1</sup> See definition on page 15 under "Non-IFRS measures"

Summarized consolidated balance sheet information is as follows:

USD Thousands	March 31, 2026	December 31, 2025
Non-current assets	1,856,050	1,847,327
Current assets	164,202	130,302
<b>Total assets</b>	<b>2,020,252</b>	<b>1,977,629</b>
Total non-current liabilities	920,324	890,204
Current liabilities	209,158	160,248
<b>Total liabilities</b>	<b>1,129,482</b>	<b>1,050,452</b>
<b>Net assets</b>	<b>890,770</b>	<b>927,177</b>
<b>Working capital (including cash)</b>	<b>(44,956)</b>	<b>(29,946)</b>

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

### 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 (comprised mainly of the Suffield area 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.

USD Thousands	Three months ended – March 31, 2026					Total
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	
Crude oil	97,751	51,084	24,560	20,636	–	194,031
NGLs	–	143	–	–	–	143
Gas	94	12,248	–	–	–	12,342
<b>Net sales of oil and gas</b>	<b>97,845</b>	<b>63,475</b>	<b>24,560</b>	<b>20,636</b>	–	<b>206,516</b>
Change in under/over lift position	–	–	–	(4,744)	–	(4,744)
Royalties	(12,200)	(5,778)	–	(698)	–	(18,676)
Hedging settlement	(6,275)	(4,015)	–	–	–	(10,290)
Other operating revenue	–	–	–	204	–	204
<b>Revenue</b>	<b>79,370</b>	<b>53,682</b>	<b>24,560</b>	<b>15,398</b>	–	<b>173,010</b>
Operating costs	(19,367)	(29,853)	(9,123)	(9,896)	–	(68,239)
Cost of blending	(33,693)	(5,198)	–	–	–	(38,891)
Change in inventory position	291	248	1,331	259	–	2,129
Depletion and decommissioning costs	(8,821)	(11,773)	(6,125)	(3,212)	–	(29,931)
Exploration and business development costs	–	–	–	–	(903)	(903)
<b>Gross profit/(loss)</b>	<b>17,780</b>	<b>7,106</b>	<b>10,643</b>	<b>2,549</b>	<b>(903)</b>	<b>37,175</b>

USD Thousands	Three months ended – March 31, 2025					Total
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	
Crude oil	98,236	63,786	15,376	12,814	–	190,212
NGLs	–	191	–	–	–	191
Gas	107	11,515	–	–	–	11,622
<b>Net sales of oil and gas</b>	<b>98,343</b>	<b>75,492</b>	<b>15,376</b>	<b>12,814</b>	–	<b>202,025</b>
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
<b>Revenue</b>	<b>84,380</b>	<b>65,451</b>	<b>15,376</b>	<b>13,285</b>	–	<b>178,492</b>
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 and decommissioning costs	(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)
<b>Gross profit/(loss)</b>	<b>24,876</b>	<b>13,953</b>	<b>2,466</b>	<b>2,885</b>	<b>(31)</b>	<b>44,149</b>

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

### Three months ended March 31, 2026 Review

#### Revenue

Total revenue amounted to USD 173,010 thousand for Q1 2026, compared to USD 178,492 thousand for Q1 2025, and is analyzed as follows:

USD Thousands	Three months ended March 31	
	2026	2025
Crude oil sales	194,031	190,212
Gas and NGL sales	12,485	11,813
Change in under/overlift position	(4,744)	1,141
Royalties	(18,676)	(23,628)
Hedging settlement	(10,290)	(1,216)
Other operating revenue	204	170
<b>Total revenue</b>	<b>173,010</b>	<b>178,492</b>

The main components of total revenue for Q1 2026, and Q1 2025, respectively, are detailed below.

#### Crude oil sales

USD Thousands	Three months ended – March 31, 2026				Total
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	
<b>Crude oil sales</b>					
- Revenue in USD thousands	97,751	51,084	24,560	20,636	<b>194,031</b>
- Quantity sold in bbls	1,716,374	886,242	223,093	279,186	<b>3,104,895</b>
- Average price realized USD per bbl	56.95	57.64	110.09	73.91	<b>62.49</b>

USD Thousands	Three months ended – March 31, 2025				Total
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	
<b>Crude oil sales</b>					
- 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

Crude oil revenue was 2% higher in Q1 2026 compared to Q1 2025 mainly due to higher price, especially in March 2026. France sales volumes are 65% higher in Q1 2026 compared to Q1 2025 as a result of the yearly lifting in Acquitaine in Q1 2026.

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 2026, WTI averaged USD 72 per bbl compared to USD 71 per bbl for Q1 2025 and the average discount to WCS used in IPC's pricing formula was USD 14 per bbl compared to USD 13 per bbl for the comparative period in 2025.

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 2026 and one cargo lifting in Q1 2025. Produced unsold oil barrels from Bertam at the end of Q1 2026 amounted to 134,000 barrels, see Change in Inventory Position section below. The average Dated Brent crude oil price was USD 81 per bbl for Q1 2026 compared to USD 76 per bbl for the comparative period.

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

### Gas and NGL sales

	Three months ended – March 31, 2026		
	Canada – Northern Assets	Canada – Southern Assets	Total
<b>Gas and NGL sales</b>			
- Revenue in USD thousands	94	12,391	12,485
- Quantity sold in Mcf	71,289	6,691,310	6,762,599
- Average price realized USD per Mcf	1.32	1.85	1.85

	Three months ended – March 31, 2025		
	Canada – Northern Assets	Canada – Southern Assets	Total
<b>Gas and NGL sales</b>			
- 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

Gas and NGL sales revenue was 6% higher for the Q1 2026 compared to Q1 2025, driven by marginally higher prices.

IPC's achieved gas price is based on AECO pricing plus a premium. For Q1 2026, IPC realized an average price of CAD 2.51 per Mcf compared to AECO average pricing of CAD 1.98 per Mcf.

### Hedging settlement

IPC enters into oil and gas prices risk management contracts in order to ensure a certain level of cash flow. It focuses mainly on oil and gas price swaps and on collars to a lesser extent, to mitigate these commodities price exposure. Oil and gas hedging contracts are not entered into for speculative purposes and only account for a portion of our production.

The realized hedging settlement for the Q1 2026 amounted to a loss of USD 10,290 thousand on the oil 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 105,001 thousand for Q1 2026 compared to USD 103,379 thousand for Q1 2025 and is analyzed as follows:

USD Thousands	Three months ended – March 31, 2026					Total
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	
<b>Operating costs<sup>1</sup></b>	19,367	29,853	9,123	9,896	–	<b>68,239</b>
USD/boe <sup>2</sup>	14.62	14.45	30.30	56.40	n/a	<b>17.64</b>
<b>Cost of blending</b>	33,693	5,198	–	–	–	<b>38,891</b>
<b>Change in inventory position</b>	(291)	(248)	(1,331)	(259)	–	<b>(2,129)</b>
<b>Production costs</b>	<b>52,769</b>	<b>34,803</b>	<b>7,792</b>	<b>9,637</b>	<b>–</b>	<b>105,001</b>

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

Three months ended – March 31, 2025

USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other <sup>3</sup>	Total
Operating costs <sup>1</sup>	19,180	33,325	11,802	8,067	(3,221)	69,153
USD/boe <sup>2</sup>	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

<sup>1</sup> See definition on page 15 under “Non-IFRS measures”.

<sup>2</sup> USD/boe in the tables above is calculated by dividing the cost by the production volume for each country for the period and for 2025.

<sup>3</sup> Up to April 2025, 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.

### Operating costs

Operating costs amounted to USD 68,239 thousand for Q1 2026 compared to USD 69,153 thousand for Q1 2025. Operating costs per boe amounted to USD 17.64 per boe in Q1 2026 slightly below the guidance for the quarter and compared with USD 17.30 per boe in Q1 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 38,891 thousand for Q1 2026 compared to USD 37,726 thousand for Q1 2025.

### 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 2026, IPC had crude entitlement of 134,000 bbls 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 29,931 thousand for Q1 2026 compared to USD 29,016 thousand for Q1 2025.

The depletion charge is analyzed in the following tables:

USD Thousands	Three months ended – March 31, 2026				Total
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	
Depletion cost in USD thousands	8,821	11,773	6,125	3,212	29,931
USD per boe <sup>2</sup>	6.66	5.70	20.34	18.31	7.74

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

<sup>1</sup> In Canada, excludes the adjustment for accelerated decommissioning activities.

<sup>2</sup> 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.

### Depreciation of other tangible fixed assets

The total depreciation of other tangible fixed assets amounted to nil for Q1 2026 compared to USD 1,917 thousand for Q1 2025. In 2025, the depreciation relates to FPSO Bertam, which has been depreciated to its residual value by the end of 2025.

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

### Exploration and business development costs

The total exploration and business developments costs amounted to a cost of USD 903 thousand for Q1 2026.

### Net financial items

Net financial items amounted to a charge of USD 20,737 thousand for Q1 2026, compared to a charge of USD 18,855 thousand for Q1 2025, and included a net foreign exchange loss of USD 6,268 thousand and no realized currency hedge loss for Q1 2026 compared to a realized currency hedge loss and a net foreign exchange gain of respectively USD 6,858 thousand and USD 18 thousand for Q1 2025. 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 14,469 thousand for Q1 2026, compared to a charge of USD 12,015 thousand for Q1 2025.

The interest expense amounted to USD 9,560 thousand for Q1 2026, compared to USD 8,761 thousand for the comparative period in 2025, mainly related to the bond interest at a fixed coupon rate of 7.5% per annum (former bonds in 2025 were bearing a fixed coupon rate of 7.25% per annum). Interest income generated on cash balances held amounted to USD 125 thousand for Q1 2026 and USD 1,634 thousand for Q1 2025.

The unwinding of the asset retirement obligation discount rate amounted to USD 4,162 thousand for Q1 2026 compared to USD 3,957 thousand for Q1 2025.

### Income tax

The corporate income tax amounted to a charge of USD 3,386 thousand for Q1 2026 compared to a charge of USD 4,679 thousand for Q1 2025.

The current income tax amounted to a charge of USD 456 thousand for Q1 2026 and 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 2026 due to the usage of historical tax pools.

### Capital Expenditure

Development and exploration and evaluation expenditures incurred during the quarter ended March 31, 2026 was as follows:

USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Development	66,269	1,459	561	671	68,960
Exploration and evaluation	1,701	–	–	–	1,701
	67,970	1,459	561	671	70,661

Capital expenditures of USD 70,661 thousand was mainly spent in Canada on the Blackrod Phase 1 Development project.

### Other tangible fixed assets

Other tangible fixed assets amounted to USD 11,186 thousand as at March 31, 2026, which included USD 9,200 thousand in respect of the FPSO Bertam. The FPSO Bertam has been depreciated to its residual value.

### Financial Position and Liquidity

#### Financing

As at January 1, 2025, IPC had USD 450 million of senior unsecured bonds outstanding, maturing in February 2027 with a fixed coupon rate of 7.25% per annum. In October 2025, IPC completed the issuance of USD 450 million of new senior unsecured bonds, maturing in October 2030 with a fixed coupon rate of 7.50% per annum, payable in semi-annual instalments in April and October, and with semi-annual amortizations of USD 25 million commencing in April 2028. The proceeds of the new bonds were used to fully redeem and cancel the previous bonds.

The bond repayment obligations as at March 31, 2026, are classified as non-current as there are no mandatory repayments within the next twelve months.

In addition, as at March 31, 2026, the Group had a senior secured revolving credit facility of CAD 250 million (the "Canadian RCF") in connection with its oil and gas assets in Canada, with a maturity date in May 2027. As at March 31, 2026, CAD 104 million (approximately USD 74 million) was drawn under the Canadian RCF. In April 2026, the Group amended and extended the Canadian RCF, increasing the committed facility size to CAD 348.5 million and extending the maturity to May 2028. As at March 31, 2026, the Group also had a letter of credit facility in Canada (the "LC Facility"). As at March 31, 2026, operational letters of credit in an aggregate of CAD 11.9 million have been issued under the LC Facility.

## Management's Discussion and Analysis

### For the three months ended March 31, 2026

As at March 31, 2026, IPC had an unsecured Euro credit facility in France (the "France Facility") which will be fully repaid in May 2026. The outstanding under the France Facility as at March 31, 2026 was USD 1 million (EUR 0.8 million) which 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, 2026.

Net debt as at March 31, 2026 amounted to USD 513 million. Cash and cash equivalents held amounted to USD 12 million as at March 31, 2026.

IPC intends to fund the budgeted capital expenditures in 2026 with forecast cash flow generated by its operations, cash on hand and Canadian RCF loan drawing.

#### Working Capital

As at March 31, 2026, the Group had a working capital balance including cash of negative USD 44,956 thousand compared to negative USD 29,946 thousand as at December 31, 2025. The difference is mainly a result of the decreased cash following capital expenditures on the Blackrod Phase 1 development project.

#### 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 and administrative 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 and business development costs, impairment costs and depreciation and before 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:

USD Thousands	Three months ended March 31	
	2026	2025
Revenue	173,010	178,492
Production costs and net sales of diluent to third party <sup>1</sup>	(104,819)	(103,188)
Current tax	(456)	(514)
Operating cash flow	<b>67,735</b>	74,790

<sup>1</sup> Includes net sales of diluent to third party amounting to USD 182 thousand for the first quarter of 2026.

## Management's Discussion and Analysis

### For the three months ended March 31, 2026

#### Free cash flow

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

USD Thousands	Three months ended March 31	
	2026	2025
Operating cash flow - see above	67,735	74,790
Capital expenditures	(70,661)	(98,886)
Abandonment and farm-in expenditures <sup>1</sup>	(472)	(321)
General and administrative expenses before depreciation <sup>2</sup>	(3,902)	(4,358)
Cash financial items <sup>3</sup>	(9,786)	(14,397)
Free cash flow	<b>(17,086)</b>	(43,172)

<sup>1</sup> See note 15 to the Financial Statements.

<sup>2</sup> Depreciation is not specifically disclosed in the Financial Statements.

<sup>3</sup> See note 4 to the Financial Statements.

#### EBITDA

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

USD Thousands	Three months ended March 31	
	2026	2025
Net result	12,762	16,231
Net financial items	20,737	18,855
Income tax	3,386	4,679
Depletion and decommissioning costs	29,931	29,016
Depreciation of other tangible fixed assets	–	1,917
Exploration and business development costs	903	31
Sale of assets <sup>1</sup>	(3,793)	(94)
Depreciation included in general and administrative expenses <sup>2</sup>	363	311
EBITDA	<b>64,289</b>	70,946

<sup>1</sup> Sale of assets is included under "Other income/(expense)" but not specifically disclosed in the Financial Statements.

<sup>2</sup> Item is not shown in the Financial Statements.

#### Operating costs

The following table sets out how operating costs is calculated:

USD Thousands	Three months ended March 31	
	2026	2025
Production costs	105,001	103,379
Cost of blending	(38,891)	(37,726)
Change in inventory position	2,129	3,500
Operating costs	<b>68,239</b>	69,153

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

### Net cash/(debt)

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

USD Thousands	March 31, 2026	December 31, 2025
Bank loans	(75,230)	(40,652)
Bonds	(450,000)	(450,000)
Cash and cash equivalents	11,817	7,037
Net cash/(debt)	<b>(513,413)</b>	(483,615)

### Off-Balance Sheet Arrangements

IPC, through its subsidiary IPC Canada Ltd, had issued five letters of credit as at March 31, 2026 as follows: (a) MCAD 1.0 in respect of its obligations related to the Ferguson asset; (b) MCAD 1.3 in respect of pipeline access; (c) MCAD 0.5 in respect of the hedging of electricity prices; (d) MCAD 3.9 in respect of electricity distribution services; and (e) MCAD 5.3 in respect of the land acquisition completed in October 2025.

### 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, 2025, 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 December 4, 2025, IPC purchased and cancelled 6,641,970 common shares under the normal course issuer bid (NCIB) and 261,818 common shares under certain other exemptions in Canada.

As at December 31, 2025, IPC had a total of 112,155,527 common shares issued and outstanding, with no common shares held in treasury.

In February 2026, IPC issued 671,225 common shares in connection with the vesting of previously issued IPC Share Unit Plan awards. As at March 31, 2026 and May 5, 2026, IPC had a total of 112,826,752 common shares issued and outstanding, with no common shares held in treasury.

Nemesia S.à.r.l., an investment company ultimately controlled by trusts whose settlor is the late Adolf H. Lundin, holds 42,597,533 common shares in IPC, representing 37.8% of the outstanding common shares as at March 31, 2026.

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 2,541,095 IPC Share Unit Plan awards outstanding as at May 5, 2026 of which 788,036 awards were granted in 2026.

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 recognized as liabilities. The following table summarizes the Group's commitments in Canada as at March 31, 2026:

MCAD	2026	2027	2028	2029	2030	Thereafter
Transportation service <sup>1</sup>	45.8	83.8	99.5	100.8	101.7	1,355.0
Power <sup>2</sup>	9.3	12.4	9.8	–	–	–
<b>Total commitments</b>	<b>55.1</b>	<b>96.2</b>	<b>109.3</b>	<b>100.8</b>	<b>101.7</b>	<b>1,355.0</b>

<sup>1</sup> IPC has firm transportation commitments on oil and natural gas pipelines that expire between 2037 and 2046.

<sup>2</sup> IPC has physical delivery power hedges to purchase 15MWh at a weighted average price of CAD 74.92/MWh from April 1, 2026 to December 31, 2028, and an additional 5MWh at a weighted average price of CAD 58.31/MWh from April 1, 2026 to December 31, 2027.

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

### Material 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.

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

#### ***Oil and gas reserves, impairment and asset retirement obligations***

The accounting for oil and gas assets requires significant estimates and judgements, particularly in relation to reserves, impairment and asset retirement obligations. Estimates of proved and probable oil and gas reserves, prepared using standard recognized evaluation techniques and reviewed by independent qualified reserves auditors, are fundamental to impairment testing, depletion calculations under the unit of production method, and the timing and measurement of asset retirement obligations. These estimates are based on management's assumptions regarding expected production volumes, future oil and gas prices, development and production costs, and economic factors such as oil price and inflation.

Impairment tests are performed when there are indicators of impairment. Key assumptions in the impairment models include oil and gas reserve estimates, forward price curves, long-term cost assumptions and the discount rate, all of which are subject to change as new information becomes available or economic conditions evolve.

Provisions for asset retirement obligations are based on estimates of future decommissioning and restoration costs, reflecting current legal and constructive requirements, available technology and prevailing price levels. Actual cash outflows may differ from estimates due to changes in legislation, technical requirements or cost levels, and therefore these 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 it 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 recognizes 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 2026, 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, 2026, the Group had entered into oil, gas and electricity 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.

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

### 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, 2026, which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
April 1, 2026 - June 30, 2026	9,000	WTI Sale Swap	USD 62.36/bbl
April 1, 2026 - December 31, 2026	5,000	WTI/WCS Differential	USD -12.50/bbl
July 1, 2026 - December 31, 2027	5,000	WCS (Hardisty vs Houston) <sup>1</sup>	USD -7.55/bbl
July 1, 2026 - December 31, 2026	2,000	ARV <sup>2</sup>	USD -3.65/bbl
April 1, 2026 - June 30, 2026	2,000	Brent Sale Swap	USD 68.06/bbl

<sup>1</sup> Represents the cost of transporting a barrel of WCS quality from Hardisty to Houston.

<sup>2</sup> Represents the difference in USD of a barrel of WCS in Houston against a barrel of WTI quality.

The Group had gas price sale financial hedges outstanding as at March 31, 2026, which are summarized as follows:

Period	Volume (Gigajoules (GJ) per day)	Type	Average Pricing
April 1, 2026 - October 31, 2026	15,000	AECO Gas Swap	CAD 2.73/GJ

The Group had electricity financial hedges outstanding as at March 31, 2026, which are summarized as follows:

Period	Volume (MWh)	Type	Average Pricing
April 1, 2026 - 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 28,010 thousand as at March 31, 2026.

### 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.

### 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.

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

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 its operations are subject to various risks and uncertainties which include, but are not limited to, those listed below. For further information and discussion of these risks and uncertainties, please see IPC's Annual Information Form for the year ended December 31, 2025 ("AIF") available on SEDAR+ at [www.sedarplus.ca](http://www.sedarplus.ca) or on IPC's website at [www.international-petroleum.com](http://www.international-petroleum.com). See also "Cautionary Statement Regarding Forward-Looking Information" and "Reserves and Resources Advisory" below.

### 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 ended March 31, 2026, 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, 2026.

### 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".

## Management's Discussion and Analysis

### For the three months ended March 31, 2026

Forward-looking statements include, but are not limited to, statements with respect to:

- 2026 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 IPC's 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, net present values and future phase developments;
- 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 of IPC to maintain current and forecast production in France and Malaysia;
- The intention and ability of IPC to acquire 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 GHG 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, tariffs, 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 duration and impact of tariffs that are currently in effect on goods exported from or imported into Canada, and that other than the tariffs that are currently in effect, neither the U.S. nor Canada (i) increases the rate or scope of such tariffs, reenacts tariffs that are currently suspended, 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; IPC's ability to maintain its existing credit ratings; IPC's ability to achieve its 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 IPC will be able to implement its 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; IPC's intention to complete share repurchases under the normal course issuer bid program, including the funding of such share repurchases, existing and future market conditions, including with respect to the price of IPC's 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.

## Management's Discussion and Analysis

For the three months ended March 31, 2026

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 IPC's systems, including 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 current and potential future conflicts in Ukraine, the Middle East, South America and elsewhere and their potential impact on, among other things, global market conditions;
- Political or economic developments, including, without limitation, the risk that (i) the tariffs that are currently in effect on goods exported from or imported into Canada continue in effect for an extended period of time, the tariffs that have been threatened are implemented, that tariffs that are currently suspended are reactivated, the rate or scope of tariffs are increased, or new tariffs are imposed, 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 or threatened to be imposed by the U.S. on other countries and retaliatory tariffs imposed or threatened to be imposed by other countries on the U.S. will trigger a broader global trade war which 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, including by decreasing demand for, and the price of oil, and natural gas, disrupting supply chains, increasing costs, causing volatility in the global financial markets, and limiting access to financing; 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 2026 to 2030 and 2031 to 2035, less net debt of USD 484 million as at December 31, 2025, with assumptions based on the reports of IPC's independent reserves evaluator and auditor, and including certain corporate adjustments relating to estimated general and administration costs and hedging, and excluding shareholder distributions and certain refinancing costs. Assumptions include average net production of approximately 62 Mboepd over the period of 2026 to 2030, average capital expenditures of approximately USD 5 per boe, average operating costs of approximately USD 18 to 20 per boe, average Brent oil prices of USD 65 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 auditor 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, 2025 (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](http://www.sedarplus.ca)) or IPC's website ([www.international-petroleum.com](http://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 and France/Malaysia are effective as of December 31, 2025, and are included in the reports prepared by Sproule International Limited and ERC Equipoise Ltd., respectively (collectively, Sproule ERCE), an independent qualified reserves evaluator and auditor, 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 ERCE's December 31, 2025 price forecasts.

The price forecasts used in the Sproule ERCE reports, are available on the website of Sproule ERCE ([sproule-erice.com](http://sproule-erice.com)) and are contained in the AIF. These price forecasts are as at December 31, 2025 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 521 MMboe as at December 31, 2025, by the mid-point of the 2026 CMD production guidance of 44,000 to 47,000 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 unrisks values by the chance of development.

## Management's Discussion and Analysis

### For the three months ended March 31, 2026

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

2P reserves and contingent resources included in the reports prepared by Sproule ERCE have been aggregated. 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 reserves and resources evaluations will be attained and variances could be material.

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)
<b>Three months ended</b>				
March 31, 2026	22.4	6.3	85.7 MMcf (14.3 Mboe)	43.0
March 31, 2025	23.2	6.5	88.2 MMcf (14.7 Mboe)	44.4
<b>Year ended December 31, 2025</b>				
December 31, 2025	23.6	6.4	89.6MMcf (14.9 Mboe)	44.9

This MD&A also makes reference to IPC's forecast total average daily production of 44,000 to 47,000 boepd for 2026. IPC estimates that approximately 57% of that production will be comprised of heavy crude oil, approximately 12% will be comprised of light and medium crude oil and approximately 31% will be comprised of conventional natural gas.

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

### OTHER SUPPLEMENTARY INFORMATION

#### Currency Abbreviations

CAD	Canadian dollar
MCAD	Million Canadian dollar
EUR	Euro
MEUR	Million Euro
USD	US dollar
MUSD	Million US dollar
MYR	Malaysian Ringgit
MMYR	Million Malaysian Ringgit

#### 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
ARV	Argus WCS Houston (represents the differential, in USD, between a barrel of WCS quality in Houston and WTI)
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 <sub>2</sub> e	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
FPSO	Floating Production Storage and Offloading (facility)
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

# Management's Discussion and Analysis

## For the three months ended March 31, 2026

### 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  
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Curtis White  
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Calgary, Alberta, and Toronto, Ontario

### STOCK EXCHANGE LISTINGS

Toronto Stock Exchange and NASDAQ Stockholm  
Trading Symbol: IPCO



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