Q3

International Petroleum Corporation

Management's Discussion and Analysis

For the three and nine months ended September 30, 2025

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Contents

Non-IFRS Measures
References are made in this MD&A to "operating cash flow" (OCF), "free cash flow" (FCF), "Earnings Before Interest, Tax, Depreciation and Amortization" (EBITDA), "operating costs" and "net debt"/"net cash" which are not generally accepted accounting measures under IFRS Accounting Standards (IFRS) and do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with definitions of OCF, FCF, EBITDA, operating costs and net debt/net cash that may be used by other public companies. Management believes that OCF, FCF, EBITDA, operating costs and net debt/net cash are useful supplemental measures that may assist shareholders and investors in assessing the cash generated by and the financial performance and position of the Corporation. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-IFRS measure is presented in this MD&A. See "Non-IFRS Measures" on page 18.
Forward-Looking Statements
Certain statements contained in this MD&A constitute "forward-looking statements" or "forward-looking information" (within the meaning of applicable securities legislation). Such statements and information (together, "forward-looking statements") relate to future events, including the Corporation's future performance, business prospects or opportunities. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, forecasts, guidance, budgets, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "forecast", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", "budget" and similar expressions) are not statements of historical fact and may be "forward-looking statements". Although IPC believes that the expectations and assumptions on which such forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because IPC can give no assurances that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. For additional information underlying forward-looking statements, refer to the "Cautionary Statement Regarding Forward-Looking Information" on page 23.

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

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France and Malaysia are effective as of December 31, 2024, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2024, price forecasts.
Certain abbreviations and technical terms used in this MD&A are defined or described under the heading "Other Supplementary Information".

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 November 4, 2025 and is intended to provide an overview of the Group's operations, financial performance and current and future business opportunities. This MD&A should be read in conjunction with IPC's unaudited interim condensed consolidated financial statements for the three and nine months ended September 30, 2025 as well as the audited consolidated financial statements and accompanying notes for the year ended December 31, 2024 ("Financial Statements").

Group Overview

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

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

Basis of Preparation

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

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

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

	September 30, 2025		September 30, 2024		December 31, 2024	
	Average	Period end	Average	Period end	Average	Year end
1 EUR equals USD	1.1180	1.1741	1.0870	1.1196	1.0821	1.0389
1 USD equals CAD	1.3993	1.3922	1.3602	1.3516	1.3698	1.4388
1 USD equals MYR	4.3265	4.2085	4.6352	4.1235	4.5759	4.4715

HIGHLIGHTS

Q3 2025 Business Highlights

- Average net production of approximately 45,900 boepd for Q3 2025, above guidance (53% heavy crude oil, 14% light and medium crude oil and 33% natural gas).[1]
- Continued progress of Blackrod Phase 1 development activity with Central Processing Facility (CPF) construction almost complete, progressive commissioning advancing, and first steam and first oil forecast a quarter earlier than originally guided.
- At Onion Lake Thermal, Canada, the final two of four planned production infill wells and the final Pad L sustaining well pair were successfully brought online.
- Announced the refinancing of IPC's MUSD 450 unsecured bonds, extending the maturity to October 2030.
- 1.1 million IPC common shares purchased and cancelled during Q3 2025 under the normal course issuer bid (NCIB), completing the full 2024/2025 NCIB of approximately 7.5 million IPC common shares.
- IPC plans to seek Toronto Stock Exchange (TSX) approval for the renewal of the NCIB in December 2025.

Q3 2025 Financial Highlights

- Operating costs per boe of USD 17.9 for Q3 2025, marginally below guidance.[3]
- Operating cash flow (OCF) generation of MUSD 66 for Q3 2025, in line with guidance.[3]
- Capital and decommissioning expenditures of MUSD 82 for Q3 2025, in line with guidance.
- Free cash flow (FCF) generation for Q3 2025 amounted to MUSD -23 (MUSD 36 pre-Blackrod capital expenditures).[3]
- Gross cash of MUSD 45 and net debt of MUSD 435 as at September 30, 2025.[3]
- Net result of MUSD 4 for Q3 2025.

Reserves and Resources

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

2025 Annual Guidance

- Full year 2025 average net production guidance range forecast maintained at 43,000 to 45,000 boepd.[1]
- Full year 2025 operating costs guidance range forecast maintained at USD 18 to 19 per boe.[3]
- Full year 2025 OCF guidance range tightened to between MUSD 245 and 255 (assuming Brent USD 55 to 65 per barrel for the remainder of 2025) from previous guidance of between MUSD 245 and 260 (which assumed Brent USD 60 to 75 per barrel for the second half of 2025).[3][4]
- Full year 2025 capital and decommissioning expenditures guidance revised from MUSD 320 to MUSD 340 (including MUSD 250 for the Blackrod asset), following the advancement of Blackrod Phase 1 drilling activity into Q4 2025.
- Full year 2025 FCF revised guidance estimated at between MUSD -170 and -160 (assuming Brent USD 55 to 65 per barrel for the remainder of 2025) from previous guidance of between MUSD -135 and -120 (which assumed Brent USD 60 to 75 per barrel for the second half of 2025).[3][4]

	Three months ended September 30		Nine months ended September 30	
USD Thousands	2025	2024	2025	2024
Revenue	172,297	173,200	509,681	598,659
Gross profit	32,066	39,505	99,878	167,397
Net result	3,802	22,875	33,883	101,804
Operating cash flow[3]	66,102	72,589	195,765	263,831
Free cash flow[3]	(23,083)	(38,269)	(124,507)	(74,021)
EBITDA[3]	62,106	68,313	184,571	259,304
Net cash/(debt)[3]	(434,822)	(157,228)	(434,822)	(157,228)

OPERATIONS REVIEW

Business Overview

During the third quarter of 2025, the average Brent price was approximately USD 69 per barrel, as compared to approximately USD 68 per barrel for the second quarter of 2025. The Brent price remained relatively stable during the third quarter, with some downward pressure on prices post-quarter due to concerns over market oversupply and concerns around global trade between China and the US. Global observed petroleum inventories have increased, mainly driven by OPEC's unwinding of voluntary production cuts, long-dated non-OPEC supply growth projects coming on-stream, and sanctioned countries' production output being high relative to historical standard. Given the uncertainty and low-price strip outlook, it is unlikely near-term incremental upstream growth investment will be pursued by industry. Global oil demand is expected to be an all-time high in 2025 and is predicted to continue to rise in 2026.

Alongside the more constructive factors for stronger oil prices in the medium to longer term, the need to alleviate poverty in emerging markets coupled with meeting the infrastructure build-out requirements for technological advancements, namely with data centres and AI, places a major emphasis on the need for metals and high-density forms of energy. The precious and base metal supply needs will go hand-in-hand with a reliance on oil and its irreplaceable byproducts in order to develop and transport more mined material. While uncertainty exists with respect to forecasting oil prices, IPC has strongly positioned itself with forecast sustained higher production levels in the years ahead which should positively coincide with a higher pricing cycle at a time likely not too far into the future.

IPC's oil hedges in total represent around 50% of our aggregate forecast 2025 oil production at around USD 76 and USD 71 per barrel for Dated Brent and West Texas Intermediate (WTI), respectively, as well as a WTI collar between USD 65 and USD 75 per barrel, for the remainder of 2025.

The WTI to Western Canadian Select (WCS) price differential during the third quarter averaged less than USD 11 per barrel. 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 current and outlook of the WTI to WCS differential remains tight with excess egress capacity relative to the supply in the Western Canadian Sedimentary Basin (WCSB). There are currently no tariffs on Canadian crude oil exports to the United States, which remain covered by the US Mexico Canada trade agreement. IPC has hedged the WTI to WCS differential for approximately 50% of our forecast 2025 Canadian oil production at USD 14 per barrel for 2025. For 2026, IPC implemented WTI to WCS differential hedges in October 2025 for approximately 5,000 barrels per day at USD -12.50 per barrel.

The average Canadian gas benchmark price, AECO, was CAD 0.6 per Mcf for the third quarter of 2025 and IPC achieved an average realized price of CAD 0.8 per Mcf during the quarter. WCSB gas inventory levels remain elevated above the historical average. There is an expectation for storage levels to draw during the winter period and further supported by the ramp up of the LNG Canada project in 2026 which should drive higher natural gas prices. Approximately 50% of our net long gas exposure was hedged at CAD 2.4 per Mcf to end October 2025, with around 15% of net long gas exposure hedged for November and December at CAD 2.6 per Mcf. For 2026, IPC implemented hedges in the third quarter of 2025 for approximately 9,600 Mcf per day at CAD 2.80 per Mcf from April to October 2026.

Third Quarter 2025 Highlights and Full Year 2025 Guidance

During the third quarter of 2025, our portfolio delivered average net production of 45,900 boepd, ahead of guidance. The strong performance in the quarter was supported by the sustaining capital investment activities undertaken at the Onion Lake Thermal asset and at the Bertam field in Malaysia. We maintain the full year 2025 average net production guidance range of 43,000 to 45,000 boepd.[1]

Our operating costs per boe for the third quarter of 2025 was USD 17.9, marginally below guidance. Full year 2025 operating expenditure guidance of USD 18.0 to 19.0 per boe remains unchanged.[3]

Operating cash flow (OCF) generation for the third quarter of 2025 was MUSD 66. Full year 2025 OCF guidance is tightened to MUSD 245 to 255 (assuming Brent USD 55 to 65 per barrel for the remainder of 2025).[3][4]

Capital and decommissioning expenditure for the third quarter of 2025 was MUSD 82, in line with guidance. Full year 2025 capital and decommissioning expenditure is revised to MUSD 340, from MUSD 320, mainly due to the acceleration of the drilling of the final well pad for the Blackrod Phase 1 project into the fourth quarter of 2025.

Free cash flow (FCF) generation was MUSD -23 (MUSD 36 pre-Blackrod capital expenditures) during the third quarter of 2025. Full year 2025 FCF guidance is revised to MUSD -170 to -160 (assuming Brent USD 55 to 65 per barrel for the remainder of 2025) after taking into account MUSD 340 of forecast full year 2025 capital expenditures (including MUSD 250 relating to the Blackrod asset) and costs incurred from the bond refinancing.[3][4]

As at September 30, 2025, IPC's net debt position increased to MUSD 435, from a net debt position of MUSD 375 as at June 30, 2025, mainly driven by the funding of capital expenditures and the share repurchase program (NCIB). Gross cash as at September 30, 2025 amounted to MUSD 45.

In the third quarter of 2025, IPC announced that it had taken advantage of favourable debt capital market conditions to successfully refinance its MUSD 450 of unsecured bonds. The new bonds issued in October 2025 have a maturity in October 2030, with a coupon of 7.5% per annum. IPC believes that this is a great outcome since the US 5-year swap rates increased by almost 2% compared to IPC's inaugural bond issuance in the first quarter of 2022 while the coupon only increased by 0.25% to 7.5%. In addition, IPC continues to have access to a Canadian revolving credit facility of MCAD 250 (approximately MUSD 180), with MCAD 37 (approximately MUSD 27) drawn under that facility as at September 30, 2025. The access to liquidity supports IPC to follow through on its key strategic objectives of enhancing stakeholder value through organic growth, stakeholder returns, and pursuing value adding M&A.(3)

Blackrod

The Blackrod asset is 100% owned by IPC and contains 259 MMboe of 2P reserves and 1,025 MMboe of contingent resources (best estimate, unrisked) with regulatory approval to produce up to 80,000 bopd. In early 2023, IPC sanctioned the Phase 1 development targeting plateau production rates of 30,000 bopd with a growth capital expenditure guidance of MUSD 850. Since the Phase 1 project sanction to the end of the third quarter of 2025, capital expenditures of MUSD 785 have been incurred, or approximately 92% of the MUSD 850 growth capital guidance to first oil.(1)

All major work activities continued to advance at the Blackrod asset during the third quarter. Construction activities are nearing completion and progressive commissioning of the CPF is ahead of schedule. While full commissioning works remain to be completed, IPC is now confident that first steam at the project should occur before the end of 2025 with first oil to follow in the third quarter of 2026, a quarter earlier than originally guided. As a result of an earlier expected startup for the Phase 1 project, drilling of the final well pad is planned to be started in the fourth quarter of 2025 from early 2026.

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

Stakeholder Returns: Normal Course Issuer Bid

In the fourth quarter of 2024, IPC announced the implementation of the 2024/2025 NCIB to purchase up to approximately 7.5 million common shares over the period of December 5, 2024 to December 4, 2025. Under the 2024/2025 NCIB, IPC repurchased and cancelled approximately 0.8 million common shares in December 2024 and over 6.6 million common shares during the first nine months of 2025 under the NCIB, as well as a further 0.3 million common shares under other exemptions in Canada. The average price of common shares repurchased under the 2024/2025 NCIB during the first nine months of 2025 was around SEK 144 / CAD 20 per share.

IPC completed the 2024/2025 NCIB by the end of September 2025, purchasing and cancelling approximately 7.5 million common shares. This resulted in the cancellation of 6.2% of the common shares outstanding as at the beginning of December 2024.

As at September 30, 2025, IPC had a total of 112,180,065 common shares issued and outstanding, of which IPC held 24,538 common shares in treasury. As at November 4, 2025, IPC had a total of 112,155,527 common shares issued and outstanding and IPC held no common shares in treasury.

The IPC Board of Directors has approved, subject to acceptance by the Toronto Stock Exchange (TSX), the renewal of IPC's NCIB for a further twelve months from December 2025 to early December 2026. We expect that the 2025/2026 NCIB will permit IPC to purchase on the TSX and/or Nasdaq Stockholm, and cancel, up to a further approximately 6.5 million common shares, representing approximately 5.8% of the total current outstanding common shares (or 10% of IPC's "public float" under applicable TSX rules). IPC continues to believe that reducing the number of shares outstanding in combination with investing in long-life production growth at the Blackrod project will prove to be a winning formula for our stakeholders.

Notes:

(1) See "Supplemental Information regarding Product Types" in "Reserves and Resources Advisory" below. See also the annual information form for the year ended December 31, 2024 (AIF) available on IPC's website at www.international-petroleum.com and under IPC's profile on SEDAR+ at www.sedarplus.ca.

(2) See "Reserves and Resources Advisory" below. Further information with respect to IPC's reserves, contingent resources and estimates of future net revenue, including assumptions relating to the calculation of net present value (NPV), are described in the AIF. NAV is calculated as NPV less net debt of MUSD 209 as at December 31, 2024.

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

(4) OCF and FCF forecasts at Brent USD 55 to 65 per barrel assume Brent to WTI and WTI to WCS differentials of USD 3 and 10 per barrel, respectively, for the remainder of 2025. OCF and FCF forecasts assume gas price on average of CAD 1.75 per Mcf for the fourth quarter of 2025.

Operations Overview

Q3 2025 Overview
In Q3 2025, IPC continued to successfully demonstrate its commitment to operational excellence, delivering production performance and operating expenditure in line with our Capital Markets Day (CMD) guidance with no material safety or environmental incidents recorded in the quarter.

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

Production
Average daily net production for Q3 2025 was ahead of IPC's high end CMD guidance at 45,900 boepd. In Canada, strong operational performance at the major oil and gas assets has been supplemented by recent production infill well drilling at Onion Lake Thermal. Stable performance continued at our Malaysian and French assets.

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

The production during Q3 2025 with comparatives is summarized below:

Production in Mboepd	Three months ended September 30		Nine months ended September 30		Year ended December 31
	2025	2024	2025	2024	2024
Crude oil					
Canada – Northern Assets	15.8	12.7	14.5	14.0	14.2
Canada – Southern Assets	9.9	10.9	10.4	11.1	11.1
Malaysia	3.2	3.7	2.8	4.0	3.8
France	2.1	2.4	2.1	2.5	2.4
Total crude oil production	**31.0**	29.7	**29.8**	31.6	31.5
Gas					
Canada – Northern Assets	0.5	0.4	0.4	0.4	0.5
Canada – Southern Assets	14.4	14.9	14.4	15.4	15.4
Total gas production	**14.9**	15.3	**14.8**	15.8	15.9
Total production	**45.9**	45.0	**44.6**	47.4	47.4
Quantity in MMboe	**4.22**	4.14	**12.19**	12.98	17.34

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

CANADA

Production in Mboepd	Working Interest (WI)	Three months ended September 30		Nine months ended September 30		Year ended December 31
		2025	2024	2025	2024	2024
- Oil Onion Lake Thermal	100%	13.1	10.7	12.0	12.4	12.3
- Oil Suffield Area	100%	8.7	9.2	9.0	9.7	9.7
- Oil Other	50-100%	3.9	3.7	3.9	3.0	3.3
- Gas	~100%	14.9	15.3	14.8	15.8	15.9
Canada		**40.6**	38.9	**39.7**	40.9	**41.2**

Production
Net production from IPC's assets in Canada during Q3 2025 was ahead of guidance at 40,600 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.

Organic Growth and Capital Projects
The Blackrod Phase 1 development project in Canada continues to progress, with construction almost complete and progressive commissioning of the central processing facility (CPF) advancing ahead of schedule. As at the end of Q3 2025, acceleration of construction and commissioning activity has supported early delivery of the first commercial fuel gas to the CPF site. Both site power generators have been commissioned and the Blackrod CPF is energized in preparation for final first steam commissioning activities. On the back of the latest progress, IPC is confident that first steam and subsequently first oil should be achieved a quarter earlier than our original guidance. Based on this progress, IPC has decided to accelerate the drilling of the final production well pad into Q4 2025 from the previously planned commencement in early 2026.

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

MALAYSIA

Production in Mboepd	WI	Three months ended September 30		Nine months ended September 30		Year ended December 31
		2025	2024	**2025**	2024	2024
Bertam	100%	**3.2**	3.7	**2.8**	4.0	3.8

Production
Net production at Bertam in Malaysia in Q3 2025 was in line with guidance at 3,200 boepd. Planned maintenance shutdown activity that commenced towards the end of Q3 has been completed on time and in line with budget in early Q4 2025.

Organic Growth and Capital Projects
In Malaysia, the planned infill well and well maintenance activity was completed early in Q3 2025. Wells A21 and A15 were brought on to production in late July with overall performance in line with expectations.

FRANCE

Production in Mboepd	WI	Three months ended September 30		Nine months ended September 30		Year ended December 31
		2025	2024	**2025**	2024	2024
France						
- Paris Basin	100%[1]	1.8	2.1	1.8	2.2	2.1
- Aquitaine	50%	0.3	0.3	0.3	0.3	0.3
		2.1	2.4	**2.1**	2.5	2.4

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

Production
Net production in France during Q3 2025 was in line with guidance at 2,100 boepd with stable performance across all the producing fields.

Organic Growth
In France, field development studies continued in Q3 2025 with the next phase of production well targets matured and ready for sanction decision at IPC's discretion.

FINANCIAL REVIEW

Financial Results

Selected Annual Financial Information

Selected consolidated statement of operations is as follows:

USD Thousands	Q3-25	Q2-25	Q1-25	Q4-24	Q3-24	Q2-24	Q1-24	Q4-23
Revenue	**172,297**	158,892	178,492	199,124	173,200	219,040	206,419	198,460
Gross profit	**32,066**	23,663	44,149	42,774	39,505	72,708	55,184	39,955
Net result	**3,802**	13,850	16,231	415	22,875	45,210	33,719	29,710
Earnings per share – USD	**0.03**	0.12	0.14	0.00	0.19	0.36	0.27	0.23
Earnings per share fully diluted – USD	**0.03**	0.12	0.13	0.00	0.18	0.36	0.26	0.22
Operating cash flow[1]	**66,102**	54,873	74,790	78,158	72,589	101,941	89,301	73,634
Free cash flow[1]	**(23,083)**	(58,252)	(43,172)	(61,476)	(38,269)	7,559	(43,311)	(64,688)
EBITDA[1]	**62,106**	51,519	70,946	76,184	68,313	103,971	87,020	66,284
Net cash/(debt) at period end[1]	**(434,822)**	(374,977)	(314,255)	(208,528)	(157,228)	(88,220)	(60,572)	58,043

[1] *See definition on page 18 under "Non-IFRS measures"*

Summarized consolidated balance sheet information is as follows:

USD Thousands	September 30, 2025	December 31, 2024
Non-current assets	1,798,672	1,554,833
Current assets	170,703	398,849
Total assets	**1,969,375**	1,953,682
Total non-current liabilities	877,741	806,134
Current liabilities	170,191	208,078
Total liabilities	**1,047,932**	1,014,212
Net assets	**921,443**	939,470
Working capital (including cash)	**512**	190,771

Selected Interim Financial Information

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

	Three months ended – September 30, 2025					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	99,686	54,768	15,581	11,870	–	**181,905**
NGLs	–	177	–	–	–	**177**
Gas	25	4,605	–	–	–	**4,630**
Net sales of oil and gas	**99,711**	**59,550**	**15,581**	**11,870**	–	**186,712**
Change in under/over lift position	–	–	–	1,585	–	**1,585**
Royalties	(14,269)	(7,672)	–	(931)	–	**(22,872)**
Hedging settlement	1,886	4,701	–	–	–	**6,587**
Other operating revenue	–	–	–	197	88	**285**
Revenue	**87,328**	**56,579**	**15,581**	**12,721**	**88**	**172,297**
Operating costs	(20,707)	(33,758)	(10,908)	(8,254)	–	**(75,627)**
Cost of blending	(27,588)	(4,863)	–	–	–	**(32,451)**
Change in inventory position	(26)	(353)	2,327	(253)	–	**1,695**
Depletion	(10,360)	(12,425)	(6,504)	(2,956)	–	**(32,245)**
Depreciation of other assets	–	–	(1,419)	–	–	**(1,419)**
Exploration and business development costs	–	–	–	–	(184)	**(184)**
Gross profit/(loss)	**26,647**	**5,180**	**(923)**	**1,258**	**(96)**	**32,066**

	Three months ended – September 30, 2024					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	88,579	68,544	17,876	15,939	–	190,938
NGLs	–	243	–	–	–	243
Gas	26	3,863	–	–	–	3,889
Net sales of oil and gas	88,605	72,650	17,876	15,939	–	195,070
Change in under/over lift position	–	–	–	1,289	–	1,289
Royalties	(15,693)	(11,911)	–	(1,164)	–	(28,768)
Hedging settlement	2,934	2,432	–	–	–	5,366
Other operating revenue	–	–	–	216	27	243
Revenue	75,846	63,171	17,876	16,280	27	173,200
Operating costs	(20,546)	(36,412)	(9,140)	(7,823)	–	(73,921)
Cost of blending	(24,113)	(5,705)	–	–	–	(29,818)
Change in inventory position	369	(699)	3,516	(431)	–	2,755
Depletion	(8,204)	(12,888)	(6,285)	(3,114)	–	(30,491)
Depreciation of other assets	–	–	(2,023)	–	–	(2,023)
Exploration and business development costs	–	–	–	–	(197)	(197)
Gross profit/(loss)	23,352	7,467	3,944	4,912	(170)	39,505

USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
	Nine months ended – September 30, 2025					
Crude oil	283,855	172,623	42,785	36,147	–	**535,410**
NGLs	–	535	–	–	–	**535**
Gas	204	25,800	–	–	–	**26,004**
Net sales of oil and gas	**284,059**	**198,958**	**42,785**	**36,147**	–	**561,949**
Change in under/over lift position	–	–	–	4,285	–	**4,285**
Royalties	(39,321)	(26,293)	–	(2,503)	–	**(68,117)**
Hedging settlement	3,279	7,467	–	–	–	**10,746**
Other operating revenue	–	–	–	572	246	**818**
Revenue	**248,017**	**180,132**	**42,785**	**38,501**	**246**	**509,681**
Operating costs	(61,673)	(97,583)	(31,257)	(24,789)	–	**(215,302)**
Cost of blending	(87,265)	(16,181)	–	–	–	**(103,446)**
Change in inventory position	143	(509)	5,869	(427)	–	**5,076**
Depletion	(28,042)	(37,379)	(17,146)	(8,015)	–	**(90,582)**
Depreciation of other assets	–	–	(4,797)	–	–	**(4,797)**
Exploration and business development costs	–	–	–	–	(752)	**(752)**
Gross profit/(loss)	**71,180**	**28,480**	**(4,546)**	**5,270**	**(506)**	**99,878**

USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
	Nine months ended – September 30, 2024					
Crude oil	308,206	209,551	75,770	49,909	–	643,436
NGLs	–	762	–	–	–	762
Gas	195	24,786	–	–	–	24,981
Net sales of oil and gas	308,401	235,099	75,770	49,909	–	669,179
Change in under/over lift position	–	–	–	6,420	–	6,420
Royalties	(53,565)	(32,811)	–	(3,464)	–	(89,840)
Hedging settlement	6,666	5,262	–	–	–	11,928
Other operating revenue	–	–	–	670	302	972
Revenue	261,502	207,550	75,770	53,535	302	598,659
Operating costs	(60,464)	(106,184)	(23,385)	(24,538)	–	(214,571)
Cost of blending	(97,283)	(19,416)	–	–	–	(116,699)
Change in inventory position	737	(1,024)	3,726	(279)	–	3,160
Depletion	(27,413)	(39,069)	(20,208)	(9,615)	–	(96,305)
Depreciation of other assets	–	–	(6,503)	–	–	(6,503)
Exploration and business development costs	–	–	–	–	(344)	(344)
Gross profit/(loss)	77,079	41,857	29,400	19,103	(42)	167,397

Three and nine months ended September 30, 2025, Review

Revenue

Revenue amounted to USD 172,297 thousand for Q3 2025 compared to USD 173,200 thousand for Q3 2024 and USD 509,681 thousand for the first nine months of 2025 compared to the USD 598,659 thousand for the first nine months of 2024, is analyzed as follows:

USD Thousands	Three months ended September 30		Nine months ended September 30	
	2025	2024	**2025**	2024
Crude oil sales	181,905	190,938	535,410	643,436
Gas and NGL sales	4,807	4,132	26,539	25,743
Change in under/overlift position	1,585	1,289	4,285	6,420
Royalties	(22,872)	(28,768)	(68,117)	(89,840)
Hedging settlement	6,587	5,366	10,746	11,928
Other operating revenue	285	243	818	972
Revenue	**172,297**	173,200	**509,681**	598,659

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

Crude oil sales

USD Thousands	Three months ended – September 30, 2025				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	99,686	54,768	15,581	11,870	**181,905**
- Quantity sold in bbls	1,849,991	993,748	209,107	170,751	**3,223,597**
- Average price realized USD per bbl	53.88	55.11	74.51	69.52	**56.43**

USD Thousands	Three months ended – September 30, 2024				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	88,579	68,544	17,876	15,939	190,938
- Quantity sold in bbls	1,446,627	1,107,248	221,082	198,101	2,973,058
- Average price realized USD per bbl	61.23	61.90	80.86	80.46	64.22

Crude oil revenue was 5% lower in Q3 2025 compared to Q3 2024 due to higher sales volumes offset by lower prices. Canadian-Northern Assets sales volumes are 28% higher in Q3 2025 compared to Q3 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 Q3 2025, WTI averaged USD 65 per bbl compared to USD 75 per bbl for Q3 2024 and the average discount to WCS used in IPC's pricing formula was USD 10 per bbl compared to USD 14 per bbl for the comparative period in 2024.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices. There was one cargo lifting in Malaysia during Q3 2025 and one cargo lifting in Q3 2024. Produced unsold oil barrels from Bertam at the end of Q3 2025 amounted to 188,000 barrels, see Change in Inventory Position section below. The average Dated Brent crude oil price was USD 69 per bbl for Q3 2025 compared to USD 80 per bbl for the comparative period in 2024.

USD Thousands	Nine months ended – September, 2025 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	283,855	172,623	42,785	36,147	**535,410**
- Quantity sold in bbls	5,153,175	3,086,686	580,067	507,167	9,327,095
- Average price realized USD per bbl	55.08	55.93	73.76	71.27	57.40

USD Thousands	Nine months ended – September, 2024 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	308,206	209,551	75,770	49,909	643,436
- Quantity sold in bbls	5,012,498	3,353,780	845,411	602,713	9,814,402
- Average price realized USD per bbl	61.49	62.48	89.63	82.81	65.56

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

Crude oil revenue was lower by 17% during the first nine months of 2025 compared to the first nine months of 2024 due to oil prices lower by 12% and production by 5%.

The Canadian realized sales price is based on the WCS price which trades at a discount to WTI. For the first nine months of 2025, WTI averaged USD 67 per bbl compared to USD 77 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 71per bbl for the first nine months of 2025 compared to USD 83 per bbl for the comparative period.

Gas and NGL sales

	Three months ended – September 30, 2025 Canada – Northern Assets	Canada – Southern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	25	4,782	**4,807**
- Quantity sold in Mcf	69,170	7,404,566	**7,473,736**
- Average price realized USD per Mcf	0.37	0.65	**0.64**

	Three months ended – September 30, 2024 Canada – Northern Assets	Canada – Southern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	26	4,106	4,132
- Quantity sold in Mcf	74,249	7,335,019	7,409,268
- Average price realized USD per Mcf	0.35	0.56	0.56

Gas and NGL sales revenue was 16% higher for the Q3 2025 compared to Q3 2024 mainly due to the higher achieved gas price.

IPC's achieved gas price is based on AECO pricing plus a premium. For Q3 2025, IPC realized an average price of CAD 0.84 per Mcf compared to AECO average pricing of CAD 0.62 per Mcf.

	Nine months ended – September 30, 2025		
	Canada – Northern Assets	Canada – Southern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	203	26,336	**26,539**
- Quantity sold in Mcf	212,242	21,611,998	21,824,240
- Average price realized USD per Mcf	0.96	1.22	1.22

	Nine months ended – September 30, 2024		
	Canada – Northern Assets	Canada – Southern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	195	25,548	25,743
- Quantity sold in Mcf	208,107	22,810,152	23,018,259
- Average price realized USD per Mcf	0.94	1.12	1.12

Gas and NGL sales revenue was 3% higher for the first nine months of 2025 compared to the first nine months of 2024 mainly due to the higher achieved gas price.

IPC's achieved gas price is based on AECO pricing plus a premium. For the first nine months of 2025, IPC realized an average price of CAD 1.67 per Mcf compared to AECO average pricing of CAD 1.45 per Mcf.

Hedging settlement

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

The realized hedging settlement for the first nine months of 2025 amounted to a gain of USD 10,746 thousand and consisted of a gain of USD 5,628 thousand on the oil contracts and a gain of USD 5,118 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 106,383 thousand for Q3 2025 compared to USD 100,984 thousand for Q3 2024 and USD 313,672 thousand for the first nine months of 2025 compared to USD 328,110 thousand for the first nine months of 2024, and is analyzed as follows:

	Three months ended – September 30, 2025					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	22,707	33,758	10,908	8,254	–	**75,627**
USD/boe[2]	15.16	15.10	37.44	41.54	n/a	**17.91**
Cost of blending	27,588	4,863	–	–	–	**32,451**
Change in inventory position	26	353	(2,327)	253	–	**(1,695)**
Production costs	**50,321**	**38,974**	**8,581**	**8,507**	–	**106,383**

	Three months ended – September 30, 2024					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	20,546	36,412	13,235	7,823	(4,095)	73,921
USD/boe[2]	17.07	15.35	39.27	34.99	n/a	17.87
Cost of blending	24,113	5,705	–	–	–	29,818
Change in inventory position	(369)	699	(3,516)	431	–	(2,755)
Production costs	44,290	42,816	9,719	8,254	(4,095)	100,984

	Nine months ended – September 30, 2025					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	61,673	97,583	34,785	24,789	(3,528)	**215,302**
USD/boe[2]	15.15	14.12	45.28	42.33	n/a	**17.66**
Cost of blending	87,265	16,181	–	–	–	**103,446**
Change in inventory position	(143)	509	(5,869)	427	–	**(5,076)**
Production costs	**148,795**	**114,273**	**28,916**	**25,216**	(3,528)	**313,672**

	Nine months ended – September 30, 2024					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	60,464	106,184	35,670	24,538	(12,285)	214,571
USD/boe[2]	15.28	14.65	32.92	35.65	n/a	16.53
Cost of blending	97,283	19,416	–	–	–	116,699
Change in inventory position	(737)	1,024	(3,726)	279	–	(3,160)
Production costs	157,010	126,624	31,944	24,817	(12,285)	328,110

[1] *See definition on page 18 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 37.44 for Q3 2025 and USD 27.12 for the comparative period and USD 40.69 and USD 21.58 for the nine months ended September 30, 2025, and September 30, 2024, respectively*

Operating costs
Operating costs amounted to USD 75,627 thousand for Q3 2025 compared to USD 73,921 thousand for Q3 2024 and USD 215,302 thousand for the first nine months of 2025 compared to USD 214,571 thousand for the first nine months of 2024. Operating costs per boe amounted to USD 17.91 per boe in Q3 2025 marginally below the guidance for the quarter and compared with USD 17.87 per boe in Q3 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 32,451 thousand for Q3 2025 compared to USD 29,818 thousand for Q3 2024 and USD 103,446 thousand for the first nine months of 2025 compared to USD 116,699 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 Q3 2025, IPC had crude entitlement of 188,000 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 32,245 thousand for Q3 2025 compared to USD 30,491 thousand for Q3 2024 and USD 90,582 thousand for the first nine months of 2025 compared to USD 96,305 thousand for the first nine months of 2024.

The depletion charge is analyzed in the following tables:

	Three months ended – September 30, 2025				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Depletion cost in USD thousands	10,360	12,425	6,504	2,956	**32,245**
USD per boe	6.92	5.56	22.32	14.89	**7.64**

	Three months ended – September 30, 2024				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Depletion cost in USD thousands	8,204	12,888	6,285	3,114	30,491
USD per boe	6.82	5.43	18.65	13.93	7.37

	Nine months ended – September 30, 2025				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Depletion cost in USD thousands[1]	28,042	37,379	17,146	8,015	**90,582**
USD per boe[2]	6.89	5.52	22.32	13.69	**7.43**

	Nine months ended – September 30, 2024				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Depletion cost in USD thousands[1]	27,413	39,069	20,208	9,615	96,305
USD per boe[2]	6.93	5.39	18.65	13.97	7.42

[1] *In Canada, excludes the adjustment for accelerated decommissioning activities.*
[2] *USD/boe in the tables above is calculated by dividing the depletion cost by the production volume for each country for the period.*

The depletion charge is derived by applying the depletion rate per boe to the volumes produced in the period by each field. The depletion rate in Malaysia has significantly increased compared to the prior period due to lower production as a result of planned infill well and well maintenance activity completed in Q3 2025 and wells A21 and A15 brought on production in late July 2025. Overall though, depletion costs on a USD per boe basis have been very stable.

Depreciation of other tangible fixed assets
The total depreciation of other tangible fixed assets amounted to USD 1,419 thousand for Q3 2025 compared to USD 2,023 thousand for Q3 2024 and USD 4,797 thousand for the first nine months of 2025 compared to USD 6,503 thousand for the first nine months of 2024. This relates to the depreciation of the FPSO Bertam, which has been depreciated to its residual value on a unit of production basis to August 2025.

Exploration and business development costs
The total exploration and business developments costs amounted to a cost of USD 752 thousand for the first nine months of 2025 and USD 344 thousand for the first nine months of 2024.

Net financial items
Net financial items amounted to a charge of USD 21,030 thousand for Q3 2025 compared to a charge of USD 4,124 thousand for Q3 2024 and a charge of USD 39,726 thousand for the first nine months of 2025 compared to a charge of USD 23,942 thousand for the first nine months of 2024. Net financial items included a realized currency hedge loss of USD 8,039 thousand and a net foreign exchange gain of USD 8,502 thousand for the first nine months of 2025 compared to no realized currency hedges and a net foreign exchange gain of USD 1,743 thousand for the first nine months of 2024. The foreign exchange movements are mainly resulting from the revaluation of intra-group loan funding balances and are non-cash items.

Excluding foreign exchange movements and realized currency cashflow hedges, the net financial items amounted to a charge of USD 14,778 thousand for Q3 2025 compared to USD 9,484 thousand for Q3 2024 and a charge of USD 40,189 thousand for the first nine months of 2025 compared to a charge of USD 25,685 thousand for the first nine months of 2024.

The interest expense are stable and amounted to USD 10,082 thousand for Q3 2025 compared to USD 9,119 thousand for the comparative period in 2024 and USD 27,823 thousand for the first nine months of 2025 compared to USD 26,865 thousand for the first nine months of 2024 and mainly related to the bond interest at a coupon rate of 7.25% per annum. Interest income generated on cash balances held amounted to USD 501 thousand for Q3 2025 and USD 4,112 thousand for Q3 2024 and USD 2,829 thousand for the first nine months of 2025 compared to USD 14,646 thousand for the first nine months of 2024.

The unwinding of the asset retirement obligation discount rate amounted to USD 4,229 thousand for Q3 2025 compared to USD 3,680 thousand for Q3 2024 and USD 12,301 thousand for the first nine months of 2025 compared to USD 10,939 thousand for the first nine months of 2024.

Income tax

The corporate income tax amounted to a charge of USD 3,030 thousand for Q3 2025 compared to a charge of USD 8,257 thousand for the comparative period in 2024 and a charge of USD 13,876 thousand for the first nine months of 2025 compared to a charge of USD 29,473 thousand for the comparative period in 2024.

The current income tax amounted to a gain of USD 97 thousand for Q3 2025 and a charge of USD 754 thousand during the first nine months of 2025 and mainly related to France. No corporate income tax is expected to be payable in Canada in 2025 due to the usage of historical tax pools.

Capital Expenditure

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

USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Development	223,043	6,424	39,161	4,782	**273,410**
Exploration and evaluation	3,529	–	–	–	**3,529**
	226,572	6,424	39,161	4,782	**276,939**

Capital expenditures of USD 276,939 thousand was mainly spent in Canada on the Blackrod Phase 1 Development project and in Malaysia for the A21 infill well drilling.

Other tangible fixed assets

Other tangible fixed assets amounted to USD 11,866 thousand as at September 30, 2025, which included USD 10,000 thousand in respect of the FPSO Bertam. The FPSO Bertam has been depreciated to its residual value on a unit of production basis to August 2025.

Financial Position and Liquidity

Financing

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

On September 25, 2025, IPC announced the placement of MUSD 450 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 MUSD 25 commencing in April 2028. The new bonds were issued in October 2025, with the proceeds being 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 expected cash refinancing costs, which include the call option costs of the senior unsecured bonds, and the related transaction costs, to be incurred in Q4 2025, are estimated at approximately USD 18 million.

In addition, as at September 30, 2025, the Group had a senior secured revolving credit facility of MCAD 250 (the "Canadian RCF") in connection with its oil and gas assets in Canada, with a maturity date in May 2027. As at September 30, 2025 MCAD 37 (MUSD 27) was drawn under the Canadian RCF. As at September 30,2025, the Group also had a letter of credit facility in Canada (the "LC Facility") to cover operational letters of credit. As at September 30, 2025, operational letters of credit in an aggregate of MCAD 33.7 have been issued under the LC Facility, of which MCAD 24.5 relates to a third party pipeline construction agreement for the Blackrod Phase 1 Development project which is expected to be released when the pipeline become operational.

As at September 30, 2025, IPC had an unsecured Euro credit facility in France (the "France Facility"), with maturity in May 2026. IPC makes quarterly repayments of the France Facility. The amount remaining outstanding under the France Facility as at September 30, 2025 was MUSD 2.9 which is classified as current representing the repayment planned within the next twelve months.

The Group is in compliance with the covenants of the bonds and its other credit facilities as at September 30, 2025. Net debt as at September 30, 2025 amounted to MUSD 435. Cash and cash equivalents held amounted to MUSD 45 as at September 30, 2025.

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

Working Capital
As at September 30, 2025, the Group had a working capital balance including cash of USD 512 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 for non-recurring profit/loss on sale of assets and other income.

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

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

Reconciliation of Non-IFRS Measures

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

	Three months ended September 30		Nine months ended September 30	
USD Thousands	**2025**	2024	**2025**	2024
Revenue	172,297	173,200	509,681	598,659
Production costs and net sales of diluent to third party[1]	(106,292)	(100,984)	(313,162)	(328,110)
Current tax	97	373	(754)	(6,718)
Operating cash flow	**66,102**	72,589	**195,765**	263,831

[1] Includes net sales of diluent to third party amounting to USD 91 thousand for the third quarter of 2025 and USD 510 thousand for the first nine months of 2025.

Free cash flow

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

	Three months ended September 30		Nine months ended September 30	
USD Thousands	2025	2024	2025	2024
Operating cash flow - see above	66,102	72,589	195,765	263,831
Capital expenditures	(80,128)	(99,100)	(276,939)	(308,457)
Abandonment and farm-in expenditures[1]	5,374	(2,575)	2,956	(4,938)
General and administrative expenses before depreciation[2]	(3,899)	(3,903)	(11,948)	(11,245)
Cash financial items[3]	(10,532)	(5,280)	(34,341)	(13,212)
Free cash flow	**(23,083)**	(38,269)	**(124,507)**	(74,021)

[1] *See notes 11 and 16 to the Financial Statements.*
[2] *Depreciation is not specifically disclosed in the Financial Statements.*
[3] *See notes 4 and 5 to the Financial Statements.*

EBITDA

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

	Three months ended September 30		Nine months ended September 30	
USD Thousands	2025	2024	2025	2024
Net result	3,802	22,875	33,883	101,804
Net financial items	21,030	4,124	39,726	23,942
Income tax	3,030	8,257	13,876	29,473
Depletion and decommissioning costs	32,245	30,491	90,582	96,305
Depreciation of other tangible fixed assets	1,419	2,023	4,797	6,503
Exploration and business development costs	184	197	752	344
Sale of assets[1]	–	–	(104)	–
Depreciation included in general and administrative expenses[2]	396	346	1,059	933
EBITDA	**62,106**	68,313	**184,571**	259,304

[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 September 30		Nine months ended September 30	
USD Thousands	2025	2024	2025	2024
Production costs	106,383	100,984	313,672	328,110
Cost of blending	(32,451)	(29,818)	(103,446)	(116,699)
Change in inventory position	(1,695)	2,755	5,076	3,160
Operating costs	**75,627**	73,921	**215,302**	214,571

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

USD Thousands	September 30, 2025	December 31, 2024
Bank loans	(29,483)	(5,121)
Bonds[1]	(450,000)	(450,000)
Cash and cash equivalents	44,661	246,593
Net cash/(debt)	**(434,822)**	(208,528)

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

Off-Balance Sheet Arrangements

IPC, through its subsidiary IPC Canada Ltd, has issued six letters of credit as follows: (a) MCAD 2.6 in respect of its obligations to purchase diluent; (b) MCAD 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 24.5 in respect of its obligations related to Blackrod Phase 1 pipelines; and (f) MCAD 3.9 in respect of electricity distribution services.

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 September 30, 2025, IPC purchased 6,641,970 common shares under the NCIB and 261,818 common shares under certain other exemptions in Canada. During the first nine months of 2025, IPC cancelled 6,989,406 of these purchased common shares, including the common shares held in treasury as at December 31, 2024. As at September 30, 2025, IPC had a total of 112,180,065 common shares issued and outstanding, of which IPC held 24,538 common shares in treasury. In October 2025, the shares held in treasury were cancelled and as at November 4, 2025, IPC had a total of 112,155,527 common shares issued and outstanding, with no common shares in treasury.

Nemesia S.à.r.l., an investment company ultimately controlled by trusts whose settlor is the late Adolf H. Lundin, holds 42,597,533 common shares in IPC, representing 38.0% of the outstanding common shares as at September 30, 2025.

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

IPC has 2,941,020 IPC Share Unit Plan awards outstanding as at November 4, 2025, of which 948,938 awards were granted in 2025.

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

Contractual Obligations and Commitments

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

MCAD	2025	2026	2027	2028	2029	Thereafter
Transportation service[1]	9.9	59.3	91.6	99.1	103.1	1,488.7
Power[2]	3.6	12.4	12.4	9.8	–	–
Total commitments	**13.5**	**71.7**	**104.0**	**108.9**	**103.1**	**1,488.7**

[1] *IPC has firm transportation commitments on oil and natural gas pipelines that expire between 2037 and 2047.*
[2] *IPC has physical delivery power hedges to purchase 15MWh at a weighted average price of CAD 74.92/MWh from October 1, 2025 to December 31, 2028, an additional 5MWh at a weighted average price of CAD 58.31/MWh from October 1, 2025 to December 31, 2027, and an additional 5MWh at a weighted average price of CAD 46.85/MWh from October 1, 2025 to December 31, 2025.*

Material Accounting Policies and Estimates

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

Transactions with Related Parties

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

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

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

Financial Risk Management

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

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

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

Period	Volume (Gigajoules (GJ) per day))	Type	Average Pricing
October 1, 2025 - October 31, 2025	20,000	AECO Swap	CAD 2.25/GJ
October 1, 2025 - December 31, 2025	10,000	AECO Swap	CAD 2.50/GJ
April 1, 2026 - October 31, 2026	10,000	AECO Swap	CAD 2.65/GJ

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

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

The above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. The hedges had a positive fair value of USD 11,101 thousand as at September 30, 2025.

Currency Risk
The Group's policy on currency rate hedging is, in the case of currency exposure, to consider fixing the rate of exchange. The Group will take into account the currency exposure, current rates of exchange and market expectations in comparison to historic trends and volatility in making the decision to hedge.
The Group entered into currency hedges to purchase:
(i) a total MCAD 97.5 for the period October 2025 to December 2025 at an average rate of CAD 1.36 (sell USD);
(ii) a total MEUR 6.75 for the period October 2025 to December 2025 at an average rate of EUR 1.08 (sell USD);
(iii) a total MMYR 30 for the period October 2025 to December 2025 at an average rate of MYR 4.38 (sell USD).

The outstanding portion of all of the above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. The hedges had a negative fair value of USD 723 thousand as at September 30, 2025.

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

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

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

RISK FACTORS

IPC is engaged in the exploration, development and production of oil and gas and is exposed to various operational, environmental, market and financial risks and uncertainties. For further information and discussion of these risks and uncertainties, please see IPC's Annual Information Form for the year ended December 31, 2024 ("AIF") available on SEDAR+ at www.sedarplus.ca or on IPC's website at www.international-petroleum.com. See also "Cautionary Statement Regarding Forward Looking Information" and "Reserves and Resources Advisory" in this MD&A.

DISCLOSURE CONTROLS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

There have been no material changes to the Groups internal control over financial reporting during the three and nine months ended September 30, 2025, that have materially affected, or are reasonably likely to materially affect, the Group's internal control over financial reporting.

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

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

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

Forward-looking statements include, but are not limited to, statements with respect to:
- 2025 production ranges (including total daily average production), production composition, cash flows, operating costs and capital and decommissioning expenditure estimates;
- Estimates of future production, cash flows, operating costs and capital expenditures that are based on IPC's current business plans and assumptions regarding the business environment, which are subject to change;
- IPC's financial and operational flexibility to navigate the Corporation through periods of volatile commodity prices;
- The ability to fully fund future expenditures from cash flows and current borrowing capacity;
- IPC's intention and ability to continue to implement its strategies to build long-term shareholder value;
- The ability of IPC's portfolio of assets to provide a solid foundation for organic and inorganic growth;
- The continued facility uptime and reservoir performance in IPC's areas of operation;
- Development of the Blackrod project in Canada, including estimates of resource volumes, future production, timing, regulatory approvals, third party commercial arrangements, breakeven oil prices and net present values;
- Current and future production performance, operations and development potential of the Onion Lake Thermal, Suffield, Brooks, Ferguson and Mooney operations, including the timing and success of future oil and gas drilling and optimization programs;
- The potential improvement in the Canadian oil egress situation and IPC's ability to benefit from any such improvements;
- The ability to maintain current and forecast production in France and Malaysia;
- The ability of IPC to renew the NCIB and the number of common shares which may be purchased under a renewed NCIB;
- The intention and ability of IPC to acquire further common shares under the NCIB, including the timing of any such purchases;
- The return of value to IPC's shareholders as a result of the NCIB;
- IPC's ability to implement its greenhouse gas (GHG) emissions intensity and climate strategies and to achieve its net GHG emissions intensity reduction targets;
- IPC's ability to implement projects to reduce net emissions intensity, including potential carbon capture and storage;
- Estimates of reserves and contingent resources;
- The ability to generate free cash flows and use that cash to repay debt;
- IPC's continued access to its existing credit facilities, including current financial headroom, on terms acceptable to the Corporation;
- IPC's ability to identify and complete future acquisitions;
- Expectations regarding the oil and gas industry in Canada, Malaysia and France, including assumptions regarding future royalty rates, regulatory approvals, legislative changes, tariffs, and ongoing projects and their expected completion; and
- Future drilling and other exploration and development activities.

Statements relating to "reserves" and "contingent resources" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated and that the reserves and resources can be profitably produced in the future. Ultimate recovery of reserves or resources is based on forecasts of future results, estimates of amounts not yet determinable and assumptions of management. See also "Reserves and Resources Advisory".

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

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

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

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

Estimated production and FCF generation are based on IPC's current business plans over the periods of 2025 to 2029 and 2030 to 2034, less net debt of MUSD 209 as at December 31, 2024, with assumptions based on the reports of IPC's independent reserves evaluators, and including certain corporate adjustments relating to estimated general and administration costs and hedging, and excluding shareholder distributions and financing costs. Assumptions include average net production of approximately 57 Mboepd

over the period of 2025 to 2029, average net production of approximately 63 Mboepd over the period of 2030 to 2034, average Brent oil prices of USD 75 to 95 per bbl escalating by 2% per year, and average Brent to Western Canadian Select differentials and average gas prices as estimated by IPC's independent reserves evaluator and as further described in the AIF. IPC's current business plans and assumptions, and the business environment, are subject to change. Actual results may differ materially from forward-looking estimates and forecasts.

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

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

RESERVES AND RESOURCES ADVISORY

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

	Heavy Crude Oil (Mbopd)	Light and Medium Crude Oil (Mbopd)	Conventional Natural Gas (per day)	Total (Mboepd)
Three months ended				
September 30, 2025	24.5	6.5	89.3 MMcf (14.9 Mboe)	45.9
September 30, 2024	21.9	7.8	91.9 MMcf (15.3 Mboe)	45.0
Nine months ended				
September 30, 2025	23.5	6.3	89.1 MMcf (14.8 Mboe)	44.6
September 30, 2024	23.7	7.9	94.8 MMcf (15.8 Mboe)	47.4
Year ended				
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 43,000 to 45,000 boepd for 2025. IPC estimates that approximately 53% of that production will be comprised of heavy crude oil, approximately 14% will be comprised of light and medium crude oil and approximately 33% will be comprised of conventional natural gas.

OTHER SUPPLEMENTARY INFORMATION

Abbreviations

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

Oil related terms and measurements

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

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