Q4

International Petroleum Corporation

Management's Discussion and Analysis

For the three months ended and year ended December 31, 2019

International Petroleum Corp.

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 International Financial Reporting 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 23.

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 34.

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, 2019, and are included in the report 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, 2019, 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, 2019, 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, 2019, price forecasts.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of the oil and gas assets of Granite Oil Corp. (Granite) are effective as of December 31, 2019, and are included in reports prepared by Sproule on behalf of IPC, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2019, price forecasts.

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

INTRODUCTION

This management's discussion and analysis ("MD&A") for International Petroleum Corporation ("IPC" or the "Corporation" and, together with its subsidiaries, the "Group") is dated February 11, 2020, and is intended to provide an overview of the Group's operations, financial performance and current and future business opportunities. This MD&A should be read in conjunction with IPC's audited consolidated financial statements and accompanying notes for the year ended December 31, 2019 ("Financial Statements").

Formation of and changes in the Group

In April 2017, Lundin Petroleum AB ("Lundin Petroleum") spun-off its oil and gas assets in Malaysia, France and the Netherlands into a newly formed company called International Petroleum Corporation and distributed the IPC shares, on a pro-rata basis, to Lundin Petroleum shareholders (the "Spin-Off").

On April 24, 2017, the Spin-Off was completed and IPC's shares commenced trading on the Toronto Stock Exchange and Nasdaq First North under the ticker symbol "IPCO". In June 2018, the shares of IPC ceased trading on Nasdaq First North and commenced trading on the Nasdaq Stockholm.

On January 5, 2018, IPC completed the acquisition of the Suffield area oil and gas assets in southern Alberta, Canada (the "Suffield Assets").

On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.

On December 14, 2018, IPC completed the acquisition of all of the issued and outstanding shares of BlackPearl Resources Inc. ("BlackPearl") by way of a plan of arrangement under the Canada Business Corporation Act (the "BlackPearl Acquisition").

On January 20, 2020, IPC announced the proposed acquisition of all of the issued and outstanding shares of Granite Oil Corp. ("Granite") by way of a plan of arrangement under the Business Corporations Act (Alberta) (the "Granite Acquisition"). The completion of the Granite Acquisition remains subject to certain conditions and is expected to occur in early March 2020.

The main business of IPC is 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.

Basis of Preparation

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

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

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

	December 31, 2019		December 31, 2018	
	Average	Period end	Average	Year end
1 EUR equals USD	1.1196	1.1234	1.1815	1.1450
1 USD equals CAD	1.3270	1.2994	1.2958	1.3629
1 USD equals MYR	4.1422	4.0905	4.0354	4.1325

2019 HIGHLIGHTS

Business Development

- In January 2020, IPC announced the proposed light oil acquisition of proved plus probable ("2P") reserves of 14.0 million barrels of oil equivalent (MMboe) and 6.2 MMboe of contingent resources (best estimate, unrisked) as at December 31, 2019, for total equity and debt consideration of approximately USD 59 million[2]. The acquisition of Granite will be IPC's third acquisition in less than three years. Completion of the Granite transaction remains subject to satisfaction of certain conditions and is expected to occur in early March 2020.

Operational and Resource Highlights

- Average net production of approximately 47,200 barrels of oil equivalent (boe) per day (boepd) for the fourth quarter of 2019.
- Full year 2019 average net production of approximately 45,800 boepd, in line with Q3 2019 guidance.
- Full year 2019 operating costs[1] per boe of USD 12.8, slightly ahead of Q3 2019 guidance.
- Capital expenditure for full year 2019 of USD 181 million, USD 4 million below Q3 2019 guidance with USD 3 million phased into 2020.
- Successfully delivered a 26 development well program in the Suffield area, Canada.
- Extensive Suffield area gas swabbing and well optimization program delivered during 2019.
- Onion Lake Thermal facility expansion and upgrades completed in Canada, as well as the addition of the new F-Pad wells.
- Third well pair at the Blackrod project, Canada, completed with approximately 1,400 metres of horizontal section; commencing steam injection in early 2020.
- Successful delivery of the Vert La Gravelle field Phase I redevelopment project, lifting Q4 2019 production in France by 28 percent relative to Q3 2019.
- Successfully delivered the three well infill drilling programme at the Bertam field in Malaysia and identified additional infill potential.
- 2P reserves as at December 31, 2019, increased to 300 MMboe[2], with a 2019 reserves replacement ratio of 89 percent excluding acquisitions and 173 percent including acquisitions[2].
- Contingent resources (best estimate, unrisked) increased from 849 MMboe as at December 31, 2018, to 1,089 MMboe[2] as at December 31, 2019.

[1] *See definition on page 23 under "Non-IFRS measures"*
[2] *Includes 2P reserves and contingent resources attributable to the oil and gas assets of Granite. The acquisition cost of USD 59 million includes USD 29 million in cash and USD 30 million in net debt assumption. See "Cautionary Statement Regarding Forward-Looking Information" and "Reserves and Resources Advisory".*

Financial Highlights

	Three months ended December 31		Year ended December 31	
USD Thousands	**2019**	2018	**2019**	2018
Revenue	145,535	111,898	553,749	454,443
Gross profit	43,245	26,311	152,904	146,864
Net result	38,372	29,346	103,588	103,644
Operating cash flow[1]	78,888	58,322	307,944	279,018
Free cash flow[1]	4,432	34,864	89,308	203,282
EBITDA[1]	77,353	58,032	302,513	264,041
Net Debt[1]	231,503	276,761	231,503	276,761

[1] *See definition on page 23 under "Non-IFRS measures"*

- Full year 2019 operating cash flow ("OCF")[1] generation of USD 308 million, the highest annual OCF since IPC's inception.
- Full year 2019 free cash flow ("FCF")[1] generation of USD 89 million.
- Net debt[1] reduced from USD 277 million as at December 31, 2018 to USD 231.5 million as at December 31, 2019.
- Net debt[1] to EBITDA[1] ratio of less than 0.8 times as at December 31, 2019.

- In November 2019, IPC announced a share repurchase program, with the ability to repurchase up to approximately 11.5 million IPC shares over a twelve month period. Repurchased for USD 16.9 million and cancelled approximately 3.9 million IPC shares as at end December 2019 and a further approximately 2.9 million IPC shares were repurchased for USD 11.8 million, of which approximately 2.5 million shares were cancelled, as at end January 2020.

OPERATIONS REVIEW

Business Overview

Our focus since launching IPC in April 2017 remains unchanged: seeking to deliver operational excellence, demonstrating financial resilience, maximizing the value of our resource base and targeting growth organically and through acquisition.

Our vision and strategy from the outset was to use the IPC platform to build a new international upstream company focused on creating long-term value for our shareholders, launched at a favorable time in the industry cycle to acquire and grow a significant resource base.

With financial results delivered at the high end of guidance and the most active quarter of investment across all areas of operations, as well as the announcement of another corporate acquisition and the ongoing execution of IPC's second share repurchase program, we continue to make excellent progress on all fronts in delivering on that strategy.

Delivering Operational Excellence

During Q4 2019, our assets delivered average daily net production of 47,200 boepd, a four percent increase from Q3 2019. Full year average production was 45,800 boepd, in line with our Q3 2019 guidance.

Record high net production levels above 49,000 boepd were achieved in early December 2019, marginally below the previously guided 50,000 boepd exit rate as the start-up of our A-20 well in Malaysia was moved into mid-January 2020. Initial rates from the A-20 well are encouraging with production in excess of 2,000 boepd net to IPC. In late December 2019, we lost productivity on our A-15 well that has been on production since 2016. As a result, the full field production of the Bertam field following the 2019 infill campaign is expected to be reduced by around 1,500 boepd net during Q1 2020 until the A-15 remedial works are completed.

The net average production from the Suffield area assets in Canada of 24,500 boepd during Q4 2019 was in line with our Q3 2019 guidance. It is noteworthy that our full year 2019 average net production levels at the Suffield area were two percent higher than 2018 levels demonstrating the positive impact of our ongoing oil drilling and gas optimization programs more than offsetting natural declines. Our N2N enhanced oil recovery (EOR) project and drilling program was completed as scheduled in 2019. Seven out of eight injection wells are receiving Alkaline Surfactant Polymer (ASP) and all six production wells are on line. In addition, preparatory work continued during Q4 2019 which is expected to allow our single rig drilling program to continue through 2020.

The average production from the Onion Lake Thermal facility in Canada during Q4 2019 was in line with our Q3 2019 guidance at 11,400 boepd, a 14 percent increase on Q3 2019. Facility optimization work had been completed earlier in the year that allowed for steam injection to commence at F-Pad during Q3 2019 and production ramp up through Q4 2019. Following completion of the ramp up of production, average production rates during December 2019 were just below 12,000 boepd in line with expectation. As we look forward, we plan to add another drilling pad during 2020 to increase production toward facility capacity levels of 14,000 boepd by year-end 2020.

In Malaysia, a world class uptime performance on the Bertam FPSO in excess of 99 percent continued during Q4 2019. Fourth quarter 2019 production on the Bertam field was 5,400 bopd, in line with our Q3 2019 guidance and five percent higher than Q3 2019 production as we started to benefit from production from the three well infill drilling program. Current net production is above 5,800 bopd with the A-15 well shut-in pending remedial works. This demonstrates a current full field production potential at the Bertam field of close to 7,500 boepd net to IPC. The A-15 well is expected back online in early Q2 2020. Following encouraging results from the 2019 infill drilling program, two additional infill drilling locations have been identified and booked as contingent resources in the A-15/A-20 area. Further technical work is planned on these locations during 2020, for potential drilling in 2021.

Production in France in Q4 2019 was 28 percent higher than Q3 2019 production, averaging 3,200 boepd. The drilling in mid-September 2019 of our first horizontal development well (VGR113) at the Vert La Gravelle field was a major milestone for IPC. Production from VGR113 continues to exceed expectation with current rates averaging above 1,000 boepd. The remaining wells of this campaign have been completed and are expected to start production and injection in late Q1 2020. We continue to observe and analyze what potential sustained production levels can be achieved going forward, however we are certainly off to an encouraging start.

With Phase I of the Vert La Gravelle redevelopment now being completed, our focus and attention now turns to the Phase I development of the Villeperdue West field in 2020 with three horizontal production wells planned, as well as assessing the potential for completion of further horizontal wells in Rhaetian fields. Furthermore, IPC holds around 7 MMboe of undeveloped contingent resources in similar Triassic reservoirs to the Vert La Gravelle field that are subject to assessment for future development potential.

Our operating costs per boe for Q4 2019 was USD 12.4, in line with guidance, with the full year at USD 12.8 per boe, marginally below Q3 2019 guidance. Full year capital expenditure of USD 181 million was slightly below Q3 guidance of USD 188 million with approximately USD 3 million of activities carried over into 2020.

Demonstrating Financial Resilience

IPC delivered a very strong full year financial performance generating an operating cash flow of USD 308 million, at the upper end of Q3 2019 guidance and a full year net result of USD 104 million. The Q4 2019 operating cash flow amounted to USD 79 million. Free cash flow generation for the full year was USD 89 million (excluding the share repurchase program and before payment of the Spin-Off residual working capital liability to Lundin Petroleum). This robust financial performance allowed IPC to fund its expenditure and share repurchase programs, whilst reducing net debt levels from USD 277 million at the end of 2018 to USD 231.5 million by the end of 2019.

The strong operating cash flow generation is the result of good operational delivery combined with stronger realized oil and gas prices relative to forecast. The average full year Brent price of USD 64 per barrel was USD 4 per barrel above our mid-point guidance of USD 60 per barrel, with the average WTI-WCS differential averaging USD 13 per barrel for the full year, better than our USD 15 per barrel upside case. Realized gas prices of CAD 2.77 per Mcf were above our mid-point guidance of CAD 2.50 per Mcf.

Maximizing the Value of our Resource Base

Good progress has been made in adding value to IPC's resource base since April 2017. As at the end of December 2019, IPC's 2P reserves have increased more than tenfold from inception to 300 MMboe. This included a reserves replacement ratio of 89 percent in 2019, excluding acquisition additions, following upgrades predominantly in Canada.

In addition, our best estimate contingent resources as at the end of December 2019 increased to 1,089 MMboe (unrisked). The largest single addition to the contingent resource base is the Blackrod land acquisition that was completed in Q2 2019. We are confident that we have a solid contingent resource base in place that can provide the feedstock to add significantly to IPC's reserves and value in the future.

Growth from Acquisition

IPC has transformed itself following the completion of two large acquisitions in 2018, and this Q4 2019 report shows the material positive impact on reserves, resources, production and cash flow.

In January 2020, we were very pleased to announce the agreement reached for our third acquisition of high quality operated assets in less than three years since IPC was created. The acquisition of Granite is expected to provide access to a new resource play fairway that adds additional reserves, resources and production of long life, high margin light oil with significant growth potential. We believe that we can more than double the current production levels of Granite's assets within the next three years, and more than fully fund this growth with the cash flows generated from these assets. The Granite transaction is expected to be completed in early March 2020, subject to satisfaction of certain conditions.

Notwithstanding this acquisition, with significant undrawn credit facilities at our disposal, we continue to opportunistically evaluate additional acquisition targets that we believe can deliver long-term value for our shareholders.

HSE Performance

Health, Safety & Environmental performance (HSE) remains a priority for all operational assets. Our objective is to reduce risk and eliminate hazards to prevent the occurrence of accidents, ill health and environmental damage, as these are essential to the success of our operations. During 2019, IPC recorded no material safety or environmental incidents.

Share Repurchase Program

In November 2019, IPC announced the implementation of a share repurchase program because we believe that the current common share price does not reflect the underlying value of those shares. IPC believes that the share repurchase program represents an effective use of IPC's capital and an efficient way to return value to IPC's shareholders. During Q4 2019, a total of 3,929,196 shares were repurchased and cancelled for an aggregate consideration of USD 16.9 million. A further 2,919,280 shares were repurchased during January 2020 of which 2,540,000 shares were cancelled.

Operations Overview

Reserves and Resources

The 2P reserves attributable to IPC oil and gas assets have grown by around five percent to 300 MMboe of 2P reserves as at December 31, 2019 (including the 2P reserves to be acquired in the Granite Acquisition) compared to 288 MMboe of 2P reserves as at December 31, 2018, in each case as certified by independent third party reserves auditors. The reserves life index (RLI) as at December 31, 2019 (including the 2P reserves to be acquired in the Granite Acquisition) was approximately 17 years. Best estimate contingent resources as at December 31, 2019, increased to 1,089 MMboe (unrisked) (and including the contingent resources to be acquired in the Granite Acquisition).

IPC remains focused on organic growth, maturing and executing opportunities across all our operated assets in 2020. In Canada, oil drilling activities continued through 2019, complemented by gas optimization activities that continue to generate excellent production performance, offsetting the historical production decline. In Malaysia, the planned three well infill drilling program commenced in Q2 2019 and continued through Q4 2019 with the last well in the program brought online in January 2020. In France, the Vert La Gravelle redevelopment project commenced on schedule in Q2 2019, with the successful delivery of the first ever horizontal production well in the field in Q3 2019.

Production

The average net production during Q4 2019 was in line with our Q3 2019 guidance at 47,200 boepd. Production levels peaked in early December at 49,000 boepd, and without the operational issues on the A-15 well and the rescheduled start-up of the A-20 well on the Bertam field, we would have exceeded our exit rate guidance of 50,000 boepd. At Onion Lake Thermal, production ramp up continued in Q4 2019 with daily production rates averaging just under 12,000 boepd in December 2019. Production from the first sustaining well pad (F-Pad) commenced in Q3 2019 with ramp up and production rate optimization continuing into Q4 2019. The first well of the Vert La Gravelle redevelopment was brought online in Q3 2019 with production performance exceeding expectations. Initial rates on the VGR113 well were in excess of 1,000 boepd and increased IPC's aggregate net production rates in France to over 3,000 boepd for Q4 2019.

Integration of the former BlackPearl assets has delivered a significant increase in production volumes for IPC relative to 2018 levels. The production during Q4 2019 with comparatives was comprised as follows:

	Three months ended December 31		Year ended December 31	
Production in Mboepd	2019	2018	2019	2018
Crude oil				
Canada – Suffield	6.5	6.3	6.4	6.3
Canada – Onion Lake Thermal	11.4	–	10.2	–
Canada – Other	2.6	–	2.9	–
Malaysia	5.4	6.8	5.8	7.3
France	3.2	2.4	2.5	2.5
Total crude oil production	**29.1**	15.5	**27.8**	16.1
Gas				
Canada – Suffield	18.0	18.6	17.9	17.6
Canada – Other	0.1	–	0.1	–
Netherlands [1]	–	0.5	–	0.7
Total gas production	**18.1**	19.1	**18.0**	18.3
Total production	**47.2**	34.6	**45.8**	34.4
Quantity in MMboe	**4.34**	3.18	**16.72**	12.56

[1] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

CANADA

Production in Mboepd	WI	Three months ended December 31 2019	Three months ended December 31 2018	Year ended December 31 2019	Year ended December 31 2018
- Oil Suffield	100%	6.5	6.3	6.4	6.3
- Oil Onion Lake Thermal	100%	11.4	–	10.2	–
- Oil Other	50 - 100%	2.6	–	2.9	–
- Gas	99.7%[1]	18.1	18.6	18.0	17.6
Canada		**38.6**	24.9	**37.5**	23.9

[1] *On a well count basis.*

Production

Net production from the Canadian assets during Q4 2019 was in line with guidance at 38,600 boepd. Strong production performance continued from the Suffield assets in Q4 2019, with the gas optimization program and the newly drilled oil wells driving Suffield performance beyond expectation in Q4 2019. At Onion Lake Thermal, production ramp up continued in Q4 2019 with average rates of just under 12 Mboepd in December 2019. Production from the first sustaining well pad (F-Pad) commenced in Q3 2019 and ramp up and production optimization continued through Q4 2019.

Organic Growth and Capital Projects

In Canada, IPC completed a comprehensive capital expenditure program including drilling, optimization and project work with operating costs in line with the guidance for 2019.

In the Suffield area, at the end of Q4 2019, eighteen oil wells (including one additional well accelerated from 2020) had been drilled and brought online with initial rates increasing production from the Suffield area significantly. The accelerated construction and start-up of the N2N EOR development project at Suffield commenced in Q2 2019, with all six producing wells and seven out of eight injection wells online and on full ASP injection by end of January 2020. Gas optimization activity also continued at Suffield throughout 2019, with completion of over 9,150 swabs and execution of 150 well recompletions by the end of Q4 2019.

At Onion Lake Thermal, production commenced from sustaining well F-Pad in Q3 2019. At the end of Q4 2019, all seven production wells had been brought online and ramped up, with Onion Lake Thermal production averaging slightly below 12 Mboepd in December 2019.

The third well pair at the BlackRod SAGD pilot project was completed in early Q3 2019 with steam start-up scheduled for early 2020.

MALAYSIA

Production in Mboepd	WI	Three months ended December 31 2019	Three months ended December 31 2018	Year ended December 31 2019	Year ended December 31 2018
Bertam	75%	**5.4**	6.8	**5.8**	7.3

Production

Net production from the Bertam field on Block PM307 during Q4 2019 was 5,400 boepd. The Bertam field is expected to return to production expectations in early Q2 2020 when remedial work is completed on the A-15 well. Exceptional operational performance continued in Q4 2019 with facility uptime of 100 percent. Following encouraging results from the 2019 infill drilling program, two additional infill drilling locations have been identified and booked as contingent resources in the A-15/A-20 area. Further technical work is planned on these locations during 2020, for potential drilling in early 2021.

EUROPE

Production in Mboepd	WI	Three months ended December 31 2019	Three months ended December 31 2018	Year ended December 31 2019	Year ended December 31 2018
France					
- Paris Basin	100%[1]	2.7	1.9	2.0	2.0
- Aquitaine	50%	0.5	0.5	0.5	0.5
Netherlands[2]	Various	–	0.5	–	0.7
		3.2	2.9	2.5	3.2

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

[2] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

Production
Net production in France during Q4 2019 was ahead of guidance at 3,200 boepd with exceptional performance from the first of the three new wells in the Vert La Gravelle redevelopment project.

Organic Growth
IPC continues to work its undeveloped resource base in the Paris Basin. In parallel with the optimization of the Vert La Gravelle redevelopment project, a number of fields are undergoing study and planning work with the goal of maturing contingent resources into reserves.

The first phase of the Vert La Gravelle redevelopment, a three well program, commenced in Q2 2019. The first well in the program (VGR113) was brought online in late Q3 2019 and continued to exceed expectations through Q4 2019. Drilling operations on Vert La Gravelle continued into Q4 2019 with completion in early February 2020.

FINANCIAL REVIEW

Financial Results

The acquisition of BlackPearl was completed on December 14, 2018. For accounting purposes, the acquisition was reflected as at December 31, 2018, as the financial results from the acquired assets from the date of acquisition to December 31, 2018, were not material to the Group. The contribution of these assets is reported commencing from January 1, 2019.

Selected Annual Financial Information

Selected consolidated statement of operations is as follows:

USD Thousands	2019	2018	2017
Revenue	553,749	454,443	203,001
Gross profit	152,904	146,864	48,758
Net result	103,588	103,644	22,723
Earnings per share – USD	0.63	1.13	0.23
Earnings per share fully diluted – USD	0.62	1.12	0.23
Operating cash flow[1]	307,944	279,018	138,368
EBITDA[1]	302,513	264,041	129,259
Net debt at period end[1, 2]	231,503	276,761	26,321

[1] *See definition on page 23 under "Non-IFRS measures".*
[2] *Net debt of USD 111,156 thousand was assumed from BlackPearl as at December 31, 2018.*

Summarized consolidated balance sheet information is as follows:

USD Thousands	December 31, 2019	December 31, 2018	December 31, 2017
Non-current assets	1,252,600	1,200,035	455,235
Current assets	112,041	98,899	134,476
Total assets	**1,364,641**	1,298,934	589,711
Total non-current liabilities	474,200	506,832	219,097
Current liabilities	99,632	96,315	63,672
Total liabilities	**573,832**	587,296	282,769
Net assets	**790,809**	695,787	306,942
Working capital (including cash)	**12,409**	2,584	70,804

Selected Interim Financial Information

Selected interim condensed consolidated statement of operations is as follows:

USD Thousands	2019	Q4-19	Q3-19	Q2-19	Q1-19	2018	Q4-18	Q3-18	Q2-18	Q1-18
Revenue	**553,749**	145,535	131.437	129,357	147,420	**454,443**	111,898	106,746	120,637	115,162
Gross profit	**152,904**	43,245	23,487	39,287	46,885	**146,864**	26,311	37,060	45,920	37,573
Net result	**103,588**	38,372	6,330	25,744	33,142	**103,644**	29,346	26,487	21,498	26,313
Earnings per share – USD	**0.63**	0.23	0.04	0.16	0.20	**1.13**	0.29	0.30	0.24	0.30
Earnings per share fully diluted – USD	**0.62**	0.23	0.04	0.15	0.20	**1.12**	0.29	0.29	0.23	0.30
Operating cash flow[1]	**307,944**	78,888	69,504	76,496	83,056	**279,018**	58,322	67,949	76,687	76,060
EBITDA[1]	**302,513**	77,353	68,885	74,600	81,675	**264,041**	58,032	66,240	74,478	65,291
Net debt at period end[1, 2]	**231,503**	231,503	207,778	239,322	256,962	**276,761**	276,761	213,217	254,628	309,184

[1] *See definition on page 23 under "Non-IFRS measures".*

[2] *Net debt of USD 111,156 thousand was assumed from BlackPearl as at December 31, 2018.*

Segment 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) Suffield Assets, (ii) Onion Lake Thermal and (iii) other Canadian assets. This is consistent with the internal reporting provided to IPC management. The following tables present certain segment information.

	Three months ended – December 31, 2019						
USD Thousands	Canada – Suffield	Canada - Thermal	Canada - Other	Malaysia	France	Other	Total
Crude oil	27,950	36,037	7,754	36,618	16,167	–	124,526
NGLs	79	–	–	–	–	–	79
Gas	19,335	–	122	–	–	–	19,457
Net sales of oil and gas	**47,364**	**36,037**	**7,876**	**36,618**	**16,167**	**–**	**144,062**
Change in under/over lift position	–	–	–	–	3,030	–	3,030
Royalties	(1,838)	(3,579)	(1,083)	–	–	–	(6,500)
Hedging settlement	–	523	–	–	–	–	523
Other operating revenue	–	–	–	3,910	301	209	4,420
Revenue	**45,526**	**32,981**	**6,793**	**40,528**	**19,498**	**209**	**145,535**
Production costs	(25,252)	(12,470)	(6,724)	(12,286)	(8,590	–	(65,322)
Depletion	(12,560)	(7,386)	(897)	(7,034)	(4,581)	–	(32,458)
Depreciation of other assets	–	–	–	(3,805)	–	–	(3,805)
Exploration and business development costs	–	–	–	(262)	–	(443)	(705)
Gross profit/(loss)	**7,714**	**13,125**	**(828)**	**17,141**	**6,327**	**(234)**	**43,245**

	Three months ended – December 31, 2018					
USD Thousands	Canada – Suffield	Malaysia	France	Netherlands[1]	Other	Total
Crude oil	13,970	48,643	20,258	11	–	82,882
NGLs	56	–	–	21	–	77
Gas	22,665	–	–	2,096	–	24,761
Net sales of oil and gas	**36,691**	**48,643**	**20,258**	**2,128**	**–**	**107,720**
Change in under/over lift position	–	–	22	–	–	22
Royalties	(559)	–	–	–	–	(559)
Other operating revenue	(2)	3,909	327	369	112	4,715
Revenue	**36,130**	**52,552**	**20,607**	**2,497**	**112**	**111,898**
Production costs	(27,604)	(12,717)	(11,791)	(700)	–	(52,812)
Depletion	(11,201)	(8,059)	(3,209)	(376)	–	(22,845)
Depreciation of other assets	–	(7,790)	–	–	–	(7,790)
Exploration and business development costs	–	(9)	(45)	–	(2,086)	(2,140)
Gross profit/(loss)	**(2,675)**	**23,977**	**5,562**	**1,421**	**(1,974)**	**26,311**

[1] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

	Year ended – December 31, 2019						
USD Thousands	Canada – Suffield	Canada - Thermal	Canada - Other	Malaysia	France	Other	Total
Crude oil	123,943	140,887	35,380	129,789	55,232	–	**485,231**
NGLs	331	–	–	–	–	–	**331**
Gas	77,053	–	277	–	–	–	**77,330**
Net sales of oil and gas	**201,327**	**140,887**	**35,657**	**129,789**	**55,232**	**–**	**562,892**
Change in under/over lift position	–	–	–	–	3,817	–	**3,817**
Royalties	(7,597)	(14,292)	(5,915)	–	–	–	**(27,804)**
Hedging settlement	(374)	(1,971)	–	–	–	–	**(2,345)**
Other operating revenue	–	–	–	15,513	1,005	671	**17,189**
Revenue	**193,356**	**124,624**	**29,742**	**145,302**	**60,054**	**671**	**553,749**
Production costs	(107,333)	(46,021)	(24,144)	(33,378)	(29,895)	–	**(240,771)**
Depletion	(49,236)	(26,160)	(2,281)	(30,077)	(13,905)	–	**(121,659)**
Depreciation of other assets	–	–	–	(23,020)	–	–	**(23,020)**
Exploration and business development costs	–	–	(44)	(13,697)	–	(1,654)	**(15,395)**
Gross profit/(loss)	**36,787**	**52,443**	**3,273**	**45,130**	**16,254**	**(983)**	**152,904**

	Year ended – December 31, 2018					
USD Thousands	Canada – Suffield	Malaysia	France	Netherlands[1]	Other	Total
Crude oil	106,661	181,722	69,596	66	–	**358,045**
NGLs	340	–	–	300	–	**640**
Gas	71,453	–	–	11,254	–	**82,707**
Net sales of oil and gas	**178,454**	**181,722**	**69,596**	**11,620**	**–**	**441,392**
Change in under/over lift position	–	–	408	11	–	**419**
Royalties	(6,296)	–	–	–	–	**(6,296)**
Other operating revenue	134	15,512	1,216	1,642	424	**18,928**
Revenue	**172,292**	**197,234**	**71,220**	**13,273**	**424**	**454,443**
Production costs	(113,003)	(26,959)	(34,120)	(5,776)	–	**(179,858)**
Depletion	(43,415)	(34,488)	(13,596)	(2,352)	–	**(93,851)**
Depreciation of other assets	–	(31,328)	–	–	–	**(31,328)**
Exploration and business development costs	–	(215)	(45)	–	(2,282)	**(2,542)**
Gross profit/(loss)	**15,874**	**104,244**	**23,459**	**5,145**	**(1,858)**	**146,864**

[1] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

Three months and year ended December 31, 2019 Review

Revenue

Total revenue amounted to USD 145,535 thousand for Q4 2019 compared to USD 111,898 thousand for Q4 2018 and USD 553,749 thousand for the year ended December 2019 compared to USD 454,443 thousand for the year ended December 31, 2018 and is analyzed as follows:

	Three months ended December 31		Year ended December 31	
USD Thousands	2019	2018	2019	2018
Crude oil sales	124,526	82,882	485,231	358,045
Gas and NGL sales	19,536	24,838	77,661	83,347
Change in under/overlift position	3,030	22	3,817	419
Royalties	(6,500)	(559)	(27,804)	(6,296)
Hedging settlement	523	–	(2,345)	–
Other operating revenue	4,420	4,715	17,189	18,928
Total revenue	145,535	111,898	553,749	454,443

The main components of total revenue for the three months and year ended December 31, 2019, and December 31, 2018, respectively are detailed below.

Crude oil sales

	Three months ended – December 31, 2019					
	Canada - Suffield	Canada - Thermal	Canada - Other	Malaysia	France	Total
Crude oil sales						
- Revenue in USD thousands	27,950	36,037	7,754	36,618	16,167	**124,526**
- Quantity sold in bbls	683,853	1,048,651	224,663	522,197	252,902	**2,732,266**
- Average price realized USD per bbl	40.87	34.36	34.52	70.12	63.92	**45.58**

	Three months ended – December 31, 2018				
	Canada - Suffield	Malaysia	France	Netherlands[1]	Total
Crude oil sales					
- Revenue in USD thousands	13,970	48,643	20,257	12	**82,882**
- Quantity sold in bbls	655,906	665,466	305,579	154	**1,627,105**
- Average price realized USD per bbl	21.30	73.10	66.29	80.05	**50.94**

[1] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

Crude oil revenue was 50 percent higher for Q4 2019 compared to Q4 2018 mainly due to the contribution of the former BlackPearl assets in Canada from January 1, 2019. The sales volume in Malaysia was lower in Q4 2019 compared to Q4 2018 due to lower production volumes.

The Suffield Assets crude oil in Canada is blended with purchased condensate diluent volumes to meet pipeline specifications. As a result of the blended volumes, actual sales volumes are higher than produced volumes for Canada. The Canadian realized sales price is based on the Western Canadian Select ("WCS") price which trades at a discount to West Texas Intermediate ("WTI"). For Q4 2019, WTI averaged USD 57 per bbl compared to USD 59 per bbl for Q4 2018 and the average discount from WTI to WCS used in our pricing formula was USD 16 per bbl compared to USD 39 per bbl for Q4 2018. The discount from WTI to WCS was unusually high in November and December 2018 at USD 46 per bbl and USD 43 per bbl respectively, before production curtailments were implemented by the Alberta government in December 2018.

Onion Lake Thermal and other Canadian assets production is sold without being blended with condensate. It is heavier than the WCS quality and as a result trades at a discount to WCS prices.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices and the average Dated Brent crude oil price was USD 63 per bbl for Q4 2019 compared to USD 69 per bbl for the comparative period in 2018.

	Year ended – December 31, 2019					
	Canada – Suffield	Canada - Thermal	Canada - Other	Malaysia	France	Total
Crude oil sales						
- Revenue in USD thousands	123,943	140,887	35,380	129,789	55,232	**485,231**
- Quantity sold in bbls	2,715,914	3,724,543	912,663	1,857,694	870,380	**10,081,194**
- Average price realized USD per bbl	45.64	37.83	38.77	69.87	63.46	**48.13**

	Year ended – December 31, 2018				
	Canada - Suffield	Malaysia	France	Netherlands[1]	Total
Crude oil sales					
- Revenue in USD thousands	106,661	181,721	69,596	67	**358,045**
- Quantity sold in bbls	2,655,404	2,426,797	991,057	1,063	**6,074,321**
- Average price realized USD per bbl	40.17	74.88	70.22	63.50	**58.94**

[1] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

Crude oil sales were 36 percent higher for the year ended December 31, 2019, compared to the year ended December 31, 2018, mainly due to the contribution of the former BlackPearl assets in Canada from January 1, 2019, partly offset by lower sales volumes in Malaysia due to lower production volumes, and lower sales volumes in France due to the impact of the refinery shut-in during Q2 2019.

The Canadian realized sales price is based on the WCS price which trades at a discount to WTI. WTI averaged USD 57 per bbl and the average discount from WTI to WCS was approximately USD 13 per bbl for the year ended December 31, 2019, compared to an average WTI of USD 65 per bbl and an average discount from WTI to WCS of USD 26 per bbl for the comparative period in 2018.

All sales and expenses from the Blackrod asset SAGD pilot evaluation are being recorded as an adjustment to the capitalized costs of the project until commercial production commences. The Blackrod asset sales volume and revenue are therefore not included in the crude oil sales tables above. Revenue from the Blackrod asset amounted to USD 4,434 thousand for the year ended December 31, 2019.

The realized sales price for Malaysia and France is based on Brent crude oil prices and the average Dated Brent crude oil price was USD 64 per bbl for the year ended December 31, 2019 compared to USD 71 per bbl for the comparative period in 2018.

Gas and NGL sales

	Three months ended – December 31, 2019		
	Canada - Suffield	Canada - Other	Total
Gas and NGL sales			
- Revenue in USD thousands	19,414	122	**19,536**
- Quantity sold in Mcf	9,358,478	71,640	**9,430,118**
- Average price realized USD per Mcf	2.07	1.70	**2.07**

	Three months ended – December 31, 2018		
	Canada - Suffield	Netherlands[1]	Total
Gas and NGL sales			
- Revenue in USD thousands	22,721	2,117	**24,838**
- Quantity sold in Mcf	9,707,890	255,500	**9,963,390**
- Average price realized USD per Mcf	2.34	8.29	**2.49**

[1] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

Gas and NGL sales revenue was 21 percent lower for Q4 2019 compared to Q4 2018 mainly due to the sale of the Netherlands business in December 2018. Approximately 98 percent of the Suffield gas production was sold on the Alberta/Saskatchewan border at Empress with the remainder being delivered in Alberta based on AECO pricing. For Q4 2019, IPC realized an average price of CAD 2.73 per Mcf which was above Empress average pricing for Q4 2019 of CAD 2.55 per Mcf, as a result of forward sales contracts entered into for Q4 2019.

	Year ended – December 31, 2019		
	Canada - Suffield	Canada – Other	Total
Gas and NGL sales			
- Revenue in USD thousands	77,384	277	**77,661**
- Quantity sold in Mcf	36,829,902	230,592	**37,060,494**
- Average price realized USD per Mcf	2.10	1.20	**2.10**

	Year ended – December 31, 2018		
	Canada - Suffield	Netherlands[1]	Total
Gas and NGL sales			
- Revenue in USD thousands	71,793	11,554	**83,347**
- Quantity sold in Mcf	36,439,974	1,551,527	**37,991,501**
- Average price realized USD per Mcf	1.97	7.45	**2.19**

[1] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

In Canada, gas and NGL sales revenue was 8 percent higher during the year ended December 31, 2019, compared to the comparative period in 2018 due to higher sales volumes sold and higher gas prices achieved. For the year ended December 31, 2019, IPC realized an average price of CAD 2.77 per Mcf compared to CAD 2.54 per Mcf for the comparative period in 2018 and Empress average pricing for 2019 of CAD 2.49 per Mcf.

Hedging settlement

IPC entered into risk management contracts in order to comply with the covenants of a financing facility arrangement that was repaid and terminated during Q2 2019. The hedges are mainly oil price swaps and collars to manage pricing exposure. IPC uses natural gas at the Onion Lake Thermal project and the Blackrod SAGD pilot project to generate steam and manages the pricing risk by entering into fixed price swaps. The oil and gas pricing contracts are not entered into for speculative purposes. No new hedging contracts were entered into during Q4 2019 and IPC no longer has any hedging requirements under its financing facilities. The realized hedging settlements for Q4 2019 amounted to a gain of USD 523 thousand and for the year ended December 31, 2019, amounted to a loss of USD 2,345 thousand. Also see the Financial Risk Management section below.

Other operating revenue

Other operating revenue amounted to USD 4,420 thousand for Q4 2019 compared to USD 4,715 thousand for Q4 2018 and USD 17,189 thousand for the year ended December 31, 2019, compared to USD 18,928 thousand for the year ended December 31, 2018. The significant part of other operating revenue is third party lease fee income received by the Group for the leasing of the owned FPSO Bertam to the Bertam field in Malaysia. Other operating revenue also consists of tariff income and fees for strategic storage of inventory in France.

Production costs

Production costs including inventory movements amounted to USD 65,322 thousand for Q4 2019 compared to USD 52,812 thousand for Q4 2018 and USD 240,771 thousand for the year ended December 31, 2019, compared to USD 179,858 thousand for the year ended December 31, 2018, and is analyzed as follows:

	Three months ended – December 31, 2019						
USD Thousands	Canada - Suffield	Canada – Thermal	Canada – Other	Malaysia	France	Other[3]	Total
Operating costs[1]	19,616	12,470	6,724	18,189	8,286	(11,730)	53,555
USD/boe[2]	8.71	11.89	26.23	36.87	28.24	n/a	12.33
Cost of blending	5,069	–	–	–	–	–	5,069
Change in inventory position	567	–	–	5,827	304	–	6,698
Production costs	25,252	12,470	6,724	24,016	8,590	(11,730)	65,322

	Three months ended – December 31, 2018					
USD Thousands	Canada - Suffield	Malaysia	France	Netherlands[4]	Other [3]	Total
Operating costs[1]	23,314	21,643	7,737	700	(11,730)	41,664
USD/boe[2]	10.17	34.75	34.47	16.38	n/a	13.09
Cost of blending	4,678	–	–	–	–	4,678
Change in inventory position	(388)	2,804	4,054	–	–	6,470
Production costs	27,604	24,447	11,791	700	(11,730)	52,812

	Year ended – December 31, 2019						
USD Thousands	Canada - Suffield	Canada – Thermal	Canada – Other	Malaysia	France	Other[3]	Total
Operating costs[1]	85,419	46,021	24,144	75,471	29,291	(46,538)	213,808
USD/boe[2]	9.62	12.36	22.33	35.78	31.89	n/a	12.79
Cost of blending	21,919	–	–	–	–	–	21,919
Change in inventory position	(5)	–	–	4,445	604	–	5,044
Production costs	107,333	46,021	24,144	79,916	29,895	(46,538)	240,771

USD Thousands	Year ended – December 31, 2018					
	Canada - Suffield	Malaysia	France	Netherlands[4]	Other[3]	Total
Operating costs[1]	90,068	75,966	30,084	5,776	(46,538)	**155,356**
USD/boe[2]	10.32	28.50	33.26	22.22	n/a	**12.37**
Cost of blending	24,512	–	–	–	–	**24,512**
Change in inventory position	(1,577)	(2,469)	4,036	–	–	(10)
Production costs	113,003	73,497	34,120	5,776	(46,538)	179,858

[1] *See definition on page 23 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.*

[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 cost per boe for Malaysia to USD 13.09 and USD 15.92 for Q4 2019 and Q4 2018, respectively, and USD 13.72 and USD 11.04 for the year ended December 31, 2019, and the year ended December 31, 2018, respectively.*

[4] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

Operating costs

Operating costs amounted to USD 53,555 thousand for Q4 2019 compared to USD 41,664 thousand for Q4 2018 and USD 213,808 thousand for the year ended December 31, 2019, compared to USD 155,356 thousand for the year ended December 31, 2018. The increase in operating costs is mainly due to the contribution of the former BlackPearl assets in Canada. Operating costs per boe for the full year 2019 amounted to USD 12.79 per boe which was ahead of CMD guidance of USD 12.90 per boe.

Cost of blending

For the Suffield Assets in Canada, oil production is blended with purchased condensate diluent to meet pipeline specifications. The cost of the diluent net of proceeds from the sale of surplus diluent amounted to USD 5,069 thousand for Q4 2019 compared to USD 4,678 thousand for Q4 2018 and USD 21,919 thousand for the year ended December 31, 2019, compared to USD 24,512 thousand for the year ended December 31, 2018. As a result of the blending, actual sales volumes are higher than produced barrels. A cost of USD 445 thousand and a profit of USD 295 thousand was recognized relating to the difference between the cost and sale proceeds of the surplus diluent for Q4 2019 and Q4 2018 respectively, and costs of USD 2,289 thousand and USD 684 thousand were recognized for the year ended December 31, 2019, and December 31, 2018, respectively.

Change in inventory position

The Bertam field in Malaysia is located offshore and production is lifted and sold from the FPSO Bertam when a cargo parcel size is reached. Accordingly, the timing of a lifting varies based on the inventory level on the FPSO facility and the change in inventory position varies, both positively and negatively, from period to period. Inventories are valued at the lower of cost including depletion and market value and the difference in the valuation between period ends is reflected in the change in inventory position in the statement of operations. At the end of Q4 2019, IPC had crude entitlement of 59,000 barrels of oil on the FPSO Bertam facility.

In the Aquitaine Basin, France, there was one cargo lifting during Q3 2019 compared to two cargo liftings in the year 2018 in Q1 2018 and Q4 2018.

Depletion and decommissioning costs

The total depletion and decommissioning costs amounted to USD 32,458 thousand for Q4 2019 compared to USD 22,845 thousand for Q4 2018 and USD 121,659 thousand for the year ended December 31, 2019 compared to USD 93,851 thousand for the year ended December 31, 2018. The depletion charge is analyzed in the following tables:

	Three months ended – December 31, 2019					
	Canada – Suffield	Canada – Thermal	Canada – Other	Malaysia	France	Total
Depletion cost in USD thousands	12,560	7,386	897	7,034	4,581	**32,458**
USD per boe	5.58	7.04	3.50	14.26	15.61	**7.47**

	Three months ended – December 31, 2018				
	Canada – Suffield	Malaysia	France	Netherlands[1]	Total
Depletion cost in USD thousands	11,201	8,059	3,209	376	**22,845**
USD per boe	4.89	12.94	14.30	8.79	**7.18**

[1] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

	Year ended – December 31, 2019					
	Canada – Suffield	Canada – Thermal	Canada – Other	Malaysia	France	Total
Depletion cost in USD thousands	49,236	26,160	2,281	30,077	13,905	**121,659**
USD per boe	5.55	7.02	2.11	14.26	15.14	**7.28**

	Year ended – December 31, 2018				
	Canada – Suffield	Malaysia	France	Netherlands[1]	Total
Depletion cost in USD thousands	43,415	34,488	13,596	2,352	**93,851**
USD per boe	4.97	12.94	15.03	9.05	**7.47**

[1] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

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

Depreciation of other assets

The total depreciation of other assets amounted to USD 3,805 thousand for Q4 2019 compared to USD 7,790 thousand for Q4 2018 and USD 23,020 thousand for the year ended December 31, 2019, compared to USD 31,328 thousand for the year ended December 31, 2018. This related to the depreciation of the FPSO Bertam, which is being depreciated on a unit of production basis from July 2019 based on the Bertam field 2P reserves. Prior to this date the Bertam FPSO was being depreciated on a straight line basis over the six year lease period on the Bertam field from April 2015.

Exploration and business development costs

The total exploration and business developments costs amounted to USD 705 thousand for Q4 2019 and USD 15,395 thousand for the year ended December 31, 2019. The full year costs mainly related to unsuccessful drilling in Malaysia on the Keruing exploration prospect and the infill pilot well in the A-14 area.

General, administrative and depreciation expenses

General, administrative and depreciation expenses amounted to USD 12,042 thousand for the year ended December 31, 2019, compared to USD 11,065 thousand for the year ended December 31, 2018.

Net financial items

Net financial items amounted to a charge of USD 18,026 thousand for the year ended December 31, 2019, compared to USD 46,930 thousand for the year ended December 31, 2018, and included a largely non-cash net foreign exchange gain of USD 9,553 thousand for 2019 compared to a net foreign exchange loss of USD 17,354 thousand for 2018. The foreign exchange movements mainly result from the revaluation of intra-group loan funding balances.

Excluding foreign exchange movements, the net financial items amounted to a charge of USD 27,579 thousand for the year ended December 31, 2019, compared to USD 29,576 thousand for the year ended December 31, 2018. The interest expense amounted to USD 17,508 thousand for the year ended December 31, 2019, compared to USD 14,732 thousand for the comparative period and included a make-whole expense for the senior notes which were redeemed early as part of the Canadian refinancing during Q2 2019. The unwinding of the asset retirement obligation discount rate amounted to USD 10,664 thousand for the year ended December 31, 2019, compared to USD 9,190 thousand for year ended December 31, 2018, and the increase is due to the inclusion of the former BlackPearl asset retirement obligation at the year-end partly offset by the removal of the unwinding expense following the sale of the assets in the Netherlands in December 2018.

An amount of TUSD 4,576 was included in other financial income during Q4 2019 relating to the release of provisions for the estimated contingent consideration and other adjustments relating to the acquisition of the Suffield Assets.

Income tax

The corporate income tax charge amounted to USD 19,248 thousand for the year ended December 31, 2019, compared to a charge of USD 10,265 thousand for the year ended December 31, 2018. There was a current tax credit of USD 7,196 thousand in Q1 2018 largely related to a non-recurring Dutch petroleum tax refund relating to historical intragroup charges and an industry change in the calculation of the present value of the asset retirement obligation.

Capital Expenditure

Development and exploration and evaluation expenditure incurred in the year ended December 31, 2019, was as follows:

USD Thousands	Canada – Suffield	Canada – Thermal	Canada – Other	Malaysia	France	Total
Development	43,312	23,925	5,482	36,714	39,693	**149,126**
Exploration and evaluation	–	–	13,654	17,330	477	**31,461**
	43,312	23,925	19,136	54,044	40,170	**180,587**

Capital expenditure of USD 180,587 thousand was mainly spent on drilling on the Suffield Assets, Onion Lake Thermal facilities, the drilling campaign in Malaysia and the Vert La Gravelle redevelopment in France. In addition, costs of the Blackrod appraisal and the acquisition costs of the land and contingent resource position adjacent to the Blackrod property are reflected under Canada – Other exploration and evaluation costs. Capital expenditure for the year ended December 31, 2019, is below the full year guidance given of USD 188 million due to overall cost savings of USD 4 million and a carry over of activities of USD 3 million.

Other tangible fixed assets

Other tangible fixed assets amounted to USD 69,015 thousand as at December 31, 2019, which included USD 65,255 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated on a unit of production basis from July 2019 based on the Bertam field 2P reserves.

Acquisition of BlackPearl

On December 14, 2018, IPC completed the BlackPearl Acquisition for total consideration of USD 288,643 thousand. The purchase price has been allocated as set out in the table below.

USD Thousands	
Cash and cash equivalents	2,572
Trade and other receivables	883
Inventory	42
Prepaid expenses and deposits	882
Fair value of risk management assets	13,909
Deferred tax assets	69,592
Property, plant and equipment	370,647
Other fixed assets	1,037
Accounts payable and accrued liabilities	(16,587)
Fair value of risk management liabilities	(1,564)
Decommissioning liabilities	(28,708)
Long-term debt	(113,728)
Other provisions	(1,321)
MTM reserve in equity	(9,013)
Total Consideration	288,643
Settled by:	
Equity instruments (75,798,219 common shares of IPC)	288,643

Acquisition-related costs of approximately USD 2.3 million were recognized in the income statement for the year ended December 31, 2018. No material acquisition-related costs were recognized in the year ended December 31, 2019.

Financial Position and Liquidity

Financing

In connection with the completion of the acquisition of the Suffield Assets in January 2018, the Group entered into an amendment to its reserve-based lending credit facility to increase such facility from USD 100 million to USD 200 million and to extend the maturity to end June 2022. Concurrently, IPC Alberta Ltd entered into a CAD 250 million reserve-based lending credit facility and a CAD 60 million second lien facility in Canada in January 2018.

In August 2018, the Group fully repaid and cancelled the Canadian second lien CAD 60 million loan facility.

In December 2018, in connection with the completion of the BlackPearl Acquisition, the Group assumed the debt of BlackPearl consisting of a reserve-based lending credit facility of CAD 120 million and senior secured notes outstanding of CAD 75 million. The reserve-based lending facility had a maturity date in May 2021 and the senior secured notes had a maturity date in June 2020.

Effective as of June 1, 2019, IPC Alberta Ltd. and BlackPearl amalgamated into IPC Canada Ltd., which is a wholly-owned subsidiary of IPC. At the same time, the reserve-based lending credit facilities of IPC Alberta and BlackPearl were combined into one reserve-based lending credit facility of IPC Canada in the amount of CAD 375 million. The IPC Canada reserve-based credit lending facility has a maturity date in May 2021. The senior secured notes of BlackPearl of CAD 75 million were fully repaid and cancelled in June 2019, from a drawdown under the CAD 375 million reserve-based lending credit facility.

The borrowing base availability under the Group's reserve-based lending credit facility outside Canada is currently USD 125 million of which USD 73 million was outstanding as at December 31, 2019. The borrowing base availability of IPC Canada's reserve-based lending credit facility is currently CAD 375 million of which CAD 226 million was outstanding as at December 31, 2019.

Total net debt as at December 31, 2019, amounted to USD 231.5 million. This included USD 17 million in respect of the purchases made by IPC under the share repurchase program.

In connection with the Granite Acquisition, the Group is expected to assume approximately CAD 40 million of net debt, including amounts owing by Granite to two Canadian banks under a committed CAD 42.50 million credit facility.

The Group expects to fully fund the proposed 2020 capital program and any shares that may be purchased under the share repurchase program in 2020 from its operating cash flows and available credit facilities.

The Group is in full compliance with the covenants under the credit facilities, which are customary for the size and nature of such facilities.

Cash and cash equivalents held amounted to USD 15,571 thousand as at December 31, 2019. The Corporation holds cash to meet imminent operational funding requirements in the different countries.

Working Capital

As at December 31, 2019, the Group had a net working capital balance including cash of USD 12,409 thousand compared to USD 2,584 thousand as at December 31, 2018. The increase in the net working capital balance including cash position is mainly due to the increased trade receivables position as at the end of 2019.

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

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

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

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

Reconciliation of Non-IFRS Measures

Operating cash flow

The following table sets out how operating cash flow is calculated from figures shown in the consolidated financial statements:

	Three months ended December 31		Year ended December 31	
USD Thousands	2019	2018	2019	2018
Revenue	145,535	111,898	553,749	454,443
Production costs	(65,322)	(52,812)	(240,771)	(179,858)
Current tax	(1,325)	(764)	(5,034)	4,433
Operating cash flow	**78,888**	58,322	**307,944**	279,018

Free cash flow
The following table sets out how free cash flow is calculated from figures shown in the consolidated financial statements:

	Three months ended December 31		Year ended December 31	
USD Thousands	2019	2018	2019	2018
Operating cash flow - see above	78,888	58,322	307,944	279,018
Capital expenditures	(66,471)	(16,367)	(180,587)	(39,044)
Abandonment and farm-in expenditures[1]	(1,674)	(2,343)	(8,137)	(8,939)
General, administration and depreciation expenses before depreciation[2]	(2,861)	(1,054)	(10,465)	(10,544)
Cash financial items[3]	(3,450)	(3,694)	(19,447)	(17,209)
Free cash flow	**4,432**	34,864	**89,308**	203,282

[1] *See note 21 to the financial statements*

[2] *Depreciation is not specifically disclosed in the consolidated financial statements*

[3] *See notes 5 and 6 to the financial statements. 2019 full year excludes other financial income of TUSD 4,576 which is non-cash.*

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

	Three months ended December 31		Year ended December 31	
USD Thousands	2019	2018	2019	2018
Net result	38,372	29,346	103,588	103,644
Net financial items	(3,429)	19,438	18,026	46,930
Income tax	4,984	1,414	19,248	10,265
Depletion	32,458	22,845	121,659	93,851
Depreciation of other assets	3,805	7,790	23,020	31,328
Exploration and business development costs	705	2,140	15,395	2,542
Sale of assets	–	(25,040)	–	(25,040)
Depreciation included in general, administration and depreciation expenses[1]	458	99	1,577	521
EBITDA	**77,353**	58,032	**302,513**	264,041

[1] *Item is not specifically disclosed in the consolidated financial statements*

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

	Three months ended December 31		Year ended December 31	
USD Thousands	2019	2018	2019	2018
Production costs	65,322	52,812	240,771	179,858
Cost of blending[1]	(5,069)	(4,678)	(21,919)	(24,512)
Change in inventory position	(6,698)	(6,470)	(5,044)	10
Operating costs	**53,555**	**41,664**	**213,808**	**155,356**

[1] *Item is not specifically disclosed in the consolidated financial statements. See production costs section above.*

Net debt
The following table sets out how net debt is calculated from figures shown in the consolidated financial statements:

USD Thousands	December 31, 2019	December 31, 2018
Bank loans	247,074	232,357
Senior secured notes	–	55,030
Cash and cash equivalents	(15,571)	(10,626)
Net debt	**231,503**	276,761

Off-Balance Sheet Arrangements

On May 1, 2018, IPC, through its subsidiary IPC Canada Ltd (then known as IPC Alberta Ltd.), had issued a letter of credit for an amount of CAD 4 million in respect of its obligations to purchase diluent. This letter of credit is still outstanding.

IPC has also guaranteed the pipeline obligations of its subsidiary, IPC Canada Ltd, in respect of its gathering and transportation of crude oil for a maximum amount of CAD 3.6 million.

Outstanding Share Data

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

As at January 1, 2018, the total number of common shares issued and outstanding in IPC was 87,921,846. In connection with the completion of the BlackPearl Acquisition, IPC issued a total of 75,798,219 common shares to the former shareholders of BlackPearl.

On November 7, 2019, IPC announced the commencement of a share repurchase program. During the period up to December 31, 2019, IPC repurchased an aggregate of 3,929,196 common shares and all of these shares were cancelled. As at December 31, 2019, IPC had a total of 159,790,869 common shares issued and outstanding. As at February 11, 2020, following the cancellation of a further 2,540,000 common shares repurchased during January 2020, IPC has a total of 157,250,869 common shares issued and outstanding with no par value.

Nemesia S.à.r.l. and Zebra Holdings and Investments S.à.r.l., investment companies wholly owned by a Lundin family trust, own 40,697,533 common shares in IPC, representing 25.88 percent of the outstanding common shares as at February 11, 2020.

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 1,808,566 stock options and 2,340,205 IPC Performance and Restricted Share Plan awards (636,767 awards granted in July 2018, 314,365 awards granted in March 2019, 1,363,724 awards granted in July 2019 and 25,349 awards granted in January 2020), outstanding as at February 11, 2020.

Contractual Obligations and Commitments

As part of the acquisition of the Suffield Assets, the Group was required to pay Cenovus Energy Inc. additional cash consideration dependent upon the future prices of oil and natural gas for each month between January 2018 and December 2019. The contingent consideration relating to 2018 and in 2019 amounted to CAD 7,711 thousand (USD 5,934 thousand) in total, being CAD 5,708 thousand (USD 4,393 thousand) for oil and CAD 2,003 thousand (USD 1,541 thousand) for gas.

IPC has an obligation to make payments towards historic costs on Block PM307 in Malaysia payable on the Bertam field for every 1 MMboe gross that the field produces above 10 MMboe gross. The estimated liability based on current 2P reserves has been provided for in the Group's Balance Sheet – see Note 21 Provisions of the Financial Statements.

The Bertam field (IPC working interest of 75%) has leased the FPSO Bertam from another Group company for an initial period of six years commencing April 2015, with four one-year options to extend such lease beyond the initial period, up to April 2025.

Critical 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

As a result of the Spin-Off, the Group had a residual liability for working capital owed to Lundin Petroleum. The final settlement of USD 14,243 thousand was paid in June 2019 and no further amounts are outstanding to Lundin Petroleum in respect of the working capital.

Lundin Petroleum has charged the Group USD 651 thousand in respect of office space rental and USD 2,005 thousand in respect of shared services provided during the year 2019.

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.

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 the oil price. The Group seeks to control these risks through sound management practice and the use of internationally accepted financial instruments, such as oil and gas price, interest rate or foreign exchange hedges as the case may be. Financial instruments will be solely used for the purpose of managing risks in the business. As at December 31, 2019, the Corporation had entered into oil and gas price 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 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, the 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 had gas price purchase hedges outstanding as at December 31, 2019, which are summarized as follows:

Period	Volume (Gigajoules (GJ) per day)	Basis	Average Pricing
Gas Purchase			
January 1, 2020 – December 31, 2020	4,000	AECO 5a	CAD 1.49/GJ

The Group had oil price sales hedges outstanding as at December 31, 2019, which are summarized as follows:

Period	Volume (barrels per day)	Weighted Average Floor (WTI in USD)	Weighted Average Cap (WTI in USD)
Oil Sales			
January 1, 2020 – March 31, 2020	3,500	50.00	77.50
April 1, 2020 – June 30, 2020	6,150	35.00	71.74

All of the above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income.

These hedges had a fair value net asset of USD 4 thousand at December 31, 2019.

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

Interest Rate Risk
Interest rate risk is the risk to earnings due to uncertain future interest rates on borrowings. The Group will take into account the level of external debt, current interest rates and market expectations in comparison to historic trends and volatility in making the decision to hedge.

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 AND UNCERTAINTIES

IPC is engaged in the exploration, development and production of oil and gas and its operations are subject to various risks and uncertainties which include but are not limited to those listed below. The risks and uncertainties below are not the only ones that the Group faces. Additional risks and uncertainties not presently known to the Group or that the Group currently considers immaterial may also impair the business and operations of the Group and cause the price of the IPC's shares to decline. If any of the following risks actually occur, the Group's business may be harmed and the financial condition and results of operations may suffer significantly.

Non Financial Risks

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

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

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

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

Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions in Europe, Asia, the United States, Canada and elsewhere, the actions of OPEC, governmental regulation, political instability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports, the availability of alternative fuel sources and the potential for increased supply of oil and gas for unconventional shale oil and shale gas and other services.

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

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

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

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

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

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

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

References to "contingent resources" do not constitute, and should be distinguished from, references to "reserves". References to "prospective resources" do not constitute, and should be distinguished from, references to "contingent resources" and "reserves". This MD&A contains estimates of the net present value of the future net revenue from IPC's reserves. 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 evaluations will be attained and variances could be material. See also "Reserves and Resource Advisory" below.

SAGD Recovery Process: The Group has implemented a SAGD recovery process at the Onion Lake thermal project and would use the SAGD process at the Blackrod project. The SAGD recovery process requires a significant amount of natural gas or other fuels to produce steam for use in the recovery process. The amount of steam required in the production process can vary and impact costs significantly. The quality and performance of the reservoir can impact the timing, cost and levels of production using this technology. There can be no assurance that the Group's operations will produce at the expected levels or on schedule.

In addition, a significant amount of water is used in SAGD operations. Government regulations apply to access to and use of water. Any shortages in water supplies could lead to increased costs and have a material adverse effect on results of operation and financial condition.

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

The French government has enacted legislation to cease granting new petroleum exploration licenses in France and to restrict the production of oil and gas under existing production licenses in France from 2040. The Group continues to work closely with other industry participants and the French authorities with respect to this legislation. IPC does not expect that this legislation will have a material adverse effect on the Group's operations or financial condition.

In Alberta, the oil and gas regulatory authorities have implemented regulations regarding the ability to transfer leases, licenses, permits, wells and facilities between parties. These authorities have increased the minimum abandonment liability rating of the buyer before they will accept a transfer of oil and gas assets. These regulations may make it difficult and costly for producers, such as IPC, to transfer or sell assets to other parties.

Aboriginal Land Claims in Canada: In Canada, aboriginal groups have filed claims in respect of their aboriginal and treaty rights against the federal and certain provincial governments. The Group is not aware of any claims made with respect to its properties or assets; however; if a claim arose and was successful, it may have a material adverse effect on the Group's business, financial condition, results of operation and prospects. The majority of the Group's interests at Onion Lake are situated on traditional reserve lands and are subject to the federal rules and regulations of Indian Oil and Gas Canada as well as of the Onion Lake Cree Nation of Saskatchewan/Alberta. There are risks associated with the management of the Group's interests on these lands, including access and lease terms.

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

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

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

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

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

In addition, the maximum amount that the Group is permitted to borrow under its senior credit facilities is subject to periodic review by the lenders. The Group's lenders generally review its oil and gas production and reserves, forecast oil and gas prices, general business environment and other factors to establish the amount which the Group is entitled to borrow. In the event the lenders decide to reduce the amount of credit available under the senior credit facilities, the Group may be required to repay all or a portion of the amounts owing thereunder.

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

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

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

Climate Change Legislation: The oil and natural gas industry is subject to environmental regulation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of the Group or the Group's assets, some of which may be material. Furthermore, management of the Corporation believes the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions or emissions intensity. There is a risk that any such programs, laws or regulations, if proposed and enacted, may contain emission reduction targets which will require substantial capital investments to adapt processes in place or lead to financial penalties or charges as a result of the failure to meet such targets.

Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. Implementation of strategies by any level of government within the countries in which the Corporation operates, and whether to meet international agreed limits, or as otherwise determined, for reducing greenhouse gases could have a material impact on the operations and financial condition of the Corporation. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation, transportation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Group and its operations and financial condition.

For example, emission and carbon tax regulations in Canada are evolving and as these regulations are established or amended, they may have an impact on organizations involved in heavy oil production. It is difficult to assess the overall impact these regulations will have on the Group at this time but it could result in increased costs to comply, delays in having projects approved and potentially a reduction in demand for oil from these regions, all of which could have a material negative impact on the Group's business.

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

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

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

Repatriation of Earnings: A portion of the revenue-generating operations of the Group's assets is located in Malaysia. In December 2016, the Central Bank of Malaysia implemented measures to facilitate its management of foreign exchange risk. These rules to date have not had a material adverse effect on the Group, but there is a risk that the Central Bank of Malaysia or another authority may implement further measures that will restrict the future repatriation of earnings.

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

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

Economic and Political Developments in Countries in which the Group Operates: International operations are subject to political, economic and other uncertainties. The Group's assets could also be adversely affected by changes in applicable laws and policies of Canada, Malaysia and France, which could have a negative impact on the Group.

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

Information Security: The Group is heavily dependent on its information systems and computer based programs. Failure, malfunction or security breaches by computer hackers and cyberterrorists of any such systems or programs may have a material adverse effect on the Group's business and systems, potentially affecting network assets and people's privacy.

The Group manages cyber security risk by ensuring appropriate technologies, processes and practices are effectively designed and implemented to help prevent, detect and respond to threats as they emerge and evolve. The primary risks to the Group include, loss of data, destruction or corruption of data, compromising of confidential customer or employee information, leaked information, disruption of business, theft or extortion of funds, regulatory infractions, loss of competitive advantage and reputational damage.

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

Significant Shareholders: Nemesia S.à.r.l. and Zebra Holdings and Investments S.à.r.l., investment companies wholly owned by a Lundin family trust (the "Trust Entities"), own approximately 25.88 percent of the aggregate voting shares of the Corporation. The Trust Entities' holdings may allow them to significantly affect substantially all the actions taken by the shareholders of the Corporation, including the election of directors. As long as the Trust Entities maintain a significant interest in the Corporation, it is likely that the Trust Entities will exercise significant influence on the ability of the Corporation to, among other things, amend the articles of the Corporation, enter into a change in control transaction of the Corporation that might otherwise be beneficial to its shareholders and may also discourage acquisition bids for the Corporation. There is a risk that the interests of the Trust Entities will not be aligned with the interests of other shareholders.

Financial Risks

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

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

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

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

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

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

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

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

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

DISCLOSURE CONTROLS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Disclosure Controls and Procedures

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

Internal Controls over Financial Reporting

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

There have been no material changes to the Groups internal control over financial reporting during the three and twelve month periods ended December 31, 2019, 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).

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:

- our intention and ability to continue to implement our strategies to build long-term shareholder value;
- our intention to review future potential growth opportunities;
- the ability of our portfolio of assets to provide a solid foundation for organic and inorganic growth;
- the continued facility uptime and reservoir performance in our areas of operation;
- the timing and success of the Villeperdue West development project, including drilling and related production rates as well as future phases of the Vert La Gravelle redevelopment project, and other organic growth opportunities in France;
- future development potential of Triassic reservoirs in France and the ability to maintain current and forecast production in France;
- the ability of IPC to achieve and maintain current and forecast production from the third phase of infill drilling in Malaysia and the ability to identify, mature and drill additional infill drilling locations;
- the success and timing of remedial works in respect of the A-15 well in Malaysia;
- future development potential of the Suffield operations, including continued and future oil drilling and gas optimization programs, the ability to offset natural declines and the N2N EOR development project;
- the proposed further conventional oil drilling in Canada, including the ability of such drilling to identify further drilling or development opportunities;
- development of the Blackrod project in Canada, including continued current operations at the project and steam injection in the third well pair;
- the results of the facility optimization program, the work to debottleneck the facilities and injection capability and the F-Pad production, as well as water intake and steam generation issues, at Onion Lake Thermal;
- the plan to add another drilling pad in 2020 at Onion Lake Thermal and the production resulting from such pad;
- the timing and certainty regarding completion of the Granite Acquisition, including the ability of the IPC and Granite to obtain necessary approvals and otherwise satisfy the conditions to such completion and the absence of material events which may interfere with such completion;

- the ability of IPC to achieve and maintain current and forecast production and take advantage of production growth and development upside opportunities related to Granite's assets post-completion of the Granite Acquisition;
- the ability of IPC to integrate Granite's Assets into its current operations;
- the ability of Granite's existing infrastructure to enable EOR projects, as well as capacity to allow for potential further field development opportunities in respect of Granite's assets;
- the existence of drill-ready opportunities in respect of Granite's assets and their ability to add further near-term production of high netback, light oil barrels;
- the ability to IPC to acquire further common shares under the share repurchase program, including the timing of any such purchases;
- the return of value to IPC's shareholders as a result of the share repurchases program;
- 2020 production range, operating costs and capital 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;
- potential further acquisition opportunities;
- estimates of reserves;
- estimates of contingent resources;
- the ability to generate free cash flows and use that cash to repay debt and to continue to deleverage; 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 Resource Advisory".

The forward-looking statements are based on certain key expectations and assumptions made by IPC, including expectations and assumptions concerning: 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; 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; 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, labor and services; 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:

- 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 and exchange rate fluctuations;
- interest rate fluctuations;
- marketing and transportation;
- loss of markets;
- environmental risks;
- competition;
- 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; 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.

Additional information on these and other factors that could affect IPC, or its operations or financial results, are included in the Financial Statements, the Corporation's material change report dated February 11, 2020 (MCR), the Corporation's Annual Information Form (AIF) for the year ended December 31, 2018 (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.sedar.com) or IPC's website (www.international-petroleum.com).

RESERVES AND RESOURCE ADVISORY

This MD&A contains references to estimates of gross and net reserves and resources attributed to the Corporation's and Granite'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, 2019, and are included in 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, 2019, 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, 2019, 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, 2019, price forecasts.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of the oil and gas assets of Granite Oil Corp. (Granite) are effective as of December 31, 2019, and are included in reports prepared by Sproule on behalf of IPC, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2019, 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 MCR.

2P reserves as at December 31, 2019 of 300 MMboe includes 286.2 MMboe attributable to IPC's oil and gas assets and 14.0 MMboe attributable to Granite's oil and gas assets. Contingent resources (best estimate, unrisked) as at December 31, 2019 of 1,089 MMboe includes 1,082.5 MMboe attributable to IPC's oil and gas assets and 6.2 MMboe attributable to Granite's oil and gas assets.

The reserve life index (RLI) is calculated by dividing the 2P reserves of 300 MMboe as at December 31, 2019 (including the 2P reserves attributable to the Granite Acquisition which is expected to be completed in March 2020), by the mid-point of the 2020 production guidance of 46,000 to 50,000 boepd. The reserves replacement ratio is based on 2P reserves of 288 MMboe as at December 31, 2018, production during 2019 of 16.7 MMboe, additions to 2P reserves during 2019 of 14.8 MMboe (or 28.8 MMboe including the 2P reserves attributable to the acquisition of the Granite assets which is expected to be completed in early March 2020) and 2P reserves of 286.2 MMboe (or 300 MMboe including the 2P reserves attributable to the Granite Acquisition which is expected to be completed in March 2020) as at December 31, 2019.

Light, medium and heavy crude oil 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% 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 contingencies can be clearly defined. Chance of development is the probability of a project being commercially viable.

The reserve estimates and contingent resource estimates included in the Sproule reports related to Granite's oil and gas assets are based on IPC's assessment of potential development activities related to these assets which may differ from Granite's assessment and reported figures. All of Granite's contingent resources are classified by IPC as development unclarified. The chance of development risk of 70% has been applied by IPC to all of Granite's contingent resources. The risked contingent resources (best estimate) as at December 31, 2019 is 4.3 MMboe. The contingency for all of the unrisked best estimate contingent resources is IPC's corporate commitment whether to proceed with the specific opportunities, following completion of the Granite Acquisition.

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 the 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 the MD&A.

2P reserves and contingent resources included in the reports prepared by Sproule and ERCE in respect of IPC's oil and gas assets in Canada, France and Malaysia have been aggregated by IPC and may also be aggregated by IPC with the 2P reserves and contingent resources of Granite included in the reports prepared by Sproule on behalf of 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, as well as estimates of the net present value of the future net revenue from Granite's reserves prepared on behalf of IPC. 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 evaluations will be attained and variances could be material.

The reserves and resources information and data provided in this MD&A presents only a portion of the disclosure required under NI 51-101. All of the required information will be contained in the Corporation's Annual Information Form for the year ended December 31, 2019, which will be filed on SEDAR (accessible at www.sedar.com) on or before April 1, 2020. Further information with respect to IPC's and Granite's 2P reserves, contingent resources and estimates of future net revenue, including assumptions relating to the calculation of net present value and other relevant information related to the contingent resources disclosed, is disclosed in the MCR available under IPC's profile on www.sedar.com and on IPC's website at www.international-petroleum.com.

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.

OTHER SUPPLEMENTARY INFORMATION

Abbreviations

CAD or CA$	Canadian dollar
EUR or €	Euro
USD or US$	US dollar
MYR	Malaysian Ringgit
FPSO	Floating Production Storage and Offloading (facility)

Oil related terms and measurements

AECO	The daily average benchmark price for natural gas at the AECO hub in southeast Alberta
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[1]	Barrels of oil equivalents
boepd	Barrels of oil equivalents per day
bopd	Barrels of oil per day
Bscf	Billion standard cubic feet
Empress	The benchmark price for natural gas at the Empress point at the Alberta/Saskatchewan border
EOR	Enhanced Oil Recovery
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
NGL	Natural gas liquid
SAGD	Steam assisted gravity drainage (a thermal recovery process)
WTI	West Texas Intermediate (a light oil reference price)
WCS	Western Canadian Select (a heavy oil reference price)

[1] *All volume references to boe are calculated on the basis of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 Mcf: 1 bbl) unless otherwise indicated. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, particularly if used in isolation. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.*

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