Q2

International Petroleum Corporation

Management's Discussion and Analysis

For the three and six months ended June 30, 2018

International Petroleum Corp.

Contents

Non-IFRS Measures
References are made in this MD&A to "operating cash flow" (OCF), "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, EBITDA, operating costs and net debt/net cash that may be used by other public companies. Management believes that OCF, 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 20.

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 31.

Reserve estimates, contingent resource estimates, prospective resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France, Malaysia and the Netherlands are effective as of December 31, 2017 and were prepared by IPC and audited by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook), and using McDaniel's January 1, 2018 price forecasts as referred to below.

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 January 5, 2018, being the completion date for the acquisition of these assets by IPC, and were evaluated by McDaniel & Associates Consultants Ltd. (McDaniel), an independent qualified reserves evaluator, in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's January 1, 2018 price forecasts. The volumes are reported and aggregated by IPC in this MD&A as being as at December 31, 2017.

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 August 7, 2018 and is intended to provide an overview of the Group's operations, financial performance and current and future business opportunities. This MD&A should be read in conjunction with IPC's unaudited interim condensed consolidated financial statements and accompanying notes for the three and six months ended June 30, 2018 ("Financial Statements").

Formation of IPC

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").

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, France and the Netherlands 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"). Historically, financial statements were not prepared by IPC for the assets that were spun-off as they were not operated as a separate business by Lundin Petroleum and accordingly, prior to the Spin-Off date, the results have been carved out from the historical consolidated financial statements of Lundin Petroleum. Refer to the Financial Statements for additional information on the basis of preparation.

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:

	June 30, 2018		June 30, 2017		December 31, 2017	
	Average	Period end	Average	Period end	Average	Period end
1 EUR equals USD	1.2108	1.1658	1.0825	1.1412	1.1293	1.1993
1 USD equals CAD	1.2774	1.3246	1.3342	1.2956	1.2982	1.2540
1 USD equals MYR	3.9384	4.0384	4.3892	4.2925	4.2994	4.0470

SECOND QUARTER 2018 HIGHLIGHTS

Swedish Listing

- IPC's shares commenced trading on the Nasdaq Stockholm on June 8, 2018.

Operational Highlights

Production and Operating Costs

- Net production levels averaged 34,900 barrels of oil equivalent (boe) per day (boepd) for the second quarter of 2018, six percent higher than the first quarter production and at the high end the Capital Markets Day (CMD) guidance for the second quarter of 2018.
- Production guidance range for the full year 2018 is revised from 30,000 to 34,000 boepd to 32,500 to 34,000 boepd net to IPC.
- High uptime across all assets with Canadian and Malaysian shutdowns completed ahead of plan; strong recovery in Canadian gas production following the cold winter.
- Bertam field in Malaysia performing ahead of expectation driven predominantly by the combination of good reservoir performance from the last three infill wells and high field uptime performance.
- Operating costs[1] per boe ahead of guidance at USD 11.96 for the second quarter of 2018 (CMD - USD 13.60) and USD 12.17 year to date (CMD – USD 13.10). Full year guidance of USD 12.60 maintained.

Resources and Projects

- Progressing plans to drill the Keruing prospect in Malaysia in late 2018.
- Expanding the gas optimization program in Canada following year to date success; low breakeven activity.
- Full year 2018 capital expenditure guidance increased from USD 39.4 million to USD 44.0 million mainly related to increased gas optimization activity in Canada.

[1] *See definition on page 20 under "Non-IFRS measures"*

Financial Highlights

	Three months ended June 30		Six months ended June 30	
USD Thousands	**2018**	2017	**2018**	2017
Revenue	120,637	48,496	235,799	100,428
Gross profit	45,920	10,361	83,493	28,031
Net result	21,498	7,113	47,811	11,574
Operating cash flow [1]	76,687	32,644	152,747	72,319
EBITDA [1]	74,478	30,049	139,769	69,435

[1] *See definition on page 20 under "Non-IFRS measures"*

- CAD 12 million deferred purchase price payment for the acquisition of the Suffield Assets made in June 2018.
- Net debt reduced by over USD 100 million since completion of the acquisition of the Suffield Assets on January 5, 2018 to USD 254.6 million as at June 30, 2018 from USD 309.2 million as at March 31, 2018.
- In May 2018, CAD 45 million of the CAD 60 million second lien credit facility, which was partly used to fund the acquisition of the Suffield Assets and carried the Group's highest interest cost, was repaid. In August 2018, the remaining CAD 15 million was repaid and the facility was cancelled.

OPERATIONS REVIEW

Business Overview

On April 24, 2018, IPC passed our first anniversary as an independently listed company in Canada and Sweden. On June 8, 2018, the Corporation's shares commenced trading on the main Nasdaq Stockholm exchange.

Our focus since launching remains unchanged: seeking to deliver operational excellence, demonstrating financial resilience, maximizing the value of our resource base and targeting growth 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. We continue to make excellent progress on all fronts in delivering on that strategy.

Delivering Operational Excellence
During the second quarter of 2018 our assets delivered an excellent average daily net production performance at the high end of our CMD guidance of 34,900 boepd, six percent higher than our first quarter production. Given the strong first half performance, we are revising our full year 2018 average production guidance range from 30,000 to 34,000 boepd to 32,500 to 34,000 boepd net to IPC.

Production in Canada of 24,000 boepd during the second quarter of 2018 was ahead of our high case CMD guidance and ten percent above our first quarter production, driven partially by the first full quarter of production contribution in Canada as the acquisition completed on January 5, 2018. In addition, excellent facility uptime performance, a recovery in gas production as the warmer weather arrived and increased gas optimization activity contributed to the outperformance.

A world class uptime performance on the Bertam FPSO in excess of 99 percent continued during the second quarter of 2018 (excluding the planned shutdown for an underwater FPSO inspection). The two new infill wells that commenced production in January and February 2018 respectively, performed ahead of expectation during the second quarter related to good reservoir performance in these regions of the field. Second quarter production on the Bertam field was 7,600 bopd, net to IPC, nine percent ahead of the comparative production for the second quarter of 2017, demonstrating that the infill wells have more than offset the natural decline through 2017.

Production in Europe was at the high end of our CMD guidance driven by good performance at a number of our Paris Basin and Aquitaine fields.

Our operating costs per barrel of oil equivalent for the second quarter were ahead of guidance at USD 11.96.

Our full year capital expenditure guidance of USD 39.4 million is being increased to USD 44.0 million mainly related to increased gas optimization activity in Canada.

Demonstrating Financial Resilience
IPC has delivered a robust financial performance during the second quarter of 2018 generating operating cash flow of USD 76.7 million. This allowed IPC to pay the CAD 12 million deferred purchase price payment for the acquisition of the Suffield Assets, fund the capital expenditure program and reduce net debt from USD 309 million at the end of the first quarter to USD 255 million by the end of the second quarter. First half 2018 operating cash flow was in excess of USD 150 million and net debt reduction was in excess of USD 100 million since completion of the Suffield acquisition in early January 2018.

Maximizing the Value of our Resource Base
Good progress has been made in adding value to IPC's resource base since the Spin-Off. As at end December 2017, IPC's 2P reserves more than quadrupled to 129.1 MMboe (including 2P reserves attributable to the Suffield Assets). This includes a reserves replacement ratio of 76 percent for the non-Canadian assets and follows the maturation of contingent resources from the infill drilling program in Malaysia and certain upgrades in France and the Netherlands.

In addition, we reported that our best estimate contingent resources as at end December 2017 have more than tripled to 63.4 MMboe (unrisked), after giving effect to the Suffield acquisition in Canada. Two additional infill locations on the Bertam field in Malaysia have been booked as contingent resources as well as the inclusion of the acquired contingent resources in Canada. We are confident that we have a solid contingent resource base in place to mature that can provide the feedstock to add to reserves and our value in the future.

In Malaysia, following positive results from the previous infill drilling programs and continued good reservoir performance, we continue to assess potential further infill drilling on the Bertam field. In addition, we are progressing plans to drill the Keruing prospect in late 2018, subject to Petronas approval and rig contracting.
In Canada we are preparing for the launch of the first oil drilling campaign in the Suffield Assets since 2014, with six wells expected to be completed by the end of 2018. Work runs in parallel to mature additional oil drilling and water injection candidates to extend the program into 2019. In addition, the immediate focus is on gas optimization efforts to offset natural declines as opposed to new gas drilling and the team has evaluated a wide range of activities over and above those already approved in our 2018 budget. We have approved additional activity that will see us expand the swabbing program and commence a refracture and recomplete program in late 2018.

In France, our team is focused on maturing the Vert La Gravelle redevelopment and the Villeperdue West development projects following the acquisition of the 3D seismic on the latter in 2017, as well as maturing the deep prospectivity within the new 3D area.

Growth from Acquisition

During the first quarter of 2018, IPC announced the completion of the transformational acquisition of the Suffield and Alderson oil and gas assets in Alberta, Canada. The Suffield and Alderson oil and gas assets are high quality conventional assets that have been operated safely and efficiently for many years. This acquisition is demonstrating success in IPC's strategy of leveraging our existing producing asset base as a platform for value accretive acquisitions of long-life, low-decline producing assets in stable jurisdictions with upside development potential.

The transaction was completed on January 5, 2018, fully debt financed, with USD 355 million of net debt outstanding immediately post completion. Since then, net debt has been reduced by more than USD 100 million. With strengthening commodity prices, a low operating cost base and good post completion integration, we are beginning to see some green shoots of delivery on our acquisition driven strategy as we seek to ramp up development and optimization activity through 2018 and into 2019.

IPC remains proactive in looking for additional acquisition opportunities that we believe can add long term shareholder value.

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 the reporting period, IPC recorded two low severity Lost Time Incident (LTI) in France and four reportable spills in Canada, all of which were small volumes, contained and recovered at the spill location.

Operations Overview

Reserves and Resources

The IPC producing assets more than quadrupled to 129.1 MMboe of 2P reserves as at 31 December 2017 (after giving effect to the Suffield acquisition in Canada), compared to 29.4 MMboe of 2P reserves as at 31 December 2016, in each case as certified by independent third party reserves auditors. The reserves life index (RLI) as at 31 December 2017 (after giving effect to the Suffield acquisition in Canada) is approximately 11 years. Best estimate contingent resources as at 31 December 2017 more than tripled to 63.4 MMboe (unrisked), including the resources acquired in Canada and two additional infill drilling locations in the Bertam field in Malaysia.

IPC remains focused on organic growth and is maturing opportunities across all our operated assets. In Canada, there is a planned program of oil drilling activities in Q4 2018 which is expected to continue into 2019 and beyond, complemented by gas optimization activities aimed at reducing decline rates. In Malaysia, we have just completed a second phase of infill drilling with two infill wells now on stream and producing ahead of pre-drill expectations. We expect to drill the Keruing prospect in late 2018. In France, work continues to mature the Villeperdue and Vert-la-Gravelle opportunities towards sanction and execution as well as maturing the deeper prospectivity within the new 3D area that was acquired in late 2017.

Production

Production for the IPC assets during the second quarter of 2018 was at the high end of CMD guidance at 34.9 Mboepd. Integration of the Canadian assets has delivered a significant increase in production volumes for IPC relative to 2017 levels. In Malaysia, the addition of the two infill wells has increased production from the field relative to the first half of 2017. The production during the reporting period with comparatives was comprised as follows:

Production in Mboepd	Three months ended June 30		Six months ended June 30		12 months ended December 31
	2018	2017	**2018**	2017	2017
Crude oil					
Canada	6.2	–	6.3	–	–
Malaysia	7.6	7.0	7.7	7.3	6.7
France	2.5	2.5	2.5	2.5	2.4
Total crude oil production	**16.3**	9.5	**16.5**	9.8	9.1
Gas					
Canada	17.8	–	16.6	–	–
Netherlands	0.8	1.1	0.8	1.3	1.2
Total gas production	**18.6**	1.1	**17.4**	1.3	1.2
Total production	**34.9**	10.6	**33.9**	11.1	10.3
Quantity in MMboe	**3.18**	0.96	**6.14**	2.00	3.76

CANADA

Production in Mboepd	WI	Three months ended June 30		Six months ended June 30		12 months ended December 31
		2018	2017	**2018**	2017	2017
- Crude Oil	100%	6.2	–	6.3	–	–
- Gas	99.7%[1]	17.8	–	16.6	–	–
Canada		**24.0**	–	**22.9**	–	–

[1] *On a well count basis.*

Production

Net production from the Canadian assets during the second quarter was above our high end CMD guidance at 24.0 Mboepd due to continued excellent oil facility uptime performance, notwithstanding a planned four day shut down for turnaround activities at the main 1-27 oil facility. Gas production outperformed CMD guidance due to strong recovery with the warmer weather and successful gas optimization campaign results to date. As at the end of the second quarter, over 3,100 wells have been swabbed compared to the original budget for the full year 2018 of 5,500 wells with a further 100 of 200 planned siphon string / coil tubing optimizations being completed. As part of the review of gas optimization completed in the first half, our budget has been increased to allow for significantly more optimization activities including coil tubing clean outs, siphon string optimization work, increased swabbing and other optimization activities such as refracturing and recompleting wells. Initial rates for activities completed to date has shown higher than expected production performance.

Organic Growth and Capital Projects

A program of drilling and optimization activities was sanctioned by IPC as a part of the operational and capital budgets for 2018 and we remain on track to deliver the programs as planned and announced at our Capital Markets Day in February. New drilling in the oil pools in Canada is planned to commence in the fourth quarter of 2018 with six locations and this will be the first drilling activity on the Suffield Assets in more than four years. Required regulatory approvals are well underway to support continued drilling through to the end of 2019, with the inventory of well locations being actively matured to continue development beyond 2019.

A review of the opportunities to increase production from the shallow gas wells has been ongoing since the start of 2018 and the optimization program has already shown significant benefits. In addition a capital program has been approved to target well recompletions, stimulation activities and activation of reservoir zones which are currently not on production. Capital activities on the gas side have been minimal since 2010 and there is significant opportunity to add volumes with minimal investment. The IPC team in Canada has identified opportunities to target wells which will benefit from stimulation and recompletion, or have unproduced zones.

Capital projects have also been identified to potentially add further value for the Suffield Assets and there are a range of additional opportunities under review. During the course of the second quarter of 2018, a project to reroute around eight percent of produced gas volumes from Alderson to be sold at Empress pricing rather than AECO pricing was sanctioned. As the Empress price has had a premium to AECO over the course of 2018, this project has a payout of around 3 months based on the average price differential in 2018 and is expected to allow for almost 100% of IPC gas volumes to be sold at Empress pricing from Q4 2018.

SOUTH EAST ASIA

Malaysia

		Three months ended June 30		Six months ended June 30		12 months ended December 31
Production in Mboepd	WI	**2018**	2017	**2018**	2017	2017
Bertam	75%	**7.6**	7.0	**7.7**	7.3	6.7

Production

Net production from the Bertam field on Block PM307 during the second quarter of 2018 was ahead of guidance at 7.6 Mboepd. Strong reservoir performance was primarily attributed to production from the new infill wells, A-16 & A-17 which came on stream in the first quarter of 2018, along with the ongoing A-15 performance. The Bertam facility uptime during the second quarter of 2018 remained above 99% excluding the planned outage for underwater inspection activities, which were completed safely and ahead of the original schedule.

Organic Growth

The latest two well infill campaign was completed and brought online in the first quarter of 2018, and both wells continue to produce ahead of expectation. Initial study work post the results of the A-16 and A-17 campaign has identified opportunities for further infill wells which are under review.

The subsurface technical evaluation for the Keruing prospect was completed in the second quarter and preparations continue for a spud date in late 2018, subject to regulatory and partner approvals. The development solution in the success case is expected to be a tie-back to the Bertam FPSO and utilization of the existing facilities, leading to a high value project.

CONTINENTAL EUROPE

Production in Mboepd	WI	Three months ended June 30 2018	Three months ended June 30 2017	Six months ended June 30 2018	Six months ended June 30 2017	12 months ended December 31 2017
France						
- Paris Basin	100% [1]	2.0	2.1	2.1	2.1	2.0
- Aquitaine	50%	0.5	0.4	0.4	0.4	0.4
Netherlands	Various	0.8	1.1	0.8	1.3	1.2
		3.3	3.6	**3.3**	3.8	3.6

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

France
Net production in France during the second quarter of 2018 was above forecast at 2.5 Mboepd.

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 converting contingent resources into reserves.

The Vert La Gravelle redevelopment project passed the concept selection milestone in December 2017 and is progressing towards an investment decision by year end 2018. Final engineering and planning work is now focusing on optimizing the drilling and completion design. Processing and interpretation of the Villeperdue West 2017 seismic data is ongoing which is planned to lead to refinement of the development plan and concept select milestone later in 2018, as well as understanding the potential prospectivity of the deeper Triassic horizon which is produced by IPC in other parts of the Paris Basin.

The Netherlands
Net production from the Netherlands fields during the second quarter of 2018 was slightly below forecast at 0.8 Mboepd due to lower than expected production from the onshore Slootdorp and Gorredijk fields. In addition, the Q16a field was shut-in due to technical constraints. The reduced production from the Gorredijk field is due to third party gas utilizing shared infrastructure. The Gorredijk gas is expected to be recovered at a later date and IPC is receiving a compensation tariff for the backed out volumes minimizing the impact on revenues. On Q16a repairs have been successfully completed and production has been fully restored.

Offshore, the E17 field development well planned for second half of 2018 has been delayed until 2019 due to the existing wells producing ahead of expectation.

FINANCIAL REVIEW

Financial Results

Selected Financial Information

Selected interim condensed consolidated statement of operations is as follows:

USD Thousands	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016
Revenue	**120,637**	115,162	54,647	47,926	48,496	51,932	59,592	48,498
Gross profit/(loss)	**45,920**	37,573	13,471	7,256	10,361	17,670	(114,600)	9,631
Net result	**21,498**	26,313	8,977	2,172	7,113	4,461	(76,097)	4,522
Earnings/(loss) per share – USD[1]	**0.24**	0.30	0.10	0.02	0.07	0.04	(0.67)	0.04
Earnings/(loss) per share fully diluted – USD[1]	**0.23**	0.30	0.10	0.02	0.07	0.04	(0.67)	0.04
Operating cash flow [2]	**76,687**	76,060	37,156	28,893	32,643	39,675	42,083	38,911
EBITDA [2]	**74,478**	65,291	33,383	26,440	30,049	39,387	41,126	38,439
Net debt [2]	**254,628**	309,184	26,321	47,241	35,348	(20,082)	(13,410)	(8,443)

[1] *For comparative purposes, the Corporation's common shares issued under the Spin-Off, have been assumed to be outstanding as of the beginning of each period prior to the Spin-Off.*

[2]*See definition on page 20 under "Non-IFRS measures".*

Summarized consolidated balance sheet information is as follows:

USD Thousands	June 30, 2018	December 31, 2017
Non-current assets	825,542	455,235
Current assets	104,845	134,476
Total assets	**930,387**	589,711
Total non-current liabilities	495,041	219,097
Current liabilities	81,200	63,672
Total liabilities	**576,241**	282,769
Net assets	**354,146**	306,942
Working capital (including cash)	**23,645**	70,804

Segment Information

The Group operates within several geographical areas. Operating segments are reported at country level which is consistent with the internal reporting provided to IPC management. The following tables present certain segment information.

	Three months ended – June 30, 2018					
USD Thousands	Canada	Malaysia	France	Netherlands	Other	Total
Crude oil	34,483	50,683	14,683	23	–	**99,872**
NGLs	88	–	–	89	–	**177**
Gas	14,688	–	–	2,666	–	**17,354**
Net sales of oil and gas	**49,259**	**50,683**	**14,683**	**2,778**	**–**	**117,403**
Change in under/over lift position	–	–	212	–	–	**212**
Royalties	(1,639)	–	–	–	–	**(1,639)**
Other operating revenue	(72)	3,868	302	457	106	**4,661**
Revenue	**47,548**	**54,551**	**15,197**	**3,235**	**106**	**120,637**
Production costs	(28,609)	(6,494)	(6,190)	(1,643)	**–**	**(42,936)**
Depletion	(10,873)	(8,985)	(3,660)	(600)	**–**	**(24,118)**
Depreciation of other assets	**–**	(7,789)	**–**	**–**	**–**	**(7,789)**
Exploration and business development costs	–	150	–	–	(24)	**126**
Gross profit/(loss)	**8,066**	**31,433**	**5,347**	**992**	**82**	**45,920**

	Three months ended – June 30, 2017				
USD Thousands	Malaysia	France	Netherlands	Other	Total
Crude oil	32,679	8,508	13	–	41,200
NGLs	–	–	96	–	96
Gas	–	–	3,183	–	3,183
Net sales of oil and gas	32,679	8,508	3,292	–	44,479
Change in under/over lift position	–	(113)	(177)	–	(290)
Other operating revenue	3,975	266	112	(46)	4,307
Revenue	36,654	8,661	3,227	(46)	48,496
Production costs	(9,793)	(4,405)	(1,852)	10	(16,040)
Depletion	(8,920)	(3,855)	(1,169)	–	(13,944)
Depreciation of other assets	(7,906)	–	–	–	(7,906)
Exploration and business development costs	175	(4)	–	(580)	(409)
Impairment costs	164	–	–	–	164
Gross profit/(loss)	10,374	397	206	(616)	10,361

	Six months ended – June 30, 2018					
USD Thousands	Canada	Malaysia	France	Netherlands	Other	Total
Crude oil	61,497	94,369	35,233	46	–	**191,145**
NGLs	172	–	–	208	–	**380**
Gas	31,889	–	–	6,067	–	**37,956**
Net sales of oil and gas	**93,558**	**94,369**	**35,233**	**6,321**	**–**	**229,481**
Change in under/over lift position	–	–	171	12	–	**183**
Royalties	(3,345)	–	–	–	–	**(3,345)**
Other operating revenue	136	7,693	580	844	227	**9,480**
Revenue	**90,349**	**102,062**	**35,984**	**7,177**	**227**	**235,799**
Production costs	(57,123)	(11,834)	(16,903)	(3,374)	–	**(89,234)**
Depletion	(20,898)	(18,074)	(6,952)	(1,356)	–	**(47,280)**
Depreciation of other assets	–	(15,749)	–	–	–	**(15,749)**
Exploration and business development costs	–	(15)	–	–	(28)	**(43)**
Gross profit/(loss)	**12,328**	**56,390**	**12,129**	**2,447**	**199**	**83,493**

	Six months ended – June 30, 2017				
USD Thousands	Malaysia	France	Netherlands	Other	Total
Crude oil	58,333	25,744	38	–	84,115
NGLs	–	–	198	–	198
Gas	–	–	7,767	–	7,767
Net sales of oil and gas	58,333	25,744	8,003	–	92,080
Change in under/over lift position	–	(202)	(393)	–	(595)
Other operating revenue	7,693	539	551	160	8,943
Revenue	66,026	26,081	8,161	160	100,428
Production costs	(10,642)	(13,794)	(3,475)	10	(27,901)
Depletion	(18,505)	(7,371)	(2,572)	–	(28,448)
Depreciation of other assets	(15,666)	–	–	–	(15,666)
Exploration and business development costs	58	(24)	–	(580)	(546)
Impairment costs	164	–	–	–	164
Gross profit/(loss)	21,435	4,892	2,114	(410)	28,031

Three and six months ended June 30, 2018 Review

Revenue
Total revenue amounted to USD 120,637 thousand for Q2 2018 compared to USD 48,496 thousand for Q2 2017 and USD 235,799 thousand for the first six months of 2018 compared to USD 100,428 thousand for the first six months of 2017 and is analyzed as follows:

	Three months ended June 30		Six months ended June 30	
USD Thousands	**2018**	2017	**2018**	2017
Crude oil sales	99,872	41,200	191,145	84,115
Gas and NGL sales	17,531	3,279	38,336	7,965
Change in under/overlift position	212	(290)	183	(595)
Royalties	(1,639)	–	(3,345)	–
Other operating revenue	4,661	4,307	9,480	8,943
Total revenue	**120,637**	48,496	**235,799**	100,428

The components of total revenue for the three and six months ended 30 June 2018 and June 30, 2017, respectively are detailed below:

Crude oil sales

	Three months ended – June 30, 2018				
	Canada	**Malaysia**	**France**	**Netherlands**	**Total**
Crude oil sales					
- Revenue in USD thousands	34,483	50,683	14,683	23	**99,872**
- Quantity sold in bbls	685,597	647,149	192,681	369	**1,525,796**
- Average price realized USD per bbl	50.30	78.32	76.20	63.63	**65.46**

	Three months ended – June 30, 2017			
	Malaysia	**France**	**Netherlands**	**Total**
Crude oil sales				
- Revenue in USD thousands	32,679	8,508	13	41,200
- Quantity sold in bbls	622,967	187,243	347	810,557
- Average price realized USD per bbl	52.46	45.44	36.34	50.83

Crude oil revenue was 142 percent higher for Q2 2018 compared to Q2 2017 mainly due to the contribution of Suffield Assets in Canada from January 5, 2018 and an increase in the underlying oil price.

The 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 is traded at a discount to West Texas Intermediate ("WTI"). WTI averaged USD 68 per bbl and the average discount to WCS was approximately USD 19 per bbl for Q2 2018.

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 74 per bbl for Q2 2018 compared to USD 50 per bbl for the comparative period.

	Six months ended – June 30, 2018				
	Canada	Malaysia	France	Netherlands	Total
Crude oil sales					
- Revenue in USD thousands	61,497	94,369	35,233	46	191,145
- Quantity sold in bbls	1,358,750	1,266,393	503,652	761	3,129,556
- Average price realized USD per bbl	45.26	74.52	69.96	60.92	61.08

	Six months ended – June 30, 2017			
	Malaysia	France	Netherlands	Total
Crude oil sales				
- Revenue in USD thousands	58,335	25,744	38	**84,115**
- Quantity sold in bbls	1,069,837	521,887	887	**1,592,611**
- Average price realized USD per bbl	54.53	49.33	43.30	**52.82**

Crude oil sales were 127 percent higher for the first six months of 2018 compared to the first six months of 2017 due to the contribution of Suffield Assets in Canada from January 5, 2018, one additional cargo lifting in Malaysia and an increase in the underlying oil price.

The Canadian realized sales price is based on the WCS price which is traded at a discount to WTI. WTI averaged USD 65 per bbl and the average discount to WCS was approximately USD 22 per bbl for the first six months of 2018.

The realized sales price for Malaysia and France is based on Brent crude oil prices and the average market Brent crude oil price was USD 71 per bbl in the first six months of 2018 compared to USD 52 per bbl for the comparative period. There were six cargoes sold in Malaysia during the first six months of 2018 compared to five cargoes in the comparative period.

Gas and NGL sales

	Three months ended – June 30, 2018		
	Canada	Netherlands	Total
Gas and NGL sales			
- Revenue in USD thousands	14,776	2,755	**17,531**
- Quantity sold in Mcf	9,002,137	414,777	**9,416,914**
- Average price realized USD per Mcf	1.64	6.64	**1.86**

	Three months ended – 30 June 2017	
	Netherlands	Total
Gas and NGL sales		
- Revenue in USD thousands	3,279	**3,279**
- Quantity in Mcf	638,801	**638,801**
- Average price realized USD per Mcf	5.13	**5.13**

Gas and NGL sales revenue was 435 percent higher for Q2 2018 compared to Q2 2017 mainly due to the contribution of the Suffield Assets from January 5, 2018. Canadian gas and sales represented approximately 85 percent of the total revenue from gas and NGL sales for Q2 2018. Over 90 percent of the Suffield gas production is sold on the Alberta/Saskatchewan border at Empress with the remainder being delivered in Alberta based on AECO pricing. For Q2 2018, IPC realized an average price of CAD 2.11 per Mcf which was CAD 0.93 per Mcf, or approximately 80%, above AECO pricing.

Dutch gas volumes sold in Q2 2018 are 35 percent lower than the comparative period due to the naturally declining production, but this has been partly offset by a 29 percent higher realized gas price.

	Six months ended – June 30, 2018		
	Canada	Netherlands	Total
Gas and NGL sales			
- Revenue in USD thousands	32,061	6,275	**38,336**
- Quantity sold in Mcf	17,078,797	904,907	**17,983,704**
- Average price realized USD per Mcf	1.88	6.93	**2.13**

	Six months ended – 30 June 2017	
	Netherlands	Total
Gas and NGL sales		
- Revenue in USD thousands	7,965	**7,965**
- Quantity in Mcf	1,455,883	**1,455,883**
- Average price realized USD per Mcf	5.47	**5.47**

Gas and NGL sales revenue was 381 percent higher for the first six months of 2018 compared to the first six months of 2017 mainly due to the Suffield Assets from January 5, 2018. For the six months ended 2018, IPC realized an average price of CAD 2.39 per Mcf which was CAD 0.77 per Mcf, or approximately 50%, above AECO pricing.

Other operating revenue

Other operating revenue amounted to USD 4,661 thousand for Q2 2018 compared to USD 4,307 thousand for Q2 2017 and USD 9,480 thousand for the first six months of 2018 compared to USD 8,943 thousand for the first six months of 2017. Other operating revenue mainly represents third party lease fee income received by the Group for the leasing of the owned FPSO Bertam to the Bertam field in Malaysia.

Production costs

Production costs including inventory movements amounted to USD 42,936 thousand for Q2 2018 compared to USD 16,040 thousand for Q2 2017 and USD 89,234 thousand for the first six months of 2018 compared to USD 27,901 thousand for the first six months of 2017 and is analyzed as follows:

	Three months ended – June 30, 2018					
USD Thousands	Canada	Malaysia	France	Netherlands	Other [3]	Total
Operating costs[1]	22,228	18,252	7,456	1,643	(11,603)	**37,976**
USD/boe[2]	10.20	26.29	32.14	23.62	n/a	**11.96**
Cost of blending[4]	7,238	–	–	–	–	**7,238**
Change in inventory position	(857)	(155)	(1,266)	–	–	(2,278)
Production costs	**28,609**	**18,097**	**6,190**	**1,643**	**(11,603)**	**42,936**

	Three months ended – June 30, 2017				
USD Thousands	Malaysia	France	Netherlands	Other [3]	Total
Operating costs[1]	18,088	5,512	1,842	(11,603)	**13,839**
USD/boe[2]	28.45	24.33	18.39	n/a	**14.38**
Change in inventory position	3,308	(1,107)	–	–	**2,201**
Production costs	**21,396**	**4,405**	**1,842**	**(11,603)**	**16,040**

	Six months ended – June 30, 2018					
USD Thousands	Canada	Malaysia	France	Netherlands	Other [3]	Total
Operating costs[1]	44,122	35,200	15,133	3,374	(23,078)	**74,751**
USD/boe[2]	10.65	25.20	33.84	22.22	n/a	**12.17**
Cost of blending[4]	14,145	–	–	–	–	**14,145**
Change in inventory position	(1,144)	(288)	1,770	–	–	**338**
Production costs	**57,123**	**34,912**	**16,903**	**3,374**	**(23,078)**	**89,234**

	Six months ended – June 30, 2017				
USD Thousands	Malaysia	France	Netherlands	Other [3]	Total
Operating costs[1]	35,172	11,059	3,465	(23,078)	**26,618**
USD/boe[2]	26.67	24.64	15.01	n/a	**13.32**
Change in inventory position	(1,452)	2,735	–	–	**1,283**
Production costs	**33,720**	**13,794**	**3,465**	**(23,078)**	**27,901**

[1] *See definition on page 20 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 9.57 and USD 10.20 for Q2 2018 and Q2 2017 respectively and USD 8.67 and USD 9.17 for the six months ended June 30, 2018 and June 30, 2017 respectively.*

[4] *Cost of blending represents the contracted purchase of diluent used for blending net of proceeds from the sale of surplus diluent.*

Operating costs

Operating costs amounted to USD 37,976 thousand for Q2 2018 compared to USD 13,839 thousand for Q2 2017 and USD 74,751 thousand for the first six months of 2018 compared to USD 26,618 thousand for the first six months of 2017. The increase in operating costs is mainly due to the contribution of Suffield Assets in Canada from January 5, 2018 and is four percent below CMD guidance for the first six months of 2018. Operating costs per boe amounted to USD 11.96 in Q2 2018 compared to USD 14.38 in Q2 2017 with Canada for Q2 2018 costing USD 10.20 per boe. The operating costs in France for the first six months of 2018 increased compared to the first six months of 2017 as a result of the increased production taxes due to tax legislation changes made in Q4 2017, project cost phasing and the stronger US Dollar against the Euro. The full year operating costs guidance for 2018 remains unchanged at USD 12.60 per boe.

Cost of blending

In Canada, the oil from the Suffield Assets 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 7,238 thousand for Q2 2018 and to USD 14,145 thousand for the first six months of 2018. As a result of the blending, actual sales volumes are higher than produced barrels.

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. The inventory is 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. In the Aquitaine Basin, France, there was a cargo lifting in both Q1 2018 and Q1 2017. The next lifting from the Aquitaine fields is expected to be in the fourth quarter of 2018.

Depletion and decommissioning costs

The total depletion and decommissioning costs amounted to USD 24,118 thousand for Q2 2018 compared to USD 13,944 thousand for Q2 2017 and USD 47,280 thousand for the first six months of 2018 compared to USD 28,448 thousand for the first six months of 2017, with the inclusion of a USD 10,873 thousand depletion charge for Q2 2018 and USD 20,898 thousand for the first six months of 2018 relating to the Suffield Assets. The depletion charge per country is analyzed in the following tables:

	Three months ended – June 30, 2018				
	Canada	Malaysia	France	Netherlands	Total
Depletion and decommissioning costs in USD thousands	10,873	8,985	3,660	600	**24,118**
USD per boe	4.99	12.94	15.78	8.63	**7.59**

	Three months ended – June 30, 2017			
	Malaysia	France	Netherlands	Total
Depletion and decommissioning costs in USD thousands	8,920	3,855	1,169	**13,944**
USD per boe	14.03	17.01	11.67	**14.49**

	Six months ended – June 30, 2018				
	Canada	Malaysia	France	Netherlands	Total
Depletion and decommissioning costs in USD thousands	20,898	18,074	6,952	1,356	**47,280**
USD per boe	5.04	12.94	15.54	8.93	**7.70**

	Six months ended – June 30, 2017			
	Malaysia	France	Netherlands	Total
Depletion and decommissioning costs in USD thousands	18,505	7,371	2,572	**28,448**
USD per boe	14.03	16.42	11.14	**14.23**

The depletion rates for 2018 have been calculated following the 2017 year end reserves revisions. The depletion charge is derived by applying the depletion rate per boe to the volumes produced in the period by each field. Following the allocation of the purchase price for the Suffield Assets, the depletion rate for Canada is calculated at CAD 6.44 per boe.

Depreciation of other assets

The total depreciation of other assets amounted to USD 7,789 thousand for Q2 2018 compared to USD 7,906 thousand for Q2 2017 and USD 15,749 thousand for the first six months of 2018 compared to USD 15,666 thousand for the first six months of 2017. This related to the depreciation of the FPSO Bertam, which is being depreciated on a straight line basis over the six year lease period on the Bertam field from April 2015.

General, administrative and depreciation expenses

General, administrative and depreciation expenses amounted to USD 3,343 thousand for Q2 2018 compared to USD 2,854 thousand for Q2 2017 and USD 7,077 thousand for the first six months of 2018 compared to USD 3,780 thousand for the first six months of 2017. Until the Spin-Off date in April 2017, the general administrative and depreciation expenses are a carve out from Lundin Petroleum's financial statements and are not representative of the general, administrative and depreciation expenses associated with the Group's corporate structure post Spin-Off.

Net financial items

Net financial items for Q2 2018 amounted to USD 15,048 thousand compared to USD 502 thousand for Q2 2017 and USD 24,201 thousand for the first six months of 2018 compared to USD 11,453 thousand for the first six months of 2017. Included in Q2 2018 is interest expense of USD 3,939 thousand on the external loan facilities which were drawn to fund the Suffield acquisition at the beginning of January 2018 and a largely non-cash net foreign exchange loss of USD 8,175 thousand mainly resulting from the revaluation of external loan balances and intra-group loan funding balances. In addition, the unwinding of the discount rate on the asset retirement obligations amounted to a non-cash charge of USD 2,341 thousand for Q2 2018 compared to USD 873 thousand for Q2 2017. The increase is largely due to the unwinding of the discounting on the Suffield Assets retirement obligation included on January 5, 2018. The net financial items for the comparative period included a non-cash net foreign exchange loss of USD 9,255 thousand mainly resulting from the revaluation of intercompany loans prior to the reorganization and Spin-Off.

Income tax

The corporate income tax charge for Q2 2018 amounted to USD 6,031 thousand compared to a credit of USD 108 thousand for Q2 2017 and a charge of USD 4,404 thousand for the first six months of 2018 compared to USD 1,224 thousand for the first six months of 2017. 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. The deferred tax charge for Q2 2018 amounted to USD 5,017 thousand compared to USD 80 thousand for the comparative period and included a charge relating to the utilization of part of the tax losses carried forward in Malaysia during Q2 2018.

Capital Expenditure

Development and exploration and evaluation expenditure incurred in the first six months of 2018 was as follows:

USD Thousands	Canada	Malaysia	France	Netherlands	Total
Development	2,086	12,662	1,686	261	**16,695**
Exploration and evaluation	–	688	374	81	**1,143**
	2,086	13,350	2,060	342	**17,838**

Capital expenditure for the first six months of 2018 is in line with the guidance given at Q1 2018 and the development expenditure in Malaysia mainly relates to the drilling of the second infill well on the Bertam field. The two drilling campaign started in December 2017 and was completed under budget in Q1 2018. The capital guidance for 2018 has been increased to USD 44.0 million from 39.4 million at Q1 2018 mainly related to increased gas optimization activities in Canada.

Other tangible fixed assets

Other tangible fixed assets amounted to USD 106,817 thousand as at June 30, 2018, which included USD 104,753 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated on a straight line basis over the six year lease period on the Bertam field from April 2015.

Acquisition of the Suffield Assets

On January 5, 2018, IPC acquired the Suffield Assets from Cenovus Energy Inc. for a total consideration, after preliminary closing adjustments and an assessment of the contingent consideration, of USD 375,862 thousand. The amount has reduced from USD 378,567 thousand recorded at March 31, 2018 following the receipt of an updated statement of adjustments. The purchase price has been allocated, on a preliminary basis, as follows:

USD Thousands	
Property, Plant and Equipment, net	453,630
Deferred tax liabilities	(2,682)
Abandonment retirement obligation	(75,086)
Net assets acquired	**375,862**

There was no goodwill or negative goodwill recorded on the acquisition.

The amounts disclosed above were determined provisionally pending the finalization of the valuation for those assets and liabilities. Up to twelve months from the effective date of the acquisition, further adjustments may be made to the fair values assigned to the identifiable assets acquired and liabilities assumed, as well as to the fair value of the consideration transferred.

Financial Position and Liquidity

Financing

In April 2017, the Group entered into a USD 100 million reserve-based lending credit facility, which was used to fund the offer to purchase common shares of IPC announced on April 24, 2017.

The credit facility was initially drawn for USD 80.0 million in May 2017 to partly fund the share purchase offer made to all shareholders totaling USD 90.6 million and the balance was paid from Group's available cash.

In connection with the completion of the Suffield acquisition, the Group entered into an amendment to the existing reserve-based lending credit facility on December 20, 2017 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 on January 5, 2018.

On January 5, 2018, following completion of the Suffield acquisition, the Group had net debt of approximately USD 355 million which was mainly used to pay the Suffield acquisition price of CAD 449 million (net of closing adjustments and including a CAD 40 million deposit).

During Q2 2018, after all operations related costs and capital expenditure, free cash flows were principally dedicated to debt repayment, leading to net debt of USD 255 million at the end of June 2018, or a USD 55 million repayment in Q2 2018 alone.

Subsequent to June 30, 2018, the Group is continuing to deleverage and has fully repaid and cancelled the Canadian second lien CAD 60 million loan facility. This will further reduce the average cost of capital for the Group going forward.

The Group's free cash flows going forward, after operations related costs and capital expenditure, are planned to continue to be used to repay outstanding debt under the 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 8,962 thousand as at June 30, 2018. The Corporation holds cash to meet imminent operational funding requirements in the different countries.

In connection with the Spin-Off, effective January 1, 2017, IPC owed working capital in favour of Lundin Petroleum. USD 31.4 million of the working capital adjustment was paid back to Lundin Petroleum in 2017. The final settlement of USD 23.6 million is due before June 30, 2019.

Working Capital

As at June 30, 2018, the Group had a net working capital balance including cash of USD 23,645 thousand compared to USD 70,804 thousand as at December 31, 2017. The main movement in working capital during the first six months of 2018 was the allocation of the deposit in relation to the Suffield acquisition of USD 31,898 thousand to the purchase price for the Suffield Assets. The amounts are derived from the balance sheet and the change in working capital differs to the amount stated in the statement of cash flow due to the inclusion of the cash balances and the non-cash foreign exchange differences arising on the revaluation of the balances held in subsidiaries with a different functional currency to the Group's presentational currency.

Non-IFRS Measures

In addition to using financial measures prescribed under IFRS, references are made in this MD&A to "operating cash flow", "EBITDA", "operating costs" and "net debt", 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. 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.

"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 interim condensed consolidated financial statements:

	Three months ended June 30		Six months ended June 30	
USD Thousands	**2018**	2017	**2018**	2017
Revenue	120,637	48,496	235,799	100,428
Production costs	(42,936)	(16,040)	(89,234)	(27,901)
Current tax	(1,014)	188	6,182	(208)
Operating cash flow	**76,687**	32,644	**152,747**	72,319

EBITDA

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

	Three months ended June 30		Six months ended June 30	
USD Thousands	**2018**	2017	**2018**	2017
Net result	21,498	7,113	47,811	11,574
Net financial items	15,048	502	24,201	11,453
Income tax	6,031	(108)	4,404	1,224
Depletion	24,118	13,944	47,280	28,448
Depreciation of other assets	7,789	7,906	15,749	15,666
Exploration and business development costs	(126)	409	43	546
Impairment costs	–	(164)	–	(164)
Depreciation included in general, administration and depreciation expenses [1]	120	447	281	688
EBITDA	**74,478**	30,049	**139,769**	69,435

[1] *Item is not shown in the interim condensed consolidated financial statements*

Operating costs

The following table sets out how operating costs is calculated:

	Three months ended June 30		Six months ended June 30	
USD Thousands	**2018**	2017	**2018**	2017
Production costs	42,936	16,040	89,234	27,901
Cost of blending[1]	(7,238)	–	(14,145)	–
Change in inventory position	2,278	(2,201)	(338)	(1,283)
Operating costs	**37,976**	13,839	**74,751**	26,618

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

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

USD Thousands	June 30, 2018	December 31, 2017
Bank loans	263,590	60,000
Cash and cash equivalents	(8,962)	(33,679)
Net debt	**254,628**	26,321

Off-Balance Sheet Arrangements

As at June 30, 2018, IPC, through its subsidiary IPC Malaysia BV, had issued bank guarantees to the Malaysian customs authorities for an amount of USD 1,277 thousand.

On May 1, 2018, IPC, through its subsidiary IPC Alberta Ltd, had issued a letter of credit for an amount of CAD 4 million in respect of its obligations to purchase diluent. The letter of credit automatically renews from July 31, 2018, and every six months thereafter unless notice is given to terminate the letter of credit.

IPC has also guaranteed the pipeline obligations of its subsidiary, IPC Alberta 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 started trading on both the Toronto Stock Exchange and the Nasdaq First North in Stockholm on April 24, 2017 with a total of 113,462,148 common shares issued and outstanding. As part of the share purchase offer by a subsidiary of IPC announced following listing, 25,540,302 common shares were tendered (including the 22,805,892 common shares owned by Statoil) and, as part of a subsequent internal reorganization, these shares were subsequently cancelled. The total number of common shares issued and outstanding in IPC is now 87,921,846. In June 2018, IPC's shares ceased trading on the Nasdaq First North and commenced trading on the Nasdaq Stockholm.

Nemesia S.à.r.l., an investment company wholly owned by a Lundin family trust, owns 28,062,512 common shares in IPC. In addition, an investment company wholly owned by a trust whose settlor is Ian H. Lundin, owns a further 2,643,777 common shares.

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 1,846,600 stock options and 1,218,152 IPC transitional PSP and RSP awards granted in connection with the Spin-off, outstanding as of the date of this report.

Contractual Obligations and Commitments

As part of the acquisition of the Suffield Assets, IPC made a deferred consideration payment to Cenovus Energy Inc. of CAD 12 million in June 2018. IPC may also be 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 potential undiscounted amount of all future payments that the Group could be required to pay as at June 30, 2018 is up to CAD 27 million. An estimated contingent consideration of USD 7,250 thousand as at January 5, 2018 has been reflected in the Financial Statements. The Group has paid, or will pay, a total amount of CAD 2,250 thousand as contingent consideration related to the oil price for the first six months of 2018. No amounts have been paid or accrued in respect of the price of natural 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 17 Provisions of the Financial Statements.

The Bertam field (IPC working interest of 75 percent) has leased the FPSO Bertam from another Group company for an initial period of six years commencing April 2015.

IPC has a residual liability for working capital owed to Lundin Petroleum – see Transactions with Related Parties section below.

Critical Accounting Policies and Estimates

In connection with the preparation of the Corporation's interim condensed 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

Transactions with corporate entities

As at the date of the Spin-Off, the Group had a residual liability for working capital owed to Lundin Petroleum of USD 27,429 thousand which has been reduced to USD 23,591 thousand as at June 30, 2018. Instalments relating to this amount bear interest at 3.5% from the date of the original repayment schedule. This amount is reflected as a current liability as it is due before the end of June 2019. Expensed interest of USD 131 thousand is included in the first six months of 2018 related to this liability.

Lundin Petroleum has charged the Group USD 330 thousand in respect of office space rental and USD 1,325 thousand in respect of shared services provided during the first six months of 2018. IPC has charged Lundin Petroleum USD 96 thousand in respect of consultancy fees during the first six months of 2018.

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 June 30, 2018, the Corporation had entered into 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. As at June 30, 2018, the following gas volumes were hedged:

Period	Volume (Gigajoules (GJ) per day)	Average Pricing
July 1, 2018 - October 31, 2018	15,000	AECO 5a + CAD 1.15/GJ
July 1, 2018 - December 31, 2018	20,000	AECO 5a + CAD 0.87/GJ
July 1, 2018 - March 31, 2019	25,000	AECO 5a + CAD 0.89/GJ
November 1, 2018 - December 31, 2018	10,000	AECO 5a + CAD 0.85/GJ
July 1, 2018 - July 31, 2018	15,000	Fixed Price @ CAD 2.50/GJ
July 1, 2018 - October 31, 2018	10,000	Fixed Price @ CAD 2.31/GJ

These hedges had a fair value net asset of USD 1,335 thousand at June 30, 2018.

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.

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.

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". See also "Reserves and Resource Advisory" above.

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 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.

In 2017, the French government 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.

Change of Control under Licences: Certain of the licence areas associated with the Group's oil and gas assets, including in France, require government consent 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 Canada. 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.

FPSO Flagging Regulations in Malaysia: The FPSO Bertam is required to be Malaysian flagged in order to be able to offload crude in Malaysian waters. In February 2018, following a corporate restructuring transaction, Malaysian flagging status for the FPSO Bertam was confirmed by the Malaysian authorities. As the FPSO provides a significant revenue stream, a failure to maintain the flagging status may result in a reduction of earnings for the Group and may also have a significant impact on offloading of crude from the FPSO Bertam.

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 acquisition of the Suffield Assets. 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 each of the licence, lease and PSC areas associated with the Group's assets. In some cases, including in the Aquitaine Basin in France and the Netherlands, 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, 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 Facility:
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.

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, and there is a risk that any such programs, laws or regulations, if proposed and enacted, will contain emission reduction targets which the Corporation cannot meet, and financial penalties or charges could be incurred 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.

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 significant 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 are not expected to have 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, France and the Netherlands, 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 Shareholder: Nemesia S.à.r.l., 100 percent of the shares of which are owned by a trust settled by the late Adolf H. Lundin, owns approximately 32 percent of the aggregate voting shares of the Corporation. Nemesia S.à.r.l.'s holding allows it to significantly affect substantially all the actions taken by the shareholders of the Corporation, including the election of directors. As long as Nemesia S.à.r.l. maintains a significant interest in the Corporation, it is likely that Nemesia S.à.r.l. 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 Nemesia S.à.r.l. 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 favourable 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 Group's internal control over financial reporting during the three months ended June 30, 2018.

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).

Acquisition of the Suffield Assets

The acquisition of the Suffield Assets in southern Alberta, Canada was completed less than 365 days from the end of the current financial period. As such, under applicable Canadian reporting requirements, the Group is not required to and is not certifying as to the design and operating effectiveness of disclosure controls and procedures and internal controls over financial reporting in respect of these assets.

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 to continue to implement our strategies to build long-term shareholder value;
- IPC's intention to review future potential growth opportunities;
- the ability of our high quality portfolio of assets to provide a solid foundation for organic and inorganic growth;
- the resource base in place to provide feedstock to add to reserves and value;
- organic growth opportunities in France, including the Villeperdue and the Vert-la-Gravelle projects and potential deeper prospectivity within the new 3D area acquired in late 2017;
- results of previous infill drilling and the potential for future infill drilling in Malaysia;
- the drilling of the Keruing prospect in Malaysia and the development options if drilling is successful;
- future development potential of the Suffield operations, including oil drilling and gas optimization;
- potential acquisition opportunities;
- estimates of reserves;
- estimates of contingent resources;
- estimates of prospective 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", "contingent resources" and "prospective 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.

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 Corporation's Annual Information Form (AIF) for the year ended December 31, 2017 (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 DATA

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

Reserve estimates, contingent resource estimates, prospective resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France, Malaysia and the Netherlands are effective as of December 31, 2017 and were prepared by IPC and audited by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook), and using McDaniel's January 1, 2018 price forecasts.

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 January 5, 2018, being the completion date for the acquisition of these assets by IPC, and were evaluated by McDaniel & Associates Consultants Ltd. (McDaniel), an independent qualified reserves evaluator, in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's January 1, 2018 price forecasts. The volumes are reported and aggregated by IPC in this MD&A as being as at December 31, 2017.

The price forecasts used in the reserve audit / evaluation are available on the website of McDaniel (www.mcdan.com), and are contained in the AIF.

The reserve life index (RLI) is calculated by dividing the 2P reserves of 129.1 MMboe as at December 31, 2017, after giving effect to the Suffield acquisition in Canada, by the mid-point of the initial 2018 production guidance of 30,000 to 34,000 boepd. Reserves replacement ratio is based on 2P reserves of 29.4 MMboe as at December 31, 2016, production during 2017 of 3.7 MMboe, additions to 2P reserves during 2017 of 2.8 MMboe and 2P reserves of 28.5 MMboe as at December 31, 2017. Such figures do not include the reserves attributable to the acquisition of the Suffield Assets which completed on January 5, 2018.

The assumptions underlying the net asset value per share are further described in the Corporation's press release dated February 26, 2018, available on the SEDAR website (www.sedar.com) or IPC's website (www.international-petroleum.com).

Light and medium 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. "Possible reserves" are those reserves that are less certain to be recovered than probable reserves. There is a 10 percent probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Each of the reserves categories (proved, probable and possible) 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, possible) to which they are assigned.

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

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

Contingent resources are further classified based on project maturity. The project maturity subclasses include development pending, development on hold, development unclarified and development not viable. All of the Corporation's contingent resources are classified as development unclarified. 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. Of the Corporation's 63.4 MMboe best estimate contingent resources (unrisked), 17.4 MMboe are light and medium crude oil, 7.4 MMboe are heavy crude oil and 38.6 MMboe are conventional natural gas.

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.

Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Chance of discovery is the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum. There is no certainty that any portion of the prospective resources estimated in the report audited by ERCE and summarized in this MD&A will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources audited. Estimates of the prospective resources should be regarded only as estimates that may change as additional information becomes available. Not only are such prospective resources estimates based on that information which is currently available, but such estimates are also subject to uncertainties inherent in the application of judgmental factors in interpreting such information. Prospective resources should not be confused with those quantities that are associated with contingent resources or reserves due to the additional risks involved. Because of the uncertainty of commerciality and the lack of sufficient exploration drilling, the prospective resources estimated in the report audited by ERCE and summarized in this MD&A cannot be classified as contingent resources or reserves. The quantities that might actually be recovered, should they be discovered and developed, may differ significantly from the estimates in the report audited by ERCE and summarized in this MD&A.

Reserves and contingent resources audited by ERCE and evaluated by McDaniel, as applicable, have been aggregated in this document by IPC. Estimates of reserves, resources and future net revenue for individual properties may not reflect the same level of confidence as estimates of reserves, resources and future net revenue for all properties, due to aggregation. This MD&A contains estimates of the net present value of the future net revenue from IPC's reserves. 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.

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".

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

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
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
Empress	The benchmark price for natural gas at the Empress point at the Alberta/Saskatchewan border
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
Mcf	Thousand cubic feet
Bscf	Billion standard cubic feet
NGL	Natural gas liquid

[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.*

DIRECTORS

Lukas H. Lundin
Director, Chairman
Geneva, Switzerland

Mike Nicholson
Director, President and Chief Executive Officer
Geneva, Switzerland

Chris Bruijnzeels
Director
Geneva, Switzerland

C. Ashley Heppenstall
Lead Director
London, England

Donald Charter
Director
Toronto, Ontario

Torstein Sanness
Director
Oslo, Norway

Daniella Dimitrov
Director
Toronto, Ontario

OFFICERS

Christophe Nerguararian
Chief Financial Officer
Geneva, Switzerland

Jeffrey Fountain
General Counsel and Corporate Secretary
Geneva, Switzerland

Daniel Fitzgerald
Vice President Operations
Geneva, Switzerland

Ryan Adair
Vice President Reservoir Development
Geneva, Switzerland

INVESTOR RELATIONS

Rebecca Gordon
VP Corporate Planning and Investor Relations
Geneva, Switzerland

Sophia Shane
Vancouver, British Columbia Canada

CORPORATE OFFICE

Suite 2000 – 885 West Georgia Street Vancouver,
British Columbia V6C 3E8 Canada
Telephone: +1 604 689 7842
Facsimile: +1 604 689 4250
Website: www.international-petroleum.com

OPERATIONS OFFICE

5 Chemin de la Pallanterie
1222 Vésenaz
Switzerland
Telephone: +41 22 595 10 50
E-mail: info@international-petroleum.com

REGISTERED AND RECORDS OFFICE

Suite 2600 - 595 Burrard Street
Vancouver, British Columbia
V7X 1L3 Canada

INDEPENDENT AUDITORS

PricewaterhouseCoopers AG
Basel, Switzerland

TRANSFER AGENT

Computershare Trust Company of Canada
Toronto, Ontario

MEDIA RELATIONS

Robert Eriksson
Stockholm, Sweden

STOCK EXCHANGE LISTINGS

Toronto Stock Exchange and NASDAQ
Stockholm Trading Symbol: IPCO

Corporate Office
International Petroleum Corp
Suite 2000
885 West Georgia Street
Vancouver, BC
V6C 3E8, Canada

Tel: +1 604 689 7842
E-mail: info@international-petroleum.com
Web: international-petroleum.com