

# Q2

**International Petroleum Corporation**

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***Management's Discussion  
and Analysis***

*For the three and six months ended June 30, 2025*



**International  
Petroleum  
Corp.**

# Management's Discussion and Analysis

## For the three and six months ended June 30, 2025

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#### 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 18.

#### 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 23.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada are effective as of December 31, 2024, and are included in the reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Sproule's December 31, 2024, price forecasts.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France and Malaysia are effective as of December 31, 2024, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2024, price forecasts.

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

# Management's Discussion and Analysis

## For the three and six months ended June 30, 2025

### 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 August 5, 2025 and is intended to provide an overview of the Group's operations, financial performance and current and future business opportunities. This MD&A should be read in conjunction with IPC's unaudited interim condensed consolidated financial statements for the three and six months ended June 30, 2025 as well as the audited consolidated financial statements and accompanying notes for the year ended December 31, 2024 ("Financial Statements").

### Group Overview

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

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

### Basis of Preparation

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

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

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

|                  | Six months ended<br>June 30, 2025 |            | Six months ended<br>June 30, 2024 |            | Twelve months ended<br>December 31, 2024 |          |
|------------------|-----------------------------------|------------|-----------------------------------|------------|--|----------|
|                  | Average                           | Period end | Average                           | Period end | Average                                  | Year end |
| 1 EUR equals USD | 1.0930                            | 1.1720     | 1.0812                            | 1.0705     | 1.0821                                   | 1.0389   |
| 1 USD equals CAD | 1.4102                            | 1.3675     | 1.3583                            | 1.3704     | 1.3698                                   | 1.4388   |
| 1 USD equals MYR | 4.3772                            | 4.2120     | 4.7270                            | 4.7175     | 4.5759                                   | 4.4715   |

# Management's Discussion and Analysis

For the three and six months ended June 30, 2025

## HIGHLIGHTS

### Q2 2025 Business Highlights

- Average net production of approximately 43,600 boepd for the second quarter of 2025, within the guidance range for the period (52% heavy crude oil, 14% light and medium crude oil and 34% natural gas).<sup>(1)</sup>
- Continued progressing Phase 1 development activity as well as future phase resource maturation works at the Blackrod asset in Canada.
- At Onion Lake Thermal, Canada, two of four planned production infill wells and the eighth Pad L sustaining well pair were brought online.
- Successfully completed the drilling and workover program at the Bertam Field, Malaysia during July 2025.
- 1.8 million IPC common shares purchased and cancelled during Q2 2025 under the normal course issuer bid (NCIB) and continuing with target to complete the full 2024/2025 NCIB this year.

### Q2 2025 Financial Highlights

- Operating costs per boe of USD 17.8 for Q2 2025, marginally below guidance.<sup>(3)</sup>
- Operating cash flow (OCF) generation of MUSD 55 for Q2 2025, in line with guidance.<sup>(3)</sup>
- Capital and decommissioning expenditures of MUSD 100 for Q2 2025, in line with guidance.
- Free cash flow (FCF) generation for Q2 2025 amounted to MUSD -58 (MUSD 6 pre-Blackrod capital expenditures).<sup>(3)</sup>
- Gross cash of MUSD 79 and net debt of MUSD 375 as at June 30, 2025.<sup>(3)</sup>
- Net result of MUSD 14 for Q2 2025.

### Reserves and Resources

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

### 2025 Annual Guidance

- Full year 2025 average net production guidance range forecast maintained at 43,000 to 45,000 boepd.<sup>(1)</sup>
- Full year 2025 operating costs guidance range forecast maintained at USD 18 to 19 per boe.<sup>(3)</sup>
- Full year 2025 OCF revised guidance estimated at between MUSD 245 and 260 (assuming Brent USD 60 to 75 per barrel for the remainder of 2025) from previous guidance of between MUSD 240 and 270.<sup>(3)(4)</sup>
- Full year 2025 capital and decommissioning expenditures guidance forecast maintained at MUSD 320 (including MUSD 230 for the Blackrod asset).
- Full year 2025 FCF revised guidance estimated at between MUSD -135 and -120 (assuming Brent USD 60 to 75 per barrel for the remainder of 2025) from previous guidance of between MUSD -135 and -110.<sup>(3)(4)</sup>

| USD Thousands                      | Three months ended<br>June 30 |          | Six months ended<br>June 30 |          |
|------------------------------------|-------------------------------|----------|-----------------------------|----------|
|                                    | 2025                          | 2024     | 2025                        | 2024     |
| Revenue                            | 158,892                       | 219,040  | 337,384                     | 425,459  |
| Gross profit                       | 23,663                        | 72,708   | 67,812                      | 127,892  |
| Net result                         | 13,850                        | 45,210   | 30,081                      | 78,929   |
| Operating cash flow <sup>(3)</sup> | 54,873                        | 101,941  | 129,663                     | 191,242  |
| Free cash flow <sup>(3)</sup>      | (58,252)                      | 7,559    | (101,424)                   | (35,752) |
| EBITDA <sup>(3)</sup>              | 51,519                        | 103,971  | 122,465                     | 190,991  |
| Net cash/(debt) <sup>(3)</sup>     | (374,977)                     | (88,220) | (374,977)                   | (88,220) |

# Management's Discussion and Analysis

## For the three and six months ended June 30, 2025

### OPERATIONS REVIEW

#### Business Overview

During the second quarter of 2025, oil prices were volatile with Brent prices ranging from lows of USD 60 per barrel to highs of over USD 77 per barrel. The average Brent price for the quarter was approximately USD 68 per barrel, as compared to just below USD 76 per barrel for the first quarter of 2025. This second quarter volatility was driven by announcements early in the quarter by OPEC and the OPEC+ group to increase supply in excess of expectations, at the same time as the United States proposing high tariffs to countries deemed in a trade surplus of US goods. The US then delayed implementation of these tariffs which, combined with the increased conflicts in the Middle East, influenced higher world oil prices in early June. From the end of the quarter and into July 2025, Brent prices have remained more stable in a range just below USD 70 per barrel. Beyond the short-term shocks during the second quarter, global oil inventories remain below the 5-year average, high geopolitical tensions continue, and non-OPEC oil production (in particular in the US) is unlikely to grow at current prices. These factors should be positive for future oil prices. During this large expenditure year for the Blackrod Phase 1 project, IPC continued to hedge oil prices in the second quarter of 2025 through zero cost collars. IPC's oil hedges in total represent around 50% of our aggregate forecast 2025 oil production at around USD 76 and USD 71 per barrel for Dated Brent and West Texas Intermediate (WTI), respectively, as well as a WTI collar between USD 65 and USD 75 per barrel, for the remainder of 2025.

In Canada, WTI to Western Canadian Select (WCS) crude price differentials during the second quarter of 2025 averaged USD 10.2 per barrel. The WTI to WCS differential has benefited from the TMX pipeline expansion and tightened as the pipeline provides an alternative transportation route away from the US Gulf Coast. There are currently no tariffs on Canadian crude oil exports to the United States, which are covered by the US Mexico Canada free trade agreement. IPC has hedged the WTI to WCS differential for approximately 50% of our forecast 2025 Canadian oil production at USD 14 per barrel for 2025.

Natural gas markets in Canada for the second quarter of 2025 remained weak. The average AECO gas price was CAD 1.7 per Mcf for the second quarter of 2025 and IPC achieved an average realized price of CAD 1.8 per Mcf during the quarter. There is a potential for improved pricing for Canadian gas benchmark prices following the start-up of the LNG Canada project in British Columbia, which may relieve elevated Canadian gas inventories. Approximately 50% of our net long exposure is hedged at CAD 2.4 per Mcf to end October 2025, dropping to around 15% for November and December at CAD 2.6 per mcf.

#### Second Quarter 2025 Highlights and Full Year 2025 Guidance

During the second quarter of 2025, our portfolio delivered average net production of 43,600 boepd, in line with guidance. At Onion Lake Thermal, two infill wells and a Pad L sustaining well pair were brought online in the quarter. In Malaysia, the extended reach drilling and workover program was successfully completed with the new infill well A21 and worked over well A15 brought on stream at the end of July. Early indications are in line with expectations as the production wells go through an initial clean up and stabilisation period. We maintain the full year 2025 average net production guidance range of 43,000 to 45,000 boepd.<sup>(1)</sup>

Our operating costs per boe for the second quarter of 2025 was USD 17.8, marginally below guidance. Full year 2025 operating expenditure guidance of USD 18.0 to 19.0 per boe remains unchanged.<sup>(3)</sup>

Operating cash flow (OCF) generation for the second quarter of 2025 was MUS\$ 55. Full year 2025 OCF guidance is tightened to MUS\$ 245 to 260 (assuming Brent USD 60 to 75 per barrel for the remainder of 2025).<sup>(3)(4)</sup>

Capital and decommissioning expenditure for the second quarter of 2025 was MUS\$ 100 in line with guidance. Full year 2025 capital and decommissioning expenditure of MUS\$ 320 is maintained.

Free cash flow (FCF) generation was MUS\$ -58 (MUS\$ 6 pre-Blackrod capital expenditures) during the second quarter of 2025. Full year 2025 FCF guidance is tightened to MUS\$ -135 to -120 (assuming Brent USD 60 to 75 per barrel for the remainder of 2025) after taking into account MUS\$ 320 of forecast full year 2025 capital expenditures (including MUS\$ 230 relating to the Blackrod asset).<sup>(3)(4)</sup>

As at June 30, 2025, IPC's net debt position increased to MUS\$ 375, from a net debt position of MUS\$ 314 as at March 31, 2025, mainly driven by the funding of capital expenditures and the continuing share repurchase program (NCIB). Gross cash as at June 30, 2025 amounts to MUS\$ 79 and IPC has access to a Canadian revolving credit facility of greater than MUS\$ 180 (fully committed, available and undrawn as at June 30, 2025), following the increase of that facility from MCAD 180 to MCAD 250 during the second quarter. The access to liquidity supports IPC to follow through on its key strategic objectives of enhancing stakeholder value through organic growth, stakeholder returns, and pursuing value adding M&A.<sup>(3)</sup>

#### Blackrod

The Blackrod asset is 100% owned by IPC and contains 259 MMboe of 2P reserves and 1,025 MMboe of contingent resources (best estimate, unrisked) with regulatory approval to produce up to 80,000 bopd. In early 2023, IPC sanctioned the Phase 1 development targeting plateau production rates of 30,000 bopd with a growth capital expenditure guidance of MUS\$ 850 and first oil expected in late 2026, marking the first major commercial Steam Assisted Gravity Drainage (SAGD) development undertaken in Alberta since the mid to late 2010s. The multi-year Phase 1 development guidance is maintained, with significant progress achieved to date. Since the Phase 1 project sanction to the end of Q2 2025, capital expenditures of MUS\$ 729 have been spent, or approximately 86% of the MUS\$ 850 growth capital guidance to first oil.<sup>(1)</sup>

## Management's Discussion and Analysis

### For the three and six months ended June 30, 2025

All major work activities continued to advance in accordance with plan at the Blackrod asset during the second quarter. The final Central Processing Facility (CPF) module was delivered to site during the quarter, marking a significant milestone achievement for the project. Mechanical, electrical and instrumentation installations remain the key areas of focus for the CPF and well pad facilities prior to start-up. IPC remains strongly positioned to deliver the transformational Phase 1 development as planned. In parallel, with the responsible Phase 1 development activity, IPC is progressing future resource maturation works at Blackrod.

IPC intends to fund the remaining Blackrod capital expenditure with forecast cash flow generated by its operations, cash on hand and drawing under the existing Canadian credit facility if needed.<sup>(3)</sup>

#### Stakeholder Returns: Normal Course Issuer Bid

In Q4 2024, IPC announced the renewal of the NCIB, with the ability to repurchase up to approximately 7.5 million common shares over the period of December 5, 2024 to December 4, 2025. Under the 2024/2025 NCIB, IPC repurchased and cancelled approximately 0.8 million common shares in December 2024, 5.5 million common shares during the first half of 2025, and a further 0.2 million common shares purchased under other exemptions in Canada. The average price of common shares repurchased under the 2024/2025 NCIB during the first half of 2025 was around SEK 140 / CAD 19 per share.

As at June 30, 2025, IPC had a total of 113,354,532 common shares issued and outstanding and IPC held no common shares in treasury. As at July 31, 2025, IPC had a total of 113,278,532 common shares issued and outstanding and IPC held no common shares in treasury. Notwithstanding the final major capital investment year at Blackrod in 2025, IPC has purchased and cancelled approximately 85% of the maximum 7.5 million common shares allowed under the 2024/2025 NCIB by the end of July 2025 and intends to purchase and cancel the remaining 1.1 million common shares under that program in 2025. This would result in the cancellation of 6.2% of common shares outstanding as at the beginning of December 2024. IPC continues to believe that reducing the number of shares outstanding in combination with investing in long-life production growth at the Blackrod project will prove to be a winning formula for our stakeholders.

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

Alongside the publication of our second quarter 2025 financial report, IPC releases its sixth annual Sustainability Report. The Sustainability Report provides details on IPC's approach to sustainability and material sustainability topics highlighting specific initiatives and progress. The Sustainability Report is available on IPC's website at [www.international-petroleum.com](http://www.international-petroleum.com).

During the second quarter of 2025, IPC recorded no material safety or environmental incidents.

As previously announced, IPC targets a reduction of our net GHG emissions intensity by the end of 2025 to 50% of IPC's 2019 baseline and IPC remains on track to achieve this reduction. IPC has also made a commitment to maintain 2025 levels of 20 kg CO<sub>2</sub>/boe through to the end of 2028.<sup>(5)</sup>

#### Notes:

- (1) See "Supplemental Information regarding Product Types" in "Reserves and Resources Advisory" below. See also the annual information form for the year ended December 31, 2024 (AIF) available on IPC's website at [www.international-petroleum.com](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. NAV is calculated as NPV less net debt of MUSD 209 as at December 31, 2024.
- (3) Non-IFRS measures, see "Non-IFRS Measures" below.
- (4) OCF and FCF forecasts at Brent USD 60 and 75 per barrel assume Brent to WTI differential of USD 3 and 5 per barrel, respectively, and WTI to WCS differential of USD 10 and 15 per barrel, respectively, for the remainder of 2025. OCF and FCF forecasts assume gas price on average of CAD 1.25 per Mcf for the third quarter of 2025 and CAD 2.50 per Mcf for the fourth quarter of 2025.
- (5) Emissions intensity is the ratio between oil and gas production and the associated carbon emissions, and net emissions intensity reflects gross emissions less operational emission reductions and carbon offsets.

# Management's Discussion and Analysis

## For the three and six months ended June 30, 2025

### Operations Overview

#### Q2 2025 Overview

In Q2 2025, IPC continued to successfully demonstrate its commitment to operational excellence, delivering production performance and expenditure in line with our Capital Markets Day (CMD) guidance with no material safety or environmental incidents recorded in the quarter.

#### Reserves and Resources

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

#### Production

Average daily net production for Q2 2025 was in line with our CMD guidance at 43,600 boepd. In Canada, strong operational performance at the major oil and gas assets has been supplemented by a continued positive production response at the Mooney Phase 2 enhanced oil recovery (EOR) polymer flood. Stable performance continued at our Malaysian and French assets despite incurring planned well downtime during Bertam infill well drilling operations.

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

The production during Q2 2025 with comparatives is summarized below:

| Production<br>in Mboepd           | Three months ended<br>June 30 |             | Six months ended<br>June 30 |             | Year ended<br>December 31 |
|-----------------------------------|-------------------------------|-------------|-----------------------------|-------------|---------------------------|
|                                   | 2025                          | 2024        | 2025                        | 2024        | 2024                      |
| <b>Crude oil</b>                  |                               |             |                             |             |                           |
| Canada – Northern Assets          | 13.6                          | 14.5        | 13.8                        | 14.7        | 14.2                      |
| Canada – Southern Assets          | 10.4                          | 11.1        | 10.6                        | 11.2        | 11.1                      |
| Malaysia                          | 2.4                           | 4.1         | 2.6                         | 4.1         | 3.8                       |
| France                            | 2.2                           | 2.6         | 2.2                         | 2.6         | 2.4                       |
| <b>Total crude oil production</b> | <b>28.6</b>                   | <b>32.3</b> | <b>29.2</b>                 | <b>32.6</b> | <b>31.5</b>               |
| <b>Gas</b>                        |                               |             |                             |             |                           |
| Canada – Northern Assets          | 0.4                           | 0.5         | 0.4                         | 0.4         | 0.5                       |
| Canada – Southern Assets          | 14.6                          | 15.6        | 14.4                        | 15.6        | 15.4                      |
| <b>Total gas production</b>       | <b>15.0</b>                   | <b>16.1</b> | <b>14.8</b>                 | <b>16.0</b> | <b>15.9</b>               |
| <b>Total production</b>           | <b>43.6</b>                   | <b>48.4</b> | <b>44.0</b>                 | <b>48.6</b> | <b>47.4</b>               |
| <b>Quantity in MMboe</b>          | <b>3.97</b>                   | <b>4.41</b> | <b>7.97</b>                 | <b>8.84</b> | <b>17.34</b>              |

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

### CANADA

| Production<br>in Mboepd  | Working<br>Interest<br>(WI) | Three months ended<br>June 30 |             | Six months ended<br>June 30 |             | Year ended<br>December 31 |
|--------------------------|-----------------------------|-------------------------------|-------------|-----------------------------|-------------|---------------------------|
|                          |                             | 2025                          | 2024        | 2025                        | 2024        | 2024                      |
| - Oil Onion Lake Thermal | 100%                        | 11.4                          | 13.0        | 11.4                        | 13.2        | 12.3                      |
| - Oil Suffield Area      | 100%                        | 9.1                           | 9.7         | 9.2                         | 9.9         | 9.7                       |
| - Oil Other              | 50-100%                     | 3.5                           | 2.9         | 3.8                         | 2.8         | 3.3                       |
| - Gas                    | ~100%                       | 15.0                          | 16.1        | 14.8                        | 16.0        | 15.9                      |
| <b>Canada</b>            |                             | <b>39.0</b>                   | <b>41.7</b> | <b>39.2</b>                 | <b>41.9</b> | <b>41.2</b>               |

# Management's Discussion and Analysis

## For the three and six months ended June 30, 2025

### Production

Net production from IPC's assets in Canada during Q2 2025 was in line with guidance at 39,000 boepd with continued strong operational performance at the major oil and gas producing assets. At Mooney, the Phase 2 EOR polymer flood project is performing ahead of expectations. Stable performance continued at Onion Lake Thermal during the quarter.

### Organic Growth and Capital Projects

The Blackrod Phase 1 development project is progressing in line with schedule and budget. As at the end of Q2 2025, process facility fabrication is substantially complete with all facility pipe rack and equipment modules delivered to site. Critical equipment site installation, piping inter-connects, electrical and instrumentation installation continues to progress in line with plan and remains a key area of focus for the construction team. Drilling, completions and wellpad facilities installations are advancing as planned. Third-party transport pipeline installations are progressing on schedule. Commercial operational readiness is progressing in line with our progressive commissioning strategy to ensure a seamless transition from build to start-up. In addition, resource maturation works for future phase expansion continued during the second quarter of 2025.

At Onion Lake Thermal, two of the four planned production infill wells and the eighth Pad L sustaining well pair were brought online in the second quarter of 2025 with initial production performance in line with expectations.

## MALAYSIA

| Production<br>in Mboepd | WI   | Three months ended<br>June 30 |      | Six months ended<br>June 30 |      | Year ended<br>December 31 |
|-------------------------|------|-------------------------------|------|-----------------------------|------|---------------------------|
|                         |      | 2025                          | 2024 | 2025                        | 2024 | 2024                      |
| Bertam                  | 100% | 2.4                           | 4.1  | 2.6                         | 4.1  | 3.8                       |

### Production

Net production at Bertam in Malaysia in Q2 2025 was in line with guidance at 2,400 boepd with the planned well downtime during the drilling and workover operations.

### Organic Growth and Capital Projects

In Malaysia, drilling of the planned infill well and well maintenance activity commenced in Q2 2025 and have progressed in line with schedule. A21 and A15 wells started production late July with early indications in line with expectation as well clean up and production testing is ongoing.

## FRANCE

| Production<br>in Mboepd | WI                | Three months ended<br>June 30 |      | Six months ended<br>June 30 |      | Year ended<br>December 31 |
|-------------------------|-------------------|-------------------------------|------|-----------------------------|------|---------------------------|
|                         |                   | 2025                          | 2024 | 2025                        | 2024 | 2024                      |
| France                  |                   |                               |      |                             |      |                           |
| - Paris Basin           | 100% <sup>1</sup> | 1.9                           | 2.3  | 1.9                         | 2.3  | 2.1                       |
| - Aquitaine             | 50%               | 0.3                           | 0.3  | 0.3                         | 0.3  | 0.3                       |
|                         |                   | 2.2                           | 2.6  | 2.2                         | 2.6  | 2.4                       |

<sup>1</sup> Except for the working interest in the Dommartin Lettree field of 43%

### Production

Net production in France during Q2 2025 was in line with guidance at 2,200 boepd with stable performance across all the producing fields.

### Organic Growth

In France, field development studies continued in Q2 2025 with the next phase of production well targets matured and ready for sanction decision at IPC's discretion.



# Management's Discussion and Analysis

For the three and six months ended June 30, 2025

## FINANCIAL REVIEW

### Financial Results

#### Selected Annual Financial Information

Selected consolidated statement of operations is as follows:

| USD Thousands                              | Q2-25     | Q1-25     | Q4-24     | Q3-24     | Q2-24    | Q1-24    | Q4-23    | Q3-23   |
|--|-----------|-----------|-----------|-----------|----------|----------|----------|---------|
| Revenue                                    | 158,892   | 178,492   | 199,124   | 173,200   | 219,040  | 206,419  | 198,460  | 257,366 |
| Gross profit                               | 23,663    | 44,149    | 42,774    | 39,505    | 72,708   | 55,184   | 39,955   | 93,429  |
| Net result                                 | 13,850    | 16,231    | 415       | 22,875    | 45,210   | 33,719   | 29,710   | 71,681  |
| Earnings per share – USD                   | 0.12      | 0.14      | 0.00      | 0.19      | 0.36     | 0.27     | 0.23     | 0.56    |
| Earnings per share fully diluted – USD     | 0.12      | 0.13      | 0.00      | 0.18      | 0.36     | 0.26     | 0.22     | 0.54    |
| Operating cash flow <sup>1</sup>           | 54,873    | 74,790    | 78,158    | 72,589    | 101,941  | 89,301   | 73,634   | 119,142 |
| Free cash flow <sup>1</sup>                | (58,252)  | (43,172)  | (61,476)  | (38,269)  | 7,559    | (43,311) | (64,688) | 34,703  |
| EBITDA <sup>1</sup>                        | 51,519    | 70,946    | 76,184    | 68,313    | 103,971  | 87,020   | 66,284   | 123,054 |
| Net cash/(debt) at period end <sup>1</sup> | (374,977) | (314,255) | (208,528) | (157,228) | (88,220) | (60,572) | 58,043   | 83,097  |

<sup>1</sup> See definition on page 18 under “Non-IFRS measures”

Summarized consolidated balance sheet information is as follows:

| USD Thousands                           | June 30, 2025    | December 31, 2024 |
|---|------------------|-------------------|
| Non-current assets                      | 1,780,971        | 1,554,833         |
| Current assets                          | 242,905          | 398,849           |
| <b>Total assets</b>                     | <b>2,023,876</b> | <b>1,953,682</b>  |
| Total non-current liabilities           | 854,775          | 806,134           |
| Current liabilities                     | 206,486          | 208,078           |
| <b>Total liabilities</b>                | <b>1,061,261</b> | <b>1,014,212</b>  |
| <b>Net assets</b>                       | <b>962,615</b>   | <b>939,470</b>    |
| <b>Working capital (including cash)</b> | <b>36,419</b>    | <b>190,771</b>    |

# Management's Discussion and Analysis

For the three and six months ended June 30, 2025

## Selected Interim Financial Information

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

| USD Thousands                              | Three months ended June 30, 2025 |                          |                |               |              | Total          |
|--|----------------------------------|--------------------------|----------------|---------------|--------------|----------------|
|  | Canada – Northern Assets         | Canada – Southern Assets | Malaysia       | France        | Other        |                |
| Crude oil                                  | 85,933                           | 54,069                   | 11,828         | 11,463        | –            | 163,293        |
| NGLs                                       | –                                | 167                      | –              | –             | –            | 167            |
| Gas  | 72                               | 9,680                    | –              | –             | –            | 9,752          |
| <b>Net sales of oil and gas</b>            | <b>86,005</b>                    | <b>63,916</b>            | <b>11,828</b>  | <b>11,463</b> | <b>–</b>     | <b>173,212</b> |
| Change in under/over lift position         | –                                | –                        | –              | 1,559         | –            | 1,559          |
| Royalties                                  | (11,932)                         | (8,953)                  | –              | (732)         | –            | (21,617)       |
| Hedging settlement                         | 2,236                            | 3,139                    | –              | –             | –            | 5,375          |
| Other operating revenue                    | –                                | –                        | –              | 205           | 158          | 363            |
| <b>Revenue</b>                             | <b>76,309</b>                    | <b>58,102</b>            | <b>11,828</b>  | <b>12,495</b> | <b>158</b>   | <b>158,892</b> |
| Operating costs                            | (19,786)                         | (30,500)                 | (11,768)       | (8,468)       | –            | (70,522)       |
| Cost of blending                           | (27,286)                         | (5,983)                  | –              | –             | –            | (33,269)       |
| Change in inventory position               | (695)                            | 380                      | 203            | (7)           | –            | (119)          |
| Depletion                                  | (8,885)                          | (12,652)                 | (4,891)        | (2,893)       | –            | (29,321)       |
| Depreciation of other assets               | –                                | –                        | (1,461)        | –             | –            | (1,461)        |
| Exploration and business development costs | –                                | –                        | –              | –             | (537)        | (537)          |
| <b>Gross profit/(loss)</b>                 | <b>19,657</b>                    | <b>9,347</b>             | <b>(6,089)</b> | <b>1,127</b>  | <b>(379)</b> | <b>23,663</b>  |

| USD Thousands                              | Three months ended June 30, 2024 |                          |               |               |            | Total          |
|--|----------------------------------|--------------------------|---------------|---------------|------------|----------------|
|  | Canada – Northern Assets         | Canada – Southern Assets | Malaysia      | France        | Other      |                |
| Crude oil                                  | 115,482                          | 75,536                   | 39,341        | 17,253        | –          | 247,612        |
| NGLs                                       | –                                | 275                      | –             | –             | –          | 275            |
| Gas  | 44                               | 6,631                    | –             | –             | –          | 6,675          |
| <b>Net sales of oil and gas</b>            | <b>115,526</b>                   | <b>82,442</b>            | <b>39,341</b> | <b>17,253</b> | <b>–</b>   | <b>254,562</b> |
| Change in under/over lift position         | –                                | –                        | –             | 2,215         | –          | 2,215          |
| Royalties                                  | (22,377)                         | (11,912)                 | –             | (1,161)       | –          | (35,450)       |
| Hedging settlement                         | (1,523)                          | (1,121)                  | –             | –             | –          | (2,644)        |
| Other operating revenue                    | –                                | –                        | –             | 237           | 120        | 357            |
| <b>Revenue</b>                             | <b>91,626</b>                    | <b>69,409</b>            | <b>39,341</b> | <b>18,544</b> | <b>120</b> | <b>219,040</b> |
| Operating costs                            | (19,260)                         | (30,541)                 | (7,229)       | (7,804)       | –          | (64,834)       |
| Cost of blending                           | (34,876)                         | (6,799)                  | –             | –             | –          | (41,675)       |
| Change in inventory position               | –                                | (96)                     | (4,829)       | 53            | –          | (4,872)        |
| Depletion                                  | (9,465)                          | (13,021)                 | (6,893)       | (3,282)       | –          | (32,661)       |
| Depreciation of other assets               | –                                | –                        | (2,218)       | –             | –          | (2,218)        |
| Exploration and business development costs | –                                | –                        | –             | –             | (72)       | (72)           |
| <b>Gross profit/(loss)</b>                 | <b>28,025</b>                    | <b>18,952</b>            | <b>18,172</b> | <b>7,511</b>  | <b>48</b>  | <b>72,708</b>  |

# Management's Discussion and Analysis

For the three and six months ended June 30, 2025

## Six months ended June 30, 2025

| USD Thousands                              | Canada – Northern Assets | Canada – Southern Assets | Malaysia       | France        | Other        | Total          |
|--|--------------------------|--------------------------|----------------|---------------|--------------|----------------|
| Crude oil                                  | 184,169                  | 117,855                  | 27,204         | 24,277        | –            | 353,505        |
| NGLs                                       | –                        | 358                      | –              | –             | –            | 358            |
| Gas  | 179                      | 21,195                   | –              | –             | –            | 21,374         |
| <b>Net sales of oil and gas</b>            | <b>184,348</b>           | <b>139,408</b>           | <b>27,204</b>  | <b>24,277</b> | <b>–</b>     | <b>375,237</b> |
| Change in under/over lift position         | –                        | –                        | –              | 2,700         | –            | 2,700          |
| Royalties                                  | (25,052)                 | (18,621)                 | –              | (1,572)       | –            | (45,245)       |
| Hedging settlement                         | 1,393                    | 2,766                    | –              | –             | –            | 4,159          |
| Other operating revenue                    | –                        | –                        | –              | 375           | 158          | 533            |
| <b>Revenue</b>                             | <b>160,689</b>           | <b>123,553</b>           | <b>27,204</b>  | <b>25,780</b> | <b>158</b>   | <b>337,384</b> |
| Operating costs                            | (38,966)                 | (63,825)                 | (20,349)       | (16,535)      | –            | (139,675)      |
| Cost of blending                           | (59,677)                 | (11,318)                 | –              | –             | –            | (70,995)       |
| Change in inventory position               | 169                      | (156)                    | 3,542          | (174)         | –            | 3,381          |
| Depletion                                  | (17,682)                 | (24,954)                 | (10,642)       | (5,059)       | –            | (58,337)       |
| Depreciation of other assets               | –                        | –                        | (3,378)        | –             | –            | (3,378)        |
| Exploration and business development costs | –                        | –                        | –              | –             | (568)        | (568)          |
| <b>Gross profit/(loss)</b>                 | <b>44,533</b>            | <b>23,300</b>            | <b>(3,623)</b> | <b>4,012</b>  | <b>(410)</b> | <b>67,812</b>  |

## Six months ended June 30, 2024

| USD Thousands                              | Canada – Northern Assets | Canada – Southern Assets | Malaysia      | France        | Other      | Total          |
|--|--------------------------|--------------------------|---------------|---------------|------------|----------------|
| Crude oil                                  | 219,627                  | 141,007                  | 57,894        | 33,970        | –          | 452,498        |
| NGLs                                       | –                        | 519                      | –             | –             | –          | 519            |
| Gas  | 169                      | 20,923                   | –             | –             | –          | 21,092         |
| <b>Net sales of oil and gas</b>            | <b>219,796</b>           | <b>162,449</b>           | <b>57,894</b> | <b>33,970</b> | <b>–</b>   | <b>474,109</b> |
| Change in under/over lift position         | –                        | –                        | –             | 5,131         | –          | 5,131          |
| Royalties                                  | (37,872)                 | (20,900)                 | –             | (2,300)       | –          | (61,072)       |
| Hedging settlement                         | 3,732                    | 2,830                    | –             | –             | –          | 6,562          |
| Other operating revenue                    | –                        | –                        | –             | 454           | 275        | 729            |
| <b>Revenue</b>                             | <b>185,656</b>           | <b>144,379</b>           | <b>57,894</b> | <b>37,255</b> | <b>275</b> | <b>425,459</b> |
| Operating costs                            | (39,918)                 | (69,772)                 | (14,245)      | (16,715)      | –          | (140,650)      |
| Cost of blending                           | (73,170)                 | (13,711)                 | –             | –             | –          | (86,881)       |
| Change in inventory position               | 368                      | (325)                    | 210           | 152           | –          | 405            |
| Depletion                                  | (19,209)                 | (26,181)                 | (13,923)      | (6,501)       | –          | (65,814)       |
| Depreciation of other assets               | –                        | –                        | (4,480)       | –             | –          | (4,480)        |
| Exploration and business development costs | –                        | –                        | –             | –             | (147)      | (147)          |
| <b>Gross profit/(loss)</b>                 | <b>53,727</b>            | <b>34,390</b>            | <b>25,456</b> | <b>14,191</b> | <b>128</b> | <b>127,892</b> |

# Management's Discussion and Analysis

For the three and six months ended June 30, 2025

## Three and six months ended June 30, 2025, Review

### Revenue

Revenue amounted to USD 158,892 thousand for Q2 2025, compared to USD 219,040 thousand for Q2 2024 and USD 337,384 thousand for the first six months of 2025 compared to the USD 425,459 thousand for the first six months of 2024 is analyzed as follows:

| USD Thousands                     | Three months ended June 30 |                | Six months ended June 30 |                |
|-----------------------------------|----------------------------|----------------|--------------------------|----------------|
|                                   | 2025                       | 2024           | 2025                     | 2024           |
| Crude oil sales                   | 163,293                    | 247,612        | 353,505                  | 452,498        |
| Gas and NGL sales                 | 9,919                      | 6,950          | 21,732                   | 21,611         |
| Change in under/overlift position | 1,559                      | 2,215          | 2,700                    | 5,131          |
| Royalties                         | (21,617)                   | (35,450)       | (45,245)                 | (61,072)       |
| Hedging settlement                | 5,375                      | (2,644)        | 4,159                    | 6,562          |
| Other operating revenue           | 363                        | 357            | 533                      | 729            |
| <b>Revenue</b>                    | <b>158,892</b>             | <b>219,040</b> | <b>337,384</b>           | <b>425,459</b> |

The main components of revenue for the three and six months ended June 30, 2025 and June 30, 2024, respectively, are detailed below:

### Crude oil sales

| USD Thousands                        | Three months ended June 30, 2025 |                          |          |         | Total            |
|--------------------------------------|----------------------------------|--------------------------|----------|---------|------------------|
|                                      | Canada – Northern Assets         | Canada – Southern Assets | Malaysia | France  |                  |
| <b>Crude oil sales</b>               |                                  |                          |          |         |                  |
| - Revenue in USD thousands           | 85,933                           | 54,069                   | 11,828   | 11,463  | <b>163,293</b>   |
| - Quantity sold in bbls              | 1,614,538                        | 1,010,851                | 175,829  | 167,394 | <b>2,968,612</b> |
| - Average price realized USD per bbl | 53.22                            | 53.49                    | 67.27    | 68.49   | <b>55.01</b>     |

| USD Thousands                        | Three months ended June 30, 2024 |                          |          |         | Total     |
|--------------------------------------|----------------------------------|--------------------------|----------|---------|-----------|
|                                      | Canada – Northern Assets         | Canada – Southern Assets | Malaysia | France  |           |
| <b>Crude oil sales</b>               |                                  |                          |          |         |           |
| - Revenue in USD thousands           | 115,482                          | 75,536                   | 39,341   | 17,253  | 247,612   |
| - Quantity sold in bbls              | 1,739,097                        | 1,119,518                | 421,810  | 203,008 | 3,483,433 |
| - Average price realized USD per bbl | 66.40                            | 67.47                    | 93.27    | 84.98   | 71.08     |

Crude oil revenue was 34% lower in Q2 2025 compared to Q2 2024 driven by prices and sales volumes.

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 Q2 2025, WTI averaged USD 64 per bbl compared to USD 81 per bbl for Q2 2024 and the average discount to WCS used in IPC's pricing formula was USD 10 per bbl compared to USD 14 per bbl for the comparative period in 2024.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices. There was one cargo lifting in Malaysia during Q2 2025 and two cargo liftings in Q2 2024. Produced unsold oil barrels from Bertam at the end of Q2 2025 amounted to 152,000 barrels, see Change in Inventory Position section below. The average Dated Brent crude oil price was USD 68 per bbl for Q2 2025 compared to USD 85 per bbl for the comparative period in 2024.

## Management's Discussion and Analysis

For the three and six months ended June 30, 2025

### Six months ended June 30, 2025

| USD Thousands                        | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France  | Total     |
|--------------------------------------|--------------------------|--------------------------|----------|---------|-----------|
| <b>Crude oil sales</b>               |                          |                          |          |         |           |
| - Revenue in USD thousands           | 184,169                  | 117,855                  | 27,204   | 24,277  | 353,505   |
| - Quantity sold in bbls              | 3,303,184                | 2,092,938                | 370,960  | 336,416 | 6,103,498 |
| - Average price realized USD per bbl | 55.75                    | 56.31                    | 73.33    | 72.17   | 57.92     |

### Six months ended June 30, 2024

| USD Thousands                        | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France  | Total     |
|--------------------------------------|--------------------------|--------------------------|----------|---------|-----------|
| <b>Crude oil sales</b>               |                          |                          |          |         |           |
| - Revenue in USD thousands           | 219,627                  | 141,007                  | 57,894   | 33,970  | 452,498   |
| - Quantity sold in bbls              | 3,565,871                | 2,246,532                | 624,329  | 404,612 | 6,841,344 |
| - Average price realized USD per bbl | 61.59                    | 62.77                    | 92.73    | 83.96   | 66.14     |

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

Crude oil revenue were lower by 22% during the first six months of 2025 compared to the first six months of 2024 due to lower oil prices and lower production.

The Canadian realized sales price is based on the WCS price which trades at a discount to WTI. For the first six months of 2025, WTI averaged USD 68 per bbl compared to USD 79 per bbl for the comparative period and the average discount to WCS used in our pricing formula was USD 11 per bbl compared to USD 16 per bbl for the comparative period.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices and the average market Brent crude oil price was USD 72 per bbl for the first six months of 2025 compared to USD 84 per bbl for the comparative period.

### Gas and NGL sales

#### Three months ended June 30, 2025

|                                      | Canada – Northern Assets | Canada – Southern Assets | Total     |
|--------------------------------------|--------------------------|--------------------------|-----------|
| <b>Gas and NGL sales</b>             |                          |                          |           |
| - Revenue in USD thousands           | 72                       | 9,847                    | 9,919     |
| - Quantity sold in Mcf               | 64,237                   | 7,321,587                | 7,385,824 |
| - Average price realized USD per Mcf | 1.13                     | 1.34                     | 1.34      |

#### Three months ended June 30, 2024

|                                      | Canada – Northern Assets | Canada – Southern Assets | Total     |
|--------------------------------------|--------------------------|--------------------------|-----------|
| <b>Gas and NGL sales</b>             |                          |                          |           |
| - Revenue in USD thousands           | 44                       | 6,906                    | 6,950     |
| - Quantity sold in Mcf               | 63,367                   | 7,806,525                | 7,869,892 |
| - Average price realized USD per Mcf | 0.70                     | 0.88                     | 0.88      |

Gas and NGL sales revenue was 43% higher for the Q2 2025 compared to Q2 2024 mainly due to the higher achieved gas price.

IPC's achieved gas price is based on AECO pricing plus a premium. For Q2 2025, IPC realized an average price of CAD 1.82 per Mcf compared to AECO average pricing of CAD 1.65 per Mcf.

## Management's Discussion and Analysis

For the three and six months ended June 30, 2025

|                                      | Six months ended June 30, 2025 |                          |            |
|--------------------------------------|--------------------------------|--------------------------|------------|
|                                      | Canada – Northern Assets       | Canada – Southern Assets | Total      |
| <b>Gas and NGL sales</b>             |                                |                          |            |
| - Revenue in USD thousands           | 179                            | 21,553                   | 21,732     |
| - Quantity sold in Mcf               | 143,072                        | 14,207,432               | 14,350,504 |
| - Average price realized USD per Mcf | 1.25                           | 1.52                     | 1.51       |

|                                      | Six months ended June 30, 2024 |                          |            |
|--------------------------------------|--------------------------------|--------------------------|------------|
|                                      | Canada – Northern Assets       | Canada – Southern Assets | Total      |
| <b>Gas and NGL sales</b>             |                                |                          |            |
| - Revenue in USD thousands           | 169                            | 21,442                   | 21,611     |
| - Quantity sold in Mcf               | 133,858                        | 15,475,133               | 15,608,991 |
| - Average price realized USD per Mcf | 1.26                           | 1.39                     | 1.38       |

Gas and NGL sales revenue was 1% higher for the first six months of 2025 compared to the first six months of 2024 mainly due to the higher achieved gas price.

IPC's achieved gas price is based on AECO pricing plus a premium. For the first six months of 2025, IPC realized an average price of CAD 2.10 per Mcf compared to AECO average pricing of CAD 1.89 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 first six months of 2025 amounted to a gain of USD 4,159 thousand and consisted of a gain of USD 2,464 thousand on the oil contracts and a gain of USD 1,695 thousand on the gas contracts. Also see the Financial Position and Liquidity and the Financial Risk Management sections below.

### Production costs

Production costs including inventory movements amounted to USD 103,910 thousand for Q2 2025 compared to USD 111,381 thousand for Q2 2024 and USD 207,288 thousand for the first six months of 2025 compared to USD 227,126 thousand for the first six months of 2024, and is analyzed as follows:

| USD Thousands                       | Three months ended June 30, 2025 |                          |               |              |                    | Total          |
|-------------------------------------|----------------------------------|--------------------------|---------------|--------------|--------------------|----------------|
|                                     | Canada – Northern Assets         | Canada – Southern Assets | Malaysia      | France       | Other <sup>3</sup> |                |
| <b>Operating costs<sup>1</sup></b>  | 19,786                           | 30,500                   | 12,075        | 8,468        | (307)              | <b>70,522</b>  |
| USD/boe <sup>2</sup>                | 15.47                            | 13.42                    | 55.10         | 42.40        | n/a                | <b>17.76</b>   |
| <b>Cost of blending</b>             | 27,286                           | 5,983                    | –             | –            | –                  | <b>33,269</b>  |
| <b>Change in inventory position</b> | 696                              | (380)                    | (203)         | 7            | –                  | <b>119</b>     |
| <b>Production costs</b>             | <b>47,767</b>                    | <b>36,103</b>            | <b>11,872</b> | <b>8,475</b> | <b>(307)</b>       | <b>103,910</b> |

| USD Thousands                       | Three months ended June 30, 2024 |                          |               |              |                    | Total          |
|-------------------------------------|----------------------------------|--------------------------|---------------|--------------|--------------------|----------------|
|                                     | Canada – Northern Assets         | Canada – Southern Assets | Malaysia      | France       | Other <sup>3</sup> |                |
| <b>Operating costs<sup>1</sup></b>  | 19,260                           | 30,541                   | 11,369        | 7,804        | (4,140)            | <b>64,834</b>  |
| USD/boe <sup>2</sup>                | 14.10                            | 12.55                    | 30.76         | 33.13        | n/a                | <b>14.72</b>   |
| <b>Cost of blending</b>             | 34,876                           | 6,799                    | –             | –            | –                  | <b>41,675</b>  |
| <b>Change in inventory position</b> | –                                | 96                       | 4,829         | (53)         | –                  | <b>4,872</b>   |
| <b>Production costs</b>             | <b>54,136</b>                    | <b>37,436</b>            | <b>16,198</b> | <b>7,751</b> | <b>(4,140)</b>     | <b>111,381</b> |

# Management's Discussion and Analysis

## For the three and six months ended June 30, 2025

### Six months ended June 30, 2025

| USD Thousands                | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Other <sup>3</sup> | Total   |
|------------------------------|--------------------------|--------------------------|----------|--------|--------------------|---------|
| Operating costs <sup>1</sup> | 38,966                   | 63,825                   | 23,877   | 16,535 | (3,528)            | 139,675 |
| USD/boe <sup>2</sup>         | 15.14                    | 14.09                    | 50.08    | 42.73  | n/a                | 17.53   |
| Cost of blending             | 59,677                   | 11,318                   | –        | –      | –                  | 70,995  |
| Change in inventory position | (169)                    | 156                      | (3,542)  | 174    | –                  | (3,381) |
| Production costs             | 98,474                   | 75,299                   | 20,335   | 16,709 | (3,528)            | 207,289 |

### Six months ended June 30, 2024

| USD Thousands                | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Other <sup>3</sup> | Total   |
|------------------------------|--------------------------|--------------------------|----------|--------|--------------------|---------|
| Operating costs <sup>1</sup> | 39,918                   | 69,772                   | 22,435   | 16,715 | (8,190)            | 140,650 |
| USD/boe <sup>2</sup>         | 14.50                    | 14.30                    | 30.05    | 35.97  | n/a                | 15.91   |
| Cost of blending             | 73,170                   | 13,711                   | –        | –      | –                  | 86,881  |
| Change in inventory position | (368)                    | 325                      | (210)    | (152)  | –                  | (405)   |
| Production costs             | 112,720                  | 83,808                   | 22,225   | 16,563 | (8,190)            | 227,126 |

<sup>1</sup> See definition on page 18 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 2024.

<sup>3</sup>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 53.70 for Q2 2025 and USD 19.56 for the comparative period and USD 42.68 and USD 19.08 for the six months ended June 30, 2025, and June 30, 2024, respectively.

### Operating costs

Operating costs amounted to USD 70,522 thousand for Q2 2025 compared to USD 64,834 thousand for Q2 2024 and USD 139,675 thousand for the first six months of 2025 compared to USD 140,650 thousand for the first six months of 2024. Operating costs per boe amounted to USD 17.76 per boe in Q2 2025 marginally below the guidance for the quarter and compared with USD 14.72 per boe in Q2 2024.

Operating costs per boe in Malaysia increased in Q2 2025 compared to Q2 2024 due to lower production with one production well offline awaiting workover intervention planned in Q3 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 33,269 thousand for Q2 2025 compared to USD 41,675 thousand for Q2 2024 and USD 70,995 thousand for the first six months of 2025 compared to USD 86,881 thousand for the comparative period.

### 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 Q2 2025, IPC had crude entitlement of 152,000 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 29,321 thousand for Q2 2025 compared to USD 32,661 thousand for Q2 2024 and USD 58,337 thousand for the first six months of 2025 compared to USD 65,814 thousand for the first six months of 2024.

## Management's Discussion and Analysis

### For the three and six months ended June 30, 2025

The depletion charge is analyzed in the following tables:

| USD Thousands                   | Three months ended June 30, 2025 |                          |          |        | Total  |
|---------------------------------|----------------------------------|--------------------------|----------|--------|--------|
|                                 | Canada – Northern Assets         | Canada – Southern Assets | Malaysia | France |        |
| Depletion cost in USD thousands | 8,885                            | 12,652                   | 4,891    | 2,893  | 29,321 |
| USD per boe <sup>2</sup>        | 6.95                             | 5.57                     | 22.32    | 14.48  | 7.38   |

| USD Thousands                   | Three months ended June 30, 2024 |                          |          |        | Total  |
|---------------------------------|----------------------------------|--------------------------|----------|--------|--------|
|                                 | Canada – Northern Assets         | Canada – Southern Assets | Malaysia | France |        |
| Depletion cost in USD thousands | 9,465                            | 13,021                   | 6,893    | 3,282  | 32,661 |
| USD per boe <sup>2</sup>        | 6.93                             | 5.35                     | 18.65    | 13.93  | 7.41   |

| USD Thousands                   | Six months ended June 30, 2025 |                          |          |        | Total  |
|---------------------------------|--------------------------------|--------------------------|----------|--------|--------|
|                                 | Canada – Northern Assets       | Canada – Southern Assets | Malaysia | France |        |
| Depletion cost in USD thousands | 17,682                         | 24,954                   | 10,642   | 5,059  | 58,337 |
| USD per boe <sup>2</sup>        | 6.87                           | 5.51                     | 22.32    | 13.07  | 7.32   |

| USD Thousands                   | Six months ended June 30, 2024 |                          |          |        | Total  |
|---------------------------------|--------------------------------|--------------------------|----------|--------|--------|
|                                 | Canada – Northern Assets       | Canada – Southern Assets | Malaysia | France |        |
| Depletion cost in USD thousands | 19,209                         | 26,181                   | 13,923   | 6,501  | 65,814 |
| USD per boe <sup>2</sup>        | 6.98                           | 5.37                     | 18.65    | 13.99  | 7.44   |

<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. The depletion rate in Malaysia has significantly increased compared to the prior period due to lower production with one production well offline awaiting workover intervention planned in Q3 2025. Overall though, depletion costs on a USD per boe basis have been very stable.

#### Depreciation of other tangible fixed assets

The total depreciation of other assets amounted to USD 1,461 thousand for Q2 2025 compared to USD 2,218 thousand for Q2 2024 and USD 3,378 thousand for the first six months of 2025 compared to USD 4,480 thousand for the first six months of 2024. This relates to the depreciation of the FPSO Bertam, which is being depreciated to its residual value on a unit of production basis to August 2025.

#### Exploration and business development costs

The total exploration and business developments costs amounted to a cost of USD 568 thousand for the first six months of 2025 and USD 147 thousand for the first six months of 2024.

#### Net financial items

Net financial items amounted to a gain of USD 159 thousand for Q2 2025, compared to a charge of USD 10,048 thousand for Q2 2024 and a charge of USD 18,696 thousand for the first six months of 2025 compared to a charge of USD 19,818 thousand for the first six months of 2024, and included a realized currency hedge loss and a net foreign exchange gain of respectively USD 7,518 thousand and USD 14,233 thousand for the first six months of 2025 compared to no realized currency hedges and a net foreign exchange loss of USD 3,617 thousand for the first six months of 2024. The foreign exchange movements are mainly resulting from the revaluation of intra-group loan funding balances and are non-cash items.

Excluding foreign exchange movements and realized currency cashflow hedges, the net financial items amounted to a charge of USD 13,396 thousand for Q2 2025, compared to USD 8,492 thousand for Q2 2024 and a charge of USD 25,411 thousand for the first six months of 2025 compared to a charge of USD 16,201 thousand for the first six months of 2024.



## Management's Discussion and Analysis

### For the three and six months ended June 30, 2025

The interest expense are very stable and amounted to USD 8,980 thousand for Q2 2025, compared to USD 8,928 thousand for the comparative period in 2024 and USD 17,741 thousand for the first six months of 2025 compared to USD 17,746 thousand for the first six months of 2024 and mainly related to the bond interest at a coupon rate of 7.25% per annum. Interest income generated on cash balances held amounted to USD 694 thousand for Q2 2025 and USD 4,917 thousand for Q2 2024 and USD 2,328 thousand for the first six months of 2025 compared to USD 10,534 thousand for the first six months of 2024.

The unwinding of the asset retirement obligation discount rate amounted to USD 4,115 thousand for Q2 2025 compared to USD 3,641 thousand for Q2 2024 and USD 8,072 thousand for the first six months of 2025 compared to USD 7,259 thousand for the first six months of 2024.

#### Income tax

The corporate income tax amounted to a charge of USD 6,167 thousand for Q2 2025, compared to a charge of USD 13,470 thousand for the comparative period and a charge of USD 10,846 thousand for the first six months of 2025 compared to a charge of USD 21,216 thousand for the comparative period.

The current income tax amounted to a charge of USD 337 thousand for Q2 2025 and USD 851 thousand during the first six months of 2025 and mainly related to France. No corporate income tax is expected to be payable in Canada in 2025 due to the usage of historical tax pools.

#### Capital Expenditure

Development and exploration and evaluation expenditures incurred for the first six months of 2025 was as follows:

| USD Thousands              | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total   |
|----------------------------|--------------------------|--------------------------|----------|--------|---------|
| Development                | 159,831                  | 4,896                    | 24,652   | 4,033  | 193,412 |
| Exploration and evaluation | 3,399                    | –                        | –        | –      | 3,399   |
|                            | 163,230                  | 4,896                    | 24,652   | 4,033  | 196,811 |

Capital expenditures of USD 196,811 thousand was mainly spent in Canada on the Blackrod Phase 1 Development project and in Malaysia for the A21 infill well drilling.

#### Other tangible fixed assets

Other tangible fixed assets amounted to USD 13,242 thousand as at June 30, 2025, which included USD 11,419 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated to its residual value on a unit of production basis to August 2025.

#### Financial Position and Liquidity

##### Financing

As at June 30, 2025, IPC had MUSD 450 of bonds outstanding, maturing in February 2027 with a fixed coupon rate of 7.25% per annum, payable in semi-annual instalments in August and February. The bond repayment obligations as at June 30, 2025, are classified as non-current as there are no mandatory repayments within the next twelve months.

In addition, as at June 30, 2025, the Group had a revolving credit facility of MCAD 250 (the "Canadian RCF") in connection with its oil and gas assets in Canada. During Q2 2025, the Group increased the Canadian RCF from MCAD 180 to MCAD 250 and extended the maturity date. The Canadian RCF has a maturity in May 2027 and was undrawn and fully available as at June 30, 2025. During 2024, the Group entered into a letter of credit facility in Canada (the "LC Facility") to cover existing operational letters of credit. As at June 30, 2025, operational letters of credit in an aggregate of MCAD 40.2 have been issued under the LC Facility, including letters of credit of MCAD 35 to support the third party pipeline construction agreements for the Blackrod Phase 1 Development project which are expected to be released when these pipelines become operational.

As at June 30, 2025, IPC had an unsecured Euro credit facility in France (the "France Facility"), with maturity in May 2026. IPC makes quarterly repayments of the France Facility. The amount remaining outstanding under the France Facility as at June 30, 2025 was MUSD 3.9 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 other credit facilities as at June 30, 2025.

Net debt as at June 30, 2025 amounted to MUSD 375. Cash and cash equivalents held amounted to MUSD 79 as at June 30, 2025.

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

# Management's Discussion and Analysis

## For the three and six months ended June 30, 2025

### Working Capital

As at June 30, 2025, the Group had a working capital balance including cash of USD 36,419 thousand compared to USD 190,771 thousand as at December 31, 2024. The difference as at June 30, 2025, from December 31, 2024, is mainly a result of the decreased cash following capital expenditures on the Blackrod Phase 1 development project and the continuing NCIB program.

### Non-IFRS Measures

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

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

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

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

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

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

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

### Reconciliation of Non-IFRS Measures

#### Operating cash flow

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

| USD Thousands   | Three months ended June 30 |           | Six months ended June 30 |           |
|---|----------------------------|-----------|--------------------------|-----------|
|   | 2025                       | 2024      | 2025                     | 2024      |
| Revenue   | 158,892                    | 219,040   | 337,384                  | 425,459   |
| Production costs and net sales of diluent to third party <sup>1</sup> | (103,682)                  | (111,381) | (206,870)                | (227,126) |
| Current tax   | (337)                      | (5,718)   | (851)                    | (7,091)   |
| Operating cash flow   | 54,873                     | 101,941   | 129,663                  | 191,242   |

<sup>1</sup> Includes net sales of diluent to third party amounting to USD 228 thousand for the second quarter of 2025 and USD 419 thousand for the first six months of 2025.

# Management's Discussion and Analysis

## For the three and six months ended June 30, 2025

### 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 June 30 |              | Six months ended June 30 |                 |
|--|----------------------------|--------------|--------------------------|-----------------|
|  | 2025                       | 2024         | 2025                     | 2024            |
| Operating cash flow - see above  | 54,873                     | 101,941      | 129,663                  | 191,242         |
| Capital expenditures   | (97,925)                   | (84,101)     | (196,811)                | (209,357)       |
| Abandonment and farm-in expenditures <sup>1</sup>                                  | (2,097)                    | (2,241)      | (2,418)                  | (2,363)         |
| General, administration and depreciation expenses before depreciation <sup>2</sup> | (3,691)                    | (3,689)      | (8,049)                  | (7,342)         |
| Cash financial items <sup>3</sup>  | (9,412)                    | (4,351)      | (23,809)                 | (7,932)         |
| Free cash flow   | <b>(58,252)</b>            | <b>7,559</b> | <b>(101,424)</b>         | <b>(35,752)</b> |

<sup>1</sup> See note 16 to the Financial Statements

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

<sup>3</sup> See notes 4 and 5 to the Financial Statements.

### EBITDA

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

| USD Thousands   | Three months ended June 30 |                | Six months ended June 30 |                |
|---|----------------------------|----------------|--------------------------|----------------|
|   | 2025                       | 2024           | 2025                     | 2024           |
| Net result  | 13,850                     | 45,210         | 30,081                   | 78,929         |
| Net financial items   | (159)                      | 10,048         | 18,696                   | 19,818         |
| Income tax  | 6,167                      | 13,470         | 10,846                   | 21,216         |
| Depletion and decommissioning costs   | 29,321                     | 32,661         | 58,337                   | 65,814         |
| Depreciation of other tangible fixed assets   | 1,461                      | 2,218          | 3,378                    | 4,480          |
| Exploration and business development costs  | 537                        | 72             | 568                      | 147            |
| Sale of assets <sup>1</sup>   | (10)                       | –              | (104)                    | –              |
| Depreciation included in general, administration and depreciation expenses <sup>2</sup> | 352                        | 292            | 663                      | 587            |
| EBITDA  | <b>51,519</b>              | <b>103,971</b> | <b>122,465</b>           | <b>190,991</b> |

<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 June 30 |               | Six months ended June 30 |                |
|------------------------------|----------------------------|---------------|--------------------------|----------------|
|                              | 2025                       | 2024          | 2025                     | 2024           |
| Production costs             | 103,910                    | 111,381       | 207,289                  | 227,126        |
| Cost of blending             | (33,269)                   | (41,675)      | (70,995)                 | (86,881)       |
| Change in inventory position | (119)                      | (4,872)       | 3,381                    | 405            |
| Operating costs              | <b>70,522</b>              | <b>64,834</b> | <b>139,675</b>           | <b>140,650</b> |

# Management's Discussion and Analysis

## For the three and six months ended June 30, 2025

### Net cash/(debt)

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

| USD Thousands             | June 30, 2025 | December 31, 2024 |
|---------------------------|---------------|-------------------|
| Bank loans                | (3,863)       | (5,121)           |
| Bonds <sup>1</sup>        | (450,000)     | (450,000)         |
| Cash and cash equivalents | 78,886        | 246,593           |
| Net cash/(debt)           | (374,977)     | (208,528)         |

<sup>1</sup> The bond amount represents the redeemable value at maturity (February 2027).

### Off-Balance Sheet Arrangements

IPC, through its subsidiary IPC Canada Ltd, has issued six letters of credit as follows: (a) MCAD 2.6 in respect of its obligations to purchase diluent; (b) MCAD 1.0 in respect of its obligations related to the Ferguson asset; (c) MCAD 1.3 in respect of pipeline access; (d) MCAD 0.5 in relation to the hedging of electricity prices; (e) and (f) MCAD 24.5 and MCAD 10.5 in respect of its obligations related to Blackrod Phase 1 pipelines.

### Outstanding Share Data

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

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

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

Over the period of January 1, 2025 to June 30, 2025, IPC purchased 5,492,965 common shares under the NCIB and 211,818 common shares under certain other exemptions in Canada. All of these purchased common shares, including the common shares held in treasury as at December 31, 2024, were cancelled during the first six months of 2025. As at June 30, 2025, IPC had a total of 113,354,532 common shares issued and outstanding, with no common shares in treasury.

Nemesia S.à.r.l., an investment company ultimately controlled by trusts whose settlor is the late Adolf H. Lundin, holds 42,597,533 common shares in IPC, representing 37.6% of the outstanding common shares as at June 30, 2025.

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

IPC has 2,941,020 IPC Share Unit Plan awards outstanding as at August 5, 2025, of which 948,938 awards were granted in 2025.

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

### Contractual Obligations and Commitments

In the normal course of business, the Group has committed to certain payments which are not recognised as liabilities. The following table summarizes the Group's commitments in Canada as at June 30, 2025:

| MCAD                                | 2025        | 2026        | 2027         | 2028         | 2029        | Thereafter     |
|-------------------------------------|-------------|-------------|--------------|--------------|-------------|----------------|
| Transportation service <sup>1</sup> | 17.5        | 59.3        | 89.2         | 94.3         | 98.2        | 1,421.9        |
| Power <sup>2</sup>                  | 7.3         | 12.4        | 12.4         | 9.8          | –           | –              |
| <b>Total commitments</b>            | <b>24.8</b> | <b>71.7</b> | <b>101.6</b> | <b>104.2</b> | <b>98.2</b> | <b>1,421.9</b> |

<sup>1</sup> IPC has firm transportation commitments on oil and natural gas pipelines that expire between 2037 and 2045.

<sup>2</sup> IPC has physical delivery power hedges to purchase 15MWh at a weighted average price of CAD 74.92/MWh from July 1, 2025 to December 31, 2028, an additional 5MWh at a weighted average price of CAD 58.31/MWh from July 1, 2025 to December 31, 2027, and an additional 5MWh at a weighted average price of CAD 46.85/MWh from July 1, 2025 to December 31, 2025.

# Management's Discussion and Analysis

## For the three and six months ended June 30, 2025

### 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.

### Transactions with Related Parties

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

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

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

### Financial Risk Management

As an international oil and gas exploration and production company, IPC is exposed to financial risks such as interest rate risk, currency risk, credit risk, liquidity risks as well as the risk related to the fluctuation in oil and gas prices. The Group seeks to control these risks through sound management practice and the use of internationally accepted financial instruments, such as oil and gas, condensate and electricity price, interest rate or foreign exchange hedges as the case may be. Financial instruments will be solely used for the purpose of managing risks in the business. As at June 30, 2025, the Corporation had entered into oil, gas, electricity and currency hedges – see below.

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

### Capital Management

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

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

### Price of Oil and Gas

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

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

The Group had oil price sale financial hedges outstanding as at June 30, 2025, which are summarized as follows:

| Period                           | Volume (barrels per day) | Type                 | Average Pricing                             |
|----------------------------------|--------------------------|----------------------|---|
| July 1, 2025 - December 31, 2025 | 11,700                   | WTI/WCS Differential | USD -14.26/bbl                              |
| July 1, 2025 - December 31, 2025 | 10,000                   | WTI Sale Swap        | USD 71.30/bbl                               |
| July 1, 2025 - December 31, 2025 | 4,000                    | WTI Collar           | USD 65.00/bbl (Put)<br>USD 75.45/bbl (Call) |
| July 1, 2025 - December 31, 2025 | 2,000                    | Brent Sale Swap      | USD 75.78/bbl                               |

## Management's Discussion and Analysis

### For the three and six months ended June 30, 2025

The Group had gas price sale financial hedges outstanding as at June 30, 2025, which are summarized as follows:

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

The Group had electricity financial hedges outstanding as at June 30, 2025, which are summarized as follows:

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

The above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. The hedges had a positive fair value of USD 21,683 thousand as at June 30, 2025.

#### Currency Risk

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

The Group entered into currency hedges to purchase:

- (i) a total CAD 230 million for the period July 2025 to December 2025 at an average rate of CAD 1.36 (sell USD);
- (ii) a total EUR 13.5 million for the period July 2025 to December 2025 at an average rate of EUR 1.07 (sell USD);
- (iii) a total MYR 66 million for the period July 2025 to December 2025 at an average rate of MYR 4.39 (sell USD).

The outstanding portion of all of the above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. The hedges had a negative fair value of USD 2,347 thousand as at June 30, 2025.

#### Interest Rate Risk

Interest rate risk is the risk to earnings due to uncertain future interest rates on borrowings. The Group will take into account the level of external debt, current interest rates and market expectations in comparison to historic trends and volatility in making the decision to hedge. There are currently no interest rate hedges.

#### Credit Risk

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

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

### RISK FACTORS

IPC is engaged in the exploration, development and production of oil and gas and is exposed to various operational, environmental, market and financial risks and uncertainties. For further information and discussion of these risks and uncertainties, please see IPC's Annual Information Form for the year ended December 31, 2024 ("AIF") available on SEDAR+ at [www.sedarplus.ca](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" in this MD&A.

### DISCLOSURE CONTROLS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

#### Disclosure Controls and Procedures

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



# Management's Discussion and Analysis

## For the three and six months ended June 30, 2025

### 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 and six months ended June 30, 2025, that have materially affected, or are reasonably likely to materially affect, the Group's internal control over financial reporting.

### Control Framework

Management assesses the effectiveness of the Corporation's internal control over financial reporting using the Internal Control – Integrated Framework (2013 Framework) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management concluded that the Corporation's internal control over financial reporting was effective as of June 30, 2025.

### CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

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

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

- 2025 production ranges (including total daily average production), production composition, cash flows, operating costs and capital and decommissioning expenditure estimates;
- Estimates of future production, cash flows, operating costs and capital expenditures that are based on IPC's current business plans and assumptions regarding the business environment, which are subject to change;
- IPC's financial and operational flexibility to navigate the Corporation through periods of volatile commodity prices;
- The ability to fully fund future expenditures from cash flows and current borrowing capacity;
- IPC's intention and ability to continue to implement its strategies to build long-term shareholder value;
- The ability of IPC's portfolio of assets to provide a solid foundation for organic and inorganic growth;
- The continued facility uptime and reservoir performance in IPC's areas of operation;
- Development of the Blackrod project in Canada, including estimates of resource volumes, future production, timing, regulatory approvals, third party commercial arrangements, breakeven oil prices and net present values;
- Current and future production performance, operations and development potential of the Onion Lake Thermal, Suffield, Brooks, Ferguson and Mooney operations, including the timing and success of future oil and gas drilling and optimization programs;
- The potential improvement in the Canadian oil egress situation and IPC's ability to benefit from any such improvements;
- The ability to maintain current and forecast production in France and Malaysia;
- The intention and ability of IPC to acquire further common shares under the NCIB, including the timing of any such purchases;
- The return of value to IPC's shareholders as a result of the NCIB;
- IPC's ability to implement its greenhouse gas (GHG) emissions intensity and climate strategies and to achieve its net GHG emissions intensity reduction targets;
- IPC's ability to implement projects to reduce net emissions intensity, including potential carbon capture and storage;
- Estimates of reserves and contingent resources;
- The ability to generate free cash flows and use that cash to repay debt;
- IPC's continued access to its existing credit facilities, including current financial headroom, on terms acceptable to the Corporation;
- IPC's ability to identify and complete future acquisitions;
- Expectations regarding the oil and gas industry in Canada, Malaysia and France, including assumptions regarding future royalty rates, regulatory approvals, legislative changes, 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".

## Management's Discussion and Analysis

For the three and six months ended June 30, 2025

The forward-looking statements are based on certain key expectations and assumptions made by IPC, including expectations and assumptions concerning: the potential impact of tariffs implemented in 2025 by the U.S. and Canadian governments and that other than the tariffs that have been implemented, neither the U.S. nor Canada (i) increases the rate or scope of such tariffs, or imposes new tariffs, on the import of goods from one country to the other, including on oil and natural gas, and/or (ii) imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas; prevailing commodity prices and currency exchange rates; applicable royalty rates and tax laws; interest rates; future well production rates and reserve and contingent resource volumes; operating costs; our ability to maintain our existing credit ratings; our ability to achieve our performance targets; the timing of receipt of regulatory approvals; the performance of existing wells; the success obtained in drilling new wells; anticipated timing and results of capital expenditures; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the successful completion of acquisitions and dispositions and that we will be able to implement our standards, controls, procedures and policies in respect of any acquisitions and realize the expected synergies on the anticipated timeline or at all; the benefits of acquisitions; the state of the economy and the exploration and production business in the jurisdictions in which IPC operates and globally; the availability and cost of financing, labour and services; our intention to complete share repurchases under our normal course issuer bid program, including the funding of such share repurchases, existing and future market conditions, including with respect to the price of our common shares, and compliance with respect to applicable limitations under securities laws and regulations and stock exchange policies; and the ability to market crude oil, natural gas and natural gas liquids successfully.

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

These include, but are not limited to:

- General global economic, market and business conditions;
- The risks associated with the oil and gas industry in general such as operational risks in development, exploration and production;
- Delays or changes in plans with respect to exploration or development projects or capital expenditures;
- The uncertainty of estimates and projections relating to reserves, resources, production, revenues, costs and expenses;
- Health, safety and environmental risks;
- Commodity price fluctuations;
- Interest rate and exchange rate fluctuations;
- Marketing and transportation;
- Loss of markets;
- Environmental and climate-related risks;
- Competition;
- Innovation and cybersecurity risks related to our systems, including our costs of addressing or mitigating such risks;
- The ability to attract, engage and retain skilled employees
- Incorrect assessment of the value of acquisitions;
- Failure to complete or realize the anticipated benefits of acquisitions or dispositions;
- The ability to access sufficient capital from internal and external sources;
- Failure to obtain required regulatory and other approvals;
- Geopolitical conflicts, including the war between Ukraine and Russia and the conflict in the Middle East, and their potential impact on, among other things, global market conditions
- Political or economic developments, including, without limitation, the risk that (i) one or both of the U.S. and Canadian governments increases the rate or scope of tariffs implemented in 2025, or imposes new tariffs on the import of goods from one country to the other, including on oil and natural gas, (ii) the U.S. and/or Canada imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas, and (iii) the tariffs imposed by the U.S. on other countries and responses thereto could have a material adverse effect on the Canadian, U.S. and global economies, and by extension the Canadian oil and natural gas industry and the Corporation; and
- Changes in legislation, including but not limited to tax laws, royalties, environmental and abandonment regulations.

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

Estimated production and FCF generation are based on IPC's current business plans over the periods of 2025 to 2029 and 2030 to 2034, less net debt of MUS\$ 209 as at December 31, 2024, with assumptions based on the reports of IPC's independent reserves evaluators, and including certain corporate adjustments relating to estimated general and administration costs and hedging, and excluding shareholder distributions and financing costs. Assumptions include average net production of approximately 57 Mboepd over the period of 2025 to 2029, average net production of approximately 63 Mboepd over the period of 2030 to 2034, average Brent oil prices of USD 75 to 95 per bbl escalating by 2% per year, and average Brent to Western Canadian Select differentials and average gas prices as estimated by IPC's independent reserves evaluator and as further described in the AIF. IPC's current business plans and assumptions, and the business environment, are subject to change. Actual results may differ materially from forward-looking estimates and forecasts.

Additional information on these and other factors that could affect IPC, or its operations or financial results, are included in the Financial Statements, the Corporation's Annual Information Form (AIF) for the year ended December 31, 2024 (see "Cautionary Statement Regarding Forward-Looking Information", "Reserves and Resources Advisory" and "Risk Factors") and other reports on file with applicable securities regulatory authorities, including previous financial reports, management's discussion and analysis and material change reports, which may be accessed through the SEDAR+ website ([www.sedarplus.ca](http://www.sedarplus.ca)) or IPC's website ([www.international-petroleum.com](http://www.international-petroleum.com)).



## Management's Discussion and Analysis

### For the three and six months ended June 30, 2025

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

#### RESERVES AND RESOURCES ADVISORY

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

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada are effective as of December 31, 2024, and are included in the reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Sproule's December 31, 2024 price forecasts.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France and Malaysia are effective as of December 31, 2024, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2024 price forecasts.

The price forecasts used in the Sproule and ERCE reports, are available on the website of Sproule ([sproule.com](http://sproule.com)) and are contained in the AIF. These price forecasts are as at December 31, 2024 and may not be reflective of current and future forecast commodity prices.

The reserve life index (RLI) is calculated by dividing the 2P reserves of 493 MMboe as at December 31, 2024, by the mid-point of the 2025 CMD production guidance of 43,000 to 45,000 boepd.

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

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

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

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

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

## Management's Discussion and Analysis

### For the three and six months ended June 30, 2025

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 risk resources are presented, they have been adjusted based on the chance of development by multiplying the unrisked values by the chance of development.

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

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

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

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

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

#### Supplemental Information regarding Product Types

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

|                                     | Heavy Crude Oil<br>(Mbopd) | Light and Medium<br>Crude Oil (Mbopd) | Conventional Natural Gas<br>(per day) | Total<br>(Mboepd) |
|-------------------------------------|----------------------------|---------------------------------------|---------------------------------------|-------------------|
| <b>Three months ended</b>           |                            |                                       |                                       |                   |
| June 30, 2025                       | 22.7                       | 5.9                                   | 89.8 MMcf<br>(15.0 Mboe)              | 43.6              |
| June 30, 2024                       | 24.3                       | 8.0                                   | 96.5 MMcf<br>(16.1 Mboe)              | 48.4              |
| <b>Six months ended</b>             |                            |                                       |                                       |                   |
| June 30, 2025                       | 23.0                       | 6.2                                   | 89.0 MMcf<br>(14.8 Mboe)              | 44.0              |
| June 30, 2024                       | 24.6                       | 8.0                                   | 96.2 MMcf<br>(16.0 Mboe)              | 48.6              |
| <b>Year ended December 31, 2024</b> |                            |                                       |                                       |                   |
| December 31, 2024                   | 23.9                       | 7.7                                   | 95.1MMcf<br>(15.8 Mboe)               | 47.4              |

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

# Management's Discussion and Analysis

For the three and six months ended June 30, 2025

## OTHER SUPPLEMENTARY INFORMATION

### Abbreviations

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

### Oil related terms and measurements

|                   |  |
|-------------------|--|
| AECO              | The daily average benchmark price for natural gas at the AECO hub in southeast Alberta                     |
| AESO              | Alberta Electric System Operator   |
| API               | An indication of the specific gravity of crude oil on the API (American Petroleum Institute) gravity scale |
| ASP               | Alkaline surfactant polymer (an EOR process)   |
| bbl               | Barrel (1 barrel = 159 litres)   |
| boe               | Barrels of oil equivalents   |
| boepd             | Barrels of oil equivalents per day   |
| bopd              | Barrels of oil per day   |
| Bcf               | Billion cubic feet   |
| C5                | Condensate   |
| CO <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  |
| 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 and six months ended June 30, 2025

### DIRECTORS

C. Ashley Heppenstall  
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London, England

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

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Director  
Abcoude, The Netherlands

Donald K. Charter  
Director  
Toronto, Ontario, Canada

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

Emily Moore  
Director  
Toronto, Ontario, Canada

Mike Nicholson  
Director  
Monaco

Deborah Starkman  
Director  
Toronto, Ontario, Canada

### OFFICERS

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

Ryan Adair  
Vice President Asset Management and  
Corporate Planning, Canada  
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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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