# Q4

## International Petroleum Corporation

# *Management's Discussion and Analysis*

*For the three months and year ended December 31, 2025*

International Petroleum Corp.

# Management's Discussion and Analysis
## For the three months and year ended December 31, 2025

## Contents



Non-IFRS Measures
References are made in this MD&A to "operating cash flow" (OCF), "free cash flow" (FCF), "Earnings Before Interest, Tax, Depreciation and Amortization" (EBITDA), "operating costs" and "net debt"/"net cash" which are not generally accepted accounting measures under IFRS Accounting Standards ("IFRS") and do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with definitions of OCF, FCF, EBITDA, operating costs and net debt/ net cash that may be used by other public companies. Management believes that OCF, FCF, EBITDA, operating costs and net debt/net cash are useful supplemental measures that may assist shareholders and investors in assessing the cash generated by and the financial performance and position of the Corporation. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-IFRS measure is presented in this MD&A. See "Non-IFRS Measures" on page 21.

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 36.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada and France/Malaysia are effective as of December 31, 2025, and are included in the reports prepared by Sproule International Limited and ERCE Equipoise Ltd., respectively (collectively, Sproule ERCE), an independent qualified reserves evaluator and auditor, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Sproule ERCE's December 31, 2025, price forecasts.

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

## 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 February 10, 2026 and is intended to provide an overview of the Group's operations, financial performance and current and future business opportunities. This MD&A should be read in conjunction with IPC's audited consolidated financial statements and accompanying notes for the year ended December 31, 2025 ("Financial Statements").

### Group Overview

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

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

### Basis of Preparation

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

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

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

| | December 31, 2025 | | December 31, 2024 | |
|---|---|---|---|---|
| | Average | Year end | Average | Year end |
| 1 EUR equals USD | 1.1293 | 1.1750 | 1.0821 | 1.0389 |
| 1 USD equals CAD | 1.3975 | 1.3692 | 1.3698 | 1.4388 |
| 1 USD equals MYR | 4.2791 | 4.0580 | 4.5759 | 4.4715 |

## HIGHLIGHTS

### 2025 Business Highlights

- Average net production of approximately 45,600 boepd for the fourth quarter of 2025 was in line with the guidance range for the period (52% heavy crude oil, 15% light and medium crude oil and 33% natural gas).[1]
- Full year 2025 average net production was 44,900 boepd, at the high end of the 2025 annual guidance of 43,000 to 45,000 boepd.[1]
- Development activities on Phase 1 of the Blackrod project progressed in 2025 ahead of schedule and on budget, with first steam injection achieved in Q4 2025 and forecast first oil in Q3 2026.
- Completed the acquisition of lands adjacent to the Blackrod project, adding 64 MMboe of contingent resources (best estimate, unrisked).[1][2]
- At Onion Lake Thermal, Canada, four production infill wells and the final Pad L sustaining well pair were brought online by Q3 2025.
- Successfully completed the drilling and workover program at the Bertam Field, Malaysia during Q3 2025.
- 7.7 million IPC common shares purchased and cancelled from December 2024 to early December 2025.
- In Q3 2025, published IPC's sixth annual Sustainability Report.

### 2025 Financial Highlights

- Operating costs per boe of USD 18.4 for the fourth quarter of 2025 and USD 17.8 for the full year, below the low end of the 2025 guidance of USD 18.0 to 19.0 per boe.[3]
- Strong operating cash flow (OCF) generation for the fourth quarter and full year 2025 amounted to MUSD 63 and MUSD 259, respectively.[3]
- Capital and decommissioning expenditures of MUSD 63 for the fourth quarter and MUSD 344 for the full year 2025, in line with the latest full year guidance.
- Free cash flow (FCF) generation for the full year 2025 of negative MUSD 153, with negative MUSD 29 for the fourth quarter in line with expectations. FCF for the full year 2025, before 2025 Blackrod capital expenditure of MUSD 256, was MUSD 103.[3]
- Net debt of MUSD 484 as at December 31, 2025.[3]
- Net result of negative MUSD 5 for the fourth quarter of 2025 and positive MUSD 29 for the full year 2025.
- Amended and extended IPC's MCAD 250 revolving credit facility in Q2 2025, extending the maturity to May 2027.
- Refinanced IPC's MUSD 450 unsecured bonds in Q4 2025, extending the maturity to October 2030.

### Reserves and Resources

- Total 2P reserves as at December 31, 2025 of 521 MMboe, with a reserve life index (RLI) of 31 years and a reserves replacement ratio of 277%.[1][2]
- Proved developed producing (PDP) reserves increase of 28% from year-end 2024 to year-end 2025 to 125 MMboe, primarily driven from Blackrod Phase 1.[1][2]
- Contingent resources (best estimate, unrisked) as at December 31, 2025 of 1,224 MMboe.[1][2]

### 2026 Annual Guidance

- Full year 2026 average net production forecast at 44,000 to 47,000 boepd.[1]
- Full year 2026 operating costs forecast at USD 18 to 20 per boe.[3]
- Full year 2026 OCF estimated at between MUSD 100 and 250 (assuming Brent USD 55 to 75 per barrel).[3]
- Full year 2026 capital and decommissioning expenditures guidance forecast at MUSD 122.
- Full year 2026 FCF forecast ranges from approximately negative MUSD 70 to positive MUSD 85 (assuming Brent USD 55 to 75 per barrel).[3]

### Current Business Plan FCF Forecasts

- Cumulative forecast FCF of approximately MUSD 1,000 to 2,000 over the period of 2026 to 2030 and approximately MUSD 700 to 1,600 over the period of 2031 to 2035 (assuming Brent USD 65 to 85 per barrel).[3][7]

| USD Thousands | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | 2025 | 2024 | 2025 | 2024 |
| Revenue | 176,207 | 199,124 | 685,888 | 797,783 |
| Gross profit | 28,242 | 42,774 | 128,120 | 210,171 |
| Net result | (4,941) | 415 | 28,942 | 102,219 |
| Operating cash flow(3) | 63,138 | 78,158 | 258,903 | 341,989 |
| Free cash flow(3) | (28,627) | (61,476) | (153,134) | (135,497) |
| EBITDA(3) | 58,966 | 76,184 | 243,537 | 335,488 |
| Net cash/(debt)(3) | (483,615) | (208,528) | (483,615) | (208,528) |

## OPERATIONS REVIEW

### Business Overview

International Petroleum Corporation is an entrepreneurially driven company that seeks to maximise shareholder value through responsible business operations and accretive growth. IPC started in 2017 with 113.5 million common shares outstanding and a debt-free portfolio of high-quality producing assets in Malaysia, France and the Netherlands, hosting combined 2P reserves of 29 MMboe, production of 10 Mboepd, a reserve life index of 8 years and a NPV10 of USD 0.5 billion.

This platform acted as a springboard for IPC to carry out countercyclical strategic moves including building a position in Canada through acquisitions and sanctioning a major Steam Assisted Gravity Drainage (SAGD) greenfield development project. The decisive moves undertaken by the company have been grounded by taking a long-term view and increasing exposure to oil. We are very pleased to see the positive market recognition in Canadian E&Ps, validating the bold decisions made to enter and grow in the jurisdiction given the vast resource and favourable fiscal terms.

As IPC enters its tenth year of existence in 2026, excluding the Blackrod Phase 1 growth capital expenditures, over USD 1.6 billion in free cash flow (FCF) has been generated and our current common shares outstanding is less than the starting amount at approximately 112.2 million shares. Current 2P reserves are 18 times higher standing at 521 MMboe and contingent resources (best estimate, unrisked) have grown from 0 MMboe in 2017 to now greater than 1,200 MMboe. Our reserve life index is four times higher at 31 years based on our 2026 mid-point production guidance of 45.5 Mboepd. Production is expected to grow to greater than 65 Mboepd by 2028 which underpins material FCF per share growth in the years ahead.(1)(2)(3)

Oil prices in 2025 ranged from Brent USD 59 to 77 per barrel, with a full year Brent averaging USD 69 per barrel compared to USD 81 per barrel averaged over the previous year 2024. The fourth quarter 2025 Brent price averaged USD 64 per barrel. The volatility in benchmark oil prices during 2025 was largely due to changing US economic and tariff policies and the corresponding potential effects on global economic growth, continuing geopolitical conflicts, and concerns regarding oil oversupply including from releases of OPEC production curtailments. IPC believes that these short-term uncertainties will lead to underinvestment in the industry, which combined with continued projected record breaking annual global oil demand into 2026 and beyond, should have a positive effect on oil prices at a time when IPC is ramping up Blackrod Phase 1 production.

IPC has hedged 1,500 barrels per day of forecast 2026 oil production at around USD 67 per barrel for Dated Brent and 7,500 barrels per day of forecast 2026 oil production at around USD 61.5 per barrel for West Texas Intermediate (WTI).

The fourth quarter 2025 WTI to Western Canadian Select (WCS) price differential averaged USD 11 per barrel, in line with the full year 2025 average. The WTI to WCS differential continues to benefit from the TMX pipeline expansion, driving up competitive tension for Canadian oil and increased buying from Asia. The outlook of the WTI to WCS differential remains tight with excess egress capacity relative to the supply in the Western Canadian Sedimentary Basin (WCSB), balanced against the potential of Venezuelan heavy oil barrels to the US Gulf Coast PADD III refineries. There are currently no tariffs on Canadian crude oil exports to the United States, which remain covered by the US Mexico Canada trade agreement. For 2026, IPC has implemented WTI to WCS differential hedges for 5,000 barrels per day at USD -12.50 per barrel.

The average Canadian gas benchmark price, AECO, was CAD 2.16 per Mcf for the fourth quarter of 2025 and CAD 1.63 for the full year 2025. WCSB gas inventory levels remain elevated above the historical average. There is an expectation for storage levels to draw during the winter period, with very cold weather experienced in North America in early 2026 and further supported by the ramp up of the LNG Canada project in 2026 which should drive higher natural gas prices in Canada. IPC has implemented hedges for 15,000 GJ per day at CAD 2.73 per GJ for 2026 from April to October 2026.

**Fourth Quarter and Full Year 2025 Highlights**
During the fourth quarter of 2025, IPC's assets delivered average net production of 45,600 boepd, in line with guidance for the quarter. Full year 2025 average net production of 44,900 boepd was the high end of the 2025 guidance range of 43,000 to 45,000 boepd.(1)

IPC's operating costs per boe for the fourth quarter of 2025 was USD 18.4. Full year 2025 operating costs per boe was USD 17.8, below the low end of the 2025 annual guidance of USD 18.0 to 19.0 per boe.(3)

Operating cash flow (OCF) generation for the fourth quarter of 2025 was USD 63 million. Full year 2025 OCF was USD 259 million above the most recent Q3 2025 guidance of USD 245 to 255 million.(3)

Capital and decommissioning expenditure for the fourth quarter of 2025 was USD 63 million. Full year 2025 capital and decommissioning expenditure of USD 344 million was in line with latest guidance of USD 340 million.

Free cash flow (FCF) generation was in line with guidance at negative USD 29 million during the fourth quarter of 2025. Full year 2025 FCF generation was negative USD 153 million, better than the most recent guidance of negative USD 160 to 170 million.(3)

As at December 31, 2025, IPC's net debt position was USD 484 million. IPC prudently refinanced its USD 450 million of unsecured bonds in Q4 2025, extending maturity to October 2030. IPC also has access to a revolving credit facility of CAD 250 million, with approximately CAD 200 million undrawn as at the end of 2025.(3)

**Blackrod**
The Blackrod asset is 100% owned by IPC and hosts the largest booked reserves and contingent resources within the IPC portfolio. After more than a decade of pilot operations, subsurface delineation and commercial engineering studies, IPC sanctioned the Phase 1 SAGD development in the first quarter of 2023. The Phase 1 development targets 311 MMboe of 2P reserves, with a multi-year forecast capital expenditure of USD 850 million to first oil planned in Q3 2026. The Phase 1 development is planned for plateau production of 30,000 bopd which is expected by the end of 2027.(1)(2)

As previously announced, IPC achieved first steam at the Blackrod Phase 1 project in December 2025, a quarter earlier than originally guided. By the end of 2025, USD 820 million of cumulative growth capital has been spent on the Blackrod Phase 1 development since sanction. Construction is nearing completion at the central processing facility (CPF), commissioning activities are ongoing, and drilling plus completions continue to track favourably. Site health and safety control has been excellent with no material safety incidents since commercial development activities commenced.

Approximately USD 30 million of growth capital budget remains to reach first oil at Blackrod Phase 1 in 2026. IPC is well-positioned to deliver in line with the multi-year budget of USD 850 million to first oil. The total growth capital expenditure comprises the total installed costs for the facilities and associated 40 well pairs needed to fill the plant capacity of 30,000 bopd and has remained unchanged since the time of sanction in 2023.(1)

The remaining capital expenditure planned to be spent at Blackrod in 2026 of approximately USD 60 million includes acceleration of sustaining capital, taking advantage of economies of scale and the positive momentum seen by the drilling rig at site, capitalised operations for the operating costs incurred prior to first oil, and resource maturation works.

Blackrod realised a material uplift in recoverable resource through 2025 through a combination of favourable drilling results within and outside of the initial development area and further supplemented by acquiring adjacent lands with 64 MMboe of contingent resources (best estimate, unrisked). The 2P reserves attributable to Phase 1 has increased by 52 MMboe to 311 MMboe from year-end 2024 to year-end 2025. The contingent resources (best estimate, unrisked) attributed to the Blackrod asset realised a net increase of 117 MMboe to 1,142 MMboe.(1)(2)

**Stakeholder Returns: Normal Course Issuer Bid**
During the period of December 5, 2024 to December 4, 2025, IPC purchased and cancelled an aggregate of approximately 7.7 million common shares under the 2024/2025 NCIB and certain other exemptions in Canada. The average price of shares purchased under the 2024/2025 NCIB was SEK 144 / CAD 20 per share.

Since inception, IPC has returned over USD 600 million in shareholder returns in the form of share buybacks, cancelling over 77 million common shares at an aggregate average share price of around SEK 79 / CAD 11 per share. Since 2022, more than 27% of the shares outstanding have been repurchased and cancelled.

In Q4 2025, IPC announced the renewal of the NCIB, with the ability to repurchase up to approximately 6.5 million common shares over the period of December 5, 2025 to December 4, 2026. IPC remains focused on progressing the Blackrod Phase 1 development project first oil and will continue to monitor commodity prices in 2026 before acquiring IPC common shares under the current NCIB.

As at December 31, 2025 and February 10, 2026, IPC had a total of 112,155,527 common shares issued and outstanding and IPC holds no common shares in treasury.

**Environmental, Social and Governance (ESG) Performance**
As part of IPC's commitment to operational excellence and responsible development, IPC's objective is to reduce risk and eliminate hazards to prevent occurrence of accidents, ill health, and environmental damage, as these are essential to the success of our business operations. During the fourth quarter and for the full year 2025, IPC recorded no material safety or environmental incidents.

As previously announced, IPC targeted a reduction of our net GHG emissions intensity by the end of 2025 to 50% of IPC's 2019 baseline and IPC is on track to achieve this reduction for 2025 net GHG emissions intensity. IPC is committed to remain at end 2025 levels of 20 kg $CO_2$/boe through to the end of 2028.(4)

**Reserves, Resources and Value**
As at the end of December 2025, IPC's 2P reserves are 521 MMboe. During 2025, IPC replaced 277% of the annual 2025 production. The reserve life index (RLI) as at December 31, 2025, is approximately 31 years.(1)(2)

The net present value (NPV) of IPC's 2P reserves as at December 31, 2025 was around USD 2.7 billion. The net asset value (NAV) of IPC's 2P reserves as at December 31, 2025 was around USD 2.2 billion. Based on IPC's current business plans, the cumulative forecast FCF is approximately MUSD 1,000 to 2,000 over the period of 2026 to 2030 and approximately MUSD 700 to 1,600 over the period of 2031 to 2035 (assuming Brent USD 65 to 85 per barrel).(1)(2)(5)(6)(7)

In addition, IPC's best estimate contingent resources (unrisked) as at December 31, 2025 are 1,224 MMboe, of which 1,142 MMboe relate to future potential phases of the Blackrod project.(1)(2)

**2026 Budget and Operational Guidance**
IPC is pleased to announce its 2026 average net production guidance is 44,000 to 47,000 boepd. IPC forecasts operating costs for 2026 between USD 18 and 20 per boe.(1)(3)

IPC's 2026 capital and decommissioning expenditure budget is USD 122 million, with USD 90 million forecast relating to Blackrod capital expenditure. The remainder of the 2026 budget relates mainly to routine maintenance and ongoing optimization work at the other producing assets. In all of IPC's areas of operation, IPC has significant flexibility to control its pace of spend based on the development of commodity prices during 2026.

Further details regarding IPC's proposed 2026 budget and operational guidance will be provided at IPC's Capital Markets Day presentation to be held on February 10, 2026 at 15:00 CET. A copy of the Capital Markets Day presentation will be available on IPC's website at www.international-petroleum.com.

Notes:

(1) See "Supplemental Information regarding Product Types" in "Reserves and Resources Advisory" below. See also the material change report (MCR) available on IPC's website at www.international-petroleum.com and filed on the date of this press release under IPC's profile on SEDAR+ at www.sedarplus.ca.

(2) See "Reserves and Resources Advisory" below. Further information with respect to IPC's reserves, contingent resources and estimates of future net revenue, including assumptions relating to the calculation of NPV, are described in the MCR. The reserve life index (RLI) is calculated by dividing the 2P reserves of 521 MMboe as at December 31, 2025 by the mid-point of the 2026 CMD production guidance of 44,000 to 47,000 boepd. Reserves replacement ratio is based on 2P reserves of 493 MMboe as at December 31, 2024, sales production during 2025 of 15.7 MMboe, net additions to 2P reserves during 2025 of 43.4 MMboe, and 2P reserves of 521 MMboe as at December 31, 2025.

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

(4) 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.

(5) Net present value (NPV) is after tax, discounted at 10% and based upon the forecast prices and other assumptions further described in the MCR. See "Reserves and Resources Advisory" below.

(6) Net asset value (NAV) is calculated as NPV less net debt of USD 484 million as at December 31, 2025.

(7) Estimated FCF generation is based on IPC's current business plans over the periods of 2026 to 2030 and 2031 to 2035, including net debt of USD 484 million as at December 31, 2025, with assumptions based on the reports of IPC's independent reserves evaluator and auditor, and including certain corporate adjustments relating to estimated general and administration costs and hedging, and excluding shareholder distributions and certain refinancing costs. Assumptions include average net production of approximately 62 Mboepd over the period of 2026 to 2030, average capital expenditures of approximately USD 5 per boe, average operating costs of approximately USD 18 to 20 per boe, average Brent oil prices of USD 65 to 85 per bbl escalating by 2% per year, and average Brent to Western Canadian Select differentials and average gas prices as estimated by IPC's independent reserves evaluator and auditor and as further described in the MCR. Estimated FCF generation at Brent oil prices of USD 95 per barrel escalating by 2% per year, based on the same assumptions set out above, are approximately MUSD 2,500 and 2,100 for the same periods, respectively. IPC's market capitalization is at close on February 2, 2026 (USD 2,277 million based on 182 SEK/share, 112.2 million IPC shares outstanding and exchange rate of 8.97 SEK/ USD). 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. See "Forward-Looking Statements" and "Non-IFRS Measures" below.

## Operations Overview

**2025 Overview**
In 2025, IPC continued to successfully demonstrate its commitment to operational excellence, delivering high end production performance with strong cost discipline resulting in operating expenditure at the low end of our Capital Markets Day (CMD) guidance. No material safety or environmental incidents were recorded in the year.

The Blackrod Phase 1 development delivered first steam ahead of schedule, with the remaining project scope and the overall project budget continuing to progress in line with guidance. The warm-up process, through steam circulation, for the initial set of wells is ongoing and IPC continues to forecast first oil production from Blackrod Phase 1 in Q3 2026. Remaining central processing facility construction (CPF) handover and progressive commissioning is on track. Final construction works and commissioning of the CPF is ongoing, with additional well pairs scheduled for steam circulation in Q2 2026. Drilling of the final well pad commenced in Q4 2025 and is ongoing. To take advantage of the economies of scale and to provide additional well capacity, IPC plans to drill sixteen well pairs on the final pad, providing six additional sustaining well pairs beyond the original budget of the Phase 1 development. As of the end of Q4 2025, the fuel gas input line is in service and supporting well steam circulation operations. Final third-party export pipeline commissioning is progressing in line with plan with only minor work remaining ahead of all three lines being operational.

At Onion Lake Thermal in Canada, the four 2025 drilled production infill wells and the ninth and final Pad L sustaining well pair are online with continued production performance ahead of expectations.

In Malaysia, field development studies continued in Q4 2025 on the back of the successful A21 drilling and A15 well workover which was finalized in Q3 2025.

In France, field development studies continued in Q4 2025. The next three well sidetrack drilling targets at the Fontaine-au-Bron have been matured and are ready for sanction decision at the company's discretion.

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

**Production**
Average daily net production for Q4 2025 was at IPC's high end CMD guidance at 45,600 boepd. In Canada, strong operational performance has been supplemented by recent production infill well drilling at Onion Lake Thermal. Stable performance continued at IPC's Malaysian and French assets.

With strong operational delivery through 2025, IPC exits the year with a net average daily production for 2025 at the high end of our CMD guidance at 44,900 boepd.

The production during Q4 2025 with comparatives is summarized below:

| Production in Mboepd | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2025** | 2024 | **2025** | 2024 |
| **Crude oil** | | | | |
| Canada – Northern Assets | 15.4 | 14.6 | 14.7 | 14.2 |
| Canada – Southern Assets | 9.6 | 11.2 | 10.2 | 11.1 |
| Malaysia | 3.4 | 3.5 | 3.0 | 3.8 |
| France | 2.1 | 2.1 | 2.1 | 2.4 |
| **Total crude oil production** | **30.5** | 31.4 | **30.0** | 31.5 |
| **Gas** | | | | |
| Canada – Northern Assets | 0.4 | 0.5 | 0.4 | 0.5 |
| Canada – Southern Assets | 14.7 | 15.5 | 14.5 | 15.4 |
| **Total gas production** | **15.1** | 16.0 | **14.9** | 15.9 |
| **Total production** | **45.6** | 47.4 | **44.9** | 47.4 |
| **Quantity in MMboe** | **4.19** | 4.36 | **16.38** | 17.34 |

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

## CANADA

| Production in Mboepd | Working Interest (WI) | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|---|
| | | 2025 | 2024 | 2025 | 2024 |
| - Oil Onion Lake Thermal | 100% | 12.7 | 12.2 | 12.2 | 12.3 |
| - Oil Suffield Area | 100% | 8.5 | 9.8 | 8.9 | 9.7 |
| - Oil Other | 50-100% | 3.7 | 3.8 | 3.8 | 3.3 |
| - Gas | ~100% | 15.1 | 16.0 | 14.9 | 15.9 |
| Canada | | **40.0** | 41.8 | **39.8** | 41.2 |

**Production**
Net production from IPC's assets in Canada during Q4 2025 was ahead of guidance at 40,000 boepd with continued strong operational performance at the major oil and gas producing assets. At Onion Lake Thermal, recent production infill well drilling contributed to strong production rates during the quarter. At Mooney, the Phase 2 polymer flood project continues to deliver ahead of expectations.

## MALAYSIA

| Production in Mboepd | WI | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|---|
| | | 2025 | 2024 | 2025 | 2024 |
| Bertam | 100% | **3.4** | 3.5 | **3.0** | 3.8 |

**Production**
Net production at Bertam in Malaysia in Q4 2025 was in line with guidance at 3,400 boepd. Planned maintenance shutdown activity was completed on time and in line with budget in early Q4 2025.

## FRANCE

| Production in Mboepd | WI | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|---|
| | | 2025 | 2024 | 2025 | 2024 |
| France | | | | | |
| - Paris Basin | 100%[1] | 1.7 | 1.8 | 1.8 | 2.1 |
| - Aquitaine | 50% | 0.3 | 0.3 | 0.3 | 0.3 |
| | | **2.0** | 2.1 | **2.1** | 2.4 |

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

**Production**
Net production in France during Q4 2025 was in line with guidance at 2,000 boepd with stable performance across all the major producing fields.

## FINANCIAL REVIEW

### Financial Results

### *Selected Annual Financial Information*

Selected consolidated statement of operations is as follows:

| USD Thousands | 2025 | 2024 | 2023 |
|---|---|---|---|
| Revenue | **685,888** | 797,783 | 853,906 |
| Gross profit | **128,120** | 210,171 | 250,514 |
| Net result | **28,942** | 102,219 | 172,979 |
| Earnings per share – USD | **0.25** | 0.82 | 1.31 |
| Earnings per share fully diluted – USD | **0.25** | 0.81 | 1.28 |
| Operating cash flow[1] | **258,903** | 341,989 | 353,048 |
| Free cash flow[1] | **(153,134)** | (135,497) | 2,689 |
| EBITDA[1] | **243,537** | 335,488 | 350,618 |
| Net cash / (debt) at period end[1] | **(483,615)** | (208,528) | 58,043 |

[1] *See definition on page 21 under "Non-IFRS measures"*

Summarized consolidated balance sheet information is as follows:

| USD Thousands | December 31, 2025 | December 31, 2024 | December 31, 2023 |
|---|---|---|---|
| Non-current assets | 1,847,327 | 1,554,833 | 1,372,388 |
| Current assets | 130,302 | 398,849 | 690,597 |
| **Total assets** | **1,977,629** | 1,953,682 | 2,062,985 |
| Total non-current liabilities | 890,204 | 806,134 | 779,838 |
| Current liabilities | 160,248 | 208,078 | 202,888 |
| **Total liabilities** | **1,050,452** | 1,014,212 | 982,726 |
| **Net assets** | **927,177** | 939,470 | 1,080,259 |
| **Working capital (including cash)** | **(29,946)** | 190,771 | 487,709 |

### *Selected Interim Financial Information*

Selected interim condensed consolidated statement of operations is as follows:

| USD Thousands | 2025 | Q4-25 | Q3-25 | Q2-25 | Q1-25 | 2024 | Q4-24 | Q3-24 | Q2-24 | Q1-24 |
|---|---|---|---|---|---|---|---|---|---|---|
| Revenue | **685,888** | 176,207 | 172,297 | 158,892 | 178,492 | **797,783** | 199,124 | 173,200 | 219,040 | 206,419 |
| Gross profit | **128,120** | 28,242 | 32,066 | 23,663 | 44,149 | **210,171** | 42,774 | 39,505 | 72,708 | 55,184 |
| Net result | **28,942** | (4,942) | 3,802 | 13,850 | 16,231 | **102,219** | 415 | 22,875 | 45,210 | 33,719 |
| Earnings per share – USD | **0.25** | (0.04) | 0.03 | 0.12 | 0.14 | **0.82** | 0.00 | 0.19 | 0.36 | 0.27 |
| Earnings per share fully diluted – USD | **0.25** | (0.04) | 0.03 | 0.12 | 0.13 | **0.81** | 0.00 | 0.18 | 0.36 | 0.26 |
| Operating cash flow[1] | **258,903** | 63,138 | 66,102 | 54,873 | 74,790 | **341,989** | 78,158 | 72,589 | 101,941 | 89,301 |
| Free cash flow[1] | **(153,134)** | (28,627) | (23,083) | (58,252) | (43,172) | **(135,497)** | (61,476) | (38,269) | 7,559 | (43,311) |
| EBITDA[1] | **243,537** | 58,966 | 62,106 | 51,519 | 70,946 | **335,488** | 76,184 | 68,313 | 103,971 | 87,020 |
| Net cash/(debt) at period end[1] | **(483,615)** | (483,615) | (434,822) | (374,977) | (314,255) | **(208,528)** | (208,528) | (157,228) | (88,220) | (60,572) |

[1] *See definition on page 21 under "Non-IFRS measures"*

### *Selected Interim Financial Information*

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

| | Three months ended – December 31, 2025 | | | | | |
|---|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Other | Total |
| Crude oil | 86,933 | 46,004 | 23,545 | 10,154 | – | **166,636** |
| NGLs | – | 155 | – | – | – | **155** |
| Gas | 108 | 13,078 | – | – | – | **13,186** |
| **Net sales of oil and gas** | **87,041** | **59,237** | **23,545** | **10,154** | – | **179,977** |
| Change in under/over lift position | – | – | – | 1,064 | – | **1,064** |
| Royalties | (11,807) | (5,808) | – | (473) | – | **(18,088)** |
| Hedging settlement | 7,274 | 5,659 | – | – | – | **12,933** |
| Other operating revenue | – | – | – | 204 | 117 | **321** |
| **Revenue** | **82,508** | **59,088** | **23,545** | **10,949** | **117** | **176,207** |
| Operating costs | (28,727) | (29,076) | (10,091) | (9,173) | – | **(77,067)** |
| Cost of blending | (26,822) | (4,362) | – | – | – | **(31,184)** |
| Change in inventory position | 3 | (65) | (5,622) | (16) | – | **(5,700)** |
| Depletion and decommissioning costs | (9,952) | (12,076) | (7,048) | (3,091) | – | **(32,167)** |
| Depreciation of other tangible fixed assets | – | – | (800) | – | – | **(800)** |
| Exploration and business development costs | – | – | (698) | (15) | (334) | **(1,047)** |
| **Gross profit/(loss)** | **17,010** | **13,509** | **(714)** | **(1,346)** | **(217)** | **28,242** |

| USD Thousands | Three months ended – December 31, 2024 | | | | | |
|---|---|---|---|---|---|---|
| | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Other | Total |
| Crude oil | 96,884 | 63,453 | 29,675 | 21,039 | – | 211,051 |
| NGLs | – | 165 | – | – | – | 165 |
| Gas | 69 | 8,990 | – | – | – | 9,059 |
| Net sales of oil and gas | 96,953 | 72,608 | 29,675 | 21,039 | – | 220,275 |
| Change in under/over lift position | – | – | – | (6,379) | – | (6,379) |
| Royalties | (14,048) | (10,690) | – | (821) | – | (25,559) |
| Hedging settlement | 5,430 | 5,012 | – | – | – | 10,442 |
| Other operating revenue | – | – | – | 244 | 101 | 345 |
| Revenue | 88,335 | 66,930 | 29,675 | 14,083 | 101 | 199,124 |
| Operating costs | (23,554) | (35,573) | (9,386) | (10,926) | – | (79,439) |
| Cost of blending | (29,653) | (6,383) | – | – | – | (36,036) |
| Change in inventory position | (741) | 434 | (4,750) | 424 | – | (4,633) |
| Depletion and decommissioning costs | (9,141) | (12,960) | (7,273) | (2,713) | – | (32,087) |
| Depreciation of other tangible fixed assets | – | – | (2,430) | – | – | (2,430) |
| Exploration and business development costs | – | – | (1,407) | (12) | (306) | (1,725) |
| **Gross profit/(loss)** | 25,246 | 12,448 | 4,429 | 856 | (205) | 42,774 |

| USD Thousands | Year ended – December 31, 2025 | | | | | |
|---|---|---|---|---|---|---|
| | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Other | Total |
| Crude oil | 370,788 | 218,627 | 66,330 | 46,301 | – | **702,046** |
| NGLs | – | 690 | – | – | – | **690** |
| Gas | 312 | 38,878 | – | – | – | **39,190** |
| **Net sales of oil and gas** | **371,100** | **258,195** | **66,330** | **46,301** | – | **741,926** |
| Change in under/over lift position | – | – | – | 5,349 | – | **5,349** |
| Royalties | (51,128) | (32,101) | – | (2,976) | – | **(86,205)** |
| Hedging settlement | 10,553 | 13,126 | – | – | – | **23,679** |
| Other operating revenue | – | – | – | 776 | 363 | **1,139** |
| **Revenue** | **330,525** | **239,220** | **66,330** | **49,450** | **363** | **685,888** |
| Operating costs | (90,400) | (126,659) | (41,348) | (33,962) | – | **(292,369)** |
| Cost of blending | (114,087) | (20,543) | – | – | – | **(134,630)** |
| Change in inventory position | 146 | (574) | 247 | (443) | – | **(624)** |
| Depletion and decommissioning costs | (37,994) | (49,455) | (24,194) | (11,106) | – | **(122,749)** |
| Depreciation of other tangible fixed assets | – | – | (5,597) | – | – | **(5,597)** |
| Exploration and business development costs | – | – | (698) | (15) | (1,086) | **(1,799)** |
| **Gross profit/(loss)** | **88,190** | **41,989** | **(5,260)** | **3,924** | **(723)** | **128,120** |

| USD Thousands | Year ended – December 31, 2024 | | | | | |
|---|---|---|---|---|---|---|
| | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Other | Total |
| Crude oil | 405,090 | 273,004 | 105,445 | 70,948 | – | 854,487 |
| NGLs | – | 927 | – | – | – | 927 |
| Gas | 264 | 33,776 | – | – | – | 34,040 |
| Net sales of oil and gas | 405,354 | 307,707 | 105,445 | 70,948 | – | 889,454 |
| Change in under/over lift position | – | – | – | 41 | – | 41 |
| Royalties | (67,613) | (43,501) | – | (4,285) | – | (115,399) |
| Hedging settlement | 12,096 | 10,274 | – | – | – | 22,370 |
| Other operating revenue | – | – | – | 914 | 403 | 1,317 |
| Revenue | 349,837 | 274,480 | 105,445 | 67,618 | 403 | 797,783 |
| Operating costs | (84,018) | (141,757) | (32,771) | (35,464) | – | (294,010) |
| Cost of blending | (126,936) | (25,799) | – | – | – | (152,735) |
| Change in inventory position | (4) | (590) | (1,024) | 145 | – | (1,473) |
| Depletion and decommissioning costs | (36,554) | (52,029) | (27,481) | (12,328) | – | (128,392) |
| Depreciation of other tangible fixed assets | – | – | (8,933) | – | – | (8,933) |
| Exploration and business development costs | – | – | (1,407) | (12) | (650) | (2,069) |
| Gross profit/(loss) | 102,325 | 54,305 | 33,829 | 19,959 | (247) | 210,171 |

### *Three months and year ended December 31, 2025, Review*

**Revenue**

Total revenue amounted to USD 176,207 thousand for Q4 2025, compared to USD 199,124 thousand for Q4 2024 and USD 685,888 thousand for the year ended December 31, 2025 compared to USD 797,783 thousand for the year ended December 31, 2024 and is analyzed as follows:

| USD Thousands | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2025** | 2024 | **2025** | 2024 |
| Crude oil sales | 166,636 | 211,051 | 702,046 | 854,487 |
| Gas and NGL sales | 13,341 | 9,224 | 39,880 | 34,967 |
| Change in under/overlift position | 1,064 | (6,379) | 5,349 | 41 |
| Royalties | (18,088) | (25,559) | (86,205) | (115,399) |
| Hedging settlement | 12,933 | 10,442 | 23,679 | 22,370 |
| Other operating revenue | 321 | 345 | 1,139 | 1,317 |
| **Total revenue** | **176,207** | 199,124 | **685,888** | 797,783 |

The main components of total revenue for the three months and year ended December 31, 2025, and December 31, 2024, respectively, are detailed below.

***Crude oil sales***

| | Three months ended – December 31, 2025 | | | | |
|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total |
| Crude oil sales | | | | | |
| - Revenue in USD thousands | 86,933 | 46,004 | 23,545 | 10,154 | **166,636** |
| - Quantity sold in bbls | 1,833,241 | 957,670 | 347,943 | 158,369 | **3,297,223** |
| - Average price realized USD per bbl | 47.42 | 48.04 | 67.67 | 64.12 | **50.54** |

| | Three months ended – December 31, 2024 | | | | |
|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total |
| Crude oil sales | | | | | |
| - Revenue in USD thousands | 96,884 | 63,453 | 29,675 | 21,039 | 211,051 |
| - Quantity sold in bbls | 1,715,195 | 1,088,790 | 379,569 | 284,053 | 3,467,607 |
| - Average price realized USD per bbl | 56.49 | 58.28 | 78.18 | 74.07 | 60.86 |

Crude oil revenue was 21% lower in Q4 2025 compared to Q4 2024 mainly due to lower prices. Canadian-Northern Assets sales volumes are 7% higher in Q4 2025 compared to Q4 2024 as a result of sustaining capital investment activities undertaken at Onion Lake Thermal.

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 Q4 2025, WTI averaged USD 59 per bbl compared to USD 70 per bbl for Q4 2024 and the average discount to WCS used in IPC's pricing formula was USD 11 per bbl compared to USD 13 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 were two cargo liftings in Malaysia during Q4 2025 and two cargo liftings in Q4 2024. Produced unsold oil barrels from Bertam at the end of Q4 2025 amounted to 106,000 barrels, see Change in Inventory Position section below. The average Dated Brent crude oil price was USD 64 per bbl for Q4 2025 compared to USD 75 per bbl for the comparative period in 2024.

| | Year ended – December 31, 2025 | | | | |
|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total |
| Crude oil sales | | | | | |
| - Revenue in USD thousands | 370,788 | 218,627 | 66,330 | 46,301 | **702,046** |
| - Quantity sold in bbls | 6,986,416 | 4,044,356 | 928,010 | 665,536 | **12,624,318** |
| - Average price realized USD per bbl | 53.07 | 54.06 | 71.48 | 69.57 | **55.61** |

| | Year ended – December 31, 2024 | | | | |
|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total |
| Crude oil sales | | | | | |
| - Revenue in USD thousands | 405,090 | 273,004 | 105,445 | 70,948 | 854,487 |
| - Quantity sold in bbls | 6,727,693 | 4,442,570 | 1,224,980 | 886,766 | 13,282,009 |
| - Average price realized USD per bbl | 60.21 | 61.45 | 86.08 | 80.01 | 64.33 |

The Suffield area assets and Onion Lake 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.

Crude oil revenue was lower by 18% during 2025 compared to 2024 due to oil prices lower by 14% and sales volume lower by 5%.

The Canadian realized sales price is based on the WCS price which trades at a discount to WTI. For the year ended December 31, 2025, WTI averaged USD 65 per bbl compared to USD 76 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 15 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 69 per bbl for the year ended December 31, 2025 compared to USD 81 per bbl for the comparative period.

***Gas and NGL sales***

| | Three months ended – December 31, 2025 | | |
|---|---|---|---|
| | Canada – Northern Assets | Canada – Southern Assets | Total |
| **Gas and NGL sales** | | | |
| - Revenue in USD thousands | 108 | 13,233 | **13,341** |
| - Quantity sold in Mcf | 75,328 | 7,715,625 | **7,490,953** |
| - Average price realized USD per Mcf | 1.43 | 1.78 | **1.78** |

| | Three months ended – December 31, 2024 | | |
|---|---|---|---|
| | Canada – Northern Assets | Canada – Southern Assets | Total |
| Gas and NGL sales | | | |
| - Revenue in USD thousands | 69 | 9,155 | 9,224 |
| - Quantity sold in Mcf | 76,102 | 7,791,291 | 7,867,393 |
| - Average price realized USD per Mcf | 0.91 | 1.18 | 1.17 |

Gas and NGL sales revenue was 45% higher for the Q4 2025 compared to Q4 2024 due to the higher achieved gas price.

IPC's achieved gas price is based on AECO pricing plus a premium. For Q4 2025, IPC realized an average price of CAD 2.46 per Mcf compared to AECO average pricing of CAD 2.16 per Mcf.

| | Year ended – December 31, 2025 | | |
|---|---|---|---|
| | Canada – Northern Assets | Canada – Southern Assets | Total |
| **Gas and NGL sales** | | | |
| - Revenue in USD thousands | 312 | 39,568 | **39,880** |
| - Quantity sold in Mcf | 287,570 | 29,027,623 | **29,315,193** |
| - Average price realized USD per Mcf | 1.08 | 1.36 | **1.36** |

| | Year ended – December 31, 2024 | | |
|---|---|---|---|
| | Canada – Northern Assets | Canada – Southern Assets | Total |
| Gas and NGL sales | | | |
| - Revenue in USD thousands | 264 | 34,703 | 34,967 |
| - Quantity sold in Mcf | 284,209 | 30,601,443 | 30,885,652 |
| - Average price realized USD per Mcf | 0.93 | 1.13 | 1.13 |

Gas and NGL sales revenue was 14% higher for 2025 compared to 2024 mainly due to the higher achieved gas price.

IPC's achieved gas price is based on AECO pricing plus a premium. For the year ended December 31, 2025, IPC realized an average price of CAD 1.87 per Mcf compared to AECO average pricing of CAD 1.63 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 year ended December 31, 2025 amounted to a gain of USD 23,679 thousand and consisted of a gain of USD 17,869 thousand on the oil contracts and a gain of USD 5,810 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 113,951 thousand for Q4 2025 compared to USD 120,108 thousand for Q4 2024 and USD 427,623 thousand for the full year 2025 compared to USD 448,218 thousand for the full year 2024, and is analyzed as follows:

| | Three months ended – December 31, 2025 | | | | | |
|---|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Other[3] | Total |
| **Operating costs[1]** | 28,727 | 29,076 | 10,091 | 9,173 | – | **77,067** |
| USD/boe[2] | 19.75 | 13.02 | 31.95 | 48.50 | n/a | **18.38** |
| **Cost of blending** | 26,822 | 4,362 | – | – | – | **31,184** |
| **Change in inventory position** | (3) | 65 | 5,622 | 16 | – | **5,700** |
| **Production costs** | **55,546** | **33,503** | **15,713** | **9,189** | – | **113,951** |

| | Three months ended – December 31, 2024 | | | | | |
|---|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Other[3] | Total |
| Operating costs[1] | 23,554 | 35,573 | 13,418 | 10,926 | (4,032) | 79,439 |
| USD/boe[2] | 17.04 | 14.47 | 41.31 | 55.91 | n/a | 18.21 |
| Cost of blending | 29,653 | 6,383 | – | – | – | 36,036 |
| Change in inventory position | 741 | (434) | 4,750 | (424) | – | 4,633 |
| Production costs | 53,948 | 41,522 | 18,168 | 10,502 | (4,032) | 120,108 |

| | Year ended – December 31, 2025 | | | | | |
|---|---|---|---|---|---|---|
| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Other[3] | Total |
| **Operating costs[1]** | 90,400 | 126,659 | 44,876 | 33,962 | (3,528) | **292,369** |
| USD/boe[2] | 16.36 | 14.07 | 41.40 | 43.83 | n/a | **17.84** |
| **Cost of blending** | 114,087 | 20,543 | – | – | – | **134,630** |
| **Change in inventory position** | (146) | 574 | (247) | 443 | – | **624** |
| **Production costs** | **204,341** | **147,776** | **44,629** | **34,405** | **(3,528)** | **427,623** |

| USD Thousands | Year ended – December 31, 2024 Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Other[3] | Total |
|---|---|---|---|---|---|---|
| Operating costs[1] | 84,018 | 141,757 | 49,089 | 35,464 | (16,318) | 294,010 |
| USD/boe[2] | 15.74 | 14.60 | 34.85 | 40.13 | n/a | 16.96 |
| Cost of blending | 126,936 | 25,799 | – | – | – | 152,735 |
| Change in inventory position | 4 | 590 | 1,024 | (145) | – | 1,473 |
| Production costs | 210,958 | 168,146 | 50,113 | 35,319 | (16,318) | 448,218 |

*[1] See definition on page 21 under "Non-IFRS measures".*
*[2] USD/boe in the tables above is calculated by dividing the cost by the production volume for each country for the period and for 2024.*
*[3] Included in the Malaysia operating costs is the lease cost for the FPSO Bertam which is owned by the Group. Other represents the FPSO Bertam lease fee self-to-self payment elimination. Netting the self-to-self elimination against the operating costs in Malaysia reduces the operating costs per boe for Malaysia to USD 31.95 for Q4 2025 and USD 28.89 for the comparative period and USD 38.14 and USD 23.27 for the year ended December 31, 2025, and December 31, 2024, respectively.*

**Operating costs**
Operating costs amounted to USD 77,067 thousand for Q4 2025 compared to USD 79,439 thousand for Q4 2024 and USD 292,369 thousand for 2025 compared to USD 294,010 thousand for 2024. Operating costs per boe amounted to USD 18.38 per boe in Q4 2025 in line with the guidance for the quarter and compared with USD 18.21 per boe in Q4 2024.

**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 31,184 thousand for Q4 2025 compared to USD 36,036 thousand for Q4 2024 and USD 134,630 thousand for 2025 compared to USD 152,735 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 Q4 2025, IPC had crude entitlement of 106,000 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 32,167 thousand for Q4 2025 compared to USD 32,087 thousand for Q4 2024 and USD 122,749 thousand for the full year 2025 compared to USD 128,392 thousand for the full year 2024.
The depletion charge is analyzed in the following tables:

| USD Thousands | Three months ended – December 31, 2025 Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total |
|---|---|---|---|---|---|
| **Depletion cost in USD thousands** | 9,952 | 12,076 | 7,048 | 3,091 | **32,167** |
| **USD per boe** | 6.84 | 5.41 | 22.32 | 16.34 | **7.67** |

| USD Thousands | Three months ended – December 31, 2024 Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total |
|---|---|---|---|---|---|
| Depletion cost in USD thousands | 9,141 | 12,960 | 7,273 | 2,713 | 32,087 |
| USD per boe | 6.61 | 5.27 | 22.39 | 13.88 | 7.36 |

| USD Thousands | Year ended – December 31, 2025 Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total |
|---|---|---|---|---|---|
| **Depletion cost in USD thousands** | 37,994 | 49,455 | 24,194 | 11,106 | **122,749** |
| **USD per boe** | 6.88 | 5.50 | 22.32 | 14.33 | **7.49** |

| USD Thousands | Year ended – December 31, 2024 Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total |
|---|---|---|---|---|---|
| Depletion cost in USD thousands | 36,554 | 52,029 | 27,481 | 12,328 | 128,392 |
| USD per boe | 6.85 | 5.36 | 19.51 | 13.95 | 7.40 |

The depletion charge is derived by applying the depletion rate per boe to the volumes produced in the period by each field.

**Depreciation of other tangible fixed assets**
The total depreciation of other tangible fixed assets amounted to USD 800 thousand for Q4 2025 compared to USD 2,430 thousand for Q4 2024 and USD 5,597 thousand for the year ended December 31, 2025 compared to USD 8,933 thousand for the year ended December 31, 2024. This relates to the depreciation of the FPSO Bertam, which has been depreciated to its residual value.

**Exploration and business development costs**
The total exploration and business developments costs amounted to a cost of USD 1,799 thousand for the year ended December 31, 2025 and USD 2,069 thousand for the comparative period.

**Net financial items**
Net financial items amounted to a charge of USD 65,765 thousand for the year ended December 31, 2025 compared to a charge of USD 59,709 thousand for the year ended December 31, 2024. Net financial items included a realized currency hedge loss of USD 9,029 thousand and a net foreign exchange gain of USD 14,654 thousand for 2025 compared to a realized currency hedge loss of USD 10,773 thousand and a net foreign exchange loss of USD 12,654 thousand for the year ended December 31, 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 71,390 thousand for the year ended December 31, 2025 compared to USD 36,282 thousand for the year ended December 31, 2024.

The interest expense amounted to USD 41,983 thousand for the year ended December 31, 2025 compared to USD 35,905 thousand for the comparative period in 2024, mainly related to the bond interest at a fixed coupon rate of 7.25% per annum for the previous bonds and of 7.5% for the new bonds from October 2025. In Q4 2025, the remaining capitalized bond discount recognized in the balance sheet with the completion of the tap issue of USD 150 million in 2023 were charged to the interest expense line. Interest income generated on cash balances held amounted to USD 3,160 thousand for the year ended December 31, 2025 and USD 17,721 thousand for the year ended December 31, 2024.

In Q4 2025, net financial items included approximately USD 16 million of costs relating to the refinancing of the USD 450 million senior unsecured bonds. That amount includes the call option paid (cash cost) to redeem the previous bonds as well as the amortisation (non-cash) of prior costs associated with the issuance of a portion of the previous bonds. The cash costs associated with the issuance of the new bonds are capitalised and will be amortised over the tenor of these bonds. The total cash costs from the new bonds issuance amounted to approximately USD 18 million. See "Financial Position and Liquidity – Financing" below.

The unwinding of the asset retirement obligation discount rate amounted to USD 16,498 thousand for the year ended December 31, 2025 compared to USD 14,568 thousand for the year ended December 31, 2024.

**Income tax**
The corporate income tax amounted to a charge of USD 17,380 thousand for the year ended December 31, 2025 compared to a charge of USD 33,325 thousand for the year ended December 31, 2024.

The current income tax amounted to a charge of USD 9 thousand for the year ended December 31, 2025 and a charge of USD 8,313 thousand the year ended December 31, 2024 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 during the year ended December 31, 2025 was as follows:

| USD Thousands | Canada – Northern Assets | Canada – Southern Assets | Malaysia | France | Total |
|---|---|---|---|---|---|
| Development | 278,933 | 8,942 | 40,877 | 5,759 | **334,511** |
| Exploration and evaluation | 3,731 | – | – | 15 | **3,746** |
| | 282,664 | 8,942 | 40,877 | 5,774 | **338,257** |

Capital expenditures of USD 338,257 thousand was mainly spent in Canada on the Blackrod Phase 1 Development project and in Malaysia for the A21 infill well drilling.

On October 24, 2025, IPC completed an acquisition of certain undeveloped petroleum and natural gas mineral rights adjacent to our Blackrod oilsands project in Northern Alberta for total purchase consideration of USD 7.3 million (CAD 10 million).

**Other tangible fixed assets**
Other tangible fixed assets amounted to USD 11,220 thousand as at December 31, 2025, which included USD 9,200 thousand in respect of the FPSO Bertam. The FPSO Bertam has been depreciated to its residual value.

## Financial Position and Liquidity

**Financing**
As at January 1, 2025, IPC had MUSD 450 of senior unsecured bonds outstanding, maturing in February 2027 with a fixed coupon rate of 7.25% per annum. In October 2025, IPC completed the issuance of USD 450 million of new senior unsecured bonds, maturing in October 2030 with a fixed coupon rate of 7.50% per annum, payable in semi-annual instalments in April and October, and with semi-annual amortizations of USD 25 million commencing in April 2028. The proceeds of the new bonds were used to fully redeem and cancel the previous bonds. IPC exercised its call option to redeem the previous bonds at a price equal to 102.18% of the nominal amount, plus accrued and unpaid interest. The cash refinancing costs, which include the call option costs of the previous bonds, and the related transaction costs, incurred in Q4 2025, amounted to approximately USD 18 million.

The bond repayment obligations as at December 31, 2025, are classified as non-current as there are no mandatory repayments within the next twelve months.

In addition, as at December 31, 2025, the Group had a senior secured revolving credit facility of CAD 250 million (the "Canadian RCF") in connection with its oil and gas assets in Canada, with a maturity date in May 2027. As at December 31, 2025, CAD 53 million (approximately USD 39 million) was drawn under the Canadian RCF. As at December 31, 2025, the Group also had a letter of credit facility in Canada (the "LC Facility") to cover operational letters of credit. As at December 31, 2025, operational letters of credit in an aggregate of CAD 19.7 million have been issued under the LC Facility, of which one letter of credit of CAD 5.3 million was fully released in January 2026.

As at December 31, 2025, IPC had an unsecured Euro credit facility in France (the "France Facility"), with maturity in May 2026. IPC makes quarterly repayments of the France Facility and the amount remaining outstanding under the France Facility as at December 31, 2025 was USD 1.9 million (EUR 1.7 million) which is classified as current representing the repayment planned within the next twelve months.

The Group is in compliance with the covenants of the bonds and its financing facilities as at December 31, 2025.

Net debt as at December 31, 2025 amounted to USD 484 million. Cash and cash equivalents held amounted to USD 7 million as at December 31, 2025.

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

**Working Capital**
As at December 31, 2025, the Group had a working capital balance including cash of negative USD 29,946 thousand compared to USD 190,771 thousand as at December 31, 2024. The difference 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 and administrative expenses before depreciation and less cash financial items. Free cash flow is used to analyze the amount of cash that is being generated by the business and that is available for such purposes as repaying debt, funding acquisitions and returning capital to shareholders.

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

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

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

### Reconciliation of Non-IFRS Measures

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

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| USD Thousands | **2025** | 2024 | **2025** | 2024 |
| Revenue | 176,207 | 199,124 | 685,888 | 797,783 |
| Production costs and net sales of diluent to third party[1] | (113,814) | (119,371) | (426,976) | (447,481) |
| Current tax | 745 | (1,595) | (9) | (8,313) |
| Operating cash flow | **63,138** | 78,158 | **258,903** | 341,989 |

*[1] Includes net sales of diluent to third party amounting to USD 137 thousand for the fourth quarter of 2025 and USD 647 thousand for the year ended December 31, 2025.*

**Free cash flow**

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

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| USD Thousands | 2025 | 2024 | 2025 | 2024 |
| Operating cash flow - see above | 63,138 | 78,158 | 258,903 | 341,989 |
| Capital expenditures | (61,318) | (126,256) | (338,257) | (434,713) |
| Abandonment and farm-in expenditures[1] | (1,810) | (3,364) | 1,146 | (8,302) |
| General, administration and depreciation expenses before depreciation[2] | (3,427) | (3,569) | (15,375) | (14,814) |
| Cash financial items[3] | (25,210) | (6,445) | (59,551) | (19,657) |
| Free cash flow | **(28,627)** | (61,476) | **(153,134)** | (135,497) |

*[1] See 19 to the Financial Statements. Includes in 2025 secured amounts received of USD 7.7 million towards the future asset retirement obligation for the Bertam field.*
*[2] Depreciation is not specifically disclosed in the Financial Statements.*
*[3] See notes 5 and 6 to the Financial Statements.*

**EBITDA**

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

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| USD Thousands | 2025 | 2024 | 2025 | 2024 |
| Net result | (4,941) | 415 | 28,942 | 102,219 |
| Net financial items | 26,039 | 35,767 | 65,765 | 59,709 |
| Income tax | 3,504 | 3,852 | 17,380 | 33,325 |
| Depletion and decommissioning costs | 32,167 | 32,087 | 122,749 | 128,392 |
| Depreciation of other tangible fixed assets | 800 | 2,430 | 5,597 | 8,933 |
| Exploration and business development costs | 1,047 | 1,725 | 1,799 | 2,069 |
| Sale of assets[1] | – | (400) | (104) | (400) |
| Depreciation included in general and administrative expenses[2] | 350 | 308 | 1,409 | 1,241 |
| EBITDA | **58,966** | 76,184 | **243,537** | 335,488 |

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

**Operating costs**

The following table sets out how operating costs is calculated:

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| USD Thousands | 2025 | 2024 | 2025 | 2024 |
| Production costs | 113,951 | 120,108 | 427,623 | 448,218 |
| Cost of blending | (31,184) | (36,036) | (134,630) | (152,735) |
| Change in inventory position | (5,700) | (4,633) | (624) | (1,473) |
| Operating costs | **77,067** | 79,439 | **292,369** | 294,010 |

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

| USD Thousands | December 31, 2025 | December 31, 2024 |
|---|---|---|
| Bank loans | (40,652) | (5,121) |
| Bonds | (450,000) | (450,000) |
| Cash and cash equivalents | 7,037 | 246,593 |
| Net cash/(debt) | **(483,615)** | (208,528) |

## Off-Balance Sheet Arrangements

IPC, through its subsidiary IPC Canada Ltd, had issued seven letters of credit as at December 31, 2025 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 respect of the hedging of electricity prices; (e) MCAD 3.9 in respect of electricity distribution services; and (f) two letters of credit of MCAD 5.3 each in respect of the land acquisition completed in October 2025, of which one letter of credit of MCAD 5.3 was fully released in January 2026.

## 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, with IPC being 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 December 4, 2025, IPC purchased and cancelled 6,641,970 common shares under the NCIB and 261,818 common shares under certain other exemptions in Canada.

As at December 31, 2025 and February 10, 2026, IPC had a total of 112,155,527 common shares issued and outstanding, with no common shares held in treasury.

Nemesia S.à.r.l., an investment company ultimately controlled by trusts whose settlor is the late Adolf H. Lundin, holds 42,597,533 common shares in IPC, representing 38.0% of the outstanding common shares as at December 31, 2025.

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

IPC has 2,577,198 IPC Share Unit Plan awards outstanding as at February 10, 2026 of which 789,431 awards were granted in 2026.

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

## Contractual Obligations and Commitments

In the normal course of business, the Group has committed to certain payments which are not recognized as liabilities. The following table summarizes the Group's commitments in Canada as at December 31, 2025:

| MCAD | 2026 | 2027 | 2028 | 2029 | 2030 | Thereafter |
|---|---|---|---|---|---|---|
| Transportation service[1] | 60.4 | 91.6 | 99.1 | 103.1 | 103.9 | 1,384.7 |
| Power[2] | 12.4 | 12.4 | 9.8 | – | – | – |
| **Total commitments** | **72.8** | **104.0** | **108.9** | **103.1** | **103.9** | **1,384.7** |

*[1] IPC has firm transportation commitments on oil and natural gas pipelines that expire between 2037 and 2046.*
*[2] IPC has physical delivery power hedges to purchase 15MWh at a weighted average price of CAD 74.92/MWh from January 1, 2026 to December 31, 2028, and an additional 5MWh at a weighted average price of CAD 58.31/MWh from January 1, 2026 to December 31, 2027.*

## Material Accounting Policies and Estimates

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

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

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

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

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

Provisions for asset retirement obligations are based on estimates of future decommissioning and restoration costs, reflecting current legal and constructive requirements, available technology and prevailing price levels. Actual cash outflows may differ from estimates due to changes in legislation, technical requirements or cost levels, and therefore these provisions are reviewed on a regular basis.

***Deferred income tax assets***

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

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

## Transactions with Related Parties

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

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

During the year 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 December 31, 2025, the Group 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 December 31, 2025, which are summarized as follows:

| Period | Volume (barrels per day) | Type | Average Pricing |
|---|---|---|---|
| January 1, 2026 - December 31, 2026 | 5,000 | WTI/WCS Differential | USD -12.50/bbl |

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

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

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

| Period | Volume (MWh) | Type | Average Pricing |
|---|---|---|---|
| January 1, 2026 - September 30, 2040 | 3 | AESO | CAD 75.00/MWh |

The above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. The hedges had a positive fair value of USD 2,507 thousand as at December 31, 2025.

In January 2026, the Group entered into the following oil price sale financial hedges:

| Period | Volume (barrels per day) | Type | Average Pricing |
|---|---|---|---|
| February 1, 2026 - June 30, 2026 | 5,000 | WTI Sale Swap | USD 60.04/bbl |
| February 1, 2026 - June 30, 2026 | 2,500 | WTI Sale Swap | USD 64.50/bbl |
| February 1, 2026 - June 30, 2026 | 1,500 | Brent Sale Swap | USD 66.67/bbl |

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

**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 its operations are subject to various risks and uncertainties which include, but are not limited to, those listed below. The risks and uncertainties below are not the only ones that the Group faces. Additional risks and uncertainties not presently known to the Group or that the Group currently considers immaterial may also impair the business and operations of the Group and cause the price of IPC's common shares ("Common Shares") to decline. If any of the following risks actually occur, the Group's business may be adversely affected, and the Group's financial condition and results of operations may suffer significantly.

See also "Cautionary Statement Regarding Forward-Looking Information" and "Reserves and Resources Advisory" below.

### Non Financial Risks

**Exploration, Development and Production Risks:** Oil and gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Group depends on its ability to find, acquire, develop and commercially produce oil and gas reserves. Without the continual addition of new reserves, any existing reserves associated with the Group's oil and gas assets at any particular time, and the production therefrom, will decline over time as such existing reserves are exploited. There is a risk that additional commercial quantities of oil and gas will not be discovered or acquired by the Group. Production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Future oil and gas development may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development of EOR technologies can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

IPC uses multi-well pad drilling in certain situations where practicable. With multi-well pad drilling, problems affecting a single well could adversely affect production from all other wells on the pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production, or interruption in ongoing production. These delays or interruptions may cause volatility in operating results.

Oil and gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, hydrocarbon releases and spills, each of which could result in substantial damage to oil and gas wells, production facilities, other property and the environment or personal injury. In accordance with industry practice, the Group will not fully insure against all of these risks, nor are all such risks insurable. The Group maintains liability insurance in an amount that it considers consistent with industry practice. Due to the nature of these risks, however, there is a risk that such liabilities could exceed policy limits, in which event the Group could incur significant costs.

**Volatility in Oil and Gas Commodity Prices and Price Differentials and Tariffs:** The demand for energy, including oil and gas, is generally linked to broad-based economic activities. If there was a slowdown in economic growth, an economic downturn or recession, or other adverse economic or political developments in the United States, Europe, Asia or elsewhere, there could be a significant adverse effect on global financial markets and commodity prices. In addition, current and potential future hostilities in the Middle East, Ukraine, South America and elsewhere and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy.

The marketability and price of oil and gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and gas may depend upon its ability to access space on pipelines that deliver oil and gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities, the capacity of such pipelines and facilities, and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and gas and many other aspects of the oil and gas business.

Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions in Europe, Asia, the United States, Canada and elsewhere, the actions of OPEC and OPEC+, strategic petroleum reserve management and imposition of tariffs by the United States, current and potential future conflicts in the Middle East, Ukraine, South America and elsewhere, the impact of pandemics, governmental regulation, political instability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources.

In 2025, the United States imposed tariffs on goods exported out of Canada into the United States, other than goods from both Canada and Mexico that are covered by the United States-Mexico-Canada Agreement. These tariffs, and any changes to these tariffs or imposition of any new tariffs, taxes or import or export restrictions or prohibitions, could have a material adverse effect on the Canadian oil and natural gas industry and the Corporation. Furthermore, there is a risk that the tariffs imposed by the U.S. on other countries could have a material adverse effect on the global economy, and by extension the Canadian oil and natural gas industry and the Corporation. It is uncertain how long the current tariffs will remain in place and what the impact will be on the prices of Canadian oil and gas and on the financial condition of the Corporation. The introduction of new trade policies or barriers, including the imposition of new tariffs, duties or other trade restrictions on Canadian hydrocarbon products exported to the U.S., or the imposition of new or retaliatory tariffs, duties or trade restrictions on hydrocarbon products imported into Canada from the U.S., could result in a decrease in, or increase the volatility of, commodity prices and/or price differentials which could, in turn, reduce the demand for oil and natural gas and have an adverse effect on the Corporation's business, financial condition and results of operations.

Oil and gas prices have fluctuated widely during recent years and may continue to be volatile in the future. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the carrying value of the reserves and resources, borrowing capacity, revenues, profitability and cash flows associated with the Group's assets and may have a material adverse effect on the business, financial condition, results of operations and prospects associated with the Group's assets.

The Group's financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials in Canada between the Group's heavy crude oil (in particular the heavy crude oil differential) and quoted market prices. The market price for heavy crude oil and bitumen in Canada is generally lower than market prices for light oil, due principally to the higher costs associated with refining a barrel of heavy crude oil and higher transportation costs (diluent is required to be purchased and blended with heavy crude oil to transport on most pipelines). Heavy crude oil differentials are also influenced by other factors such as capacity and interruptions, refining demand and the quality of the oil produced, all of which are beyond the Group's control. It is difficult to predict future price differentials and any increase in heavy crude oil differentials could have an adverse effect on the Group's business, financial condition, results of operations and cash flows.

In addition, there has not been, at times, sufficient pipeline capacity to export all Canadian crude oil and the availability of alternative transport capacity is more expensive and variable, therefore, the price for Canadian crude oil is very sensitive to pipeline and refinery outages. This has resulted in significantly lower prices being realized by Canadian producers compared with the WTI price and the Brent price for crude oil. In addition, the pro-rationing of capacity on inter-provincial pipeline systems may affect the ability to export oil and gas from Canada. There can be no certainty that current investment in pipelines will provide sufficient long-term export capacity or that currently operating systems will remain in service. There is also no certainty that short- term operational constraints on pipeline systems, arising from pipeline interruption, refinery outages and/or increased supply of crude oil, will not occur.

In order to transport crude oil production in Canada to sales markets, the Group is required to meet certain pipeline specifications. Heavy crude oil and bitumen is usually blended with diluent to increase its flow characteristics. The cost of diluent is generally correlated to crude oil prices. A shortfall in the supply of diluent may cause its price to increase which would adversely affect the Group's financial position and cash flow.

**Climate Change:** Climate change issues are an important factor for the oil and gas industry.

*Transition Risks*

The Group's facilities and operations, and the oil and gas that the Group markets, result in the emission of greenhouse gas ("GHG") which makes the Group subject to GHG emissions legislation and regulation. Governments continue to evaluate and implement policy, legislation, and regulations focused on restricting GHG emissions commonly and promoting adaptation to climate change. It is not possible to predict what measures governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented. Given the evolving nature of climate change policy and the control of GHG emissions and resulting requirements, including carbon taxes and carbon pricing schemes implemented by varying levels of government, it is expected that current and future climate change regulations will have the effect of increasing the Group's operating expenses, and, in the long-term, potentially reducing the value of oil and gas assets.

Regulatory climate change related risks arise from increased or amended environmental regulation. A breach of such regulations may result in the imposition of fines or issuance of clean up orders in respect of the Group or the Group's assets, some of which may be material. Furthermore, new environmental laws and regulation, particularly in relation to the reduction of, or limitations on, GHG emissions or emissions intensity could be implemented. There is a risk that any such programs, laws or regulations, if proposed and enacted, may contain emission reduction targets which will require substantial capital investments to adapt processes in place or lead to financial penalties or charges as a result of the failure to meet such targets.

Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. Implementation of strategies by any level of government within the countries in which the Corporation operates, and whether to meet international agreed limits, or as otherwise determined, for reducing GHGs could have a material impact on the operations and financial condition of the Corporation. Increased scrutiny of applications for oil and gas licenses, permits and authorizations to develop assets and projects could lead to delay, limit or prevent future development of assets or affect the productivity of assets and the costs associated.

In addition, concerns about climate change and public discussion that oil and gas operations may be associated with climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation, transportation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHGs and resulting requirements, it is not possible to predict the impact on the Group and its operations and financial condition.

Claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. Individuals, governmental authorities, or other organizations may make claims against oil and natural gas companies, including members of the Group, for alleged personal injury, property damage, or other potential liabilities. While no member of the Group is a party to any such litigation or proceedings, IPC could be named in actions making similar allegations. An unfavourable ruling in any such case could adversely affect the demand for and price of the Common Shares, impact the Group's operations and have an adverse impact on IPC's financial condition.

Emission and carbon tax regulations in Canada federally and regionally are evolving and as these regulations are established or amended, they may have an impact on companies involved in oil production in Canada. The federal Government of Canada established the Canadian Net-Zero Emissions Accountability Act that brings into law the commitment to achieve net-zero GHG emissions by 2050 and issued the 2030 Emissions Reduction Plan that describes the measures Canada is undertaking to reduce emissions to 40 to 45 percent below 2005 levels by 2030. In November 2024, the Government of Canada commenced a consultation process with respect to draft Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations, under which specific limits on emissions from the oil and gas sector would be imposed with the intention to reduce the carbon intensity of oil and gas production in Canada, with a focus on improving energy efficiency, fostering the adoption of cleaner technologies, and accelerating the transition to more sustainable practices. It is difficult to assess the overall impact all of these regulations will have on the Group at this time but it could result in increased costs to comply, delays in having projects approved and potentially a reduction in demand for oil from these regions, all of which could have a material negative impact on the Group's business. There remains uncertainty whether the Canadian federal government will in the future amend or replace these regulations. In November 2025, the Canadian federal government entered into a memorandum of understanding with the Alberta provincial government which may eliminate the proposed limits on emissions from the oil and gas sector.

The International Sustainability Standards Board ("ISSB") was created in 2021 with the aim to develop globally consistent, comparable and reliable sustainability disclosure standards. In 2023, the ISSB issued IFRS S1 "General Requirements for Disclosure of Sustainability-related Financial Information" and IFRS S2 "Climate-related Disclosures". The Corporation continues to evaluate the potential effects of the ISSB issued sustainability standards; however, at this time, the Corporation is not able to determine the impact on future financial statements, nor the potential costs to comply with these sustainability standards.

In December 2024, the Canadian Sustainability Standards Board released its voluntary and non-binding Canadian Sustainability Disclosure Standards modelled on those developed by the ISSB. While these Canadian standards are non-binding, they could influence the development by securities regulators of sustainability and climate-related reporting obligations for Canadian public companies under applicable Canadian law. In 2025, Canadian securities regulators stated that they have paused efforts to develop mandatory sustainability-related disclosure rules for public companies.

In 2024, Malaysia announced plans to introduce a carbon tax on the Malaysian energy industry commencing in 2026. The Group will continue to monitor this situation and, when further details are provided by the Malaysian authorities, will assess the potential effects of this proposed tax on the Group's business in Malaysia.

If the Group is not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, IPC's business and ability to attract and retain skilled employees, obtain regulatory permits, licences, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected.

*Physical Risks*

Physical climate change related risks can be event-driven with increased severity of extreme weather events, such as cyclones, hurricanes, wildfires, droughts or floods, or long-term shifts in climate patterns with sustained higher temperatures, water stress or sea level rise. These physical risks may have financial and operational implications for the Group, such as direct damage to assets and indirect impacts from supply chain disruption to the delivery of goods and services. Certain of IPC's oil and gas assets are in locations that are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage.

**Sustainability Targets and Disclosures:** IPC is targeting to reduce its net GHG emissions intensity. IPC's ability to achieve these targets is subject to numerous risks and uncertainties, and actions taken in implementing these objectives may also expose the Group to certain additional and/or heightened financial and operational risks. In addition, the cost associated with achieving emissions reductions targets and other climate and sustainability targets could be significant, and could require significant capital expenditures and resources, potentially including the acquisition of technology, with the potential that the costs required to achieve targets could differ from original estimates and expectations, which differences may be material. Failure to achieve emissions, climate or sustainability targets could have a negative impact on IPC's reputation, business, cash flows, results of operations, and on the Group's access to, and cost of, capital.

In June 2024, the Canadian federal government amended the Competition Act (Canada) with respect to how companies communicate about environmental goals and performance and to address «greenwashing», meaning false, misleading, or deceptive environmental claims made for the purpose of promoting a product or a business interest. There is uncertainty regarding how this new legislation will be interpreted and applied. In 2025, the Canadian federal government proposed revisions to these provisions intended to reduce the burden on businesses and to provide more clarity on the applicability of these provisions. Any statements made in respect of activities undertaken or to be undertaken by IPC with respect to protecting or restoring the environment or mitigating environmental and ecological causes or effects of climate change, including the provision of emissions figures and forecasts, the acquisition and use of carbon offsets, activities to potentially reduce emissions, and activities to provide for environmental stewardship, including water management and biodiversity, should not be relied upon for the purposes of investing in securities of IPC or otherwise be considered as promoting IPC's products or business interests.

**Reputational Risks:** Reputational risks arise from societal pressure on the fossil fuel industry in relation to its contribution to global GHG emissions. Maintaining a positive reputation in the eyes of investors, regulators, communities, employees and the general public is an important aspect for the success of the Corporation. Negative impact on the industry and the Corporation's reputation could result in the long-term delays in obtaining regulatory approvals, increased operating costs, lower shareholder confidence, or availability of insurance and financing.

Oil and gas operations may be subject to public opposition. Such public opposition could result in higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental groups and other organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses, and direct legal challenges, including the possibility of climate-related litigation.

**Project Risks:** The Group is undertaking various projects, including Phase 1 of the Blackrod project. Project interruptions may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. IPC's ability to execute projects depends upon numerous factors beyond its control, including: processing, pipeline and storage capacity, availability of water, electricity, gas, diluent and other operational supplies, effects of weather, availability of personnel and equipment, unexpected cost increases, accidents, regulatory and third party approvals and commercial arrangements, stakeholder consultations (including Indigenous consultation) and regulatory changes (including carbon tax). As a result of these and other factors, the Group may be unable to execute projects on time, on budget, or at all.

**Inflationary Pressures and Costs:** The Group's operating costs could escalate and make operations unprofitable due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention. Labour costs, abandonment, reclamation, gas, electricity, water, diluent and chemicals are examples of some of the operating and other costs that are susceptible to significant fluctuation. The inability to manage costs may impact project returns and future development decisions, which could have an adverse effect on financial performance. The cost or availability of oil and gas field equipment may adversely affect IPC's ability to undertake projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services. These materials and services may not be available when required at reasonable prices. A failure to secure the services and equipment necessary to operations or projects for the expected price, on the expected timeline, or at all, may have an adverse effect on financial performance.

The Group's financial performance is significantly affected by the cost of operating and the capital costs associated with its assets. Operating and capital costs are affected by a number of factors including, but not limited to inflationary price pressure, scheduling delays, failure to maintain quality construction standards and supply chain disruptions. Fluctuations in operating and capital costs could negatively impact the Group's business, financial condition, results of operations, cash flows and value of its oil and gas reserves.

**Operational Risks Relating to Facilities and Pipelines:** The pipelines and facilities associated with the Group's assets, are exposed to operational risks that can lead to hydrocarbon releases, production interruptions and unplanned outages. Other operating risks relating to the facilities and pipelines associated with the Group's assets include: the breakdown or failure of equipment; breakdown or malicious attacks on information systems or processes; the performance of equipment at levels below those originally intended; operator error; disputes and other issues with interconnected facilities; and catastrophic events such as natural disasters, fires, explosions, acts of terrorists and saboteurs and other similar events, many of which will be beyond the control of the Group. The occurrence or continuance of any of these or other operational events could curtail sales or production or materially increase the cost of operating the facilities and pipelines associated with the Group's oil and gas assets and reduce revenues accordingly.

**Reductions in Demand for Oil and Gas:** Increasing consumer demand for alternatives to oil and gas, conservation measures, alternative fuel requirements, and technological advances in fuel economy and renewable energy generation systems, could reduce the demand for oil and gas. Some jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and to encourage the use of renewable fuel alternatives, which could reduce the demand for oil and gas. Advancements in energy efficient products have a similar effect on the demand for oil and gas. The Corporation cannot predict the impact of changing demand for oil and gas products, and any major changes may have an adverse effect on IPC's business, financial condition, results of operations and cash flow from operations by decreasing increasing costs, limiting access to capital and decreasing the value of oil and gas assets.

**Uncertainties Associated with Estimating Reserves and Resources Volumes:** There are numerous uncertainties inherent in estimating quantities of oil and gas reserves and resources (contingent and prospective) and the future cash flows attributed to such reserves and resources. The cash flow information associated with reserves and resources set forth in this MD&A are estimates only. The actual production, revenues, taxes and development and operating expenditures with respect to the reserves and resources associated with the Group's assets will vary from estimates thereof and such variations could be material. Estimates of reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources.

In accordance with applicable securities laws, the Corporation and the Corporation's independent reserves evaluator and auditor have used forecast prices and costs in estimating the reserves, resources and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and gas, curtailments or increases in consumption by oil and gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

References to "contingent resources" do not constitute, and should be distinguished from, references to "reserves". References to "prospective resources" do not constitute, and should be distinguished from, references to "contingent resources" and "reserves". This MD&A contains estimates of the net present value of the future net revenue from IPC's reserves and resources. The estimated values of future net revenue disclosed in this MD&A do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserves and resource evaluations will be attained and variances could be material. See also "Reserves and Resources Advisory" below.

**SAGD Recovery Process:** The Group has implemented a SAGD recovery process at the Onion Lake Thermal project and the Blackrod project. The SAGD recovery process requires a significant amount of gas or other fuels to produce steam for use in the recovery process. The amount of steam required in the production process can vary and impact costs significantly. The quality and performance of the reservoir can impact the timing, cost and levels of production using this technology. There can be no assurance that the Group's operations will produce at the expected levels or on schedule. In addition, a significant amount of water is used in SAGD operations. Government regulations apply to access to and use of water. Any shortages in water supplies could lead to increased costs and have a material adverse effect on results of operation and financial condition.

**Hydraulic Fracturing:** Hydraulic fracturing involves the injection of water, sand, and small amounts of additives under high pressure into tight rock formations that were previously unproductive to stimulate the production of oil and gas. Concerns about seismic activity, including earthquakes, caused by hydraulic fracturing has resulted in regulatory authorities implementing additional protocols for areas that are prone to seismic activity or completely banning hydraulic fracturing in other areas. Any new laws, regulations, or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third-party or governmental claims, and could increase costs of compliance, as well as delay development of certain oil and gas resources. Restrictions or bans on hydraulic fracturing could result in restricting the economic recovery of oil and gas reserves. In addition, the Group may need to dispose of the fluids produced from oil and gas production operations, including produced water. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities.

**Water:** Water is an essential component of IPC's drilling and hydraulic fracturing processes. Limitations or restrictions on IPC's ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact IPC's operations. Severe drought conditions can result in local water authorities taking steps to restrict the use of water in their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. For example, in 2024, in the face of severe drought risks following several warm, dry winters causing Alberta's snowpack, rivers and reservoirs to be low, the provincial government of Alberta entered into water-sharing agreements with a number of the largest and oldest water licensees in southern Alberta. If the Group is unable to obtain water to use in IPC's operations from local sources, water may need to be obtained from new sources and transported to drilling sites, resulting in increased costs. Cost increases could have a material adverse effect on drilling economics resulting in delays or suspensions of drilling which ultimately would have a detrimental effect on IPC's financial condition, results of operations, and funds flow.

**Regulatory Approvals and Compliance and Changes in Legislation and the Regulatory Environment:** Oil and gas operations (including exploration, development, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. Governments may regulate or intervene with respect to exploration, production and abandonment activities, price, taxes (including carbon taxes), GHG emission restrictions, royalties and the export of oil and gas. The implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could reduce demand for oil and gas and increase the costs associated with the Group's oil and gas assets, any of which may have a material adverse effect on the business, financial condition, results of operations and prospects of the Group's oil and gas assets. In order to conduct oil and gas operations, the Group will require regulatory permits, licences, registrations, approvals, authorizations and concessions from various governmental authorities. There is a risk that the permits, licences, registrations, approvals, authorizations and concessions currently granted to the Group will not be renewed or that the Group will be unable to obtain all of the permits, licences, registrations, approvals, authorizations and concessions that may be required to conduct operations that it may wish to undertake.

The French government has enacted legislation to cease granting new petroleum exploration licences in France and to restrict the production of oil and gas under existing production licences in France from 2040. There is a risk that France could implement further legislative changes and that the licence regime in France could become more onerous. In Canada, the oil and gas regulatory authorities have implemented regulations regarding the ability to transfer leases, licences, permits, wells and facilities between parties. These regulations may make it difficult and costly for producers, such as IPC, to transfer or sell assets to other parties.

IPC may be adversely impacted by political, legal, or regulatory developments in Canada and elsewhere that affect local operations and local and international markets. Changes in government, government policy or regulations, changes in law or interpretation of settled law, third-party opposition to industrial activity generally or projects specifically, and duration of regulatory reviews could impact IPC's existing operations and planned projects. This includes actions by regulators or other political actors to delay or deny necessary licences and permits for activities or restrict the operation of third-party infrastructure on which the Group relies. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact results. Other government and political factors that could adversely affect financial results include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements. Further, the adoption of regulations mandating efficiency standards and mandating the sale of electric vehicles, and the use of alternative fuels or uncompetitive fuel components, could affect the demand for oil and gas. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels, technologies or electric vehicles. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources. The success of these initiatives may decrease demand for oil and gas. A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. The oil and natural gas industry has become an increasingly politically polarizing topic resulting in a rise in civil disobedience surrounding oil and natural gas development, particularly with respect to infrastructure projects such as pipelines. Protests, blockades, demonstrations and vandalism have the potential to delay and disrupt the Group's activities.

**Indigenous Land and Rights Claims:** In Canada, Indigenous groups have filed claims in respect of their Indigenous and treaty rights against the federal and certain provincial governments as well as private individuals and companies. Consultation delays, claims or objections related to Indigenous rights may disrupt or delay third-party operations, new development or new project approvals on the Group's properties. The Group is not aware of any claims made with respect to its properties or assets; however; if a claim arose and was successful, it may have a material adverse effect on the Group's business, financial condition, results of operation and prospects. The Group's interests at Onion Lake are situated on traditional reserve lands and are subject to the federal rules and regulations of Indian Oil and Gas Canada as well as of the Onion Lake Cree Nation of Saskatchewan/Alberta. There are risks associated with the management of the Group's interests on these lands, including access and lease terms.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of litigation. The fulfilment of the duty to consult Indigenous people and any associated accommodations may adversely affect the Group's ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals, or to advance project development, including current and potential future phases of the Blackrod project.

In addition, the Canadian federal government has introduced legislation to implement the United Nations Declaration of the Rights of Indigenous Peoples ("UNDRIP"). Other Canadian jurisdictions have introduced or passed similar legislation and have begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by government are uncertain. Additional processes may be created and legislation associated with project development and operations may be amended or introduced, further increasing uncertainty with respect to project regulatory approval timelines and requirements.

**Change of Control under Licences:** The licence areas associated with the Group's oil and gas assets require government consent or compliance with regulations imposed by oil and gas regulatory authorities to effect a change of control of the owner or an assignment of the ownership interest in the licence area. There may also be contractual restrictions on assignment and change of control, including in the Suffield area of Canada where certain operations are conducted within a Canadian Forces Base under access agreements with Canadian federal government and the Alberta provincial government. Accordingly, should the Group propose to dispose of assets or if there is a change of control of the Corporation, consent may be required in order to remain in compliance with the applicable licences and concessions. The failure to obtain such consent may have a material adverse effect on the Corporation. Further, the requirement to obtain such consent may limit the ability of a third party to effect a change of control transaction with the Corporation.

**Failure to Realize Anticipated Benefits of Acquisitions and Dispositions:** The Group may make acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Group's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Group. In addition, non-core assets may be periodically disposed of, so that the Group can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Group, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Group.

**Reliance on Third Party Infrastructure:** The Group delivers the products associated with the Group's assets by gathering, processing and pipeline systems, most of which it does not own. The amount of oil and gas that the Group is able to produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could ceased refining and result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production or increased operating or transportation costs. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Group's business financial condition, results of operations, cash flows and future prospects.

**Credit Facilities and Bonds:** The Group is, and may in the future become, party to credit facilities with international financial institutions. The Corporation has also issued bonds and may issue further bonds in the future. The terms of these facilities and bonds may contain operating and financial covenants and restrictions on the ability of the Group to, among other things, incur or lend additional debt, pay dividends or distributions and make restricted payments, encumber its assets, sell assets and enter into certain merger or consolidation transactions. The failure of the Group to comply with the covenants contained in these facilities and bonds could result in an event of default, which could, through acceleration of debt, enforcement of security or otherwise, materially and adversely affect the operating results and financial condition of the Group.

In addition, the maximum amount that the Group is permitted to borrow under its credit facilities may be subject to periodic review by the lenders. The Group's lenders generally review its oil and gas production and reserves, forecast oil and gas prices, general business environment and other factors to establish the amount which the Group is entitled to borrow. In the event the lenders decide to reduce the amount of credit available under the credit facilities, the Group may not have the ability to borrow funds under such facilities or may be required to repay all or a portion of the amounts owing thereunder.

If the Group fails to comply with the covenants in these facilities and bonds, is unable to repay or refinance amounts owned at maturity or pay the debt service charges or otherwise commit an event of default, such as bankruptcy, it could result in the seizure and/or sale of the Group's assets by the creditors. The proceeds from any sale of the Group's assets would be applied to satisfy amounts owed to the secured creditors and then unsecured creditors. Only after the proceeds of that sale were applied towards the Group's debt would the remainder, if any, be available for the benefit of shareholders.

**Credit Ratings:** Credit ratings affect the Corporation's ability to obtain short term and long-term financing and the cost of such financing. A reduction in the current rating or a negative change in the rating outlook could adversely affect the cost of financing and access to sources of liquidity and capital. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant. Credit ratings are not recommendations to buy, sell or hold any of the Corporation's securities.

**Competition for Resources and Markets:** The international oil and gas industry is competitive in all its phases. The Group competes with numerous other organizations in the search for, and the acquisition of, oil and gas properties and in the marketing of oil and gas. The Corporation's competitors include oil and gas companies that may have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves and resources in the future depends not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory and development drilling. Competitive factors in the distribution and marketing of oil and gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources and renewable energies.

**Marketing:** A decline in the Group's ability to market oil and gas production could have a material adverse effect on its production levels or on the price that the Group receives for production, which in turn may affect the financial condition of the Corporation and the market price of the Common Shares. IPC's business depends in part upon the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities as well as, potentially, rail loading facilities and railcars. Applicable regulation of oil and gas production, processing and transportation, tax and energy policies, general economic conditions, and changes in supply and demand could adversely affect IPC's ability to produce and market oil and gas. If market factors change and inhibit the marketing of production, overall production or realized prices may decline, which may affect the financial condition of the Corporation and the market price of the Common Shares.

**Hedging Strategies:** From time to time, the Group may enter into agreements to receive fixed prices on its oil and gas production to offset the risk of revenue reduction if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Group will not benefit from such increases. Similarly, from time to time, the Group may enter into agreements to fix the exchange rate of certain currencies. However, if a currency declines in value compared to another currency, the Group may not benefit from the fluctuating exchange rate if an agreement has fixed such exchange rate

**Fraud, Bribery and Corruption:** The operations relating to the Group's oil and gas assets are governed by the laws of many jurisdictions, which generally prohibit bribery and other forms of corruption. While the Corporation has implemented an anti-corruption compliance program across the Group, the Corporation cannot guarantee that the Group's employees, officers, directors, agents, or business partners have not in the past or will not in the future engage in conduct undetected by the processes and procedures to be adopted by the Corporation and for which the Corporation might be held liable under applicable anti-corruption laws. Despite the Corporation's compliance program and other related training initiatives, it is possible that the Corporation, or some of its subsidiaries, employees or contractors, could be subject to an investigation related to charges of bribery or corruption as a result of the unauthorized actions of its employees or contractors, which could result in significant corporate disruption, onerous penalties and reputational damage.

**Decommissioning, Abandonment and Reclamation Costs:** The Group is responsible for compliance with all applicable laws, regulations and contractual requirements regarding the decommissioning, abandonment and reclamation of the Group's assets at the end of their economic life, the costs of which may be substantial. It is not possible to predict these costs with certainty since they will be a function of requirements at the time of decommissioning, abandonment and reclamation and the actual costs may exceed current estimates. Laws, regulations and contractual requirements with regard to abandonment and decommissioning may be implemented or amended in the future.

Certain jurisdictions in Canada, including Alberta and Saskatchewan, have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines if a licensee or permit holder is unable to satisfy its regulatory obligations. The implementation of or changes to the requirements of liability management programs may result in significant increases to the security that must be posted by licensees, increased and more frequent financial disclosure obligations or the denial of licence or permit transfers, which could impact the availability of capital to be spent by the Group, which could in turn materially adversely affect IPC's business and financial condition. In addition, these liability management programs may prevent or interfere with IPC's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets.

**Third Party Credit Risk:** The Group may be exposed to third-party credit risk through the contractual arrangements associated with the Group's assets with its current or future joint venture partners, marketers of its petroleum and gas production, third party uses of its facilities and other parties. In the event such entities fail to meet their contractual obligations in respect of the Group's assets, such failures may have a material adverse effect on the Group's business, financial condition, results of operations and prospects.

**Repatriation of Earnings:** Jurisdictions in which the Group operates may implement measures to facilitate management of foreign exchange risk. Such measures could restrict the Group's ability to repatriate earning or other funds.

**Expiration and Renewal of Licences, Leases and Production Sharing Contracts:** Certain of the Group's oil and gas assets are held in the form of licences, leases and production sharing contracts (PSCs). If the holder of the licence, lease or PSC or the operator of the licence, lease or PSC fails to meet the specific requirement of a licence, lease or PSC, including compliance with environmental, health and safety requirements, the licence, lease or PSC may terminate or expire. There is a risk that the obligations required to maintain each licence, lease or PSC will not be met. The termination or expiration of the licence, lease or PSC, or the working interests relating to a licence may have a material adverse effect on the business, financial condition, results of operations and prospects associated with the Group's oil and gas assets. From time to time, the licences and leases may, in accordance with their terms, become due for renewal; there is a risk that these licences, leases and PSCs associated with the Group's oil and gas assets will not be renewed by the relevant government authorities on terms that will be acceptable to the Corporation. There also can be significant delay in obtaining licence renewals which may already affect the operations associated with the Group's oil and gas assets.

**Reliance on Third Party Operators:** The Group has partners in some of the licence areas associated with the Group's assets. In some cases, including in the Aquitaine Basin in France, the Group is not the operator of the licence and concession areas and must depend on the competence, expertise, judgment and financial resources (in addition to those of its own and, where relevant, other partnership and joint venture companies) of the partner operator and the operator's compliance with the terms of the licences, leases and contractual arrangements. Mismanagement of licence areas by the Group's partner operators or defaults by them in meeting required obligations may result in significant exploration, production or development delays, losses or increased costs to the Group.

**Litigation:** In the normal course of the Group's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Group and as a result, could have a material adverse effect on the Group's assets, liabilities, business, financial condition and results of operations.

**Terrorism and Sabotage:** If any of the properties, wells or facilities comprising the Group's assets is the subject of terrorist attack or sabotage, it may have a material adverse effect on the Group's business, financial condition, results of operations, cash flows and future prospects.

**Information Security and Artificial Intelligence:** The Group is dependent on its information systems and computer-based programs. Failure, malfunction or security breaches by computer hackers and cyberterrorists of any such systems or programs may have a material adverse effect on the Group's business and systems, potentially disrupting operations and affecting network assets and people's privacy. The Group manages cybersecurity risk by ensuring appropriate technologies, processes and practices are effectively designed and implemented to help prevent, detect and respond to threats as they emerge and evolve. The Chief Operating Officer of the Corporation is principally responsible for overseeing cybersecurity risk management and for reporting such risks to other members of executive management and to the Board. The primary risks to the Group include, loss of data, destruction or corruption of data, compromising of confidential customer or employee information, leaked information, disruption of business, theft or extortion of funds, regulatory infractions, loss of competitive advantage and reputational damage.

Further, the Group is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to business activities. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, credit card and banking details (and money), or approval of wire transfer requests, by disguising themselves as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If IPC were to become a victim to a cyber phishing attack it could result in a loss or theft of financial resources or critical data and information, or could result in a loss of control of the Group's technological infrastructure or financial resources.

The controls implemented by the Group may not adequately prevent cybersecurity breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on performance and earnings, as well as IPC's reputation, and any damages sustained may not be adequately covered by current insurance coverage, or at all. The significance of any such event is difficult to quantify but may in certain circumstances be material and could have a material adverse effect on the Group's business, financial condition and results of operations. The protection of customer, employee, and company data is also critical to IPC's business. The regulatory environment surrounding information security and privacy is increasingly demanding, with the frequent imposition of new and constantly changing requirements. A significant breach of employee or company data could attract a substantial amount of media attention, damage relationships and reputation, and result in fines or lawsuits. In addition, an increasing number of countries have introduced and/or increased enforcement of comprehensive privacy laws or are expected to do so. The continued emphasis on information security as well as increasing concerns about government surveillance may lead to the Group being required to take additional measures to enhance security and/or assume higher liability.

The increasing prevalence of artificial intelligence («AI») tools may also increase the risk of cyber-attacks or data breaches as a result of the use of AI to launch more automated, targeted and coordinated attacks to the Corporation's technology infrastructure. The Corporation's information technology systems may incorporate the use of AI and the development of such capabilities remains ongoing. Although the Corporation has implemented policies with respect to its employees' use of AI tools, AI presents risks, challenges and unintended consequences that could affect its adoption, and therefore the Corporation's business. AI algorithms and training methodologies may be flawed. The use of AI to support business operations of the Corporation, its partners, vendors, suppliers, contractors or others carries inherent risks related to data privacy and cybersecurity, such as intended, unintended or inadvertent transmission of proprietary or sensitive information, as well as challenges related to implementing and maintaining AI tools, including the development and maintenance of appropriate datasets for such support.

Dependence on AI to make certain business decisions without adequate safeguards may introduce additional operational vulnerabilities by producing inaccurate outcomes or other unintended results, based on flaws or deficiencies in the underlying data. Further, AI tools or software may rely on data sets to produce derivative work which may contain content subject to licence, copyright, patent or trademark protection or sensitive personal information and can produce outputs that infringe intellectual property rights or compromise privacy of individuals or organizations, raising concerns about data privacy. As AI is an emerging technology for which the legal and regulatory landscape is not fully developed, including potential liability for breaching intellectual property or privacy rights or laws, new laws and regulations applicable to AI initiatives remain uncertain and the Corporation's obligation to comply with such laws could entail significant costs, negatively affect the Corporation's business or limit the Corporation's ability to incorporate certain AI capabilities into its operations.

**Insurance:** Although the Group maintains insurance in accordance with industry standards to address certain risks related to oil and gas operations, such insurance has limitations on liability and may not be sufficient to cover the full extent of potential liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Group may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to IPC. The occurrence of a significant event that IPC is not fully insured against, or the insolvency of the insurer of such event, may have an adverse effect on IPC's business, financial condition, results of operations and prospects. The Group's insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, policy limits and/or deductibles for certain insurance policies can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage.

**Forced or Child Labour in Supply Chains:** The Fighting Against Forced Labour and Child Labour in Supply Chains Act came into force in Canada in 2024. Pursuant to this legislation, any company that is subject to the reporting requirements, including IPC, is required to conduct certain due diligence on its supply chains and to file an annual report accordingly. Further, in late 2024 the Canadian federal government stated its intention to create a new and more onerous supply chain due diligence regime overseen by a new oversight agency whereby reporting entities will be required to scrutinize their international supply chains for human rights risks and take action to resolve any such risks. While IPC is currently unaware of any forced or child labour in any of the Group's supply chains, the increased scrutiny on the supply chains of Canadian companies could uncover the risk or existence of forced or child labour in a supply chain to which IPC has a connection, which could negatively impact IPC's reputation.

**Pandemics:** The Covid-19 virus and the restrictions and disruptions related to it had a material effect on the world demand for, and prices of, oil and gas as well as the market price of the shares of oil and gas companies generally. There can be no assurance that these effects will not resume or that commodity prices will not decrease or remain volatile in the future due to pandemics. These factors are beyond the control of the Corporation, and it is difficult to assess how these, and other factors, will continue to affect the Corporation and the market price of IPC's Common Shares.

**Potential Conflicts of Interest:** Certain of the individuals who are directors of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions.

**Key Personnel:** IPC's success is in part dependent upon management, leadership capabilities and the quality and competency of key personnel. If IPC is unable to retain key personnel and critical talent or to attract and retain new talent with the necessary leadership, professional and technical competencies, it could have an adverse effect on the Group's financial condition, results of operations and prospects.

**Change in Investors:** Some institutional and other investors have announced that they no longer are willing to fund or invest in oil and gas assets or companies, or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Corporation. Failing to implement the policies and practices, as requested by institutional investors, may result in such investors reducing their investment in the Corporation, or not investing in IPC at all.

**Significant Shareholder:** Nemesia S.à.r.l., an investment company wholly owned by trusts whose settlor is the late Adolf H. Lundin ("Nemesia"), owns approximately 38 percent of the aggregate Common Shares of the Corporation. Nemesia's holdings may allow it to significantly affect substantially all the actions taken by the shareholders of the Corporation, including the election of directors. As long as Nemesia maintains a significant interest in the Corporation, it is likely that Nemesia will exercise significant influence on the ability of the Corporation to, among other things, enter into a change in control transaction of the Corporation and may also discourage acquisition bids for the Corporation. There is a risk that the interests of Nemesia may not be aligned with the interests of other shareholders.

### Financial Risks

**Management Estimates and Assumptions:** In preparing consolidated financial statements in conformity with IFRS Accounting Standards, estimates and assumptions are used by management in determining the reported amounts of assets and liabilities, revenues and expenses recognized during the periods presented and disclosures of contingent assets and liabilities known to exist as of the date of the financial statements. These estimates and assumptions must be made because certain information that is used in the preparation of such financial statements is dependent on future events, cannot be calculated with a high degree of precision from data available, or is not capable of being readily calculated based on generally accepted methodologies. In some cases, these estimates are particularly difficult to determine and the Corporation must exercise significant judgment. Actual results for all estimates could differ materially from the estimates and assumptions used by the Corporation, which could have a material adverse effect on the Group's business, financial condition, results of operations, cash flows and future prospects.

**Disclosure Controls and Procedures and Internal Controls over Financial Reporting:** Effective disclosure controls and procedures and internal controls over financial reporting are necessary for the Corporation to provide reliable financial and other disclosures and to help prevent fraud. The Corporation cannot be certain that the procedures it undertakes to help ensure the reliability of its financial reports and other disclosures, including those imposed on it under Canadian securities laws, will ensure that it maintains adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm the Group's results of operations or cause it to fail to meet its reporting obligations. If the Corporation or its independent auditor discovers a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Corporation's consolidated financial statements and harm the trading price of the Common Shares.

**Income Taxes:** Income tax laws relating to the oil and gas industry, such as the treatment of resource taxation or dividends and the imposition of carbon taxes, may in the future be changed or interpreted in a manner that adversely affects the Group's assets. Furthermore, there is a risk that the relevant tax authorities will not agree with management's calculation of the income for tax purposes associated with the Group's assets or that such tax authorities will change their administrative practices to the detriment of the Corporation. In the event of a successful reassessment of the Corporation's income tax returns, such reassessment may have an impact on current and future taxes payable.

The EU previously imposed a tax on energy companies deriving income from operations in EU countries, which tax was applicable to the Group in France in 2022. Such tax could be reinstated in the future or similar taxes could be levied in other jurisdictions in which the Group operates or proposes to operate.

**Additional Funding Requirements:** The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's funds from operations is not sufficient to satisfy its capital expenditure requirements, there is a risk that debt or equity financing will be unavailable to meet these requirements or, if available, will be on terms unacceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects and also negatively impact the market price of the Common Shares.

**Variations in Foreign Exchange Rates and Interest Rates:** World oil and gas prices are quoted in United States dollars and are therefore affected by exchange rates, which will fluctuate over time. Future exchange rates could accordingly impact the future value of the Corporation's reserves and resources as determined by independent reserve auditors. To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there will be a credit risk associated with counterparties of the Corporation. An increase in interest rates could result in a significant increase in the amount the Corporation pays to service any debt that it may incur, which could negatively impact the market price of the Common Shares.

**Issuance of Further Debt:** From time to time, the Corporation may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may create debt or increase the Corporation's then-existing debt levels above industry standards for oil and gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional equity and/or debt financing that may not be available or, if available, may not be available on favorable terms. The level of the indebtedness that the Corporation may have from time to time could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

**Common Share Price Volatility:** The market price for Common Shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond the Corporation's control, including the following:

- Actual or anticipated fluctuations in the Corporation's results of operations;
- Recommendations by securities research analysts;
- Changes in the economic performance or market valuations of other companies that investors deem comparable to the Corporation;
- The loss of executive officers and other key personnel of the Corporation;
- Issuances or perceived issuances of additional Common Shares;
- Significant acquisitions or business combinations, strategic partnerships, joint ventures or capital;
- Commitments by or involving the Corporation or its competitors; and
- Trends, concerns, technological or competitive developments, regulatory changes and other related issues in the Corporation's business segments or target markets.

Financial markets can experience significant price and volume fluctuations that may particularly affect the market prices of equity securities of companies and that may be unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the Common Shares may decline even if the Corporation's operating results, underlying asset values or prospects have not changed. These factors, as well as other related factors, may cause decreases in asset values, which may result in impairment losses.

## DISCLOSURE CONTROLS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

### Disclosure Controls and Procedures

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

### Internal Controls over Financial Reporting

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

There have been no material changes to the Groups internal control over financial reporting during the three and nine months ended December 31, 2025, that have materially affected, or are reasonably likely to materially affect, the Group's internal control over financial reporting.

### Control Framework

Management assesses the effectiveness of the Corporation's internal control over financial reporting using the Internal Control – Integrated Framework (2013 Framework) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management concluded that the Corporation's internal control over financial reporting was effective as of December 31, 2025.

## CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

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

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

- 2026 production ranges (including total daily average production), production composition, cash flows, operating costs and capital and decommissioning expenditure estimates;
- Estimates of future production, cash flows, operating costs and capital expenditures that are based on IPC's current business plans and assumptions regarding the business environment, which are subject to change;
- IPC's financial and operational flexibility to navigate the Corporation through periods of volatile commodity prices;
- The ability to fully fund 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 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".

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 current and potential conflicts in Ukraine, the Middle East, South America and elsewhere and their potential impact on, among other things, global market conditions;
- Political or economic developments, including, without limitation, the risk that (i) 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 2026 to 2030 and 2031 to 2035, less net debt of USD 484 million as at December 31, 2025, with assumptions based on the reports of IPC's independent reserves evaluator and auditor, and including certain corporate adjustments relating to estimated general and administration costs and hedging, and excluding shareholder distributions and certain refinancing costs. Assumptions include average net production of approximately 62 Mboepd over the period of 2026 to 2030, average capital expenditures of approximately USD 5 per boe, average operating costs of approximately USD 18 to 20 per boe, average Brent oil prices of USD 65 to 95 per bbl escalating by 2% per year, and average Brent to Western Canadian Select differentials and average gas prices as estimated by IPC's independent reserves evaluator and auditor and as further described in the MCR. 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 material change report (MCR) dated February 10, 2026, the Corporation's Annual Information Form (AIF) for the year ended December 31, 2024 (see "Cautionary Statement Regarding Forward-Looking Information", "Reserves and Resources Advisory" and "Risk Factors") and other reports on file with applicable securities regulatory authorities, including previous financial reports, management's discussion and analysis and material change reports, which may be accessed through the SEDAR+ website (www.sedarplus.ca) or IPC's website (www. international-petroleum.com).

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

## RESERVES AND RESOURCES ADVISORY

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

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada and France/Malaysia are effective as of December 31, 2025, and are included in the reports prepared by Sproule International Limited and ERCE Equipoise Ltd., respectively (collectively, Sproule ERCE), an independent qualified reserves evaluator and auditor, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Sproule ERCE's December 31, 2025 price forecasts.

The price forecasts used in the Sproule ERCE reports, are available on the website of Sproule ERCE (sproule-erce.com) and are contained in the MCR. These price forecasts are as at December 31, 2025 and may not be reflective of current and future forecast commodity prices.

The reserve life index (RLI) is calculated by dividing the 2P reserves of 521 MMboe as at December 31, 2025, by the mid-point of the 2026 CMD production guidance of 44,000 to 47,000 boepd.

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

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

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

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

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

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

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

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

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

The reserves and resources information and data provided in this MD&A present only a portion of the disclosure required under NI 51-101. All of the required information will be contained in the Corporation's Annual Information Form for the year ended December 31, 2025, which will be filed on SEDAR+ (accessible at www.sedarplus.ca) on or before April 1, 2026. Further information with respect to IPC's reserves, contingent resources and estimates of future net revenue is disclosed in the MCR available under IPC's profile on www.sedarplus.ca and on IPC's website at www.international-petroleum.com.

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

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

| | Heavy Crude Oil (Mbopd) | Light and Medium Crude Oil (Mbopd) | Conventional Natural Gas (per day) | Total (Mboepd) |
|---|---|---|---|---|
| Three months ended | | | | |
| December 31, 2025 | 23.9 | 6.6 | 90.9 MMcf (15.1 Mboe) | 45.6 |
| December 31, 2024 | 24.3 | 7.1 | 95.9 MMcf (16.0 Mboe) | 47.4 |
| Year ended | | | | |
| December 31, 2025 | 23.6 | 6.4 | 89.6 MMcf (14.9 Mboe) | 44.9 |
| December 31, 2024 | 23.9 | 7.7 | 95.1 MMcf (15.8 Mboe) | 47.4 |

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

## OTHER SUPPLEMENTARY INFORMATION

### Currency Abbreviations

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

### Oil related terms and measurements

| | |
|---|---|
| AECO | The daily average benchmark price for natural gas at the AECO hub in southeast Alberta |
| AESO | Alberta Electric System Operator |
| API | An indication of the specific gravity of crude oil on the API (American Petroleum Institute) gravity scale |
| ASP | Alkaline surfactant polymer (an EOR process) |
| bbl | Barrel (1 barrel = 159 litres) |
| boe | Barrels of oil equivalents |
| boepd | Barrels of oil equivalents per day |
| bopd | Barrels of oil per day |
| Bcf | Billion cubic feet |
| C5 | Condensate |
| $CO_2e$ | Carbon dioxide equivalents, including carbon dioxide, methane and nitrous oxide |
| Empress | The benchmark price for natural gas at the Empress point at the Alberta/Saskatchewan border |
| EOR | Enhanced Oil Recovery |
| FPSO | Floating Production Storage and Offloading (facility) |
| GJ | Gigajoules |
| Mbbl | Thousand barrels |
| MMbbl | Million barrels |
| Mboe | Thousand barrels of oil equivalents |
| Mboepd | Thousand barrels of oil equivalents per day |
| Mbopd | Thousand barrels of oil per day |
| MMboe | Million barrels of oil equivalents |
| MMbtu | Million British thermal units |
| Mcf | Thousand cubic feet |
| Mcfpd | Thousand cubic feet per day |
| MMcf | Million cubic feet |
| MW | Mega watt |
| MWh | Mega watt per hour |
| NGL | Natural gas liquid |
| SAGD | Steam assisted gravity drainage |
| WTI | West Texas Intermediate |
| WCS | Western Canadian Select |

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