This prospectus does not constitute an offer to sell or the solicitation of an offer to buy any securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

PROSPECTUS

No securities are being offered or sold pursuant to this non-offering prospectus. This prospectus has been prepared in conjunction with the admission of trading of all of International Petroleum Corporation's ("**IPC**" or the "**Corporation**", whereby references to IPC or the Corporation include the IPC Subsidiaries where the context requires, however, the "**Group**" always means IPC (as parent company) and its subsidiaries) common shares (the "**Common Shares**") on the regulated market operated by Nasdaq Stockholm ("**Nasdaq Stockholm**"). The prospectus may not be distributed, directly or indirectly, in any other country where such distribution requires additional registration or other measures than those provided for under Swedish law or that contravene applicable regulations in such country.

This prospectus has been prepared in accordance with the provisions of the Swedish Financial Instruments Trading Act (1991:980) and European Commission Regulation (EC) No 809/2004 implementing Directive 2003/71/EC of the European Parliament and the Council. The prospectus has been approved and registered by the Swedish Financial Supervisory Authority in accordance with the provisions of Chapter 2, Sections 25 and 26 of the Swedish Financial Instruments Trading Act (1991:980). Approval and registration of the prospectus does not imply a guarantee by the Swedish Financial Supervisory Authority that the facts presented in the prospectus are correct or complete.

Since no securities are being offered pursuant to this prospectus, no proceeds will be raised and all expenses in connection with the preparation and filing of this prospectus will be paid by the Corporation from general corporate funds.

The Common Shares are traded on the Toronto Stock Exchange (the "**TSX**") and are currently also traded on Nasdaq First North ("**Nasdaq First North**").

An investment in the Common Shares is subject to certain risks that should be considered by investors. In particular, the Corporation's business is subject to the risks normally encountered by a company in the oil and gas exploration, production and infrastructure business. See "Risk Factors".

In this prospectus, unless otherwise specified or the context otherwise requires, all references to "**Canadian dollars**", "**CAD**" and "**C$**" are to Canadian dollars, all references to "**U.S. dollars**", "**USD**" and "**$**" are to United States dollars and all references to "**Swedish krona**" and "**SEK**" are to Swedish krona. Certain amounts and percentages stated in this prospectus have been rounded off and may therefore not add up correctly. Other than what is expressly stated herein, no information in this prospectus has been examined or audited by the Corporation's auditors.

No person has been authorized to give any information or to make any representation not contained in this prospectus and, if given or made, such information or representation not contained herein must not be relied upon as having been authorized by the Corporation. In the event of any material changes to the prospectus during the period from the date of the announcement of the prospectus to the first day of trading of the Common Shares on Nasdaq Stockholm ("**Nasdaq Stockholm**"), such changes will be announced pursuant to the rules in the Swedish Financial Instruments Trading Act (1991:980), which governs the publication of the prospectus supplements.

Any dispute concerning or relating to this prospectus shall be resolved in accordance with Swedish law and exclusively by a Swedish court of law. The prospectus is available in paper form at IPC's head office and in electronic form on IPC's website, www.international-petroleum.com, as well as on the website of the Swedish Financial Supervisory Authority (the "**SFSA**"), www.fi.se.

FORWARD-LOOKING STATEMENTS

Certain statements contained in this prospectus constitute forward-looking information. These statements relate to future events or future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "forecast", "estimate", "expect", "seek", "anticipate", "plan", "continue", "project", "predict", "intend", "objectives", "strategies", "potential", "target", "guidance", "may", "will", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this prospectus should not be unduly relied upon.

Although the forward-looking statements contained in this prospectus are based upon assumptions that the Corporation believes to be reasonable, the Corporation cannot assure investors that actual results will be consistent with these forward-looking statements. With respect to forward-looking statements contained in this prospectus, the Corporation has made assumptions regarding, among other things: that the Corporation will conduct its operations in a manner consistent with its expectations; future commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future currency exchange and interest rates; the impact of increasing competition; general conditions in economic and financial markets; availability of drilling and related equipment; effects of regulation by governmental agencies; the continuance of existing tax and regulatory regimes; future operating costs; availability of future sources of funding; the Corporation's ability to conclude new transactions, including financings and acquisitions, in a satisfactory manner; and the availability of debt and/or equity financing and cash flow to fund the Corporation's capital and operating requirements as needed. The Corporation has included the above summary of assumptions and risks related to forward-looking information provided in this prospectus in order to provide investors with a more complete perspective on the Corporation's future operations and such information may not be appropriate for other purposes. The Corporation's actual results, performance or achievement could differ materially from those expressed in, or implied by, forward-looking statements in this prospectus and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits the Corporation will derive therefrom. These forward-looking statements are made as of the date of this prospectus and the Corporation disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

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PROSPECTUS SUMMARY

The following is a summary of this prospectus and should be read together with the more detailed information and financial data and statements contained elsewhere in this prospectus.

Summaries are made up of disclosure requirements (hereinafter referred to as "**Elements**"). The Elements are numbered in Sections A – E (A.1 – E.7). All Elements should be listed, even if they do not apply in the circumstances. Because some Elements are not required to be addressed, there may be gaps in the numbering sequence of the Elements. Where an Element is listed but where there is no relevant disclosure, the Element is accompanied by the statement "not applicable".

Section A – Introduction and warnings		
A.1	*Introduction and warnings*	This summary should be read as an introduction to the prospectus. Any decision to invest in International Petroleum Corporation's ("**IPC**" or the "**Corporation**", whereby references to the Corporation include the IPC Subsidiaries where the context requires, however, the "**Group**" always means IPC (as parent company) and its subsidiaries) common shares (the "**Common Shares**") should be based on consideration of the prospectus as a whole by the investor. Where a claim relating to the information contained in the prospectus is brought before a court, the plaintiff investor might, under the national legislation of the member states of the European Union, have to bear the costs of translating the prospectus before the legal proceedings are initiated. Civil liability attaches only to those persons who have tabled the summary including any translation thereof, but only if the summary is misleading, inaccurate or inconsistent when read together with the other parts of the prospectus or it does not provide, when read together with the other parts of the prospectus, key information in order to aid investors when considering whether to invest in such securities.
A.2	*Financial intermediaries*	Not applicable. Financial intermediaries are not entitled to use the prospectus for subsequent resale or final placement of securities.
Section B – Issuer and any guarantor		
B.1	*Legal and commercial name*	The Corporation's legal and commercial name is International Petroleum Corporation.
B.2	*Domicile, legal form, legislation and country of incorporation*	IPC is domiciled in British Columbia, Canada. IPC is a public limited liability company incorporated in British Columbia, Canada, under the *Business Corporations Act* (British Columbia) with British Columbia Registry number BC1103721.
B.3	*Current operations and principal activities*	The Corporation was incorporated on January 13, 2017 for the purpose of acquiring all of the oil and gas exploration and production properties and related assets of Lundin Petroleum AB ("**Lundin Petroleum**") located in Malaysia, France and the Netherlands (the "**Initial Oil and Gas Assets**") held through various subsidiaries of Lundin Petroleum. The transfer of the Initial Oil and Gas Assets was effected by an internal reorganization of Lundin Petroleum pursuant to which, among other things, the Corporation became the direct or indirect owner of a number of the subsidiaries of Lundin Petroleum (the "**Reorganization**"). In January 2018, the Corporation completed the acquisition of the Suffield area oil and gas assets in southern Alberta, Canada (the "**Suffield Assets**" or the "**Oil and Gas Assets in Canada**", while the acquisition of those assets is referred to as the "**Acquisition**"). The Initial Oil and Gas Assets

		together with the Oil and Gas Assets in Canada are referred to as the "**Oil and Gas Assets**". The main business of the Corporation is exploring for, developing and producing oil and gas. The Corporation holds a portfolio of oil and gas production assets and development projects in Canada, Malaysia, France and the Netherlands with exposure to growth opportunities. Since listing the Common Shares on April 24, 2017 at Toronto Stock Exchange ("**TSX**") in Canada and at Nasdaq First North ("**Nasdaq First North**") in Sweden, the Corporation has been focused on delivering operational excellence, demonstrating financial resilience, maximizing the value of Corporation's resource base and targeting growth through acquisition. The vision and strategy of IPC's management from the outset was to use the Corporation as a platform to build an international upstream company focused on creating long term value for Corporation's shareholders, launched at a favorable time in the industry cycle to acquire and grow a significant resource base.
B.4a	*Recent trends in the industry*	The oil and gas industry continues to remain dynamic in response to global macroeconomic trends, including global supply of oil stocks, transportation costs, US shale production, emerging market demand, and production quotas imposed by the Organization of the Petroleum Exporting Countries ("**OPEC**"). As a result of an increased supply and reduced demand growth, the oil price fell from a peak of around USD 115/bbl in June 2014 to USD 26/bbl in January 2016. Since that time, the oil price has been volatile, yet generally increasing. From the middle of 2016 until near the end of 2017, the oil price ranged around USD 50/bbl, and then has increased above USD 70/bbl into 2018. Management believes that the recent low oil price environment has driven asset divestitures by exploration and production companies struggling with liquidity issues, while also limiting the ability of balance sheet-constrained competitors to acquire such assets. Management's recent experience indicates that the oil majors and large international oil and gas companies are increasingly focused on larger volumes in new frontier basins, not long-life, low decline assets in established basins, and will continue to dispose of high quality assets to meet their public divestment undertaking. The Oil and Gas Assets have continued to perform well during the first quarter of 2018 in line with expectations, with excellent facility uptime.
B.5	*Group structure*	The Corporation is the British Columbia, Canada, parent company in a group of companies. The Group consists of 27 direct and indirect subsidiaries of the Corporation in Canada, France, Malaysia, the Netherlands and Switzerland (whereby 11 of the subsidiaries are either inactive or under liquidation).
B.6	*Notifiable interests, different voting rights and controlling interests*	To the knowledge of the Corporation, no person or corporation owns or controls or directs, directly or indirectly, more than 10% of the issued and outstanding Common Shares other than as set out below: **Name** | **Ownership** | **Number of Common Shares[(2)]** | **Percentage of Common Shares[(2)]** Nemesia S.à.r.l.[(1)] | Of record and beneficially | 29,062,512 | 33.05% **Notes:** (1) Lorito Holdings S.a.r.l. and Zebra Holdings and Investments S.a.r.l., two private companies controlled by a trust settled by the late Adolf H. Lundin, together hold 100% of the outstanding Class C shares of Nemesia and control Nemesia. In addition, an investment company wholly owned by a trust whose settlor is Ian H. Lundin, owns a further 3,517,326 Common Shares. (2) All Common Shares carry the same voting rights.

B.7 *Selected historical financial information*

The financial data that is presented below has been derived from the audited consolidated financial statements for the financial years ended December 31, 2017 and 2016, the audited combined carve-out from Lundin Petroleum financial statements for the Initial Oil and Gas Assets for the financial year ended December 31, 2015 (together the "**FY Financial Statements**") and the unaudited consolidated interim financial statements for the three-month period ending on March 31, 2018 and 2017 (the "**Interim Financial Statements**"). The FY Financial Statements and the Interim Financial Statements are together referred to as the "**Financial Statements**". The FY Financial Statements, which have been audited by the auditor of the Corporation, PricewaterhouseCoopers AG as indicated in their report, and the Interim Financial Statements, which have been reviewed by PricewaterhouseCoopers AG as indicated in their report, have been prepared in accordance with International Financial Reporting Standards ("**IFRS**"), as adopted by the International Accounting Standards Board ("**IASB**"). With respect to the Interim Financial Statements, PricewaterhouseCoopers AG reported that they have applied limited procedures in accordance with International Standard on Review Engagements (ISRE) 2410. However, their review report states that they did not audit and they do not express an opinion on the Interim Financial Statements. Accordingly, the degree of reliance on their report on such information should be restricted in light of the limited nature of the review procedures applied. Rounding-off differences may arise in all tables.

The 2015 FY Financial Statements exclude the Discontinued Operations, since these carve-out statements were prepared for the purposes of the Spin-Off and therefore were only intended to show the results of on-going operations. In accordance with applicable accounting rules, the 2016 and 2017 FY Financial Statements and the Interim Financial Statements include certain line items related to the Discontinued Operations. Accordingly, there may be certain discrepancies in respect of comparing the 2015 FY Financial Statements to the 2016 and 2017 FY Financial Statements and the Interim Financial Statements.

Condensed Consolidated Statement of Operations

	Unaudited	**Unaudited**	**Audited**	**Audited**	**Audited**
USD Thousands	**Jan – Mar 2018**	**Jan – Mar 2017**	**FY 2017**	**FY 2016**	**FY 2015**
Revenue	**115,162**	**51,932**	**203,001**	**209,880**	**172,094**
Cost of sales					
Production costs	(46,298)	(11,861)	(64,437)	(59,155)	(41,474)
Depletion and decommissioning costs	(23,162)	(14,504)	(54,555)	(85,187)	(92,573)
Depreciation of other assets	(7,960)	(7,760)	(31,629)	(31,073)	(23,685)
Exploration and business development costs	(169)	(137)	(3,786)	(14,141)	(37,638)
Impairment costs	–	–	164	(125,963)	(191,758)
Gross profit/(loss)	**37,573**	**17,670**	**48,758**	**(105,639)**	**(215,034)**
Other income	–	–	–	4,804	–
Sale of assets	–	–	–	(3,452)	–
General, administration and depreciation expenses	(3,734)	(926)	(10,400)	(1,931)	(18,046)
Profit/(loss) before financial items	**33,839**	**16,744**	**38,358**	**(106,218)**	**(233,080)**

Finance income	15	12	94	19,132	54,337
Finance costs	(9,168)	(10,963)	(15,001)	(3,747)	(3,826)
Net financial items	**(9,153)**	**(10,951)**	**(14,907)**	**15,385**	**50,511**
Profit/(loss) before tax	**24,686**	**5,793**	**23,451**	**(90,833)**	**(182,569)**
Income tax	1,627	(1,332)	(728)	(4,887)	1,004
Net result	**26,313**	**4,461**	**22,723**	**(95,720)**	**(181,565)**
Net result attributable to:					
Shareholders of the Corporation	26,305	4,456	22,718	(95,728)	(181,571)
Non-controlling interest	8	5	5	8	6
	26,313	**4,461**	**22,723**	**(95,720)**	**(181,565)**
Earnings per share – USD[1]	0.30	0.04	0.23	(0.84)	(1.60)
Earnings per share fully diluted – USD[1]	0.30	0.04	0.23	(0.84)	(1.60)

[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 to the Spin-Off.

Condensed Consolidated Statements of Comprehensive Income/(Loss)

	Unaudited	**Unaudited**	**Audited**	**Audited**	**Audited**
USD Thousands	**Jan – Mar 2018**	**Jan – Mar 2017**	**FY 2017**	**FY 2016**	**FY 2015**
Net result	**26,313**	**4,461**	**22,723**	**(95,720)**	**(181,565)**
Other comprehensive income/(loss):					
Items that may be reclassified to profit or loss:					
Cash flow hedges	(1,407)	–	1,292	–	–
Currency translation difference	1,515	–	(3,374)	–	10,034
Total comprehensive income/(loss)	**26,421**	**4,461**	**20,641**	**(95,720)**	**(171,531)**
Total comprehensive income/(loss) attributable to:					
Shareholders of the Corporation	26,408	4,456	20,620	(95,728)	(171,537)
Non-controlling interest	13	5	21	8	6
	26,421	**4,461**	**20,641**	**(95,720)**	**(171,531)**

Condensed Consolidated Balance Sheets

USD Thousands	Unaudited March 31, 2018	Unaudited March 31, 2017	Audited December 31, 2017	Audited December 31, 2016	Audited December 31, 2015
ASSETS					
Non-current assets					
Exploration and evaluation assets	8,084	4,519	7,380	2,904	137,221
Property, plant and equipment, net	751,329	306,311	312,401	317,808	382,918
Other tangible fixed assets, net	116,061	144,416	123,051	152,157	186,612
Financial assets	5	5	5	5	5
Deferred tax assets	9,980	11,444	12,398	12,049	12,331
Total non-current assets	**885,459**	**466,695**	**455,235**	**484,923**	**719,087**
Current assets					
Inventories	19,291	26,324	24,611	25,067	31,005
Trade and other receivables	61,472	43,402	74,794	48,226	40,629
Derivative instruments	–	–	1,372	–	–
Current tax	7,567	67	20	406	3,470
Cash and cash equivalents	28,174	20,082	33,679	13,410	24,373
Total current assets	**116,504**	**89,875**	**134,476**	**87,109**	**99,477**
TOTAL ASSETS	**1,001,963**	**556,570**	**589,711**	**572,032**	**818,564**
EQUITY AND LIABILITIES					
Shareholders' equity	334,605	390,217	307,166	405,348	592,889
Non-controlling interest	(212)	(246)	(224)	(252)	(277)
Net shareholders equity / Net Corporation investment	**334,393**	**389,971**	**306,942**	**405,096**	**592,612**
Non-current liabilities					
Financial liabilities	331,251	–	59,267	–	–
Provisions	185,737	99,032	105,887	93,581	113,661
Deferred tax liabilities	61,175	47,610	53,943	46,616	49,316
Total non-current liabilities	**578,163**	**146,642**	**219,097**	**140,197**	**162,977**
Current liabilities					
Trade and other payables	77,260	19,899	57,388	22,924	62,530
Provisions	11,693	–	6,025	3,815	–
Current tax liabilities	454	58	259	–	445
Total current liabilities	**89,407**	**19,957**	**63,672**	**26,739**	**62,975**
TOTAL EQUITY AND LIABILITIES	**1,001,963**	**556,570**	**589,711**	**572,032**	**818,564**

Condensed Consolidated Statements of Cash Flows

USD Thousands	Unaudited Jan – Mar 2018	Unaudited Jan – Mar 2017	Audited FY 2017	Audited FY 2016	Audited FY 2015
Cash flow from operating activities					
Net result	26,313	4,461	22,723	(95,720)	(181,565)
Adjustments for non-cash related items:					
Depletion, depreciation and amortization	31,283	22,505	87,162	117,510	117,403
Exploration costs	169	137	917	14,141	37,638
Impairment costs	–	–	(164)	125,963	191,758
Current tax	(7,196)	396	196	(2,199)	1,699
Deferred tax	5,569	936	532	7,086	(2,703)
Capitalized financing fees	708	–	700	–	–
Foreign currency exchange	3,032	10,063	8,922	(19,070)	(53,621)
Interest expense	4,434	15	1,378	8	19
Result on sale of the Singa field, Indonesia	–	–	–	3,452	–
Unwinding of asset retirement obligation discount	2,388	854	3,674	3,571	3,174
Share-based costs	1,030	–	3,224	–	1,015
Other	66	(130)	(1,058)	1,608	–
Cash flow generated from operations (before working capital adjustments and income taxes)	**67,796**	**39,237**	**128,206**	**156,350**	**114,817**
Changes in working capital	30,585	3,494	20,344	(51,790)	(44,252)
Long-term incentive plans paid	–	–	–	–	(740)
Interest paid	(4,112)	–	–	–	(4)
Income taxes paid	–	–	476	4,880	(3,044)
Net cash flow from operating activities	**94,269**	**42,731**	**149,026**	**109,440**	**66,777**
Cash flow used in investing activities					
Investment in oil and gas properties	(14,941)	(2,085)	(23,077)	(34,905)	(177,055)
Investment in other fixed assets	(541)	61	(546)	1,724	(31,122)
Deposit for business acquisition	–	–	(32,632)	–	–
Acquisition of the Suffield Assets	(362,244)	–	–	–	–
Decommissioning costs paid	(487)	(252)	(5,169)	(9,710)	–
Disposal of fixed assets	–	–	–	23,770	–
Other payments	–	–	–	(206)	(2,976)
Net cash (outflow) from investing activities	**(378,213)**	**(2,276)**	**(61,424)**	**(19,327)**	**(211,153)**

Cash flow from financing activities					
Borrowings	284,821	–	120,000	–	–
Repayments of borrowings	–	–	(60,000)	–	–
Paid financing fees	(6,168)	(10)	(1,391)	–	–
Cash funded from / (to) Lundin Petroleum	–	(31,767)	(31,394)	(102,774)	134,893
Share purchase	–	–	(90,632)	–	–
Net cash (outflow) from financing activities	**278,653**	**(31,777)**	**(63,417)**	**(102,774)**	**134,893**
Change in cash and cash equivalents	**(5,291)**	**8,678**	**24,185**	**(12,661)**	**(9,483)**
Cash and cash equivalents at the beginning of period	33,679	13,410	13,410	29,488[1]	25,108
Currency exchange difference in cash and cash equivalents	(214)	(2,006)	(3,916)	(3,417)	8,748
Cash and cash equivalents at the end of the period	**28,174**	**20,082**	**33,679**	**13,410**	**24,373**[1]

[1] *The difference in cash and cash equivalents between end of FY 2015 and beginning of FY 2016 is due to the spin-off and originates from the Discontinued Operations.*

Key Performance Indicators

USD Thousands	Unaudited Jan – Mar 2018	Unaudited Jan – Mar 2017	Audited FY 2017	Audited FY 2016	Audited FY 2015
Revenue	115,162	51,932	203,001	209,880	172,094
Gross profit/(loss)	37,573	17,670	48,758	(105,639)	(215,034)
Net result	26,313	4,461	22,723	(95,720)	(181,565)
Operating cash flow [1]	76,060	39,675	138,368	152,924	128,921
EBITDA [1]	65,291	39,387	129,259	150,043	113,720
Net debt [1]	309,184	(20,082)	26,321	(13,410)	(24,373)

[1] *Non-IFRS measures (unaudited)*

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 Corporation'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 Corporation'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 issuers.

"Operating cash flow" is calculated as revenue less production costs less current tax. Management believes that operating cash flow can be used to analyze the amount of cash that is being generated available for capital investment and servicing debt.

"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.

"EBITDA" is calculated on a per boe basis 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. Management believes that EBITDA is an important supplemental measure of operating performance to analyze operating earnings before non-operational expenses and non-cash or extraordinary charges.

"Net debt" is calculated as bank loans less cash and cash equivalents. "Net cash" is calculated as cash and cash equivalents less bank loans. Management believes that net debt/net cash is a useful calculation of a company's debt position for leverage analysis and capital allocation decisions.

Reconciliation of Non-IFRS Measures

Operating cash flow

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

	Unaudited	**Unaudited**	**Audited**	**Audited**	**Audited**
USD Thousands	**Jan – Mar 2018**	**Jan – Mar 2017**	**FY 2017**	**FY 2016**	**FY 2015**
Revenue	115,162	51,932	203,001	209,880	172,094
Production costs	(46,298)	(11,861)	(64,437)	(59,155)	(41,474)
Current tax	7,196	(396)	(196)	2,199	(1,699)
Operating cash flow (unaudited)	76,060	39,675	138,368	152,924	128,921

EBITDA

The following table sets out the reconciliation from net result from the face of the statement of operations to EBITDA in the Financial Statements:

	Unaudited	**Unaudited**	**Audited**	**Audited**	**Audited**
USD Thousands	**Jan – Mar 2018**	**Jan – Mar 2017**	**FY 2017**	**FY 2016**	**FY 2015**
Net result	26,313	4,461	22,723	(95,720)	(181,565)
Net financial items	9,153	10,951	14,907	(15,385)	(50,511)
Income tax	(1,627)	1,332	728	4,887	(1,004)
Depletion	23,162	14,504	54,555	85,187	92,573
Depreciation of other assets	7,960	7,760	31,629	31,073	23,685
Exploration and business development costs	169	137	3,786	14,141	37,638
Impairment costs	–	–	(164)	125,963	191,758
Depreciation included in general, administration and depreciation expenses [1]	161	242	1,095	1,249	1,146
Sale of assets (non-recurring)	–	–	–	3,452	–

Other income	–	–	–	(4,804)	–
EBITDA (unaudited)	65,291	39,387	129,259	150,043	113,720

[1] *Item is not shown in the Financial Statements (unaudited)*

Operating costs

The following table sets out how operating costs is calculated:

USD Thousands	**Unaudited** Jan – Mar 2018	**Unaudited** Jan – Mar 2017	**Audited** FY 2017	**Audited** FY 2016	**Audited** FY 2015
Production costs	46,298	11,861	64,437	59,155	41,474
Cost of blending[1]	(6,907)	–	–	–	–
Change in inventory position	(2,616)	917	(3,688)	994	9,776
Operating costs (unaudited)	36,775	12,778	60,749	60,149	51,250

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

Net debt / (net cash)

The following table sets out how net debt / (net cash) is calculated from figures shown in the Financial Statements:

USD Thousands	**Unaudited** March 31, 2018	**Unaudited** March 31, 2017	**Audited** December 31, 2017	**Audited** December 31, 2016	**Audited** December 31, 2015
Bank loans	337,358	–[1]	60,000	–[1]	–[1]
Cash and cash equivalents	(28,174)	(20,082)	(33,679)	(13,410)	(24,373)
Net debt / (net cash) (unaudited)	309,184	(20,082)	26,321	(13,410)	(24,373)

[1] *IPC was spun-off from Lundin Petroleum with no external bank loans*

Significant changes from January 1, 2015 to March 31, 2018

The global price of oil fell sharply during 2015 resulting in an average market price for Brent crude of USD 52/bbl. Prices remained low in 2016 and 2017 with Brent crude averaging USD 43/bbl for 2016 and USD 54/bbl for 2017. This had an impact on the revenue generated by the Oil and Gas Assets.

In April 2015, the Bertam field commenced production, significantly increasing the reported production volumes and revenue of the Initial Oil and Gas Assets, as well as increasing the production costs and deletion costs from the start up of operations. Depreciation of the floating production, storage and offloading ("**FPSO**") unit used on the Bertam field (the "**FPSO Bertam**") also commenced in April 2015 with the book value of the FPSO being depreciated over the six-year duration of the lease contract on a straight line basis.

Due to the lower oil price, there was a non-cash impairment charge to the income statement in 2015 relating to the Bertam field of USD 165.9 million pre-tax (USD 141.3 million post-tax) and a further USD 25.9 million pre- and post-tax non-cash charge relating to other Malaysian exploration blocks. In 2016, a non-cash impairment charge of USD 126.0 million was expensed to the income statement

		with no corresponding tax credit relating to gas discoveries made in Malaysia. In 2017, no significant impairment charge was booked. The reorganization whereby IPC acquired the Initial Oil and Gas Assets and the spin-off whereby Lundin Petroleum spun-off the Common Shares in IPC to its shareholders were completed during April 2017 and IPC's Common Shares started trading on the TSX and Nasdaq First North on April 24, 2017. In September 2017, IPC announced the Acquisition. The Acquisition was completed on January 5, 2018. The consideration paid on closing, net of closing adjustments, was CAD 449 million. A further payment of CAD 12 million will be paid by the end of June 2018. In addition, certain capped, additional contingent payments may become payable based on oil and natural gas prices. The Acquisition was fully funded from internally generated cash flow and existing and new lending facilities. The Acquisition financing package, consisting of an increase in the reserve based lending facility from USD 100 million to USD 200 million and new credit facilities of CAD 310 million, was fully underwritten by BMO Capital Markets. Following completion of the Suffield acquisition, the Group had net debt of approximately USD 355 million. In December 2017, IPC announced that drilling of the first of two planned infill wells had commenced on the Bertam field, offshore Malaysia. The two infill wells were successfully completed and put on production in early 2018. In February 2018, IPC announced that, following the submission of an application to the relevant Malaysian authorities, the FPSO Bertam received registration as a Malaysian flagged vessel under the applicable Malaysian marine regulations. In February 2018, IPC also announced that the 2018 production guidance is 30,000 to 34,000 boepd, with operating costs for 2018 expected to be USD 12.6 per boe. IPC's 2018 capital expenditure budget is USD 32 million, primarily targeting production growth in Canada and Malaysia. The Group has allocated approximately USD 11 million to oil drilling in Suffield and approximately USD 14 million as carry-over costs related to the 2017-2018 infill drilling campaign in Malaysia, with the remainder on continued project, maintenance and optimization activities in France and the Netherlands. **Significant changes after March 31, 2018** In May 2018, IPC announced the decision to approve additional capital expenditure of USD 6.5 million (net) to drill the Keruing (formerly I35) prospect in Malaysia in late 2018, subject to Petronas approval and rig contracting. There have been no other significant changes in the operations or operating results of the Corporation since March 31, 2018 up to the date of this prospectus.
B.8	*Selected pro forma financial information*	The financial information presented below shows the unaudited condensed pro forma income statement for the year ended December 31, 2017, giving effect to the Acquisition as if it had occurred on January 1, 2017 (the "**Unaudited Condensed Pro Forma Income Statement**").

Unaudited Pro Forma Income Statement for 2017

USD Thousands	Audited IPC Consolidated Income Statement	Audited Suffield Assets Operating Statement[1]	Unaudited Pro Forma Adjustments	Unaudited IPC Condensed Pro Forma Income Statement
Sales of oil and gas	185,182	185,659	–	370,841
Change in under/over lift position	(613)	–	–	(613)
Other revenue	18,432	–	–	18,432
Royalties	–	(7,183)	–	(7,183)
Total Revenue	**203,001**	**178,476**	**–**	**381,477**
Cost of operations	(53,389)	(54,984)	–	(108,373)
Tariff and transportation expenses	(3,361)	(36,202)	24,172	(15,391)
Direct production taxes	(3,999)	(112)	–	(4,111)
Change in inventory position	(3,688)	–	–	(3,688)
Other costs	–	–	(24,172)	(24,172)
Production costs	**(64,437)**	**(91,298)**	**–**	**(155,735)**
Depletion and decommissioning costs	(54,555)		(44,315)	(98,870)
Depreciation of other assets	(31,629)		–	(31,629)
Exploration and business development costs	(3,786)		–	(3,786)
Impairment costs	164		–	164
Gross Profit	**48,758**		**(44,315)**	**91,621**
General administrative and depreciation expenses	(10,400)		(1,600)	(12,000)
Profit before financial items	**38,358**		**(45,915)**	**79,621**
Finance income	94		–	94
Foreign exchange loss, net	(8,922)		–	(8,922)
Unwinding of asset retirement obligation discount	(3,557)		(5,346)	(8,903)
Interest expense	(1,378)		(12,285)	(13,663)
Amortization of loan fees	(700)		(2,748)	(3,448)
Loan commitment fees	(391)		(902)	(1,293)
Other financial costs	(53)		–	(53)
Net financial items	**(14,907)**		**(21,281)**	**(36,188)**
Profit before tax	**23,451**		**(67,196)**	**43,433**
Income tax	(728)		(5,395)	(6,123)
Net result	**22,723**		**(72,591)**	**37,310**

[1] Note that the Suffield Assets operating statement was audited to the production costs line only and has been translated into US dollars using the average rate for the year ended December 31, 2017 of 1.2982 CAD/USD.

See the accompanying notes to the Unaudited Condensed Pro Forma Income Statement

Note 1 – Basis of Presentation

The Unaudited Condensed Pro Forma Income Statement of the Corporation for the year ended December 31, 2017 has been prepared by management of the Corporation for illustrative purposes only and gives effect to the Acquisition of the Suffield Assets and the debt issuances necessary to finance the Acquisition as if the Acquisition had occurred on January 1, 2017. The Unaudited Condensed Pro Forma Income Statement has been compiled in accordance with the requirements of Annex II to Commission Regulation (EC) No 809/2004 and on a basis consistent with the Corporation's accounting policies.

The Unaudited Condensed Pro Forma Income Statement has been compiled from information derived from, and should be read in conjunction with:

• the audited consolidated financial statements of the Corporation as at and for the year ended December 31, 2017; and

• the audited operating statement for the Suffield Assets for the year ended December 31, 2017.

For the purposes of the Unaudited Condensed Pro Forma Income Statement, the audited operating statement for the Suffield Assets for the year ended December 31, 2017, which is presented in Canadian dollars, has been translated into US dollars using the following foreign exchange rate:

Average rate for the year ended December 31, 2017: 1.2982 CAD/USD

The description of certain line items in the audited operating statement for the Suffield Assets for the year ended December 31, 2017 has been changed to be consistent with the IPC Audited Consolidated Financial Statements classification.

The Unaudited Condensed Pro Forma Income Statement may not be indicative of the results that would have occurred if the events reflected therein had been in effect on the date indicated or of the results, which may be obtained in the future. The actual results of operations of the Corporation for any period following the closing of the Acquisition will vary from the amounts set forth in the Unaudited Condensed Pro Forma Income Statement and such variation may be material.

The Unaudited Condensed Pro Forma Income Statement has been compiled using accounting policies consistent with those applied by IPC for the preparation of its consolidated financial statements. Pro forma financial information is by its nature intended to describe a hypothetical situation. The Corporation is only presenting the Unaudited Condensed Pro Forma Income Statement for illustrative purposes, and the Unaudited Condensed Pro Forma Income Statement should not be seen as an indication of the actual profits that would have occurred had the events mentioned above actually have occurred at the indicated dates. Further, the Unaudited Condensed Pro Forma Income Statement should not be seen as an indication of the Corporation's future profit.

The Unaudited Condensed Pro Forma Income Statement should be read together with other information in the prospectus.

Note 2 – Pro Forma adjustments

The Unaudited Condensed Pro Forma Income Statement gives effect to the Acquisition as if it had occurred on January 1, 2017, considering the assumptions described below.

Certain items have been reclassified in the Unaudited Condensed Pro Forma Operating Statement to appropriately align the revenues and expenses of the Suffield Assets to IPC's financial statements presentation. Cenovus purchased condensate to dilute oil production and meet pipeline specification for its Suffield oil products. A pro forma adjustment of USD 24,172 thousand relating to condensate used for blending, has been reflected in the Unaudited Condensed Pro Forma Income Statement to reclassify such item from the line "Tariff and transportation expenses" as reported under the Suffield Assets information into the line "Other costs".

Other than this reclassification, management did not identify any material difference between the accounting policies applied by IPC and the accounting policies used in the preparation of the audited operating statements for the Suffield Assets.

Pro forma Adjustments have been made in the following lines of the Unaudited Condensed Pro Forma Income Statement:

		(i) Depletion and decommissioning costs A depletion rate of CAD 6.44 per boe has been applied to total production volumes produced by the Suffield Assets for the year ended 2017. This depletion rate is based on the rate calculated for the financial statements for the first quarter of 2018 following the preliminary allocation of the purchase price. (ii) *General administrative and depreciation expenses* Additional general, administrative and depreciation expenses have been included in the pro forma to reflect the estimated annual amount that would have been charged to the income statement had the Acquisition completed on January 1, 2017. *(iii) Unwinding of asset retirement obligation discount* The unwinding of the discounting of the abandonment retirement obligation for the Suffield Assets has been included based on the calculation made for the preliminary allocation of the purchase price. The discount rate assumed is 8 per cent and the discounting is being assumed to be unwound to the estimated dates of abandoning each well and facility belonging to the Suffield Assets. *(iv) Interest expense, amortization of loan fees and loan commitment fees* The interest expense, amortization of loan fees and loan commitment fees have been calculated assuming that the financing associated with the Acquisition was entered into on January 1, 2017. All cash flow generated for 2017 from the Suffield Assets has been assumed to have been used to partly repay the Canadian loan facility. Average 2017 floating interest rates of 1.2 percent and 1.1 percent were applied for the International reserve-based lending facility and the Canadian loan facility respectively. *(v) Income tax* Income tax on the pro forma Canadian taxable income for 2017 has been applied at the Canadian tax rate of 27 percent. PricewaterhouseCoopers AG has performed an assurance engagement on the Unaudited Condensed Pro Forma Income Statement in accordance with International Standard on Assurance Engagements 3420, Assurance Engagements to Report on the Compilation of Pro Forma Financial Information Included in a Prospectus. However, neither the assumptions underlying the pro forma adjustments nor the resulting pro forma financial information have been audited in accordance with International Standards on Auditing ("**ISA**"). Any reliance investors place on this information should fully take this into consideration.
B.9	*Profit forecasts*	Not applicable. The prospectus does not contain any profit forecasts.
B.10	*Remarks in the audit report*	Not applicable. There are no remarks in the audit report.
B.11	*Insufficient working capital*	Not applicable. In the opinion of the board of directors of the Corporation (the "**Board**"), the Corporation's working capital is sufficient for the Corporation's requirements for the next twelve months.

Section C – Securities		
C.1	*Securities being admitted to trading*	The Corporation's issued and outstanding Common Shares (i.e. 87,921,846 Common Shares). The International Securities Identification Number (i.e. the ISIN) for the Common Shares is CA46016U1084.
C.2	*Currency*	The Common Shares are denominated in Canadian dollars.
C.3	*Total number of shares in the Corporation*	The Corporation is authorized to issue an unlimited number of Common Shares without par value, of which 87,921,846 Common Shares are currently issued and outstanding, an unlimited number of Class A Preferred Shares, of which 117,485,389 Class A Preferred Shares (the "**Class A Preferred Shares**") are currently issued and outstanding and an unlimited number of Class B Preferred Shares (the "**Class B Preferred Shares**"), issuable in series, none of which is issued and outstanding.
C.4	*Rights attached to the securities*	Holders of Common Shares have equal rights to dividends, if, as and when declared by the Board, and upon liquidation, to receive such assets of the Corporation as are distributable to holders of Common Shares and are also entitled to receive notice of meetings of shareholders of the Corporation and one vote per share at such meetings.
C.5	*Transfer restrictions*	Not applicable. The Corporation's articles do not impose any transfer restrictions on the Common Shares.
C.6	*Admission to trading on a regulated market*	The Board of the Corporation has applied for a listing of the Common Shares on Nasdaq Stockholm and Nasdaq Stockholm has conditionally approved the application. The first day of trading is expected to be June 8, 2018. The Common Shares are currently listed on the TSX and Nasdaq First North under the symbol "IPCO".
C.7	*Dividend policy*	The Corporation does not currently anticipate paying any dividends on its Common Shares in the foreseeable future. The Corporation currently intends to utilize its earnings to finance the growth and development of its business and to otherwise reinvest in its business. Any decision to pay dividends on the Common Shares in the future will be made by the Board on the basis of the Corporation's earnings and financial requirements as well as other conditions existing at such time. Unless the Corporation commences the payment of dividends, holders of Common Shares will not be able to receive a return on their Common Shares unless they sell them.
Section D – Risks		
D.1	*Key risks specific to the issuer and its industry*	The Corporation is subject to risks that are wholly or partly outside of its control and which affect or may affect the Corporation's operations, results, financial position and future prospects. The following risk factors, which are non-exhaustive and described in no particular order, are some of the risks the Corporation faces and are considered to be the key risks for the Corporation's future development. **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 Corporation 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 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

		Corporation. 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. 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 Corporation will not fully insure against all of these risks, nor are all such risks insurable. Due to the nature of these risks, there is a risk that such liabilities could exceed insurance policy limits, in which event the Corporation 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. 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 Corporation's assets and may have a material adverse effect on the business, financial conditions, results of operations and prospects associated with the Corporation's assets. **Operational Risks Relating to Facilities and Pipelines:** The pipelines and facilities associated with the Corporation's assets, including the FPSO Bertam, are exposed to operational risks, many of which will be beyond the control of the Corporation. 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 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 or 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 Corporation's assets will vary from estimates thereof and such variations could be material. **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 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 Oil and Gas Assets. As an example of a government in a country in which the Corporation operates recently changing legislation relating to the oil and natural gas industry, the French government enacted legislation in 2017 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. In this example, IPC does not expect that this legislation will have a material adverse effect on the Corporation's operations or financial conditions, however there is a risk to investors in Common Shares that further or other legal or regulatory changes could be enacted in France or in other countries in which the Corporation operates or proposes to operate which could have material adverse effects on the Corporation's operations.

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 Corporation 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 Corporation 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 Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. In addition, non-core assets may be periodically disposed of, so that the Corporation 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 Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Reliance on Third-Party Operators: The Corporation has partners in each of the licence, lease and production sharing contract ("**PSC**") areas associated with the Corporation's assets. In some cases, including in the Aquitaine Basin in France and the Netherlands, the Corporation 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 Corporation'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 Corporation.

Reliance on Third-Party Infrastructure: The Corporation delivers the products associated with the Corporation's assets by gathering, processing and pipeline systems, some of which it does not own. The amount of oil and natural gas that the Corporation 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.

Credit Facilities: The Corporation 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 Corporation 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 Corporation 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 Corporation. **Competition for Resources and Markets:** The international petroleum industry is competitive in all its phases. The Corporation 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. **Marketing:** A decline in the Corporation's ability to market oil and gas production could have a material adverse effect on its production levels or on the price that the Corporation receives for production, which in turn may affect the financial condition of the Corporation and the market price of the Common Shares. The Corporation'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 the Corporation'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. **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 Corporation or the Corporation'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. **Fraud, Bribery and Corruption:** The operations relating to the Oil and Gas Assets are governed by the laws of many jurisdictions, which generally prohibit bribery and other forms of corruption. There is a risk that the Group's employees, officers, directors, agents, or business partners have in the past or will in the future engage in conduct undetected by the Corporation and for which the Corporation might be held liable under applicable anti-corruption laws. 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 Corporation is responsible for compliance with all applicable laws, regulations and contractual requirements regarding the decommissioning, abandonment and reclamation of the Corporation'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.

		Expiration and Renewal of Licences, Leases and Production Sharing Contracts: Certain properties constituting the 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 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 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 Oil and Gas Assets. **Economic and Political Developments in Countries in which the Corporation Operates:** International operations are subject to political, economic and other uncertainties. The Corporation'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 Corporation. **Information Security:** The Corporation 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 Corporation's business and systems, potentially affecting network assets and people's privacy. The primary risks to the Corporation 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.
D.3	*Key risks specific to the shares*	Any investment in securities involves risks. Any such risks could cause the trading price of the Common Shares to decline significantly and investors could lose some or all of their investment. Some of the key risks related to the Common Shares include the following. **Significant Shareholder:** Nemesia S.à.r.l., 100% of the shares of which are owned by a trust settled by the late Adolf H. Lundin, owns approximately 33% 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 operations of 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. **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. **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.
Section E – Offer		
E.1	*Net proceeds and expenses*	Not applicable. No securities are being offered or sold pursuant to this prospectus.
E.2a	*Reasons for the offer and use of proceeds*	No securities are being offered or sold pursuant to this prospectus. The Corporation believes that the listing of the Common Shares on the Nasdaq Stockholm will expand the group of potential investors available to acquire Common Shares, thus increasing the liquidity of the Common Shares for the benefit of all shareholders. In addition, such listing on a regulated market will improve the Corporation's access to capital markets for potential future equity financings.
E.3	*Terms and conditions of the offer*	Not applicable. No securities are being offered or sold pursuant to this prospectus.
E.4	*Interests material to the offer*	No securities are being offered or sold pursuant to this prospectus. There are no conflicting interests material to the matters described in this prospectus.
E.5	*Seller / lock-up arrangements*	No securities are being offered or sold pursuant to this prospectus. There are no lock-up arrangements in respect of the Common Shares.
E.6	*Dilution*	Not applicable. No securities are being offered or sold pursuant to this prospectus.
E.7	*Expenses charged to the investor*	Not applicable. No securities are being offered or sold pursuant to this prospectus.

PROSPEKTSAMMANFATTNING

Nedanstående text är en översättning av den engelska originaltexten ovan. Vid avvikelser mellan den svenska översättningen och den engelska originalversionen ska den engelska originalversionen ha företräde.

Nedanstående text är en sammanfattning av detta prospekt och ska läsas tillsammans med den mer detaljerade informationen och de finansiella uppgifterna och uttalandena som finns på andra ställen i prospektet.

Sammanfattningen omfattar information som enligt svensk rätt måste offentliggöras (s.k. ”**Punkter**”). Punkterna är numrerade i avsnitt A – E (A.1 – E.7). Samtliga Punkter listas även om de inte är tillämpliga på omständigheterna. Eftersom inte samtliga Punkter behöver adresseras kan det förekomma luckor i numreringen av Punkterna. När en viss Punkt listas i sammanfattningen men det inte finns någon relevant information att ange följs Punkten av kommentaren ”Ej tillämplig”.

Avsnitt A – Introduktion och varningar		
A.1	*Introduktion och varningar*	Denna sammanfattning bör läsas som en introduktion till prospektet. Varje beslut om att investera i International Petroleum Corporations (”**IPC**” eller ”**Bolaget**”, varmed hänvisning till Bolaget inkluderar IPC:s dotterbolag om sammanhanget så kräver, dock att ”**Koncernen**”, alltid avser IPC (som moderbolag) och dess dotterbolag) aktier (”**Aktierna**”) ska baseras på en bedömning av prospektet i dess helhet från investerarens sida. Om ett yrkande avseende informationen i prospektet anförs vid domstol kan den investerare som är kärande, i enlighet med Europeiska unionens medlemsstaters nationella lagstiftning, bli tvungen att svara för kostnaderna för översättning av prospektet innan det rättsliga förfarandet inleds. Civilrättsligt ansvar kan enbart åläggas de personer som lagt fram sammanfattningen, inklusive översättningar därav, men endast om sammanfattningen är vilseledande, felaktig eller oförenlig med de andra delarna av prospektet eller om den inte, tillsammans med andra delar av prospektet, ger nyckelinformation för att hjälpa investerare som överväger att investera i sådana värdepapper.
A.2	*Finansiella mellanhänder*	Ej tillämplig. Finansiella mellanhänder har ingen rätt att nyttja prospektet för efterföljande återförsäljning eller slutlig placering av värdepapper.
Avsnitt B – Emittent och eventuella garantigivare		
B.1	*Registrerad firma och handelsbeteckning*	Bolagets registrerade firma och handelsbeteckning är International Petroleum Corporation.
B.2	*Säte, bolagsform, bildningsland*	Bolaget har sitt säte i British Columbia, Kanada. Bolaget är ett publikt aktiebolag bildat (Eng: *incorporated)* i enlighet med *Business Corporations Act* (British Columbia) med organisationsnummer BC1103721.

B.3	*Huvudsaklig verksamhet*	Bolaget bildades den 13 januari 2017 med syftet att förvärva samtliga olje- och gasprospekterings och produktionstillgångar, samt relaterade tillgångar, från Lundin Petroleum AB ("**Lundin Petroleum**"). Dessa tillgångar är belägna i Malaysia, Frankrike och Nederländerna ("**Initiala Olje- och Gastillgångarna**") och ägs av olika dotterbolag till Lundin Petroleum. Överlåtelsen av de Initiala Olje- och Gastillgångarna verkställdes genom en intern omorganisation i Lundin Petroleum enligt vilken bl.a. Bolaget blev direkt eller indirekt ägare av ett antal av Lundin Petroleums dotterbolag ("**Omorganisationen**"). I januari 2018 slutförde Bolaget förvärvet av Suffieldområdets olje- och gastillgångar i södra Alberta, Kanada ("**Suffieldtillgångarna**" eller "**Olje- och Gastillgångarna i Kanada**", medan förvärvet av de tillgångarna hänvisas till som "**Förvärvet**"). Initiala Olje- och Gastillgångarna tillsammans med Olje- och Gastillgångarna i Kanada hänvisas till som "**Olje- och Gastillgångarna**". Bolagets huvudsakliga verksamhet är prospektering, utbyggnad och produktion av olja och gas. Bolaget har en portfölj av olje- och gasproduktionstillgångar och utbyggnadsprojekt i Kanada, Malaysia, Frankrike och Nederländerna med exponering mot tillväxtmöjligheter. Sedan noteringen av Aktierna den 24 april 2017 vid Toronto Stock Exchange ("**TSX**") i Kanada och vid Nasdaq First North ("**Nasdaq First North**") i Sverige har IPC fokuserat på att leverera hög kvalité i den operativa verksamheten, demonstrera finansiell förmåga, maximera värdet av Bolagets resursbas och tillväxtmål genom förvärv. Visionen och strategin för IPC:s ledning var från början att använda Bolaget som en plattform för att bygga ett internationellt utvinningsbolag fokuserat på att skapa långsiktigt värde för Bolagets aktieägare, lanserat vid en fördelaktig tidpunkt i industricykeln för att förvärva och växa en betydande resursbas.
B.4a	*De senaste trenderna i branschen*	Olje- och gasindustrin fortsätter att vara dynamisk till följd av globala makroekonomiska trender, innefattande global tillgång till oljelager, transporteringskostnader, amerikansk produktion av skifferolja, ett växande marknadsbehov, och produktionskvoter införda av Organization of the Petroleum Exporting Countries ("**OPEC**"). Som ett resultat av det ökade utbudet och nedgången i tillväxten på efterfrågan föll oljepriset från en topp på cirka 115 USD/bbl i juni 2014 till 26 USD/bbl i januari 2016. Sedan dess har oljepriset varit volatilt, dock generellt i ökning. Från och med mitten av 2016 fram till nära slutet av 2017 har oljepriset varierat runt 50 USD/bbl och har sedan ökat över 70 USD/bbl under 2018. Ledningen tror att den senaste tidens låga oljepris har medfört att flera prospekterings- och produktionsbolag fått likviditetsproblem och därför tvingats avyttra tillgångar, samtidigt som det låga oljepriset begränsat möjligheten för konkurrenter, med ansträngda balansräkningar, att förvärva sådana tillgångar. Ledningen senaste erfarenheter indikerar att de största oljebolagen och de stora internationella olje- och gasbolagen i allt högre grad fokuserar på större volymer i nya frontområden och inte på långlivade tillgångar med låg produktionsminskningsgrad i etablerade områden, och att de kommer att fortsätta minska sina innehav av högkvalitativa tillgångar för att infria sina offentliga avyttringsåtaganden. Olje- och Gastillgångarna har enligt förväntan fortsatt att prestera väl under det första kvartalet 2018 och med en utmärkt anläggningsdrifttid.

B.5	*Koncernstruktur*	Bolaget är det kanadensiska (British Columbia) moderbolaget i en koncern. Koncernen består av 27 av Bolaget direkt eller indirekt ägda dotterbolag i Kanada, Frankrike, Malaysia, Nederländerna och Schweiz (varigenom 11 av dotterbolagen antingen är inaktiva eller under likvidation).
B.6	*Anmälningspliktiga innehav, olika röststyrka och kontrollinnehav*	Enligt Bolagets kännedom äger eller kontrollerar ingen fysisk eller juridisk person, direkt eller indirekt, mer än 10 % av de emitterade och utestående Aktierna, utöver än vad som anges nedan: **Namn** | **Ägarskap** | **Antal aktier**[(2)] | **Procentandel av Aktier**[(2)] Nemesia S.à.r.l.[(1)] | Registrerat | 29 062 512 | 33,05 % **Fotnoter:** (1) Lorito Holdings S.a.r.l. och Zebra Holdings och Investments S.a.r.l., två privata bolag som kontrolleras av en trust som har stiftats av den bortgångne Adolf H. Lundin, innehar tillsammans 100 % av de utestående Klass C aktierna i Nemesia och kontrollerar Nemesia. Därutöver äger ett investmentbolag som är helägt av en trust som har stiftats av Ian H. Lundin ytterligare 3 517 326 Aktier. (2) Alla Aktier innehar samma rösträtt.
B.7	*Historisk finansiell information i sammandrag*	Den finansiella information som redovisas nedan härrör från den reviderade och konsoliderade finansiella information för räkenskapsåret som avslutades den 31 december 2017 och 2016, Lundin Petroleums speciellt framtagna, reviderade och konsoliderade finansiella information avseende de Initiala Olje- och Gastillgångarna för räkenskapsåren som avslutades den 31 december 2015 (tillsammans "**RÅ Finansiella Informationen**") och från den oreviderade konsoliderade finansiella delårsinformationen för den tremånadersperiod som slutade den 31 mars 2018 och 2017 ("**Finansiella Delårsinformationen**". RÅ Finansiella informationen och Finansiella Delårsinformationen benämns i det följande tillsammans som **"Finansiella Informationen"**). RÅ Finansiella Informationen, som har reviderats av Bolagets revisor, PricewaterhouseCoopers AG, som indikerat i dennes rapport, och den Finansiella Delårsinformationen, som har reviderats av Bolagets revisor, PricewaterhouseCoopers AG, som indikerat i dennes rapport, har upprättats i enlighet med International Financial Reporting Standards ("**IFRS**"), som antagits av International Accounting Standards Board ("**IASB**"). Vad gäller den Finansiella Delårsinformationen har PricewaterhouseCoopers AG rapporterat att de har tillämpat begränsade förfaranden i enlighet med standarden för översiktliga granskningsuppdrag (ISRE 2410) Deras granskningsrapport anger dock att de inte har reviderat och att de inte uttalar sig om den Finansiella Delårsinformationen. Följakteligen bör graden av tilltro till deras rapport om sådan information begränsas i ljuset av den begränsade omfattningen av det tillämpade granskningsförfarandet. Avvikelser med anledning av avrundningar kan förekomma i samtliga tabeller. 2015 RÅ Finansiella Informationen utelämnar den del av verksamheten som har upphört, eftersom dessa speciellt framtagna rapporter upprättades för avknoppningen och var därför endast avsedd att visa resultaten av den pågående verksamheten. I enlighet med tillämpliga redovisningsprinciper, inkluderar 2016 och 2017 RÅ Finansiella Informationen och Finansiella Delårsinformationen vissa separata poster med relaterat till den verksamhet som upphört. Det kan därför förekomma vissa diskrepanser vid jämförelse av 2015 RÅ Finansiella Informationen

och 2016 och 2017 RÅ Finansiella Informationen samt Finansiella Delårsinformationen.

Koncernens resultaträkning

Belopp i tusen USD	**Oreviderat** **jan – mar 2018**	**Oreviderat** **jan – mar 2017**	**Reviderat** **RÅ 2017**	**Reviderat** **RÅ 2016**	**Reviderat** **RÅ 2015**
Intäkter	**115 162**	**51 932**	**203 001**	**209 880**	**172 094**
Rörelsens kostnader					
Produktionskostnader	(46 298)	(11 861)	(64 437)	(59 155)	(41 474)
Substansminskningar och nedläggningskostnader	(23 162)	(14 504)	(54 555)	(85 187)	(92 573)
Avskrivningar av övriga tillgångar	(7 960)	(7 760)	(31 629)	(31 073)	(23 685)
Kostnader för prospektering och verksamhetsutveckling	(169)	(137)	(3 786)	(14 141)	(37 638)
Nedskrivningar	–	–	164	(125 963)	(191 758)
Bruttoresultat	**37 573**	**17 670**	**48 758**	**(105 639)**	**(215 034)**
Övriga intäkter	–	–	–	4 804	–
Försäljning av tillgångar	–	–	–	(3 452)	–
Generella-, administrations- och avskrivningskostnader	(3 734)	(926)	(10 400)	(1 931)	(18 046)
Rörelseresultat före finansiella poster	**33 839**	**16 744**	**38 358**	**(106 218)**	**(233 080)**
Finansiella intäkter	15	12	94	19 132	54 337
Finansiella kostnader	(9 168)	(10 963)	(15 001)	(3 747)	(3 826)
Finansiella poster, netto	**(9 153)**	**(10 951)**	**(14 907)**	**15 385**	**50 511**
Resultat före skatt	**24 686**	**5 793**	**23 451**	**(90 833)**	**(182 569)**
Inkomstskatt	1 627	(1 332)	(728)	(4 887)	1 004
Periodens resultat	**26 313**	**4 461**	**22 723**	**(95 720)**	**(181 565)**
Nettoresultat hänförligt till:					
Bolagets aktieägare	26 305	4 456	22 718	(95 728)	(181 571)
Innehav utan bestämmande inflytande	8	5	5	8	6
	26 313	**4 461**	**22 723**	**(95 720)**	**(181 565)**
Vinst per aktie – USD[1]	0,30	0,04	0,23	(0,84)	(1,60)
Vinst per aktie efter utspädning – USD[1]	0,30	0,04	0,23	(0,84)	(1,60)

[1] För jämförande resultatet har Bolagets aktier som utfärdades under avknoppningen antagits varit utestående vid början av varje period för avknoppningen.

Koncernens rapport över totalresultatet

Belopp i tusen USD	Oreviderat jan – mar 2018	Oreviderat jan – mar 2017	Reviderat RÅ 2017	Reviderat RÅ 2016	Reviderat RÅ 2015
Resultat	**26 313**	**4 461**	**22 723**	**(95 720)**	**(181 565)**
Övrigt totalresultat:					
Poster som kan omklassificeras till resultaträkningen:					
Kassaflödessäkringar	(1 407)	–	1 292	–	–
Valutakursdifferenser	1 515	–	(3 374)	–	10 034
Summa totalresultat	**26 421**	**4 461**	**20 641**	**(95 720)**	**(171 531)**
Summa totalresultat hänförligt till:					
Bolagets aktieägare	26 408	4 456	20 620	(95 728)	(171 537)
Innehav utan bestämmande inflytande	13	5	21	8	6
	26 421	**4 461**	**20 641**	**(95 720)**	**(171 531)**

Koncernens balansräkning

Belopp i tusen USD	Oreviderat 31 mar 2018	Oreviderat 31 mar 2017	Reviderat 31 dec 2017	Reviderat 31 dec 2016	Reviderat 31 dec 2015
TILLGÅNGAR					
Anläggningstillgångar					
Prospekterings- och utvärderings-tillgångar	8 084	4 519	7 380	2 904	137 221
Fasta/materiella tillgångar, fabriker och utrustning, netto	751 329	306 311	312 401	317 808	382 918
Övriga materiella anläggnings-tillgångar, netto	116 061	144 416	123 051	152 157	186 612
Finansiella tillgångar	5	5	5	5	5
Uppskjutna skattefordringar	9 980	11 444	12 398	12 049	12 331
Summa anläggningstillgångar	**885 459**	**466 695**	**455 235**	**484 923**	**719 087**
Omsättningstillgångar					
Lager	19 291	26 324	24 611	25 067	31 005
Kundfordringar och andra fordringar	61 472	43 402	74 794	48 226	40 629
Derivatinstrument	–	–	1 372	–	–
Kortfristiga skattefordringar	7 567	67	20	406	3 470
Likvida medel	28 174	20 082	33 679	13 410	24 373

Summa omsättningstillgångar	**116 504**	**89 875**	**134 476**	**87 109**	**99 477**
SUMMA TILLGÅNGAR	**1 001 963**	**556 570**	**589 711**	**572 032**	**818 564**
EGET KAPITAL OCH SKULDER					
Eget kapital hänförligt till aktieägare	334 605	390 217	307 166	405 348	592 889
Innehav utan bestämmande inflytande	(212)	(246)	(224)	(252)	(277)
Eget nettokapital hänförligt till aktieägare / nettoinvestering i Bolaget	**334 393**	**389 971**	**306 942**	**405 096**	**592 612**
Långsiktiga skulder					
Finansiella åtaganden	331 251	–	59 267	–	–
Avsättningar	185 737	99 032	105 887	93 581	113 661
Uppskjutna skatteskulder	61 175	47 610	53 943	46 616	49 316
Summa långfristiga skulder	**578 163**	**146 642**	**219 097**	**140 197**	**162 977**
Kortfristiga skulder					
Leverantörsskulder och andra skulder	77 260	19 899	57 388	22 924	62 530
Avsättningar	11 693	–	6 025	3 815	–
Kortfristiga skatteskulder	454	58	259	–	445
Summa kortfristiga skulder	**89 407**	**19 957**	**63 672**	**26 739**	**62 975**
SUMMA EGET KAPITAL OCH SKULDER	**1 001 963**	**556 570**	**589 711**	**572 032**	**818 564**

Koncernens kassaflödesanalys

	Oreviderat	**Oreviderat**	**Reviderat**	**Reviderat**	**Reviderat**
Belopp i tusen USD	**jan – mar 2018**	**jan – mar 2017**	**RÅ 2017**	**RÅ 2016**	**RÅ 2015**
Kassaflöde från verksamheten					
Periodens resultat	26 313	4 461	22 723	(95 720)	(181 565)
Justeringar för ej kassaflödespåverkande poster:					
Substansminskningar, avskrivningar och amorteringar	31 283	22 505	87 162	117 510	117 403
Prospekteringskostnader	169	137	917	14 141	37 638
Nedskrivningar	–	–	(164)	125 963	191 758
Aktuell skatt	(7 196)	396	196	(2 199)	1 699
Uppskjuten skatt	5 569	936	532	7 086	(2 703)
Kapitaliserade finansieringsavgifter	708	–	700	–	–

Valutakursdifferenser	3 032	10 063	8 922	(19 070)	(53 621)
Räntekostnader	4 434	15	1 378	8	19
Resultat från försäljningen av Singafältet, Indonesien	–	–	–	3 452	–
Förändring i nuvärdet av skyldighet att utrangera tillgångar	2 388	854	3 674	3 571	3 174
Aktierelaterade kostnader	1 030	–	3 224	–	1 015
Övrigt	66	(130)	(1 058)	1 608	–
Rörelsegenererat kassaflöde (före justering för rörelsekapital och inkomstskatt)	**67 796**	**39 237**	**128 206**	**156 350**	**114,817**
Förändringar i rörelsekapital	30 585	3 494	20 344	(51 790)	(44 252)
Betalda långsiktiga incitamentsprogram	–	–	–	–	(740)
Betald ränta	(4 112)	–	–	–	(4)
Betald inkomstskatt	–	–	476	4 880	(3 044)
Nettokassaflöde från rörelsen	**94 269**	**42 731**	**149 026**	**109 440**	**66 777**
Kassaflöde från investeringar					
Investering i olje- och gastillgångar	(14 941)	(2 085)	(23 077)	(34 905)	(177 055)
Investeringar i övriga anläggningstillgångar	(541)	61	(546)	1 724	(31 122)
Deposition för företagsförvärv	–	–	(32 632)	–	–
Förvärv av Suffieldtillgångarna	(362 244)	–	–	–	–
Betalda nedläggningskostnader	(487)	(252)	(5 169)	(9 710)	–
Avyttring av anläggningstillgångar	–	–	–	23 770	–
Andra betalningar	–	–	–	(206)	(2 976)
Nettokassa (utflöde) från investeringar	**(378 213)**	**(2 276)**	**(61 424)**	**(19 327)**	**(211 153)**
Kassaflöde från finansiering					
Upptagna lån	284 821	–	120 000	–	–
Återbetalning av upptagna lån	–	–	(60 000)	–	–
Betalda finansieringsavgifter	(6 168)	(10)	(1 391)	–	–
Kassa finansierat från / (till) Lundin Petroleum	–	(31 767)	(31 394)	(102 774)	134 893
Aktieförvärv	–	–	(90 632)	–	–
Nettokassa (utflöde) från finansiering	**278 653**	**(31 777)**	**(63 417)**	**(102 774)**	**134 893**
Förändring av likvida medel	**(5 291)**	**8 678**	**24 185**	**(12 661)**	**(9 483)**
Likvida medel vid periodens början	33 679	13 410	13 410	29 488[1]	25 108
Valutakursdifferens i likvida medel	(214)	(2 006)	(3 916)	(3 417)	8 748
Likvida medel vid periodens slut	**28 174**	**20 082**	**33 679**	**13 410**	**24 373[1]**

[1] *Skillnaden mellan likvida medel vid slutet av RÅ 2015 och början av RÅ 2016 är ett resultat av avknoppningen och härrör från den avvecklade verksamheten.*

Nyckeltal

Belopp i tusen USD	Oreviderat jan – mar 2018	Oreviderat jan – mar 2017	Reviderat RÅ 2017	Reviderat RÅ 2016	Reviderat RÅ 2015
Intäkter	115 162	51 932	203 001	209 880	172 094
Bruttovinst/(förlust)	37 573	17 670	48 758	(105 639)	(215 034)
Nettoresultat	26 313	4 461	22 723	(95 720)	(181 565)
Operativt kassaflöde [1]	76 060	39 675	138 368	152 924	128 921
EBITDA [1]	65 291	39 387	129 259	150 043	113 720
Nettoskuldsättningsgrad [1]	309 184	(20 082)	26 321	(13 410)	(24 373)

[1] *Alternativa nyckeltal (oreviderat)*

Bolaget använder alternativa nyckeltal (Eng. *Non-IFRS measures*) i syfte att tillhandahålla kompletterande information till investerare. Ledningen använder dessa alternativa nyckeltal internt för att underlätta jämförelser av verksamhetens prestationer mellan olika perioder, förbereda årliga driftbudgetar and bedöma Bolagets förmåga att möta framtida kapitalutgifter och rörelsekapitalbehov. Bolagets ledning anser att dessa alternativa nyckeltal är viktiga komplement för att bedöma verksamhetens prestation, eftersom de belyser trender i kärnverksamheten som annars inte tydliggörs om endast nyckeltal enligt IFRS används. Ledningen anser att dessa alternativa nyckeltal ger ett underlag för bedömning av Bolagets verksamhet och finansiella situation som är mer konsekvent och jämförbar mellan olika rapporteringsperioder. Vidare tror Bolaget att värdepappersanalytiker, investerare och andra intressenter regelbundet använder alternativa nyckeltal för att bedöma emittenter.

”Operativt kassaflöde” beräknas genom att nettointäkterna justeras mot produktionskostnaderna och aktuell skatt. Ledningen anser att det operativa kassaflödet kan användas för att analysera mängden likvida medel tillgängligt för kapitalinvesteringar och förvaltning av skulder.

”Driftkostnader” beräknas genom att produktionskostnaderna utan någon förändring i lagersaldot och kostnad för blandning och används för att analysera de rörliga kostnaderna för att producera olje- och gasvolymerna.

”EBITDA” beräknas på en per boe basis som rörelseresultat före finansiella poster, skatter, förbrukning av olje- och gasanläggningar, prospekteringskostnader, kostnader för ned- och avskrivningar och justerat för icke återkommande resultat (profit/loss) vid försäljning av tillgångar. Ledningen anser att EBITDA är ett viktigt komplement mått av operativ prestanda för att analysera rörelseintäkter före kostnader inte hänförliga till driften och icke-likvida medel eller extraordinära belastningar.

”Nettoskuldsättningsgrad” beräknas genom att banklån justeras mot likvida medel. ”Nettokassa” beräknas genom att likvida medel justeras mot banklån. Ledningen anser att nettoskuldsättningsgrad/nettokassa är ett användbart mått på ett företags skuldposition för att analysera hävstångseffekter och kapitalfördelningsbeslut.

Avstämningar av alternativa nyckeltal

Operativt kassaflöde

Följande tabell utvisar hur det operativa kassaflödet beräknats genom siffror som framgår i den Finansiella Informationen:

Belopp i tusen USD	Oreviderat jan – mar 2018	Oreviderat jan – mar 2017	Reviderat RÅ 2017	Reviderat RÅ 2016	Reviderat RÅ 2015
Intäkter	115 162	51 932	203 001	209 880	172 094
Produktionskostnader	(46 298)	(11 861)	(64 437)	(59 155)	(41 474)
Aktuell skatt	7 196	(396)	(196)	2 199	(1 699)
Operativt kassaflöde (oreviderat)	76 060	39 675	138 368	152 924	128 921

EBITDA

Följande tabell utvisar hur EBITDA beräknats genom siffror som framgår i den Finansiella Informationen:

Belopp i tusen USD	Oreviderat jan – mar 2018	Oreviderat jan – mar 2017	Reviderat RÅ 2017	Reviderat RÅ 2016	Reviderat RÅ 2015
Rörelseresultat	26 313	4 461	22 723	(95 720)	(181 565)
Finansiella poster, netto	9 153	10 951	14 907	(15 385)	(50 511)
Inkomstskatt	(1 627)	1 332	728	4 887	(1 004)
Substansminskningar	23 162	14 504	54 555	85 187	92 573
Avskrivningar av andra tillgångar	7 960	7 760	31 629	31 073	23 685
Kostnader för prospektering och verksamhetsutveckling	169	137	3 786	14 141	37 638
Kostnader för nedskrivningar	–	–	(164)	125 963	191 758
Av- och nedskrivningar inkluderade i allmänna administrations- och avskrivningskostnader[1]	161	242	1 095	1 249	1 146
Försäljning av tillgångar (icke återkommande)	–	–	–	3 452	–
Andra intäkter	–	–	–	(4 804)	–
EBITDA (oreviderat)	65 291	39 387	129 259	150 043	113 720

[1] *Detta framgår inte i den Finansiella Informationen (oreviderat)*

Driftkostnader

Följande tabell utvisar hur driftkostnader beräknats:

Belopp i tusen USD	Oreviderat jan – mar 2018	Oreviderat jan – mar 2017	Reviderat RÅ 2017	Reviderat RÅ 2016	Reviderat RÅ 2015
Produktionskostnader	46 298	11 861	64 437	59 155	41 474
Kostnad för blandning[1]	(6 907)	–	–	–	–
Förändringar i lagersaldo	(2 616)	917	(3 688)	994	9 776
Driftskostnader (oreviderat)	36 775	12 778	60 749	60 149	51 250

[1] *Kostnad för blandning representerar det upphandlade utspädningsmedlet för blandning, netto, efter intäkter från försäljning av överflödigt utspädningsmedel.*

Nettoskuld / (nettokassa)

Följande tabell utvisar hur nettoskuld / (nettokassa) beräknats genom siffror som framgår i den Finansiella Informationen:

Belopp i tusen USD	**Oreviderat** **31 mars 2018**	**Oreviderat** **31 mars 2017**	**Reviderat** **31 december 2017**	**Reviderat** **31 december 2016**	**Reviderat** **31 december 2015**
Banklån	337 358	–[1]	60 000	–[1]	–[1]
Likvida medel	(28 174)	(20 082)	(33 679)	(13 410)	(24 373)
Nettoskuld / (nettokassa) (oreviderat)	309 184	(20 082)	26 321	(13 410)	(24 373)

[1] *IPC delades ut från Lundin Petroleum utan externa banklån*

Väsentliga förändringar från den 1 januari 2015 till den 31 mars 2018

Det globala oljepriset föll kraftigt under 2015 vilket resulterade i att det genomsnittliga marknadspriset på brentolja låg på 52 USD/bbl. Priserna var fortsatt låga under 2016 och 2017 och det genomsnittliga priset på brentolja låg på 43 USD/bbl under 2016 och 54 USD/bbl under 2017. Detta påverkade intäkterna från Olje- och Gastillgångarna.

Under april 2015 startade Bertamfältet sin produktion, vilket medförde en betydande ökning av de rapporterade produktionsvolymerna och intäkterna från Initiala Olje- och Gastillgångarna, samt ökade produktions- och nedläggningskostnaderna vid uppstartandet av den nya verksamheten. Under april 2015 började även en s.k. *floating production, storage and offloading unit* ("**FPSO**"), som användes på Bertamfältet ("**FPSO:n Bertam**"), att skrivas ned genom att det bokförda värdet skrivs av linjärt över den sexårsperiod som leasingavtalet gäller.

Det lägre oljepriset medförde nedskrivningar i resultaträkningen 2015, som inte påverkade likvida medel, relaterade till Bertamfältet om 165,9 miljoner USD före skatt (141,3 miljoner USD efter skatt) och ytterligare 25,9 miljoner USD före och efter skatt, som inte påverkade likvida medel, relaterade till andra malaysiska prospekteringsblock. Under 2016 kostnadsfördes en nedskrivning, som inte påverkade likvida medel, i resultaträkningen om 126 miljoner USD utan någon korresponderande skattekredit relaterad till gjorda gasfyndigheter i Malaysia. Inga väsentliga nedskrivningar kostnadsfördes under 2017.

Omorganisationen, varigenom IPC anskaffade de Initiala Olje- och Gastillgångarna, och avknoppningen, varigenom Lundin Petroleum knoppade av Aktierna i IPC till sina aktieägare, slutfördes under april 2017 och IPCs Aktier började handlas på Torontobörsen och Nasdaq First North den 24 april 2017.

I september 2017 offentliggjorde IPC Förvärvet. Förvärvet slutfördes den 5 januari 2018. Den justerade nettoköpeskillingen vid closing var 449 miljoner CAD. Ytterligare 12 miljoner CAD kommer att betalas vid slutet av juni 2018. I tillägg till detta kan vissa begränsade, tillkommande eventualbetalningar utfalla baserat på priserna av olja och naturgas.

Förvärvet finansierades till fullo av interngenerat kassaflöde och existerande och nya lånefaciliteter. Förvärvsfinansieringspaketet, bestående av en ökning i den reservbaserade lånefaciliteten från 100 miljoner USD till 200 miljoner USD och nya kreditfaciliteter om 310 miljoner CAD, garanterades av BMO Capital Markets. Efter genomförandet av Suffieldförvärvet hade Koncernen en nettoskuldsättningsgrad om cirka 355 miljoner USD.

I december 2017 offentliggjorde IPC att borrning av den första av två planerade kompletterande borrningar hade inletts på Bertamfältet, utanför Malaysias kust. Båda kompletterande borrningarna var slutförda och satta på produktion i början av 2018.

I februari 2018 offentliggjorde IPC att FPSO Bertam, efter ansökan hos de relevanta malaysiska myndigheterna, registrerats som ett fartyg under malaysisk flagg under gällande malaysiskt marinreglemente.

I februari 2018 offentliggjorde IPC även att 2018 produktionsvägledning är 30 000 till 34 000 boepd, med driftskostnader för 2018 förväntas till 12,6 USD/boe. IPC’s kapitalutgiftsbudget för 2018 är 32 miljoner USD, med huvudsakligt fokus på produktionstillväxt i Kanada och Malaysia. Koncernen har avsatt cirka 11 miljoner USD för oljeborrning i Suffield och cirka 14 miljoner USD som övergångskostnader hänförliga till den kompletterande borrningskampanjen i Malaysia 2017-2018, med resterande belopp avsett på fortsatta projekterings-, underhålls- och optimeringsaktiviteter i Frankrike och Nederländerna.

Väsentliga förändringar efter den 31 mars 2018

I maj 2018 offentliggjorde IPC beslutet att bevilja ytterligare kapitalutgifter om 6,5 miljoner USD (netto) för att borra Keruingprospektet (tidigare I35) i Malaysia i slutet av 2018, villkorat av Petronas godkännande och riggkontrakt.

Det har inte skett några andra väsentliga förändringar i Bolagets verksamhet eller resultaträkning sedan den 31 mars 2018 och fram till dagen för detta prospekt.

B.8 *Utvald proformaredovisning*

Den finansiella information som presenteras nedan visar koncernens oreviderade proforma-resultaträkning för räkenskapsåret som avslutades den 31 december 2017, med uttryck för Förvärvet som om det hade inträffat den 1 januari 2017 (den “**Oreviderade Proforma-Resultaträkningen”**).

Proforma-resultaträkning för 2017

	Reviderat	**Reviderat**	**Oreviderat**	**Oreviderat**
Belopp i tusen USD	IPC Konsoliderad Resultaträkning	Verksamhetsredovisning för Suffieldtillgångarna[1]	Proforma-Justeringar	IPC Konsoliderad Proforma-Resultaträkning
Försäljning av olja och gas	185 182	185 659	–	370 841
Förändringar i under- och överuttagsposition	(613)	–	–	(613)
Andra intäkter	18 432	–	–	18 432
Royalties	–	(7 183)	–	(7 183)
Totala intäkter	**203 001**	**178 476**	**–**	**381 477**
Rörelsekostnader	(53 389)	(54 984)	–	(108 373)
Tariff- och transportkostnader	(3 361)	(36 202)	24 172	(15 391)
Direkta produktionsskatter	(3 999)	(112)	–	(4 111)
Förändringar i lagersaldo	(3 688)	–	–	(3 688)
Övriga kostnader	–	–	(24 172)	(24 172)
Produktionskostnader	**(64 437)**	**(91 298)**	**–**	**(155 735)**
Kostnader för substansminskning och nedläggning	(54 555)		(44 315)	(98 870)

Avskrivningar av andra tillgångar	(31 629)	–	(31 629)
Kostnader för prospektering och verksamhetsutveckling	(3 786)	–	(3 786)
Kostnader för nedskrivningar	164	–	164
Bruttoresultat	**48 758**	**(44 315)**	**91 621**
Av- och nedskrivningar inkluderade i allmänna administrations- och avskrivningskostnader	(10 400)	(1 600)	(12 000)
Resultat före finansiella poster	**38 358**	**(45 915)**	**79 621**
Finansiella intäkter	94	–	94
Valutakursförlust, netto	(8 922)	–	(8 922)
Förändring i nuvärdet av skyldigheten att utrangera tillgångar	(3 557)	(5 346)	(8 903)
Räntekostnader	(1 378)	(12 285)	(13 663)
Amortering av låneavgifter	(700)	(2 748)	(3 448)
Lånförpliktelser	(391)	(902)	(1 293)
Andra finansiella kostnader	(53)	–	(53)
Netto finansiella poster	**(14 907)**	**(21 281)**	**(36 188)**
Resultat före skatt	**23 451**	**(67 196)**	**43 433**
Inkomstskatt	(728)	(5 395)	(6 123)
Nettoresultat	**22 723**	**(72 591)**	**37 310**

[1] Notera att verksamhetsredovisningen för Suffieldtillgångarna endast reviderades till linjen för produktionskostnader och har omräknats till US dollar med tillämpande av genomsnittskursen för året som avslutades den 31 december 2017 med 1.2982 CAD/USD.

Se medföljande noter till den Orevidare Proforma-Resultaträkningen.

Not 1 – Presentationens grund

Bolagets Oreviderade Proforma-Resultaträkning för räkenskapsåret som avslutades den 31 december 2017 har upprättats av Bolagets ledning endast för illustrativa ändamål och ger uttryck för Förvärvet av Suffieldtillgångarna och skuldemissionerna nödvändiga för att finansiera Förvärvet som om Förvärvet hade genomförts den 1 januari 2017. Den Oreviderade Proforma-Resultaträkningen har sammanställts i enlighet med kraven i Bilaga II till Kommissionens Förordningen (EG) nr 809/2004 och i enlighet med Bolagets redovisningsprinciper.

Den Oreviderade Proforma-Resultaträkningen har sammanställts utifrån information härrörande från, och bör läsas tillsammans med:

• den reviderade och konsoliderade finansiella information för Bolaget vid och för räkenskapsåret som avslutades den 31 december 2017; och

• den reviderade resultaträkningen för Suffieldtillgångarna för räkenskapsåret som avslutades den 31 december 2017.

För den Oreviderade Proforma-Resultaträkningen har den reviderade resultaträkningen för Suffieldtillgångarna för räkenskapsåret som avslutades den 31 december 2017, och som presenteras i kanadensiska dollar, översatts till amerikanska dollar med tillämpning av följande valutakurs:

Genomsnittskurs för räkenskapsåret som avslutades den 31 december 2017: 1,2982 CAD/USD

Beskrivningen av vissa poster i den reviderade verksamhetsredovisningen för Suffieldtillgångarna för räkenskapsåret som avslutades den 31 december 2017 har ändrats för att vara förenliga med klassifikationer enligt IPC:s Konsoliderade Bokslut.

Den Oreviderade Proforma-Resultaträkningen behöver inte vara indikativ av det resultat som skulle ha uppnåtts för det fall de händelser som återges i framställningen hade varit i kraft vid indikerade datumet, eller det resultat som kan uppnås i framtiden. Det faktiska resultatet av Bolagets verksamhet vid varje given tidpunkt efter Förvärvets genomförande kommer att variera från de belopp som angivits i den Oreviderade Konsoliderade Proforma-Resultaträkningen och sådana variationer kan vara väsentliga.

Den Oreviderade Proforma-Resultaträkningen har sammanställts genom att använda redovisningsprinciper förenliga med de som tillämpas av Bolaget i samband med upprättandet av dess koncernredovisning. Finansiell proformainformation är av sin natur endast avsedd att beskriva en hypotetisk situation. Bolaget presenterar endast den Oreviderade Proforma-Resultaträkningen för illustrativa ändamål och den Oreviderade Proforma-Resultaträkningen ska inte ses som en indikation på de faktiska vinster som skulle ha inträffat om de händelser som nämns ovan faktiskt hade inträffat vid de indikerade datumen. Vidare ska den Oreviderade Proforma-Resultaträkningen inte ses som en indikation på framtida vinster.

Den Oreviderade Proforma-Resultaträkningen bör läsas tillsammans med övrig information i prospektet.

Not 2 – Proforma-justeringar

Den Oreviderade Proforma-Resultaträkningen ger uttryck för Förvärvet så som om det hade inträffat den 1 januari 2017, utifrån de antaganden som beskrivs nedan.

Vissa poster har omklassificerats i den Oreviderade Proforma-Resultaträkningen för att på lämpligt vis anpassa intäkterna och kostnader för Suffieldtillgångarna till framställningen av IPC’s finansiella information. Cenovus förvärvade kondensat för att späda ut oljeproduktionen och möta pipeline-specifikationerna för dess Suffieldoljeprodukter. En proforma-justering om 24 172 tusen USD hänförlig till kondensat som används för blandning har reflekterats i den Oreviderade Proforma-Resultaträkningen för att omklassificera sådana poster från och med raden ”Tariff- och transportkostnader” som rapporterarats under verksamhetsredovisningen för Suffieldtillgångarna i raden ”Andra kostnader”.

Förutom denna omklassificering identifierade bolagets ledning inte någon väsentlig skillnad mellan de redovisningsprinciper som tillämpas av IPC och de redovisningsprinciper som använts för att upprätta den reviderade resultaträkningen för Suffieldtillgångarna.

Proforma-Justeringar har gjorts avseende följande poster I den Oreviderade Proforma-Resultaträkningen:

(i) *Kostnader för substansminskning och nedläggning*

En substansminskningsgrad om 6,44 CAD/boe har tillämpats för totala produktionsvolymer av Suffieldtillgångarna för räkenskapsåret 2017. Denna substansminskningsgrad baseras på den grad som beräknas för de finansiella rapporterna för det första kvartalet 2018 efter den preliminära allokeringen av köpeskillingen.

(ii) *Allmänna-, administrative- och avskrivningskostnader*

Ytterligare allmänna-, administrativa- och avskrivningskostnader har inkluderats i proforman för att återspegla det beräknade årliga belopp som skulle ha belastat resultaträkningen om Förvärvet hade genomförts den 1 januari 2017. Detta grundar sig på budgetprognoserna för 2018.

(iii) *Förändring i nuvärdet av skyldigheten att utrangera tillgångar*

		Förändringen i nuvärdet av skyldigheten att utrangera tillgångar för Suffieldtillgångarna har inkluderats baserat på en beräkning utifrån den preliminära allokeringen av köpeskillingen. Diskonteringsräntan antas vara 8 procent och diskonteringen antas förändras vid de uppskattade datumen för nedläggningen av varje brunn och anläggning som tillhör Suffieldtillgångarna. *(iv) Räntekostnader, amortering av låneavgifter och lånförpliktelseavgifter* Räntekostnader, amortering av låneavgifter och lånförpliktelseavgifter har beräknas med antagandet att finansieringen i samband med Förvärvet ingicks den 1 januari 2017. Allt kassaflöde som genererats för 2017 från Suffieldtillgångarna har antagits ha använts för att delvis återbetala den kanadensiska lånefaciliteten. Genomsnittliga rörliga räntor för 2017 om 1,2 procent och 1,1 procent tillämpades för den Internationella reservbaserade lånefaciliteten respektive den kanadensiska lånefaciliteten. *(v) Inkomstskatt* Inkomstskatt på den kanadensisk skattepliktiga pro forma-inkomsten för 2017 har tillämpats med den kanadensiska skattesatsen på 27 procent. PricewaterhouseCoopers AG har utfört ett bestyrkandeuppdrag i enlighet med den internationella standarden om bestyrkandeuppdrag 3420, Bestyrkandeuppdrag att rapportera om sammanställning av finansiell proformainformation i ett prospekt. Varken de antagandet som ligger till grund för proformajusteringarna eller den resulterande finansiella proformainformationen har reviderats i enlighet med International Standards on Auditing (”**ISA**”). En investerare som placerar sin tilltro till denna information bör ta full hänsyn till detta.
B.9	*Resultatprognos*	Ej tillämplig. Prospektet innehåller inga resultatprognoser.
B.10	*Revisors-anmärkningar*	Ej tillämplig. Det finns inga revisorsanmärkningar.
B.11	*Otillräckligt rörelsekapital*	Ej tillämplig. Styrelsen i Bolaget är av den uppfattningen att Bolagets rörelsekapital är tillräckligt för att täcka Bolagets behov över de kommande tolv månaderna.
Avsnitt C – Värdepapper		
C.1	*Värdepapper som upptas till handel*	Bolagets emitterade och utestående Aktier (dvs. 87 921 846 Aktier). Aktiernas ISIN-nummer är CA46016U1084.
C.2	*Valuta*	Aktierna är noterade i kanadensiska dollar.

C.3	*Antal Aktier i Bolaget*	Bolaget har bemyndigats att utfärda ett obegränsat antal Aktier utan nominellt värde, varav 87 921 846 Aktier för närvarande är emitterade och utestående, och ett obegränsat antal preferensaktier klass A, varav 117 485 389 preferensaktier klass A (”**Klass A Preferensaktierna**”) för närvarande är emitterade och utestående, och ett obegränsat antal preferensaktier klass B (”**Klass B Preferensaktierna**”), emitterbara i serier, varav inga är emitterade och utestående.
C.4	*Rättigheter som sammanhänger med Aktierna*	Innehavare av Aktier har lika rätt till utdelningar, om och när sådana tillkännages av Bolagets styrelse, och i händelse av likvidation att erhålla sådana tillgångar i Bolaget som är utdelningsbara till aktieägarna. Innehavare av Aktier har även rätt att erhålla kallelse till bolagsstämmor i Bolaget och till en röst per aktie vid sådana bolagsstämmor.
C.5	*Inskränkningar i rätten att fritt överlåta Aktierna*	Ej tillämplig. Bolagets bolagsordning innehåller inte någon inskränkning i rätten att fritt överlåta Aktierna.
C.6	*Upptagande till handel på en reglerad marknad*	Bolagets styrelse har ansökt om notering av Aktierna på Nasdaq Stockholm och erhållit villkorat godkännande från Nasdaq Stockholm. Första handelsdagen på Nasdaq Stockholm förväntas vara den 8 juni 2018. Aktierna är för närvarande upptagna för handel på Torontobörsen och Nasdaq First North under kortnamnet ”IPCO”.
C.7	*Utdelningspolicy*	Bolaget förväntar sig i nuläget inte att någon utdelning till aktieägarna kommer att genomföras inom en överskådlig framtid. För närvarande är Bolagets avsikt är att utnyttja sin vinst till att finansiera verksamhetens tillväxt och utveckling eller annars till att återinvestera i affärsverksamheten. Beslut om utdelning kommer i framtiden att fattas av styrelsen i Bolaget på basis av Bolagets resultat och finansiella behov, samt andra omständigheter som är aktuella vid den givna tidpunkten. I det fall Bolaget inte börjar genomföra utdelningar kommer innehavare av Aktier sakna möjlighet till avkastning på sina Aktier, såvida de inte säljer dem.
Avsnitt D – Risker		
D.1	*Huvudsakliga risker som är specifika för Bolaget och dess industri*	Bolaget är föremål för ett antal risker som ligger helt eller delvis utanför Bolagets kontroll och som påverkar eller kan påverka Bolagets verksamhet, resultat, finansiella ställning och framtidsutsikter. De riskfaktorer som beskrivs nedan, som inte är uttömmande eller beskrivna i någon särskild ordning, är några av de risker Bolaget ställs inför och anses vara nyckelriskerna för Bolagets framtida utveckling: **Risker kopplade till prospektering, utbyggnad och produktion:** Olje- och gasverksamhet involverar många risker som kanske inte ens en kombination av erfarenhet, kunskap och noggrann bedömning kan överkomma. Bolagets långsiktiga kommersiella framgångar beror på dess förmåga att hitta, förvärva, utveckla och kommersiellt producera olje- och naturgasreserver. Utan ett löpande tillskott av nya reserver kommer Olje- och Gastillgångarnas vid varje given tidpunkt existerande reserver, och produktionen från dessa, att minska över tid alltefterom sådana reserver utvinns. Det finns en risk att ytterligare kvantiteter av olja och gas inte kommer att upptäckas eller förvärvas av Bolaget. Framtida olje- och gasprospektering kan innebära ansträngningar som inte är lönsamma, inte bara i form av torra brunnar, utan även genom brunnar som producerar olja men inte producerar tillräckligt för att generera en positiv avkastning med hänsyn till kostnaderna för borrning,

		drift och i övrigt. Slutförandet av en brunn garanterar inte avkastning i förhållande till investeringen eller återbetalning av kostnader för borrning, slutförande och drift. Olje- och gasprospekterings-, utbyggnads- och produktionsverksamhet är föremål för samtliga risker och faror som typiskt sett är förenade med sådan verksamhet, inklusive bränder, explosioner, utblåsningar, kraterbildning, utsläpp av sura gaser eller andra utsläpp, som var och en kan resultera i betydande skada på olje- och naturgasrelaterade brunnar, produktionsanläggningar eller andra tillgångar, samt förorsaka miljö- och personskador. I enlighet med marknadspraxis kommer Bolaget inte fullt försäkra sig mot alla dessa risker, varav inte alla går att försäkra sig mot heller. På grund av dessa riskers natur finns det en risk att förpliktelser med anledning av dessa skulle kunna överstiga försäkringarna, varför Bolaget skulle kunna ådra sig betydande kostnader. **Volatilitet i priset på olja och gas:** Priset på, och möjligheten att sälja, oljan och naturgasen som kan förvärvas eller upptäckas av Bolaget påverkas, och kommer att fortsätta påverkas, av ett antal faktorer som ligger utanför Bolagets kontroll. Olje- och gaspriserna har fluktuerat kraftigt under senaste år och kan fortsatta att vara volatila i framtiden. En omfattande eller längre nedgång i olje- och gaspriserna skulle ha en ogynnsam inverkan på balansvärdet av reserverna och resurserna, lånekapacitet, intäkter, avkastning och kassaflöde relaterat till driften av Bolagets tillgångar och skulle kunna ha en väsentligt ogynnsam inverkan på rörelsen, finansiella förhållanden, verksamhetsresultat och framtidsutsikterna för Bolagets tillgångar. **Operationella risker relaterade till Bolagets anläggningar och pipelines:** Pipelines och anläggningar kopplade till Bolagets tillgångar, inklusive FPSO:n Bertam, är exponerade för operationella risker, varav många är utom Bolagets kontroll. Inträffandet eller förekomsten av sådana eller andra operationella händelser skulle kunna medföra nedgångar i försäljning eller produktion eller väsentligt öka de kostnader som är hänförliga till driften av de anläggningar och pipelines som hör till Olje- och Gastillgångarna eller medföra en minskning av intäkterna i motsvarande mån. **Osäkerheter relaterade till uppskattningen av reserver och resursvolymer:** Det finns ett flertal inneboende osäkerhetsfaktorer kopplade till uppskattningen av kvantiteten av olje- och naturgasreserverna och resurserna (betingade eller prospektiva) och framtida kassaflöden hänförliga till sådana reserver och resurser. Kassaflödesinformation relaterad till reserver och resurser angivna häri är endast uppskattningar. Den faktiska produktionen och de faktiska intäkterna, skatterna och utvecklings- och operationella utgifter med beaktande av reserverna och resurserna hänförliga till Bolagets tillgångar kommer att avvika från uppskattningen och dessa avvikelser kan vara väsentliga. **Regulatoriska tillstånd och regelefterlevnad samt förändringar i lagstiftningen eller den regulatoriska miljön:** Olje- och gasverksamhet (inklusive prospektering, utbyggnad, produktion, prissättning, marknadsföring och transportering) är föremål för omfattande kontroll och reglering från myndigheter på olika nivåer, som från tid till annan kan komma att förändras. Regeringar kan komma att reglera eller intervenera i prospektering, produktions- och nedläggningsaktiviteter, priser, skatter, royalties och exportering av olja och naturgas. Implementering av nya regler, eller ändringar i befintliga, som påverkar olje- och gasindustrin kan minska efterfrågan på råolja och naturgas och även öka kostnaderna som är förenade med Olje- och Gastillgångarna, något som kan få väsentliga negativa effekter för

		verksamheten, den finansiella ställningen, resultatet och utsikterna för Olje- och Gastillgångarna. Som ett exempel på en regering i ett land där Bolaget är verksamt som nyligen ändrat lagstiftning relaterat till olje- och naturgasindustrin är den franska regeringen som under 2017 antog lagstiftning om att upphöra med att tillåta nya licenser för oljeprospektering i Frankrike och att begränsa produktionen av olja och gas under befintliga produktionslicenser i Frankrike från och med 2040. I detta exempel förväntar sig IPC inte att denna lagstiftning kommer ha en väsentligt ogynnsam inverkan på Bolagets verksamhet eller finansiella ställning, men det finns en risk för investerare i Aktierna att ytterligare eller annan förändring i lagar och reglar kan antas i Frankrike och i andra länder i vilka Bolaget är verksamt eller föreslår att vara verksam i vilket skulle kunna ha väsentligt ogynnsam inverkan på Bolagets verksamhet. **FPSO:n och regler om flaggning i Malaysia:** FPSO:n Bertam måste gå under malaysisk flagg för att den ska få lasta råolja i malaysiska vatten. I februari 2018, efter en omorganisation, beviljades FPSO:n Bertam status som malaysiskt flaggat fartyg av de malaysiska myndigheterna. Eftersom FPSO:n utgör en betydande intäktskälla skulle en underlåtenhet att bibehålla flaggstatusen kunna resultera i en minskning av Bolagets intäkter och resultat och skulle även kunna ha en betydande inverkan på avlastningen av råolja från FPSO:n Bertam. **Misslyckande med att genomföra de förväntade fördelarna med förvärv och dispositioner:** Bolaget kan i den löpande verksamheten genomföra förvärv och andra överlåtelser av verksamheter och tillgångar, inklusive det nyligen genomförda förvärvet av Suffieldtillgångarna. Bolagets möjlighet att tillgodogöra sig fördelarna med förvärven är dels beroende av en framgångsrik sammanläggning av verksamheterna och att dess funktioner och rutiner integreras på ett tidseffektivt och i övrigt effektivt sätt, dels att Bolaget har förmåga att realisera de förväntade tillväxtmöjligheterna och synergierna från sammanläggningen av de förvärvade verksamheterna och Bolagets befintliga verksamhet. I tillägg till detta kan Bolaget avyttra vissa tillgångar utanför kärnverksamheten så att Bolaget kan fokusera sina ansträngningar och resurser mer effektivt. Beroende på marknaden för sådana tillgångar skulle vissa sådana Bolaget tillhörande tillgångar kunna förväntas uppbära mindre ersättning än dess balansvärde såsom det upptagits i Bolagets finansiella rapportering. **Beroende av tredjepartsaktörer:** Bolaget har samarbetspartners i varje licens-, leasing-, och produktionsdelningskontrakt (”**PSC**”) inom de områden som är relevanta för Bolagets tillgångar. I vissa fall, exempelvis i Aquitaine Basin (Frankrike) och Nederländerna, är Bolaget inte operatör och måste förlita sig på sina samarbetspartners kompetens, expertis, omdöme och finansiella resurser (utöver sina egna och, när relevant, andra partner- och joint venture-bolag) och att samarbetspartnern följer villkoren i licens- och leasingavtalen, PSC:n och andra kontraktuella arrangemang. Missbruk av Bolagets samarbetspartners i licensområden eller om dessa inte skulle kunna möta sina åtaganden kan resultera i betydande prospekterings-, produktions- och utbyggnadsfördröjningar, förluster eller ökade kostnader för Bolaget. **Beroende av tredje parters infrastruktur:** Bolagets produkter från dess tillgångar levereras genom insamlings-, bearbetnings- och pipelinesystem som Bolaget i vissa fall inte äger. Mängden olja och naturgas som Bolaget kan producera och sälja är beroende av tillgången, tillgängligheten, närheten och kapaciteten av dessa insamlings-, bearbetnings- och pipelinesystem. Avsaknaden av

		tillgänglighet eller kapacitet i något av insamlings-, bearbetnings- och pipelinesystemen, särskilt vad gäller bearbetningsanläggningarna, kan resultera i att Bolaget inte kan realisera den fulla ekonomiska potentialen i sin produktion eller en nedgång i det pris som erbjuds på Bolagets produktion. **Kreditfaciliteter:** Bolaget är part i kreditfaciliteter med internationella finansinstitutioner. Villkoren i dessa faciliteter innehåller operationella och finansiella kovenanter och begränsningar på Bolagets förmåga att, bland annat, åta sig eller låna till ytterligare skuldsättning, betala utdelning eller erlägga begränsade betalningar, belasta sina tillgångar, sälja tillgångar eller ingå vissa fusions- och konsolideringstransaktioner. Bolagets misslyckande med att fullfölja villkoren i kovenanterna i dessa faciliteter kan resultera i ett förtida avslut, vilket skulle, genom accelererad skuldsättning, genomförandet av säkerhetsåtgärder eller annars, kunna ha en väsentligt ogynnsam inverkan på verksamhetsresultat och de finansiella villkoren för Bolaget. **Konkurrens om resurser och marknader:** Den internationella oljemarknaden är konkurrensutsatt i alla dess delar. Bolaget konkurrerar med ett flertal andra aktörer vid sökandet efter, och förvärven av, olje- och naturgastillgångar samt vid försäljningen av olja och naturgas. Bolagets konkurrenter inkluderar olje- och gasbolag som kan ha betydligt större finansiella resurser, personal och anläggningar än Bolaget. Bolagets möjlighet att öka sina reserver och resurser i framtiden beror inte enbart på dess förmåga att prospektera och bygga ut befintlig egendom utan även dess förmåga att välja ut och förvärva annan lämplig egendom eller potentiell sådan för prospekterings- och utbyggnadsborrning. **Marknadsföring:** En nedgång i Bolagets förmåga att marknadsföra olje- och gasproduktion skulle kunna ha en väsentligt ogynnsam inverkan på dess produktionsnivåer eller på priset som Bolaget erhåller för sin produktion, vilket i sin tur skulle kunna påverka Bolagets finansiella förhållanden och marknadspriset på Aktierna. Bolagets verksamhet är delvis beroende av tillgängligheten, närheten till och kapaciteten av olje- och gasinsamlingssystem, pipelines och bearbetningsanläggningar och även, potentiellt, spårbundna lastningsanläggningar och rälsbussar. Tillämpliga regler på olje- och gasproduktion, bearbetning och transportering, skatte- och energipolitik, allmänna ekonomiska förhållanden, och förändringar i utbud och efterfrågan skulle kunna ha ogynnsam inverkan på Bolagets möjligheter att producera och marknadsföra olja och gas. Om marknadsfaktorer förändras och hindrar marknadsföringen av produktion kan övergripande produktion eller realiserade priser minska vilket kan påverka Bolagets finansiella förhållanden och marknadspriset på Aktierna. **Lagstiftning om klimatförändringar:** Olje- och gasindustrin är föremål för miljörättslig lagstiftning. Överträdelse av sådan lagstiftning kan resultera i att Bolaget åläggs att betala väsentliga böter eller tvingas vidta omfattande saneringsåtgärder avseende Bolaget eller Bolagets tillgångar, varav vissa kan vara väsentliga. Bolagets ledning anser dessutom att det politiska klimatet idag gynnar nya initiativ till miljölagar och miljöregleringar, särskilt vad gäller minskningen av utsläpp eller utsläppsintensiteten, och det finns en risk att sådana program, lagar eller regleringar, om de föreslås och antas, kommer att inrymma utsläppsmål som Bolaget inte kan uppnå, och att finansiella sanktioner eller böter därmed kan komma att påföras Bolaget. **Bedrägerier, mutor och korruption:** Verksamheten avseende Olje- och Gastillgångarna regleras av lagar i många jurisdiktioner som i allmänhet

		förbjuder mutor och andra former av korruption. Det finns en risk för att Bolagets anställda, tjänstemän, styrelseledamöter, agenter eller affärspartners tidigare har, eller kommer att, vidta åtgärder som inte upptäcks av Bolaget och för vilka Bolaget kan hållas ansvarig för i enlighet med gällande korruptionslagar. Det är möjligt att Bolaget, eller några av dess dotterbolag, anställda eller leverantörer, skulle kunna bli föremål för en utredning i samband med anklagelser om mutor eller korruption som ett resultat av obehöriga handlingar av dess anställda eller leverantörer, vilket kan leda till betydande företagsstörningar, betungande påföljder och ryktesskador. **Avvecklings-, nedläggnings- eller regenereringskostnader:** Koncernen är ansvarig för följsamhet med alla tillämpliga lagar, regler och kontraktuella skyldigheter avseende avveckling, nedläggning och regenerering av Koncernens tillgångar i slutet av dess ekonomiska livscykel, kostnader som kan vara betydande. Det är inte möjligt att förutse dessa kostnader med säkerhet eftersom de är en funktion av de krav som gäller vid tiden för avveckling, nedläggning eller regenerering och den faktiska kostnaden kan överstiga nuvarande uppskattningar. Lagar, regler och kontraktuella skyldigheter med hänsyn till nedläggning och avveckling kan implementeras eller förändras i framtiden. **Upphörande och förnyelse av licenser, leases eller produktionsdelningskontrakt (PSC:s):** Viss egendom som konstituerar Olje- och Gastillgångarna innehas i form av licenser, leases och PSC:s. Om innehavaren av licensen, leasingkontraktet eller PSC:n eller operatören av licensen, leasingkontraktet eller PSC:n misslyckas med att möta de specifika krav som en licens, lease eller PSC ställer, inklusive följsamhet i förhållande till miljö, hälsa och säkerhet, kan licensen, leasingkontrakt eller PSC:n avslutas eller upphöra. Det finns en risk att förpliktelserna som krävs för att bibehålla varje licens, leasingkontrakt eller PSC inte kommer att uppfyllas. Avslutandet eller upphörandet av en licens, lease eller PSC, eller av en licensandel, kan ha en väsentligt ogynnsam inverkan på rörelsen, finansiella förhållandet, verksamhetsresultat och framtidsutsikterna för Olje- och Gastillgångarna. Från tid till annan kan licenser och leasingkontrakt, i enlighet med dess villkor, behöva förnyas; det finns en risk att dessa licenser, leasingkontrakt och PSC:s avseende Olje- och Gastillgångarna inte kommer att förnyas av relevanta statliga myndigheter på villkor som kan godtas av Bolaget. Det kan också förekomma betydande förseningar i att erhålla licensförnyelser som redan påverkar verksamheten i förhållande till Olje- och Gastillgångarna. **Ekonomisk och politisk utveckling i länder där Bolaget bedriver verksamhet:** Internationella rörelser är underkastade politiska, ekonomiska och andra osäkerhetsfaktorer. Bolagets tillgångar kan också påverkas negativt av förändringar i tillämplig lagstiftning och riktlinjer i Kanada, Malaysia, Frankrike och Nederländerna, vilket skulle kunna ha negativ inverkan på Bolaget. **Informationssäkerhet:** Koncernen är starkt beroende av dess informationssystem och datorbaserade program. Krascher, tekniska fel eller säkerhetsöverträdelser av datorhackers eller cyberterrorister av något sådant system eller program kan ha en väsentligt ogynnsam inverkan på Bolagets verksamhet och system, vilket potentiellt kan påverka nätverkstillgångar och personers integritet. De primära riskerna för Koncernen innefattar förlust av data, förstörd eller korrupt data, äventyr av konfidentiell information om kunder eller anställda, läckt information, verksamhetsstörningar, stöld eller utpressning av medel,

		regulatoriska överträdelser, förlust av konkurrensfördelar och skadat anseende.
D.3	*Huvudsakliga risker som är specifika för värdepapperen*	Varje investering i värdepapper är förenad med risk. Varje sådan risk kan orsaka att Aktiekursen faller väsentligt och medföra att investerare förlorar delar eller hela värdet av sina investeringar. Några av de risker som är relaterade till Aktierna är följande. **Betydande aktieinnehav:** Nemesia S.à.r.l., vars aktier till 100% ägs av en stiftelse med den bortgångne Adolf H. Lundin som stiftare, äger cirka 33 % av det aggregerade röstkapitalet i Bolaget. Nemesia S.à.r.l.:s innehav möjliggör för stiftelsen att utöva betydande aktieägarinflytande på Bolaget, inklusive valet av styrelseledamöter. Så länge som Nemesia S.à.r.l. behåller ett betydande intresse i Bolaget är det sannolikt att Nemesia S.à.r.l. kommer att utöva betydande inflytande över Bolagets verksamhet. Det finns en risk att Nemesia S.à.r.l.:s intressen inte överensstämmer med övriga aktieägares intressen. **Ytterligare behov av finansiering:** Bolagets kassaflöden från sina reserver kanske inte alltid kommer att vara tillräckliga för att finansiera den pågående verksamheten. Från tid till annan kan Bolaget komma att behöva ytterligare finansiering för att kunna utföra sina olje- och gasförvärv, prospekteringar och utbyggnadsaktiviteter. Skulle Bolaget misslyckas med att erhålla sådan finansiering i rätt tid kan det medföra att Bolaget tvingas ge upp innehav i viss egendom, gå miste om vissa förvärvsmöjligheter eller tvingas minska eller lägga ned viss verksamhet. Om Bolagets intäkter från dess reserver minskar till följd av lägre olje- och gaspriser eller av andra skäl kommer det påverka Bolagets möjligheter att utöka det nödvändiga kapitalet för att ersätta dess reserver eller bibehålla dess produktion. Om bolagets medel från verksamheten inte är tillräckliga för att tillgodose kapitalutgiftskraven finns det en risk att skuldsättning eller finansiering med eget kapital kommer vara otillgängligt för att möta dessa krav eller, om tillgängligt, på krav som Bolaget inte kan godta. Fortsatt osäkerhet i nationella och internationella kreditmarknader skulle kunna ha väsentlig påverkan på Bolagets tillgång till tillräckligt kapital för dess kapitalutgifter och förvärv vilket som resultat kan ha en väsentligt ogynnsam inverkan på Bolagets möjlighet att genomföra sin verksamhetsstrategi och på dess rörelse, finansiella förhållanden, verksamhetsresultat och framtidsutsikter och även negativt påverka marknadspriset på Aktierna. **Upptagande av skuld:** Från tid till annan kan Bolaget komma att genomföra transaktioner i form av förvärv av tillgångar eller aktier i andra aktörer. Dessa förvärv kan finansieras helt eller delvis genom lån, vilket kan skapa skulder eller medföra att Bolagets existerande skuldnivå överstiger marknadsnivåerna för olje- och naturgasbolag av likvärdig storlek. Beroende på framtida prospekterings- och utbyggnadsplaner kan Bolaget få ett behov av ytterligare kapital och/eller skuldfinansiering, vilket kanske inte är tillgängligt, eller är tillgängligt på ofördelaktiga villkor. Bolagets skuldsättningsgrad kan, från tid till annan, komma att hämma Bolagets utsikter att erhålla ytterligare finansiering i rätt tid, något som kan behövas för att kunna dra nytta av de affärsmöjligheter som uppstår. **Aktiernas prisvolatilitet:** Marknadspriset på Aktierna kan vara volatilt och föremål för stora fluktuationer beroende på flertalet omständigheter, av vilka många ligger utanför Bolagets kontroll.

Avsnitt E – Erbjudande		
E.1	*Nettointäkter och kostnader*	Ej tillämplig. Inga värdepapper erbjuds eller säljs enligt detta prospekt.
E.2a	*Motiv till erbjudandet och användning av medel*	Inga värdepapper erbjuds eller säljs enligt detta prospekt. Bolagets ledning anser att noteringen av Aktierna på Nasdaq Stockholm kommer att expandera den grupp potentiella investerare som är tillgänglig för förvärv av Aktierna och därigenom öka likviditeten i Aktierna till fördel för samtliga aktieägare. Dessutom kommer en sådan notering på en reglerad marknad att förbättra Bolagets tillgång till kapitalmarknader för potentiella framtida finansieringar av eget kapital.
E.3	*Erbjudandets former och villkor*	Ej tillämplig. Inga värdepapper erbjuds eller säljs enligt detta prospekt.
E.4	*Intressen som har betydelse för erbjudandet*	Inga värdepapper erbjuds eller säljs enligt detta prospekt. Det finns inga motstridiga intressen som är viktiga för de frågor som beskrivs i detta prospekt.
E.5	*Säljare/lock-up-överenskommelser*	Inga värdepapper erbjuds eller säljs enligt detta prospekt. Det finns inga lock-up-överenskommelser avseende Aktierna.
E.6	*Utspädning*	Ej tillämplig. Inga värdepapper erbjuds eller säljs enligt detta prospekt.
E.7	*Kostnader för investerare*	Ej tillämplig. Inga värdepapper erbjuds eller säljs enligt detta prospekt.

RISK FACTORS

Investors in Common Shares should carefully consider the following risk factors in addition to the other information contained in this prospectus. The risks and uncertainties below are not the only ones that the Corporation faces. Additional risks and uncertainties not presently known to the Corporation or that the Corporation currently considers immaterial may also impair the business and operations of the Corporation and cause the price of the Common Shares to decline. If any of the following risks actually occur, the Corporation's business may be harmed and the financial condition and results of operations may suffer significantly. In that event, the trading price of the Common Shares could decline and holders of the Common Shares may lose all or part of their investment.

Risks Relating to the Corporation and the Industry

IPC is engaged in the exploration, development and production of oil and gas and its operations are subject to various risks and uncertainties which include but are not limited to those listed below. The risks and uncertainties below are not the only ones that the Group faces. Additional risks and uncertainties not presently known to the Group or that the Group currently considers immaterial may also impair the business and operations of the Group and cause the price of IPC's 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.

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 Corporation 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 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 Corporation. 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 Corporation will not fully insure against all of these risks, nor are all such risks insurable. Due to the nature of these risks, there is a risk that such liabilities could exceed insurance policy limits, in which event the Corporation 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 the Organization of the Petroleum Exporting Countries ("**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 Corporation's assets and may have a material adverse effect on the business, financial condition, results of operations and prospects associated with the Corporation's assets.

Operational Risks Relating to Facilities and Pipelines

The pipelines and facilities associated with the Corporation's assets, including the floating production, storage and offloading ("**FPSO**") unit used on the Bertam field (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 Corporation'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 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 or 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 Group and the Group'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".

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 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 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.

As an example of a government in a country in which the Corporation operates recently changing legislation relating to the oil and natural gas industry, the French government enacted legislation in 2017 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. In this example, IPC does not expect that this legislation will have a material adverse effect on the Corporation's operations or financial condition, however there is a risk to investors in Common Shares that further or other legal or regulatory changes could be enacted in France or in other countries in which the Corporation operates or proposes to operate which could have material adverse effects on the Corporation's operations.

Change of Control under Licences

Certain of the licence areas associated with the 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 Corporation and may also have a significant impact on offloading of crude from the FPSO Bertam.

***Failure to Realize Anticipated Benefits of Acquisitions and Disposition*s**

The Corporation 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 Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. In addition, non-core assets may be periodically disposed of, so that the Corporation 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 Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Reliance on Third-Party Operators

The Corporation has partners in each of the licence, lease and production sharing contract ("**PSC**") areas associated with the Corporation's assets. In some cases, including in the Aquitaine Basin in France and the Netherlands, the Corporation 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 Corporation'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 Corporation.

Reliance on Third-Party Infrastructure

The Corporation delivers the products associated with the Corporation's assets by gathering, processing and pipeline systems, some of which it does not own. The amount of oil and natural gas that the Corporation 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 Corporation's business financial condition, results of operations, cash flows and future prospects.

Credit Facilities

The Corporation 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 Corporation 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 Corporation 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 Corporation.

Competition for Resources and Markets

The international petroleum industry is competitive in all its phases. The Corporation 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 Corporation's ability to market oil and gas production could have a material adverse effect on its production levels or on the price that the Corporation receives for production, which in turn may affect the financial condition of the Corporation and the market price of the Common Shares. The Corporation'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 the Corporation'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 Corporation 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 Corporation will not benefit from such increases. Similarly, from time to time, the Corporation 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 Corporation'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 Corporation or the Corporation'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 Corporation and its operations and financial condition.

Fraud, Bribery and Corruption

The operations relating to the Oil and Gas Assets are governed by the laws of many jurisdictions, which generally prohibit bribery and other forms of corruption. There is a risk that the Group's employees, officers, directors, agents, or business partners have in the past or will in the future engage in conduct undetected by the Corporation and for which the Corporation might be held liable under applicable anti-corruption laws. 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 Corporation is responsible for compliance with all applicable laws, regulations and contractual requirements regarding the decommissioning, abandonment and reclamation of the Corporations 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 Corporation may be exposed to third-party credit risk through the contractual arrangements associated with the Corporation'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 Corporation's assets, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Repatriation of Earnings

A significant portion of the revenue-generating operations of the Corporation'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 Corporation, 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 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 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 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 Oil and Gas Assets.

Litigation

In the normal course of the Corporation'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 Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations.

Economic and Political Developments in Countries in which the Corporation Operates

International operations are subject to political, economic and other uncertainties. The Corporation'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 Corporation.

Terrorism and Sabotage

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

Information Security

The Corporation 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 Corporation's business and systems, potentially affecting network assets and people's privacy. The primary risks to the Corporation 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 there is a risk that certain investment opportunities may not be offered to the Corporation, or may not be approved by the directors.

Management Estimates and Assumptions

In preparing consolidated financial statements in conformity with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board ("**IASB**"), 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 Corporation'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 Corporation'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 Corporation'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 Corporation'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.

Forward-Looking Information May Prove Inaccurate

This prospectus contains forward-looking information, including, without limitation, the Corporation's strategic estimation relating to the Oil and Gas Assets. By its nature, forward-looking information involves numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, estimations or projections will prove to be materially inaccurate. In particular, the Corporation's strategic estimation is based upon estimates and assumptions of management which may prove incorrect. The factors discussed in this section should therefore be weighed carefully and investors should not place undue reliance on the forward-looking information provided in this prospectus.

The assumptions used in the preparation of an estimation, although considered reasonable by management at the time of preparation, may not materialize as estimated, and unanticipated events and circumstances may occur subsequent to the date of the estimation. Accordingly, there is a significant risk that actual results achieved for the estimation period will vary from the estimated results and that such variations may be material. There is no representation that actual results achieved during the estimation period will be the same in whole or in part as those estimated. Important factors that could cause actual results to vary materially from the estimation include those disclosed under "Risk Factors".

Risks Relating to the Common Shares

Any investment in securities involves risks. Any such risks could cause the trading price of the Common Shares to decline significantly and investors could lose some or all of their investment.

Significant Shareholder

Nemesia S.à.r.l., 100% of the shares of which are owned by a trust settled by the late Adolf H. Lundin, owns approximately 33% 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.

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.

Further Sales of Common Shares

Future sales of, or the ability to sell, substantial amounts of the Common Shares in the public market could adversely affect the prevailing market price for the Common Shares. If the Corporation's shareholders sell substantial amounts of their Common Shares in the public, the market price of the Common Shares could decline. These sales might also make it more difficult for the Corporation to sell equity or equity-related securities in the future at a time and price that the Corporation deems appropriate.

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.

There is a risk that an active or liquid trading market in the Common Shares may not develop or be sustained after the Listing. If such market fails to develop or be sustained, it could have a negative impact on the liquidity and price of the Common Shares, and could increase the price volatility of the Common Shares. Investors may not be in a position to sell their Common Shares quickly or at the market price if there is no active trading in the Common Shares.

ADVISORY

For an explanation of certain terms used in this prospectus, please refer to "Glossary". References in this prospectus to "management" mean the executive officers of the Corporation. Any statements in this prospectus made by or on behalf of management are made in such persons' capacities as officers of the Corporation and not in their personal capacities.

Investors should read this entire prospectus and consult their own professional advisors to assess the income tax, legal, risk factors and other aspects of ownership of the Common Shares. Investors should rely only on the information contained in this prospectus and should not rely on parts of the information contained in this prospectus to the exclusion of others. The Corporation has not authorized anyone to provide additional or different information than is contained herein. If anyone provides an investor with additional, different or inconsistent information, including statements in the media about the Corporation or the Oil and Gas Assets, it should not be relied on.

The information contained in this prospectus is accurate only as of the date of this prospectus or as of the date stated. The Corporation's business, financial condition, results of operations and prospects may have changed since the date of this prospectus.

Reserves and Resources Advisory

This prospectus contains references to estimates of gross and net reserves and resources attributed to the 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 the Initial 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 the Oil and Gas Assets in Canada are effective as of January 5, 2018, being the completion date for the Acquisition, 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 prospectus 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 "Reserves and Other Oil and Gas Information relating to the Oil and Gas Assets".

Light and medium crude oil reserves/resources disclosed in this prospectus 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% 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% 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 prospectus 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 Group’s control. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources referred to in the prospectus.

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 prospectus 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 prospectus 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 prospectus.

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 prospectus 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 prospectus 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.

Certain Units of Measurement

In this prospectus, the abbreviations set forth below have the following meanings:

Abbreviation	Equivalent Word or Phrase	Abbreviation	Equivalent Word or Phrase
bbl	barrels of oil standard conditions of pressure (14365 psla) and temperature (60° F)	MMboe	million barrels of oil equivalent
bopd	barrels of oil per day	MMboepd	million barrels of oil equivalent per day
bcf	billion cubic feet	MMcf	million cubic feet
boe	barrel of oil equivalent	MMcfpd	million cubic feet per day
boepd	barrel of oil equivalent per day	MMscfpd	million standard cubic feet per day
Bscf	billion standard cubic feet	m^3	cubic metres
ha	hectares	NGLs	natural gas liquids
km	kilometers	p/therm	US dollars per therm
km^2	square kilometers	$MM	million US dollars
Mboe	thousand barrels of oil equivalent	$/bbl	US dollars per barrel of oil
Mboepd	thousand barrels of oil equivalent per day	$/boe	US dollars per barrel of oil equivalent
Mcf	thousand cubic feet	$/Mcf	US dollars per thousand cubic feet
MMbbl	million barrels of oil	3D	three dimensional

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.3168
cubic metres	cubic feet	35.3147
bbl	cubic metres	0.159
cubic metres	bbl	6.290
litre	bbl	0.0063
miles	km	1.609
km	miles	0.621
feet	metres	0.305
metres	feet	3.281
acres	hectares	0.405
hectares	acres	2.471
tonnes	bbl	7.1475

In all cases where percentage figures are provided, such percentages have generally been rounded to the nearest whole number.

Currency and Exchange Rates

The financial statements and oil reserves estimates for the Oil and Gas Assets and the Corporation, as applicable, are presented in US dollars. Unless otherwise indicated, in this prospectus all references to: (i) "**$**" or "**USD**" are to United States dollars; (ii) "**C$**" or "**CAD**" are to Canadian dollars; (iii) "**CHF**" are to Swiss Francs; (iv) "**€**" are to Euros; (v) "**£**" are to British Pounds; and (vi) "**SEK**" are to Swedish krona.

The Swedish central national bank (Sw. *Sveriges Riksbank*) rates of exchange for SEK on May 18, 2018 were:

United States Dollars	Swiss Francs	Euros	British Pounds	Canadian Dollars
$ 1=SEK 8,724	CHF 1=SEK 8,7261	€ 1=SEK 10,3083	£ 1 = SEK 11,7857	C$ 1=SEK 6,8103

Forward-Looking Information

This prospectus 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 prospectus are expressly qualified by this cautionary statement. Forward-looking statements speak only as of the date of this prospectus, 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;
- The benefits of the Suffield acquisition;
- 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;
- The integration of the Suffield-related operations into IPC;
- Potential future growth opportunities in North America;
- Organic growth opportunities in France;

- 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 that drilling is successful;

- Results of 3D seismic survey in France;

- 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

- 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, labour 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.

References may be made in this prospectus 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 under “Key Performance Indicators”.

Market and Industry Data

This prospectus contains certain statistical, market and industry data obtained from government or other industry publications and reports or based on estimates derived from same and management’s knowledge of, and experience in, the markets in which the Corporation will operate. Government and industry publications and reports generally indicate that information has been obtained from sources believed to be reliable. None of the authors of such publications and reports has provided any form of consultation, advice or counsel regarding any aspect of, or is in any way whatsoever associated with, the Corporation. Further, certain of these organizations are participants in, or advisors to participants in, the oil and natural gas industry, and they may present information in a manner that is more favourable to the industry than would be presented by an independent source. Actual outcomes may vary materially from those forecast in such reports or publications, and the prospect for material variation can be expected to increase as the length of the forecast period increases. While the Corporation believes this data to be reliable, market and industry data is subject to variations and cannot be verified with complete certainty due to limits on the availability and reliability of raw data, the voluntary nature of the data gathering process and other limitations and uncertainties inherent in any statistical survey. The Corporation has not independently verified any of the data from third party sources referred to in this prospectus or ascertained the underlying assumptions relied upon by such sources.

The information obtained from third parties has been accurately reproduced, and as far as the Corporation is aware and is able to ascertain from information published by such third parties, no facts have been omitted which would render the reproduced information inaccurate or misleading.

REGISTRATION WITH EUROCLEAR SWEDEN

Only Common Shares registered in the Swedish local central securities depositary system with Euroclear Sweden will be subject to trading on Nasdaq Stockholm following the Listing. Holders of Common Shares listed on the TSX will be entitled to register those Common Shares in the depositary system at Euroclear Sweden in order to trade their securities on Nasdaq Stockholm and vice versa. In order to trade Common Shares on Nasdaq Stockholm, holders of Common Shares are advised to contact their nominee, bank or broker, as applicable. No physical share certificates representing Common Shares will be issued to holders of Common Shares through Euroclear Sweden.

APPLICATION TO LIST ON NASDAQ STOCKHOLM

The Corporation believes that the listing of the Common Shares on the Nasdaq Stockholm will expand the group of potential investors available to acquire Common Shares, thus increasing the liquidity of the Common Shares for the benefit of all shareholders. In addition, such listing on a regulated market will improve the Corporation's access to capital markets for potential future equity financings.

Nasdaq Stockholm has conditionally approved the admission of trading of the Common Shares on such exchange. The Listing is subject to the Corporation fulfilling all of the requirements of Nasdaq Stockholm. The estimated first day of trading of the Common Shares on Nasdaq Stockholm is June 8, 2018.

The Common Shares will be listed on Nasdaq Stockholm under the symbol "IPCO". The intention to complete the Listing can be withdrawn. Notice of such will be made public through a press release.

RESPONSIBILITY FOR THE PROSPECTUS

The Board is responsible for the contents of this prospectus. The Board hereby declares that, having taken all reasonable care to ensure that such is the case, the information contained in this prospectus is, to the best of its knowledge, in accordance with the facts and contains no omission likely to affect its import.

The board of directors of International Petroleum Corporation
Vancouver, British Columbia, Canada
June 5, 2018

THE CORPORATION

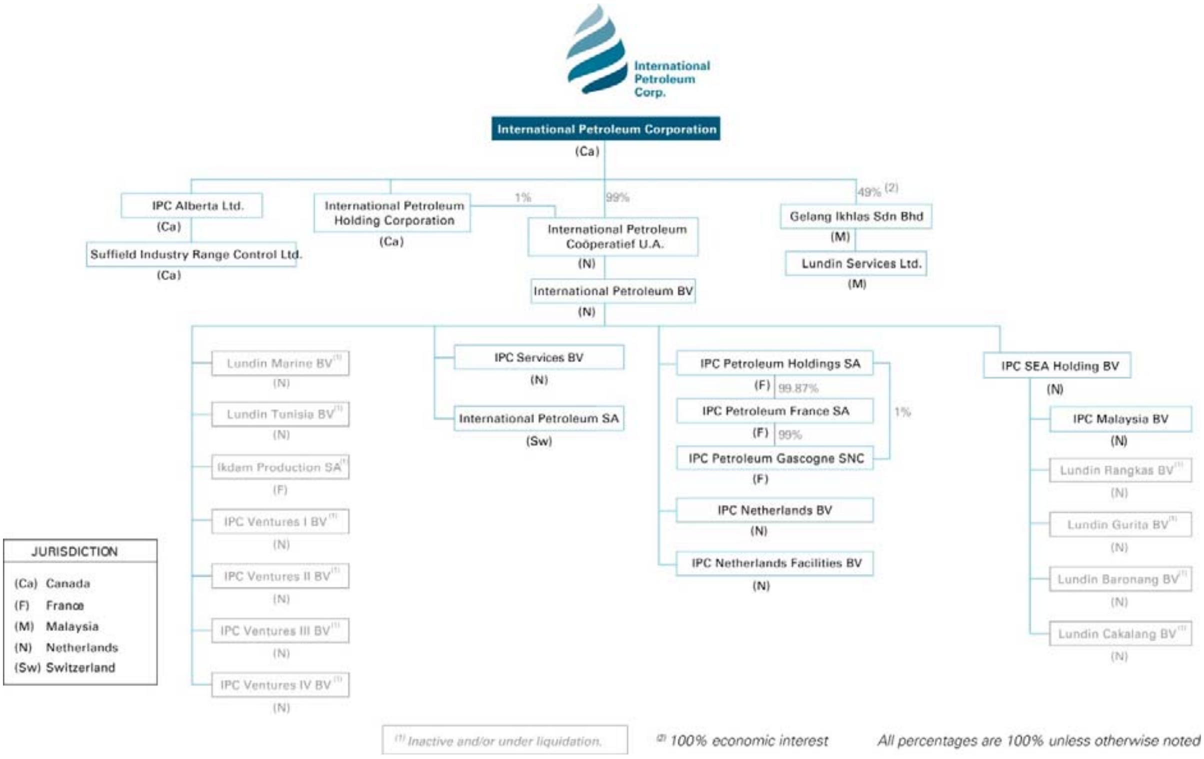
International Petroleum Corporation

The full corporate and commercial name of the Corporation is International Petroleum Corporation. The Corporation's head office is located at Suite 2000, 885 West Georgia Street, Vancouver, British Columbia, Canada V6C 3E8 and the registered and records office is located at 2600, 595 Burrard Street Vancouver, British Columbia, Canada V7X 1L3.

IPC is a reporting issuer in Alberta and Ontario. The Common Shares trade on the TSX and currently on Nasdaq First North under the symbol "IPCO".

International Petroleum Corporation was incorporated under the laws of the Province of British Columbia on January 13, 2017, under the name "1103721 BC. LTD." and domiciled in British Columbia, Canada under the Business Corporations Act (British Columbia) with British Columbia Registry number BC1103721. On January 23, 2017 the name of the Corporation was changed from "1103721 B.C. LTD" to International Petroleum Corporation. IPC is domiciled in British Columbia, Canada.

Substantially all of the Corporation's business is carried on through its various subsidiaries. The following chart illustrates, as at the date of this prospectus, the Corporation's significant subsidiaries, including their respective jurisdiction of incorporation and the percentage of voting securities in each that are held by the Corporation either directly or indirectly:



Prior to the Reorganization, all of the Initial Oil and Gas Assets were indirectly owned, through the IPC Subsidiaries, by Lundin Petroleum and the Corporation's sole shareholder was Lundin Petroleum.

Prior to the Spin-Off, Lundin Petroleum completed the Reorganization, which resulted in all of the Initial Oil and Gas Assets being acquired by the Corporation through the acquisition by the Corporation of the IPC Subsidiaries. Under the Contribution and Transfer Agreements, all of the shares of IPBV and all of the shares of Lundin Services Ltd. were transferred to the Corporation in exchange for the issuance by the Corporation to Lundin Petroleum of an aggregate of 113,462,147 Common Shares based on a price of CAD 4.77 per Common Share, for aggregate consideration of USD 410 million plus working capital as at the effective date. The Corporation then transferred IPBV to International Petroleum Coöperatief UA, a subsidiary of the Corporation. In connection with the Reorganization, IPBV transferred its interest in Lundin Norway AS, Lundin Petroleum Marketing SA, Lundin Petroleum SA and Lundin Russia BV to its wholly-owned subsidiary incorporated in the Netherlands, Lundin Petroleum Holding BV. IPBV then transferred all of the issued and outstanding shares of Lundin Petroleum Holding BV to Lundin Petroleum.

The Corporation, through its acquisition of all of the shares of IPBV, owns assets and entities previously owned by Lundin Petroleum related to discontinued operations located in Indonesia, Tunisia, Cambodia and the Republic of Congo (the "**Discontinued Operations**"). In respect of the Gurita Block PSC (see "The Oil and Gas Assets – Discontinued Operations – Indonesia"), Lundin Petroleum agreed in the Contribution and Transfer Agreements to indemnify the Corporation for any potential liabilities related to the Indonesian court case.

The Reorganization was completed on April 7, 2017, with an effective date of January 1, 2017. The Contribution and Transfer Agreements provide for a working capital adjustment as at January 1, 2017 which will be paid by the Corporation to Lundin Petroleum by financial adjustments during the period from January 1, 2017 to the date of the Spin-Off which was completed with a record date on April 24, 2017.

Since January 1, 2017, USD 31.4 million of cash generated by the Group had been funded to Lundin Petroleum up until the Spin-Off. This amount was offset against the agreed net working capital amount of USD 56.9 million owing by the Group to Lundin Petroleum as at December 31, 2016 which was comprised of trade receivables, hydrocarbon inventories, well supplies and cash, net of trade payables and accruals. The net outstanding balance as at March 31, 2018 of USD 23.5 million is due to Lundin Petroleum in December 2018.

Following receipt of all necessary approvals and consents, including the approval of Lundin Petroleum's shareholders and the satisfaction or waiver of all other conditions to the Reorganization, all of the Common Shares was distributed by Lundin Petroleum *pro rata* on the basis of one Common Share for every three shares held in Lundin Petroleum to all of its shareholders pursuant to a Lex Asea dividend in kind in accordance with the rules and laws of Sweden, Lundin Petroleum's jurisdiction of incorporation. The Common Shares were distributed to Lundin Petroleum's shareholders on the record date April 24, 2017. Following the Spin-Off, all of the Common Shares were distributed to Lundin Petroleum's shareholders and Lundin Petroleum is no longer a shareholder of the Corporation.

Pursuant to the Reorganization and the Spin-Off, the Group acquired ownership of the Initial Oil and Gas Assets and is independent of Lundin Petroleum.

In May 2017, the Group decided to change the capital structure of the Corporation through a share purchase offer. The primary objective of the offer was to provide an orderly exit for Statoil ASA (a shareholder of Lundin Petroleum) as a large non-core shareholder of IPC and a potential risk to liquidity of the Common Shares. In June 2017, 25,540,302 Common Shares were purchased by IPBV under the share purchase offer for a consideration of approximately USD 90 million. These Common Shares were subsequently cancelled through an internal reorganization, resulting in shareholder negative dilution of approximately 22.5 percent. The total number of issued and outstanding Common Shares following such cancellation was 87,921,846. A USD 100 million reserve based lending facility was put in place in April 2017 and drawn upon by IPBV to facilitate completion of the share purchase offer.

In August 2017, IPC announced that the Corporation planned to drill two additional infill wells on the Bertam field in Malaysia during the fourth quarter of 2017. In addition, IPC planned to proceed with 3D seismic acquisition on the Villeperdue field in the Paris Basin, France. IPC also announced that following technical work undertaken by IPC's teams in France and Malaysia, the best estimate contingent resource base was 17.5 MMboe as at June 30, 2017.

In September 2017, IPC announced that a wholly-owned subsidiary of IPC has entered into an agreement with Cenovus Energy Inc. ("**Cenovus**") to acquire all of Cenovus' interests in the conventional oil and natural gas assets in the Suffield and Alderson areas of southern Alberta, Canada (the "**Suffield Assets**" or the "**Oil and Gas Assets in Canada**", while the acquisition of those assets is referred to as the "**Acquisition**"). The Suffield Assets are held over a large, contiguous land position of 800,000 net acres of shallow natural gas rights and 100,000 net acres of oil rights in south-east Alberta, Canada. Production and reserves from the assets come from conventional shallow oil and gas wells.

The Acquisition was completed on January 5, 2018. The consideration paid on closing, net of closing adjustments, was CAD 449 million. A further payment of CAD 12 million will be paid by the end of June 2018. In addition, certain capped, additional contingent payments may become payable based on oil and natural gas prices (see section "The Business"). The Acquisition was fully funded from internally generated cash flow and existing and new lending facilities. The Acquisition financing package, consisting of an increase in the reserve based lending facility from USD 100 million to USD 200 million and new credit facilities of CAD 310 million, was fully underwritten by BMO Capital Markets.

In December 2017, IPC announced that drilling of the first of two planned infill wells had commenced on the Bertam field, offshore Malaysia. The two infill wells were successfully completed and put on production in early 2018.

In February 2018, IPC announced that, following the submission of an application to the relevant Malaysian authorities, the FPSO Bertam received registration as a Malaysian flagged vessel under the applicable Malaysian marine regulations.

In February 2018, IPC also announced that the 2018 production guidance is 30,000 to 34,000 boepd, with operating costs for 2018 expected to be USD 12.6 per boe. IPC's 2018 capital expenditure budget is USD 32 million, primarily targeting production growth in Canada and Malaysia. The Group has allocated approximately USD 11 million to oil drilling in Suffield and approximately USD 14 million as carry-over costs related to the 2017-2018 infill drilling campaign in Malaysia, with the remainder on continued project, maintenance and optimization activities in France and the Netherlands.

In May 2018, the Corporation decided to approve additional capital expenditure of USD 6.5 million (net) to drill the Keruing (formerly I35) prospect in late 2018, subject to Petronas approval and rig contracting.

THE BUSINESS

Business Overview

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. Since listing the Common Shares on April 24, 2017 in Canada and Sweden, IPC has been focused on delivering operational excellence, demonstrating financial resilience, maximizing the value of IPC's resource base and targeting growth through acquisition.

The vision and strategy of IPC's management from the outset was to use the IPC platform to build an international upstream company focused on creating long term value for IPC's shareholders, launched at a favorable time in the industry cycle to acquire and grow a significant resource base.

As at the date of this prospectus the Group operates its produced volumes in the Paris Basin, France and Malaysia and owns non-operated interests in the Aquitaine Basin, France and the Netherlands. As operator, the Group is able to control the pace and strategy of its development activities and to implement execution strategies that are compatible with its approach to prudently managing operational and financial risk. The Group is also able to optimize the timing and magnitude of capital expenditure programs and to leverage the value of management's expertise and proven track record. In January 2018, the Corporation completed the Acquisition, whereby the Suffield Assets from such date are also operated by the Group.

For the full year 2017, IPC reported average daily production of 10,307 boepd. This production was driven by good performance across all of IPC's assets in Malaysia, France and the Netherlands. The uptime performance of the FPSO Bertam in excess of 99 percent continued during 2017, excluding the planned shutdowns for maintenance and infill drilling operations.

During 2017, IPC's assets generated operating cash flow of USD 138 million. This allowed IPC to fund operations and reduce the amounts drawn under the Credit Facility put in place to fund the purchase of 25.5 million Common Shares under the share purchase offer in the second quarter of 2017. By the end 2017, IPC was in a net cash position of USD 5.6 million, excluding the CAD 40 million (USD 32.6 million) deposit for the Suffield acquisition in Canada. Including the Canadian acquisition deposit, net debt as at December 31, 2017 was USD 26.3 million.

IPC's 2P reserve base amounted to 29.4 MMboe as at December 31, 2016. A portfolio re-evaluation during the first half of 2017 allowed IPC to book 17.5 MMboe of best estimate contingent resources as at June 30, 2017. A capital investment program was approved in the second half of 2017 to drill two new infill wells in Malaysia on the Bertam field and acquire a 79 km2 3D seismic survey in the Villeperdue field in France.

As at end December 2017, IPC's 2P reserves were 129.1 MMboe, including 2P reserves attributable to the Suffield acquisition in Canada which completed on January 5, 2018. In addition, IPC reported best estimate contingent resources as at end December 2017 of 63.4 MMboe (unrisked), also after giving effect to the Suffield acquisition in Canada. Two additional infill locations on the Bertam field in Malaysia have been booked as well as the inclusion of the acquired resources in Canada.

The Oil and Gas Assets in Malaysia are offshore assets characterized by a small number of highly productive wells. Production is light, high quality oil that attracts a premium to Brent crude pricing. The Malaysian assets began production in 2015. As at the date of this prospectus, there were 14 horizontal wells, fitted with electric submersible pumps and a natural aquifer drive for pressure support. The Corporation also indirectly holds a 100% economic interest in the FPSO Bertam operating in Malaysia.

The Oil and Gas Assets in France are comprised of two main operating basins, the Paris Basin, which is operated by the Group, and the Aquitaine Basin, which is operated by Vermilion. Both basins are characterized by a high number of wells with low production decline rates. Production from IPC's Oil and Gas Assets in in France is light, high quality oil only. IPC's Oil and Gas Assets in France had been under the ownership of Lundin Petroleum since 2002, are well known to the Corporation's management and are operated by the current local team in place in the Paris Basin and by Vermilion in the Aquitaine Basin.

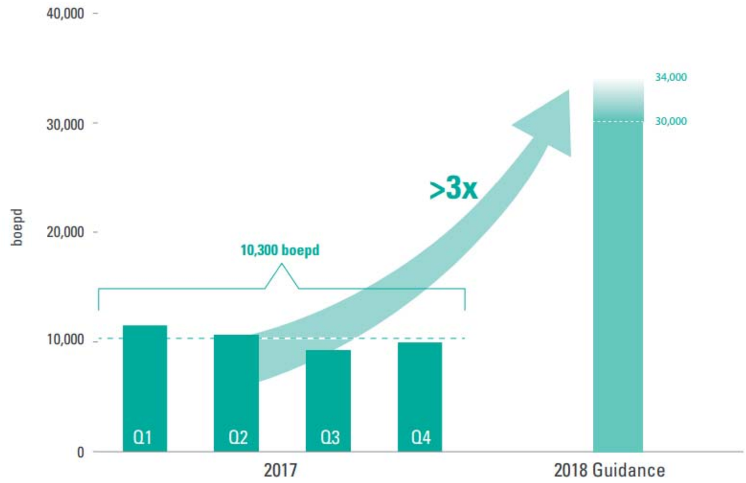
The Oil and Gas Assets in the Netherlands are non-operated, late-life natural gas fields, both onshore and offshore, that continue to provide profitable production.

The Oil and Gas Assets in Canada were acquired in January 2018. During the third quarter of 2017, IPC announced the transformational acquisition of the Suffield Oil and Gas Assets in Alberta, Canada. The Suffield Assets are high quality conventional assets that have been operated safely and efficiently for many years by Cenovus. This acquisition fits with 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.

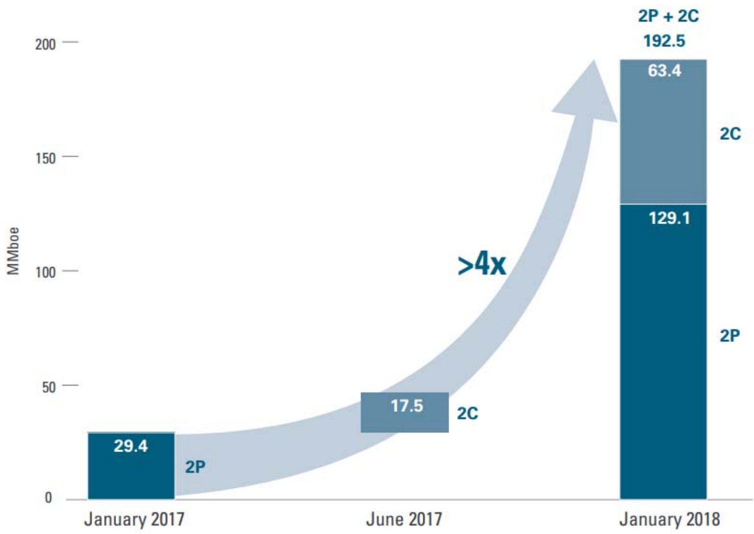
The transaction was completed on January 5, 2018. The consideration paid on closing, net of closing adjustments, was CAD 449 million. A further payment of CAD 12 million will be paid by end June 2018. In addition, certain capped, additional contingent payments may become payable based on oil and gas prices. These contingent purchase price payments may become payable based on actual average monthly oil and natural gas prices during 2018 and 2019. Payments are due for each month when the average daily price of West Texas Intermediate (WTI) is above USD 55 per bbl or natural gas prices at the Henry Hub are above USD 3.50 per million British thermal units (MMBtu). These payments are capped for each commodity on a per month basis (CAD 375,000 per month for oil and CAD 1,125,000 per month for gas) with a maximum combined payment of CAD 36 million in aggregate. The Group paid Cenovus CAD 375,000 in respect of each of the months January to March 2018 related to oil prices, with no amounts owing related to January to March 2018 gas production.

Production and Resources

International Petroleum Corp.
Production Growth



International Petroleum Corp.
Resource Growth[1]



[1] See MD&A and MCR

HSE Performance

Safety performance in 2017 and the first quarter of 2018 has been good with no major incidents, injuries to personnel or spills/releases to the environment. Safety remains a priority for all operational and asset teams and IPC is constantly looking at ways to improve performance and ensure that our operations have no impact on personnel, assets or the environment. During the first quarter of 2018, IPC recorded one low severity Lost Time Incident (LTI) in France and two reportable spills in Canada, both were small volumes which were contained and recovered at the spill location.

MANAGEMENT AND OPERATIONAL PERSONNEL

Management

The affairs of the Corporation are principally managed by Mike Nicholson and Christophe Nerguararian, the CEO and CFO of the Corporation, respectively, each of whom has entered into an employment agreement with a wholly-owned subsidiary of the Corporation.

In addition, Jeffrey Fountain serves as General Counsel, responsible for all legal matters in the Corporation. Daniel Fitzgerald, VP Operations, and Ryan Adair, VP Reservoir Development, are principally responsible for the management of all technical, operational and subsurface aspects and personnel relating to the ongoing development and operations of the Oil and Gas Assets. Rebecca Gordon, VP Corporate Planning and Investor Relations, is responsible for economics and investor relations.

Country Personnel

As of December 31, 2017, IPC had a total of 126 employees located in Malaysia, France, Switzerland and The Netherlands providing the Group with the managerial, operational, technical, financial and locally specific knowledge and experience to ensure effective and efficient management of the Initial Oil and Gas Assets.

The Group maintains an operations office in Switzerland, where certain technical, legal, financial and other administrative functions are performed, and has local offices in Malaysia, France, The Netherlands and Canada. IPC established its Calgary, Canada office in December 2017 in view of the closing of acquiring the Suffield Assets which occurred on January 5, 2018. The total number of employees as at March 31, 2018 was 230.

The Corporation has entered into the following services agreements with Lundin Petroleum in connection with the Reorganization:

- *General Services Agreement*: The Corporation leases office space from Lundin Petroleum in Vésenaz, Switzerland.
- *IPC Technical Services Agreement*: The Corporation may, but will be under no obligation to, request the services of certain employees of Lundin Petroleum to assist in the business of the Corporation. Any services provided under this agreement will be on subsequently agreed rates, based on market rates for similar services.
- *Lundin Petroleum Technical Services Agreement*: Lundin Petroleum may, but will be under no obligation to, request the services of certain employees of the Corporation to assist in the business of Lundin Petroleum. Any services provided under this agreement will be on subsequently agreed rates, based on market rates for similar services.

The Corporation has also entered into an agreement with a management services company, whereby such company will provide office facilities, administration, investor relations and corporate development services in Vancouver, British Columbia.

In France, the Corporation employs 47 individuals located at production facilities in Montmirail. In addition, the Corporation will retain contractors as required. The Oil and Gas Assets in France and their administration are managed by the general manager responsible for the Oil and Gas Assets in France, who is assisted by a management team that is responsible for various functions including operations, exploration, health and safety, environmental, human resources, accounting and finance and legal functions. A majority of the French senior management team has been in place operating the Oil and Gas Assets in France since Lundin Petroleum acquired them in 2002.

In the Netherlands, the Corporation employs five individuals located in corporate offices in The Hague. The Oil and Gas Assets in the Netherlands and their administration are managed by the general manager responsible for the Oil and Gas Assets in the Netherlands. The remaining employees are responsible for administration and maintaining accounting functions for the Oil and Gas Assets in the Netherlands.

In Malaysia, the Corporation indirectly employs 59 individuals located at the Malaysian Head Office in Kuala Lumpur. In addition, the Corporation will retain contractors as required. The Oil and Gas Assets in Malaysia and their administration are managed by the general manager responsible for the Malaysian business, who is assisted by a management team that is responsible for various functions including, operations, health and safety, environmental, human resources, accounting and finance and legal functions.

In Canada, the Corporation indirectly employs 106 individuals located at the office in Calgary and working in respect of the Oil and Gas Assets in Canada.

Employees

The IPC Subsidiaries directly and indirectly employed the following number of people at the dates set out below.

	December 31, 2017	December 31, 2016	December 31, 2015
Malaysia	59	77	119
France	47	48	44
The Netherlands	5	6	7
Switzerland	15	– [1]	– [1]
Canada	– [2]	– [2]	– [2]
Number of employees	126	131	170

[1] Before the spin-off date, all corporate functions were grouped within Lundin Petroleum. Approximately 13 individuals were employed by Lundin Petroleum and worked in Switzerland in respect to IPC operations.
[2] The Acquisition was completed in January 2018 – there were no employees in Canada during the relevant financial years.

THE OIL AND GAS ASSETS

The following is a description of the properties comprising the Oil and Gas Assets in Canada, Malaysia, France and the Netherlands. The following property descriptions are as at the date of this prospectus unless otherwise indicated.

Canada

2017 Summary

In September 2017, IPC announced the transformational acquisition of the Suffield Assets in Alberta, Canada.

The Suffield Assets are held over a large, contiguous land position of 800,000 net acres of shallow natural gas rights and 100,000 net acres of oil rights in southeast Alberta. These producing fields have future development potential from a combination of low risk development drilling, well stimulation and enhanced oil recovery (EOR) opportunities, which had not been undertaken for a number of years due to Cenovus' capital allocation priorities.

The Suffield Assets had been operated by Cenovus and its predecessors for more than 40 years. The oil is produced using conventional recovery methods via water drive with pumped multi-lateral horizontal wells. The production is collected in a network of pipelines and transported to a central processing facility, the 1-27 Battery.

Management of IPC believes that the oil upside relates to low risk development drilling. There is also low risk upside in Alkaline-Surfactant-Polymer (ASP) flood expansion. This process has been demonstrated to work in two fields, and IPC is evaluating its application into a third field which is near the existing infrastructure.

Sweet natural gas production in the Suffield area is via shallow wells producing from multiple formations. The wells produce into a network of natural gas pipelines with a number of compressor stations. IPC believes that the production is low maintenance with optimization potential.

IPC transitioned certain Cenovus employees who have the experience in managing and operating these assets across to IPC, including experience with and knowledge of the established maintenance routines and rigorous HSE procedures.

No oil wells have been drilled since 2014 and no gas wells have been drilled since 2010 due to Cenovus' capital allocation priorities.

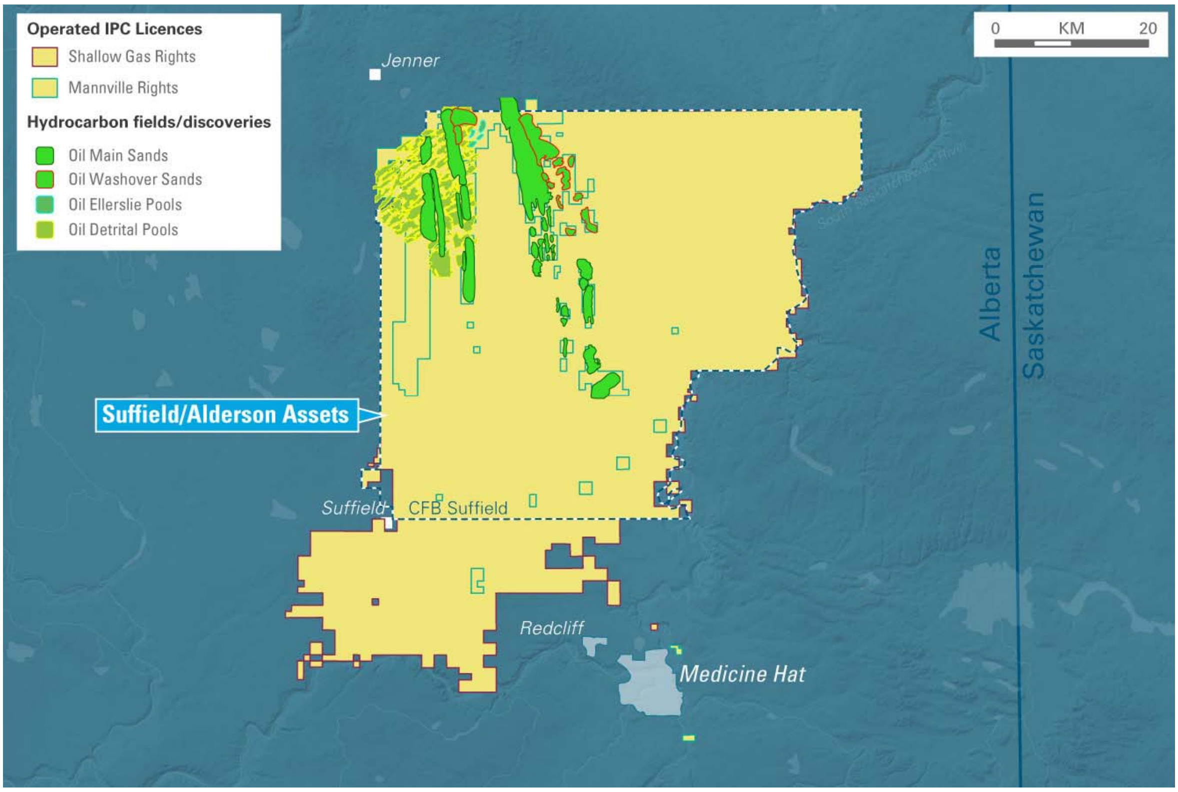
Overview

The onshore Suffield Assets are situated in southeast Alberta, Canada, and are operated by IPC. The oil assets are 100% working interest and gas assets are 99.7% working interest on a well-count basis. These assets are characterized as having a high number of wells with low production decline rates. The oil quality is 13°API and is produced via conventional, non-thermal methods. The assets are well-known to the operational team in Redcliff, Alberta and to the asset management team in Calgary, Alberta, many of whom have been working the assets for many years as Cenovus employees.

Asset Description

Oil is produced primarily from open-hole horizontal wells pumped with progressive cavity pumps, gathered and processed at the 1-27 Battery and piped to market. The reservoirs are high quality Cretaceous sandstones with reservoir pressure supported by a combination of bottom water drive and water injection. There are two pools that are benefitting from ASP injection which entails a small amount of chemical being added to the injection water to mobilize more oil than would be recoverable by water drive alone.

The shallow conventional natural gas production is from a combination of five shallow horizons produced via vertical production wells. The low pressure wells are naturally flowing assisted with siphon strings in some cases. The majority of the produced natural gas is sold at Empress reference with the balance being sold at AECO reference.



Geologic Overview

The main oil producing horizon is the Cretaceous age Glauconitic (Manville group) sand. The sand was deposited in a shoreline / Aeolian environment and is generally of very high reservoir quality. Reservoir depth is approximately 1,000 metres and oil is produced via water drive. The oil is viscous however with the good reservoir quality it can be produced via conventional, non-thermal methods.

The secondary oil reservoirs are Upper Mannville washovers, Lower Manville Ellerslie, and Lower Manville Detrital. Two of the wash-over pools are subject to ASP enhanced oil recovery.

The natural gas production is from a regional multi zone conventional play. The sands are part of the Belly River / Colorado group and are generally hydraulically fractured and commingled. Almost all of the natural gas production is from formations at less than 500 metres depth.

Production Operations

The vast majority of the oil production wells are activated by progressive cavity pumps and are tied into intra field collection lines. The oil density at surface conditions is 13°API. There is ample oil processing capacity to accommodate existing and future planned production.

Abandonment Obligations

Abandonment in Canada consists of permanent plugging of the wells, decommissioning of facilities and pipelines, and site restoration. A complete review of the wells, pipelines and facilities status is completed annually. Provisions for the abandonment activities are revised every year based on the latest information and these provisions are included in the capital expenditures budget. The Group follows the applicable Alberta regulations and reports regularly to the Alberta regulator their abandonment activities and cost estimates. On this basis, non-economic wells and/or non-producing wells are regularly abandoned as a part of ongoing business.

Infrastructure and Marketing

Oil is gathered at the 1-27 Battery, blended with condensate, and pipelined to market. The shallow natural gas is gathered into intra-field flow lines operated via 16 compressor stations. There are two egress points with the bulk of the natural gas going to Empress and the balance going to AECO.

Malaysia

2017 Summary

Net production from the Bertam field on Block PM307 (IPC working interest (WI) 75%) during 2017 was at 6.7 Mboepd. Reservoir performance for the Bertam field was in line with expectation and facilities uptime during 2017 was in excess of 99 percent (excluding planned shutdowns).

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, the FPSO Bertam was registered as a Malaysian flagged vessel under the applicable Malaysian marine regulations.

In December 2017, drilling commenced on the first of two sanctioned infill wells on the Bertam field, with production commencing in January 2018. The second well commenced drilling in January 2018 and was completed and put on production in February 2018.

Reprocessing of Bertam 3D seismic that was acquired in 1996 with the latest technology was completed during the fourth quarter of 2017, allowing for a full review of additional infill targets. This allowed the booking of 1.4 MMboe of additional best estimate contingent resources as at December 31, 2017.

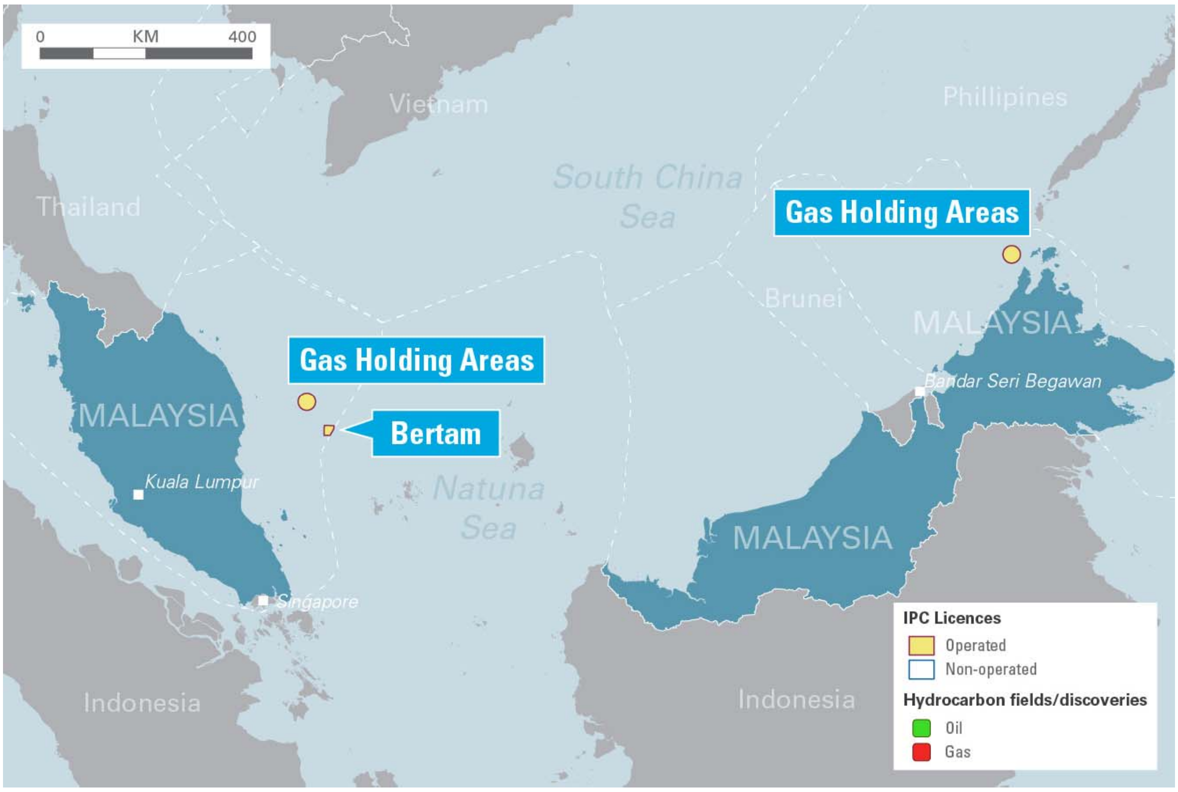
During the fourth quarter of 2017, the Group gave notice of its intention to withdraw from the PM328 exploration block. Final approval of the withdrawal was pending at the end of 2017 and was granted in February 2018. No commitments are outstanding on any blocks in Malaysia.

Overview

All of the Group’s production and reserves in Malaysia come from the Bertam oil field located offshore Peninsular Malaysia. The Bertam field has been on production since April 2015. The Group is the operator of Block PM307 with a 75% working interest, with Petronas holding the remaining 25% through its wholly owned subsidiary Petronas Carigali Sdn Bhd (“**PCSB**”).

The administrative, accounting and technical affairs of the Group’s activities in Malaysia are managed from its office in Kuala Lumpur.

The map below shows the location of the Oil and Gas Assets in Malaysia.



Concession	Area (km^2)	Offshore/ Onshore	Licence Type	Interest	Operator	Expiry	Partners
PM307	297 (Bertam)	Offshore	Production	75.00%	Lundin	Aug-25	PCSB 25%
PM307 Tembakau and Mengkuang	108	Offshore	Gas Holding Area	75.00%	Lundin	May-21	PCSB 25%
SB303	30	Offshore	Gas Holding Area	55.00%	Lundin	Apr-20	PCSB 25%, Dyas 20%

Peninsular Malaysia - Bertam

History

The Bertam field is located offshore Peninsular Malaysia on Block PM307 and was initially discovered in 1995 by the Bertam-1 well drilled by Petronas. PM307 was acquired by IPC's wholly-owned subsidiary IPC Malaysia BV in 2011 and was successfully appraised in 2012 and a field development plan was submitted and approved by Petronas in late 2013. An efficient execution of the development plan allowed the field to commence production in April 2015. The Bertam development consists of an unmanned wellhead platform and, as at December 31, 2017, 12 development wells producing to the FPSO Bertam.

Asset Description

The Bertam field is located 175 kilometres offshore to the east of Peninsular Malaysia, close to the Indonesian border at a water depth of about 74 metres. The field is a low relief, approximately 15 square kilometre, four-way closure. Maximum oil column is in the order of 20 to 25 metres. Reservoir depth is approximately 1600 metres below sea level and the reservoir was slightly underpressured at the first oil date in April 2015.

Geological Overview

The main reservoirs are Late Oligocene deltaic sandstones of the South Malay Basin K sequence. The main reservoir, K10.1, is a continuous sand with subtle variations in properties across the field. Gross thickness is in the 7 to 10 metres range, porosity is 20-25% and permeability is 80-300 milliDarcies.

Production Operations

The reservoir recovery mechanism is moderate to strong aquifer drive. As at December 31, 2017, reservoir access was through 12 horizontal producer wells placed close to the top of the K10.1 structure to minimize water coning. Since the reservoir is undersaturated with no gas cap, the wells require artificial lift using electric submersible pumps (ESP). Average quality of oil produced from the Bertam field is good with an API gravity of 37°. The wells are tied back to the FPSO Bertam where separation and storage takes place.

Bertam – FPSO Unit

In 2013, Lundin Petroleum received development plan approval for the Bertam oil field on Block PM307 which integrated an unmanned wellhead platform tied to a FPSO vessel. Lundin Petroleum completed an extensive upgrade and life extension program on the FPSO Ikdam (renamed the FPSO Bertam), and it is now operating on the Bertam field in Block PM307.

Since the FPSO Bertam started receiving oil from the Bertam field in April 2015, it has achieved an excellent operational uptime of greater than 99 percent.

The FPSO Bertam is currently leased to the PM307 joint venture under a bareboat charter arrangement with a six-year fixed term at the daily lease rate to April 2021. There are a further four, one-year year options available after the fixed period. The daily operations and maintenance of the facility are undertaken by E&P O&M Services Sendirian Berhad, an operations and maintenance service provider in Malaysia, under contract and supervision of IPC Malaysia BV. E&P O&M Services Sendirian Berhad is a wholly-owned subsidiary of PCSB that offers operations and maintenance services in Malaysia. The operations and maintenance contractor and IPC Malaysia BV are responsible for the maintenance and upkeep of the FPSO Bertam.

FPSO Flagging in Malaysia

The FPSO Bertam is required to be Malaysian flagged in order to offload oil production from the Bertam field in Malaysian waters. Following the submission of an application to the relevant Malaysian authorities in 2018, the FPSO Bertam has now received registration as a Malaysian flagged vessel under the applicable Malaysian marine regulations.

Abandonment Obligations

The Bertam field obligations for abandonment are in line with the requirements set out by the Petronas Procedures and Guidelines for Upstream Activities (the "**PPGUA**"). In accordance with the PPGUA, the FPSO Bertam must be returned to Lundin Services Limited, it must be cleaned and be gas free and the wellhead platform must be removed to below the mud line. Wells will be abandoned in line with the PPGUA. A cash provision for the abandonment of facilities is made annually into the abandonment fund at a rate relative to the annual production volumes, as per the PSC requirements. The Group also makes provisions for the abandonment of wells annually, but costs are not paid until they are actually incurred.

Oil Export Infrastructure

The Bertam field utilizes the FPSO Bertam for production and oil storage. Export is undertaken directly from the FPSO to oil tankers via an offloading hose and offtake system.

Marketing

Oil produced from the Bertam field is sold on a spot tender to the highest bidder. The tender process is managed by Petronas, on behalf of the Group. The crude is delivered directly from the FPSO Bertam into the buyer's vessel. The price of the crude achieves a premium over the Brent crude price, which varies depending on the supply and demand balances in Asia.

Petronas, PCSB, IPC Malaysia BV and Petco Trading Labuan Company Limited ("**Petco**") are parties to a marketing agency agreement dated June 17, 2015. The marketing agency agreement is effective until December 31, 2019. Under the marketing agency agreement, Petronas, PCSB and IPC Malaysia BV appoint Petco as an exclusive marketing agent to sell Petronas', PCSB's and IPC Malaysia BV's respective entitlements of crude under the PM307 PSC. Petco is paid an agency fee based on barrels of crude oil sold.

Development Plans

During the July 2017 planned shutdown, a range of instrumentation and equipment with a higher pressure rating were put in place to allow for an increase on the Bertam wells which had been constrained due to pressure limitations.

A two well infill campaign was sanctioned in 2017 and began during the fourth quarter of 2017. The campaign was completed and the infill wells were brought on production in January and February 2018. Additional development and exploration potential has been identified in the Bertam field. IPC is currently evaluating the drilling of two additional infill wells which are analogous in concept to the recently executed A16 and A17 infill wells. There are spare slots on the wellhead platform to accommodate the new wells. The Corporation has taken the decision to approve additional capital expenditure of USD 6.5 million (net) to drill the Keruing (formerly I35) prospect in late 2018, subject to Petronas approval and rig contracting. The Keruing prospect is only two kilometres from the Bertam field facilities and would be a high value tie back candidate in the success case. See "Reserves and Other Oil and Gas Information relating to the Oil and Gas Assets".

Peninsular Malaysia – PM307 Gas Holding Area (Tembakau, Mengkuang)

The first exploration well by Lundin Petroleum was Tembakau-1, which was drilled in 2012 and was a natural gas discovery in two Miocene sandstone intervals. The discovery was successfully appraised with Tembakau-2 in 2014. Subsequently, Mengkuang-1 was drilled in October 2015 to test an oil prospect in the I-35 channel system and was a small natural gas discovery.

A Gas Holding Area (GHA) application was approved in April 2017, and is effective from May 2016 until May 2021. The development of this asset is estimated to be sub-economic under current economic conditions and therefore development is presently considered not viable.

Sabah – SB 303 Gas Holding Area (Tarap, Cempulut, Berangan, Titik Terang)

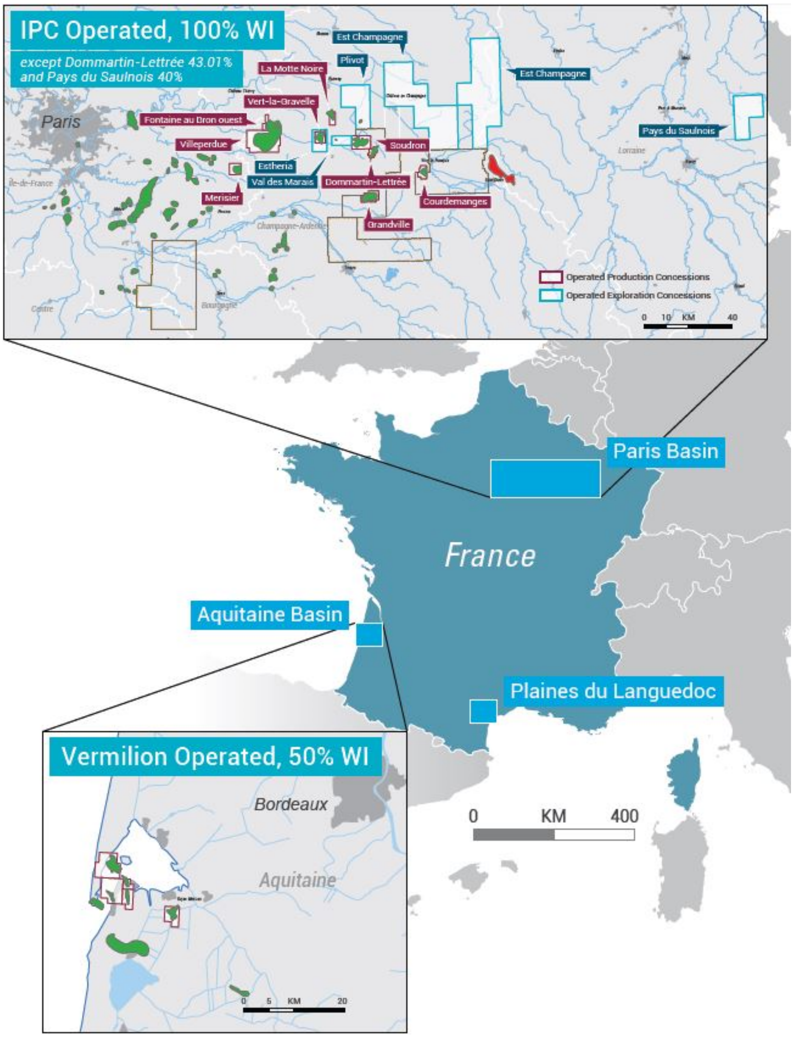
Block SB303 is located at the northern tip of Borneo and has been explored by several rounds of operations since the late 1960s. In SB303, prior to the Group's operations, nine exploration wells were drilled, resulting in one small natural gas discovery (Titik Terang). The reservoirs are well-developed sandstone of mainly Miocene age.

IPC Malaysia BV made three marginal natural gas discoveries on Block SB303 with the Tarap, Cempulut and Berangan natural gas discoveries. IPC Malaysia BV applied for a GHA covering these three discoveries and the vintage Titik Terang discovery in March 2015, which was granted in April 2015 until April 2020. The development of this asset is estimated to be sub-economic under current economic conditions and therefore development is presently considered not viable.

France

In France, the Oil and Gas Assets are situated in the Paris Basin and the Aquitaine Basin. The majority of the production and reserves of the Oil and Gas Assets comes from the operated fields in the Paris Basin. In the Aquitaine Basin, production comes from Vermilion Energy Inc.'s ("**Vermilion**") operated fields, where there is a 50% working interest.

The map below shows the location of the Oil and Gas Assets in France.



2017 Summary

Net production in France during 2017 was 2.4 Mboepd. IPC recognizes significant development upside in the Paris Basin. In parallel with maturing the contingent resources, IPC has been actively working on optimizing the Vert La Gravelle project which is already reflected in the 2P reserves base.

The Vert La Gravelle field has been on production since the mid-1980s and has long been recognized as a field with water-flood and development drilling upside. A field re-development project was sanctioned in 2014 however as a result of Lundin Petroleum's capital re-allocation priorities, the project was postponed after the construction and commissioning of the facilities and the drilling of the first two wells. IPC is taking the opportunity to revisit the development concept sanctioned in 2014 in particular IPC is investigating the merits of applying horizontal well technology as a means to optimize value.

In respect of the Villeperdue West project, the concept is to extend the development drilling to the west into an area that was considered to be water bearing when the initial field development was executed in the 1980s. Production trends on the west extension combined with our mapping and geologic assessment point towards significant bypassed oil potential which can be developed and tied into existing infrastructure. There remains structure and reservoir risk which is being addressed through the acquisition of 79 km2 of high resolution 3D seismic approved in the second quarter of 2017. The 3D seismic acquisition was completed safely and within budget in October 2017.

Seismic processing, interpretation and subsequent reservoir development studies will continue through 2018. The seismic survey will also improve the structural definition of the Villeperdue Deep prospect.

The contingent resource estimates reported for France relate to development drilling and water-flood optimization opportunities. In all cases, the product type is light crude oil. The risk and uncertainty associated with the contingent resources in France is largely due to limited seismic coverage and understanding of structural extent of the fields. To recover the contingent resources, the drilling of development wells and, in some instances, the modification of existing production facilities would be required. Project development timing for the highest ranked opportunities will potentially be in the next two to five years with the remaining within the next ten years. In all cases, the contingent resources require a definitive development plan and approval of the plan to mature from contingent resources to reserves.

France – The Paris Basin

History

Production in the Paris Basin fields started in 1959. The main Villeperdue field started production in 1983. The assets were operated by Total Exploration and Société Nationale Elf-Aquitaine (Production) before being transferred to Coparex International S.A. (now known as IPC Petroleum France S.A.) in 1993 and 1995. Lundin Petroleum acquired the Paris Basin assets in 2002 when it bought Coparex International S.A. from BNP Paribas. In 2007, Lundin Petroleum acquired a further 20% interest in four assets from Carr Production France. In 2017, Lundin Petroleum's oil and gas assets in France were acquired by the Corporation in connection with the Spin-Off.

Assets Description

The Group is the operator of nine oil field licences and five exploration permits located approximately 100 kilometres east of Paris in the central part of the Paris Basin. The Group is the operator of all of the Paris Basin fields and holds a 100% working interest in eight of the nine producing fields (43.01% working interest in Dommartin Lettrée field with Vermilion as partner).

Paris Basin Concessions	Area (km^2)	Offshore/ Onshore	Licence Type	Interest (%)	Operator	Partners	Expiry	Future Work Commitments (MM€)
Production								
Courdemanges	19.9	Onshore	Production	100.00	IPC	N/A	Mar-38	N/A
Dommartin-Lettree	13.2	Onshore	Production	43.01	IPC	Vermilion 56.99%	Feb-24	N/A
Fontaine au Bron (South and West parts including the Hautefeuille field)	25.1	Onshore	Production	100.00	IPC	Geopétrol is operator of the remaining area of the concession	Oct-17	N/A
Grandville	33.9	Onshore	Production	100.00	IPC	N/A	Aug-38	N/A
La Motte Noire	15.8	Onshore	Production	100.00	IPC	N/A	Mar-30	N/A

Paris Basin Concessions	Area (km²)	Offshore/ Onshore	Licence Type	Interest (%)	Operator	Partners	Expiry	Future Work Commitments (MM€)
Merisier	26.5	Onshore	Production	100.00	IPC	N/A	Nov-29	N/A
Soudron – Soudron field Soudron – Villeseneux field	51.6	Onshore	Production	100.00	IPC	N/A	Mar-35	N/A
Vert-La-Gravelle	23.0	Onshore	Production	100.00	IPC	N/A	Sep-28	N/A
Villeperdue	141.3	Onshore	Production	100.00	IPC	N/A	Jan-37	N/A
Exploration								
Amaltheus	37.0	Onshore	Exploration	100.00	IPC	N/A	N/A(2)	0.0
Plivot	198.0	Onshore	Exploration	100.00	IPC	N/A	Oct-20	0.9
Pays du Saulnois	198.0	Onshore	Exploration(1)	40.00	IPC	Neptune Energy (40%) Diamoco Energy (20%)	Nov-18	1.3
Est Champagne	1318	Onshore	Exploration(1)	100.00	IPC	N/A	Oct-19	0.0
Plaines du Languedoc	1095	Onshore	Exploration(1)	100.00	IPC	N/A	Oct-19	0.8
Esthéria	43	Onshore	Exploration	100.00	IPC	N/A	Sep-20	1.2
Exploration – Applications								
Cheroy	871	Onshore	Exploration	50.00	IPC	TBA if licence awarded	N/A	2.5
Camp de Mailly	433	Onshore	Exploration	100.00	IPC	N/A	N/A	3.1
Perthois	573	Onshore	Exploration	100.00	IPC	N/A	N/A	1.0
Templiers	600	Onshore	Exploration	100.00	IPC	N/A	N/A	2.0

Notes:

(1) Assumes that pending licence extension application is approved.

Geological Overview

There are two main productive horizons, namely, the Middle Jurassic (Dogger) limestones and Late Triassic (Rhaetic) sandstones. The Middle Jurassic Dogger reservoirs that are present in the Villeperdue, Merisier, and Soudron areas consist of oolitic and bioclastic limestones and are generally present within the central part of the Paris Basin. The Rhaetic sandstones extend into the northeastern part of the Paris Basin and provide the reservoirs for a number of oil fields, including Vert La Gravelle, Grandville, Dommartin-Lettrée, Soudron (which produces from both horizons) and Courdemanges.

Production Operations

The vast majority of production wells in the Paris Basin are activated by beam pumps. The injection wells are functioning with surface pumps. Oil is of good quality with 35 API gravity.

Six fields are operated by a production centre, Villeperdue, Merisier, Vert La Gravelle, Dommartin-Lettrée, Soudron and Grandville. Other fields have small gathering facilities where oil and water are separated from very small quantities of natural gas. Oil and water are then trucked to the nearest production centre where separation takes place. Produced water is reinjected in the reservoirs for pressure support.

Crude oil is trucked from the various production centres to the main Villeperdue gathering centre. Oil is sent to the Grandpuits refinery operated by Total SA via a pipeline owned by the Group.

Abandonment Obligations

Abandonment in France consists of permanent plugging of the wells, decommissioning of facilities and platforms and pipeline, and site restoration. A complete review of the wells and facilities status is completed annually on the Oil and Gas Assets in France.

Provisions for the abandonment costs are updated each year based on the latest information. The Group follows the French regulations on the subject and report regularly to the French administration their abandonment activities and cost estimates.

On this basis, non-economic wells and/or no longer producing wells are regularly abandoned as a part of ongoing business activity.

Infrastructure and Marketing

Crude oil is trucked from the various production centres to the main Villeperdue gathering centre. Oil is sent to the Total-operated Grandpuits refinery via a 100% owned pipeline. Oil is stored in tanks in the Villeperdue centre, which can hold approximately 16 days of the total Paris Basin production. It is then exported in batch mode and sold to Total under a contract with Total to the refinery.

Development Plans

A limited number of development campaigns were implemented by Lundin Petroleum, focusing on development drilling opportunities and increasing water injection for pressure maintenance: Merisier in 2004, Grandville in 2011 and Vert La Gravelle in 2014. This latter development was suspended in 2015 following execution of the facility and pipeline work having drilled two wells of a seven well campaign due to the low oil price environment.

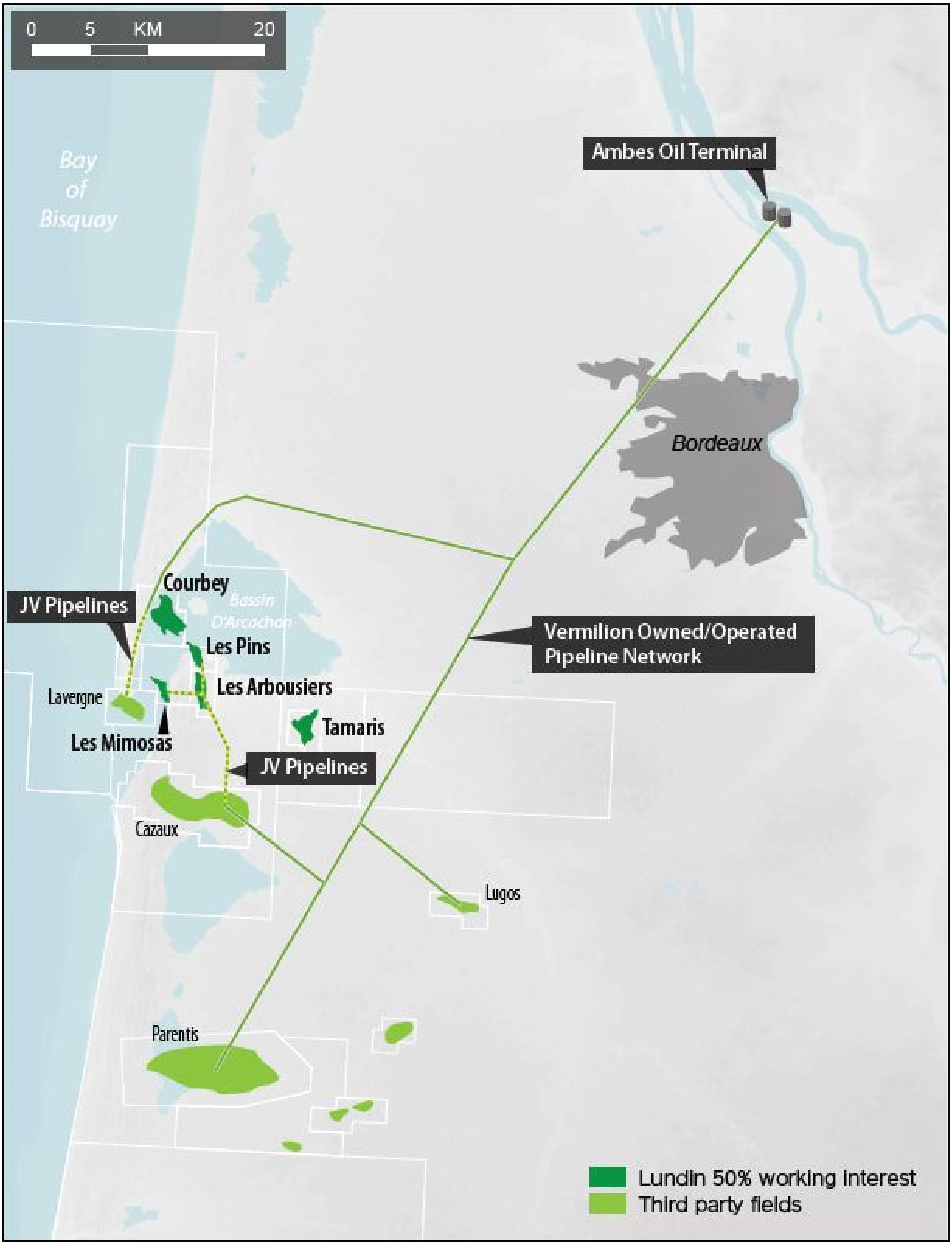
There is a renewed management focus on maturing organic growth opportunities in the Oil and Gas Assets in France, including a complete review of the remaining Vert La Gravelle development looking for areas of optimizing and capitalizing on current lower cost environment. Other opportunities are at concept stage which the company will mature and rank as technical work progresses. Execution of such opportunities could offset the already low natural decline rates.

France – The Aquitaine Basin

Assets Description

The Group has a 50% working interest in five production licences in the Aquitaine Basin. All licences associated with the Oil and Gas Assets are operated by Vermilion, who has the remaining 50% interest.

Fields are well developed with water injection for oil sweep and reservoir pressure support. The developments are constrained by the availability of surface locations resulting in wells that are long reach. All producing wells are activated by electric submersible pumps. Injector wells are equipped with surface injection pumps.


0 5 KM 20
Bay of Bisquay
Ambes Oil Terminal
Bordeaux
Courbey
Bassin D'Arcachon
JV Pipelines
Les Pins
Les Arbousiers
Lavergne
Les Mimosas
Tamaris
JV Pipelines
Vermilion Owned/Operated Pipeline Network
Cazaux
Lugos
Parentis
Lundin 50% working interest
Third party fields

Aquitaine Basin Concessions	Area (km^2)	Offshore/ Onshore	Licence Type	IPC Interest	Operator	Expiry	Partners
Les Tamaris	10.0	Onshore	Production	50.00%	Vermilion	Apr-21	Vermilion 50%
Courbey	22.1	Onshore	Production	50.00%	Vermilion	Mar-54	Vermilion 50%
Les Mimosas	20.0	Onshore	Production	50.00%	Vermilion	Nov-31	Vermilion 50%
Les Arbousiers	7.9	Onshore	Production	50.00%	Vermilion	Jan-45	Vermilion 50%
Les Pins	3.6	Onshore	Production	50.00%	Vermilion	Nov-21	Vermilion 50%

Geological Overview

The fields in the Aquitaine Basin produce from the Lower Cretaceous Purbeckian sandstones which are at a depth of 2,700 to 3,300 metres below sea level and are mainly tidal and fluviatile with generally good porosity and permeability. The fields are located either immediately under or adjacent to the Bay of Arcachon.

Production Operations

Oil is produced via water-flood drive and is of good quality with an API gravity of 28 to 34. The production wells are equipped with electric submersible pumps.

Oil and water produced from Les Pins and Les Mimosas is transported by a pipeline network to Les Arbousiers where all the oil is transported by flowline to the Vermilion 50% owned and operated Cazaux field. The Group has a 50% interest in the pipelines. From Cazaux, oil is transported via a Vermilion owned and operated pipeline into the Ambes terminal, north of Bordeaux. In 2015, there was an issue with the flowline between Les Arbousiers and Cazaux resulting in a temporary production stoppage from Les Pins, Les Arbousier and Les Mimosas fields. Production has since resumed via trucking.

Abandonment Obligations

Abandonment in France consists of permanent plugging of the wells, decommissioning of facilities and platforms and pipeline, and site restoration. A complete review of the wells and facilities status is carried out every year by the Group and provisions for the abandonment activities are made every year based on the latest information.

On this basis non-economic and/or no longer producing wells are regularly abandoned as a part of ongoing business and there is no envisioned production centre abandonment planned in the short term.

The Group follows the French regulations on the subject and reports regularly its abandonment activities to the French administration.

Infrastructure and Marketing

Oil produced from the Aquitaine Basin is sold under a sales contract with Total. Approximately each 9 to 10 months, the Group charters its own tanker to transport its equity oil to the Total-operated refineries in Le Havre or Donges on the Northwest coast of France.

Development Plans

The Group supports the operator's study initiatives to identify further development opportunities in the joint venture Aquitaine Basin fields. There are no definitive drilling plans at present.

Netherlands

2017 Summary

Net production from the Netherlands fields during 2017 was 1.2 Mboepd.

The production from the F15 field was permanently shut-in in December 2017 as planned. The facilities will be made hydrocarbon free and put on light-house mode. Testing of the Nieuwehorne-2 exploration well was completed during the fourth quarter of 2017, and the results are being evaluated.

Overview

The Netherlands is the second largest natural gas producer in Europe. It is now a mature hydrocarbon country as onshore production began in the 1950s and offshore production in the 1960s.

The Ministry of Economic Affairs (the "**MEA**") is responsible for the optimal development of oil and gas resources in the Netherlands. All oil and gas activity is governed by the terms outlined in the 2003 Mining Law, which provides the statutory framework for licensing, decommissioning and abandonment, Dutch State participation and financial obligations of licensees. The Netherlands introduced an open licensing system in 1995 in an effort to maintain exploration activity levels on the Dutch continental shelf. Under this system, all unlicensed acreage is available for allocation at any time during the year.

State participation occurs in the Netherlands via Energie Beheer Nederland BV ("**EBN**"), which acts as an independent partner in the majority of Dutch fields.

New discoveries can be feasibly developed because infrastructure is already in place. This infrastructure plays an important role in maximizing recovery from the sector and owners are working on delaying decommissioning and accelerating near-field developments. Efforts such as the Marginal Fields tax incentive and Fallow Acreage Covenant, which became effective in September 2010, are the latest measures that the Dutch government has taken to encourage exploration and ongoing development on idle acreage.

Assets Description

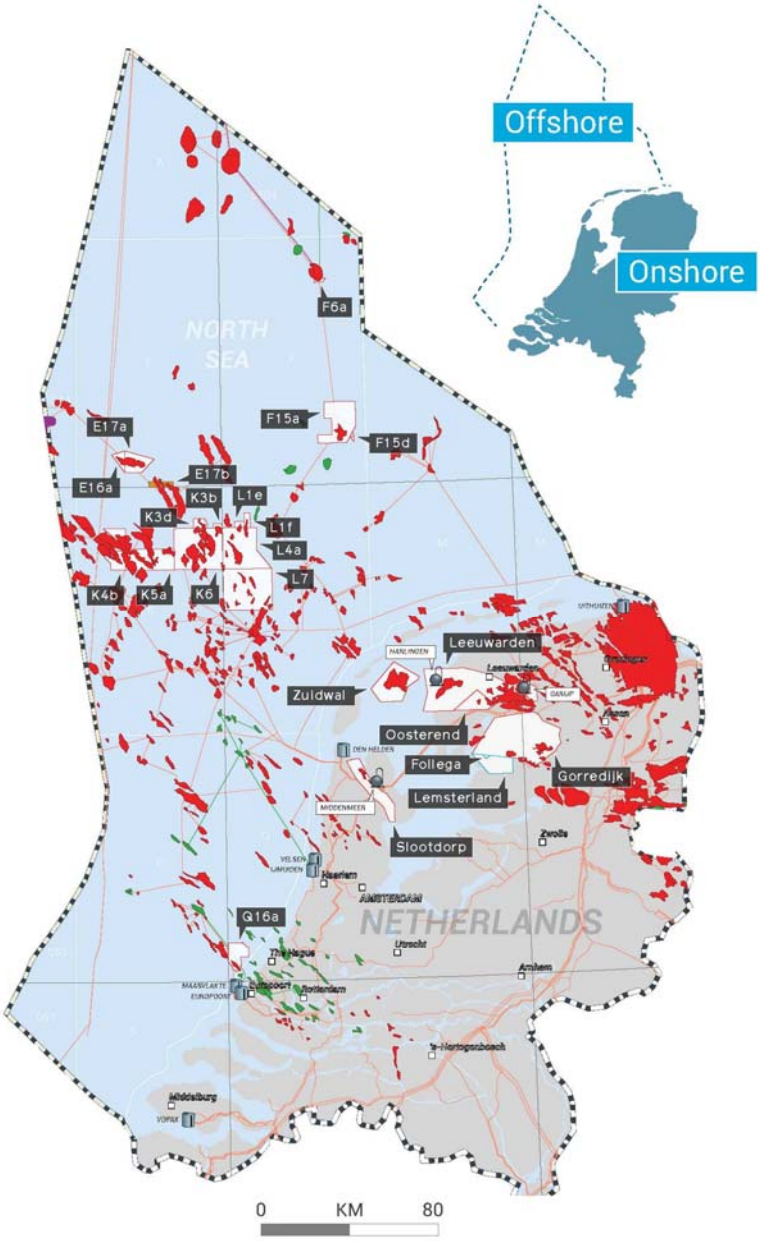
In the Netherlands, the Oil and Gas Assets are located in the southern and eastern part of the Southern North Sea gas province and onshore northern Netherlands. The Netherlands is a mature gas province providing the Group with low decline onshore and offshore production as well as providing upside potential through infill and exploration opportunities. The Group has varying interests in 20 licences and concessions of which 18 are producing licences and concessions and two are exploration licences and concessions. All of the licences and concessions held in the Netherlands are non-operated interests. Operators of the assets are large exploration and production companies in the Netherlands including Vermilion Energy Netherlands BV ("**Vermilion NL**"), Total E&P Nederland BV ("**Total**"), Neptune Energy and Oranje-Nassau Energie BV ("**ONE**"). In the Netherlands, the natural gas pricing is based upon the European gas base pricing reference point.

The administrative, accounting and technical affairs of the Group's activities in the Netherlands are managed from its office in The Hague.

This portfolio provides stable cash flow and exposure to a variety of hydrocarbon plays with reservoir targets at Carboniferous, Rotliegendes, Zechstein, Triassic, Jurassic and Lower Cretaceous intervals. These fields produce by natural pressure depletion, aided by compression.

Most of the natural gas is sold to GasTerra, a company joint owned by the Dutch Government and Shell/ExxonMobil.

The productive horizons in the Group’s portfolio of natural gas fields will be generally of Permian or early Triassic age. In the offshore portfolio, the main reservoirs are the upper and lower Slocheteren sandstones, and onshore the main reservoir is the Zechstein fractured carbonate with the secondary reservoirs being Vlieland and/or Rotliegend sandstones. Structurally, the fields, both onshore and offshore, tend to have faulting with the degree of compartmentalization varying from field to field.



Netherlands Onshore

The Group has interests in seven onshore licences and concessions, five production licences and concessions and two exploration licences and concessions. All the licences and concessions are operated by Vermilion NL. The onshore blocks are located in the northern part of the Dutch mainland.

The main onshore assets of the Group in the Netherlands are located in the Gorredijk and Slootdorp licences, where recent discoveries, such as the Vinkega and Langezwaag fields, and the Slootdorp 6 & 7 wells have made considerable contributions to field production.

The onshore fields have dedicated processing and dehydration treatment facilities in the vicinity of the concessions in the north of the Netherlands, which are operated by Vermilion NL. The Group has an interest in the following treatment facilities: Harlingen Treatment Centre which supports the Zuidwal and Leeuwarden West fields, the Garijp Treatment Centre, which supports the Gorredijk, Oosterend and Leeuwarden East fields, plus third-party field users generating considerable sharing benefits and tariff income. The Slootdorp and associated fields are treated through their own facilities, the Middenmeer Treatment Facilities. Processed gas is directly exported from these treatment facilities into the Gasunie-operated sales gas network.

Netherlands Onshore Concession	Area (km^2)	Licence Type	IPC Interest	Operator	Expiry	Partners
Follega	3	Exploration	9.300%	Vermilion NL	Does not expire	Vermilion NL 50.70%, EBN 40%
Gorredijk	629	Production	7.750%	Vermilion NL	Does not expire	Vermilion NL 42.25%, EBN 50%
Leeuwarden	614	Production	7.233%	Vermilion NL	Does not expire	Vermilion NL 92.7675%
Lemsterland	111	Exploration	9.300%	Vermilion NL	Does not expire	Vermilion NL 50.70%, EBN 40%
Oosterend	92	Production	7.750%	Vermilion NL	Does not expire	Vermilion NL 42.25%, EBN 50%
Slootdorp	161	Production	7.233%	Vermilion NL	Does not expire	Vermilion NL 92.7675%
Zuidwal	225	Production	7.796%	Vermilion NL	Does not expire	Vermilion NL 42.20405%, EBN 50%

Netherlands Offshore

The Group's offshore main portfolio in the Netherlands consists principally of acreage centred on the K and L blocks in which the predominant play is the Slochteren Formation of the Lower Permian. Elsewhere the F6 and F15 blocks are located at the southern extent of the Dutch Central Graben and block Q16a is located close to the Dutch mainland near the Rotterdam gas terminal.

The Group in the Netherlands has interests in a number of offshore platforms, subsea developments, offshore wells and the related infrastructure. Broadly, offshore natural gas production is concentrated in a core area in the K, L and E blocks. Production from the K4a/K5b is treated at the K5-P platform and transported through the Wintershall-operated, Westgastransport ("**WGT**") pipeline system to Den Helder.

In the K6, L7 area treated gas from the K6-PP platform, on K6-C, is transported to Uithuizen via the K9C A platform and the Neptune Energy-operated L10 platform where it enters the Noordgastransport (“**NGT**”) pipeline system. Production from the L4a fields is currently brought to the L7-C Central complex from which point the processed gas is also exported to the L10 complex and routed along the NGT pipeline.

Gas production from the F15 and F3 fields is exported via the Northern Offshore Gas Transport (“**NOGAT**”) pipeline system, operated by Nederlandse Aardolie Maatschappij BV (“**NAM**”), to Den Helder. Gas production from the Q16-FA single well subsea development is tied back to a TAQA (the Abu Dhabi National Energy Company, PJSC)-operated platform and pipeline.

Netherlands Offshore Concession	Area (km^2)	Licence Type	IPC Interest	Operator	Expiry	Partners
E16a	29	Production	1.440%	Neptune Energy	Aug-21	Neptune Energy 41.64%, EBN 40%, Total 16.92%
E17a & E17b	114	Production	1.200%	Neptune Energy	Aug-21	Neptune Energy 34.7%, EBN 50%, Total 14.1%
F6a (oil)	8	Production	7.757%	Total	Sep-22	Total 92.243254%
F6a (gas)	8	Production	4.654%	Total	Sep-22	Total 55.346%, EBN 40%
F15a/d	238	Production	2.531%	Total	May-31	Total 32.468625%, Dyas 7.5%, EBN 50%, First Oil Exploration 7.5%(1)
K3b	7	Production	3.841%	Total	Jan-21	Total 56.158987%, EBN 40%
K3d	26	Production	3.841%	Total	Apr-24	Total 56.158987%, EBN 40%
K4b/K5a	305	Production	2.031%	Total	Jun-33	Total 36.3067%, Dyas 11.862%, EBN 50%
K6/L7	818	Production	3.841%	Total	Jun-20	Total 56.158987%, EBN 40%
L1e	12	Production	4.340%	Total	Jun-20	Total 55.6605%, EBN 40%
L1f	17	Production	6.000%	Total	Jan-33	Total 54%, EBN 40%
L4a	313	Production	4.340%	Total	Dec-21	Total 55.6605%, EBN 40%
Q16a	85	Production	1.814%	ONE	Dec-32	ONE 41.796, EBN 50%, Total 6.48649%

Note:

(1) As of December 2015, First Oil Exploration went into liquidation. This resulted in the remaining partners increasing their interests proportionally. The IPC Subsidiaries increased their receipt of production and payment of cost to 2.9781%.

Abandonment Obligations

The Group is obliged to pay its proportion of the abandonment cost of their assets, facilities, pipelines and site restoration and are making abandonment provisions. The respective operators periodically carry out studies regarding the methodology to be applied together with the associated cost and provide abandonment cost estimates to partners.

In the offshore fields to date, other than the occasional abandonment of existing wells to make well slots available for new wells, there have been no planned field abandonments. The first field that is forecast to be abandoned is the L7 area facilities, and the operator (Total) is currently working on the abandonment plans.

Infrastructure Upstream Gas Pipelines

Two major offshore pipeline systems (NGT and WGT) were built during the 1970s to serve the central Netherlands offshore gas province. The third major trunkline (NOGAT) was constructed in the early 1990s to evacuate gas from the northern offshore sector. The NGT pipeline is owned by Noordgastransport BV, a private limited liability company owned by PensionDenmark, Neptune Energy, InfraVia, ExxonMobil and Rosewood, and is operated by Neptune Energy. The WGT pipeline is owned by EBN, NAM (a 50-50 joint venture of Shell and Exxon/Mobil), ONE, Total, Tullow Exploration & Production BV and Wintershall Noordzee BV, and is operated by NAM. The NOGAT pipeline is owned by Northern Offshore Gas Transport BV, a private limited liability company owned by EBN, Neptune Energy, Total, Centrica Production Nederland BV and PGGM, and is operated by Neptune Energy.

Gas from the assets operated by Total is sent to the shore via WGT (Western licences, K4bK5a) and NGT (Eastern licences, K6L7, K5F, L4a) pipelines. Gas production from F3 (Neptune Energy-operated) and F15 (Total-operated) licenses transit via the NOGAT pipeline. Production from E17 (Neptune Energy-operated) is sent to shore via the NGT pipeline.

Domestic Gas Infrastructure and Interconnections

The Netherlands have a well-developed onshore gas network to serve household consumers, heavy industry and gas-fired power stations as well as servicing imports and exports of gas. The domestic gas pipeline infrastructure consists of high-pressure transmission gas pipelines to which regional distribution pipelines connect. The high-pressure network is owned by Gasunie and operated by the national gas transmission system operator Gasunie Transport Services BV, a wholly-owned subsidiary of Gasunie.

The regional networks are owned and operated by regional distribution system operators. Both the transmission system operator and distribution system operators are unbundled from production, trade and supply undertakings and manage the network subject to a fully regulated third party access regime, with conditions and tariffs set by the Netherlands Authority for Consumers & Markets, the designated national regulatory authority for the Dutch electricity and gas sector.

The Group's onshore assets use the domestic gas pipelines.

Gas Marketing

Historically, the natural gas pricing mechanism, referred to as NIP, was primarily linked to the price of oil; however, with the opening of the spot market for gas, the GasTerra pricing mechanism has from 2013 changed to a spot market-based pricing mechanism using the Title Transfer Facility (the "**TTF**") as a reference point. The TTF is a virtual trading point for gas sales in the Netherlands and is similar to the NBP (National Balancing Point) in the United Kingdom. The sellers can opt for different nomination regimes with each regime attracting a different pricing mechanism. These are: "as produced", "buyer's nomination" and "seller's nomination". The Total- and Neptune Energy-operated fields sell under "seller's nomination". The Vermilion NL- and ONE-operated fields sell under "as produced". The "as produced" regime is used for smaller, more depleted fields where it is more difficult to forecast daily quantities.

GasTerra is obliged to purchase all the gas from gas fields in the Netherlands at market prices and conditions; however, the producers are not obliged to sell to GasTerra.

IPC Netherlands BV sells all its gas, other than for the K4K5 and E17A field, to GasTerra. The K4K5 gas is sold to Total and the E17A field is sold to RWE Supply & Trading GmbH, both on a European gas spot basis. In all cases, IPC Netherlands BV markets its gas jointly with its respective operators and partners.

Development Plans

The Dutch government continues to encourage investment through its small gas field policy. As a result, several development and exploration projects are ongoing which are intended to increase production.

The operators of the Oil and Gas Assets in the Netherlands are currently working on reducing operating costs to extend field lives and to add volumes to the existing infrastructure through exploration and development activities with some success. The onshore business benefits from infrastructure owned by field joint venture partners that provides third party tariff income.

Discontinued Operations

The Corporation indirectly owns or have owned certain other Oil and Gas Assets, which are or were not material to the Corporation.

Indonesia

Lundin Gurita BV, a member of the Group, holds an interest in the Gurita Block PSC which has ceased operations. In 2013, the Indonesian fiscal authorities claimed taxes from Lundin Gurita BV of approximately USD 22 million related to the surface area of the Gurita Block. Lundin Gurita BV disputes the validity of this claim and has challenged the tax in the Indonesian courts. Lundin Petroleum has agreed to indemnify Lundin Gurita BV in respect of any potential liability with respect to this dispute. Following resolution of the tax matter, the Gurita Block will be relinquished or disposed of and Lundin Gurita BV will be liquidated.

Lundin Baronang BV and Lundin Cakalang BV, members of the Group, hold interests in the Baronang and Cakalang Block PSCs, which have ceased operations and for which notices of relinquishments have been made. Following relinquishment of the blocks, each of Lundin Baronang BV and Lundin Cakalang BV will be liquidated.

Tunisia

Lundin Tunisia BV, a member of the Group, is a party to the Oudna concession agreement and joint operating agreement related to the Oudna field, offshore Tunisia. Operations on the Oudna field ceased since 2012 and the field was abandoned with no remaining operational liabilities. Lundin Tunisia BV's interest in the Oudna agreements is expected to be terminated and the company will be liquidated following resolution of certain matters with the Tunisian authorities. In December 2015, the International Centre for Settlement of Investment Disputes in Paris ordered the Tunisian State to pay approximately USD 22 million to Lundin Tunisia BV in respect of defaulted cash calls and past costs related to the Oudna field. The Tunisian fiscal authorities have made claims against Lundin Tunisia BV in respect of Tunisian taxes related to the Oudna field, which currently amounts to USD 12 million plus penalties and interest. The Tunisian authorities have also claimed approximately USD 2 million from Ikdam Production SA, a member of the Group. Lundin Tunisia BV disputes these claims and will continue to discuss an amicable settlement to these matters and/or enforcement of the International Centre for Settlement of Investment Disputes decision.

Ikdam Production SA, previously held an interest in the FPSO Bertam (then known as the FPSO Ikdam), which was contracted to operate at the Oudna field. The Tunisian fiscal authorities have made a claim against Ikdam Production SA in respect of Tunisian taxes. It is expected that these claims will be discussed in connection with the above-described Tunisian disputes with respect to Lundin Tunisia BV. Following resolution of those matters, Ikdam Production SA will be liquidated.

Management of the Corporation does not expect the Corporation to be liable for taxes claimed against either Lundin Tunisia BV or Ikdam Production SA and no contingency has been accounted for in the audited financial statements.

Cambodia

IPC Ventures IV BV, a member of the Group, held an interest in Block E, offshore Cambodia. The Block E PSC has expired. There was an outstanding well commitment in respect of this block amounting to approximately USD 2.6 million, net to IPC Ventures IV BV, which is being discussed between the operator and the Cambodian authorities. Following final closure of the Block E PSC, IPC Ventures IV BV will be liquidated.

Other

Lundin Marine SARL and Lundin Marine BV held interests in two blocks in the Republic of Congo, which have been sold and relinquished, with no further operational liabilities. Lundin Marine SARL was liquidated in 2017. Jet Arrow SA held an interest in an airplane which was sold in 2016. Jet Arrow SA was liquidated in 2017.

Health, Safety and Environmental

IPC conducts its business responsibly, exploring for and producing oil and gas in an economically, socially and environmentally responsible way. IPC respects human rights and protects the health and safety of employees and the natural environment. The Corporation promotes a strong safety culture across the Group in which the value of safety is embedded at all levels, guided by prevention and vigilance, and where risks are systematically assessed. IPC's environmental approach is based on understanding the operating environment in order to assess potential risks and take appropriate preventive measures.

The Group complies with laws and regulations, and seeks best industry practice to maintain operational efficiency through continuous improvement.

IPC's Code of Ethics and Business Conduct guides its directors, officers and employees in maintaining the commitments. Implementation is ensured through specifically tailored Policies, Procedures and Management Systems that apply to all activities of the Group.

IPC's Code of Ethics and Business conduct may be accessed on the SEDAR website at www.sedar.com under the Corporation's profile or on IPC's website at www.international-petroleum.com.

RESERVES AND OTHER OIL AND GAS INFORMATION RELATING TO THE OIL AND GAS ASSETS

Date of Statement

The Statement of Reserves Data and Other Oil and Gas Information is prepared as at March 30, 2018.

Reserve estimates, contingent resource estimates, prospective resource estimates and estimates of future net revenue in respect of IPC's Initial 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 ERCE in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's January 1, 2018 price forecasts. The report by ERCE is dated February 21, 2018 (the "**ERCE Report**").

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, and were evaluated by McDaniel in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's January 1, 2018 price forecasts. The report by McDaniel is dated February 22, 2018 (the "**McDaniel Report**").

The information on reserves, contingent resources, prospective resources and estimates of future net revenue is presented below as follows:

a) The Corporation's Initial Oil and Gas Assets in France, Malaysia and the Netherlands (summarized from the ERCE Report);

b) The Corporation's Oil and Gas Assets in Canada (summarized from the McDaniel Report); and

c) Aggregation of the Corporation's Oil and Gas Assets in Canada, France, Malaysia and the Netherlands.

IPC has generated aggregated tables which are the arithmetic sum of the two sets of results to arrive at combined IPC reserve and resource estimates with a reference date of December 31, 2017, even though the Acquisition of the Suffield area assets in Canada did not complete until January 5, 2018.

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 the effects of aggregation.

See also "Reserves and Resource Advisory".

IPC's Oil and Gas Assets in France, Malaysia and the Netherlands

Oil and Gas Reserves – Based on Forecast Prices and Costs

Proved Reserves (International)

		France	Netherlands	Malaysia	Sub Total IPC International
Proved Developed Producing (PDP) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	6.40	0.02	3.24	9.66
	net	5.61	0.02	2.79	8.42
Heavy Crude Oil (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Conventional Natural Gas (Bscf)	gross	-	5.21	-	5.21
	net	-	5.21	-	5.21
Natural Gas Liquids (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Total Oil Equivalent (MMboe)	gross	6.40	0.89	3.24	10.53
	net	5.61	0.89	2.79	9.28
Proved Developed Non Producing (PDNP) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	0.19	0.00	-	0.19
	net	0.16	0.00	-	0.16
Heavy Crude Oil (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Conventional Natural Gas (Bscf)	gross	-	0.57	-	0.57
	net	-	0.57	-	0.57
Natural Gas Liquids (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Total Oil Equivalent (MMboe)	gross	0.19	0.10	-	0.29
	net	0.16	0.10	-	0.26
Proved Undeveloped (PUD) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	2.23	0.00	0.66	2.90
	net	1.91	0.00	0.57	2.48
Heavy Crude Oil (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Conventional Natural Gas (Bscf)	gross	-	0.05	-	0.05
	net	-	0.05	-	0.05
Natural Gas Liquids (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Total Oil Equivalent (MMboe)	gross	2.23	0.01	0.66	2.90
	net	1.91	0.01	0.57	2.49
Total Proved (1P) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	8.82	0.02	3.91	12.75
	net	7.68	0.02	3.36	11.06
Heavy Crude Oil (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Conventional Natural Gas (Bscf)	gross	-	5.83	-	5.83
	net	-	5.83	-	5.83
Natural Gas Liquids (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Total Oil Equivalent (MMboe)	gross	8.82	0.99	3.91	13.72
	net	7.68	0.99	3.36	12.03

Proved plus Probable Reserves (International)

		France	Netherlands	Malaysia	Sub Total IPC International
Proved plus Probable Developed Producing (2PDP) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	13.15	0.03	7.65	20.83
	net	11.60	0.03	6.55	18.19
Heavy Crude Oil (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Conventional Natural Gas (Bscf)	gross	-	9.55	-	9.55
	net	-	9.55	-	9.55
Natural Gas Liquids (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Total Oil Equivalent (MMboe)	gross	13.15	1.62	7.65	22.42
	net	11.60	1.62	6.55	19.78
Proved plus Probable Developed Non Producing (2PDNP) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	0.52	0.00	-	0.52
	net	0.44	0.00	-	0.45
Heavy Crude Oil (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Conventional Natural Gas (Bscf)	gross	-	1.21	-	1.21
	net	-	1.21	-	1.21
Natural Gas Liquids (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Total Oil Equivalent (MMboe)	gross	0.52	0.20	-	0.72
	net	0.44	0.20	-	0.65
Proved plus Probable Undeveloped (2PUD) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	3.94	0.00	1.41	5.35
	net	3.38	0.00	1.22	4.60
Heavy Crude Oil (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Conventional Natural Gas (Bscf)	gross	-	0.06	-	0.06
	net	-	0.06	-	0.06
Natural Gas Liquids (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Total Oil Equivalent (MMboe)	gross	3.94	0.01	1.41	5.36
	net	3.38	0.01	1.22	4.61
Total Probable (PB) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	8.79	0.02	5.15	13.96
	net	7.75	0.02	4.41	12.17
Heavy Crude Oil (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Conventional Natural Gas (Bscf)	gross	-	4.99	-	4.99
	net	-	4.99	-	4.99
Natural Gas Liquids (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Total Oil Equivalent (MMboe)	gross	8.79	0.85	5.15	14.79
	net	7.75	0.85	4.41	13.01
Total Proved plus Probable (2P) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	17.61	0.04	9.06	26.70
	net	15.43	0.04	7.77	23.24
Heavy Crude Oil (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Conventional Natural Gas (Bscf)	gross	-	10.82	-	10.82
	net	-	10.82	-	10.82
Natural Gas Liquids (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Total Oil Equivalent (MMboe)	gross	17.61	1.84	9.06	28.51
	net	15.43	1.84	7.77	25.04

Proved plus Probable plus Possible Reserves (International)

		France	Netherlands	Malaysia	**Sub Total IPC International**
Proved plus Probable plus Possible Developed Producing (3PDP) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	20.56	0.05	9.78	**30.39**
	net	18.19	0.05	8.38	**26.62**
Heavy Crude Oil (MMbbl)	gross				**-**
	net				**-**
Conventional Natural Gas (Bscf)	gross		15.87		**15.87**
	net		15.87		**15.87**
Natural Gas Liquids (MMbbl)	gross				**-**
	net				**-**
Total Oil Equivalent (MMboe)	gross	20.56	2.70	9.78	**33.04**
	net	18.19	2.70	8.38	**29.26**
Proved plus Probable plus Possible Developed Non Producing (3PDNP) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	0.59	0.00	-	**0.60**
	net	0.51	0.00	-	**0.52**
Heavy Crude Oil (MMbbl)	gross	-	-	-	**-**
	net	-	-	-	**-**
Conventional Natural Gas (Bscf)	gross	-	1.88	-	**1.88**
	net	-	1.88	-	**1.88**
Natural Gas Liquids (MMbbl)	gross	-	-	-	**-**
	net	-	-	-	**-**
Total Oil Equivalent (MMboe)	gross	0.59	0.32	-	**0.91**
	net	0.51	0.32	-	**0.83**
Proved plus Probable plus Possible Undeveloped (3PUD) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	4.74	0.00	1.99	**6.73**
	net	4.05	0.00	1.67	**5.72**
Heavy Crude Oil (MMbbl)	gross	-	-	-	**-**
	net	-	-	-	**-**
Conventional Natural Gas (Bscf)	gross	-	0.12	-	**0.12**
	net	-	0.12	-	**0.12**
Natural Gas Liquids (MMbbl)	gross	-	-	-	**-**
	net	-	-	-	**-**
Total Oil Equivalent (MMboe)	gross	4.74	0.02	1.99	**6.75**
	net	4.05	0.02	1.67	**5.74**
Total Possible (PS) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	8.29	0.02	2.71	**11.02**
	net	7.32	0.02	2.28	**9.62**
Heavy Crude Oil (MMbbl)	gross	-	-	-	**-**
	net	-	-	-	**-**
Conventional Natural Gas (Bscf)	gross	-	7.05	-	**7.05**
	net	-	7.05	-	**7.05**
Natural Gas Liquids (MMbbl)	gross	-	-	-	**-**
	net	-	-	-	**-**
Total Oil Equivalent (MMboe)	gross	8.29	1.20	2.71	**12.20**
	net	7.32	1.20	2.28	**10.79**
Total Proved plus Probable plus Possible (3P) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	25.89	0.06	11.77	**37.72**
	net	22.75	0.06	10.04	**32.85**
Heavy Crude Oil (MMbbl)	gross	-	-	-	**-**
	net	-	-	-	**-**
Conventional Natural Gas (Bscf)	gross	-	17.87	-	**17.87**
	net	-	17.87	-	**17.87**
Natural Gas Liquids (MMbbl)	gross	-	-	-	**-**
	net	-	-	-	**-**
Total Oil Equivalent (MMboe)	gross	25.89	3.04	11.77	**40.70**
	net	22.75	3.04	10.04	**35.83**

Net Present Value of Future Net Revenue – Proved Reserves (International)

	Before Deducting Income Tax, Discounted at:						After Deducting Income Tax, Discounted at:						USD / net BOE
Values in MUSD	0%	5%	8%	10%	15%	20%	0%	5%	8%	10%	15%	20%	BTAX NPV10
Proved Developed Producing (PDP) Reserves													
France	93.2	91.7	86.6	82.7	72.8	63.9	60.2	68.5	67.4	65.6	59.7	53.7	14.74
Netherlands	-23.7	-10.2	-5.3	-2.8	1.3	3.7	-23.7	-10.2	-5.3	-2.8	1.3	3.7	-3.21
Malaysia	120.7	114.9	111.7	109.7	105.1	100.9	120.7	114.9	111.7	109.7	105.1	100.9	39.33
Subtotal IPC International	**190.1**	**196.4**	**193.0**	**189.5**	**179.1**	**168.5**	**157.2**	**173.3**	**173.8**	**172.5**	**166.1**	**158.3**	**20.42**
Proved Developed Non Producing (PDNP) Reserves													
France	1.7	0.9	0.6	0.4	0.1	-0.1	1.3	0.7	0.4	0.3	0.0	-0.1	2.67
Netherlands	0.7	1.6	1.8	1.9	1.9	1.8	0.7	1.6	1.8	1.9	1.9	1.8	19.22
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal IPC International	**2.4**	**2.5**	**2.4**	**2.3**	**2.0**	**1.7**	**2.0**	**2.3**	**2.2**	**2.2**	**1.9**	**1.6**	**8.84**
Proved Undeveloped (PUD) Reserves													
France	66.1	33.8	22.2	16.5	6.7	1.0	48.8	24.6	15.8	11.4	3.8	-0.7	8.61
Netherlands	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	30.09
Malaysia	32.3	30.3	29.2	28.6	27.0	25.6	32.3	30.3	29.2	28.6	27.0	25.6	50.18
Subtotal IPC International	**98.6**	**64.3**	**51.7**	**45.3**	**33.9**	**26.8**	**81.3**	**55.2**	**45.3**	**40.2**	**31.0**	**25.1**	**18.18**
Total Proved (1P) Reserves													
France	161.0	126.4	109.4	99.6	79.6	64.8	110.3	93.8	83.6	77.3	63.5	52.8	12.96
Netherlands	-22.8	-8.3	-3.2	-0.7	3.4	5.7	-22.8	-8.3	-3.2	-0.7	3.4	5.7	-0.75
Malaysia	153.0	145.2	140.9	138.3	132.1	126.5	153.0	145.2	140.9	138.3	132.1	126.5	41.16
Subtotal IPC International	**291.2**	**263.3**	**247.1**	**237.1**	**215.1**	**197.0**	**240.5**	**230.7**	**221.3**	**214.8**	**199.0**	**185.0**	**19.70**

Net Present Value of Future Net Revenue – Proved plus Probable Reserves (International)

	Before Deducting Income Tax, Discounted at:						After Deducting Income Tax, Discounted at:						USD / net BOE
Values in MUSD	0%	5%	8%	10%	15%	20%	0%	5%	8%	10%	15%	20%	BTAX NPV10
Proved plus Probable Developed Producing (2PDP) Reserves													
France	333.3	235.6	194.9	173.7	135.4	110.4	230.9	177.8	150.4	135.5	107.7	89.1	14.97
Netherlands	-6.1	8.6	12.6	14.3	16.5	17.0	-7.5	7.3	11.4	12.4	15.3	15.9	8.81
Malaysia	305.9	274.1	258.0	248.3	227.1	209.4	305.9	274.1	258.0	248.3	227.1	209.4	37.90
Subtotal IPC International	**633.1**	**518.3**	**465.5**	**436.4**	**379.0**	**336.9**	**529.4**	**459.1**	**419.7**	**396.2**	**350.1**	**314.5**	**22.06**
Proved plus Probable Developed Non Producing (2PDNP) Reserves													
France	4.0	4.1	3.1	2.5	1.5	0.9	2.4	3.2	2.5	2.0	1.1	0.6	5.74
Netherlands	3.3	4.2	4.2	4.0	3.5	3.0	2.5	3.5	3.5	3.4	2.9	2.5	19.62
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal IPC International	**7.2**	**8.3**	**7.3**	**6.6**	**5.0**	**3.9**	**4.9**	**6.8**	**6.0**	**5.4**	**4.0**	**3.1**	**10.13**
Proved plus Probable Undeveloped (2PUD) Reserves													
France	137.4	82.6	62.1	51.7	33.2	21.3	101.0	60.2	44.6	36.7	22.5	13.3	15.29
Netherlands	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.8	0.1	0.1	19.70
Malaysia	85.5	76.9	72.6	70.0	64.3	59.5	85.5	76.9	72.6	70.0	64.3	59.5	57.58
Subtotal IPC International	**223.2**	**159.7**	**134.9**	**121.9**	**97.7**	**81.0**	**186.6**	**137.3**	**117.3**	**107.4**	**86.8**	**72.9**	**26.45**
Total Probable (PB) Reserves													
France	313.7	195.9	150.8	128.5	90.5	67.8	224.0	147.3	113.8	96.9	67.7	50.3	16.58
Netherlands	20.2	21.4	20.2	19.3	16.8	14.5	18.0	19.3	18.2	17.3	14.9	12.8	22.72
Malaysia	238.5	205.8	189.7	180.0	159.3	142.4	238.5	205.8	189.7	180.0	159.3	142.4	40.84
Subtotal IPC International	**572.4**	**423.1**	**360.7**	**327.8**	**266.6**	**224.7**	**480.4**	**372.4**	**321.7**	**294.2**	**241.9**	**205.4**	**25.20**
Total Proved plus Probable (2P) Reserves													
France	474.7	322.3	260.1	228.0	170.1	132.6	334.3	241.2	197.4	174.1	131.3	103.1	14.78
Netherlands	-2.6	13.0	17.0	18.5	20.2	20.2	-4.8	11.0	15.0	16.6	18.3	18.5	10.08
Malaysia	391.4	351.0	330.6	318.3	291.4	268.9	391.4	351.0	330.6	318.3	291.4	268.9	40.98
Subtotal IPC International	**863.5**	**686.4**	**607.8**	**564.9**	**481.6**	**421.7**	**720.9**	**603.1**	**543.0**	**509.0**	**441.0**	**390.5**	**22.56**

Net Present Value of Future Net Revenue – Proved plus Probable plus Possible Reserves (International)

	Before Deducting Income Tax, Discounted at:						After Deducting Income Tax, Discounted at:						USD / net BOE
Values in MUSD	0%	5%	8%	10%	15%	20%	0%	5%	8%	10%	15%	20%	BTAX NPV10
Proved plus Probable plus Possible Developed Producing (3PDP) Reserves													
France	818.8	432.2	323.8	275.5	199.5	156.4	584.6	324.1	246.3	211.1	155.1	123.1	15.15
Netherlands	32.0	35.0	34.7	34.0	31.8	29.3	22.3	27.4	27.9	27.8	26.2	24.4	12.61
Malaysia	440.3	386.1	359.4	343.5	309.4	281.6	440.3	386.1	359.4	343.5	309.4	281.6	41.01
Subtotal IPC International	**1'291.1**	**853.3**	**717.9**	**653.1**	**540.7**	**467.3**	**1'047.3**	**737.6**	**633.6**	**582.5**	**490.8**	**429.1**	**22.32**
Proved plus Probable plus Possible Developed Non Producing (3PDNP) Reserves													
France	16.7	7.1	4.8	3.9	2.4	1.6	12.4	5.3	3.5	2.8	1.7	1.1	7.51
Netherlands	8.1	7.3	6.4	5.9	4.6	3.7	6.8	6.1	5.3	4.8	3.7	2.9	18.55
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal IPC International	**24.8**	**14.5**	**11.3**	**9.7**	**7.0**	**5.3**	**19.1**	**11.3**	**8.8**	**7.6**	**5.4**	**4.0**	**11.72**
Proved plus Probable plus Possible Undeveloped (3PUD) Reserves													
France	191.7	115.2	87.3	73.3	48.8	33.4	140.7	83.4	62.3	51.7	33.1	21.4	18.09
Netherlands	0.7	0.7	0.6	0.6	0.6	0.6	0.5	0.4	0.4	0.3	0.4	0.4	30.40
Malaysia	117.8	104.9	98.4	94.6	86.2	79.3	96.6	87.3	82.6	79.8	73.7	68.5	56.79
Subtotal IPC International	**310.1**	**220.8**	**186.4**	**168.6**	**135.6**	**113.3**	**237.7**	**171.1**	**145.4**	**131.8**	**107.1**	**90.3**	**29.37**
Total Possible (PS) Reserves													
France	552.5	232.2	155.8	124.7	80.6	58.8	403.4	171.5	114.7	91.5	58.6	42.5	17.03
Netherlands	43.4	30.0	24.8	22.0	16.9	13.4	34.4	23.0	18.6	16.3	12.0	9.2	18.37
Malaysia	166.6	140.0	127.2	119.8	104.2	92.0	145.4	122.4	111.5	105.1	91.7	81.2	52.67
Subtotal IPC International	**762.5**	**402.2**	**307.8**	**266.5**	**201.7**	**164.2**	**583.2**	**316.9**	**244.8**	**212.9**	**162.3**	**132.9**	**24.69**
Total Proved plus Probable plus Possible (3P) Reserves													
France	1'027.1	554.5	415.9	352.7	250.7	191.4	737.7	412.7	312.2	265.7	189.9	145.6	15.50
Netherlands	40.8	43.0	41.8	40.6	37.0	33.6	29.6	33.9	33.6	32.9	30.3	27.6	13.35
Malaysia	558.0	491.0	457.8	438.1	395.6	360.9	536.8	473.4	442.1	423.4	383.1	350.1	43.63
Subtotal IPC International	**1'626.0**	**1'088.5**	**915.5**	**831.4**	**683.4**	**585.9**	**1'304.1**	**920.1**	**787.8**	**721.9**	**603.3**	**523.3**	**23.20**

Elements of Future Net Revenue (International)

Total Proved (1P) Reserves MUSD	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
France	693.8	86.1	335.3	32.4	78.9	161.0	50.7	110.3
Netherlands	48.5	-	27.9	0.9	42.4	- 22.8	-	- 22.8
Malaysia	449.5	26.9	236.2	8.9	24.5	153.0	-	153.0
Subtotal IPC International	**1'191.8**	**113.1**	**599.5**	**42.2**	**145.8**	**291.2**	**50.7**	**240.5**

Total Proved and Probable (2P) Reserves MUSD	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
France	1'560.1	181.6	743.1	51.4	109.4	474.7	140.4	334.3
Netherlands	88.9	-	44.7	0.9	45.8	- 2.6	2.2	- 4.8
Malaysia	875.8	66.2	381.3	8.9	27.9	391.4	-	391.4
Subtotal IPC International	**2'524.8**	**247.8**	**1'169.1**	**61.2**	**183.1**	**863.5**	**142.6**	**720.9**

Total Proved and Probable and Possible (3P) Reserves MUSD	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
France	2'428.8	275.2	943.0	57.1	126.4	1'027.1	289.4	737.7
Netherlands	147.4	-	65.4	0.9	40.2	40.8	11.3	29.6
Malaysia	1'084.2	86.5	402.8	8.9	27.9	558.0	21.2	536.8
Subtotal IPC International	**3'660.4**	**361.7**	**1'411.3**	**66.9**	**194.5**	**1'626.0**	**321.9**	**1'304.1**

Net Present Value by Product Type (International)

IPC International Future Net Revenue BTAX at 10% Discount	Primary Product Type Light & Medium Crude Oil (MUSD)	Heavy Crude Oil (MUSD)	Conventional Natural Gas (MUSD)	Natural Gas Liquids (MUSD)	Total (MUSD)
Total Proved (1P) Reserves	237.8	-	- 0.7	-	237.1
Total Proved and Probable (2P) Reserves	546.3	-	18.5	-	564.9
Total Proved and Probable and Possible (3P) Reserves	790.8	-	40.6	-	831.4

IPC International USD per boe by product type	Primary Product Type Light & Medium Crude Oil (USD/bbl)	Heavy Crude Oil (USD/bbl)	Conventional Natural Gas (USD/Mscf)	Natural Gas Liquids (USD/bbl)	Total (USD/net boe)
Total Proved (1P) Reserves	21.54	-	- 0.12	-	19.70
Total Proved and Probable (2P) Reserves	23.55	-	1.68	-	22.56
Total Proved and Probable and Possible (3P) Reserves	24.11	-	2.22	-	23.20

Notes:

(1) Light Medium and Heavy Oil Future Net Revenue and Unit Value include associated gas

(2) Conventional natural Gas revenue and unit Value include associated condensate (light oil)

Forecast Prices used in Estimates (International)

	Reference Prices					
	Brent	WTI	WCS	NBP	AECO	Empress
	Light & Medium Oil	Light & Medium Oil	Light & Medium Oil	Conventional Natural Gas	Conventional Natural Gas	Conventional Natural Gas
Year	*USD/bbl*	*USD/bbl*	*CAD/bbl*	*USD/mmbtu*	*CAD/mmbtu*	*CAD/mmbtu*
2017	*54.35*	*50.87*	*49.70*	*n/a*	2.40	
2018	63.50	58.50	51.90	6.25	2.25	2.70
2019	61.30	58.70	57.00	6.37	2.65	2.95
2020	63.40	62.40	61.40	6.63	3.05	3.21
2021	70.10	69.00	66.00	7.00	3.40	3.56
2022	74.20	73.10	67.90	7.32	3.60	3.76
2023	75.60	74.50	69.20	7.44	3.65	3.82
2024	77.10	76.00	70.60	7.61	3.75	3.92
2025	78.60	77.50	72.00	7.73	3.80	3.97
2026	80.30	79.10	73.50	7.91	3.90	4.08
2027	81.90	80.70	74.90	8.03	3.95	4.13
2028	83.50	82.30	76.40	8.21	4.05	4.23
2029	85.10	83.90	77.90	8.39	4.15	4.34
2030	86.90	85.60	79.50	8.57	4.25	4.44
2031	88.60	87.30	81.10	8.70	4.30	4.49
2032	90.40	89.10	82.70	8.89	4.35	4.55
2033+	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%

	Field Prices						
	Canada		France		Netherlands		Malaysia
		Conventional Natural Gas	Light & Medium Oil	Light & Medium Oil	Light & Medium Oil	Conventional Natural Gas	Light & Medium Oil
Year	*USD/bbl (2)*	*USD/mcf (2)*	*USD/bbl (4)*	*USD/bbl (4)*	*USD/bbl*	*USD/mcf*	*USD/bbl (4)*
2017	*n/a*	*n/a*	*50.98*	*53.44*	*43.57*	*5.62*	*57.30*
2018	34.09	1.98	63.25	62.07	63.50	6.09	66.50
2019	38.05	2.18	61.05	59.87	61.30	6.23	64.30
2020	41.91	2.40	63.15	61.97	63.40	6.51	66.40
2021	46.87	2.77	69.85	68.67	70.10	6.89	73.10
2022	49.75	3.02	73.95	72.77	74.20	7.22	77.20
2023	50.70	3.06	75.35	74.17	75.60	7.35	78.60
2024	51.73	3.14	76.85	75.67	77.10	7.51	80.10
2025	52.75	3.19	78.35	77.17	78.60	7.64	81.60
2026	53.85	3.27	80.05	78.87	80.30	7.73	83.30
2027	54.87	3.31	81.65	80.47	81.90	7.84	84.90
2028	55.97	3.40	83.25	82.07	83.50	8.46	86.50
2029	57.07	3.48	84.85	83.67	85.10	8.66	88.10
2030	58.24	3.57	86.65	85.47	86.90	8.86	89.90
2031	59.42	3.61	88.35	87.17	88.60	9.01	91.60
2032	60.59	3.65	90.15	88.97	90.40	9.21	93.40
2033+	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%

(1) Brent, WTI, WCS, and NBP reference prices are taken from McDaniel and Associates January 1, 2018. Price forecast inflated 2%/yr from 2033 onwards
(2) Field reference prices are calculated by McDaniel and Associates and are net of transportation and crude quality adjustments
(3) Netherlands gas prices are based upon the McDaniel NBP gas price forecast and on a field by field basis are calorific value dependent.
(4) The France and Malaysia price forecasts are derived by applying differentials to the reference McDaniel

Exchange rate Assumptions

Rate	2018	2019	2020	2021	2022 on
EUR/USD	0.87	0.87	0.87	0.87	0.87
GBP/USD	0.77	0.77	0.77	0.77	0.77
MYR/USD	4.25	4.25	4.25	4.25	4.25
CAD/USD	1.27	1.27	1.25	1.21	1.18

Reconciliation of Changes in Reserves (International)

Reconciliation of Proved Reserves Mmboe	Malaysia Light & Medium Oil	France Light & Medium Oil	Netherlands Conventional Natural Gas	**Total** **Oil Equivalent**
Opening Balance December 31, 2016	4.9	11.3	0.9	**17.0**
extensions and improved recovery	+ 0.7	+ 0.0	+ 0.0	**+ 0.7**
technical revisions	+ 0.8	- 0.5	+ 0.5	**+ 0.8**
discoveries				**+ 0.0**
acquisitions				**+ 0.0**
dispositions				**+ 0.0**
economic factors	+ 0.0	- 1.1	+ 0.0	**- 1.1**
production	- 2.4	- 0.9	- 0.4	**- 3.7**
Closing Balance December 31, 2017	3.9	8.8	1.0	**13.7**

Reconciliation of Proved + Probable Reserves Mmboe	Malaysia Light & Medium Oil	France Light & Medium Oil	Netherlands Conventional Natural Gas	**Total** **Oil Equivalent**
Opening Balance December 31, 2016	9.5	18.0	1.8	**29.4**
extensions and improved recovery	+ 1.4	+ 0.5	+ 0.0	**+ 1.9**
technical revisions	+ 0.8	+ 0.3	+ 0.4	**+ 1.6**
discoveries				**+ 0.0**
acquisitions				**+ 0.0**
dispositions				**+ 0.0**
economic factors	- 0.3	- 0.3	+ 0.0	**- 0.6**
production	- 2.4	- 0.9	- 0.4	**- 3.7**
Closing Balance December 31, 2017	9.1	17.6	1.8	**28.5**

Reconciliation of Proved + Probable + Possible Reserves Mmboe	Malaysia Light & Medium Oil	France Light & Medium Oil	Netherlands Conventional Natural Gas	**Total** **Oil Equivalent**
Opening Balance December 31, 2016	13.3	23.8	3.2	**40.3**
extensions and improved recovery	+ 2.0	+ 0.7	+ 0.0	**+ 2.7**
technical revisions	- 1.1	+ 2.3	+ 0.3	**+ 1.5**
discoveries				**+ 0.0**
acquisitions				**+ 0.0**
dispositions				**+ 0.0**
economic factors	+ 0.0	- 0.0	+ 0.0	**- 0.0**
production	- 2.4	- 0.9	- 0.4	**- 3.7**
Closing Balance December 31, 2017	11.8	25.9	3.0	**40.7**

Undeveloped Reserves (International)

Undeveloped Reserves - International Assets
Volumes first attributed by year
Company Gross Basis

	Light & Medium Crude Oil (MMbbl)	Heavy Crude Oil (MMbbl)	Conventional Natural Gas (Bscf)	Natural Gas Liquids (MMboe)	Oil Equivalent (MMboe)
Proved Undeveloped					
December 31, 2015	-	-	-	-	-
December 31, 2016	3.1	-	-	-	3.1
December 31, 2017	0.7	-	-	-	0.7
Probable Undeveloped					
December 31, 2015	-	-	-	-	-
December 31, 2016	3.3	-	-	-	3.3
December 31, 2017	1.4	-	-	-	1.4

France / Malaysia Development Projects

	Light & Medium Crude Oil Reserves	Heavy Crude Oil Reserves	Convent-ional Natural Gas Resrves	Future Project Development Capital (MUSD)				Net Present Value, MUSD Before Deducting Income Tax, Discounted at:						Net Present Value, MUSD After Deducting Income Tax, Discounted at:						BTAX NPV10 per boe	ATAX NPV10 per boe
France - Vert La Gravelle Redevelopment	MMbbl gross	MMbbl gross	Bscf Gross	2018	2019	Total	USD per boe	0%	5%	8%	10%	15%	20%	0%	5%	8%	10%	15%	20%	USD per boe	USD per boe
Proved Undeveloped (PUD)	2.2	-	-	0.9	24.8	25.8	11.5	66	34	22	16	7	1	49	25	16	11	4	1	7.37	5.10
Proved and Probable Undeveloped (PPUD)	3.9	-	-	0.9	39.1	44.3	11.2	137	83	62	52	33	21	101	60	45	37	22	13	13.13	9.30
Proved plus Probable plus Possible Undeveloped (PPPUD)	4.7	-	-	0.9	39.1	49.8	10.5	192	115	87	73	49	33	141	83	62	52	33	21	15.47	10.90
Malaysia - A16 and A17 Development Wells																					
Proved Undeveloped (PUD)	0.7	-	-	7.7	-	7.7	11.7	32	30	29	29	27	26	32	30	29	29	27	26	43.15	43.15
Proved and Probable Undeveloped (PPUD)	1.4	-	-	7.7	-	7.7	5.5	85	77	73	70	64	59	85	77	73	70	64	59	49.52	49.52
Proved plus Probable plus Possible Undeveloped (PPPUD)	2.0	-	-	7.7	-	7.7	3.9	118	105	98	95	86	79	97	87	83	80	74	68	47.50	40.10
Subtotal France / Malaysia																					
Proved Undeveloped (PUD)	**2.9**	**-**	**-**	**8.7**	**24.8**	**33.5**	**11.6**	**98**	**64**	**51**	**45**	**34**	**27**	**81**	**55**	**45**	**40**	**31**	**25**	**15.55**	**13.80**
Proved and Probable Undeveloped (PPUD)	**5.4**	**-**	**-**	**8.7**	**39.1**	**52.0**	**9.7**	**223**	**159**	**135**	**122**	**97**	**81**	**186**	**137**	**117**	**107**	**87**	**73**	**22.73**	**19.92**
Proved plus Probable plus Possible Undeveloped (PPPUD)	**6.7**	**-**	**-**	**8.7**	**39.1**	**57.5**	**8.5**	**309**	**220**	**186**	**168**	**135**	**113**	**237**	**171**	**145**	**132**	**107**	**90**	**24.94**	**19.54**

IPC has proven, probable, and possible undeveloped reserves attributed to two projects: the drilling of the A16 and A17 development wells in Malaysia and the redevelopment of the Vert La Gravelle field in France.

Undeveloped Reserves are attributed in accordance with engineering and geological practices as defined under NI 51-101.

Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. These reserves have a 90% probability of being recovered.

Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. These reserves have a 50% probability of being recovered.

Possible undeveloped reserves are those reserves that are less certain to be recovered than probable reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. These reserves have a 10% probability of being recovered.

See also “Reserves and Resource Advisory”.

The pace of development of proven undeveloped reserves will be influenced by many factors, including but not limited to, the outcomes of yearly drilling and reservoir evaluations, changes in commodity pricing, changes in capital allocations, changing technical conditions, regulatory changes and impact of future acquisitions and dispositions.

In general, development of probable undeveloped reserves requires additional evaluation data to increase the probability of success to an acceptable level for the Corporation. This increases the timeline for the development of these reserves. This timetable may be altered depending on outside market forces, changes in capital allocations and impact of future acquisitions and dispositions.

Malaysia

A two well infill campaign was sanctioned in 2017 and began during the fourth quarter of 2017. The project was well progressed at December 31, 2017 but not to the extent that the reserves attributed to the project could be classed as developed. The project has been completed and the infill wells were brought on stream in mid-January (A16) and mid-February (A17).

Additional development and exploration potential has been identified in the field which is discussed further in the Contingent and Prospective Resources sections.

France

IPC has plans for a five-well drilling campaign in the 100%-operated Vert La Gravelle field in the Paris Basin. This is a continuation of a programme that was halted in 2015 as a result of the changing economic climate. The facility and flow line work is complete and the remaining project scope covers drilling and completing the new production and injection wells. This project is considered in the undeveloped reserves base and is projected to start execution in 2019.

Infrastructure investments in the short term will include a maintenance program in the central part of the Villeperdue field and a provision for future pipeline work in the Les Arbousiers field in the Aquitaine Basin.

Significant Factors or Uncertainties Affecting Reserves Data (International)

In Malaysia, the main uncertainties relate to reservoir performance in particular rate of water-cut build for the recent wells A15, A16, and A17. This uncertainty has been captured in the 1P to 3P range of estimates. Other uncertainties include, but are not limited to, facility uptime performance, electric submersible pump performance and run life, and operating cost performance. There are no material abandonment and reclamation costs other than what has been considered in the reserves assessment, high expected development or operating costs, or contractual obligations that would impair the Group’s realized prices.

In France, the main uncertainties relate to reservoir performance in the Triassic formation pools that are early in their water-flood life. This uncertainty has been captured in the 1P to 3P range of estimates. The performance of the future development at Vert La Gravelle is also an uncertainty considered in the estimates. There are no material abandonment and reclamation costs other than what has been considered in the reserves assessment, high expected development or operating costs, or contractual obligations that would impair the Group’s realized prices.In addition, the French government enacted legislation in 2017 to restrict production of oil and gas under existing production licenses in France from 2040. The reported proved reserves assume a cessation of production as at 2040, although given the uncertainties regarding the application of this new legislation, the reported probable and possible reserves do not assume cessation at such date.

In the Netherlands, the main uncertainties in the reserves data relate to reservoir and operating cost performance. There are five licenses in the Netherlands with no reserves attributed but with abandonment liability. The following table contains management estimates of the value of the liability. There are no other material abandonment and reclamation costs other than what has been considered in the reserves assessment, high expected development or operating costs, or contractual obligations that would impair the Group’s realized prices.

Abandonment Liability Estimates	After Deducting Income Tax, Discounted at:					
	0% (MUSD)	5% (MUSD)	8% (MUSD)	10% (MUSD)	15% (MUSD)	20% (MUSD)
Onshore						
Oosterend	0.5	0.5	0.5	0.5	0.4	0.4
Offshore						
F15a	1.2	0.9	0.8	0.7	0.6	0.5
F15b	0.8	0.6	0.6	0.5	0.4	0.3
F3UG	0.0	0.0	0.0	0.0	0.0	0.0
L7	12.3	9.7	8.4	7.6	6.1	4.9
Subtotal Offshore	**14.3**	**11.2**	**9.7**	**8.9**	**7.1**	**5.7**
Netherlands Total	**14.8**	**11.7**	**10.2**	**9.3**	**7.5**	**6.1**

See also “Reserves and Resource Advisory”.

Future Development Costs (International)

	2018	2019	2020	2021	2022	2023 on	Total for all years undiscounted	**Total for all years discounted at 10% p.a.**
Total Proved								
France	5.1	26.2	1.1	-	-	-	32.4	**28.4**
Netherlands	0.9	-	-	-	-	-	0.9	**0.9**
Malaysia	8.9	-	-	-	-	-	8.9	**8.8**
Total	15.0	26.2	1.1	-	-	-	42.2	**38.0**
Total Proved Plus Probable								
France	5.3	40.7	5.4	-	-	-	51.4	**44.5**
Netherlands	0.9	-	-	-	-	-	0.9	**0.9**
Malaysia	8.9	-	-	-	-	-	8.9	**8.8**
Total	15.2	40.7	5.4	-	-	-	61.2	**54.1**

Expectations of Sources and Costs of Funding (International)

The Corporation’s development program will be funded by a combination of internally generated cash flows, access to existing and future credit facilities and possible equity financings. There is no assurance that the Group will allocate funds to develop the reserves as represented in this prospectus. The Group may choose to delay or cancel discretionary development projects depending on economic factors, strategy and priorities. Equally, the Group may choose to accelerate activity where possible should circumstances allow.

Cost of funding is not included in the future net revenue estimates. The cost of funding is not expected to make further development activity uneconomic.

Producing and Non-Producing Well Counts (International)

	Oil				Gas			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross wells	Net wells	Gross wells	Net wells	Gross wells	Net wells	Gross wells	Net wells
Malaysia	11.0	8.3	-	-	-	-	-	-
France	118.0	111.3	6.0	6.0	-	-	-	-
Netherlands	3.0	0.0	-	-	96.0	5.0	-	-

Properties with No Attributed Reserves (International)

								Outstanding Work Commitments				
Country	Property	Operator	Working Interest	Location	Gross Area (ha)	Net Area (ha)	Nature of Outstanding Commitment	Detail of Work Commitment	Gross Amount (MUSD)	Amount Planned in 2018 (MUSD) Towards Commitments	Amount Planned after 2018 (MUSD) Towards Commitments	End of Commitment Period
France	Est-Champagne	IPC	100%	Onshore	132	132	none	-	-	-	-	-
	Esthéria	IPC	100%	Onshore	4'300	4'300	none	-	-	-	-	-
	Pays du Saulnois	IPC	40.0%	Onshore	19'800	7'920	none	-	-	-	-	-
	Plivot	IPC	100%	Onshore	19'800	19'800	none	-	-	-	-	-
Netherlands	Follega	Vermilion	9.30%	Onshore	300	28	none	-	-	-	-	-
	Lemsterland	Vermilion	9.30%	Onshore	11'100	1'032	none	-	-	-	-	-
Malaysia	PM328	IPC	35.0%	Offshore	560'000	196'000	none	-	-	-	-	-
	SB303 GHA	IPC	55.0%	Offshore	3'000	1'650	none	-	-	-	-	-
	PM307 GHA	IPC	75.0%	Offshore	10'800	8'100	none	-	-	-	-	-

The Corporation's properties with no attributed reserves include four exploration licenses in France, two exploration licenses in the Netherlands, one exploration license in Malaysia, and two Gas Holding Areas (GHA) in Malaysia. None of these properties have significant abandonment and reclamation costs, unusually high expected development or operating costs, or contractual obligations that would impact the realized pricing.

The Gas Holding Areas in Malaysia cover existing gas discoveries that would require transportation infrastructure to develop. The capital cost associated with such infrastructure could be high relative to the size of these potential future developments. The development could require a portion of the gas to be sold at domestic pricing.

Tax Horizon (International)

In Malaysia, the Corporation has a significant cost recovery balance of USD 332 million as of January 1, 2018 and Petroleum Income Tax loss carryforwards of USD 48 million as of January 1, 2018. In the Netherlands, the Corporation benefits from a corporate tax loss carryforward, which is non-field specific, of approximately EUR 140 million as of January 1, 2018. Management expects to utilize the benefits of these loss positions over the next several years and expects to pay insignificant taxes in Malaysia and the Netherlands over this period. IPC pays current taxes in France. In December 2017, legislation was approved in France to reduce income tax rates starting in 2019.

Costs Incurred (International)

2017 costs incurred MUSD	Property Acquisition Costs Proved Properties	Property Acquisition Costs UnProved Properties	Exploration Costs	Appraisal Costs	Development Costs
France	-	-	0.0	4.2	4.6
Malaysia	-	-	0.2	-0.3	11.7
Netherlands	-	-	0.8	-	1.8
Total	-	-	1.0	3.9	18.1

Exploration and Development Activities (International)

Exploration Activity Summary	France		Netherlands		Malaysia	
	gross	net	gross	net	gross	net
wells completed	-	-	1.0	0.0	-	-
completed as						
oil well	-	-	-	-	-	-
gas well	-	-	-	-	-	-
service well	-	-	-	-	-	-
stratigraphic test well	-	-	-	-	-	-
dry hole	-	-	1.0	0.0	-	-

Development Activity Summary	France		Netherlands		Malaysia	
	gross	net	gross	net	gross	net
wells completed	-	-	1.0	0.1	-	-
completed as						
oil well	-	-	-	-	-	-
gas well	-	-	1.0	0.1	-	-
service well	-	-	-	-	-	-
stratigraphic test well	-	-	-	-	-	-
dry hole	-	-	-	-	-	-

Production Forecast Estimates (International)

	Light & Medium Crude Oil (Mbbl/d)	Heavy Crude Oil (Mbbl/d)	Conventional Natural Gas (Mboe/d)	Natural Gas Liquids (Mboe/d)	Total (Mboe/d)
Total Proved (1P) Scenario					
France	1.96	-	-	-	1.96
Netherlands	0.02	-	0.79	-	0.80
Malaysia	5.29	-	-	-	5.29
Subtotal IPC International	**7.27**	**-**	**0.79**	**-**	**8.05**
Total Proved plus Probable (2P) Scenario					
France	2.31	-	-	-	2.31
Netherlands	0.02	-	0.94	-	0.96
Malaysia	6.58	-	-	-	6.58
Subtotal IPC International	**8.92**	**-**	**0.94**	**-**	**9.86**
Total Proved plus Probable plus Possible (3P) Scenario					
France	2.62	-	-	-	2.62
Netherlands	0.02	-	1.08	-	1.10
Malaysia	7.72	-	-	-	7.72
Subtotal IPC International	**10.36**	**-**	**1.08**	**-**	**11.44**

Production History (International)

France - Light and Medium Crude Oil	Q1 '17	Q2'17	Q3'17	Q4'17	2017
Production, Mbopd	2.47	2.49	2.47	2.38	**2.44**
Unit Volume Average (USD/bbl)					
Prices received	78.41	38.22	46.28	54.89	**54.36**
Royalties Paid	2.70	2.81	3.04	6.46	**3.74**
Production Costs	39.56	16.63	19.18	27.24	**25.59**
Netback	36.15	18.78	24.06	21.19	**25.03**

Netherlands - Conventional Natural Gas	Q1 '17	Q2'17	Q3'17	Q4'17	2017
Production, MMscf/d	8.68	6.58	6.86	6.24	**7.08**
Unit Volume Average (USD/bbl)					
Prices received	37.00	33.21	35.95	43.83	**37.38**
Royalties Paid	-	0.08	0.00	0.00	**0.02**
Production Costs	12.42	18.31	21.89	22.53	**18.33**
Netback	24.58	14.82	14.06	21.30	**19.03**

Malaysia - Light and Medium Crude Oil	Q1 '17	Q2'17	Q3'17	Q4'17	2017
Production, Mbopd	7.59	6.99	5.65	6.53	**6.68**
Unit Volume Average (USD/bbl)					
Prices received	43.15	57.48	64.98	63.75	**56.61**
Royalties Paid	0.27	0.26	0.23	0.31	**0.27**
Production Costs	0.97	15.14	22.67	12.74	**12.19**
Netback	41.91	42.08	42.08	50.70	**44.15**

IPC Total - Oil Equivalent	Q1 '17	Q2'17	Q3'17	Q4'17	2017
Production, Mboepd	11.51	10.58	9.17	9.94	**10.31**
Unit Volume Average (USD/bbl)					
Prices received	50.32	50.17	56.52	59.68	**53.96**
Royalties Paid	0.76	0.84	0.94	1.75	**1.06**
Production Costs	10.69	15.82	21.66	17.23	**16.07**
Netback	38.87	33.51	33.92	40.70	**36.83**

Contingent Resources (International)

Working Interest Contingent Resources	Project Type	Technology	Economic Sub Class	Project Maturity	Project Evaluation	Working Interest
Malaysia						
Bertam Field	Development Drilling (2)	Established	Economic	Development Unclarified	Conceptual	75%
France Paris Basin						
Amaltheus	Development Drilling, Improved Water Injection	Established	not determined	Development Unclarified	Conceptual	100%
Courdemanges	Development Drilling, Improved Water Injection	Established	not determined	Development Unclarified	Conceptual	100%
Dommartin Lettree	Development Drilling, Improved Water Injection	Established	not determined	Development Unclarified	Conceptual	43.01%
Genievre	Improved water injection	Established	not determined	Development Unclarified	Conceptual	100%
Grandville	Development Drilling	Established	not determined	Development Unclarified	Conceptual	100%
Merisier	Development Drilling	Established	not determined	Development Unclarified	Conceptual	100%
Soudron	Development Drilling, Improved Water Injection	Established	not determined	Development Unclarified	Conceptual	100%
Vert La Gravelle	Development Drilling	Established	not determined	Development Unclarified	Conceptual	100%
Villeperdue	Development Drilling, Improved Water Injection	Established	not determined	Development Unclarified	Conceptual	100%
Villeseneux	Development Drilling	Established	not determined	Development Unclarified	Conceptual	100%
France Aquitaine Basin						
Courbey	Development Drilling	Established	not determined	Development Unclarified	Conceptual	50%

Working Interest Contingent Resources	Light Crude Oil & Medium Crude Oil Mbbl			Heavy Crude Oil Mbbl			Conventional Natural Gas MMscf			Total Oil Equivalent Mboe			Chance of Develop ment
	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	
Malaysia													
Bertam Field	828	1'380	1'932	-	-	-	-	-	-	828	1'380	1'932	75%
France Paris Basin													
Amaltheus	202	719	1'245	-	-	-	-	-	-	202	719	1'245	50%
Courdemanges	428	1'558	2'651	-	-	-	-	-	-	428	1'558	2'651	50%
Dommartin Lettree	521	993	1'285	-	-	-	-	-	-	521	993	1'285	50%
Genievre	-	84	231	-	-	-	-	-	-	-	84	231	50%
Grandville	111	1'499	2'093	-	-	-	-	-	-	111	1'499	2'093	50%
Merisier	564	2'582	4'052	-	-	-	-	-	-	564	2'582	4'052	50%
Soudron	1'436	1'599	2'512	-	-	-	-	-	-	1'436	1'599	2'512	50%
Vert La Gravelle	-	104	1'010	-	-	-	-	-	-	-	104	1'010	50%
Villeperdue	2'272	4'188	4'710	-	-	-	-	-	-	2'272	4'188	4'710	50%
Villeseneux	204	512	605	-	-	-	-	-	-	204	512	605	50%
Paris Basin Subtotal Unrisked	5'738	13'838	20'393	-	-	-	-	-	-	5'738	13'838	20'393	
France Aquitaine Basin													
Courbey	1'300	2'150	3'700	-	-	-	-	-	-	1'300	2'150	3'700	50%

Working Interest Contingent Resources	Light Crude Oil & Medium Crude Oil Mbbl			Heavy Crude Oil Mbbl			Conventional Natural Gas MMscf			**Total Oil Equivalent Mboe**		
	1C	2C	3C	1C	2C	3C	1C	2C	3C	**1C**	**2C**	**3C**
Subtotal by Country Unrisked												
Malaysia	828	1'380	1'932	-	-	-	-	-	-	**828**	**1'380**	**1'932**
France	7'038	15'988	24'093							**7'038**	**15'988**	**24'093**
Total Unrisked	7'866	17'368	26'025	-	-	-	-	-	-	**7'866**	**17'368**	**26'025**
Subtotal by Country Risked by Chance of Developement												
Malaysia	621	1'035	1'449	-	-	-	-	-	-	**621**	**1'035**	**1'449**
France	3'519	7'994	12'047	-	-	-	-	-	-	**3'519**	**7'994**	**12'047**
Total Risked	4'140	9'029	13'496	-	-	-	-	-	-	**4'140**	**9'029**	**13'496**

<u>Malaysia</u>

The contingent resources in Malaysia relate to the drilling of two additional infill producers which are analogous in concept to the recently executed A16 and A17 infill wells. There are spare slots on the wellhead platform to accommodate the new wells so capital requirements relate to drilling, completion, and a minor amount for surface tie-in. No material facility modifications are required to accommodate the new wells. The estimated cost is between USD 30 and 40 million for the two well campaign.

The main contingencies relate to refinement of project definition and approval of the development concept. Timing of first commercial production, should the project proceed, is expected to be in the 2019 to 2020 horizon. Positive factors include opportunity to reduce capital requirements and to improve per well production performance relative to forecast. Negative factors include crude oil price risk as well as geologic and reservoir performance risk. The total best estimate contingent resources attributed to oil drilling is 1.4 MMboe which is classed in economic sub-category. The uncertainty in this project is captured in the 1C and 3C resource range 0.8 to 1.9 MMboe. This project is considered to have a 0.75 chance of development.

A detailed development study and discounted cash flow evaluation specific to these two wells has not been undertaken, however an economic threshold sensitivity run by IPC and reviewed by ERCE is considered adequate to classify these resources as economic under economic conditions that are the same as those used for reporting reserves.

France

The contingent resource estimates reported for France relate to development drilling and water-flood optimization opportunities. In all cases, the product type is light crude oil. The risk and uncertainty associated with the contingent resources in France is largely due to limited seismic coverage and understanding of structural extent of the fields. To recover the contingent resources, the drilling of development wells and, in some instances, the modification of existing production facilities would be required. Project development timing for the highest ranked opportunities will potentially be in the next two to five years with the remaining within the next ten years. Positive factors include opportunity to reduce capital requirements and to improve per well production performance relative to forecast. Negative factors include crude oil price risk as well as geologic and reservoir performance risk. In all cases, the contingent resources require a definitive development plan and approval of the plan to mature from contingent resources to reserves. Implicit in project approval is the demonstration of economic development scheme to recover the resources.

Prospective Resources (International)

Malaysia

Prospect	Working Interest	Gross Working Interest Light Crude Oil & Medium Crude Oil (Mbbl)			Chance of Commerciality	Risked Gross Working Interest Light Crude Oil & Medium Crude Oil (Mbbl)		
		Low	Mid	High		Low	Best	High
Bertam I-35	75%	2’025	5’400	11’775	20.2%	409	1’091	2’379
Bertam Extension	75%	180	435	1’035	35.0%	63	152	362

The prospective resources related to I-35 relate to a closure mapped in a horizon shallower than the Bertam K10.1 productive horizon. The target reservoir has been penetrated by several wells demonstrating reservoir quality however there are no clear indications of oil in the wells drilled to date. 3D seismic interpretation suggests a closure up-dip of the drilled wells indicating the potential for a hydrocarbon accumulation. Charge and closure are the two main risks with the chance of geologic success estimated at 20.2%. The prospect is in a location that could potentially be developed across the FPSO Bertam. Positive factors include the potential for a stratigraphic trapping mechanism resulting in volumes towards the high end of the estimated range. Negative factors include exploration risk and the risk of high development costs. Chance of development in a discovery scenario is considered high. The product type is expected to be light crude oil.

The cost of development in a discovery scenario is estimated to be USD 50 to 100 million depending on production and injection well requirements and infrastructure modifications at the FPSO Bertam. The recovery technology would be either natural water drive or water-flood. Timing of an exploration well might be in the next 2 years resulting in first production in the next 2 to 5 years.

The Bertam extension prospective resources relate to a feature mapped on 3D seismic less than 1 km to the east of the Bertam K10.1 field limit. This feature is analogous to the productive A-15 area accumulation, which was drilled and put on production in 2016. The target reservoir has been drilled extensively in the nearby Bertam field so reservoir, seal, and source are relatively low risk. The main risks relate to oil water contact level and closure. The chance of success has been estimated at 35%. Chance of development in a discovery scenario is considered high. This prospect is within reach of the Bertam wellhead platform and production could be accommodated in the existing facilities. Positive factors include the potential for an oil water contact deeper than the Bertam field and higher than expected reservoir properties. Negative factors include the risk of finding a limited oil column to develop. The product type is expected to be light crude oil.

The cost of development in a discovery scenario is estimated to be USD 15 to 25 million depending on pilot well requirements. No major modifications to the FPSO would be required to accommodate production from this prospect. The recovery technology would be natural water drive. Timing of an exploration well might be in the next 1 to 2 years resulting in first production within months of drilling.

IPC's Oil and Gas Assets in Canada

Oil and Gas Reserves – Based on Forecast Prices and Costs

Proved Reserves (Canada)

Light & Medium Crude Oil (MMbbl)	Proved Developed Producing	Proved Developed Non Producing	Proved Undeveloped	Total Proved
Company Gross Working Interest Reserves	-	-	-	-
Company Net Reserves	-	-	-	-
Heavy Crude Oil (MMbbl)				
Company Gross Working Interest Reserves	13.1	0.3	5.4	18.9
Company Net Reserves	12.6	0.3	5.1	17.9
Conventional Natural Gas (Bscf)				
Company Gross Working Interest Reserves	331.2	26.1	0.6	357.8
Company Net Reserves	313.9	24.8	0.6	339.2
Natural Gas Liquids (MMbbl)				
Company Gross Working Interest Reserves	0.0	0.0	0.0	0.0
Company Net Reserves	0.0	0.0	0.0	0.0
Total Oil Equivalent (Mmboe)				
Company Gross Working Interest Reserves	68.3	4.7	5.6	78.6
Company Net Reserves	64.9	4.4	5.2	74.5

Proved plus Probable Reserves (Canada)

Light & Medium Crude Oil (MMbbl)	Proved plus Probable Developed Producing	Proved plus Probable Developed Non Producing	Proved plus Probable Undeveloped	Total Probable	Total Proved plus Probable
Company Gross Working Interest Reserves	-	-	-	-	-
Company Net Reserves	-	-	-	-	-
Heavy Crude Oil (MMbbl)					
Company Gross Working Interest Reserves	17.4	0.3	9.6	8.4	27.3
Company Net Reserves	16.5	0.3	8.8	7.7	25.7
Conventional Natural Gas (Bscf)					
Company Gross Working Interest Reserves	379.3	58.7	1.1	81.3	439.1
Company Net Reserves	359.5	55.2	1.1	76.5	415.8
Natural Gas Liquids (MMbbl)					
Company Gross Working Interest Reserves	0.0	0.1	0.0	0.1	0.1
Company Net Reserves	0.0	0.0	0.0	0.0	0.1
Total Oil Equivalent (Mmboe)					
Company Gross Working Interest Reserves	80.6	10.2	9.8	22.1	100.6
Company Net Reserves	76.5	9.5	9.0	20.5	95.0

Proved plus Probable plus Possible Reserves (Canada)

Light & Medium Crude Oil (MMbbl)	Proved plus Probable plus Possible Developed Producing	Proved plus Probable plus Possible Developed Non Producing	Proved plus Probable plus Possible Undeveloped	Total Possible	Total Proved plus Probable plus Possible
Company Gross Working Interest Reserves	-	-	-	-	-
Company Net Reserves	-	-	-	-	-
Heavy Crude Oil (MMbbl)					
Company Gross Working Interest Reserves	21.7	0.5	12.3	7.2	34.5
Company Net Reserves	20.5	0.4	11.1	6.3	32.0
Conventional Natural Gas (Bscf)					
Company Gross Working Interest Reserves	427.1	69.3	1.4	58.7	497.8
Company Net Reserves	404.8	65.2	1.3	55.6	471.4
Natural Gas Liquids (MMbbl)					
Company Gross Working Interest Reserves	0.0	0.1	0.0	0.0	0.1
Company Net Reserves	0.0	0.0	0.0	0.0	0.1
Total Oil Equivalent (Mmboe)					
Company Gross Working Interest Reserves	92.9	12.1	12.6	17.0	117.6
Company Net Reserves	87.9	11.3	11.3	15.6	110.6

Net Present Value of Future Net Revenue – Proved Reserves (Canada)

Net Present Value Before Tax (MUSD)	Proved Developed Producing	Proved Developed Non Producing	Proved Undeveloped	Total Proved
0%	534.7	45.8	136.4	717.0
5%	519.6	31.5	69.4	620.5
8%	480.9	25.4	48.6	554.9
10%	454.1	22.1	38.8	515.0
15%	393.0	15.6	22.6	431.2
20%	343.2	11.0	13.0	367.1

Net Present Value After Tax (MUSD)	Proved Developed Producing	Proved Developed Non Producing	Proved Undeveloped	Total Proved
0%	419.3	34.3	117.0	570.6
5%	427.9	22.7	55.8	506.4
8%	399.9	17.8	37.4	455.1
10%	379.1	15.2	28.9	423.2
15%	330.0	10.1	15.2	355.2
20%	289.1	6.6	7.2	302.9

Net Present Value of Future Net Revenue – Proved plus Probable Reserves (Canada)

Net Present Value Before Tax (MUSD)	Proved plus Probable Developed Producing	Proved plus Probable Developed Non Producing	Proved plus Probable Undeveloped	Total Probable	Total Proved plus Probable
0%	761.3	115.1	295.7	455.1	1'172.1
5%	664.6	78.7	143.4	266.2	886.7
8%	593.7	63.5	101.2	203.5	758.4
10%	550.9	55.3	82.1	173.2	688.2
15%	461.9	39.6	51.1	121.4	552.5
20%	395.0	28.7	33.1	89.8	456.9

Net Present Value After Tax (MUSD)	Proved plus Probable Developed Producing	Proved plus Probable Developed Non Producing	Proved plus Probable Undeveloped	Total Probable	Total Proved plus Probable
0%	602.3	84.9	245.2	361.9	932.4
5%	542.8	56.6	110.7	203.8	710.2
8%	487.9	44.9	75.3	153.1	608.2
10%	453.9	38.7	59.6	129.0	552.2
15%	382.2	26.8	34.8	88.6	443.9
20%	327.9	18.8	20.8	64.6	367.4

Net Present Value of Future Net Revenue – Proved plus Probable plus Possible Reserves (Canada)

Net Present Value Before Tax (MUSD)	Proved plus Probable plus Possible Developed Producing	Proved plus Probable plus Possible Developed Non Producing	Proved plus Probable plus Possible Undeveloped	Total Possible	Total Proved plus Probable plus Possible
0%	1'013.9	156.2	435.9	433.8	1'605.9
5%	791.6	107.7	205.0	217.6	1'104.3
8%	685.4	87.1	144.8	158.8	917.2
10%	626.6	75.9	117.9	132.2	820.4
15%	512.6	54.7	74.9	89.6	642.2
20%	431.6	40.0	50.2	65.0	521.9

Net Present Value After Tax (MUSD)	Proved plus Probable plus Possible Developed Producing	Proved plus Probable plus Possible Developed Non Producing	Proved plus Probable plus Possible Undeveloped	Total Possible	Total Proved plus Probable plus Possible
0%	811.9	114.1	344.0	337.5	1'270.0
5%	642.8	77.5	154.3	164.5	874.6
8%	558.5	62.0	106.2	118.6	726.7
10%	511.6	53.7	85.1	98.2	650.4
15%	420.1	37.8	51.9	65.9	509.8
20%	354.9	27.0	33.1	47.6	415.0

Elements of Future Net Revenue (Canada)

Total Proved (1P) Reserves MUSD	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Canada	2'015.9	92.9	735.5	138.5	332.1	717.0	146.4	570.6

Total Proved and Probable (2P) Reserves MUSD	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Canada	2'814.6	152.1	955.9	184.3	350.2	1'172.1	239.7	932.4

Total Proved and Probable and Possible (3P) Reserves MUSD	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Canada	3'502.8	219.0	1'137.9	184.3	355.8	1'605.9	335.9	1'270.0

Net Present Value by Product Type (Canada)

IPC Canada Future Net Revenue BTAX at 10% Discount	Primary Product Type Light & Medium Crude Oil (MUSD)	Heavy Crude Oil (MUSD)	Conventional Natural Gas (MUSD)	Natural Gas Liquids (MUSD)	Total (MUSD)
Total Proved (1P) Reserves	-	236.6	278.5	-	515.0
Total Proved and Probable (2P) Reserves	-	340.6	347.6	-	688.2
Total Proved and Probable and Possible (3P) Reserves	-	429.3	391.1	-	820.4

IPC Canada USD per net boe by product type	Primary Product Type Light & Medium Crude Oil (USD/bbl)	Heavy Crude Oil (USD/bbl)	Conventional Natural Gas (USD/Mscf)	Natural Gas Liquids (USD/bbl)	Total (USD/net boe)
Total Proved (1P) Reserves	-	13.20	0.83	-	6.91
Total Proved and Probable (2P) Reserves	-	13.27	0.84	-	7.24
Total Proved and Probable and Possible (3P) Reserves	-	13.43	0.84	-	7.42

Notes

(1) Light, Medium, and Heavy Oil Future Net Revenue and Unit Value include associated gas
(2) Conventional natural Gas revenue and unit Value include associated condensate (light oil)

Forecast Prices used in Estimates (Canada)

See "IPC's Oil and Gas Assets in France, Malaysia and the Netherlands – Forecast Prices used in Estimates".

The same forecast prices are used with respect to Canada.

Reconciliation of Changes in Reserves (Canada)

Reconciliation of Proved Reserves Mmboe	Heavy Oil	Convent-ional Natural Gas	Natural Gas Liquids	**Oil Equivalent**
Opening Balance December 31, 2016	-	-	-	**-**
extensions and improved recovery				**+ 0.0**
technical revisions				**+ 0.0**
discoveries				**+ 0.0**
acquisitions	+ 18.9	+ 59.6	+ 0.0	**+ 78.6**
dispositions				**+ 0.0**
economic factors				**+ 0.0**
production				**+ 0.0**
Closing Balance December 31, 2017	18.9	59.6	0.0	**78.6**

Reconciliation of Proved + Probable Reserves Mmboe	Heavy Oil	Convent-ional Natural Gas	Natural Gas Liquids	**Oil Equivalent**
Opening Balance December 31, 2016	-	-	-	**-**
extensions and improved recovery				**+ 0.0**
technical revisions				**+ 0.0**
discoveries				**+ 0.0**
acquisitions	+ 27.3	+ 73.2	+ 0.1	**+ 100.6**
dispositions				**+ 0.0**
economic factors				**+ 0.0**
production				**+ 0.0**
Closing Balance December 31, 2017	27.3	73.2	0.1	**100.6**

Reconciliation of Proved + Probable + Possible Reserves Mmboe	Heavy Oil	Convent-ional Natural Gas	Natural Gas Liquids	**Oil Equivalent**
Opening Balance December 31, 2016	-	-	-	**-**
extensions and improved recovery				**+ 0.0**
technical revisions				**+ 0.0**
discoveries				**+ 0.0**
acquisitions	+ 34.5	+ 83.0	+ 0.1	**+ 117.6**
dispositions				**+ 0.0**
economic factors				**+ 0.0**
production				**+ 0.0**
Closing Balance December 31, 2017	34.5	83.0	0.1	**117.6**

Undeveloped Reserves (Canada)

	Light & Medium Crude Oil (MMbbl)	Heavy Crude Oil (MMbbl)	Conventional Natural Gas (Bscf)	Natural Gas Liquids (MMboe)	Oil Equivalent (MMboe)
Proved Undeveloped					
December 31, 2015	-	-	-	-	-
December 31, 2016	-	-	-	-	-
December 31, 2017	-	5.4	0.6	0.0	6.2
Probable Undeveloped					
December 31, 2015	-	-	-	-	-
December 31, 2016	-	-	-	-	-
December 31, 2017	-	9.6	1.1	0.0	9.8

Development Projects (Canada)

	Light & Medium Crude Oil Reserves MMbbl gross	Heavy Crude Oil Reserves MMbbl gross	Convent-ional Natural Gas Reserves Bscf Gross	Future Project Development Capital MUSD			USD per boe	Net Present Value, MUSD Before Deducting Income Tax, Discounted at:						Net Present Value, MUSD After Deducting Income Tax, Discounted at:						BTAX NPV10 per boe USD per boe	ATAX NPV10 per boe USD per boe
Canada - Oil Drilling and EOR				2018	2019	Total		0%	5%	8%	10%	15%	20%	0%	5%	8%	10%	15%	20%		
Proved Undeveloped (PUD)	-	5.4	0.6	4.1	16.4	43.1	7.8	142	70	49	39	23	13	117	56	37	29	15	7	7.03	5.21
Proved and Probable Undeveloped (PPUD)	-	9.6	1.1	4.1	22.8	65.6	6.7	296	143	101	82	51	33	245	111	75	60	35	21	8.37	6.08
Proved plus Probable plus Possible Undeveloped (PPPUD)	-	12.3	1.4	4.1	22.8	65.6	5.2	436	205	145	118	75	50	344	154	106	85	22	33	9.39	6.78

Development plans in Canada include development drilling in the glauconitic oil pools, expansion of alkaline-surfactant-polymer enhanced oil recovery to the glauconitic wash-over N2N pool, and optimization of the existing gas well stock.

The glauconitic development drilling consists of a combination of infill and step-out drilling of horizontal producers. The wells are generally 1000 metres dual leg horizontal producers although the length varies according to the reservoir and in cases single leg and triple leg producers are also considered. The wells are pumped with progressive cavity pumps and reservoir pressure is supported by natural bottom water drive supplemented by produced water re-injection.

Enhanced oil recovery expansion to the N2N pool entails commissioning already installed facilities, drilling producer and injector horizontal wells, and proceeding with injecting an alkaline-surfactant-polymer mix into the reservoir to mobilize oil that would not be recoverable with water-flooding alone. This method has been applied in the nearby and geologically analogous UU and YYY pools with positive reservoir response.

Optimization of existing well stock covers a range of activities including pulling of siphon strings, adding new completion intervals, and re-fracturing existing completions.

Significant Factors or Uncertainties Affecting Reserves Data (Canada)

In Canada, the main uncertainties relate to performance of future infill wells and the effectiveness of the alkaline-surfactant-polymer injection in mobilizing bypassed oil. These uncertainties are captured in the 1P to 3P range of estimates. Other uncertainties include weather related downtime and facility performance and effectiveness of gas optimization investments. The abandonment and reclamation liability beyond what has been considered in the reserve assessment is not material to the Canadian asset valuation. This asset does not have high expected development or operating cost, or contractual obligations that would impair the Group’s realized prices.

See also “Reserves and Resource Advisory”.

Future Development Costs (Canada)

	2018	2019	2020	2021	2022	2023 on	Total for all years undiscounted	**Total for all years discounted at 10% p.a.**
Total Proved								
Canada	6.8	29.7	33.1	16.5	3.2	49.3	138.5	**86.4**
Total Proved Plus Probable								
Canada	6.8	36.0	39.0	18.2	14.8	69.3	184.3	**116.7**

Working Interest Contingent Resources	Light Crude Oil & Medium Crude Oil Mbbl			Heavy Crude Oil Mbbl			Conventional Natural Gas MMscf			**Total Oil Equivalent Mboe**		
	1C	2C	3C	1C	2C	3C	1C	2C	3C	**1C**	**2C**	**3C**
Canada - Unrisked	-	-	-	5'462	7'373	9'954	185'385	231'732	289'665	**36'360**	**45'995**	**58'232**
Canada - risked	-	-	-	3'341	4'510	6'088	120'627	150'784	188'481	**23'446**	**29'641**	**37'502**

Expectations of Sources and Costs of Funding (Canada)

See "IPC's Oil and Gas Assets in France, Malaysia and the Netherlands – Expectations of Sources and Costs of Funding" above. The same disclosure applies with respect to Canada.

Producing and Non-Producing Well Counts (Canada)

	Oil				**Gas**			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada	550.0	550.0	393.0	393.0	10'252.0	10'226.8	527.0	527.0

Properties with No Attributed Reserves (Canada)

							Outstanding Work Commitments					
Country	Property	Operator	Working Interest	Location	Gross Area (ha)	Net Area (ha)	Nature of Outstanding Commitment	Detail of Work Commitment	Gross Amount (MUSD)	Amount Planned in 2018 (MUSD) Towards Commitments	Amount Planned after 2018 (MUSD) Towards Commitments	End of Commitment Period
Canada	Suffield	IPC	100%	Onshore	3424	3424	expiry	Mannville	-	-	-	17 May 18
	Suffield	IPC	100%	Onshore	832	832	expiry	Bow Island and Mannville	-	-	-	3 Oct 18
	Suffield	IPC	100%	Onshore	64	64	expiry	Bow Island and Mannville	-	-	-	18 Dec 18
	Suffield	IPC	100%	Onshore	64	64	expiry	Bow Island and Mannville	-	-	-	4 Sep 19

Tax Horizon (Canada)

IPC expects to pay current taxes in Canada commencing in 2019 in respect of 2018 income.

Production Forecast Estimates (Canada)

	Light & Medium Crude Oil (Mbbl/d)	Heavy Crude Oil (Mbbl/d)	Conventional Natural Gas (Mboe/d)	Natural Gas Liquids (Mboe/d)	Total (Mboe/d)
Total Proved (1P) Scenario					
Canada	-	6.12	16.10	-	22.22
Total Proved plus Probable (2P) Scenario					
Canada	-	6.32	16.27	-	22.59
Total Proved plus Probable plus Possible (3P) Scenario					
Canada	-	6.41	16.38	-	22.79

Contingent Resources (Canada)

Working Interest Contingent Resources	Project Type	Technology	Economic Sub Class	Project Maturity	Project Evaluation	Working Interest
Canada						
Washover Pools						
P3P Pool	ASP	Established	Sub-Economic	Development Unclarified	Conceptual	100%
D2D Pool	ASP	Established	Sub-Economic	Development Unclarified	Conceptual	100%
M3M Pool	WF+ASP	Established	Sub-Economic	Development Unclarified	Conceptual	100%
F3F Pool	WF+ASP	Established	Sub-Economic	Development Unclarified	Conceptual	100%
O3O Pool	WF+ASP	Established	Sub-Economic	Development Unclarified	Conceptual	100%
Oil Development Drilling (117)						
Glauconitic	Development Drilling (76)	Established	Economic	Development Unclarified	Conceptual	100%
Glauconitic	Development Drilling (41)	Established	Sub-Economic	Development Unclarified	Conceptual	100%
Gas Development Drilling (2,540)						
Alderson	Development Drilling (470)	Established	Economic	Development Unclarified	Conceptual	100%
Suffield	Development Drilling (1,061)	Established	Economic	Development Unclarified	Conceptual	100%
Suffield	Development Drilling (1,009)	Established	Sub-Economic	Development Unclarified	Conceptual	100%

Working Interest Contingent Resources	Light Crude Oil & Medium Crude Oil Mbbl			Heavy Crude Oil Mbbl			Conventional Natural Gas MMscf			Total Oil Equivalent Mboe			Chance of Development
	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	
Canada													
Washover Pools													
P3P Pool	-	-	-	498	672	908	-	-	-	498	672	908	50%
D2D Pool	-	-	-	372	502	678	-	-	-	372	502	678	50%
M3M Pool	-	-	-	351	474	639	-	-	-	351	474	639	50%
F3F Pool	-	-	-	131	176	236	-	-	-	131	176	236	50%
O3O Pool	-	-	-	191	258	349	-	-	-	191	258	349	50%
Subtotal Washover Pools	-	-	-	1543	2083	2812	-	-	-	1'543	2'083	2'812	
Oil Development Drilling (117)													
Glauconitic	-	-	-	3052	4'120	5562	-	-	-	3'052	4'120	5'562	70%
Glauconitic	-	-	-	867	1'170	1580	-	-	-	867	1'170	1'580	50%
Subtotal Oil Drilling	-	-	-	3919	5'290	7'142	-	-	-	3'919	5'290	7'142	
Gas Development Drilling (2,540)													
Alderson	-	-	-	-	-	-	36'284	45'355	56'694	6'047	7'559	9'449	70%
Suffield	-	-	-	-	-	-	103'389	129'237	161'546	17'232	21'540	26'924	70%
Suffield	-	-	-	-	-	-	45'712	57'140	71'425	7'619	9'523	11'904	50%
Subtotal Gas Drilling	-	-	-	-	-	-	185'385	231'732	289'665	30'898	38'622	48'278	
Canada Total Unrisked	-	-	-	5'462	7'373	9'954	185'385	231'732	289'665	36'360	45'995	58'231	

IPC has a 100% working interest in all of the contingent resources tabulated above. The oil contingent resources relate to heavy oil, and the gas contingent resources relate to conventional natural gas.

The contingent resources reported for Canada are consolidated into three project categories: shallow gas development drilling, oil development drilling and ASP expansion. In all cases the recovery of the resources would be via established technology, are based upon conceptual development plans, are classed in either sub-economic or economic category as discussed below, and in terms of project maturity are considered in all cases as having development unclarified status.

The shallow gas drilling project is estimated to require an estimated CAD 350 to 450 million with the main contingencies being natural gas prices, refinement of project definition, and approval of the project concept. Timing of first commercial production, should the project proceed, is expected to be in the 2019 to 2025 horizon. It is likely that the project would be approved and implemented in a number of stages. The project is primarily drilling and completion scope with minimal infrastructure investment required. Positive factors include opportunity to reduce capital requirements and to improve per well production performance relative to forecast. Negative factors include natural gas price risk as well as geologic and well completion risk. The total contingent resource attributed to shallow gas drilling is 38.6 MMboe with 9.5 MMboe considered sub-economic and 29.1 MMboe considered economic. The conventional natural gas contingent resources require a definitive development plan and approval of the plan to mature from contingent resources to reserves. Implicit in project approval is the demonstration of economic development scheme to recover the resources.

The oil development drilling is estimated by to require CAD 75 to 100 million of capital largely consisting of drilling and completion scope with minor facility and infrastructure investments. The main contingencies relate to refinement of project definition and approval of the development concept. Timing of first commercial production, should the project proceed, is expected to be in the 2019 to 2025 horizon. It is likely that the project would be approved and implemented in a number of stages. Positive factors include opportunity to reduce capital requirements and to improve per well production performance relative to forecast. Negative factors include crude oil price risk as well as geologic and reservoir performance risk. The total contingent resources attributed to oil drilling is 5.3 MMboe of which 4.1 MMboe is in economic category and 1.2 MMboe is in sub-economic category. The heavy oil development drilling contingent resources require a definitive development plan and approval of the plan to mature from contingent resources to reserves. Implicit in project approval is the demonstration of economic development scheme to recover the resources.

The ASP expansion and water-flood optimization projects are conceptually defined. The estimated capital to execute this project is CAD 40 to 80 million which is a combination of facility and pipeline expansion and drilling of injectors and producers. Timing of first commercial production, should the project proceed is expected to be in the 2022 to 2027 horizon. It is likely that the project would be approved and implemented in a number of stages. Positive factors include opportunity to reduce capital and operating cost requirements and to improve oil recovery efficiency relative to forecast. Negative factors include oil price risk, operating cost risk, geologic risk, and reservoir performance risk. The total contingent resource attributed to ASP expansion and water-flood optimization projects is 2.1 MMboe and is classed in sub-economic category. These enhanced oil recovery contingent resources require a definitive development plan and approval of the plan to mature from contingent resources to reserves. Implicit in project approval is the demonstration of economic development scheme to recover the resources.

Aggregation of IPC's Oil and Gas Assets in Canada, France, Malaysia and the Netherlands

Oil and Gas Reserves – Based on Forecast Prices and Costs

Proved Reserves (Aggregated)

		France	Netherlands	Malaysia	IPC International	Canada	Total IPC
Proved Developed Producing (PDP) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	6.40	0.02	3.24	9.66	-	9.66
	net	5.61	0.02	2.79	8.42	-	8.42
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	13.12	13.12
	net	-	-	-	-	12.59	12.59
Conventional Natural Gas (Bscf)	gross	-	5.21	-	5.21	331.16	336.37
	net	-	5.21	-	5.21	313.88	319.09
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.03	0.03
	net	-	-	-	-	0.02	0.02
Total Oil Equivalent (MMboe)	gross	6.40	0.89	3.24	10.53	68.34	78.86
	net	5.61	0.89	2.79	9.28	64.92	74.21
Proved Developed Non Producing (PDNP) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	0.19	0.00	-	0.19	-	0.19
	net	0.16	0.00	-	0.16	-	0.16
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	0.32	0.32
	net	-	-	-	-	0.27	0.27
Conventional Natural Gas (Bscf)	gross	-	0.57	-	0.57	26.06	26.63
	net	-	0.57	-	0.57	24.75	25.33
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.00	0.00
	net	-	-	-	-	0.00	0.00
Total Oil Equivalent (MMboe)	gross	0.19	0.10	-	0.29	4.66	4.95
	net	0.16	0.10	-	0.26	4.40	4.66
Proved Undeveloped (PUD) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	2.23	0.00	0.66	2.90	-	2.90
	net	1.91	0.00	0.57	2.48	-	2.48
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	5.44	5.44
	net	-	-	-	-	5.06	5.06
Conventional Natural Gas (Bscf)	gross	-	0.05	-	0.05	0.62	0.67
	net	-	0.05	-	0.05	0.59	0.64
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.01	0.01
	net	-	-	-	-	0.01	0.01
Total Oil Equivalent (MMboe)	gross	2.23	0.01	0.66	2.90	5.56	8.46
	net	1.91	0.01	0.57	2.49	5.17	7.66
Total Proved (1P) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	8.82	0.02	3.91	12.75	-	12.75
	net	7.68	0.02	3.36	11.06	-	11.06
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	18.88	18.88
	net	-	-	-	-	17.93	17.93
Conventional Natural Gas (Bscf)	gross	-	5.83	-	5.83	357.84	363.67
	net	-	5.83	-	5.83	339.22	345.05
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.03	0.03
	net	-	-	-	-	0.02	0.02
Total Oil Equivalent (MMboe)	gross	8.82	0.99	3.91	13.72	78.56	92.28
	net	7.68	0.99	3.36	12.03	74.49	86.52

Proved plus Probable Reserves (Aggregated)

		France	Netherlands	Malaysia	**Sub Total IPC International**	Canada	**Total IPC**
Proved plus Probable Developed Producing (2PDP) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	13.15	0.03	7.65	**20.83**	-	**20.83**
	net	11.60	0.03	6.55	**18.19**	-	**18.19**
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	17.39	**17.39**
	net	-	-	-	-	16.53	**16.53**
Conventional Natural Gas (Bscf)	gross	-	9.55	-	**9.55**	379.35	**388.90**
	net	-	9.55	-	**9.55**	359.55	**369.09**
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.03	**0.03**
	net	-	-	-	-	0.02	**0.02**
Total Oil Equivalent (MMboe)	gross	13.15	1.62	7.65	**22.42**	80.64	**103.06**
	net	11.60	1.62	6.55	**19.78**	76.48	**96.26**
Proved plus Probable Developed Non Producing (2PDNP) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	0.52	0.00	-	**0.52**	-	**0.52**
	net	0.44	0.00	-	**0.45**	-	**0.45**
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	0.33	**0.33**
	net	-	-	-	-	0.28	**0.28**
Conventional Natural Gas (Bscf)	gross	-	1.21	-	**1.21**	58.66	**59.87**
	net	-	1.21	-	**1.21**	55.15	**56.36**
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.06	**0.06**
	net	-	-	-	-	0.04	**0.04**
Total Oil Equivalent (MMboe)	gross	0.52	0.20	-	**0.72**	10.16	**10.89**
	net	0.44	0.20	-	**0.65**	9.51	**10.16**
Proved plus Probable Undeveloped (2PUD) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	3.94	0.00	1.41	**5.35**	-	**5.35**
	net	3.38	0.00	1.22	**4.60**	-	**4.60**
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	9.61	**9.61**
	net	-	-	-	-	8.84	**8.84**
Conventional Natural Gas (Bscf)	gross	-	0.06	-	**0.06**	1.12	**1.18**
	net	-	0.06	-	**0.06**	1.06	**1.12**
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.01	**0.01**
	net	-	-	-	-	0.01	**0.01**
Total Oil Equivalent (MMboe)	gross	3.94	0.01	1.41	**5.36**	9.81	**15.18**
	net	3.38	0.01	1.22	**4.61**	9.03	**13.64**
Total Probable (PB) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	8.79	0.02	5.15	**13.96**	-	**13.96**
	net	7.75	0.02	4.41	**12.17**	-	**12.17**
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	8.44	**8.44**
	net	-	-	-	-	7.73	**7.73**
Conventional Natural Gas (Bscf)	gross	-	4.99	-	**4.99**	81.28	**86.27**
	net	-	4.99	-	**4.99**	76.53	**81.52**
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.07	**0.07**
	net	-	-	-	-	0.05	**0.05**
Total Oil Equivalent (MMboe)	gross	8.79	0.85	5.15	**14.79**	22.06	**36.85**
	net	7.75	0.85	4.41	**13.01**	20.53	**33.54**
Total Proved plus Probable (2P) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	17.61	0.04	9.06	**26.70**	-	**26.70**
	net	15.43	0.04	7.77	**23.24**	-	**23.24**
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	27.33	**27.33**
	net	-	-	-	-	25.66	**25.66**
Conventional Natural Gas (Bscf)	gross	-	10.82	-	**10.82**	439.13	**449.95**
	net	-	10.82	-	**10.82**	415.75	**426.57**
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.10	**0.10**
	net	-	-	-	-	0.07	**0.07**
Total Oil Equivalent (MMboe)	gross	17.61	1.84	9.06	**28.51**	100.62	**129.12**
	net	15.43	1.84	7.77	**25.04**	95.02	**120.06**

Proved plus Probable plus Possible Reserves (Aggregated)

		France	Netherlands	Malaysia	**Sub Total IPC International**	Canada	**Total IPC**
Proved plus Probable plus Possible Developed Producing (3PDP) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	20.56	0.05	9.78	**30.39**	-	**30.39**
	net	18.19	0.05	8.38	**26.62**	-	**26.62**
Heavy Crude Oil (MMbbl)	gross				-	21.67	**21.67**
	net				-	20.45	**20.45**
Conventional Natural Gas (Bscf)	gross		15.87		**15.87**	427.11	**442.98**
	net		15.87		**15.87**	404.79	**420.67**
Natural Gas Liquids (MMbbl)	gross				-	0.04	**0.04**
	net				-	0.03	**0.03**
Total Oil Equivalent (MMboe)	gross	20.56	2.70	9.78	**33.04**	92.90	**125.94**
	net	18.19	2.70	8.38	**29.26**	87.95	**117.21**
Proved plus Probable plus Possible Developed Non Producing (3PDNP) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	0.59	0.00	-	**0.60**	-	**0.60**
	net	0.51	0.00	-	**0.52**	-	**0.52**
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	0.52	**0.52**
	net	-	-	-	-	0.42	**0.42**
Conventional Natural Gas (Bscf)	gross	-	1.88	-	**1.88**	69.29	**71.17**
	net	-	1.88	-	**1.88**	65.25	**67.12**
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.06	**0.06**
	net	-	-	-	-	0.04	**0.04**
Total Oil Equivalent (MMboe)	gross	0.59	0.32	-	**0.91**	12.12	**13.03**
	net	0.51	0.32	-	**0.83**	11.33	**12.16**
Proved plus Probable plus Possible Undeveloped (3PUD) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	4.74	0.00	1.99	**6.73**	-	**6.73**
	net	4.05	0.00	1.67	**5.72**	-	**5.72**
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	12.31	**12.31**
	net	-	-	-	-	11.09	**11.09**
Conventional Natural Gas (Bscf)	gross	-	0.12	-	**0.12**	1.42	**1.55**
	net	-	0.12	-	**0.12**	1.34	**1.46**
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.02	**0.02**
	net	-	-	-	-	0.02	**0.02**
Total Oil Equivalent (MMboe)	gross	4.74	0.02	1.99	**6.75**	12.56	**19.32**
	net	4.05	0.02	1.67	**5.74**	11.33	**17.07**
Total Possible (PS) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	8.29	0.02	2.71	**11.02**	-	**11.02**
	net	7.32	0.02	2.28	**9.62**	-	**9.62**
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	7.17	**7.17**
	net	-	-	-	-	6.30	**6.30**
Conventional Natural Gas (Bscf)	gross	-	7.05	-	**7.05**	58.70	**65.75**
	net	-	7.05	-	**7.05**	55.63	**62.68**
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.01	**0.01**
	net	-	-	-	-	0.01	**0.01**
Total Oil Equivalent (MMboe)	gross	8.29	1.20	2.71	**12.20**	16.96	**29.16**
	net	7.32	1.20	2.28	**10.79**	15.58	**26.38**
Total Proved plus Probable plus Possible (3P) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	25.89	0.06	11.77	**37.72**	-	**37.72**
	net	22.75	0.06	10.04	**32.85**	-	**32.85**
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	34.49	**34.49**
	net	-	-	-	-	31.96	**31.96**
Conventional Natural Gas (Bscf)	gross	-	17.87	-	**17.87**	497.82	**515.69**
	net	-	17.87	-	**17.87**	471.38	**489.25**
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.12	**0.12**
	net	-	-	-	-	0.08	**0.08**
Total Oil Equivalent (MMboe)	gross	25.89	3.04	11.77	**40.70**	117.58	**158.28**
	net	22.75	3.04	10.04	**35.83**	110.60	**146.44**

Net Present Value of Future Net Revenue – Proved Reserves (Aggregated)

	Before Deducting Income Tax, Discounted at:						After Deducting Income Tax, Discounted at:						USD / net BOE
Values in MUSD	**0%**	**5%**	**8%**	**10%**	**15%**	**20%**	**0%**	**5%**	**8%**	**10%**	**15%**	**20%**	**BTAX NPV10**
Proved Developed Producing (PDP) Reserves													
France	93.2	91.7	86.6	82.7	72.8	63.9	60.2	68.5	67.4	65.6	59.7	53.7	14.74
Netherlands	-23.7	-10.2	-5.3	-2.8	1.3	3.7	-23.7	-10.2	-5.3	-2.8	1.3	3.7	-3.21
Malaysia	120.7	114.9	111.7	109.7	105.1	100.9	120.7	114.9	111.7	109.7	105.1	100.9	39.33
Subtotal IPC International	**190.1**	**196.4**	**193.0**	**189.5**	**179.1**	**168.5**	**157.2**	**173.3**	**173.8**	**172.5**	**166.1**	**158.3**	**20.42**
Canada	534.7	519.6	480.9	454.1	393.0	343.2	419.3	427.9	399.9	379.1	330.0	289.1	6.99
Grand Total IPC	**724.8**	**716.0**	**673.9**	**643.7**	**572.1**	**511.7**	**576.5**	**601.2**	**573.7**	**551.6**	**496.0**	**447.4**	**8.67**
Proved Developed Non Producing (PDNP) Reserves													
France	1.7	0.9	0.6	0.4	0.1	-0.1	1.3	0.7	0.4	0.3	0.0	-0.1	2.67
Netherlands	0.7	1.6	1.8	1.9	1.9	1.8	0.7	1.6	1.8	1.9	1.9	1.8	19.22
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal IPC International	**2.4**	**2.5**	**2.4**	**2.3**	**2.0**	**1.7**	**2.0**	**2.3**	**2.2**	**2.2**	**1.9**	**1.6**	**8.84**
Canada	45.8	31.5	25.4	22.1	15.6	11.0	34.3	22.7	17.8	15.2	10.1	6.6	5.02
Grand Total IPC	**48.2**	**34.0**	**27.8**	**24.4**	**17.6**	**12.6**	**36.3**	**24.9**	**20.0**	**17.3**	**12.0**	**8.2**	**5.24**
Proved Undeveloped (PUD) Reserves													
France	66.1	33.8	22.2	16.5	6.7	1.0	48.8	24.6	15.8	11.4	3.8	-0.7	8.61
Netherlands	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	30.09
Malaysia	32.3	30.3	29.2	28.6	27.0	25.6	32.3	30.3	29.2	28.6	27.0	25.6	50.18
Subtotal IPC International	**98.6**	**64.3**	**51.7**	**45.3**	**33.9**	**26.8**	**81.3**	**55.2**	**45.3**	**40.2**	**31.0**	**25.1**	**18.18**
Canada	136.4	69.4	48.6	38.8	22.6	13.0	117.0	55.8	37.4	28.9	15.2	7.2	7.51
Grand Total IPC	**235.1**	**133.8**	**100.3**	**84.1**	**56.5**	**39.8**	**198.3**	**111.0**	**82.7**	**69.1**	**46.2**	**32.4**	**10.98**
Total Proved (1P) Reserves													
France	161.0	126.4	109.4	99.6	79.6	64.8	110.3	93.8	83.6	77.3	63.5	52.8	12.96
Netherlands	-22.8	-8.3	-3.2	-0.7	3.4	5.7	-22.8	-8.3	-3.2	-0.7	3.4	5.7	-0.75
Malaysia	153.0	145.2	140.9	138.3	132.1	126.5	153.0	145.2	140.9	138.3	132.1	126.5	41.16
Subtotal IPC International	**291.2**	**263.3**	**247.1**	**237.1**	**215.1**	**197.0**	**240.5**	**230.7**	**221.3**	**214.8**	**199.0**	**185.0**	**19.70**
Canada	717.0	620.5	554.9	515.0	431.2	367.1	570.6	506.4	455.1	423.2	355.2	302.9	6.91
Grand Total IPC	**1'008.1**	**883.7**	**802.0**	**752.1**	**646.3**	**564.2**	**811.1**	**737.1**	**676.4**	**638.0**	**554.3**	**487.9**	**8.69**

Net Present Value of Future Net Revenue – Proved plus Probable Reserves (Aggregated)

	Before Deducting Income Tax, Discounted at:						After Deducting Income Tax, Discounted at:						USD / net BOE
Values in MUSD	**0%**	**5%**	**8%**	**10%**	**15%**	**20%**	**0%**	**5%**	**8%**	**10%**	**15%**	**20%**	**BTAX NPV10**
Proved plus Probable Developed Producing (2PDP) Reserves													
France	333.3	235.6	194.9	173.7	135.4	110.4	230.9	177.8	150.4	135.5	107.7	89.1	14.97
Netherlands	-6.1	8.6	12.6	14.3	16.5	17.0	-7.5	7.3	11.4	12.4	15.3	15.9	8.81
Malaysia	305.9	274.1	258.0	248.3	227.1	209.4	305.9	274.1	258.0	248.3	227.1	209.4	37.90
Subtotal IPC International	**633.1**	**518.3**	**465.5**	**436.4**	**379.0**	**336.9**	**529.4**	**459.1**	**419.7**	**396.2**	**350.1**	**314.5**	**22.06**
Canada	761.3	664.6	593.7	550.9	461.9	395.0	602.3	542.8	487.9	453.9	382.2	327.9	7.20
Grand Total IPC	**1'394.4**	**1'182.9**	**1'059.3**	**987.2**	**840.8**	**731.9**	**1'131.7**	**1'002.0**	**907.7**	**850.1**	**732.3**	**642.4**	**10.26**
Proved plus Probable Developed Non Producing (2PDNP) Reserves													
France	4.0	4.1	3.1	2.5	1.5	0.9	2.4	3.2	2.5	2.0	1.1	0.6	5.74
Netherlands	3.3	4.2	4.2	4.0	3.5	3.0	2.5	3.5	3.5	3.4	2.9	2.5	19.62
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal IPC International	**7.2**	**8.3**	**7.3**	**6.6**	**5.0**	**3.9**	**4.9**	**6.8**	**6.0**	**5.4**	**4.0**	**3.1**	**10.13**
Canada	115.1	78.7	63.5	55.3	39.6	28.7	84.9	56.6	44.9	38.7	26.8	18.8	5.81
Grand Total IPC	**122.4**	**87.1**	**70.8**	**61.8**	**44.6**	**32.6**	**89.8**	**63.4**	**50.9**	**44.1**	**30.9**	**21.8**	**6.09**
Proved plus Probable Undeveloped (2PUD) Reserves													
France	137.4	82.6	62.1	51.7	33.2	21.3	101.0	60.2	44.6	36.7	22.5	13.3	15.29
Netherlands	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.8	0.1	0.1	19.70
Malaysia	85.5	76.9	72.6	70.0	64.3	59.5	85.5	76.9	72.6	70.0	64.3	59.5	57.58
Subtotal IPC International	223.2	159.7	134.9	121.9	97.7	81.0	186.6	137.3	117.3	107.4	86.8	72.9	26.45
Canada	295.7	143.4	101.2	82.1	51.1	33.1	245.2	110.7	75.3	59.6	34.8	20.8	9.09
Grand Total IPC	518.9	303.1	236.1	204.0	148.8	114.1	431.9	248.0	192.6	167.0	121.6	93.7	14.95
Total Probable (PB) Reserves													
France	313.7	195.9	150.8	128.5	90.5	67.8	224.0	147.3	113.8	96.9	67.7	50.3	16.58
Netherlands	20.2	21.4	20.2	19.3	16.8	14.5	18.0	19.3	18.2	17.3	14.9	12.8	22.72
Malaysia	238.5	205.8	189.7	180.0	159.3	142.4	238.5	205.8	189.7	180.0	159.3	142.4	40.84
Subtotal IPC International	**572.4**	**423.1**	**360.7**	**327.8**	**266.6**	**224.7**	**480.4**	**372.4**	**321.7**	**294.2**	**241.9**	**205.4**	**25.20**
Canada	455.1	266.2	203.5	173.2	121.4	89.8	361.9	203.8	153.1	129.0	88.6	64.6	8.43
Grand Total IPC	**1'027.5**	**689.3**	**564.2**	**500.9**	**387.9**	**314.4**	**842.3**	**576.2**	**474.8**	**423.2**	**330.6**	**270.0**	**14.94**
Total Proved plus Probable (2P) Reserves													
France	474.7	322.3	260.1	228.0	170.1	132.6	334.3	241.2	197.4	174.1	131.3	103.1	14.78
Netherlands	-2.6	13.0	17.0	18.5	20.2	20.2	-4.8	11.0	15.0	16.6	18.3	18.5	10.08
Malaysia	391.4	351.0	330.6	318.3	291.4	268.9	391.4	351.0	330.6	318.3	291.4	268.9	40.98
Subtotal IPC International	**863.5**	**686.4**	**607.8**	**564.9**	**481.6**	**421.7**	**720.9**	**603.1**	**543.0**	**509.0**	**441.0**	**390.5**	**22.56**
Canada	1'172.1	886.7	758.4	688.2	552.5	456.9	932.4	710.2	608.2	552.2	443.9	367.4	7.24
Grand Total IPC	**2'035.6**	**1'573.1**	**1'366.2**	**1'253.1**	**1'034.2**	**878.6**	**1'653.4**	**1'313.3**	**1'151.2**	**1'061.2**	**884.8**	**757.9**	**10.44**

Net Present Value of Future Net Revenue – Proved plus Probable plus Possible Reserves (Aggregated)

	Before Deducting Income Tax, Discounted at:						After Deducting Income Tax, Discounted at:						USD/ net BOE
Values in MUSD	**0%**	**5%**	**8%**	**10%**	**15%**	**20%**	**0%**	**5%**	**8%**	**10%**	**15%**	**20%**	**BTAX NPV10**
Proved plus Probable plus Possible Developed Producing (3PDP) Reserves													
France	818.8	432.2	323.8	275.5	199.5	156.4	584.6	324.1	246.3	211.1	155.1	123.1	15.15
Netherlands	32.0	35.0	34.7	34.0	31.8	29.3	22.3	27.4	27.9	27.8	26.2	24.4	12.61
Malaysia	440.3	386.1	359.4	343.5	309.4	281.6	440.3	386.1	359.4	343.5	309.4	281.6	41.01
Subtotal IPC International	1'291.1	853.3	717.9	653.1	540.7	467.3	1'047.3	737.6	633.6	582.5	490.8	429.1	22.32
Canada	1'013.9	791.6	658.4	626.6	512.6	431.6	811.9	642.8	558.5	511.6	420.1	354.9	7.13
Grand Total IPC	2'305.0	1'644.9	1'376.2	1'279.7	1'053.3	899.0	1'859.1	1'380.4	1'192.1	1'094.1	910.9	784.0	10.92
Proved plus Probable plus Possible Developed Non Producing (3PDNP) Reserves													
France	16.7	7.1	4.8	3.9	2.4	1.6	12.4	5.3	3.5	2.8	1.7	1.1	7.51
Netherlands	8.1	7.3	6.4	5.9	4.6	3.7	6.8	6.1	5.3	4.8	3.7	2.9	18.55
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal IPC International	24.8	14.5	11.3	9.7	7.0	5.3	19.1	11.3	8.8	7.6	5.4	4.0	11.72
Canada	156.2	107.7	87.1	75.9	54.7	40.0	114.1	77.5	62.0	53.7	37.8	27.0	6.70
Grand Total IPC	181.0	122.1	98.4	85.7	61.7	45.3	133.2	88.8	70.9	61.3	43.2	31.0	7.05
Proved plus Probable plus Possible Undeveloped (3PUD) Reserves													
France	191.7	115.2	87.3	73.3	48.8	33.4	140.7	83.4	62.3	51.7	33.1	21.4	18.09
Netherlands	0.7	0.7	0.6	0.6	0.6	0.6	0.5	0.4	0.4	0.3	0.4	0.4	30.40
Malaysia	117.8	104.9	98.4	94.6	86.2	79.3	96.6	87.3	82.6	79.8	73.7	68.5	56.79
Subtotal IPC International	310.1	220.8	186.4	168.6	135.6	113.3	237.7	171.1	145.4	131.8	107.1	90.3	29.37
Canada	435.9	205.0	144.8	117.9	74.9	50.2	344.0	154.3	106.2	85.1	51.9	33.1	10.40
Grand Total IPC	746.0	425.8	331.2	286.4	210.5	163.5	581.7	325.5	251.6	216.9	159.0	123.4	16.78
Total Possible (PS) Reserves													
France	552.5	232.2	155.8	124.7	80.6	58.8	403.4	171.5	114.7	91.5	58.6	42.5	17.03
Netherlands	43.4	30.0	24.8	22.0	16.9	13.4	34.4	23.0	18.6	16.3	12.0	9.2	18.37
Malaysia	166.6	140.0	127.2	119.8	104.2	92.0	145.4	122.4	111.5	105.1	91.7	81.2	52.67
Subtotal IPC International	762.5	402.2	307.8	266.5	201.7	164.2	583.2	316.9	244.8	212.9	162.3	132.9	24.69
Canada	433.8	217.6	158.8	132.2	89.6	65.0	337.5	164.5	118.6	98.2	65.9	47.6	8.49
Grand Total IPC	1'196.3	619.8	466.5	398.8	291.3	229.2	920.7	481.4	363.3	311.1	228.3	180.5	15.12
Total Proved plus Probable plus Possible (3P) Reserves													
France	1'027.1	554.5	415.9	352.7	250.7	191.4	737.7	412.7	312.2	265.7	189.9	145.6	15.50
Netherlands	40.8	43.0	41.8	40.6	37.0	33.6	29.6	33.9	33.6	32.9	30.3	27.6	13.35
Malaysia	558.0	491.0	457.8	438.1	395.6	360.9	536.8	473.4	442.1	423.4	383.1	350.1	43.63
Subtotal IPC International	1'626.0	1'088.5	915.5	831.4	683.4	585.9	1'304.1	920.1	787.8	721.9	603.3	523.3	23.20
Canada	1'605.9	1'104.3	917.2	820.4	642.2	521.9	1'270.0	874.6	726.7	650.4	509.8	415.0	7.42
Grand Total IPC	3'232.0	2'192.8	1'832.7	1'651.8	1'325.5	1'107.8	2'574.1	1'794.7	1'514.5	1'372.2	1'113.1	938.4	11.28

Elements of Future Net Revenue (Aggregated)

Total Proved (1P) Reserves MUSD	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
France	693.8	86.1	335.3	32.4	78.9	161.0	50.7	110.3
Netherlands	48.5	-	27.9	0.9	42.4	- 22.8	-	- 22.8
Malaysia	449.5	26.9	236.2	8.9	24.5	153.0	-	153.0
Subtotal IPC International	**1'191.8**	**113.1**	**599.5**	**42.2**	**145.8**	**291.2**	**50.7**	**240.5**
Canada	2'015.9	92.9	735.5	138.5	332.1	717.0	146.4	570.6
Grand Total IPC	**3'207.7**	**206.0**	**1'335.0**	**180.8**	**477.9**	**1'008.1**	**197.1**	**811.1**

Total Proved and Probable (2P) Reserves MUSD	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
France	1'560.1	181.6	743.1	51.4	109.4	474.7	140.4	334.3
Netherlands	88.9	-	44.7	0.9	45.8	- 2.6	2.2	- 4.8
Malaysia	875.8	66.2	381.3	8.9	27.9	391.4	-	391.4
Subtotal IPC International	**2'524.8**	**247.8**	**1'169.1**	**61.2**	**183.1**	**863.5**	**142.6**	**720.9**
Canada	2'814.6	152.1	955.9	184.3	350.2	1'172.1	239.7	932.4
Grand Total IPC	**5'339.4**	**399.9**	**2'125.0**	**245.5**	**533.3**	**2'035.6**	**382.2**	**1'653.4**

Total Proved and Probable and Possible (3P) Reserves MUSD	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
France	2'428.8	275.2	943.0	57.1	126.4	1'027.1	289.4	737.7
Netherlands	147.4	-	65.4	0.9	40.2	40.8	11.3	29.6
Malaysia	1'084.2	86.5	402.8	8.9	27.9	558.0	21.2	536.8
Subtotal IPC International	**3'660.4**	**361.7**	**1'411.3**	**66.9**	**194.5**	**1'626.0**	**321.9**	**1'304.1**
Canada	3'502.8	219.0	1'137.9	184.3	355.8	1'605.9	335.9	1'270.0
Grand Total IPC	**7'163.2**	**580.7**	**2'549.1**	**251.2**	**550.2**	**3'232.0**	**657.9**	**2'574.1**

Net Present Value by Product Type (Aggregated)

IPC Total Future Net Revenue BTAX at 10% Discount	Primary Product Type: Light & Medium Crude Oil (MUSD)	Heavy Crude Oil (MUSD)	Conventional Natural Gas (MUSD)	Natural Gas Liquids (MUSD)	Total (MUSD)
Total Proved (1P) Reserves	237.8	236.6	277.7	-	752.1
Total Proved and Probable (2P) Reserves	546.3	340.6	366.2	-	1'253.1
Total Proved and Probable and Possible (3P) Reserves	790.8	429.3	431.7	-	1'651.8

IPC Total USD per boe by product type	Primary Product Type: Light & Medium Crude Oil (USD/bbl)	Heavy Crude Oil (USD/bbl)	Conventional Natural Gas (USD/Mscf)	Natural Gas Liquids (USD/bbl)	Total (USD/boe)
Total Proved (1P) Reserves	21.5	13.20	0.81	-	8.76
Total Proved and Probable (2P) Reserves	23.5	13.27	0.86	-	10.47
Total Proved and Probable and Possible (3P) Reserves	24.1	13.43	0.89	-	11.36

Notes

(1) Light, Medium, and Heavy Oil Future Net Revenue and Unit Value include associated gas
(2) Conventional natural Gas revenue and unit Value include associated condensate (light oil)

Forecast Prices used in Estimates (Aggregated)

See "IPC's Oil and Gas Assets in France, Malaysia and the Netherlands - Forecast Prices used in Estimates" and "IPC's Oil and Gas Assets in Canada - Forecast Prices used in Estimates" above.

Reconciliation of Changes in Reserves (Aggregated)

Reconciliation of Proved Reserves Mmboe	Malaysia Light & Medium Oil	France Light & Medium Oil	Netherlands Convent-ional Natural Gas	**Sub-Total International Oil Equivalent**	Canada Heavy Oil	Canada Convent-ional Natural Gas	Canada Natural Gas Liquids	**Sub-Total Canada Oil Equivalent**	**IPC Total Oil Equivalent**
Opening Balance December 31, 2016	4.9	11.3	0.9	**17.0**	-	-	-	**-**	**17.0**
extensions and improved recovery	+ 0.7	+ 0.0	+ 0.0	**+ 0.7**				**+ 0.0**	**+ 0.7**
technical revisions	+ 0.8	- 0.5	+ 0.5	**+ 0.8**				**+ 0.0**	**+ 0.8**
discoveries				**+ 0.0**				**+ 0.0**	**+ 0.0**
acquisitions				**+ 0.0**	+ 18.9	+ 59.6	+ 0.0	**+ 78.6**	**+ 78.6**
dispositions				**+ 0.0**				**+ 0.0**	**+ 0.0**
economic factors	+ 0.0	- 1.1	+ 0.0	**- 1.1**				**+ 0.0**	**- 1.1**
production	- 2.4	- 0.9	- 0.4	**- 3.7**				**+ 0.0**	**- 3.7**
Closing Balance December 31, 2017	3.9	8.8	1.0	**13.7**	18.9	59.6	0.0	**78.6**	**92.3**

Reconciliation of Proved + Probable Reserves Mmboe	Malaysia Light & Medium Oil	France Light & Medium Oil	Netherlands Convent-ional Natural Gas	**Sub-Total International Oil Equivalent**	Canada Heavy Oil	Canada Convent-ional Natural Gas	Canada Natural Gas Liquids	**Sub-Total Canada Oil Equivalent**	**IPC Total Oil Equivalent**
Opening Balance December 31, 2016	9.5	18.0	1.8	**29.4**	-	-	-	**-**	**29.4**
extensions and improved recovery	+ 1.4	+ 0.5	+ 0.0	**+ 1.9**				**+ 0.0**	**+ 1.9**
technical revisions	+ 0.8	+ 0.3	+ 0.4	**+ 1.6**				**+ 0.0**	**+ 1.6**
discoveries				**+ 0.0**				**+ 0.0**	**+ 0.0**
acquisitions				**+ 0.0**	+ 27.3	+ 73.2	+ 0.1	**+ 100.6**	**+ 100.6**
dispositions				**+ 0.0**				**+ 0.0**	**+ 0.0**
economic factors	- 0.3	- 0.3	+ 0.0	**- 0.6**				**+ 0.0**	**- 0.6**
production	- 2.4	- 0.9	- 0.4	**- 3.7**				**+ 0.0**	**- 3.7**
Closing Balance December 31, 2017	9.1	17.6	1.8	**28.5**	27.3	73.2	0.1	**100.6**	**129.1**

Reconciliation of Proved + Probable + Possible Reserves Mmboe	Malaysia Light & Medium Oil	France Light & Medium Oil	Netherlands Convent-ional Natural Gas	**Sub-Total International Oil Equivalent**	Canada Heavy Oil	Canada Convent-ional Natural Gas	Canada Natural Gas Liquids	**Sub-Total Canada Oil Equivalent**	**IPC Total Oil Equivalent**
Opening Balance December 31, 2016	13.3	23.8	3.2	**40.3**	-	-	-	**-**	**40.3**
extensions and improved recovery	+ 2.0	+ 0.7	+ 0.0	**+ 2.7**				**+ 0.0**	**+ 2.7**
technical revisions	- 1.1	+ 2.3	+ 0.3	**+ 1.5**				**+ 0.0**	**+ 1.5**
discoveries				**+ 0.0**				**+ 0.0**	**+ 0.0**
acquisitions				**+ 0.0**	+ 34.5	+ 83.0	+ 0.1	**+ 117.6**	**+ 117.6**
dispositions				**+ 0.0**				**+ 0.0**	**+ 0.0**
economic factors	+ 0.0	- 0.0	+ 0.0	**- 0.0**				**+ 0.0**	**- 0.0**
production	- 2.4	- 0.9	- 0.4	**- 3.7**				**+ 0.0**	**- 3.7**
Closing Balance December 31, 2017	11.8	25.9	3.0	**40.7**	34.5	83.0	0.1	**117.6**	**158.3**

Undeveloped Reserves (Aggregated)

	Light & Medium Crude Oil (MMbbl)	Heavy Crude Oil (MMbbl)	Conventional Natural Gas (Bscf)	Natural Gas Liquids (MMboe)	Oil Equivalent (MMboe)
Proved Undeveloped					
December 31, 2015	-	-	-	-	-
December 31, 2016	3.1	-	-	-	3.1
December 31, 2017	0.7	5.4	0.6	0.0	6.2
Probable Undeveloped					
December 31, 2015	-	-	-	-	-
December 31, 2016	3.3	-	-	-	3.3
December 31, 2017	1.4	9.6	1.1	0.0	11.2

See "IPC's Oil and Gas Assets in France, Malaysia and the Netherlands – Undeveloped Reserves" and "IPC's Oil and Gas Assets in Canada – Undeveloped Reserves".

IPC Development Projects (Aggregated)

	Light & Medium Crude Oil Reserves MMbbl gross	Heavy Crude Oil Reserves MMbbl gross	Convent-ional Natural Gas Reserves Bscf Gross	Future Project Development Capital MUSD				Net Present Value, MUSD Before Deducting Income Tax, Discounted at:						Net Present Value, MUSD After Deducting Income Tax, Discounted at:						BTAX NPV10 per boe USD per boe	ATAX NPV10 per boe USD per boe
				2018	2019	Total	USD per boe	0%	5%	8%	10%	15%	20%	0%	5%	8%	10%	15%	20%		
France - Vert La Gravelle Redevelopment																					
Proved Undeveloped (PUD)	2.2	-	-	0.9	24.8	25.8	11.5	66	34	22	16	7	1	49	25	16	11	4	1	7.37	5.10
Proved and Probable Undeveloped (PPUD)	3.9	-	-	0.9	39.1	44.3	11.2	137	83	62	52	33	21	101	60	45	37	22	13	13.13	9.30
Proved plus Probable plus Possible Undeveloped (PPPUD)	4.7	-	-	0.9	39.1	49.8	10.5	192	115	87	73	49	33	141	83	62	52	33	21	15.47	10.90
Malaysia - A16 and A17 Development Wells																					
Proved Undeveloped (PUD)	0.7	-	-	7.7	-	7.7	11.7	32	30	29	29	27	26	32	30	29	29	27	26	43.15	43.15
Proved and Probable Undeveloped (PPUD)	1.4	-	-	7.7	-	7.7	5.5	85	77	73	70	64	59	85	77	73	70	64	59	49.52	49.52
Proved plus Probable plus Possible Undeveloped (PPPUD)	2.0	-	-	7.7	-	7.7	3.9	118	105	98	95	86	79	97	87	83	80	74	68	47.50	40.10
Canada - Oil Drilling and EOR																					
Proved Undeveloped (PUD)	-	5.4	0.6	4.1	16.4	43.1	7.8	142	70	49	39	23	13	117	56	37	29	15	7	7.03	5.21
Proved and Probable Undeveloped (PPUD)	-	9.6	1.1	4.1	22.8	65.6	6.7	296	143	101	82	51	33	245	111	75	60	35	21	8.37	6.08
Proved plus Probable plus Possible Undeveloped (PPPUD)	-	12.3	1.4	4.1	22.8	65.6	5.2	436	205	145	118	75	50	344	154	106	85	22	33	9.39	6.78
Total IPC																					
Proved Undeveloped (PUD)	**2.9**	**5.4**	**0.6**	**12.7**	**41.2**	**76.6**	**31.0**	**241**	**134**	**100**	**84**	**56**	**40**	**198**	**111**	**82**	**69**	**46**	**32**	**9.95**	**8.15**
Proved and Probable Undeveloped (PPUD)	**5.4**	**9.6**	**1.1**	**12.7**	**61.9**	**117.6**	**23.4**	**519**	**303**	**236**	**204**	**149**	**114**	**432**	**248**	**193**	**166**	**122**	**94**	**13.45**	**10.97**
Proved plus Probable plus Possible Undeveloped (PPPUD)	**6.7**	**12.3**	**1.4**	**12.7**	**61.9**	**123.1**	**19.6**	**745**	**425**	**331**	**286**	**210**	**163**	**581**	**325**	**251**	**217**	**129**	**123**	**14.82**	**11.24**

Significant Factors or Uncertainties Affecting Reserves Data (Aggregated)

See "IPC's Oil and Gas Assets in France, Malaysia and the Netherlands – Significant Factors or Uncertainties Affecting Reserves Data" and "IPC's Oil and Gas Assets in Canada – Significant Factors or Uncertainties Affecting Reserves Data".

Future Development Costs (Aggregated)

	2018	2019	2020	2021	2022	2023 on	Total for all years undiscounted	**Total for all years discounted at 10% p.a.**
Total Proved								
Canada	6.8	29.7	33.1	16.5	3.2	49.3	138.5	**86.4**
France	5.1	26.2	1.1	-	-	-	32.4	**28.4**
Netherlands	0.9	-	-	-	-	-	0.9	**0.9**
Malaysia	8.9	-	-	-	-	-	8.9	**8.8**
Total	21.8	55.8	34.2	16.5	3.2	49.3	180.8	**124.4**
Total Proved Plus Probable								
Canada	6.8	36.0	39.0	18.2	14.8	69.3	184.3	**116.7**
France	5.3	40.7	5.4	-	-	-	51.4	**44.5**
Netherlands	0.9	-	-	-	-	-	0.9	**0.9**
Malaysia	8.9	-	-	-	-	-	8.9	**8.8**
Total	22.0	76.7	44.4	18.2	14.8	69.3	245.5	**170.8**

Expectations of Sources and Costs of Funding (Aggregated)

See “IPC’s Oil and Gas Assets in France, Malaysia and the Netherlands – Expectations of Sources and Costs of Funding” and “IPC’s Oil and Gas Assets in Canada – Expectations of Sources and Costs of Funding” above.

Producing and Non-Producing Well Counts (Aggregated)

See “IPC’s Oil and Gas Assets in France, Malaysia and the Netherlands – Producing and Non-Producing Well Counts” and “IPC’s Oil and Gas Assets in Canada – Producing and Non-Producing Well Counts” above.

Properties with No Attributed Reserves (Aggregated)

See “IPC’s Oil and Gas Assets in France, Malaysia and the Netherlands – Properties with No Attributed Reserves” and “IPC’s Oil and Gas Assets in Canada – Properties with No Attributed Reserves” above.

Tax Horizon (Aggregated)

See “IPC’s Oil and Gas Assets in France, Malaysia and the Netherlands – Tax Horizon” and “IPC’s Oil and Gas Assets in Canada – Tax Horizon” above.

Production Forecast Estimates (Aggregated)

	Light & Medium Crude Oil (Mbbl/d)	Heavy Crude Oil (Mbbl/d)	Conventional Natural Gas (Mboe/d)	Natural Gas Liquids (Mboe/d)	Total (Mboe/d)
Total Proved (1P) Scenario					
France	1.96	-	-	-	1.96
Netherlands	0.02	-	0.79	-	0.80
Malaysia	5.29	-	-	-	5.29
Subtotal IPC International	**7.27**	**-**	**0.79**	**-**	**8.05**
Canada	-	6.12	16.10	-	22.22
Total IPC	**7.27**	**6.12**	**16.88**	**-**	**30.27**
Total Proved plus Probable (2P) Scenario					
France	2.31	-	-	-	2.31
Netherlands	0.02	-	0.94	-	0.96
Malaysia	6.58	-	-	-	6.58
Subtotal IPC International	**8.92**	**-**	**0.94**	**-**	**9.86**
Canada	-	6.32	16.27	-	22.59
Total IPC	**8.92**	**6.32**	**17.21**	**-**	**32.45**
Total Proved plus Probable plus Possible (3P) Scenario					
France	2.62	-	-	-	2.62
Netherlands	0.02	-	1.08	-	1.10
Malaysia	7.72	-	-	-	7.72
Subtotal IPC International	**10.36**	**-**	**1.08**	**-**	**11.44**
Canada	-	6.41	16.38	-	22.79
Total IPC	**10.36**	**6.41**	**17.46**	**-**	**34.23**

Contingent Resources (Aggregated)

See “IPC’s Oil and Gas Assets in France, Malaysia and the Netherlands – Contingent Resources” and “IPC’s Oil and Gas Assets in Canada – Contingent Resources” above.

Prospective Resources (Aggregated)

See “IPC’s Oil and Gas Assets in France, Malaysia and the Netherlands – Prospective Resources” above.

MARKET OVERVIEW

The following industry overview describes the Corporation's market. The information contained in the Section below originates from the Corporation, unless expressly stated otherwise. The Corporation has obtained this information from several sources, including industry publications and market surveys from third parties as well as publicly available information. The information obtained from third parties has been accurately reproduced, and as far as Corporation is aware and is able to ascertain from information published by such third parties, no facts have been omitted which would render the reproduced information inaccurate or misleading.

Oil and Gas Market Overview

Global energy consumption is driven by world population, economic growth and availability of resources. Overall consumption has seen a steady increase throughout modern economic history. Going forward, energy consumption is expected to increase for all forms of energy, primarily as a result of increased consumption in emerging economies as well as a growing global population and expanding economy. According to BP's 2017 Statistical Review of World Energy, oil is the most consumed source with an annual consumption of 96 million barrels per day in 2016. Oil is used for a wide array of purposes including transportation, petrochemical processes, power generation and agriculture. Currently, oil used for transportation in the form of gasoline, diesel and jet fuel is the main source of oil consumption globally. Transportation is expected to be a key source of consumption growth going forward. As a result of among other things, increased fuel efficiency and stricter environmental policies, consumption in OECD countries is expected to decrease while global consumption is expected to increase overall due to strong consumption growth in emerging economies.

Oil is found in large quantities on most continents of the world. The largest producers are Russia, Saudi Arabia and the United States. Going forward, oil production growth is expected to be dependent on increased output from the OPEC, as well as increased unconventional oil production, including Canadian oil sands, tight oil and extra heavy oil, while conventional oil production is expected to decline due to natural production decline in existing fields, reduced rate of production from new conventional fields and under-investment in the industry due to current oil price levels.

Oil is a commodity with a well-developed world market. The prices are determined on the world's leading commodities exchanges, with NYMEX in New York and the IPE in London as the most important markets for the determination of world oil prices. Prices are determined by the weight of the oil, with WTI as the main benchmark for NYMEX and Brent Crude as the main benchmark for IPE. In recent years, Brent price has emerged as the benchmark price of oil sales in global markets. Oil prices have historically experienced significant fluctuations. After a period of oil price increases, during second half of 2014, the oil price saw a sharp decline, impacted by strong supply from onshore United States, lower than expected demand growth, and OPEC deciding to not reduce its production. In February 2016, oil prices hit a ten-year low at around USD 26 per barrel. From the middle of 2016 until near the end of 2017, the oil price ranged around USD 50 per barrel, and then has increased above USD 70 per barrel into 2018.

Natural gas is recognized as a regional commodity owing to the necessity to ship produced gas via pipeline to hubs capable of redirecting and distributing to purchasers; as a result, prices are often responsive to the proximal market space where natural gas is originated.

The Canadian, Malaysian, French and Dutch Industry Overviews and Regulatory Regimes

Canada Country Overview

Companies carrying on business in the oil and natural gas industry in Canada are subject to extensive controls and regulations imposed through legislation of the federal government and the provincial governments where the companies have assets or operations. IPC holds interests in oil and natural gas properties, along with related assets, in the province of Alberta, Canada. Regulated aspects of IPC's business include activities associated with the exploration for and production of oil and natural gas, including: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations of and access to operational sites; (iv) operating standards; (v) environmental impacts; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. The discussion below outlines certain conditions and regulations that impact the oil and natural gas industry in Alberta, Canada.

Pricing and Marketing in Canada

Oil

Producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Natural Gas

The price of natural gas sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Transportation Constraints and Market Access

Producers negotiate with pipeline operators (or other transport providers) to transport their products. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Alberta have experienced low pricing relative to other markets in the last several years. Transportation availability is highly variable across different areas and regions, which can determine the nature of transportation commitments available, the numbers of potential customers that can be reached in a cost-effective manner and the price received.

Developing a strong network of transportation infrastructure for oil and natural gas, including by means of pipelines, rail, marine and trucks, in order to obtain better access to domestic and international markets has been a significant challenge to the Canadian oil and natural gas industry. Several proposals have been announced to increase pipeline capacity out of Alberta, to reach Eastern Canada, the United States and international markets, including via export shipping terminals on the west coast of Canada. While certain projects are proceeding, the regulatory approval process as well as economic and political factors for transportation and other export infrastructure has led to the delay of many pipeline projects or their cancellation altogether.

Natural gas prices in Alberta have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. While companies that secure firm access to transport their natural gas production out of Alberta may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in Alberta for their natural gas, which in the last several years has generally been depressed. Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Alberta may be further exacerbated by natural gas storage limitations.

Land Tenure

The Alberta provincial government predominantly owns the mineral rights to oil and natural gas located in Alberta. The Government of Alberta grants rights to explore for and produce oil and natural gas pursuant to leases for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. The leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time and other conditions are satisfied.

To develop oil and natural gas resources, it is necessary for the mineral estate owner to have access to the surface lands as well. Each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation for affected persons for lost land use and surface damage.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within indigenous reservations designated under the *Indian Act* (Canada).

Royalties and Incentives

General

Alberta has legislation and regulations that govern royalties, production rates and other matters. The royalty regime may be a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands where the Government of Alberta does not hold the mineral rights are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Government of Alberta lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum substance produced.

Producers and working interest owners of oil and natural gas rights may also carve out additional royalties or royalty-like interests through non-public transactions, which include the creation of instruments such as overriding royalties, net profits interests and net carried interests.

In Alberta, the provincial government royalty rates apply to Government of Alberta-owned mineral rights. In 2016, Alberta adopted a modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after January 1, 2017. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework.

The Modernized Framework applies to all hydrocarbons other than oil sands. Royalties on production under the Modernized Framework are determined on a "revenue-minus-costs" basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and/or horizontal length. The formula is based on the industry’s average drilling and completion costs as determined by the Alberta Energy Regulator (the "**AER**") on an annual basis.

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues of between 5% and 40% determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum of 5% as the mature well's production declines. As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

The Old Framework is applicable to all conventional oil and natural gas wells drilled prior to January 1, 2017. Subject to certain available incentives, royalty rates for conventional oil production under the Old Framework range from a base rate of 0% to a cap of 40%. Subject to certain available incentives, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 meters deep, as well as the acid gas content of the produced gas.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal oil and natural gas wells.

Freehold mineral taxes are levied for production from freehold mineral lands on an annual basis on calendar year production. Freehold mineral taxes are calculated using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. On average, in Alberta the tax levied is 4% of revenues reported from freehold mineral title properties. The freehold mineral taxes would be in addition to any royalty or other payment paid to the owner of such freehold mineral rights, which are established through private negotiation.

Freehold and Other Types of Non-Crown Royalties

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract.

In addition to the royalties payable to the mineral owners, producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral taxes or production taxes. Freehold mineral taxes or production taxes are taxes levied by the provincial government on oil and natural gas production from lands where the Government of Alberta does not hold the mineral rights.

Regulatory Authorities and Environmental Regulation

General

The oil and natural gas industry is subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, all of which are subject to review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and natural gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail. However, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport including interprovincial pipelines.

Alberta

The AER is the single regulator responsible for all resource development in Alberta. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The objective behind a single regulator is an enhanced regulatory regime that is intended to be efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity.

The Government of Alberta's land-use policy for surface land in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province.

Liability Management Rating Program

The AER administers the Licensee Liability Rating Program (the "**LLR Program**"). The LLR Program is a liability management program governing most conventional upstream oil and natural gas wells, facilities and pipelines. Alberta's *Oil and Gas Conservation Act* (the "**OGCA**") establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the LLR Program if a licensee or working interest participant ("**WIP**") becomes insolvent or is unable to meet its obligations. The Orphan Fund is funded by licensees in the LLR Program through a levy administered by the AER. The LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month and where a security deposit is deemed to be required, the failure to post any required amounts may result in the initiation of enforcement action by the AER. The AER publishes the liability management rating for each licensee on a monthly basis on its public website.

The AER's *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licence eligibility to operate wells and facilities, was recently amended and now requires corporate governance and shareholder information, with a particular focus on any previous companies of directors and officers that have been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all are assessed and the AER now requires all transferees to demonstrate that they have a liability management rating, being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer, or to otherwise prove that it can satisfy its abandonment and reclamation obligations.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada.

In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on IPC’s operations and cash flow from operating activities.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of February 1, 2018, 174 of the 197 parties to the convention have ratified the Paris Agreement.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at CAD 10/tonne, increasing annually until it reaches CAD 50/tonne in 2022. A draft legislative proposal for the federal carbon pricing system was released on January 15, 2018. This system would apply in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards in 2018. Four provinces currently have carbon pricing systems in place that would meet federal requirements (Alberta, British Columbia, Ontario and Quebec).

On May 27, 2017, the federal government published draft regulations to reduce emissions of methane from the oil and natural gas sector. The proposed regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that oil and natural gas operations use low-emission equipment and processes, by introducing new control measures. Among other things, the proposed regulations limit how much methane upstream oil and gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the "**CLP**"). The CLP has four areas of focus: implementing a carbon price on GHG emissions, phasing out coal-generated electricity and developing renewable energy, legislating an oil sands emission limit, and introducing a new methane emissions reduction plan. The Government of Alberta has since introduced new legislation to give effect to these initiatives. The *Climate Leadership Act* came into force on January 1, 2017 and enabled a carbon levy that increased from CAD 20 to CAD 30 per tonne on January 1, 2018. The levy is anticipated to increase again in 2021 in line with the federal legislation.

The *Carbon Competitiveness Incentives Regulation* (the "**CCIR**"), which replaces the *Specified Gas Emitters Regulation*, came into effect on January 1, 2018. Unlike the previous regulation, which set emission reduction requirements, the CCIR imposes an output-based benchmark on competitors in the same emitting industry. The aim is to reduce annual GHG emissions by 20 megatonnes by 2020 and 50 megatonnes by 2030, and targets facilities that emit more than 100,000 tonnes of GHGs per year and mandates quarterly and final reporting requirements. The CCIR compliance obligations will be reduced by 50% and 25% for 2018 and 2019, respectively, with no reduction for 2020 onward. In addition to the industry-specific benchmarks, each benchmark will decrease annually at a rate of 1%, beginning in 2020. The Government of Alberta intends for this strategy to align with the federal Framework.

The Government of Alberta also signaled its intention through its CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Regulations are planned to take effect in 2020 to ensure the 2025 target is met.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed to fund two large-scale carbon capture and storage projects that will begin commercializing the technology. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

Accountability and Transparency

In 2015, the federal government's *Extractive Sector Transparency Measures Act* (the "**ESTMA**") came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to ESTMA must report payments over CAD 100,000 made to any level of a Canadian or foreign government (including indigenous groups), including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments. IPC's ESTMA report for the year ended December 31, 2017 is available on its corporate website.

Malaysian Country Overview[1]

Industry Summary

Malaysia's upstream sector has been built upon the oil and gas fields in the shallow waters off Peninsular Malaysia and Sarawak, which have been the focus of development activity since the 1960s. As production in this region has matured, the attention of major operators switched to the deepwater potential off of Borneo in the Sarawak and Sabah basins. This change in focus has led to large oil discoveries such as Kikeh and Gumusut, offshore of Sabah. In recent years, the Malaysian state oil company Petronas and other operators have discovered large gas accumulations in carbonate pinnacle reef structures in Sarawak.

Oil production in Malaysia began in the early part of the 20th century. In the 1960s, exploration activity moved offshore and the first significant fields were brought onstream. Since reaching a peak of 770,500 bbl/d in 1995, liquids production has declined. Malaysia is now considered a relatively mature oil producer.

Gas is an increasingly important component of the energy economy of Malaysia, as evidenced by the comparison of liquids and gas production through time. Gas production in Malaysia can be split into peninsular production, supplied for domestic consumption in peninsular Malaysia, and Borneo production, the majority of which is converted to liquefied natural gas for export at the Bintulu plant in Sarawak.

Regulatory Framework

Key Legislation

Petroleum Development Act

The Petroleum Development Act 1974 (the "**PDA**") and the Petroleum Regulation 1974 enacted pursuant to the PDA (the "**Petroleum Regulation**") are the key legislative enactments that govern oil and gas exploration activities both onshore and offshore in Malaysia. The PDA came into force on October 1, 1974. Pursuant to the PDA, the entire ownership in, and the exclusive rights, powers, liberties, privileges of exploring, winning and obtaining petroleum onshore and offshore were vested in Petronas, Malaysia's national oil company. The vesting of the ownership, rights, powers, liberties and privileges from Malaysia to Petronas is in perpetuity and irrevocable. The PDA and the Petroleum Regulation also set out the licensing requirements for upstream activities and the downstream activities of refining, marketing and distributing oil products.

Petroleum (Income Tax Act) 1967

The Petroleum (Income Tax) Act 1967 ("**PITA**") governs the taxation of petroleum income in Malaysia.

Environmental and Decommissioning

Decommissioning of oil and gas facilities and pipelines is governed by a number of laws due to the variety of activities that are required to undertake abandonment and decommissioning. Such laws include the Continental Shelf Act 1966, the Exclusive Economic Zone Act 1984, the Petroleum (Safety Measures) Act 1984, the Environmental Quality Act 1974, the Occupational Safety and Health Act 1994, the Fisheries Act 1985, the Merchant Shipping Ordinance 1952 and the Merchant Shipping (Oil Pollution) Act 1994. In summary, the laws require that the abandonment and decommissioning activities be carried out safely, not cause any environmental degradation and not interfere with other offshore activities such as fishing.

Other Key Legislation

The Petroleum (Safety Measures) Act 1984 (the "**PSMA**") and the regulations thereunder govern the transportation, storage and handling of oil and oil products. The Environmental Quality Act 1974 (the "**EQA**")

[1] The "Malaysian Country Overview" section was based on Fariz Abdul Aziz, "Malaysia" in Christopher B. Strong, ed, *The Oil and Gas Law Review* (November 2016, 4th ed) 162. The parts of this disclosure reproduced or taken from the chapter have been reproduced with the permission of the author and Law Business Research Ltd.

is the main legislation governing the protection of the environment and the protection of oil spills and pollutants on land and in Malaysian waters.

Many of Malaysia's oilfields are situated in its exclusive economic zone. The exclusive Economic Zone Act (1984) governs activities in Malaysia's exclusive economic zone.

Regulatory Body

As a result of the PDA, Petronas exercises regulatory powers in respect of the upstream sector. Any person wishing to engage in exploration activities is required to be authorized to do so by Petronas, either by entering into a PSC or by obtaining a licence from Petronas to provide services to the upstream industry.

The construction and operation of petroleum pipelines is governed by the PSMA and the Petroleum (Safety Measures) (Transportation of Petroleum by Pipelines) Regulations 1985, which is under the purview of the Petroleum Safety Unit of the Ministry of Domestic Trade, Co-operatives and Consumerism.

Licensing

Production Sharing Contracts

Since the enactment of the PDA, a person seeking to obtain rights to explore, develop and produce petroleum is required to enter into a PSC with Petronas.

Almost all licences in Malaysia are presently governed by PSCs. The terms and scope of the rights granted are entirely contained in the PSC and such rights are enforceable under Malaysian law. The terms of the PSC provide that the party to the PSC (the "**PSC Contractor**") is solely responsible for the provision of all funds required directly or indirectly for petroleum operations. The PSC Contractor is then entitled to recover costs related to petroleum operations and a share of profits from the production of crude oil or natural gas in kind, based on a defined formula contained in the PSC.

PSCs also set out specific responsibilities for decommissioning and abandonment. The terms of the PSC require that PSC Contractors make payments to a fund for abandonment and decommissioning operations known as the "abandonment cess". Payment of the abandonment cess commences upon commercial production of petroleum and is payable on an annual basis. Such payments are cost recoverable under the terms of the PSC.

State Participation in Oil and Gas Production

As a matter of policy, Petronas' exploration arm, PCSB, must be a party to all PSCs awarded by Petronas, with a view to allowing the state a direct interest in the PSC awarded as well as the ability to derive knowledge from the other PSC Contractors. Under current PSC terms, PCSB has the right to a carried interest in any exploration block during the exploration period. The interest is negotiable, but it usually varies between 15% and 25%. Once a commercial discovery has been made, PCSB must elect whether or not to become a working partner in any development.

Production Restrictions

Petronas reserves the right to restrict a PSC Contractor from holding Malaysian crude oil in any form of buffer stock that is contrary to a PSC Contractor's normal market operations.

In respect of crude oil exports, PSC Contractors are free to export their respective of crude oil produced, subject to obtaining the relevant customs approvals and complying with the reporting obligations to Petronas. In terms of gas sales, PSC Contractors are required to sell their entitlement of natural gas produced on a joint dedicated basis with Petronas.

While there are generally no requirements for PSC Contractors to sell any portion of oil produced to the local market, this is subject to provisions contained in the PSC that apply to times of general shortage of supplies of petroleum in countries that are from time to time members of the Association of Southeast Asian

Nations Council on Petroleum or its successor, or to Malaysian refineries and petrochemical plants. In such times, PSC Contractors are required to give preference to prospective buyers in such countries and to Malaysian refineries and petrochemical plants provided that the prices and other terms of purchase offered are competitive.

Fiscal Terms

Petroleum (Income Tax Act) 1967

Petroleum income tax is charged on the income of every "chargeable person" derived from "petroleum operations" in Malaysia at a rate of 38%. The "chargeable persons" under PITA are Petronas, the Malaysia-Thailand Joint Authority and PSC Contractors in respect of each PSC. PSC Contractors are taxed on a per-PSC basis on the profit oil and profit gas, less allowable deductions and capital allowances, produced from its operations in Malaysia. PITA allows qualifying exploration expenditures and expenditures wholly and exclusively incurred in the production of gross income to be deducted from gross income.

Tax Incentives

To encourage the development of marginal fields, enhanced oil recovery, high carbon dioxide gas, high-pressure, high-temperature, and deep water projects, the government introduced new tax incentives through the following subsidiary legislation:

- Petroleum (Income Tax) (Exemption) Order 2013 (the "**Exemption Order**");
- Petroleum (Income Tax) (Accelerated Capital Allowances) (Marginal Field) Rules 2013 (the "**ACA Rules**");
- Petroleum (Income Tax) (Marginal Field) Regulations 2013; and
- Petroleum (Income Tax) (Investment Allowance) Regulations (the "**IA Regulations**", and collectively, the "**New Tax Incentives**").

The New Tax Incentives took effect in November 2010. The ACA Rules allow for accelerated capital allowance on qualifying plant expenditures incurred for petroleum operations in a marginal field. Applying the accelerated capital allowance rate, capital allowance on qualifying plant expenditures can be fully claimed within five years as opposed to ten years based on conventional capital allowance rates. Under the Exemption Order, the Minister exempts a portion of the statutory income derived from petroleum operations in a marginal field, which results in "chargeable income" derived from marginal fields being taxed at 24.966% instead of 38%.

The IA Regulations provide for an investment allowance equal to 60% of qualifying capital expenditures incurred in a period for a year of assessment within a period of ten years in respect of a qualifying project; or on an infrastructure asset as determined by the Minister. A "qualifying project" is a project that carries out either enhanced oil recovery, high carbon dioxide gas, high-pressure, high-temperature, or any combination thereof; or a project in an area under a PSC in respect of a deep water project. This results in a 60% investment allowance in addition to capital allowance, and 70% of statutory income from a qualifying project is tax exempted equal to the investment allowance available.

Royalties

The PDA expressly stipulates that in return for the vesting of ownership and rights in the petroleum resources, Petronas is to make cash payments to the federal government and the government of the state in which petroleum is produced. The payments are made by Petronas in the form of royalty payments to the federal government, which are in turn distributed to the applicable state governments. The source of these payments is the production of oil and gas under various PSCs. Under the PSC framework, 10% of all petroleum won and saved by PSC Contractors is paid to Petronas in order to satisfy payment of royalties under the PDA.

Profit Sharing

Apart from the royalty payments, PSC contractors are also required to share a certain proportion of profit oil or profit gas from crude oil and natural gas produced with Petronas, based on a predetermined formula. In order to share in any upside in the price of oil, PSC Contractors are required to make supplemental cash payments to Petronas for such portion of the PSC Contractor's portion of the profit oil or profit gas that exceeds the specified base price agreed in the PSC.

France Country Overview

Industry Summary

France is a mature hydrocarbon country. French production originates from three main sedimentary basins known as the Aquitaine, Paris and Alsace basins. Nearly all of the Oil and Gas Assets in France are located in the Paris Basin and the Aquitaine Basin.

Commercial oil production began in France in 1950 and peaked in 1988, when rising production from the Paris Basin exceeded the decline from the Aquitaine Basin fields. The bulk of current oil production in France comes from the Paris Basin.

Regulatory Regime Summary

As there are no formal licensing rounds in France, companies can make individual applications for unlicensed areas. There are essentially two types of licence: exploration and production. All licensing regulations are controlled by the General Department of Energy and Climate in conjunction with the General Council of Mines.

The fiscal terms which apply to the upstream oil and gas industry in France are based on a concession system. Business tax and royalties are payable to the government and further local levies are payable to the local authorities where the fields are situated. For 2017, the corporate tax rate was 33.3% with a social surtax of 3.3% on net profits over USD 2.23 million, resulting in a marginal tax rate of up to 34.43%.

In 2011, the French government imposed a ban on hydraulic fracturing. This ban remains in place and effectively prohibits exploration for and development of unconventional oil and gas deposits in France.

Regulatory Framework

Key Legislation

In France, all mining resources from the subsoil, including oil and gas, belong to the state. The 2011 Mining Code, which came into force on March 1, 2011, allows the government to delegate to companies the right to explore the subsoil and produce oil and gas. Certain provisions of the Mining Code that were in effect prior to the 2011 Mining Code remain in force until the publication of the regulatory provisions of the 2011 Mining Code. The 2011 Mining Code defines the process by which exploration permits (*permis exclusifs de recherches*) and production licences (*concessions*) may be granted and how royalties should be set. In addition, the General Code of Taxation (*Code general des impots*) details how Communal and Departmental taxes, as well as corporate income tax payable to the state, are calculated.

Management of the Corporation understands that a reform of the 2011 Mining Code was launched by the French government in 2013. However, the bill in relation to that reform has not yet been released.

Regulatory Body

The Minister of Environment, Energy and Sea, together with the Minister of the Economy, Industry and Digital Economy, who are jointly in charge of mining, are responsible for granting the licenses. License applications are processed by the General Department of Energy and Climate (*Direction Générale de l'Énergie et du Climat*) and, more specifically, the Oil & Gas Department (*Bureau Exploration-Production* *des Hydrocarbures*) of the Ministry of Environment, Energy and Sea. Regulation and administration of the mining activities are carried out through the local state representatives.

Exploration Permits (permis exclusif de recherches)

As there are no formal licensing rounds, companies can make individual applications for unlicensed areas. Applications must give information relating to the identity of the applicant, its technical and financial capacities, a technical notice, cartographical documents, a financial commitment referring to a work programme, an assurance that the work programme is within the environment protection regulations (*notice d'impact indiquant les incidences éventuelles des travaux projetés sur l'environnement et les conditions dans lesquelles l'opération projetée prend en compte les préoccupations d'environnement*) and, as the case may be, the consent of the holder of an existing mining licence.

Once awarded, the project (*projet d'attribution*) is submitted to the General Council of Economy, Industry, Energy and Technology (*Conseil général de l'économie, de l'industrie, de l'énergie et des technologies*) which has to issue an opinion. The exploration permit is then granted by an order (*arrêté*) of the Minister in charge of mining.

Exploration permits are awarded for an initial period of five years or less. In every case, there is a financial commitment referring to an agreed work programme. There are no rental payments for holding exploration permits. The permit may be renewed twice, each time for five years or less.

Applications for extension of exploration permits are submitted to the Minister in charge of mining. If the initial work programme requirements have been completed, renewals are not generally rejected. The extension of exploration permits is granted by an order (*arrêté*) of the Minister in charge of mining.

Any transfer to a new permit holder must be submitted to the Minister in charge of mining for approval. Any project for a change of control of the exploration permit holder must be prior notified to the Minister in charge of mining, who has a two-month period, that may be renewed once, to oppose the project.

Production Licences (Concessions)

The concession is granted for a period of not more than 50 years and could be renewed several times for 25 years or less. However, the initial period of the concession is flexible and is generally shorter for smaller developments, it being specified that the maximum duration of the concession shall not exceed 50 years. It should be noted that production can commence from a new field on an exploration permit prior to the award of a concession.

As for the award of exploration permits, the award of concessions is subject to a specific procedure involving competition, except in the case where the applicant has already been granted an exploration permit on the corresponding area. This specific procedure differs from that one relating to the award of exploration permits, in particular as it involves a public enquiry *(enquete publique*). The concession is granted by decree (*décret en Conseil d'Etat*).

French Decree 2006-648 dated June 2, 2006 relating to mining licences stipulates, in particular, the following:

- any project which may involve a change of control of the licence-holding company (whether direct or indirect) needs to be notified to the Minister of Mines in advance. The Minister of Mines has a two-month period (which can be extended to four months) to oppose the project; and

- any project which involves a material modification to the financial and technical capabilities taken into consideration at the time when the licence was granted must be notified to the Minister of Mines.

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.

Fiscal Terms

Mineral rights in France belong to the French State, and production of hydrocarbons occurs under a concession regime. Holders of a concession or production licence must pay the French tax authorities a royalty proportional to the value of the products extracted. This royalty is paid starting from production. The royalty regime distinguishes between "old production" (i.e., quantities extracted from wells "*puits*" put in service before January 1, 1980) and "new production" (other extracted quantities) and is ring-fenced by production concession. Under the current French Mining Code, the royalty payable is progressive and depends on annual production levels. Royalty rates applicable to oils are currently ranging between (i) 0% (for the portion of the production below 50,000 tonnes, i.e., 1,014 bbl/d) and 12% (above 300,000 tonnes, i.e., 6,082 bbl/d) for "new production", and (ii) 8% (below 50,000 tonnes, i.e., 1,014 bbl/d) and 30% (above 100,000 tonnes, i.e., 2,027 bbl/d) for "old production".

Local mining taxes, or RCDM (*redevance communale et départementale des mines*), are also payable to the applicable administrative French country and municipality on whose territory the oil is produced. Each local tax is determined by multiplying production by a unit rate, which is set each year by the Ministry of the Environment and Energy. The local mining tax is payable in arrears (production of 2015 is reported in 2016 and the corresponding tax is paid, after receipt of the notice of payment, generally end 2016 or beginning 2017), is ring-fenced by well, and the regime distinguishes between fields entered into production before and after January 1, 1992. For 2017, the RCDM was set at €22.511 per net tonne of oil equivalent for fields that commenced production prior to 1992, with a reduced rate of €6.406 per net tonne of oil equivalent for fields that started production post-1992. The 2017 offshore rate was €2.129/tonne. Each of the taxes is deductible when determining the profit subject to French corporate tax. The amounts of the local mining taxes applicable since 2013 are as follows (100 net tonnes equals 740 bbl):

Years	**Royalties (in €) per 100 net extracted tonnes**		
	Communal tax	**Departmental tax**	**Total**
2013			
Prior to January 1, 1992	812.70	1 044.00	1 856.70
From January 1, 1992	248.00	315.40	563.40
2014			
Prior to January 1, 1992	831.40	1 068.00	1 899.40
From January 1, 1992	251.20	319.50	570.70
2015			
Prior to January 1, 1992	847.20	1 088.30	1 935.50
From January 1, 1992	253.50	322.40	575.90
2016			
Prior to January 1, 1992	868.40	1 115.50	1.983.90
From January 1, 1992	256.00	325.60	581.60

Netherlands Country Overview

Industry Summary

The Netherlands is the second largest gas producer in Europe. It is now a mature hydrocarbon country as onshore production began in the 1950s and offshore production began in the 1960s. Gas production is dominated by the large onshore Groningen field, which was discovered in 1959. It is the largest gas field in Europe and among the 10 largest gas fields in the world.

Regulatory Regime Summary

The MEA is responsible for the optimal development of oil and gas resources in the Netherlands. All oil and gas activity is governed by the terms outlined in the 2003 Mining Law, which provides the statutory framework for (*inter alia*) licensing, decommissioning and abandonment, Dutch State participation and financial obligations of licensees. The Netherlands introduced an open licensing system in 1995 in an effort to maintain exploration activity levels on the Dutch continental shelf. Under this system, all unlicensed acreage is available for allocation at any time during the year.

State participation occurs in the Netherlands via EBN, which acts as an independent partner in the majority of Dutch fields.

Regulatory Framework

Key Legislation

<u>2003 Mining Act</u>

The current Mining Act (the "**2003 Mining Act**") became effective on January 1, 2003. The 2003 Mining Act, together with a Mining Decree and a Mining Regulation, has significantly reduced the administrative burden on companies operating in the Dutch upstream industry, due to the simplification of the legislation.

<u>2000 Dutch Gas Act</u>

The Dutch Gas Act, which became effective in 2000, as amended from time to time, implemented European Union regulations on market liberalization, security of supply, independent and non-discriminatory gas network operation, a fully-regulated third party access regime for access to domestic gas pipelines, domestic gas network ownership unbundling and the designation of an independent regulatory authority.

<u>Corporation Income Tax Act 1969</u>

Corporate income taxation is based on the Corporation Income Tax Act 1969 ("**CITA 1969**").

Regulatory Bodies

<u>Ministry of Economic Affairs</u>

The Energy Directorate of the MEA is responsible for ensuring optimal development of oil and gas resources in the Netherlands and sustainable use of the "deep subsurface". It is assisted by the *Bouw en Ondergrond* (Construction and Subsurface) department of TNO (the Dutch Geological Survey), which advises the Ministry on geological matters and handles the processing of information relating to exploration and production. Furthermore, the MEA may rely on technical and commercial advice of the state participation company EBN.

<u>State Supervision of Mines</u>

The State Supervision of Mines, a division of the MEA, has the task of ensuring compliance to Mining regulations and cooperation in the preparation of new Mining legislation.

State Participation in Oil and Gas Production

Based on the 2003 Mining Act and its predecessors the state is entitled to participate directly in production activities through EBN. EBN acts as an independent partner in the majority of Dutch fields. Pursuant to the 2003 Mining Act it has a right to participate with a 40% interest. In a number of older licences and concessions (issued between 1976 and 1995) this is 50%. At the acquisition of its participating interest EBN must reimburse the licence holder, at a percentage equal to EBN's interest (i.e., under current legislation, 40%), for the expenditures the licence holder incurred in exploration for and appraisal of the prospect, and any further capital investment in production facilities. This is commonly referred to as contribution reimbursement (*inbrengvergoeding*). The reimbursement as a rule includes the following: (i) investments in business assets, (ii) exploration expenses and (iii) an interest component. Each of those may lead to a taxable event for the purpose of CITA 1969 and State Profit Share (see below, Fiscal Terms).

Government Gas Fields Depletion Policy

Historical Overview

GasTerra, as successor to the former Gasunie's trade and supply business, still dominates the Dutch gas market, although sellers of gas from the Small Fields are allowed to sell gas to other buyers than GasTerra. GasTerra contracts can be terminated through contract provisions which are exercisable every three years. GasTerra has four main categories of customers to whom it sells gas directly. These are foreign companies, large industrial consumers, gas distribution companies within the Netherlands and abroad, and power generators. With the onset of liberalization, some of these customers have negotiated supply contracts with suppliers other than GasTerra.

Small Fields Policy

The government decided that from 1974 it would encourage exploration and development of smaller gas fields (Small Fields Policy). Small fields are exploited preferentially in order to reduce the load on Groningen, which is mainly used as a gas balancing field. In the winter, when gas demand is high, Groningen supplies additional gas as required. This has led to the Groningen field being conserved as a strategic reserve and for use as a swing producer. This priority of buying any domestic gas available for sale has helped to encourage exploration activity in the Netherlands. It has been consolidated in the Dutch Gas Act, which lays down the statutory obligation for GasTerra to purchase the gas produced from small fields against a market conforming price, if and when the gas is offered to it. Two exceptions to this general obligation exist. First, the MEA may temporarily release GasTerra from the obligation to purchase gas offered to it for economic or financial reasons. Second, in the event and to the extent that the specifications of the gas would require adjustments in the transmission system that are considered uneconomic to its operator, Gasunie Transport Services BV, it is released from its statutory obligation to accept the gas in the transmission system and in such case GasTerra is equally released from its obligation to purchase the gas. In addition, it should be noted that Gasunie Transport Services BV is entitled to unilaterally set conditions regarding the feeding in into the transmission system of natural gas produced by mining companies.

GasTerra Offtake Terms for Small Fields – Quantities

All gas purchase contracts signed with the domestic producers over the past decade have been for the life of the reserves by field or block. To calculate the depletion rate of a field the producer must stipulate to GasTerra the economically recoverable reserves of a field or a licence (generally on a field basis).

GasTerra Offtake Terms for Small Fields – Pricing

GasTerra has a considerable number of gas contracts with domestic gas producers. GasTerra's aim has been to market the gas at competing prices for specific sectors of the market, e.g., heavy fuel oil for power stations and industry and gas oil to the domestic user. With this pricing scenario, GasTerra has effectively been giving the domestic producers its best price for the gas after taking a reasonable profit margin, and still managing to keep demand for gas high.

GasTerra's gas contracts with producers will typically vary in price; however, the basis of the contract pricing is similar. The gas price in a contract with a producer is based on the spot market prices of the Dutch TTF and to a lesser extent the UK's National Balancing Point (NBP), have become part of the pricing formula.

Licensing

The 2003 Mining Act introduced a uniform licensing regime for onshore and offshore licensing, thereby ending the previously existing distinction between (onshore) concessions and (offshore) licences and concessions.

There are four types of licence for onshore and offshore activities:

- *Exploration* – Licence that incorporates exploration activities by means of drilling.
- *Production* – Licence awarded when a company wishes to extract hydrocarbons.

- *Gas storage* – Licence awarded when a company wishes to store hydrocarbons.
- *CO_2 storage* – Licence awarded when a company wishes to store carbon dioxide.

Offshore Licensing

The total area available for licensing offshore the Netherlands is 57,200 km^2. The offshore sector is divided into quadrants of 1° latitude by 1° longitude, designated by letters. Each of the quadrants is subdivided into 18 blocks, measuring around 23 kilometres by 18 kilometres (approximately 410 km^2) on a 3 x 6 grid.

Offshore Exploration Licences and Concessions

Under the conditions of the current licensing regime under the 2003 Mining Act, licence periods reflect the work commitments offered rather than being fixed as for historic licences and concessions.

An exploration licence may be retained after the expiry date only if the company has an application for a production licence outstanding on the licence with the approval of the government. A production licence is awarded only if it is probable that the minerals in the licence area are economically recoverable. The definition of a commercial discovery was extremely debatable under the 1967 Royal Decree legislation whilst under 1976 (and later) legislation the definition takes into account production cost, size of resource, sales price etc.

Offshore Production Licences and Concessions

On award of a production licence, the exploration licence is converted. In jointly held licences, the statutory obligation to remove the mining installation rests on the operator of the licence. The state may require the provision of a financial guarantee for removal costs of installations in the event an administrative enforcement order has been issued to enforce the obligation to remove the mining installations. The liability amongst the joint venture parties is arranged contractually.

When a production licence is awarded the MEA announces it in the State Gazette (*Staatscourant*). The licence decision enters into operation the after its publication.

Onshore Licensing

Fallow Covenant

In order to stimulate activity on licensed offshore fallow acreage, the Dutch authorities introduced new provisions in the 2003 Mining Act that empower the Minister of Economic Affairs to review the delineation of a licence area if no significant activities have taken place in that area for two consecutive years.

Financial Provisions

Rental Fees

The 2003 Mining Act applies rental fees to all Dutch exploration and production licences (onshore and offshore) and concessions. Rental fees are indexed (commensurate with a wage index as defined in a Royal Decree).

Fiscal Terms

Profits realized by companies involved with the onshore and offshore hydrocarbon E&P activities in the Netherlands and on the Dutch continental shelf are subject to both general corporation income taxation ("**CIT**") based on CITA 1969 and State Profit Share ("**SPS**") based on the 2003 Mining Act. Production licence turnover is subject to royalty (*cijns*) based on the 2003 Mining Act. In addition, in respect of onshore activities a fee (*afdracht aan de Provincie*) is due to provinces, based on the 2003 Mining Act.

CIT

The corporation income tax rate is currently 25%, for taxable profits of the company exceeding €200,000 (below this threshold a rate of 20% applies). The CIT tax base of a Dutch resident taxpayer includes (as a principle) all domestic and worldwide income. Examples of (industry relevant) costs that can be taken into account for CIT purposes are: (a) *cijns* (Royalties); (b) operating costs (under circumstances, this may include interest); (c) exploration costs; (d) depreciation; and (e) abandonment costs (deduction for anticipated future abandonment costs through the "abandonment provision").

The amount of SPS which is payable after taking into account the Creditable Amount (see below under "SPS") can also be deducted for CIT purposes.

Losses are normally available for one year carry back and nine years carry forward.

SPS

SPS is a profit based tax, specific to the upstream E&P industry. SPS is levied from the holder or co-holder of a production licence on the profit that can be allocated to the "extraction enterprise". The profits derived from the "extraction enterprise" consist of the results that can be directly and indirectly allocated to the extraction of hydrocarbons (the so-called "ring fence"). The allocation principles have been established in practice and through case law.

The rate of SPS is 50%. In the 2003 Mining Act, reference is made to the calculation of profits for CIT purposes, whereby a correlation is created between these levies. SPS is in principle calculated in a similar manner as CIT with the exception that (most) expenses are "uplifted" by an additional 10%. In order to avoid an accumulation of CIT and SPS, a notionally calculated CIT amount ("**Creditable Amount**") can be credited against SPS.

Losses for the purposes of the SPS calculation are available for a three years carry back and indefinite carry forward.

As per September 16, 2010 a marginal field SPS incentive applies. Provided certain conditions are met, a 25% deduction can be taken into account in respect of investments in new business assets that are used for marginal fields.

Royalties (*Cijns*)

For onshore production activities royalty rates based on the turnover apply. The turnover is determined by production volume (except volume used during exploration / production for processing and transport) and selling price. For offshore activities, these rates are set at 0%.

The rate is determined according to the following volume brackets:

Produced volume of gas (in millions m³)	Produced Percentage
0-200	0
200-600	2
600-1200	3
1200-2000	4
2000-4000	5
4000-8000	6
> 8000	7

Produced volume of oil (in thousands m³)	Produced Percentage
0-200	0
200-600	2
600-1200	3
1200-2000	4
2000-4000	5
4000-8000	6
> 8000	7

In addition to the rates mentioned above, the following applies:

1. The rates mentioned above will be increased by 25% if the oil prices are higher than €25 per barrel; and

2. If EBN does not participate in a licence, the rates above will be increased by 100% (regardless of the increase mentioned under 1).

Fees to the Province (*afdracht aan de Provincie*)

For producing hydrocarbons in onshore areas a one-time fee to the province (*Afdracht aan de provincie*) is due. The basis for levying the fee is the size of the area in use for the production installations (not the area to which the production licence pertains). The rate for 2003 was €4.50 per m^2. It is indexed (commensurate with a wage index as defined in a Royal Decree) and collected by the Provincial Executive.

Mining Damage Guarantee Fund

The mining companies, insofar as they are active in onshore mining activities, are under an obligation to annually contribute to the Mining Damage Guarantee Fund (*Waarborgfonds mijnbouwschade*). The fund pays out as a matter of last resort (i.e., in cases of insolvency or where the liable company has ceased to exist). It only pays out to natural persons having incurred property damage as a result of mining activities.

On September 6, 2013, around 40 Dutch private and semi-public parties reached a covenant on the development of renewable growth in the Netherlands (the "**Energy Agreement**"). The core feature of the Energy Agreement is a set of broadly supported provisions regarding energy saving, clean technology, and climate policy. The Energy Agreement implemented a comprehensive climate and energy policy programme aimed at long-term sustainability and set out agreed short to medium-term measures in 10 pillars. One of these pillars is the increase of renewable energy production from the current 4.3% to 14% in 2020, and 16% in 2023.

DIVIDEND POLICY

The Corporation does not currently anticipate paying any dividends on its Common Shares. The Corporation currently intends to utilize its earnings to finance the growth and development of its business and to otherwise reinvest in its business. Any decision to pay dividends on the Common Shares in the future will be made by the Board on the basis of the Corporation's earnings and financial requirements as well as other conditions existing at such time. Unless the Corporation commences the payment of dividends, holders of Common Shares will not be able to receive a return on their Common Shares unless they sell them.

SELECTED OPERATIONAL AND FINANCIAL INFORMATION

The financial data that is presented below has been derived from the audited consolidated financial statements for the financial years ended December 31, 2017 and 2016, the audited combined carve-out from Lundin Petroleum financial statements for the Initial Oil and Gas Assets for the financial year ended December 31, 2015 (together the "**FY Financial Statements**") and from the unaudited interim consolidated financial statements for the three-month period ending on March 31, 2018 and 2017 (the "**Interim Financial Statements**", the FY Financial Statements and the Interim Financial Statements are together referred to as the "**Financial Statements**"), incorporated by reference in the prospectus. The FY Financial Statements, which have been audited by the auditor of the Corporation as indicated in their report also incorporated reference by herein, PricewaterhouseCoopers AG, and the Interim Financial Statements, which have been reviewed PricewaterhouseCoopers AG as indicated in their report also incorporated herein by reference, have been prepared in accordance with IFRS, as adopted by the IASB. With respect to the Interim Financial Statements, PricewaterhouseCoopers AG reported that they have applied limited procedures in accordance with International Standard on Review Engagements (ISRE) 2410. However, their review report states that they did not audit and they do not express an opinion on the Interim Financial Statements. Accordingly, the degree of reliance on their report on such information should be restricted in light of the limited nature of the review procedures applied. Rounding-off differences may arise in all tables.

The 2015 FY Financial Statements exclude the Discontinued Operations, since these carve-out statements were prepared for the purposes of the Spin-Off and therefore were only intended to show the results of on-going operations. In accordance with applicable accounting rules, the 2016 and 2017 FY Financial Statements and the Interim Financial Statements include certain line items related to the Discontinued Operations. Accordingly, there may be certain discrepancies in respect of comparing the 2015 FY Financial Statements to the 2016 and 2017 FY Financial Statements and the Interim Financial Statements.

Condensed Consolidated Statements of Operations

USD Thousands	Unaudited Jan – Mar 2018	Unaudited Jan – Mar 2017	Audited FY 2017	Audited FY 2016	Audited FY 2015
Revenue	**115,162**	**51,932**	**203,001**	**209,880**	**172,094**
Cost of sales					
Production costs	(46,298)	(11,861)	(64,437)	(59,155)	(41,474)
Depletion and decommissioning costs	(23,162)	(14,504)	(54,555)	(85,187)	(92,573)
Depreciation of other assets	(7,960)	(7,760)	(31,629)	(31,073)	(23,685)
Exploration and business development costs	(169)	(137)	(3,786)	(14,141)	(37,638)
Impairment costs	–	–	164	(125,963)	(191,758)
Gross profit/(loss)	**37,573**	**17,670**	**48,758**	**(105,639)**	**(215,034)**
Other income	–	–	–	4,804	–
Sale of asset	–	–	–	(3,452)	–
General, administration and depreciation expenses	(3,734)	(926)	(10,400)	(1,931)	(18,046)
Profit/(loss) before financial items	**33,839**	**16,744**	**38,358**	**(106,218)**	**(233,080)**
Finance income	15	12	94	19,132	54,337
Finance costs	(9,168)	(10,963)	(15,001)	(3,747)	(3,826)
Net financial items	**(9,153)**	**(10,951)**	**(14,907)**	**15,385**	**50,511**
Profit/(loss) before tax	**24,686**	**5,793**	**23,451**	**(90,833)**	**(182,569)**
Income tax	1,627	(1,332)	(728)	(4,887)	1,004
Net result	**26,313**	**4,461**	**22,723**	**(95,720)**	**(181,565)**
Net result attributable to:					
Shareholders of the Corporation	26,305	4,456	22,718	(95,728)	(181,571)
Non-controlling interest	8	5	5	8	6
	26,313	**4,461**	**22,723**	**(95,720)**	**(181,565)**
Earnings per share – USD[1]	0.30	0.04	0.23	(0.84)	(1.60)
Earnings per share fully diluted – USD[1]	0.30	0.04	0.23	(0.84)	(1.60)

[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 to the Spin-Off.

Condensed Consolidated Statements of Comprehensive Income/(Loss)

USD Thousands	Unaudited Jan – Mar 2018	Unaudited Jan – Mar 2017	Audited FY 2017	Audited FY 2016	Audited FY 2015
Net result	**26,313**	**4,461**	**22,723**	**(95,720)**	**(181,565)**
Other comprehensive income/(loss):					
Items that may be reclassified to profit or loss:					
Cash flow hedges	(1,407)	–	1,292	–	–
Currency translation difference	1,515	–	(3,374)	–	10,034
Total comprehensive income/(loss)	**26,421**	**4,461**	**20,641**	**(95,720)**	**(171,531)**
Total comprehensive income/(loss) attributable to:					
Shareholders of the Corporation	26,408	4,456	20,620	(95,728)	(171,537)
Non-controlling interest	13	5	21	8	6
	26,421	**4,461**	**20,641**	**(95,720)**	**(171,531)**

Condensed Consolidated Balance Sheets

USD Thousands	Unaudited March 31, 2018	Unaudited March 31, 2017	Audited December 31, 2017	Audited December 31, 2016	Audited December 31, 2015
ASSETS					
Non-current assets					
Exploration and evaluation assets	8,084	4,519	7,380	2,904	137,221
Property, plant and equipment, net	751,329	306,311	312,401	317,808	382,918
Other tangible fixed assets, net	116,061	144,416	123,051	152,157	186,612
Financial assets	5	5	5	5	5
Deferred tax assets	9,980	11,444	12,398	12,049	12,331
Total non-current assets	**885,459**	**466,695**	**455,235**	**484,923**	**719,087**
Current assets					
Inventories	19,291	26,324	24,611	25,067	31,005
Trade and other receivables	61,472	43,402	74,794	48,226	40,629
Derivative instruments	–	–	1,372	–	–
Current tax	7,567	67	20	406	3,470
Cash and cash equivalents	28,174	20,082	33,679	13,410	24,373
Total current assets	**116,504**	**89,875**	**134,476**	**87,109**	**99,477**
TOTAL ASSETS	**1,001,963**	**556,570**	**589,711**	**572,032**	**818,564**
EQUITY AND LIABILITIES					
Shareholders' equity	334,605	390,217	307,166	405,348	592,889
Non-controlling interest	(212)	(246)	(224)	(252)	(277)
Net shareholders equity / Net Corporation investment	**334,393**	**389,971**	**306,942**	**405,096**	**592,612**
Non-current liabilities					
Financial liabilities	331,251	–	59,267	–	–
Provisions	185,737	99,032	105,887	93,581	113,661
Deferred tax liabilities	61,175	47,610	53,943	46,616	49,316
Total non-current liabilities	**578,163**	**146,642**	**219,097**	**140,197**	**162,977**
Current liabilities					
Trade and other payables	77,260	19,899	57,388	22,924	62,530
Provisions	11,693	–	6,025	3,815	–
Current tax liabilities	454	58	259	–	445
Total current liabilities	**89,407**	**19,957**	**63,672**	**26,739**	**62,975**
TOTAL EQUITY AND LIABILITIES	**1,001,963**	**556,570**	**589,711**	**572,032**	**818,564**

Condensed Consolidated Statements of Cash Flows

	Unaudited	**Unaudited**	**Audited**	**Audited**	**Audited**
USD Thousands	**Jan – Mar 2018**	**Jan – Mar 2017**	**FY 2017**	**FY 2016**	**FY 2015**
Cash flow from operating activities					
Net result	26,313	4,461	22,723	(95,720)	(181,565)
Adjustments for non-cash related items:					
Depletion, depreciation and amortization	31,283	22,505	87,162	117,510	117,403
Exploration costs	169	137	917	14,141	37,638
Impairment costs	–	–	(164)	125,963	191,758
Current tax	(7,196)	396	196	(2,199)	1,699
Deferred tax	5,569	936	532	7,086	(2,703)
Capitalized financing fees	708	–	700	–	–
Foreign currency exchange	3,032	10,063	8,922	(19,070)	(53,621)
Interest expense	4,434	15	1,378	8	19
Result on sale of the Singa field, Indonesia	–	–	–	3,452	–
Unwinding of asset retirement obligation discount	2,388	854	3,674	3,571	3,174
Share-based costs	1,030	–	3,224	–	1,015
Other	66	(130)	(1,058)	1,608	–
Cash flow generated from operations (before working capital adjustments and income taxes)	**67,796**	**39,237**	**128,206**	**156,350**	**114,817**
Changes in working capital	30,585	3,494	20,344	(51,790)	(44,252)
Long-term incentive plans paid	–	–	–	–	(740)
Interest paid	(4,112)	–	–	–	(4)
Income taxes paid	–	–	476	4,880	(3,044)
Net cash flow from operating activities	**94,269**	**42,731**	**149,026**	**109,440**	**66,777**
Cash flow used in investing activities					
Investment in oil and gas properties	(14,941)	(2,085)	(23,077)	(34,905)	(177,055)
Investment in other fixed assets	(541)	61	(546)	1,724	(31,122)
Deposit for business acquisition	–	–	(32,632)	–	–
Acquisition of the Suffield Assets	(362,244)	–	–	–	–
Decommissioning costs paid	(487)	(252)	(5,169)	(9,710)	–
Disposal of fixed assets	–	–	–	23,770	–
Other payments	–	–	–	(206)	(2,976)
Net cash (outflow) from investing activities	**(378,213)**	**(2,276)**	**(61,424)**	**(19,327)**	**(211,153)**
Cash flow from financing activities					
Borrowings	284,821	–	120,000	–	–
Repayments of borrowings	–	–	(60,000)	–	–
Paid financing fees	(6,168)	(10)	(1,391)	–	–
Cash funded from / (to) Lundin Petroleum	–	(31,767)	(31,394)	(102,774)	134,893
Share purchase	–	–	(90,632)	–	–

Net cash (outflow) from financing activities	**278,653**	**(31,777)**	**(63,417)**	**(102,774)**	**134,893**
Change in cash and cash equivalents	**(5,291)**	**8,678**	**24,185**	**(12,661)**	**(9,483)**
Cash and cash equivalents at the beginning of period	33,679	13,410	13,410	29,488[1]	25,108
Currency exchange difference in cash and cash equivalents	(214)	(2,006)	(3,916)	(3,417)	8,748
Cash and cash equivalents at the end of the period	**28,174**	**20,082**	**33,679**	**13,410**	**24,373[1]**

[1] The difference in cash and cash equivalents between end of FY 2015 and beginning of FY 2016 is due to the spin-off and originates from the Discontinued Operations.

Condensed Consolidated Statement of Changes in Equity as at March 31, 2018

	Unaudited	**Unaudited**	**Unaudited**	**Unaudited**	**Unaudited**	**Unaudited**	**Unaudited**	**Unaudited**	**Unaudited**
USD Thousands	**Parental investment**	**Share capital**	**Share premium**	**Retained earnings**	**Non-controlling interest**	**IFRS 2 reserve**	**MTM reserve**	**CTA**	**Total**
Balance at January 1, 2017	**405,348**	**–**	**–**	**–**	**(252)**	**–**	**–**	**–**	**405,096**
IPC net investment/(proceeds)	(19,586)	–	–	–	–	–	–	–	(19,586)
Net result prior to Spin-Off	4,456	–	–	–	5	–	–	–	4,461
Balance at March 31, 2017	**390,218**	**–**	**–**	**–**	**(247)**	**–**	**–**	**–**	**389,971**
IPC net investment / (proceeds)	(11,808)	–	–	–	7	–	–	–	(11,801)
Net result prior to Spin-Off	(7,818)	–	–	–	4	–	–	–	(7,814)
Balance at Spin-Off date	**370,592**	**–**	**–**	**–**	**(236)**	**–**	**–**	**–**	**370,356**
Formation of the Corporation	(410,000)	86,342	323,658	–	–	–	–	–	–
Valuation adjustments	39,408	–	(39,408)	–	–	–	–	–	–
Net result after formation of the Corporation	–	–	–	26,080	(4)	–	–	–	26,076
Cash flow hedge	–	–	–	–	–	–	1,292	–	1,292
Other comprehensive income					16	231	80	(3,701)	(3,374)
Purchase and cancellation of Common Shares	–	(19,436)	(71,196)	–	–	–	–	–	(90,632)

Share-based payments	–	–	–	–	–	3,224	–	–	3,224
Balance at December 31, 2017	**–**	**66,906**	**213,054**	**26,080**	**(224)**	**3,455**	**1,372**	**(3,701)**	**306,942**
Net result	–	–	–	26,305	8	–	–	–	26,313
Cash flow hedge	–	–	–	–	–	–	(1,407)	–	(1,407)
Currency translation difference	–	–	–	–	4	(49)	35	1,525	1,515
Total comprehensi ve income	**–**	**–**	**–**	**26,305**	**12**	**(49)**	**(1,372)**	**1,525**	**26,421**
Share-based payments	–	–	–	–	–	1,030	–	–	1,030
Balance at March 31, 2018	**–**	**66,906**	**213,054**	**52,385**	**(212)**	**4,436**	**–**	**(2,176)**	**334,393**

CAPITAL STRUCTURE, INDEBTEDNESS AND RELATED INFORMATION

Financial Position

The Corporation is in a financially strong position with its producing asset base in Canada, Malaysia, France and the Netherlands and is expected to generate free cash flow from its operations in the medium term. In addition, the Corporation and certain of the IPC Subsidiaries have entered into the Credit Facilities. The Corporation expects to be able to leverage its existing assets to raise capital for any growth opportunities through acquisitions.

Capitalization and Net Indebtedness

	(unaudited)
Shareholders' equity and debt as at March 31, 2018	**USD thousands**
Guaranteed	–
Secured	77,714
Unguaranteed and unsecured	11,693
Total current debt	**89,407**
Guaranteed	–
Secured [1]	331,251
Unguaranteed and unsecured	146,912
Total non-current debt	**578,163**
Total shareholders' equity	**334,393**
TOTAL EQUITY AND DEBT	**1,001,963**

[1] The Credit Facilities are secured by packages customary for these types of facilities. See "Financing and Credit Facilities" below.

Net interest-bearing indebtedness

Net financial debt or net financial assets as at March 31, 2018	USD thousands
A. Cash	28,174
B. Cash equivalents	–
C. Trading securities	–
D. Liquidity (A + B + C)	**28,174**
E. Current financial receivables	**61,472**
F. Current bank debt	–
G. Current portion of non-current debt	–
H. Other current financial debt	–
I. Total current financial debt (F + G + H)	**–**
J. Net current financial Indebtedness (I)-(E)-(D)	**(89,646)**
K. Non-current bank loans	337,358
L. Bonds issued	–
M. Other non-current loans	–
N. Non-current financial indebtedness (K + L + M)	337,358
O. Net financial indebtedness (J + N)	247,712

Working Capital

In the opinion of the Board, the Corporation's working capital is sufficient for the Corporation's requirements for the next twelve months.

Principal Ongoing and Future Investments

In February 2018, the Corporation announced estimated net 2018 oil and gas capital expenditures of USD 32.2 million with 34% allocated to Canada for oil drilling and maintenance capital, 18% allocated to France for well reactivations and maintenance capital, 5% allocated to the Netherlands for one development well and maintenance capital, and 44% allocated to Malaysia for the recently completed infill drilling campaign. The capital expenditure programme is discretionary (other than in Malaysia where the drilling campaign is completed) and will be funded from cash flow from the Oil and Gas Assets.

In Malaysia, the Corporation has taken the decision to approve additional capital expenditure of USD 6.5 million (net) to drill the Keruing (formerly I35) prospect in late 2018, subject to Petronas approval and rig contracting. Best estimate gross unrisked prospective resources are estimated at 7.2 MMboe gross (5.4 MMboe net). The Keruing prospect is only two kilometres from the Bertam field facilities and would be a high value tie back candidate in the success case. The unrisked prospective resource numbers represent 60% of the year end 2P gross reserves for the Bertam field of 12.1 MMboe gross (9.1 MMboe net).

As of the date of the prospectus, the Corporation has not resolved upon, or committed to make any other investments than stated above.

Property, Plant and Equipment

Property, plant and equipment primarily represents the Corporation's share of oil and gas installations used for the extraction and production of hydrocarbons, including offshore and onshore platforms and pipelines and the FPSO Bertam in Malaysia. The Corporation, through Lundin Services Ltd., leases the FPSO to the Bertam field co-venturers at a fixed daily rate under a lease contract with an initial six year period (which commenced in April 2015) and options to extend the term. See "Management's Discussion and Analysis". There are no environmental issues that may affect the Corporation's utilization of the tangible fixed assets.

Financing and Credit Facilities

On April 20, 2017, and as amended on December 20, 2017, the Corporation and certain of the IPC Subsidiaries entered into a senior secured USD 200 million reserve-based lending credit facility with a syndicate of banks led by BNP Paribas, Bank of Montreal, London Branch, Australia and New Zealand Banking Group (ANZ), ABN AMRO Bank and Commbank Europe (the "**International Facility**"). The International Facility is a revolving facility with a final maturity date fall on the earlier of June 22, 2022 and the date the reserves of the borrowing base assets reach certain limits.

The International Facility is secured by a package customary for this type of facility, including but not limited to: (a) an on-demand guarantee and indemnity from the Corporation and the IPC Subsidiaries who are party to it; (b) pledges over all of the shares of certain of the IPC Subsidiaries; and (c) pledges and/or assignment of the relevant facility bank accounts, intercompany loans, insurance policies and hedging arrangements.

The International Facility contains a provision entitling the lenders to cancel the facility in the event any person, or group of persons acting in concert, gains control of the Corporation ("control being defined as *inter alia* when a person, or a group of persons acting in concert, holds beneficially more than 50% of the issued share capital of the Corporation). The International Facility further contains certain financial covenants.

On January 5, 2018 IPC Alberta Ltd ("**IPC Alberta**") entered into a senior secured CAD 250 million credit facility with a syndicate of banks including Bank of Montreal, ABN AMRO Capital USA, Canadian Imperial Bank of Commerce, Commonwealth Bank of Australia, Export Development Canada and Royal Bank of Canada (the "**First Lien Credit Facility**"). The First Lien Credit Facility amount is reduced by CAD 5 million on each of February 28, March 28, April 27, May 28 and June 28, 2018. The final maturity date of the First Lien Credit Facility is January 5, 2020. At the request of IPC Alberta, the commitment of each participating bank may be extended, at the discretion of the respective bank, once every year for a period of up to a further 364 days. Furthermore, on the same day IPC Alberta entered into a secured CAD 60 million credit facility with Bank of Montreal (the "**Second Lien Credit Facility**"). The final maturity date of the Second Lien Credit Facility is January 5, 2021.

The First and Second Lien Credit Facilities contains certain covenants and are guaranteed and secured by essentially the same guarantees and security which includes, but is not limited to: (a) an on-demand guarantee from the Corporation and material subsidiaries of IPC Alberta; (b) pledges over all of the shares in IPC Alberta and its subsidiary Suffield Industry Range Control Ltd (in relation to which the First Lien Credit Facility enjoys a first ranking priority compared to the Second Lien Credit Facility); and (c) debentures from IPC Alberta and its material subsidiaries in the amount of CAD 1 billion respectively, granting a first and second ranking lien respectively in and to all of its present and after required real and personal assets, together with a pledge of the debenture in respect thereof.

The First Lien Credit Facility and the Second Lien Credit Facility contain provisions entitling the Lenders to cancel the facility foremost in the event any person, or group of persons acting in concert, gains control of more than 30% of the issued share capital of the Corporation.

The International Facility, the First Lien Credit Facility and the Second Lien Credit Facility are collectively referred to in this prospectus as the "Credit Facilities". Net debt as at March 31, 2018 was USD 309 million after deducting cash balances from the amount drawn under the Credit Facilities.

With the availability of the Credit Facilities and the cash resources, other current assets and cash flow from operations of the Oil and Gas Assets, the Corporation does not foresee a need to obtain further credit to finance the Corporation's operations and capital expenditures program for the Oil and Gas Assets over the next year. In the event the Corporation would pursue any transaction opportunities in accordance with the Corporation's strategy, the Corporation may need to raise debt or equity financing to finance such transactions.

Recent Trends in the Industry

The oil and gas industry continues to remain dynamic in response to global macroeconomic trends, including global supply of oil stocks, transportation costs, US shale production, emerging market demand, and production quotas imposed by the OPEC. As a result of an increased supply and reduced demand growth, the oil price fell from a peak of around USD 115/bbl in June 2014 to USD 26/bbl in January 2016. Since that time, the oil price has been volatile, yet generally increasing. From the middle of 2016 until near the end of 2017, the oil price ranged around USD 50/bbl, and then has increased above USD 70/bbl into 2018.

Management believes that the recent low oil price environment has driven asset divestitures by exploration and production companies struggling with liquidity issues, while also limiting the ability of balance sheet-constrained competitors to acquire such assets. Management's recent experience indicates that the oil majors and large international oil and gas companies are increasingly focused on larger volumes in new frontier basins, not long-life, low decline assets in established basins, and will continue to dispose of high quality assets to meet their public divestment undertaking.

The Oil and Gas Assets have continued to perform well during the first quarter of 2018 in line with expectations, with excellent facility uptime

Significant Changes after March 31, 2018

In May 2018, the Group, through its Canadian subsidiary, IPC Alberta Ltd, entered into hedges to sell natural gas summarized as follows:

Period	Volume (Gigajoules per day)	Average Pricing
June 1, 2018 – March 31, 2019	25,000	AECO 5a + CAD 0.89 per Gigajoule
June 1, 2018 – December 31, 2018	20,000	AECO 5a + CAD 0.87 per Gigajoule

Subsequent to March 31, 2018, the Group repaid CAD 45 million of the Second Lien Credit Facility by drawing under the International Facility.

Financial Risk Management

As an international oil and gas exploration and production company, IPC is exposed to financial risks such as interest rate risk, currency risk, credit risk, liquidity risks as well as the risk related to the fluctuation in oil and gas prices. The Group seeks to control these risks through sound management practice and the use of internationally accepted financial instruments, such as oil or 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.

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 establishing 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.

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 crude 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.

Other Information

At the date of this prospectus, the Corporation is not aware of any issues regarding public, economic, fiscal, monetary or other political actions which, direct or indirect, could have a significant effect on the Corporation's operations, apart from what is stated in the section "Risk Factors".

CERTAIN FINANCIAL INFORMATION REGARDING THE ACQUIRED ASSETS

Operating Statements

The financial information presented below shows the operating statements of the Acquired Assets for the years ended December 31, 2017 and December 31, 2016 prepared by the previous owner of the assets, Cenovus Energy Inc. The operating statements were audited by Pricewaterhouse Coopers LLP, Calgary, Alberta.

Operating Statements of the Acquired Assets

Suffield Assets
Operating Statements containing Gross Sales, Royalties, Transportation and Blending, Production and Mineral Taxes and Operating Expenses

($ Canadian thousands)

	Year Ended December 31, 2017 (audited)	Year Ended December 31, 2016 (audited)
Gross Sales	$ 241,023	$ 215,748
Royalties	9,325	5,424
Revenues	231,698	210,324
Expenses		
Transportation and Blending	46,998	48,751
Production and Mineral Taxes	145	64
Operating	71,380	65,676
Operating Margin	$ 113,175	$ 95,833

See accompanying Notes to Operating Statements

Suffield Assets
Notes to Operating Statements containing Gross Sales, Royalties, Transportation and Blending, Production and Mineral Taxes and Operating Expenses

For the Years Ended December 31, 2017 and December 31, 2016
(all amounts in $ thousands unless otherwise noted)

1. Basis of presentation

The Operating Statements containing Gross Sales, Royalties, Transportation and Blending, Production and Mineral Taxes and Operating Expenses (the "Operatings Statements") includes Cenovus Energy Inc.'s ("Cenovus's") net working interest of the operating results relating to the Suffield Assets (the "Property").

The line items in the Operating Statements have been prepared in all material respects using accounting policies that are permitted by International Financial Reporting Standards applicable to publicly accountable enterprises, with such accounting policies applying to those line items as if such line items were presented as part of a complete set of financial statements. The Operating Statements are prepared in accordance with the financial reporting framework specified in subsection 3.11(5) of National Instrument 52-107 Acceptable Accounting Principles and Auditing Standards for an operating statement.

Accordingly, the Operating Statements include the following line items: gross sales, royalties, transportation and blending, production and mineral taxes and operating expenses related to the Property.

The Operating Statements for the Suffield Assets do not include any provision for depletion, depreciation and amortization, decommissioning liabilities, capital costs, impairment, general and administrative costs and income taxes for the Property as these amounts are based on the consolidated operations of the vendor of which the Suffield Assets form only a part.

2. Significant accounting policies

(A) Joint Operations

Where the Property is operated through a unincorporated joint operation, the Operating Statements reflect only the vendor's proportionate interest.

(B) Revenue Recognition

Gross sales associated with the sales of crude oil and natural gas are recognized when the significant risks and rewards of ownership have been transferred to the customer, the sales price and costs can be measured reliably and it is probable that the economic benefits will flow to the Property.

(C) Royalties

Royalties are recorded at the time the product is produced and sold. Royalties are calculated in accordance with the applicable regulations and/or the terms of individual royalty agreements.

(D) Transportation and Blending

The costs associated with the transportation of crude oil and natural gas, including the cost of diluent used in blending, are recognized when the product is sold.

(E) Operating Expenses

Operating expenses include amounts incurred on extraction of product to the surface, gathering, field processing, treating and field storage. More specifically they include field workforce, electricity, energy, chemicals, repairs & maintenance, waste fluid handling & trucking, workovers, property tax & lease costs, overhead and other direct expenses. Costs or credits that are corporate based are excluded from these Operating Statements.

Polymer used to flood reservoirs as part of an Enhanced Oil Recovery project ("EOR") is expensed in the period it is consumed.

(F) Use of Estimates
Certain management estimates and assumptions in regards to revenues and expenses have been used. Such estimates relate to unsettled transactions and events. Estimates by their nature are subject to measurement uncertainty. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

3. Commitments and contingencies

As at December 31, 2017, future payments for transportation commitments associated with the Suffield Assets are below.

The transportation commitment is for a twenty year initial term agreement with one year renewal terms commencing January 1, 2003 with Altagas Suffield Pipeline to deliver a minimum amount of gas for a fixed demand charge. The base quantity of gas for 2017 is 105,141 GJ per day and declines by approximately 10% each year and reduces to zero at December 31, 2022.

($ Canadian thousands)	2018	2019	2020	2021	2022	Total
Altagas Suffield Pipeline	4,900	4,400	4,000	3,600	3,200	20,100

February 23, 2018

Independent Auditor's Report

To the Directors of Cenovus Energy Inc.

We have audited the accompanying operating statement containing gross revenue, royalties, transportation and blending, production and mineral taxes and operating expenses for the Suffield properties (the "Property") for the years ended December 31, 2017 and December 31, 2016, and the related notes, which comprise a summary of significant accounting policies and other explanatory information (the "operating statement").

Management's responsibility for the operating statement
Management of Cenovus Energy Inc. is responsible for the preparation of the operating statement of the Property in accordance with the financial reporting framework specified in subsection 3.11(5) of National Instrument 52-107, Acceptable Accounting Principles and Auditing Standards, for operating statements of an acquired oil and gas property, and for such internal control as management determines is necessary to enable the preparation of the operating statement that is free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on the operating statement based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the operating statement is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the operating statement. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the operating statement, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation of the operating statement in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the operating statement.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

PricewaterhouseCoopers LLP
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Opinion
In our opinion, the operating statement of the Property for the years ended December 31, 2017 and December 31, 2016, is prepared in all material respects in accordance with the financial reporting framework specified in subsection 3.11(5) of National Instrument 52-107, Acceptable Accounting Principles and Auditing Standards, for operating statements of an acquired oil and gas property.

PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, Alberta

Pro Forma

The financial information presented below shows the unaudited pro forma income statement for the year ended December 31, 2017, giving effect to the Acquisition as if it had occurred on January 1, 2017 (the "**Unaudited Condensed Pro Forma Income Statement**").

Unaudited Pro Forma Income Statement for 2017

USD Thousands	**Audited** IPC Consolidated Income Statement	**Audited** Suffield Assets Operating Statement[1]	**Unaudited** Pro Forma Adjustments	**Unaudited** IPC Condensed Pro Forma Income Statement
Sales of oil and gas	185,182	185,659	–	370,841
Change in under/over lift position	(613)	–	–	(613)
Other revenue	18,432	–	–	18,432
Royalties	–	(7,183)	–	(7,183)
Total Revenue	**203,001**	**178,476**	**–**	**381,477**
Cost of operations	(53,389)	(54,984)	–	(108,373)
Tariff and transportation expenses	(3,361)	(36,202)	24,172	(15,391)
Direct production taxes	(3,999)	(112)	–	(4,111)
Change in inventory position	(3,688)	–	–	(3,688)
Other costs	–	–	(24,172)	(24,172)
Production costs	**(64,437)**	**(91,298)**	–	(155,735)
Depletion and decommissioning costs	(54,555)		(44,315)	(98,870)
Depreciation of other assets	(31,629)		–	(31,629)
Exploration and business development costs	(3,786)		–	(3,786)
Impairment costs	164		–	164
Gross Profit	**48,758**		**(44,315)**	**91,621**
General administrative and depreciation expenses	(10,400)		(1,600)	(12,000)
Profit before financial items	**38,358**		**(45,915)**	**79,621**
Finance income	94		–	94
Foreign exchange loss, net	(8,922)		–	(8,922)
Unwinding of asset retirement obligation discount	(3,557)		(5,346)	(8,903)
Interest expense	(1,378)		(12,285)	(13,663)
Amortization of loan fees	(700)		(2,748)	(3,448)
Loan commitment fees	(391)		(902)	(1,293)
Other financial costs	(53)		–	(53)
Net financial items	**(14,907)**		**(21,281)**	**(36,188)**
Profit before tax	**23,451**		**(67,196)**	**43,433**
Income tax	(728)		(5,395)	(6,123)
Net result	**22,723**		**(72,591)**	**37,310**

[1] Note that the Suffield Assets operating statement was audited to the production costs line only and has been translated into US dollars using the average rate for the year ended December 31, 2017 of 1.2982 CAD/USD.

See the accompanying notes to the Unaudited Condensed Pro Forma Income Statement.

Note 1 – Basis of Presentation

The Unaudited Condensed Pro Forma Income Statement of the Corporation for the year ended December 31, 2017 has been prepared by management of the Corporation for illustrative purposes only and gives effect to the Acquisition of the Suffield Assets and the debt issuances necessary to finance the Acquisition as if the Acquisition had occurred on January 1, 2017. The Unaudited Condensed Pro Forma Income

Statement has been compiled in accordance with the requirements of Annex II to Commission Regulation (EC) No 809/2004 and on a basis consistent with the Corporation's accounting policies.

The Unaudited Condensed Pro Forma Income Statement has been compiled from information derived from, and should be read in conjunction with:

• the audited consolidated financial statements of the Corporation as at and for the year ended December 31, 2017; and

• the audited operating statement for the Suffield Assets for the year ended December 31, 2017.

For the purposes of the Unaudited Condensed Pro Forma Income Statement, the audited operating statement for the Suffield Assets for the year ended December 31, 2017, which is presented in Canadian dollars, has been translated into US dollars using the following foreign exchange rate:

Average rate for the year ended December 31, 2017: 1.2982 CAD/USD

The description of certain line items in the audited operating statement for the Suffield Assets for the year ended December 31, 2017 has been changed to be consistent with the IPC Audited Consolidated Financial Statements classification.

The Unaudited Condensed Pro Forma Income Statement may not be indicative of the results that would have occurred if the events reflected therein had been in effect on the date indicated or of the results, which may be obtained in the future. The actual results of operations of the Corporation for any period following the closing of the Acquisition will vary from the amounts set forth in the Unaudited Condensed Pro Forma Income Statement and such variation may be material.

The Unaudited Condensed Pro Forma Income Statement has been compiled using accounting policies consistent with those applied by IPC for the preparation of its consolidated financial statements. Pro forma financial information is by its nature intended to describe a hypothetical situation. The Corporation is only presenting the Unaudited Condensed Pro Forma Income Statement for illustrative purposes, and the Unaudited Condensed Pro Forma Income Statement should not be seen as an indication of the actual profits that would have occurred had the events mentioned above actually have occurred at the indicated dates. Further, the Unaudited Condensed Pro Forma Income Statement should not be seen as an indication of the Corporation’s future profit.

The Unaudited Condensed Pro Forma Income Statement should be read together with other information in the prospectus.

Note 2 – Pro Forma adjustments

The Unaudited Condensed Pro Forma Income Statement gives effect to the Acquisition as if it had occurred on January 1, 2017, considering the assumptions described below.

Certain items have been reclassified in the Unaudited Condensed Pro Forma Operating Statement to appropriately align the revenues and expenses of the Suffield Assets to IPC’s financial statements presentation. Cenovus purchased condensate to dilute oil production and meet pipeline specification for its Suffield oil products. A pro forma adjustment of USD 24,172 thousand relating to condensate used for blending, has been reflected in the Unaudited Condensed Pro Forma Income Statement to reclassify such item from the line “Tariff and transportation expenses” as reported under the Suffield Assets information into the line “Other costs”.

Other than this reclassification, management did not identify any material difference between the accounting policies applied by IPC and the accounting policies used in the preparation of the audited operating statements for the Suffield Assets.

Pro forma Adjustments have been made in the following lines of the Unaudited Condensed Pro Forma Income Statement:

(i) *Depletion and decommissioning costs*

A depletion rate of CAD 6.44 per boe has been applied to total production volumes produced by the Suffield Assets for the year ended 2017. This depletion rate is based on the rate calculated for the financial statements for the first quarter of 2018 following the preliminary allocation of the purchase price.

(ii) *General administrative and depreciation expenses*

Additional general, administrative and depreciation expenses have been included in the pro forma to reflect the estimated annual amount that would have been charged to the income statement had the Acquisition completed on January 1, 2017.

(iii) *Unwinding of asset retirement obligation discount*

The unwinding of the discounting of the abandonment retirement obligation for the Suffield Assets has been included based on the calculation made for the preliminary allocation of the purchase price. The discount rate assumed is 8 per cent and the discounting is being assumed to be unwound to the estimated dates of abandoning each well and facility belonging to the Suffield Assets.

(iv) *Interest expense, amortization of loan fees and loan commitment fees*

The interest expense, amortization of loan fees and loan commitment fees have been calculated assuming that the financing associated with the Acquisition was entered into on January 1, 2017. All cash flow generated for 2017 from the Suffield Assets has been assumed to have been used to partly repay the Canadian loan facility. Average 2017 floating interest rates of 1.2 percent and 1.1 percent were applied for the International reserve-based lending facility and the Canadian loan facility respectively.

(v) *Income tax*

Income tax on the pro forma Canadian taxable income for 2017 has been applied at the Canadian tax rate of 27 percent.

PricewaterhouseCoopers AG has performed an assurance engagement on the Unaudited Condensed Pro Forma Income Statement in accordance with International Standard on Assurance Engagements 3420, Assurance Engagements to Report on the Compilation of Pro Forma Financial Information Included in a Prospectus as is described below. However, neither the assumptions underlying the pro forma adjustments nor the resulting pro forma financial information have been audited in accordance with International Standards on Auditing ("**ISA**"). Any reliance investors place on this information should fully take this into consideration.

Assurance Report

INDEPENDENT PRACTIONER'S ASSURANCE REPORT ON THE COMPILATION OF PRO FORMA FINANCIAL INFORMATION INCLUDED IN A PROSPECTUS

To the Board of Directors of International Petroleum Corporation ("IPC"):

Report on the Compilation of Pro Forma Financial Information Included in a Prospectus

We have completed our assurance engagement to report on the compilation of pro forma financial information of IPC by management. The pro forma financial information consists of the condensed pro forma income statement for the year ended December 31, 2017 and related notes as set out on pages 157-159 of the prospectus issued by IPC. The applicable criteria on the basis of which management has compiled the pro forma financial information are specified in Annex II to Commission Regulation (EC) No 809/2004 and described in Note 1 – *Basis of Presentation* (the applicable criteria).

The pro forma financial information has been compiled by management to illustrate the impact of the acquisition of the Suffield Assets on IPC's financial performance for the year ended December 31, 2017 as if the transaction had taken place at January 1, 2017. As part of this process, information about the financial performance of IPC and the Suffield Assets has been extracted by management from IPC's consolidated financial statements for the year ended December 31, 2017, on which an audit report has been published and from the Suffield Assets' operating statements for the year ended December 31, 2017, on which an audit report has been published.

Management's Responsibility for the Pro Forma Financial Information

Management is responsible for compiling the pro forma financial information on the basis of the applicable criteria.

Independence and Quality Control

We have complied with the independence and other ethical requirements of the Code of Ethics for Professional Accountants issued by the International Ethics Standards Board for Accountants, which is founded on fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behaviour.

The firm applies International Standard on Quality Control 1 and, accordingly, maintains a comprehensive system of quality control including documented policies and procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

Practitioner's Responsibilities

Our responsibility is to express an opinion as required by Annex II item 7 of Commission Regulation (EC) No 809/2004 about whether the pro forma financial information has been compiled, in all material respects, by management on the basis of the applicable criteria.

We conducted our engagement in accordance with International Standard on Assurance Engagements (ISAE) 3420 *Assurance Engagements to Report on the Compilation of Pro Forma Financial Information Included in a Prospectus*, issued by the International Auditing and Assurance Standards Board.

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This standard requires that the practitioner plan and perform procedures to obtain reasonable assurance about whether management has compiled, in all material respects, the pro forma financial information on the basis of the applicable criteria.

For purposes of this engagement, we are not responsible for updating or reissuing any reports or opinions on any historical financial information used in compiling the pro forma financial information, nor have we, in the course of this engagement, performed an audit or review of the financial information used in compiling the pro forma financial information.

The purpose of pro forma financial information included in a prospectus is solely to illustrate the impact of a significant event or transaction on unadjusted financial information of the entity as if the event had occurred or the transaction had been undertaken at an earlier date selected for purposes of the illustration. Accordingly, we do not provide any assurance that the actual outcome of the event or transaction at January 1, 2017 would have been as presented.

A reasonable assurance engagement to report on whether the pro forma financial information has been compiled, in all material respects, on the basis of the applicable criteria involves performing procedures to assess whether the applicable criteria used by management in the compilation of the pro forma financial information provide a reasonable basis for presenting the significant effects directly attributable to the event or transaction, and to obtain sufficient appropriate evidence about whether:

- The related pro forma adjustments give appropriate effect to those criteria; and
- The pro forma financial information reflects the proper application of those adjustments to the unadjusted financial information.

The procedures selected depend on the practitioner's judgment, having regard to the practitioner's understanding of the nature of the company, the event or transaction in respect of which the pro forma financial information has been compiled, and other relevant engagement circumstances.

The engagement also involves evaluating the overall presentation of the pro forma financial information.

We believe that the evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Opinion

In our opinion, the pro forma financial information has been properly compiled on the basis stated and such basis is consistent with the accounting policies of IPC.

PricewaterhouseCoopers AG

June 5, 2018

Stephen Johnson Colin Johnson

MANAGEMENT'S DISCUSSION AND ANALYSIS

Introduction

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. IPC also acquired certain legacy non-producing interests and non-active entities as part of the Spin-Off, which are in the process of being relinquished and liquidated.

The MD&A for the three months ended March 31, 2018 (the "**Interim MD&A**") is intended to provide an overview of the Group's operations, financial performance and current and future business opportunities. The MD&A for the three months ended March 31, 2018 should be read in conjunction with the Interim Financial Statements.

The MD&A for the year ended December 31, 2017 compared to year ended December 31, 2016 and for the year ended December 31, 2016 compared to year ended December 31, 2015 (the "**FY MD&A**") has been prepared in respect of the Oil and Gas Assets only and consequently covers the results of Lundin Petroleum's Malaysian, French and Dutch operations for the years ended December 31, 2017, 2016 and 2015 and the financial position as at December 31, 2017 and 2016. The MD&A for the year ended December 31, 2017 compared to year ended December 31, 2016 and for the year ended December 31, 2016 compared to year ended December 31, 2015 should be read in conjunction with the FY Financial Statements.

Basis of Preparation

The Interim MD&A and Interim Financial Statements have been prepared in accordance with International Accounting Standard 34, Interim Financial Reporting. 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 Interim Financial Statements for additional information on the basis of preparation.

The FY Financial Statements relating to the Initial Oil and Gas Assets have been carved out from Lundin Petroleum's historical consolidated financial statements for the Malaysian, French and Dutch operations prior to the Reorganization and prepared in accordance with prevailing IFRS. The presentation currency of the financial statements is US dollars. Refer to the FY Financial Statements for additional information on the Basis of Preparation.

The 2015 FY Financial Statements exclude the Discontinued Operations, since these carve-out statements were prepared for the purposes of the Spin-Off and therefore were only intended to show the results of on-going operations. In accordance with applicable accounting rules, the 2016 and 2017 FY Financial Statements and the Interim Financial Statements include certain line items related to the Discontinued Operations. Accordingly, there may be certain discrepancies in respect of comparing the 2015 FY Financial Statements to the 2016 and 2017 FY Financial Statements and the Interim Financial Statements.

Critical Accounting Estimates and Judgments

Management of the Corporation has to make estimates and judgments when preparing the financial statements. Uncertainties in the estimates and judgments could have an impact on the carrying amount of assets and liabilities and the financial result.

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

The most important estimates and judgments in relation thereto are set out below.

Estimates of Oil and Gas Reserves

Estimates of oil and gas reserves are used in the calculations for impairment tests and accounting for depletion and site restoration. Standard recognized evaluation techniques are used to estimate 2P Reserves. These techniques take into account the future level of development required to produce the reserves. An independent qualified reserves auditor reviews these estimates**.** The estimation of reserves is a subjective process. Estimates are based on engineering data, projected future rates of production, and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. Reserves estimates can be revised upward or downward based on the results of future drilling, testing, production levels and economics of recovery.

Changes in estimates of oil and gas reserves, resulting in different future production profiles, will affect the discounted cash flows used in impairment testing, the anticipated date of site decommissioning and restoration and the depletion charges in accordance with the unit of production method. Changes in estimates of oil and gas reserves could, for example, result from additional drilling, observation of long-term reservoir performance or changes in economic factors such as oil price and inflation rates.

Impairment of Oil and Gas Properties

At each balance sheet date, an assessment is made as to whether there is an indication that an asset may be impaired. Where an indicator of impairment exists or when impairment testing for an asset is required, the formal assessment of the recoverable amount is made. Where the carrying value of an asset exceeds its recoverable amount the asset is considered impaired and is written down to its recoverable amount.

The recoverable amount is the higher of fair value less costs of disposal and value in use. In determining fair value less costs of disposal, recent market transactions are considered, if available. In the absence of such transactions, an appropriate valuation model is used. Value in use is calculated by discounting estimated future cash flows to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. When the recoverable amount is less than the carrying value an impairment loss is recognized with the expensed charge to the income statement.

Key assumptions in the impairment models relate to prices and costs that are based on forward curves and the related long-term corporate assumptions. Annual impairment tests are performed on an asset basis and in conjunction with the annual reserves audit process. The calculation of the impairment requires the use of estimates. The assumptions that management uses to estimate the future cash flows for value-in-use are expected future oil and gas prices and expected production volumes. These assumptions, and the judgments of management that are based on them, are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates. The discount rate applied is reviewed throughout the year.

Provision for Asset Retirement Obligation

Asset retirement obligations are legal obligations of the Corporation to retire tangible long-lived assets such as producing well sites and offshore production platforms amounts used in recording a provision for asset retirement obligations are estimates based on current legal and constructive requirements and current technology and price levels for the removal of facilities and decommissioning. Due to changes in relation to these items, the future actual cash outflows in relation to the site decommissioning and restoration can be different from the amount recorded as provision for asset retirement obligations. To reflect the effects of changes in legislation, regulatory requirements, technology and relevant price levels, the carrying amounts of asset retirement obligation provisions are reviewed on a regular basis.

On fields where there is an obligation to contribute to asset retirement obligation costs, a provision is recorded to recognise the future commitment. An asset is created, as part of the oil and gas property, to represent the discounted value of the anticipated asset retirement obligation liability and depleted over the life of the field on a unit of production basis. The corresponding accounting entry to the creation of the asset recognizes the discounted value of the future liability. The discount applied to the anticipated asset retirement obligation liability is subsequently released over the life of the field and is charged to financial expenses. Changes in asset retirement obligation costs and reserves are treated prospectively and consistent with the treatment applied upon initial recognition.

These estimates will impact net earnings through accretion of the asset retirement obligation in addition to depletion of the asset retirement cost included in property, plant and equipment. Actual expenditures incurred are charged against the accumulated asset retirement obligation.

Performance Measurement

To measure financial performance, management's primary focus is on the operating results and capital expenditure at a country and asset level. Production and sales volumes and revenues are monitored and managed on a hydrocarbon product level, as is common in the oil and gas industry.

Key Performance Indicators

	Unaudited	**Unaudited**	**Audited**	**Audited**	**Audited**
USD Thousands	**Jan – Mar 2018**	**Jan – Mar 2017**	**FY 2017**	**FY 2016**	**FY 2015**
Revenue	115,162	51,932	203,001	209,880	172,094
Gross profit/(loss)	37,573	17,670	48,758	(105,639)	(215,034)
Net result	26,313	4,461	22,723	(95,720)	(181,565)
Operating cash flow [1]	76,060	39,675	138,368	152,924	128,921
EBITDA [1]	65,291	39,387	129,259	150,043	113,720
Net debt / (net cash) [1]	309,184	(20,082)	26,321	(13,410)	(24,373)

[1] *Non-IFRS measures (unaudited)*

In addition to using financial measures prescribed under IFRS, references are made in this prospectus 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 issuers. 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 Corporation'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 Corporation'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 issuers.

"Operating cash flow" is calculated as revenue less production costs less current tax. Management believes that operating cash flow can be used to analyze the amount of cash that is being generated available for capital investment and servicing debt.

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

"EBITDA" is calculated on a per boe basis 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. Management believes that EBITDA is an important supplemental measure of operating performance to analyze operating earnings before non-operational expenses and non-cash or extraordinary charges.

"Net debt" is calculated as bank loans less cash and cash equivalents. "Net cash" is cash and cash equivalents less bank loans. Management believes that net debt/net cash is a useful calculation of a company's debt position for leverage analysis and capital allocation decisions.

Reconciliation of Non-IFRS Measures

Operating cash flow

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

	Unaudited	**Unaudited**	**Audited**	**Audited**	**Audited**
USD Thousands	**Jan – Mar 2018**	**Jan – Mar 2017**	**FY 2017**	**FY 2016**	**FY 2015**
Revenue	115,162	51,932	203,001	209,880	172,094
Production costs	(46,298)	(11,861)	(64,437)	(59,155)	(41,474)
Current tax	7,196	(396)	(196)	2,199	(1,699)
Operating cash flow (unaudited)	76,060	39,675	138,368	152,924	128,921

EBITDA

The following table sets out the reconciliation from net result from the face of the statement of operations to EBITDA in the Financial Statements:

USD Thousands	**Unaudited** **Jan – Mar 2018**	**Unaudited** **Jan – Mar 2017**	**Audited** **FY 2017**	**Audited** **FY 2016**	**Audited** **FY 2015**
Net result	26,313	4,461	22,723	(95,720)	(181,565)
Income tax	(1,627)	1,332	728	4,887	(1,004)
Depletion	23,162	14,504	54,555	85,187	92,573
Depreciation of other assets	7,960	7,760	31,629	31,073	23,685
Exploration and business development costs	169	137	3,786	14,141	37,638
Impairment costs	–	–	(164)	125,963	191,758
Depreciation included in general, administration and depreciation expenses[1]	161	242	1,095	1,249	1,146
Sale of assets (non-recurring)	–	–	–	3,452	–
Other income	–	–	–	(4,804)	–
Net financial items	9,153	10,951	14,907	(15,385)	(50,511)
EBITDA (unaudited)	65,291	39,387	129,259	150,043	113,720

[1] *Item is not shown in the Financial Statements (unaudited)*

Operating costs

The following table sets out how operating costs is calculated:

USD Thousands	**Unaudited** **Jan – Mar 2018**	**Unaudited** **Jan – Mar 2017**	**Audited** **FY 2017**	**Audited** **FY 2016**	**Audited** **FY 2015**
Production costs	46,298	11,861	64,437	59,155	41,474
Cost of blending [1]	(6,907)	–	–	–	–
Change in inventory position	(2,616)	917	(3,688)	994	9,776
Operating costs (unaudited)	36,775	12,778	60,749	60,149	51,250

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

Net debt / (net cash)

The following table sets out how net debt / (net cash) is calculated from figures shown in the Financial Statements:

USD Thousands	Unaudited March 31, 2018	Unaudited March 31, 2017	Audited December 31, 2017	Audited December 31, 2016	Audited December 31, 2015
Bank loans	337,358	– [1]	60,000	– [1]	– [1]
Cash and cash equivalents	(28,174)	(20,082)	(33,679)	(13,410)	(24,373)
Net debt / (net cash) (unaudited)	309,184	(20,082)	26,321	(13,410)	(24,373)

[1] *IPC was spun-off from Lundin Petroleum with no external bank loans*

The Period January 1, 2018 – March 31, 2018 Compared to the Period January 1, 2017 – March 31, 2017

Operations Review

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 program of 2 infill wells which are now on stream and we expect to drill the Keruing prospect in the latter part of 2018, with a third infill well campaign planned for 2019 execution. In France work continues to mature the Villeperdue and Vert-la-Gravelle opportunities towards sanction and execution.

Production

Production for the IPC assets during the first quarter of 2018 was in line with guidance at 32.9 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 infill wells has increased production from the field relative to year end 2017 and also Q1 2017. All assets performed strongly through the course of Q1 2018 allowing IPC to meet guidance targets for the quarter. The production during the reporting period with comparatives was comprised as follows:

Production in Mboepd	Three months ended March 31		Year ended December 31
	2018	2017	**2017**
Crude oil			
Canada	6.4	–	–
Malaysia	7.8	7.6	6.7
France	2.4	2.5	2.4
Total crude oil production	**16.6**	10.1	**9.1**
Gas			
Canada	15.4	–	–
Netherlands	0.9	1.4	1.2
Total gas production	**16.3**	1.4	**1.2**
Total production	**32.9**	11.5	**10.3**
Quantity in MMboe	**2.96**	1.04	**3.76**

Canada

Production in Mboepd	WI	Three months ended March 31		Year ended December 31
		2018	2017	**2017**
- Crude Oil	100%	**6.4**	–	–
- Gas	99.7% [1]	**15.4**	–	–
Canada		**21.8**	–	–

[1] *On a well count basis*

Production

Net production from the Canadian assets during the first quarter was slightly ahead of forecast at 21.8 Mboepd due to strong oil production performance, underpinned by 100% availability at the 1-27 oil facilities. Gas production was in line with guidance despite the anticipated cold weather which impacted production during Q1 2018. Ambient temperatures on site have risen in the latter part of April leading to an increase in production rates and allowing full access to facilities and wells. Optimization activities on the gas wells which were on hold in February and March have now resumed and we are investigating opportunities to increase activity levels through the course of 2018.

Organic Growth

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 shared at our Capital Markets Day in February. Oil drilling in Canada is planned to commence in the fourth quarter of 2018 with six oil locations and is the first drilling activity of the Suffield Assets in over 4 years. The teams in Canada are working to mature locations and opportunities for 2019 and beyond to maintain an oil drilling campaign once the program starts in late 2018. On the gas side there has been minimal activity on development and drilling since 2010 and we are working to identify and high grade the opportunities to start offsetting natural decline rates. Optimization activities have already started in the field with more planned throughout the course of 2018.

South East Asia

Malaysia

Production in Mboepd	WI	Three months ended March 31		Year ended December 31
		2018	2017	**2017**
Bertam	75%	**7.8**	7.6	**6.7**

Production

Net production from the Bertam field on Block PM307 during the first quarter of 2018 was in line with guidance at 7.8 Mboepd. Reservoir performance for the Bertam field was in line with expectation and facilities uptime for the reporting period was ahead of expectation in excess of 99 percent.

The FPSO Bertam is required to be Malaysian flagged in order to be able to offload crude in Malaysian waters. In February 2018, the Malaysian authorities approved the permanent flag registration for FPSO Bertam.

Organic Growth

In December 2017, drilling commenced on the A16 well, the first of two sanctioned infill wells on the Bertam field, with production commencing in January 2018. The second well, A17, commenced drilling in January 2018 and was completed and on production in February 2018. The drilling program was executed safely, on schedule and with a total gross capital cost saving of over USD 3 million relative to the original approved budget. Initial performance from both wells is in line with expectation. The post drilling review of the A16 and A17 wells and the integration of the seismic results has identified further potential in the Bertam field and the teams are working to mature the next phase of infill drilling at Bertam, which we are planning to execute through the course of 2019.

The Keruing prospect, previously known as I35, has been re-mapped and re-evaluated following reprocessing of the 3D seismic dataset in 2017. The work reveals the potential for a stratigraphically trapped oil accumulation in the Tertiary I35 sand at approximately 1,150 m depth which is 450 m shallower than the Bertam reservoir. The target I35 sand has been penetrated off structure by several wells during the Bertam development confirming the presence of high quality sands. There is a structural component of the trap leaving potential for a commercial discovery even if the stratigraphic trap mechanism fails. The expected oil type is light oil similar to the oil present in the Bertam field.

The Keruing well is planned to be spudded late in 2018 subject to approvals from Petronas and partners and subject to rig availability and contracting. The capital cost is expected to be USD 6.5 million net. 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.

Exploration Blocks

During the fourth quarter of 2017, the Group notified Petronas and partner Petronas Carigali of its intention to withdraw from the PM328 exploration block. Final approval of the withdrawal was granted in February 2018.

No commitments are outstanding on any blocks in Malaysia.

Continental Europe

Production in Mboepd	WI	Three months ended March 31 **2018**	2017	Year ended December 31 2017
France				
- Paris Basin	100% [1]	2.0	2.1	2.0
- Aquitaine	50%	0.4	0.4	0.4
Netherlands	Various	0.9	1.4	1.2
		3.3	3.9	3.6

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

<u>France</u>

Net production in France during the first quarter of 2018 was above forecast at 2.4 Mboepd.

Organic Growth

IPC recognizes significant development upside in the Paris Basin. In parallel with maturing the contingent resources, IPC has been actively working on optimizing the Vert La Gravelle project which is already reflected in the 2P reserves base.

The Vert La Gravelle redevelopment project passed the concept selection milestone in December 2017 and efforts are now focusing on refining the drilling and completion design and preparation of the final investment proposal. Final investment decision is expected before year end 2018, aligning the field development sanction decision with the evaluation of the Villeperdue West redevelopment project where there are potential operational synergies.

<u>The Netherlands</u>

Net production from the Netherlands fields during the first quarter of 2018 was slightly below forecast at 0.9 Mboepd due to lower than expected production from the onshore Slootdorp and Gorredijk fields. 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 to revenues.

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 consolidated statement of operations is as follows:

USD Thousands	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016
Revenue	**115,162**	54,647	47,926	48,496	51,932	59,592	48,498	55,568
Gross profit/(loss)	**37,573**	13,471	7,256	10,361	17,670	(114,600)	9,631	16,029
Net result	**26,313**	8,977	2,172	7,113	4,461	(76,097)	4,522	26,954
Earnings/(loss) per share – USD [1]	**0.30**	0.10	0.02	0.07	0.04	(0.67)	0.04	0.24
Earnings/(loss) per share fully diluted – USD[1]	**0.30**	0.10	0.02	0.07	0.04	(0.67)	0.04	0.24
Operating cash flow [2]	**76,060**	37,156	28,893	32,643	39,675	42,083	38,911	42,745
EBITDA [2]	**65,291**	33,383	26,440	30,049	39,387	41,126	38,439	43,005
Net debt [2]	**309,184**	26,321	47,241	35,348	(20,082)	(13,410)	(8,443)	(19,235)

[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 of the non-IFRS measures under "Management Discussion & Analysis – Key Performance Indicators".

Summarized consolidated balance sheet information is as follows:

USD Thousands	March 31, 2018	December 31, 2017
Non-current assets	885,459	455,235
Current assets	116,504	134,476
Total assets	**1,001,963**	**589,711**
Total non-current liabilities	578,163	219,097
Current liabilities	89,407	63,672
Total liabilities	**667,570**	**282,769**
Net assets	**334,393**	**306,942**
Working capital (including cash)	**27,097**	**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.

USD Thousands	Three months ended – March 31, 2018					
	Canada	Malaysia	France	Netherlands	Other	Total
Crude oil	27,014	43,686	20,550	23	–	**91,273**
NGLs	84	–	–	119	–	**203**
Gas	17,201	–	–	3,401	–	**20,602**
Net sales of oil and gas	**44,299**	**43,686**	**20,550**	**3,543**	–	**112,078**
Change in under/over lift position	–	–	(41)	12	–	**(29)**
Royalties	(1,706)	–	–	–	–	**(1,706)**
Other operating revenue	208	3,825	278	387	121	**4,819**
Revenue	**42,801**	**47,511**	**20,787**	**3,942**	**121**	**115,162**
Production costs	(28,514)	(5,340)	(10,713)	(1,731)	–	**(46,298)**
Depletion	(10,025)	(9,089)	(3,292)	(756)	–	**(23,162)**
Depreciation of other assets	–	(7,960)	–	–	–	**(7,960)**
Exploration and business development costs	–	(165)	–	–	(4)	**(169)**
Gross profit/(loss)	**4,262**	**24,957**	**6,782**	**1,455**	**117**	**37,573**

USD Thousands	Three months ended – March 31, 2017				
	Malaysia	France	Netherlands	Other	Total
Crude oil	25,654	17,236	25	–	42,915
NGLs	–	–	102	–	102
Gas	–	–	4,584	–	4,584
Net sales of oil and gas	**25,654**	**17,236**	**4,711**	**–**	**47,601**
Change in under/over lift position	–	(89)	(216)	–	(305)
Other operating revenue	3,718	273	439	206	4,636
Revenue	**29,372**	**17,420**	**4,934**	**206**	**51,932**
Production costs	(849)	(9,389)	(1,623)	–	(11,861)
Depletion	(9,585)	(3,516)	(1,403)	–	(14,504)
Depreciation of other assets	(7,760)	–	–	–	(7,760)
Exploration and business development costs	(117)	(20)	–	–	(137)
Gross profit/(loss)	**11,061**	**4,595**	**1,908**	**206**	**17,670**

Revenue

Reported revenue amounted to USD 115,162 thousand for Q1 2018 compared to USD 51,932 thousand for Q1 2017 and is analyzed as follows:

	Three months ended March 31	
USD Thousands	**2018**	2017
Crude oil sales	91,273	42,915
Gas and NGL sales	20,805	4,686
Change in under/overlift position	(29)	(305)
Royalties	(1,706)	–
Other operating revenue	4,819	4,636
Total revenue	**115,162**	**51,932**

The components of revenue for Q1 2018 and Q1 2017 are detailed below:

Crude oil sales

	Three months ended – March 31, 2018				
	Canada	**Malaysia**	**France**	**Netherlands**	**Total**
Crude oil sales					
- Revenue in USD thousands	27,014	43,686	20,550	23	91,273
- Quantity sold in bbls	673,153	619,244	310,971	392	1,603,760
- Average price realized USD per bbl	40.13	70.55	66.08	58.38	56.91

	Three months ended – March 31, 2017			
	Malaysia	**France**	**Netherlands**	**Total**
Crude oil sales				
- Revenue in USD thousands	25,654	17,236	25	42,915
- Quantity sold in bbls	446,870	334,644	540	782,054
- Average price realized USD per bbl	57.41	51.51	45.91	54.87

Crude oil revenue was 113 percent higher for Q1 2018 compared to Q1 2017 mainly due to the contribution of Suffield, Canada from January 5, 2018, an additional cargo lifted in Malaysia and an increase in the underlying oil price.

The crude oil in Canada is blended with purchased condensate diluent volumes to meet pipeline specifications before being sent to the refineries. As a result of the blended volumes, actual sales volumes are 17% 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 63/bbl and the average discount to WCS was approximately USD 24/bbl for Q1 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 67/bbl for Q1 2018 compared to USD 54/bbl for the comparative period. There were three cargoes sold in Malaysia during Q1 2018 compared to two cargoes in Q1 2017.

In addition, there was a cargo lifting in Aquitaine, France of 134 mbbls in Q1 2018 compared to a 142 mbbls lifting in Q1 2017. There are no more Aquitaine liftings forecast for the remainder of 2018.

Gas and NGL sales

	Three months ended – March 31, 2018				
	Canada	Malaysia	France	Netherlands	Total
Gas and NGL sales					
- Revenue in USD thousands	17,285	–	–	3,520	20,805
- Quantity sold in Mcf	8,076,660	–	–	490,130	8,566,790
- Average price realized USD per Mcf	2.14	–	–	7.18	2.43

	Three months ended – March 31, 2017			
	Malaysia	France	Netherlands	Total
Gas and NGL sales				
- Revenue in USD thousands	–	–	4,686	4,686
- Quantity sold in Mcf	–	–	817,082	817,082
- Average price realized USD per Mcf	–	–	5.73	5.73

Gas and NGL sales revenue was 344 percent higher for Q1 2018 compared to Q1 2017 mainly due to the contribution of Suffield, Canada from January 5, 2018. Over 90% of the Suffield gas production is sold on the Alberta/Saskatchewan border at Empress with the remainder being delivered to Alberta based on AECO pricing. At Empress, the realized price of the gas is at a premium over AECO pricing.

Dutch gas volumes sold in Q1 2018 are 25 percent lower than the comparative period due to the naturally declining production, but this has been partly offset by a 25 percent higher realized gas price.

Other operating revenue

Other operating revenue amounted to USD 4,819 thousand for Q1 2018 compared to USD 4,636 thousand for Q1 2017. Other operating revenue mainly represents third party lease fee income received by the Group for the leasing of the owned FPSO Bertam facility to the Bertam field in Malaysia.

Production costs

Production costs including inventory movements amounted to USD 46,298 thousand for Q1 2018 compared to USD 11,861 thousand for Q1 2017 and is analyzed as follows:

	Three months ended – March 31, 2018					
USD Thousands	Canada	Malaysia	France	Netherlands	Other[4]	Total
Operating costs[1]	21,894	16,948	7,677	1,731	(11,475)	**36,775**
USD/boe[2]	11.15	24.13	35.66	21.02	n/a	**12.40**
Cost of blending[3]	6,907	–	–	–	–	**6,907**
Change in inventory position	(287)	(133)	3,036	–	–	**2,616**
Production costs	**28,514**	**16,815**	**10,713**	**1,731**	**(11,475)**	**46,298**

	Three months ended – March 31, 2017				
USD Thousands	Malaysia	France	Netherlands	Other[4]	Total
Operating costs[1]	17,084	5,546	1,623	(11,475)	12,778
USD/boe[2]	25.01	24.96	12.42	n/a	12.33
Change in inventory position	(4,760)	3,843	–	–	(917)
Production Costs	12,324	9,389	1,623	(11,475)	11,861

[1] *See definition of the Non-IFRS measures under "Management Discussion & Analysis – Key Performance Indicators".*

[2] *USD/boe in the tables above is calculated by dividing the cost by the production volume for each country for the period.*

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

[4] *Included in the Malaysia production 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 to USD 7.79 and USD 8.21 for Malaysia for Q1 2018 and Q1 2017 respectively.*

Operating costs

Operating costs amounted to USD 36,775 thousand for Q1 2018 compared to USD 12,778 thousand for Q1 2017. The increase in operating costs is mainly due to the contribution of Suffield, Canada from January 5, 2018 and is in line with forecast. Operating costs per boe amounted to USD 12.40/boe in Q1 2018 compared to USD 12.33/boe in Q1 2017 with Canada for Q1 2018 costing USD 11.15/boe. The French operating costs in Q1 2018 increased by 38 percent compared to the prior quarter as a result of the increased production taxes due to tax legislation changes made in Q4 2017, cost phasing and the stronger US Dollar against the Euro.

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 for Q1 2018 amounted to USD 6,907 thousand. As a result of the blending, actual sales volumes are higher than produced barrels – see Crude Oil Sales section above.

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 income statement. In the Aquitaine Basin, France, there was a cargo lifting in both Q1 2018 and Q1 2017 and due to the relatively low level of production from the Aquitaine fields, there are no further liftings forecast in 2018.

Depletion and decommissioning costs

The total depletion and decommissioning costs amounted to USD 23,162 thousand for Q1 2018 compared to USD 14,504 thousand for Q1 2017, with the inclusion of a USD 10,025 thousand depletion charge for Q1 2018 relating to the Suffield asset. The depletion charge per country is analyzed in the following tables:

	Three months ended – March 31, 2018				
	Canada	**Malaysia**	**France**	**Netherlands**	**Total**
Depletion in USD thousands	10,025	9,089	3,292	756	**23,162**
Depletion USD per boe	5.10	12.94	15.30	9.18	**7.81**

	Three months ended – March 31, 2017			
	Malaysia	**France**	**Netherlands**	**Total**
Depletion in USD thousands	9,585	3,516	1,403	14,504
Depletion USD per boe	14.03	15.83	10.74	14.00

Following the allocation of the purchase price for the Suffield asset, the depletion rate for Canada is calculated at USD 5.10/boe. 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.

Depreciation of other assets

The total depreciation of other assets amounted to USD 7,960 thousand for Q1 2018 compared to USD 7,760 thousand for Q1 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.

Exploration and business development costs

Total expensed exploration and business development costs amounted to USD 169 thousand for Q1 2018 compared to USD 137 thousand for Q1 2017. Exploration and business development costs are capitalized as they are incurred and expensed when their recoverability is determined highly uncertain (for example, an unsuccessful exploration well is drilled).

General, administrative and depreciation expenses

General, administrative and depreciation expenses amounted to USD 3,734 thousand for Q1 2018 compared to USD 926 thousand for Q1 2017. Up until the Spin-Off date, 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 Q1 2018 amounted to USD 9,153 thousand compared to USD 10,951 thousand for Q1 2017. Included in the amount for Q1 2018 is interest expense on the external loan facilities which were drawn to fund the Suffield acquisition at the beginning of January and a net foreign exchange loss of USD 1,419 thousand mainly resulting from the revaluation of intra-group loan funding balances held by a subsidiary with a functional currency of Euro. In addition, the unwinding of the discount rate on the asset retirement obligations amounted to a non-cash charge of USD 2,388 thousand for Q1 2018 compared to USD 854 thousand for Q1 2017. The increase is largely due to the unwinding of the discounting on the Suffield asset retirement obligation included on January 5, 2018. The net financial items for Q1 2017 consisted of a non-cash net foreign exchange loss of USD 10,063 thousand mainly resulting from the revaluation of intercompany loans prior to the reorganization and Spin-Off.

Income tax

The corporate income tax credit for Q1 2018 amounted to USD 1,627 thousand compared to a charge of USD 1,332 thousand for Q1 2017. There was a current tax credit of USD 7,196 thousand in Q1 2018 compared to a USD 396 thousand charge in the comparative period and 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 Q1 2018 amounted to USD 5,569 thousand compared to USD 936 thousand for the comparative period which included a deferred tax charge relating to the Suffield Purchase Price Allocation.

Capital Expenditure

Oil and Gas Properties

Development and exploration and evaluation expenditure incurred in Q1 2018 was as follows:

USD Thousands	Canada	Malaysia	France	Netherlands	Total
Development	730	12,356	1,014	168	**14,268**
Exploration and evaluation	–	429	185	59	**673**
	730	12,785	1,199	227	**14,941**

Capital expenditure is in line with forecast 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.

Other tangible fixed assets

Other tangible fixed assets amounted to USD 116,061 thousand as at March 31, 2018, which included USD 113,868 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 completed the Acquisition of the Suffield assets from Cenovus Energy Inc. The total consideration, after preliminary closing adjustments and including deferred and estimated contingent consideration, amounted to USD 378,567 thousand. The purchase price was allocated, on a preliminary basis, as follows:

USD Thousands	
Property, Plant and Equipment, net	456,335
Deferred tax liabilities	(2,682)
Abandonment retirement obligation	(75,086)
Net assets acquired	**378,567**

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

On April 20, 2017, the Group entered into a 2.25-year senior secured 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 on May 31, 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 mostly used to pay the Suffield acquisition price of CAD 449 million (net of closing adjustments and including a CAD 40 million deposit).

During Q1 2018, after all operations related costs and capital expenditure, mostly in Malaysia, free cash flows was dedicated to debt repayment, leading to net debt of USD 309 million at the end of March 2018.

Subsequent to March 31, 2018, the Group is continuing to deleverage and has repaid CAD 45 million of the Canadian second lien loan facility by drawing under the International reserve-based lending credit facility. This will result in a lower average cost of capital for the Group going forward.

The Group's free cash flows going forward are planned to continue to be used to repay outstanding debts, with a view to lowering the Group's average cost of capital. 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 28.2 million as at March 31, 2018. The Corporation holds cash to meet imminent operational funding requirements in the different countries.

Pursuant to the IPC spin off from Lundin Petroleum, 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 is expected on December 31, 2018 and amounts to USD 23.5 million.

Working Capital

As at March 31, 2018, the Group had a net working capital balance including cash of USD 27,097 thousand compared to USD 70,804 thousand as at December 31, 2017. The main movement in working capital during Q1 2018 is the allocation of the deposit in relation to the Suffield acquisition of USD 31,898 thousand to the purchase price. 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.

Off-balance Sheet Arrangements

As at March 31, 2018 IPC, through its subsidiary IPC Malaysia BV, had issued bank guarantees to the customs authorities for an amount of USD 941 thousand.

Contractual Obligations and Commitments

As part of the Acquisition of the Suffield Assets, IPC is required to make a deferred consideration payment to Cenovus Energy Inc. of CAD 12 million before June 29, 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 is up to CAD 36 million as at January 5, 2018. An estimated contingent consideration of USD 7,250 thousand as at January 5, 2018 has been reflected in the Financial Statements. The Group paid an amount of CAD 750 thousand for January and February 2018 in Q1 2018 as contingent consideration related to the price of oil. For March 2018, the Group has accrued an amount of CAD 375 thousand related to the price of oil. 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 Interim Financial Statements incorporated by reference herein.

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

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

Related Party Transactions

As at the date of the Spin-Off, the Group had a residual liability for working capital owed to Lundin Petroleum AB of USD 27,429 thousand which has been reduced to USD 23,513 thousand as at March 31, 2018. Instalments of this amount bear interest at 3.5% from the date of an original repayment schedule. This amount is reflected as a current liability as it is due before the end of December 2018. Expensed interest of USD 53 thousand is included in Q1 2018 interim condensed consolidated financial statements related to this liability.

Lundin Petroleum has charged the Group USD 189 thousand in respect of office space rental and USD 325 thousand in respect of shared services provided in Q1 2018. IPC has charged Lundin Petroleum USD 88 thousand in respect of consultancy fees in Q1 2018.

All transactions with related parties are carried out as part of the Group's normal course of business and are made on an arm's length basis.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Operational Review

During 2017, our assets have continued to perform well with average production of 10,307 boepd, three percent ahead of our mid-point CMD guidance.

This has been driven by a good performance across all of our assets in Malaysia, France and the Netherlands. A world class uptime performance on the Bertam FPSO in excess of 99 percent was achieved in 2017 (excluding the planned shutdown for infill drilling operations). It is remarkable that such a sustained performance has been delivered since Bertam started producing in April 2015.

In addition, lower than forecast operating costs have allowed us to deliver full year operating costs of USD 16.15 per boe, 14 percent below our CMD guidance.

During 2017, IPC assets generated significant operating cash flow of USD 138 million. This allowed IPC to pay down the Credit Facility put in place to fund the purchase of 25.5 million IPC Common Shares under the share purchase offer in the second quarter of 2017. By the end 2017, IPC was in a net cash position of USD 5.6 million, excluding the CAD 40 million (USD 32.6 million) deposit for the Suffield acquisition in Canada. Including the Canadian acquisition deposit, year-end net debt stood at USD 26.3 million.

Good progress has been made during 2017 in adding value to IPC's resource base. IPC's 2P reserve base amounted to 29.4 MMboe as at December 31, 2016. A portfolio re-evaluation during the first half of 2017 allowed IPC to book 17.5 MMboe of best estimate contingent resources. A capital investment program was approved in the second quarter of 2017 to drill two new infill wells in Malaysia on the Bertam field and acquire a 79 km^2 3D seismic survey in the Villeperdue field in France.

The two infill wells on the Bertam field in Malaysia have now been completed and commenced production in January and February of 2018 respectively.

In France, the 3D seismic acquisition on the western flank of the Villeperdue field was completed in October 2017. Work is ongoing on the seismic interpretation and we expect to be in a position by the end of 2018 to reach the concept selection milestone. In parallel, work continues on the Vert La Gravelle development plan, progressing towards a final investment decision during 2018.

As at end December 2017, IPC's 2P reserves more than quadrupled to 129.1 MMboe (including 2P reserves attributable to the Suffield acquisition in Canada). 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 reflecting recent performance.

Production

Production of 10.3 Mboepd for the reporting period was three percent ahead of original mid-point CMD guidance. The production during the reporting period with comparatives was comprised as follows:

Production [1] in Mboepd	Year ended December 31 **2017**	 2016
Crude oil		
Malaysia	6.7	8.6
France	2.4	2.6
Total crude oil production	**9.1**	11.2
Gas		
Netherlands	1.2	1.6
Total gas production	**1.2**	1.6
Total production	**10.3**	12.8
Quantity in MMboe	**3.76**	4.66

[1] *Excludes 1.17 MMboe produced by the Singa field, Indonesia, in 2016 prior to the sale of the asset in April 2016.*

Financial Review

During the year ended December 31, 2017, the Oil and Gas Assets generated revenue of USD 203.0 million, compared to USD 209.9 million for the year ended December 31, 2016. This decrease was primarily related to Indonesia which was divested in Q2 2016.

Net result for the financial year 2017 amounted to a profit of USD 22.7 million, compared with a charge of USD 95.7 million for 2016. The net result in 2016 was reduced by non-cash USD 126.0 million after-tax impairment charges in relation to the impairment of gas discoveries in Malaysia relating to the Bertam field and exploration blocks.

Total cash flow from operations for the financial year 2017 amounted to USD 149.0 million, compared to USD 109.4 million for 2016. The increase is mainly due to favourable changes in working capital balances. Investment in oil and gas properties amounted to USD 23.1 million for 2017 compared to USD 34.9 million for 2016, but an additional USD 32.6 million deposit was paid in 2017 for the Acquisition in Canada.

Total assets amounted to USD 589.7 million at December 31, 2017, compared to USD 572.0 million at December 31, 2016. This increase was primarily related to an increase in cash and cash equivalents as well as trade receivables. Total liabilities amounted to USD 282.8 million at December 31, 2017, compared to USD 166.9 million at December 31, 2016. The increase in total liabilities was primarily related to the new financing of USD 60 million and to the deposit of CAD 40 million triggered by the Acquisition of the Suffield Assets. Net assets amounted to USD 306.9 million at December 31, 2017 compared to USD 405.1 million at December 31, 2016.

Income Statement

Revenue

Total revenue amounted to USD 203,001 thousand for the year ended December 31, 2017 compared to USD 209,880 thousand for the year ended December 31, 2016 and is analyzed as follows:

	Year ended December 31	
USD Thousands	**2017**	2016
Crude oil sales	169,881	165,752
Gas and NGL sales	15,301	24,964
Change in under/overlift position	(613)	217
Other operating revenue	18,432	18,947
Total revenue	**203,001**	209,880

Crude Oil Sales

Crude oil sales were 2 percent higher for the year ended December 31, 2017 compared to the year ended December 31, 2016 due to a 25 percent increase in the average sales price achieved partly offset by an 18 percent decrease in the volumes sold. The realized sales price is based on Dated Brent crude oil prices and the average Dated Brent crude oil price was USD 54.19/bbl for the year ended December 31, 2017 compared to USD 43.03/bbl for the comparative period. There were eleven cargoes sold in Malaysia during the year ended December 31, 2017 compared to twelve cargoes in the comparative period, primarily as a result of the lower production volumes.

	Year ended – December 31, 2017			
	Malaysia	**France**	**Netherlands**	**Total**
Crude oil sales				
- Revenue in USD thousands	122,595	47,238	48	**169,881**
- Quantity sold in bbls	2,139,683	890,527	1,097	**3,031,307**
- Average price realized USD per bbl	57.30	53.05	43.57	**56.04**

	Year ended – December 31, 2016			
	Malaysia	**France**	**Netherlands**	**Total**
Crude oil sales				
- Revenue in USD thousands	125,823	39,887	42	165,752
- Quantity sold in bbls	2,787,829	907,023	1,228	3,696,080
- Average price realized USD per bbl	45.13	43.98	33.82	44.85

Gas and NGL Sales

The gas sales revenue for the year ended December 31, 2016 includes revenue in respect of the Singa field in Indonesia. The Singa field was sold in April 2016. The average price realized for Singa gas revenue was based on a fixed contract price and is therefore higher compared to the Dutch assets where the price realized is based on market prices. Dutch gas volumes sold in the year ended December 31, 2017 are 22 percent lower than the comparative period due to the naturally declining production, but this has been offset by a 25 percent higher realized gas price.

	Year ended – December 31, 2017				
	Malaysia	**France**	**Netherlands**	**Indonesia**	**Total**
Gas and NGL sales					
- Revenue in USD thousands	–	–	15,301	–	**15,301**
- Quantity sold in Mcf	–	–	2,722,099	–	**2,722,099**
- Average price realized USD per Mcf	–	–	5.62	–	**5.62**

	Year ended – December 31, 2016				
	Malaysia	**France**	**Netherlands**	**Indonesia**	**Total**
Gas and NGL sales					
- Revenue in USD thousands	–	–	15,695	9,269	24,964
- Quantity sold in Mcf	–	–	3,482,363	1,069,066	4,551,429
- Average price realized USD per Mcf	–	–	4.51	8.67	5.48

Other Operating Revenue

Other operating revenue amounted to USD 18,432 thousand for the year ended December 31, 2017 compared to USD 18,947 thousand for the year ended December 31, 2016. Other operating revenue mainly represents third party lease fee income received by the Group for the leasing of the owned FPSO Bertam facility to the Bertam field in Malaysia, but also includes tariff income from France and the Netherlands and income for maintaining strategic inventory levels in France.

Production Costs

Production costs including inventory movements amounted to USD 64,437 thousand for the year ended December 31, 2017 compared to USD 59,155 thousand for the comparative period and is analyzed as follows:

	Year ended – December 31, 2017					
USD Thousands	**Malaysia**	**France**	**Netherlands**	**Indonesia**	**Other[2]**	**Total**
Operating costs	73,540	25,820	7,926	–	(46,537)	**60,749**
USD/boe[1]	30.14	29.00	18.35	–	n/a	**16.15**
Change in inventory position	3,390	298	–	–	–	**3,688**
Production costs	**76,930**	**26,118**	**7,926**	**–**	**(46,537)**	**64,437**

	Year ended – December 31, 2016					
USD Thousands	**Malaysia**	**France**	**Netherlands**	**Indonesia**	**Other[2]**	**Total**
Operating costs	73,032	22,476	9,947	1,358	(46,664)	60,149
USD/boe[1]	23.18	23.94	17.32	7.00	n/a	12.38
Change in inventory position	975	(1,969)	–	–	–	(994)
Production costs	74,007	20,507	9,947	1,358	(46,664)	59,155

[1] *USD/boe in the tables above is calculated by dividing the cost by the production volume for each country for the period.*

[2] *Included in the Malaysia production 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 to USD 11.07 and USD 8.37 for Malaysia for the year ended December 31, 2017 and 2016 respectively.*

Production costs excluding inventory movements (operating costs)

Production costs excluding inventory movements (operating costs) amounted to USD 60,749 thousand for the year ended December 31, 2017 compared to USD 60,149 thousand for the year ended December 31, 2016. Included in the year ended December 31, 2017 are costs of USD 3,309 thousand associated with the Bertam shutdown. Included in the year ended December 31, 2016 is USD 2,267 thousand for the workover of two shut-in production wells on the Bertam field and USD 1,362 which relates to the Singa field, Indonesia, which was sold in April 2016. These items combined result in a slight increase of the costs for the year ended December 31, 2017 compared to 2016, along with reduced project and maintenance activities in the Netherlands in 2017. Besides the slight increase in the costs, the cost per boe increased for the year ended December 31, 2017 compared to 2016 due to the lower production volumes in 2017.

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 income statement. In the Aquitaine Basin, France, due to the relatively low level of production from the Aquitaine fields, there was only the one lifting forecast in 2017 which was lifted in March.

Depletion

The total depletion charge amounted to USD 54,438 thousand for 2017 compared to USD 85,187 thousand for 2016. The following table summarizes the components of depletion charges for the 12 months ended 2017 and 2016, respectively.

	Year ended – December 31, 2017			
	Malaysia	**France**	**Netherlands**	**Total**
Depletion in USD thousands	34,228	13,464	6,746	**54,438**
Depletion USD per boe	14.03	15.12	15.62	**14.47**

	Year ended – December 31, 2016			
	Malaysia	**France**	**Netherlands**	**Total**
Depletion in USD thousands	61,086	14,380	9,721	85,187
Depletion USD per boe	19.39	15.32	16.93	17.53

The depletion amount for the Netherlands includes an accelerated depletion charge for the year ended December 31, 2017 of USD 1,668 thousand in connection to the permanent shut-in of the F15 field offshore in December 2017. Excluding the accelerated depletion charge the depletion rate per boe is USD 11.76 for the year ended December 31, 2017. The depletion rates for the Bertam field, Malaysia and the Dutch gas fields have reduced significantly in 2017 compared to 2016 due mainly to the reserves upgrades at the end of 2016. The depletion rate is calculated for each of the French and Dutch producing assets and therefore the rates shown in the table depend on the relative production contribution of each asset. The depletion charge is calculated by applying the depletion rate per boe to the volumes produced in the period. Note that there was no depletion charge in 2016 for the Singa field, Indonesia as it was held as an asset for sale during the period.

Depreciation of other assets

The total depreciation of other assets amounted to USD 31,629 thousand for the year ended December 31, 2017 compared to USD 31,073 thousand for the comparative period. 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.

Exploration and business development costs

Total expensed exploration and business development costs amounted to USD 3,786 thousand for the year ended December 31, 2017 compared to USD 14,141 thousand for the year ended December 31, 2016. The costs relate to unsuccessful exploration and evaluation costs and expenses related to business development activities. Exploration and evaluation costs are capitalized as they are incurred and expensed when their recoverability is determined highly uncertain (for example, an unsuccessful exploration well is drilled). Expensed costs in the year ended December 31, 2017 mainly represent the costs of business development activities for an amount of USD 2,869 thousand and some past exploration costs in France for an amount of USD 1,263 thousand related to pre-licensing costs incurred in France, following an announcement by the French government in December 2017 that no new petroleum exploration licences will be granted. The significant exploration costs in 2016 mainly related to the unsuccessful exploration wells drilled on the SB307/308 licence in Malaysia.

Impairment costs of oil and gas properties

Impairment costs of oil and gas properties amounted to USD 164 thousand credit for the year ended December 31, 2017 compared to USD 125,963 thousand for the comparative period. Impairment costs for the year ended December 31, 2016 related to a decision to remove the contingent resources associated with gas discoveries in the Sabah region offshore East Malaysia and the Tembakau gas discovery in PM307 offshore Peninsular Malaysia.

General, administrative and depreciation expenses

General, administrative and depreciation expenses amounted to USD 10,400 thousand for the year ended December 31, 2017 compared to USD 1,931 thousand for the comparative period. Up until the Spin-Off date, 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 and management post Spin-Off.

Net financial items

Net financial items amounted to USD 14,907 thousand for the year ended December 31, 2017 compared to USD 15,385 thousand credit for the comparative period. Included in the amount for the year ended December 31, 2017 is a largely non-cash foreign exchange loss of USD 8,922 mainly resulting from USD intra-group loan funding balances held by a subsidiary with a functional currency of Euro. Foreign exchange movements occur on the settlement of transactions denominated in foreign currencies and the revaluation of working capital and loan balances to the prevailing exchange rate at the balance sheet date where those monetary assets and liabilities are held in currencies other than the functional currencies of the Group's reporting entities. In addition, the unwinding of the discount rate on the asset retirement obligations amounted to USD 3,557 thousand for the year ended December 31, 2017. Asset retirement obligations estimates are discounted to a present value when reflected in the balance sheet and the discounting is unwound through the income statement. The net financial items for the year ended December 31, 2016 mainly consisted of non-cash foreign exchange gains of USD 19,070 thousand.

Income tax

The corporate income tax charge of USD 728 thousand for the year ended December 31, 2017 compared to USD 4,887 thousand for the comparative period. There was a current tax charge of USD 196 in the year ended December 31, 2017 compared to a USD 2,199 thousand credit in the comparative period relating to a Dutch petroleum tax refund. The deferred tax charge for the year ended December 31, 2017 amounted to USD 532 thousand compared to USD 7,086 thousand for the comparative period which included a deferred tax charge relating to the Singa field, Indonesia, which was sold in April 2016.

Capital Expenditure

Oil and Gas Properties

As at December 31, 2017, oil and gas properties amounted to USD 312,401 thousand, with USD 108,047 thousand capitalized in Malaysia, USD 188,301 thousand capitalized in France and USD 16,053 thousand capitalized in the Netherlands.

Development and exploration and appraisal expenditure incurred in 2017 was as follows:

USD Thousands	Malaysia	France	Netherlands	Total
Development	11,708	4,696	1,759	**18,163**
Exploration and evaluation	(92)	4,251	755	**4,914**
	11,616	**8,947**	**2,514**	**23,077**

The development expenditure in Malaysia mainly relates to the drilling of an infill well on the Bertam field. The exploration and evaluation cost in France mainly relates to the acquisition of the 3D seismic in the Villeperdue field.

Other tangible fixed assets

Other tangible fixed assets amounted to USD 123,051 thousand as at December 31, 2017, which included USD 121,213 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.

Selected Annual Financial Information

The following table sets out financial information for the Oil and Gas Assets over the last nine quarters. The financial information set out below has been derived from the Financial Statements. The following information should be read in conjunction with such financial statements and the accompanying notes. See "*Risk Factors*".

		Quarterly financial information					Quarterly financial information			
USD Thousands (unless stated)	**2017**	Q4 2017	Q3 2017	Q2 2017	Q1 2017	2016	Q4 2016	Q3 2016	Q2 2016	Q1 2016
Production (Boe/d)	**10.3**	9.9	9.2	10.6	11.5	12.8	12.3	12.9	12.8	14.5
Revenue	**203,001**	54,647	47,926	48,496	51,932	209,880	59,592	48,498	55,568	46,222
Gross profit/(loss)	**48,758**	13,471	7,256	10,361	17,670	(105,639)	(114,600)	9,631	16,029	(16,699)
Net result	**22,723**	8,977	2,172	7,113	4,461	(95,720)	(76,097)	4,522	26,954	(51,099)
Earnings per share – USD[1]	**0.23**	0.10	0.02	0.07	0.04	(0.84)	(0.67)	0.04	0.24	(0.45)
Earnings per share fully diluted – USD[1]	**0.23**	0.10	0.02	0.07	0.04	(0.84)	(0.67)	0.04	0.24	(0.45)
Operating cash flow	**138,368**	37,156	28,893	32,643	39,676	152,924	42,083	38,911	42,745	29,185
EBITDA	**129,259**	33,383	26,440	30,049	39,387	150,043	41,126	38,439	43,005	27,473
Net debt	**26,321**	26,321	47,241	35,348	(20,082)	(13,410)	(13,410)	(8,443)	(19,235)	(22,304)

[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.*

Off-Balance Sheet Arrangements

As at December 31, 2017 IPC, through its subsidiary IPC Malaysia BV, had issued bank guarantees to the customs authorities for an amount of USD 899 thousand.

Related Party Transactions

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 AB of USD 27,429 thousand which has been reduced to USD 23,460 thousand as at December 31, 2017. Instalments of this amount bear interest at 3.5% from the date of an original repayment schedule. This amount is reflected as a current liability as it is due before the end of December 2018. Expensed interest of USD 31 thousand is included in the 2017 consolidated financial statements related to this liability.

Lundin Petroleum has charged the Group USD 504 thousand in respect of office space rental and USD 2,042 thousand in respect of shared services provided since the Spin-Off date. IPC has charged Lundin Petroleum USD 461 thousand in respect of consultancy fees in 2017.

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.

Remuneration of Directors and Senior Management

Remuneration of Directors and Senior Management includes all amounts earned and awarded to the Group's Board of Directors and Senior Management. Senior Management includes the Group's President and Chief Executive Officer, Chief Financial Officer, General Counsel and Corporate Secretary, Vice President of Operations, Vice President of Reservoir Development and Vice President of Corporate Planning and Investor Relations.

Directors' fees include Board and Committee fees. Management's short-term wages, bonuses and benefits include salary, benefits, bonuses and any other compensation earned or awarded in 2017 from the Spin-Off date.

USD Thousands	**2017**
Directors' fees	334
Management's short-term wages, bonuses and benefits	2,712
	3,046

At December 31, 2017, IPC share-based incentive plans remain unvested.

There are no other material related party transactions.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Operational Review

Malaysia

Peninsular Malaysia

Average daily net production from the Bertam field on Block PM307 (WI 75%) during 2016 was ahead of forecast at 8,607 boe/d with an uptime of 99%. 2016 production increased by 58% relative to 2015, when full year average daily net production was 5,480 boe/d. The main reason for the material improvement in 2016 compared to 2015 is that the Bertam field was onstream for only a part of 2015, as first oil was achieved in April 2015. The Bertam field was producing from 11 wells as of mid-October 2015 with one additional well, the A15 long-reach well, commencing production in June 2016 following the successful Bertam-3 appraisal well from 2015, which was drilled northeast of the Bertam field. The A15 well results were better than forecast, with production being constrained by facilities limitations. Overall field performance was better than forecast due to better than expected reservoir performance. However, this outperformance was partially offset by the shut-in of two production wells in 2016 in relation to replacement of downhole electrical submersible pumps and for production shut-ins due to rig moves.

In October 2015, Lundin Petroleum drilled one exploration well on PM307 targeting the Mengkuang prospect, around 75 kilometres northwest of the Bertam field. The well identified non-commercial gas volumes in nine-metre high-quality reservoir sands.

In 2015, Lundin Petroleum was assigned 40% of JX Nippon Oil and Gas Corporation's equity in PM308A, taking Lundin Petroleum's working interest to 75%. Subsequent to this licence assignment in 2015, Lundin Petroleum drilled the Selada prospect straddling blocks PM307 and PM308A; however, the well failed to encounter any hydrocarbons.

Lundin Petroleum relinquished blocks PM308A and PM319 in 2016 due to a lack of prospectivity in the blocks.

<u>Sabah, East Malaysia</u>

Lundin Petroleum completed the drilling of the Imbok well on Block SB307/308 (WI 65%) in early January 2016. The well encountered only oil shows in Miocene sands and was plugged and abandoned as dry. Following drilling of the Imbok well, the rig was moved to drill the Bambazon prospect, also on Block SB307/308, which encountered 15 metres of net reservoir pay with oil shows. However, no moveable oil was recovered from sampling and the well was plugged and abandoned as dry. The West Prospero rig subsequently moved to the Maligan prospect on Block SB307/308 and, while gas shows were encountered, the well was plugged and abandoned as dry.

Farm-Out Agreements

Lundin Petroleum signed a farm-out agreement with Dyas in December 2015 whereby Lundin Petroleum has transferred a 20% working interest in Block SB307/308 (WI 65% after farm-out) and a 20% working interest in Block SB303 (WI 55% after farm-out), located offshore Sabah, East Malaysia. In addition, Dyas acquired from Lundin Petroleum a 15% working interest in Block PM328 (WI 35% after farm-out), located offshore Peninsular Malaysia.

France

Average daily net production in 2016 from France was slightly above forecast at 2,565 boe/d, but was 6% below the 2015 net production levels. 2015 average daily net production was 2,730 boe/d, which was substantially in line with expectations. Good production performance during 2016 was achieved from the Vert La Gravelle field (WI 100%) in the Paris Basin and the fields in the Aquitaine Basin (WI 50%).

In August 2015, it was established that production flowlines on the Villeperdue field in the Paris Basin had failed a pressure test and as a precautionary measure these flowlines were shut-in. The majority of the production reliant upon the shut-in flowlines was re-routed to a water injection flowline and thus most of the shut-in production was resumed through the water injection flowline within a few weeks from shutting-in the production flowlines.

In the Aquitaine Basin a pipeline failure in July 2015 led to trucking operations being put in place. Such trucking operations will remain in place until the pipeline has been repaired.

In 2015, the construction of onshore facilities and the drilling and completion of two development wells on the Vert la Gravelle re-development project in the Paris Basin was finalized and the wells commenced production according to expectations. Due to the lower oil price environment in 2015, it was decided to defer the remaining five wells of the Vert la Gravelle re-development until the oil price recovers.

The Netherlands

Average daily net production in 2016 from the Netherlands was ahead of forecast at 1,569 boe/d. 2016 average daily net production decreased by 11% relative to 2015 average daily net production of 1,746 boe/d, with 2015 also being ahead of expectations due to good performance from the new Slootdorp 6 and 7 development wells, which commenced production in July 2015.

The Langezwaag-3 well (WI 7.75%), on the onshore Gorredijk licence, was drilled during the third quarter 2016 and put on production in November 2016.

The drilling of the offshore K5-F3 development well was completed and the well was put on production in the third quarter of 2016.

The F3-B106 side-track well commenced drilling in December 2016 and was drilling ahead at year end. During the fourth quarter of 2016 the installation of compression on the E17a platform was completed and successfully started up.

The K5-A5 development well within the K4/K5 unit (WI 1.216%) was successfully drilled in 2014 and commenced production in May 2015. The E17-A5 (WI 1.20%) development well was successfully drilled and completed during the in 2015 and commenced production in July 2015. The K5-A6 development well within the K4/K5 unit (WI 1.216%) was drilled during 2015; however, the reservoir was found to be depleted and the well was plugged and abandoned.

Production

Average daily net production for the year ended December 31, 2016 increased by 28% to 12,742 boe/d compared to 9,955 boe/d for the year ended December 31, 2015. The increase was mainly due to a full year of production from the Bertam field in Malaysia, which came onstream in April 2015 with further development wells drilled during 2015, partly offset by natural reservoir decline in France and the Netherlands.

Production in Mboepd	Year ended December 31 **2016**	2015
Crude oil		
Malaysia	8.6	5.5
France	2.6	2.7
Total crude oil production	11.2	8.2
Gas		
Netherlands	1.6	1.7
Total gas production	1.6	1.7
Total production	12.8	9.9
Quantity in MMboe	4.66	3.63

Financial Review

During the year ended December 31, 2016, the Oil and Gas Assets generated revenue of USD 209.9 million, compared to USD 172.1 million for the year ended December 31, 2015. This increase was primarily related to higher production in 2016 compared to 2015, partially offset by realized sales prices that were 11% lower.

Net result for the financial year 2016 amounted to a charge of USD 95.7 million, compared with a charge of USD 181.6 million for 2015. The net result in 2016 was reduced by non-cash USD 126.0 million after-tax impairment charges in relation to the impairment of gas discoveries in Malaysia compared to the net result in 2015, which included a non-cash USD 191.7 million after-tax impairment charge relating to the Bertam field and exploration blocks.

Total cash flow from operating activities for the financial year 2016 amounted to USD 109.4 million, compared to USD 66.8 million for 2015. The increase is due to higher production revenues and favourable changes in working capital balances. Investment in oil and gas properties amounted to USD 34.1 million for 2016 compared to USD 177.1 million for 2015. The decrease is attributable to the continued Bertam field development incurred in 2015.

Income Statement

Revenue

Total revenue for the financial year 2016 amounted to USD 209.9 million, compared with USD 172.1 million for 2015. The following table summarizes the components of total revenue for the 12 months ended 2016 and 2015, respectively.

	Year ended December 31	
USD Thousands	**2016**	2015
Crude oil sales	**165,752**	121,842
Gas and NGL sales	**24,964**	24,620
Change in under/overlift position	**217**	-353
Other operating revenue	**18,947**	25,984
Total revenue	**209,880**	172,094

Crude Oil Sales

Crude oil sales for the financial year 2016 amounted to USD 165.8 million, compared with USD 121.8 million for 2015, representing an increase of 36%. The volumes sold in 2016 were 52% higher than in 2015 primarily due to a full year of contribution of sales from the Bertam field in Malaysia, which commenced production in April 2015. The average realized sales price achieved in 2016 was USD 44.85/bbl compared to USD 50.18/bbl in 2015, a reduction of 11%. The average realized sales price is based on quoted Brent crude prices. The average market Brent crude price was USD 43.73/bbl in 2016 and USD 52.39/bbl in 2015.

	Year ended – December 31, 2016			
	Malaysia	**France**	**Netherlands**	**Total**
Crude oil sales				
- Revenue in USD thousands	125,823	39,887	42	**165,752**
- Quantity sold in bbls	2,787,829	907,023	1,228	**3,696,080**
- Average price realized USD per bbl	45.13	43.98	33.82	**44.85**

	Year ended – December 31, 2015			
	Malaysia	**France**	**Netherlands**	**Total**
Crude oil sales				
- Revenue in USD thousands	71,208	50,577	58	**121,842**
- Quantity sold in bbls	1,455,630	971,362	1,153	**2,428,145**
- Average price realized USD per bbl	48.92	52.07	50.20	**50.18**

Gas and NGL Sales

All gas and NGL sales were attributable to the Netherlands assets. Gas and NGL sales for the financial year 2016 amounted to USD 25.0 million, compared with USD 24.6 million for 2015. The lower revenue in

2016 in Netherlands reflected lower prevailing gas prices compared to 2015. The average realized sales price achieved in 2016 was USD 27.04/boe compared to USD 38.88/boe in 2015. The following table summarizes the components of crude oil and gas and NGL sales for the 12 months ended 2016 and 2015, respectively.

	Year ended – December 31, 2016				
	Malaysia	**France**	**Netherlands**	**Indonesia**	**Total**
Gas and NGL sales					
- Revenue in USD thousands	–	–	15,695	9,269	**24,964**
- Quantity sold in Mcf	–	–	3,482,363	1,069,066	**4,551,429**
- Average price realized USD per Mcf	–	–	4.51	8.67	**5.48**

	Year ended – December 31, 2015				
	Malaysia	**France**	**Netherlands**	**Indonesia[1]**	**Total**
Gas and NGL sales					
- Revenue in USD thousands	–	–	24,620	–	24,620
- Quantity sold in Mcf	–	–	3,799,620	–	3,799,620
- Average price realized USD per Mcf	–	–	6.48	–	6.48

[1] Indonesia was not considered in the preparation of the carve-out financial statements and hence not reported as a region of the Corporation.

Change in Under/Overlift Position

An under/overlift position occurs where a partner in a field sells less (underlift) or more (overlift) than its share of liftings of production as determined by such partner's Working Interest in the relevant field. In other words, one partner will have taken more than its share (overlifted) and another will have taken less than its share (underlifted). An underlift of production from a field is included as a receivable in the balance sheet and an overlift of production is included as a liability, both valued at the reporting date market price or prevailing contract price. The change in the underlift or overlift position is recorded through the income statement as revenue. Sales versus production volume timing differences due to under/overlift of entitlement quantities amounted to a USD 0.2 million credit to the income statement in 2016 compared with a USD 0.4 million charge in 2015.

Other Operating Revenue

Other operating revenue amounted to USD 18.9 million for 2016, compared to USD 26.0 million for 2015, and included third party FPSO Bertam lease income, tariff income from France and the Netherlands, income for maintaining strategic inventory levels in France and service income for services provided by IPBV mainly to the Norwegian operations of Lundin Petroleum. Other operating revenue included FPSO Bertam lease income (which began to be received in April 2015) of USD 15.6 million in 2016 compared to USD 11.3 million in 2015 and this increase in 2016 was offset by lower service income of USD 4.5 million in 2016 compared to USD 11.4 million in 2015 due to less capital project activity.

Production Costs

Production costs amounted to USD 59.2 million for 2016, compared to USD 41.5 million for 2015. The following table summarizes production costs for the 12 months ended 2016 and 2015, respectively.

	Year ended – December 31, 2016					
USD Thousands	**Malaysia**	**France**	**Netherlands**	**Indonesia**	**Other[2]**	**Total**
Operating costs	73,032	22,476	9,947	1,358	(46,664)	**60,149**
USD/boe[1]	23.18	23.94	17.32	7.00	n/a	**12.38**
Change in inventory position	975	(1,969)	–	–	–	**(994)**
Production costs	**74,007**	**20,507**	**9,947**	**1,358**	**(46,664)**	**59,155**

	Year ended – December 31, 2015					
USD Thousands	**Malaysia**	**France**	**Netherlands**	**Indonesia**	**Other[2]**	**Total**
Operating costs	49,191	25,176	11,945	–	(35,062)	51,249
USD/boe[1]	24.59	25.26	18.75	–	n/a	14.10
Change in inventory position	(9,731)	(45)	-	–	–	(9,776)
Production costs	39,460	25,131	11,945	–	(35,062)	41,474

[1] *USD/boe in the tables above is calculated by dividing the cost by the production volume for each country for the period.*

[2] *Included in the Malaysia production 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 to USD 8.37 and USD 7.07 for Malaysia for the years ended December 31, 2016 and 2015 respectively. Due to the spin-off, such amount is not reflected for the year ended December 31, 2015.*

Cost of Operations

Operating costs in Malaysia amounted to USD 73.0 million in 2016, compared to USD 49.2 million in 2015. The increased costs in 2016 were primarily related to a full year of costs of operations from the Bertam field, which came onstream in April 2015. Two production wells that were shut-in during the first half of 2016 were successfully worked over, which also resulted in an increase in cost of operations.

The operating costs in France amounted to USD 22.5 million in 2016, compared to USD 25.2 million in 2015, and in the Netherlands amounted to USD 9.9 million in 2016, compared to USD 11.9 million in 2015. The decreases in 2016 compared to 2015 are largely attributable to cost reduction initiatives in the lower oil price environment, including optimization of operations and maintenance activities.

Change in Inventory

The change in inventory position amounted to a USD 1.0 million credit to the income statement in 2016 compared to a USD 9.8 million credit to the income statement in 2015. The inventory levels on the FPSO Bertam at the end of 2016 were similar to those at the end of 2015 and so there was not a significant movement through the income statement in respect of 2016.

Depletion

The total depletion charge amounted to USD 85.2 million for 2016 compared to USD 92.6 million for 2015. The following table summarizes the components of depletion charges for the 12 months ended 2016 and 2015, respectively.

	Year ended – December 31, 2016			
	Malaysia	**France**	**Netherlands**	**Total**
Depletion in USD thousands	61,086	14,380	9,721	**85,187**
Depletion USD per boe	19.39	15.32	16.93	**17.53**

	Year ended – December 31, 2015			
	Malaysia	**France**	**Netherlands**	**Total**
Depletion in USD thousands	66,399	15,473	10,701	**92,573**
Depletion USD per boe	33.20	15.53	16.79	**25.48**

The decrease in the total depletion charge for 2016 compared to 2015 is mainly due the lower depletion rate on the Bertam field in Malaysia following the impairment taken at the end of 2015, despite the lower rate being applied to a higher production volume from the field. In respect of France and the Netherlands, the depletion rates are calculated on a field-by-field basis and the overall charge is the weighted average of the depletion rate and production contribution for each field. In France and the Netherlands, the decreased charge in 2016 compared to 2015 is attributable to lower production volumes with the average depletion charge per boe relatively unchanged.

Depreciation of Other Assets

The total depreciation of other assets amounted to USD 31.1 million for 2016, compared to USD 23.7 million for 2015, and related to the depreciation of the FPSO Bertam, which is being depreciated on a straight line basis over the six year lease period which commenced in April 2015.

Exploration Costs

Total expensed exploration costs amounted to USD 14.4 million for 2016 compared to USD 37.6 million for 2015. In 2016, costs related to the unsuccessful Bambazon and Maligan exploration wells drilled in the first quarter of 2016 on the SB307/308 licence in Malaysia were expensed and amounted to USD 13.1 million. A further USD 1.3 million relating to the K5-F3 well in the Netherlands was expensed in 2016.

In 2015, the expensed exploration costs related mainly to three unsuccessful exploration wells drilled in Malaysia on the blocks PM308A (Selada), PM307 (Mengkuang) and SB307/308 (Imbok).

Exploration and appraisal costs are capitalized as they are incurred. When exploration drilling is unsuccessful, the capitalized costs are expensed. All capitalized exploration costs are reviewed on a regular basis and are expensed where there is uncertainty regarding their recoverability.

Impairment Costs

Impairment costs amounted to USD 126.0 million for 2016, compared to USD 191.8 million for 2015, and mainly related to the gas discoveries in the Sabah region offshore East Malaysia and the Tembakau gas discovery in PM307 offshore Peninsular Malaysia. While these discoveries will remain in the portfolio of the Corporation, management considers it unlikely that any of these discoveries can be commercialized within a reasonable timeframe and therefore deems it prudent to impair the carried costs.

Sale of asset

Sale of asset for 2016 amounted to a charge of USD 3.5 million (2015 – nil) and relates to the sale of the Singa field, Indonesia, in April 2016.

Other Income

Other income for 2016 amounted to USD 4.8 million (2015 – nil). The amount received related to a final settlement of a 2007 legal dispute in France.

General, Administrative and Depreciation Expenses

The general, administrative and depreciation expenses for 2016 amounted to USD 1.9 million, compared to USD 18.0 million for 2015. The decrease in 2016 is primarily due to the absence of management fees in 2016 as opposed to various assumptions considered in the carve-out financial statements in 2015.

Financial Income

Financial income for 2016 amounted to USD 19.1 million, compared to USD 54.3 million for 2015. Included in these amounts are net foreign exchange gains amounting to USD 23.7 million in 2016 and USD 53.6 million in 2015. The foreign exchange gains mainly related to revaluation of US Dollar intra-group loans lent by a subsidiary whose functional currency is the Euro.

Financial Expenses

Financial expenses for 2016 amounted to USD 3.7 million, compared to USD 3.8 million for 2015, and is comprised mainly of the unwinding of the discount rate on the asset retirement obligations. Asset retirement obligations estimates are discounted back to a present value when reflected in the balance sheet and the discounting is unwound through the income statement.

Income Tax

The corporate income tax charge for 2016 was USD 4.9 million, compared to a USD 1.0 million credit for 2015.

Financial Condition, Capital Resources and Liquidity

Non-Current Assets

Oil and Gas Properties

As at December 31, 2016, oil and gas properties amounted to USD 317.8 million, with USD 130.6 million capitalized in Malaysia, USD 168.3 million capitalized in France and USD 18.9 million capitalized in the Netherlands.

Development and exploration and appraisal expenditure incurred in 2016 was as follows:

USD millions	**Malaysia**	**France**	**Netherlands**	**Other**	**Total**
Development	15.2	2.8	2.5	–	**20.5**
Exploration and evaluation	14.2	0.3	0.6	(0.3)	**14.8**
	29.4	3.1	15.1	(0.3)	**35.3**

In Malaysia, USD 15.2 million in development expenditures were incurred primarily on the drilling and facilities tie-in work of the Bertam A15 development well. The exploration expenditure of USD 14.2 million mainly related to the Bambazon and Maligan exploration wells on block SB307/308.

Other Tangible Assets

Other tangible fixed assets amounted to USD 152.2 million as at December 31, 2016, which included USD 150.0 million in respect of the FPSO Bertam.

Deferred Tax Assets

Deferred tax assets amounted to USD 12.0 million as at December 31, 2016 and mainly related to the Bertam field.

Current Assets

As at December 31, 2016, current assets amounted to USD 87.1 million and is primarily comprised of USD 48.2 million in trade receivables due on oil and gas sales of, cash balances of USD 13.4 million and hydrocarbon and well inventory positions of USD 25.1 million.

Non-Current Liabilities

As at December 31, 2016, provisions amounted to USD 93.6 million. The asset retirement obligation provision as at December 31, 2016, amounted to USD 91.0 million, with USD 22.6 million relating to the Bertam field in Malaysia, USD 27.4 million relating to the French assets and USD 41.0 million relating to the Dutch assets. This amount is net of a USD 8.8 million payment that IPC Malaysia BV (formerly Lundin Malaysia BV) made into an abandonment fund administered by the Malaysian authorities in respect of the eventual decommissioning of the Bertam field. The farm-in payment provision amounted to USD 5.0 million and related to a provision for payments towards historical costs based on production milestones on the Bertam field.

The deferred taxes liability amounted to USD 46.6 million as at December 31, 2016, and mainly arises on the excess of the accounting book value over the tax value of oil and gas properties.

Current Liabilities

As at December 31, 2016, current liabilities amounted to USD 26.7 million and is primarily comprised of amounts owed to joint operations creditors of USD 14.2 million and accrued expenses of USD 3.7 million.

Selected Annual Financial Information

The following table sets out financial information for the Oil and Gas Assets over the last eight quarters. The financial information set out below has been derived from the Financial Statements. The following information should be read in conjunction with such financial statements and the accompanying notes. See "*Risk Factors*".

USD Thousands (unless stated)	2016	Quarterly financial information Q4 2016	Q3 2016	Q2 2016	Q1 2016	2015	Quarterly financial information Q4 2015	Q3 2015	Q2 2015	Q1 2015
Production (MBoe/d)	12.8	12.3	12.9	12.8	14.5	10.0	13.6	12.8	8.8	4.6
Revenue	209,880	59,592	48,498	55,568	46,222	172,094	47,055	53,842	48,325	22,873
Gross profit/(loss)	(105,639)	(114,600)	9,631	16,029	(16,699)	(215,034)	(234,704)	948	9,368	9,353
Net result	(95,720)	(76,097)	4,522	26,954	(51,099)	(181,565)	(220,918)	(979)	(16,735)	57,066
Earnings per share – USD[1]	(0.84)	(0.67)	0.04	0.24	(0.45)	(1.60)	(1.95)	(0.01)	(0.15)	(0.50)
Earnings per share fully diluted – USD[1]	(0.84)	(0.67)	0.04	0.24	(0.45)	(1.60)	(1.95)	(0.01)	(0.15)	(0.50)

[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.*

Off-Balance Sheet Arrangements

Lundin Petroleum did not enter into any off-balance sheet events in respect of the Oil and Gas Assets during 2016 and therefore had no off-balance sheet arrangements in respect of such assets as at December 31, 2016.

Related Party Transactions

In the normal course of business, the IPC Subsidiaries that own the Oil and Gas Assets have entered into various transactions with related parties on an arms-length basis, which transactions are reflected in the Financial Statements.

Management fees of USD 12.5 million were charged from Lundin Petroleum in 2016 and are reflected in the general administration and depreciation expenses line of the income statement. These fees relate to the direct and indirect costs of management and personnel in Lundin Petroleum that were managing the Oil and Gas Assets but not charging to the entities on a direct basis such as timewriting.

IPBV received a head office contribution which is reflected in other operating revenue of USD 4.1 million from its subsidiary, Lundin Norway AS. This represents 2% of total revenue for 2016. Lundin Norway AS itself does not form part of the Financial Statements as it is not held by the Corporation.

There are no other material related party transactions.

Changes in Accounting Policies

For the years 2015 to March 31, 2018, there have been no significant changes in the accounting policies adopted.

As from January 1, 2014, the following accounting standards have been applied:

- IFRS 10, “Consolidated financial statements”: The objective of the standard is to build on existing principles by identifying the concept of control as the determining factor in whether an entity should be included within the combined financial statements.

- IFRS 11, “Joint arrangements”: The standard is focusing on the rights and obligations of the joint arrangement rather than its legal form. There are two types of joint arrangement: joint operations and joint ventures. Joint operations arise where a joint operator has rights to the assets and obligations relating to the arrangement and hence accounts for its interest in assets, liabilities, revenue and expenses. Joint ventures arise where the joint operator has rights to the net assets of the arrangement and hence equity accounts for its interest.

- IFRS 12, “Disclosures of interests in other entities”: The standard introduced a range of new and expanded disclosure requirements. These require the disclosure of significant judgements and assumptions made by management in determining whether there is joint control and if there is a joint venture, a joint operation or another form of interest.

- IFRS 13, “Fair value measurement”.

As from January 1, 2018, the following accounting standards have been applied:

- IFRS 9 “Financial instruments”: The standard addresses the classification, measurement and recognition of financial assets and financial liabilities. The Group adopted IFRS 9 effective January 1, 2018 and applied it on a retrospective basis. The application of IFRS 9 has not resulted in any differences between the previous carrying amounts and the carrying amounts at the date of initial application of IFRS 9.

- IFRS 15 “Revenue from contract with customers”: The Group adopted IFRS 15 effective January 1, 2018 and applied it on a retrospective basis. IFRS 15 provides guidance on the nature, amount, timing and uncertainty of revenue and cash flows arising from a contract with a customer. The Group has reviewed its revenue contracts and has determined that there were no material impact on the financial statements with respect to the application of IFRS 15.

The Corporation has not adopted the following accounting standard that is not yet mandatory:

- IFRS 16 “Leases”: IFRS 16 will result in almost all leases being recognized on the balance sheet, as the distinction between operating and finance leases is removed. Under the new standard, an asset (the right to use the leased item) and a financial liability to pay rentals are recognized. The only exceptions are short-term and low-value leases. Application of the standard is mandatory for annual reporting periods beginning on or after January 1, 2019, with early adoption permitted. The Group does not intend to adopt the standard before its effective date. The standard will affect primarily the accounting for the Group’s operating leases. As at the reporting date, the group has no material non-cancellable operating lease commitments. The quantitative impact of the adoption of IFRS 16 is currently being evaluated.

DESCRIPTION OF SHARE CAPITAL

Common Shares

The Corporation is authorized to issue an unlimited number of Common Shares without par value, of which 87,921,846 Common Shares are issued and outstanding as at the date of this prospectus. The Corporation does not hold any treasury shares.

All of the Common Shares outsanding are fully paid and non-assessable. Holders of Common Shares are entitled to dividends if, as and when declared by the Board, to receive notice of meetings of shareholders of the Corporation, to one vote per share at meetings of the shareholders of the Corporation and, upon liquidation, to receive such assets of the Corporation as are distributable to the holders of the Common Shares. Holders of Common Shares do not have cumulative voting rights with respect to the election of directors and, accordingly, holders of a majority of the votes eligible to vote at a meeting of shareholders may elect all the directors of the Corporation standing for election. Dividends, if any, will be paid on a pro rata basis only from funds legally available therefore.

The Common Shares do not carry any pre-emptive, subscription, redemption or conversion rights, nor do they contain any sinking or purchase fund provisions.

The Common Shares are not subject to any offer made due to a mandatory bid obligation, redemption right or redemption obligation, nor have the Common Shares been subject to a public takeover offer during the current or the past financial year. The Corporation's articles do not impose any transfer restrictions on the Common Shares.

The Common Shares are currently listed on the TSX and Nasdaq First North under the symbol "IPCO". The Corporation has applied to Nasdaq Stockholm for a listing of its Common Shares on Nasdaq Stockholm. Nasdaq Stockholm has conditionally approved the admission of trading of the Common Shares on such exchange. The Listing is subject to the Corporation fulfilling all of the requirements of Nasdaq Stockholm. The Corporation cannot provide any assurances as to the price at which the Common Shares may trade. The Common Shares will be listed on Nasdaq Stockholm under the symbol "IPCO". The ISIN for the Common Shares is CA46016U1084. All Common Shares traded on Nasdaq Stockholm will be registered in Euroclear Sweden and will not be represented by physical share certificates. The Common Shares are denominated in Canadian dollars. The intention to complete the Listing can be withdrawn. Notice of such will be made public through a press release.

Preferred Shares

The Corporation is authorized to issue an unlimited number of Class A Preferred Shares (the "**Class A Preferred Shares**"), of which 117,485,389 Class A Preferred Shares are issued and outstanding as at December 31, 2017 and at the date of this Prospectus, and an unlimited number of Class B Preferred Shares (the "**Class B Preferred Shares**"), issuable in series, none of which is issued and outstanding. All of the issued and outstanding Class A Preferred Shares of the Corporation are held by a subsidiary of the Corporation.

The Class A 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 the Corporation's Common Shares. The Class A Preferred Shares are entitled to non-cumulative dividends at a rate of 5% per year (in priority to dividends on all other classes of shares of the Corporation, if, as and when declared by the Board; and no dividends may be declared or paid to holders of any other class of shares of the Corporation without the consent of the majority of the holders of the Class A Preferred Shares, acting together as a class, if the declaration and payment of such dividend would impede the ability of the Corporation to satisfy the aggregate Redemption Amount in respect of the Class A Preferred Shares.

The Class B Preferred Shares, if issued, will have priority over the Common Shares with respect to dividends and other distributions, including the distribution of assets upon liquidation, dissolution or winding-up of the Corporation. Unless required by law or by applicable stock exchanges, the Board has the authority without further shareholder authorization to issue from time to time the Class B Preferred Shares in one or more series, to fix the terms, special rights and restrictions of each series and to make any necessary alterations to its articles to effect the change.

Please refer to section "Equity Based Compensation Arrangements" – "The Corporation's Stock Option Plan", "Transitional Equity-Based Compensation Arrangements" and "Performance and Restricted Share Plan" for more information on the Share-based plans.

Prior Sales and Historic Share Capital

The following table sets forth the Common Shares issued by the Corporation since incorporation:

Date	Change in number of Common Shares	Issue Price Per Share (CAD)	Aggregate Issue Price (CAD)	Event	Nature of Consideration
January 13, 2017	1	$1.00	$1.00	New share issue	Cash
April 7, 2017	113,462,147	$4.77	$541,214,440	New share issue	Initial Oil and Gas Assets
June 14, 2017	-25,540,302	N/A	N/A	Cancellation	N/A
Balance as at December 31, 2017	**87,921,846**	**N/A**	**N/A**	**N/A**	**N/A**
Balance as at the date of prospectus	**87,921,846**	**N/A**	**N/A**	**N/A**	**N/A**

Principal Securityholders

To the knowledge of the Corporation, no person or corporation owns or controls or directs, directly or indirectly, more than 10% of the issued and outstanding Common Shares other than as set out below:

Name	Ownership	Number of Common Shares(2)	Percentage of Common Shares(2)
Nemesia S.à.r.l.(1)	Of record and beneficially	29,062,512	33.05%

Notes:

(1) Lorito Holdings S.a.r.l. and Zebra Holdings and Investments S.a.r.l., two private companies controlled by a trust settled by the late Adolf H. Lundin, together hold 100% of the outstanding Class C shares of Nemesia and control Nemesia. In addition, an investment company wholly owned by a trust whose settlor is Ian H. Lundin, owns a further 3,517,326 Common Shares.

(2) All Common Shares carry the same voting rights.

DIRECTORS AND EXECUTIVE OFFICERS

The following table provides the name, municipality of residence, positions held with the Corporation, number of Common Shares beneficially owned or controlled or directed as of the date of this prospectus and principal occupation during the preceding five years of each of the directors and executive officers of the Corporation.

Each director will hold office until the next annual meeting of shareholders or until his successor is duly elected unless his office is earlier vacated in accordance with the Corporation's articles. The executive officers' respective appointments will not be time limited and can only be terminated in accordance with their respective employments agreements or under applicable employment law.

Name	Offices Held and Time as Director or Officer	Number of Securities Beneficially Owned or Controlled	Principal Occupation (for last 5 years)
Lukas H. Lundin(1)	Chairman since April 2017	262,777 Common Shares 25,000 Options	Corporate director
Mike Nicholson	CEO and Director since April 2017	40,000 Common Shares 500,000 Options 419,124 Performance Common Shares (5)	CEO of the Corporation since April 2017; CFO, Lundin Petroleum until April 2017
C. Ashley Heppenstall(2)(3)	Director since April 2017	463,761 Common Shares 25,000 Options	Corporate director; President and CEO, Lundin Petroleum until September 2015
Donald Charter(1)(2)(4)	Director since April 2017	72,333 Common Shares 25,000 Options	Corporate director; President and CEO, Corsa Coal Corp. until 2013
Chris Bruijnzeels(2)(3)(4)	Director since April 2017	25,000 Options	President and CEO, ShaMaran Petroleum Corp. since January 2015; prior thereto, Senior Vice President Development of Lundin Petroleum
Torstein Sanness(1)(3)	Director since April 2017	25,037 Common Shares 25,000 Options	Corporate director; Managing Director and later Chairman of Lundin Norway until 2015
Daniella Dimitrov(2)(4)	Director since May 2018	Nil	Partner at Sprott Capital Partners since October 2017; corporate development, strategy and governance consulting roles through DDimitrov Advisory Corp. from March 2016 to September 2017; Chief Financial Officer then President and CEO of Orvana Mineral Corp. until February 2016
Christophe Nerguararian	CFO since April 2017	36,183 Common Shares 175,000 Options	Vice-President Corporate Finance, Lundin Petroleum until April 2017

		93,122 Performance Common Shares (5)	
Jeffrey Fountain	General Counsel and Corporate Secretary since April 2017	26,666 Common Shares 175,000 Options 166,753 Performance Common Shares (5)	Vice-President Legal of Lundin Petroleum until April 2017
Rebecca Gordon	VP Corporate Planning and Investor Relations since April 2017	2,100 Common Shares 100,000 Options 12,950 Restricted Common Shares (5)	Group Manager, Economics and Planning of Lundin Petroleum until April 2017
Daniel Fitzgerald	VP Operations since April 2017	15,000 Common Shares 100,000 Options 13,491 Restricted Common Shares (5)	Group Operations Manager of Lundin Petroleum until April 2017
Ryan Adair	VP Reservoir Development since April 2017	100,000 Options 19,276 Restricted Common Shares (5)	Group Subsurface Manager of Lundin Petroleum until April 2017

Notes:

(1) Member of Compensation Committee.
(2) Member of Audit Committee.
(3) Member of Reserves and HSE Committee.
(4) Member of Nominating and Corporate Governance Committee.
(5) Common Shares subject to the IPC Transitional PSP and the IPC Transitional RSP.

Biographies of Directors and Officers

Lukas H. Lundin, Chairman of the Board

Place of Residence: Switzerland

Born in 1958, Lukas H. Lundin graduated from the New Mexico Institute of Mining and Technology (engineering) in 1981.

In 1982, Mr. Lundin headed the oil and gas operations of International Petroleum Corporation (not related to the Corporation) and was based in Dubai, U.A.E. From 1990 to 1995, he was President of International Musto Exploration Limited and was responsible for Musto's acquisition of the Bajo de la Alumbrera deposit. Bajo de la Alumbrera was the subject of a USD 500 million takeover by Rio Algom and North Limited. Mr. Lundin was also responsible for Argentina Gold and the discovery of the multi-million ounce Veladero gold deposit. Veladero was the subject of a USD 300 million takeover by Homestake in 1999. In addition, Mr. Lundin was a senior director of Lundin Oil and was instrumental in the USD 480 million takeover of Lundin Oil by Talisman Energy in 2001.

Mr. Lundin currently serves as Executive Chairman and Director of Denison Mines Corp.; Chairman and Director of Filo Mining Corp.; Chairman and Director of Lundin Gold Inc.; Chairman and Director of Lucara Diamond Corp.; Chairman and Director of Lundin Mining Corporation; Director of Lundin Petroleum AB; Chairman and Director of NGEx Resources Inc.; and Chairman of Bukowskis Auctioner AB.

During the past five years, Mr. Lundin has been, but is no longer, President of Namdo Management Services Ltd.; Director of Newmarket Gold Inc.; Chairman and Director of RB Energy Inc. (formerly Sirocco Mining Inc./Canada Lithium Corp. and prior thereto, Atacama Minerals Corp.); Chairman and Director of Vostok Gas Ltd.; and Chairman and Director of Vostok Nafta Investment Ltd.

Mr. Lundin is independent for the purposes of NI 58-101. Based upon an assessment pursuant to the Swedish Corporate Governance Code (the "**Swedish Code**"), Mr. Lundin is considered independent of the Corporation and management, but not independent of the Corporation's major shareholders, due to the Lundin family's shareholding in the Corporation.

Mike Nicholson, CEO and Director

Place of Residence: Switzerland

Born in Scotland in 1971, Mike Nicholson graduated from Aberdeen University where he obtained a degree in Economics and Management Studies.

Between 1994 and 1996, Mr. Nicholson worked as a consulting economist for AUPEC Ltd. in Aberdeen. From 1996 to 2004, he worked in various economics, financial and banking roles with Veba Oel, Canadian Imperial Bank of Commerce and Marathon Oil in London.

Mr. Nicholson joined Lundin Petroleum in 2005 as Group Economics and Commercial Manager. He became General Manager of the Malaysia business in 2008 and Managing Director of the South East Asia business in 2012. He was appointed as CFO of Lundin Petroleum in 2013.

Mr. Nicholson has not served as a member of the administrative, management or supervisory bodies or partner of any company outside the Lundin group in the last 5 years.

Mr. Nicholson is not independent for the purposes of NI 58-101 because he is part of management of the Corporation. Based upon an assessment pursuant to the Swedish Code, Mr. Nicholson is considered independent of the Corporation's major shareholders, but not independent of the Corporation and management due to his position as Chief Executive Officer of the Corporation.

C. Ashley Heppenstall, Director

Place of Residence: Hong Kong

Born in England in 1962, Ashley Heppenstall is a graduate of Durham University where he obtained a degree in Mathematics.

From 1984 until 1990, he worked in the banking sector where he was involved in project financing of oil and mining businesses. In 1990, Mr. Heppenstall was a founding director and shareholder of Sceptre Management Limited.

Mr. Heppenstall has worked with public companies associated with the Lundin family since 1993. In 1998 he was appointed Finance Director of Lundin Oil AB. Following the acquisition of Lundin Oil by Talisman Energy in 2001, Lundin Petroleum was formed and he was appointed President & CEO in 2002 until he stood down in 2015. Mr. Heppenstall currently serves as Director of Africa Energy Corp., Etrion Corp., Filo Mining Corp., Lundin Gold Corp., Lundin Petroleum AB and ShaMaran Petroleum Corp.

During the past five years, Mr. Heppenstall has been, but is no longer, Director of Vostok Nafta Investment Ltd.

Mr. Heppenstall is independent for the purposes of NI 58-101. Based upon an assessment pursuant to the Swedish Code, Mr. Heppenstall is not independent of the Corporation's major shareholders as he is a director of several companies in which entities associated with the Lundin family hold significant ownership interests. Mr. Heppenstall is furthermore not deemed independent of the Corporation and the Corporation's management since he was the previous President and CEO of Lundin Petroleum until 30 September 2015 and thereby worked closely with the management of the Corporation and in relation to the Corporation's operations and business.

Donald Charter, Director

Place of Residence: Canada

Donald Charter became the Chairman of the Board of Directos of IAMGOLD Corporation in May 2015. An experienced corporate director, he serves on two other public company boards: Lundin Mining Corporation and Dream Office REIT. Mr. Charter has extensive senior executive leadership experience, most recently, as President and CEO of Corsa Coal, a public metallurgical coal company with operations in the US that he successfully built from a non-operating startup to an established domestic and international supplier of US low vol metallurgical coal. Mr. Charter's business experience includes financial services, mining (precious metals, base metals, iron ore, coal) and real estate.

Mr. Charter is a graduate of McGill University with degrees in Economics and Law. He began his career in Toronto, building a successful business law practice. Mr. Charter left law and joined the Dundee group of companies as an Executive Vice President with capital markets related responsibilities. He became the founding Chairman and CEO of the Dundee Securities group of companies, and oversaw its growth from a startup to a major independent financial services company. After ten years, Mr. Charter left this group and, in addition to Corsa, has focused his attention on consulting (he has had consulting roles in the private, private equity and hedge fund sectors), and corporate directorships. In addition to his executive leadership positions, Mr. Charter has extensive board level experience having been involved in several corporate boards and having sat on and chaired a number of audit, compensation, governance, special, independent and strategic committees in various corporate situations. He has completed the Institute of Corporate Directors, Directors Education Program and is a member of the Institute.

Mr. Charter currently serves as a director of Dream Office REIT, IAMGOLD Corporation, and Lundin Mining Corporation; President and Director of 3Cs Corporation and Chairman of HGC Holdings Genpar Inc.

During the past five years, Mr. Charter has been, but is no longer, Director of Corsa Coal Corp, LAC Otelnuk Mining Ltd. and Sprott Resources Holdings Inc. (formerly Adriana Resources Inc.).

Mr. Charter is independent for the purposes of NI 58-101. Based upon an assessment pursuant to the Swedish Code, Mr. Charter is considered independent of the Corporation, management and the Corporation's major shareholders.

Chris Bruijnzeels, Director

Place of Residence: Switzerland

Mr. Chris Bruijnzeels was born in the Netherlands in 1959 and is a graduate of Delft University where he obtained a degree in Mining Engineering. Mr. Bruijnzeels joined Lundin Petroleum in 2003 and was responsible for Lundin Petroleum's operations, reserves and the development of its asset portfolio. From 1985 until 1998, Mr. Bruijnzeels worked for Shell International in the Netherlands, Gabon and Oman in several reservoir engineering functions. In 1998, he joined PGS Reservoir Consultants in the UK where he worked as Principal Reservoir Engineer and Director of Evaluations. Chris Bruijnzeels became President and CEO of ShaMaran Petroleum Corp. in July 2015. Mr. Bruijnzeels previously acted as Senior Vice President Development of Lundin Petroleum. Mr. Bruijnzeels has over 33 years of experience in the oil and gas industry.

Mr. Bruijnzeels currently serves as a director of General Exploration Partners, Inc. and ShaMaran Petroleum Corp.

During the past five years, Mr. Bruijnzeels has been, but is no longer, the Senior VP of Development of Lundin Petroleum.

Mr. Bruijnzeels is independent for the purposes of NI 58-101. Based upon an assessment pursuant to the Swedish Code, Mr. Bruijnzeels is considered independent of the Corporation, management and the Corporation's major shareholders.

Torstein Sanness, Director

Place of Residence: Norway

Torstein Sanness is formerly the Managing Director until 2015 and then the Chairman until 2017 of Lundin Norway, a subsidiary of Lundin Petroleum AB. Previously, he held positions with Saga Petroleum and Norske Oljeselskap AS.

Mr. Sanness is a graduate of the Norwegian Institute of Technology in Trondheim where he obtained a Master of Engineering (geology, geophysics and mining engineering).

Mr. Sanness currently serves as Director of Lundin Petroleum AB, Sevan Marine ASA, Panoro Energy ASA and TGS-NOPEC ASA.

During the past five years, Mr. Sanness has not served as a member of the administrative, management or supervisory bodies or partner of any other company.

Mr. Sanness is independent for the purposes of NI 58-101. Based upon an assessment pursuant to the Swedish Code, Mr. Sanness is considered independent of the Corporation, management and the Corporation's major shareholders. The fact that Mr. Sanness has been employed by Lundin Petroleum up until April 2015 has not changed this assessment since Mr. Sanness did only work with Lundin Petroleum's Norwegian operations and can therefore not be deemed to have been involved in the Corporation's business or operations.

Daniella Dimitrov, Director

Place of Residence: Canada

Daniella Dimitrov was born in Romania in 1969 and has a Law degree from the University of Windsor Law School and a Global Executive Master of Business Administration from the Kellogg School of Management & Schulich School of Business. She is a Canadian citizen.

From 1994 to 2000, Ms. Dimitrov practiced corporate and securities law with one of the largest law firms in Canada and then moved on the corporate world where she worked in various executive roles, including as President and CEO and, prior to that, CFO of Orvana Minerals Corp., a gold-copper producer; Executive Vice-Chair of Baffinland Iron Mines Corporation; and COO of Dundee Securities Corporation. Currently, Ms. Dimitrov is Partner, Sprott Capital Partners, a division of Sprott Private Wealth LP, a merchant bank with a focus on natural resources.

Ms. Dimitrov currently serves as a director of Excellon Resources Inc. (also chair) and Nexa Resources S.A.

During the past five years, Ms. Dimitrov has been, but is no longer, director of Commonwealth Silver & Gold Inc. (also chair), Orvana Minerals Corp., Alloycorp Mining Inc., Aldridge Minerals Inc. as well as President and CEO/CFO of Orvana Minerals Corp. and has held corporate development, strategy and governance consulting roles through DDimitrov Advisory Corp.s.

Ms. Dimitrov is independent for the purposes of NI 58-101. Based upon an assessment pursuant to the Swedish Code, Ms. Dimitrov is considered independent of the Corporation, management and the Corporation's major shareholders.

Christophe Nerguararian, CFO

Place of Residence: Switzerland

Christophe Nerguararian was born in France in 1975 and has an Engineering degree from Ecole Centrale de Lyon and a Masters in Finance from Université Lyon II.

From 1998 to 2011, Mr. Nerguararian worked in various banking and finance roles for BNP Paribas in Paris and Geneva, most recently as Head of the Upstream Finance team for Central and Eastern Europe.

Mr. Nerguararian joined Lundin Petroleum in 2012 as Head of Corporate Debt and Commercial Manager and was appointed Vice President Corporate Finance of Lundin Petroleum in 2016. He is no longer an officer of Lundin Petroleum.

During the past five years, Mr. Nerguararian has not served as a member of the administrative, management or supervisory bodies or partner of any company outside the Lundin Petroleum group.

Jeffrey Fountain, General Counsel and Corporate Secretary

Place of Residence: Switzerland

Jeffrey Fountain was born in Canada in 1969, and has a Commerce and Economics degree and a Law degree from the University of Toronto.

He practiced corporate and securities law with a large Canadian law firm in Vancouver and then worked with the United Nations in Geneva.

Between 2003 and 2017, Mr. Fountain was Vice President Legal of Lundin Petroleum, responsible for all legal matters within the Lundin Petroleum group. He has also assisted on various legal matters related to other Lundin Group companies.

During the past five years, Mr. Fountain has not served as a member of the administrative, management or supervisory bodies or partner of any company outside the Lundin Petroleum group.

Rebecca Gordon, VP Corporate Planning and Investor Relations

Place of Residence: Switzerland

Rebecca Gordon was born in England in 1976 and has a Commerce and Masters of Business Administration degree from the University of Western Australia, and a Masters degree from the ENI Corporate University.

Between 1997 and 2005 Ms Gordon worked as a senior consultant for an Information Management consultancy in Western Australia, and then moved to Italy to work for ENI as a valuation specialist until the end of 2009.

In 2010 Ms Gordon came to Lundin Petroleum as Senior Economist and was appointed Group Economics and Planning Manager in the same year.

During the past five years, Ms. Gordon has not served as a member of the administrative, management or supervisory bodies or partner of any other company outside the Lundin Petroleum group.

Daniel Fitzgerald, VP Operations

Place of Residence: Switzerland

Daniel Fitzgerald was born in Australia in 1982 and holds a Bachelor of Chemical Engineering (Honours) degree from the University of New South Wales.

From 2005 to 2014 Mr. Fitzgerald worked for Shell's upstream business based in the UK. The majority of his career has been spent in upstream operations in a range of offshore and onshore roles, more recently, roles dealing with asset and installation management.

Between 2014 and 2017, Mr. Fitzgerald has been the Group Operations Manager for Lundin Petroleum.

During the past five years, Mr. Fitzgerald has not served as a member of the administrative, management or supervisory bodies or partner of any other company outside the Lundin Petroleum group.

Ryan Adair, VP Reservoir Development

Place of Residence: Switzerland

Born in Canada in 1976, Ryan Adair has a Bachelor of Science degree in Chemical Engineering from the University of Calgary and a Master of Science degree in Petroleum Engineering from Heriot-Watt University.

In addition to seven years in various reservoir engineering and management roles within the Lundin Petroleum organization, Mr. Adair has worked for EnCana Resources and Petrominerales Ltd.

Mr. Adair has been Lundin Petroleum Group Subsurface Manager since 2013, is a Canadian registered P.Eng, a member of the Society of Petroleum Engineers, and the Society of Petroleum Evaluation Engineers.

During the past five years, Mr. Adair has not served as a member of the administrative, management or supervisory bodies or partner of any other company outside the Lundin Petroleum group.

All members of the Board or executive officers of the Corporation can be reached at the Corporation's address at 5 chemin de la Pallanterie, 1222 Vésenaz, Switzerland, with the exception of:

- Lukas H. Lundin, who can be reached at 6 rue de Rive, Geneva, Switzerland;
- Charles Ashley Heppenstall, who can be reached at Suite 2305, Pacific Place Apartments, 88 Queensway Hong Kong;
- Donald Charter, who can be reached at 36 Strath Ave., Toronto, Ontario, Canada; and
- Torstein Sanness, who can be reached at Strandveien 4, Lysaker, Norway.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

No director or executive officer has, within the last 10 years prior to the date of this document, been a director, chief executive officer or chief financial officer of any issuer (including the Corporation) that, (i) while the person was acting in the capacity as director, chief executive officer or chief financial officer, was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days; or (ii) was subject to an order that resulted, after the director, executive officer ceased to be a director, chief executive officer or chief financial officer of an issuer, in the issuer being the subject of a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than 30 consecutive days, which resulted from an event that occurred while that person was acting as a director, chief executive officer or chief financial officer of the issuer.

Except as set forth in the following paragraph, no director or officer has, within the last 10 years prior to the date of this document, been a director or executive officer of any company (including the Corporation) that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt or liquidated, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Mr. Lundin was a director of Sirocco Mining Inc. ("**Sirocco**"). Pursuant to a plan of arrangement completed on January 31, 2014, Canadian Lithium Corp. acquired Sirocco. Under the plan of arrangement, Canadian Lithium Corp. amalgamated with Sirocco to form RB Energy Inc. ("**RBI**"). In October 2014, RBI commenced proceedings under the Companies' Creditors Arrangement Act (the "**CCAA**"). CCAA proceedings continued in 2015 and a receiver was appointed in May 2015. The TSX de-listed RBI's common shares in November 24, 2014 for failure to meet the continued listing requirements of the TSX. Mr. Lundin was never a director, officer or insider of RBI. Mr. Lundin was a director of Sirocco within the 12-month period prior to RBI filing under the CCAA. No director or executive officer has, within the last 10 years prior to the date of this document, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, officer or securityholder.

No director or executive officer has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (ii) any other penalties or sanctions imposed by a court, regulatory body or other authority that would likely be considered important to a reasonable investor in making an investment decision.

No director or executive officer has been disqualified by a court from acting as a member of the administrative, management or supervisory body of a company or from acting as the management or conducting of the affairs of a company during the past five years, or has been convicted of any fraudulent acts.

Conflicts of Interest

Except as laid out in the biography of each of the directors and executive officers, the Corporation, as at the date of this prospectus, the Corporation is not aware of any existing or potential material conflicts of interest between the Corporation or a subsidiary of the Corporation and a director or officer of the Corporation or of a subsidiary of the Corporation.

There is no family relationship between any of the individuals serving as directors or executive officers of the Corporation.

Circumstances may arise where members of the Board or officers of the Corporation are directors or officers of companies, which are in competition to the interests of the Corporation. Pursuant to applicable law, directors who have an interest in a proposed transaction upon which the Board is voting are required to disclose their interests and refrain from voting on the transaction.

Majority Voting Policy for Election of Directors

The Corporation has adopted a majority voting policy that states that if, in an uncontested election, a director nominee has more votes withheld than are voted in favour of him or her, the nominee will be considered by the Board not to have received the support of the shareholders, even though duly elected as a matter of corporate law. Such a nominee will be required to promptly submit his or her resignation to the Board, effective upon acceptance by the Board. Except in special circumstances that would warrant the continued service of the director on the Board, the Board will be expected to accept the resignation. Within 90 days after the meeting, the Board will make its decision and announce it by press release.

EQUITY-BASED COMPENSATION ARRANGEMENTS

The Corporation's Stock Option Plan

In connection with the Reorganization and the Spin-Off, the Corporation's shareholders unanimously authorized the grant of stock options to selected officers and other key employees of the Corporation on February 21, 2017, subject to, among other things, implementation by the Corporation of a stock option plan (the "**Stock Option Plan**"). Pursuant to the Stock Option Plan, which was approved by the Board and a unanimous shareholders' resolution on April 16, 2017, the Corporation has granted separate tranches of stock options to the (i) officers, as a group, 1,150,000 stock options (including Mike Nicholson); (ii) directors (excluding Mike Nicholson), as a group, 125,000 stock options; and (iii) other employees (excluding any directors or officers), as a group, 581,600 stock options. In total, the Corporation authorized the grant of 1,856,600 stock options on February 21, 2017, of which 1,846,600 were outstanding as at March 31, 2018.

Participants have been given the right to buy shares in the Corporation at an exercise price equal to the market value of the Common Shares, determined by the Board, to be CAD 4.77 at February 21, 2017. The options will vest in one-third of the amount of each grant on each of the first three anniversaries of the date of grant and will be exercisable until the fourth anniversary of the date of grant. The exercise period will be automatically extended if it ends during a black-out period, such that the exercise period will end 10 business days following the last day of the black-out period.

The Board may make further stock option grants to directors, officers and employees of the Corporation, at its sole discretion. The maximum expected value of options granted to an individual in any one year will not exceed two times base salary and awards will be entirely discretionary. The Board has the right to settle an award in whole, or in part, in cash or through cashless exercise to help reduce administrative burden and costs.

For "good leavers" under the Stock Option Plan, awards will vest on termination and the participant will have six months (or to the end of the exercise period, whichever is earlier) to exercise the award and any other vested awards, after which the awards will lapse. For any leaver who is not a "good leaver", awards will lapse immediately. The Corporation's definition of a "good leaver" includes participants that leave employment because of death, disability, illness, retirement and redundancy. The Board also has discretion to determine whether a participant is a "good leaver". Participants who change employment among the Corporation's group of subsidiaries will not be considered leavers.

On May 25, 2018, the Board amended the Stock Option Plan, subject to approval of the 2018 Plan (as defined below) at the annual general meeting of shareholders on July 10, 2018, to reduce the maximum number of Common Shares issuable under the plan to 2,100,000.

Transitional Equity-Based Compensation Arrangements

One-Time Transitional Performance Share Plan

Some individuals who are officers or other key employees of the Corporation were participants in the Lundin Petroleum Performance Share Plan (the "**Lundin Petroleum PSP**"). Those participants were made awards of Lundin Petroleum shares under the Lundin Petroleum PSP on or around July 1, 2015 and July 1, 2016. Each such award would have fully vested at the end of a three-year restricted period, subject to certain three-year performance conditions and subject to the continuing employment of the participant.

However, for "good leavers" under the Lundin Petroleum PSP, awards are pro-rated according to the time from the date of the original award by Lundin Petroleum to the date the participant leaves Lundin Petroleum. For such "good leavers", pro-rated awards vest as scheduled, subject to the performance conditions, at the original date of vesting even after a participant's departure from Lundin Petroleum. For any leaver who is not a "good leaver" under the Lundin Petroleum PSP, awards lapse immediately.

Accordingly, in connection with the Reorganization and the Spin-Off, the Corporation agreed to put in place certain one-time transitional equity-based compensation arrangements for certain officers and employees of the Corporation, as described below, in order to compensate the participant for that portion of the Lundin Petroleum PSP award that lapsed because of the participant's departure from Lundin Petroleum.

The Corporation understands that employees of the Corporation who were formerly employees of Lundin Petroleum and who received awards under the Lundin Petroleum PSP in 2015 and 2016 were treated as "good leavers" by Lundin Petroleum, as described above. Under such employees' employment contracts with the Corporation, the value of Lundin Petroleum PSP awards held by employees of the Corporation that lapse as a result of the Spin-Off was made into equivalent value share awards by the Corporation under a one-time transitional performance share plan implemented by the Corporation in connection with the Spin-Off incorporating the terms described below (the "**IPC Transitional PSP**").

The IPC Transitional PSP plan was only used in connection with the Spin-Off. The aggregate number of Common Shares issuable under the IPC Transitional PSP, assuming full vesting, was 1,154,569 Common Shares at the date of grant.

Participants in the IPC Transitional PSP were made an award, which will vest on June 30, 2018 and June 30, 2019, and be subject to share price targets: 75% of each award will vest subject to continued employment only. The remaining 25% will vest on a straight-line basis for the Common Share price performance between 100% and 125% of the fair value price of the Common Shares determined by the Board of CAD 4.77, measured against the volume weighted average price over the 20 trading days prior to and including the vesting date. No further awards may be made in the future under the IPC Transitional PSP and the IPC Transitional PSP shall terminate following the payment of awards, if any, vesting on June 30, 2019.

The leaver provisions of the IPC Transitional PSP mirror those of the Lundin Petroleum PSP.

One-Time Transitional Restricted Share Plan

Some individuals who are officers or other key employees of the Corporation were participants in the Lundin Petroleum unit bonus plan (the "**Lundin Petroleum Unit Bonus Plan**"). Those participants were made cash awards that mirror the value of Lundin Petroleum shares on, or around, June 1, 2015 and June 1, 2016. Each such award would have vested by a third on each of the first three anniversaries of the award and would have been paid in cash by Lundin Petroleum, subject only to continued employment.

For "good leavers" under the Lundin Petroleum Unit Bonus Plan, awards may vest at the original date of vesting, even after the participant's departure from Lundin Petroleum. For any leaver who is not a "good leaver" under the Lundin Petroleum Unit Bonus Plan, awards lapse immediately.

Accordingly, in connection with the Reorganization and the Spin-Off, the Corporation agreed to put in place certain one-time transitional equity-based compensation arrangements for certain officers and employees of the Corporation, as described below, in order to compensate the participant for that portion of the Lundin Petroleum Unit Bonus Plan award that lapsed because of the participant's departure from Lundin Petroleum.

The Corporation understands that employees of the Corporation who were participants in the Lundin Petroleum Unit Bonus Plan for 2015 or 2016 were treated as "good leavers" by Lundin Petroleum under such plans with unvested awards being pro rated to the end of such employees' time served with Lundin Petroleum. Under such employees' employment contracts with the Corporation, the equivalent value to the difference between each full Lundin Petroleum Unit Bonus Plan award and the pro-rated part of such award that will vest under the Lundin Petroleum Unit Bonus Plan were made into awards of Common Shares under a one-time transitional restricted share plan implemented by the Corporation incorporating the terms described below (the "**IPC Transitional RSP**").

The IPC Transitional RSP was used in connection with the Spin-Off. The aggregate number of Common Shares issuable under the IPC Transitional RSP was 152,790 Common Shares as at the date of grant.

Participants were granted an award of restricted shares under the IPC Transitional RSP, which will vest according to the same timetable as the Lundin Petroleum Unit Bonus Plan each year to May 31, 2018 and May 31, 2019, subject to continued employment. No further awards may be made in the future under the IPC Transitional RSP, and the IPC Transitional RSP shall terminate following the payment of awards, if any, vesting on May 31, 2019.

The leaver provisions of the IPC Transitional RSP mirror those of the Lundin Petroleum Unit Bonus Plan.

Performance and Restricted Share Plan

The Board approved in May 2018, subject to shareholder approval at the annual general meeting of shareholders on July 10, 2018, a Performance and Restricted Share Plan (the "**2018 Plan**") with the purposes of promoting alignment of interests between employees and the shareholders, associating a portion of employee compensation with the returns achieved by shareholders, and attracting and retaining knowledgeable and experienced employees. The 2018 Plan will be administered by the Compensation Committee on behalf of the Board. The 2018 Plan will provide for the grant of performance share units ("**PSUs**") and restricted share units ("**RSUs**") which, subject to the time and performance vesting conditions to be determined by the Committee under the 2018 Plan, will be settled by the Corporation in Common Shares, or at the discretion of the Corporation, in an equivalent cash value. It is proposed that eligible participants in the 2018 Plan will be employees, consultants and directors (however, directors who are not employees will have a separate tranche under the 2018 Plan from other eligible participants). The maximum number of Common Shares issuable under the 2018 Plan is 5,000,000 if approved by the shareholders at the annual general meeting.

Total number of Common Shares – dilution

The maximum number of Common Shares that may be issued or are issuable under all share based compensation arrangements shall not exceed 10% of the number of issued and outstanding Common Shares on a non-diluted basis.

EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Introduction

The purpose of this Compensation Discussion and Analysis is to provide information about the Corporation's philosophy, objectives, policy and processes regarding executive compensation.

Compensation Philosophy and Objectives

The Corporation's executive compensation follows a set of principles that are applicable to all employees. The Corporation aims to offer all employees compensation packages that in their totality are competitive and in line with market conditions. These packages will be designed to ensure that the Corporation can recruit, motivate and retain highly skilled individuals and to reward performance that enhances shareholder value.

The Corporation's compensation packages consist of four elements, being (a) base salary, (b) annual bonus, (c) long-term incentive (where applicable), and (d) other benefits. The purpose of base salary will be to provide predictable compensation that is competitive and takes into account the scope and responsibilities associated with each employee's position, as well as the skills, experience and performance of employees.

As part of the yearly assessment process, the Corporation has adopted a performance management process, which is designed to align individual and team performance to the strategic and operational goals and objectives of the overall business. Individual performance measures will be formally agreed and key elements of variable compensation will be clearly linked to the achievement of such stated and agreed performance measures.

The annual bonus is an important part of an individual's compensation package where associated performance targets reflect the key drivers for value creation and growth in shareholder value. The purpose of the long-term incentive plans is to align senior and key employees' incentives with shareholders' long-term interests.

The purpose of other benefits is to complete the compensation package in line with levels of market terms and to help facilitate the discharge of each individual's duties.

Executive Compensation Plan

The compensation of officers of the Corporation will follow the principles that are applicable to all employees. The compensation committee of the Board (the "**Compensation Committee**") prepared, reviewed and recommended for approval, and the Board approved, an executive compensation plan for officers.

It is the aim of the Corporation to be able to recruit, motivate and retain high caliber executives capable of achieving the objectives of the Corporation, and to encourage and appropriately reward performance that enhances shareholder value. Accordingly, the Corporation will award compensation under the executive compensation policy in accordance with current best practice that links compensation to the Corporation's business strategy, aligns officers' interests with those of shareholders and rewards officers fairly for their contribution to the Corporation's performance.

Executive Compensation Plan and the Compensation Committee

The Board has established the Compensation Committee to, among other things, administer an executive compensation policy. The members of the Compensation Committee are Lukas H. Lundin, Donald Charter and Torstein Sanness, all of whom have relevant experience and competence, having worked with compensation matters as both executives and compensation committee members of other corporate boards. See "*Directors and Executive Officers – Biographies of Executive Officers and Directors*". Mr. Charter and Mr. Sanness are considered independent directors. Although Mr. Lundin may not be considered independent of the major shareholders, he is considered independent of the Corporation and management and his experience will be important to the successful functioning of the executive compensation process.

The Compensation Committee receives information and makes recommendations to the Board and, if applicable, shareholders, on matters relating to the principles of compensation, as well as all compensation and other terms of employment of officers. The Compensation Committee meets regularly and its tasks include monitoring and evaluating programs for variable compensation for officers and the application of the executive compensation policy, as well as compensation structures, risks and levels throughout the Corporation. The Compensation Committee monitors, evaluates and approves the Corporation's performance management procedures. The Board may also decide that certain decisions may be taken by the Compensation Committee on its behalf.

The Compensation Committee proposes to the Board for approval the compensation and other terms of employment of the CEO. The CEO, in turn, proposes to the Compensation Committee, for approval by the

Board, the compensation and other terms of employment of senior management reporting directly to the CEO and any other officers appointed by the Board, including the CFO. This includes any awards of annual bonus and long-term incentives.

To ensure that the Corporation's compensation packages remain competitive and in line with market conditions, the Compensation Committee will undertake periodic benchmarking studies. For each study, peer groups of companies will be selected, against which the Corporation's compensation practices can be measured. As the Corporation will compete with peer companies to retain and attract the very best talent in the market, both at the operational and executive level, it will be important that the Corporation's compensation packages are determined primarily by reference to the compensation practices among peer companies. The levels of base salary, annual bonus and long-term incentives will be benchmarked against the median level. However, in the event of exceptional performance, deviations may be authorized.

Peer companies are expected to be primarily international upstream oil and gas companies of similar size and operational reach; however, the Compensation Committee will not necessarily limit itself to a single peer group but may consider geography, specialization and other appropriate benchmarks if necessary to ensure that its decisions are taken in the right context. It is not expected that the Compensation Committee will set pay solely based on benchmarking, but will also consider other factors such as internal relativities, performance, experience, potential and the overall business case.

The Compensation Committee will also consider any risks associated with compensation policies and practices, including possible material adverse effects on the Corporation. These risks may include, but not be limited to, financial, operational and behavioral risks that may result from the design and quantum of incentive plans and other forms of reward throughout the organization. As part of these deliberations, the Compensation Committee will look at appropriate ways to mitigate any identified risks.

With regard to equity-based compensation, described in "*Equity-Based Compensation Arrangements*" above, the Compensation Committee manages long-term incentive plans on behalf of the Board. Levels of equity-based grants for officers will follow established policy and be approved by the Board. Awards may be made at the sole discretion of the Board and the Compensation Committee will monitor the costs, dilution and context of awards, such as previous years' awards. The Board will have complete discretion with regard to participation in such plans and the assessment of any performance conditions and may reduce the vesting of plans, including reduction to zero, if it considers the underlying performance of the Corporation not to be reflected in the initial vesting outcome. Furthermore, participants in equity-based plans are not permitted to purchase financial instruments that are designed to hedge or offset a decrease in market value of equity securities granted as compensation or held, directly or indirectly, by the participant. Officers are required to build up an equity holding of 0.5 times base salary over time (two times base salary for the CEO) by retaining a minimum of 50% of shares acquired from exercised awards after tax.

The Compensation Committee is entitled to request the advice and assistance of external compensation consultants and other advisors. However, the Compensation Committee will be required to ensure that there is no conflict of interest regarding other assignments that such advisors may have for the Corporation and its management. See also section "Corporate Governance" – "Compensation Committee".

Elements of Compensation

As noted above, there are four key elements to the compensation of the Corporation's management: (a) base salary, (b) annual bonus, (c) long-term incentives and (d) other benefits.

(a) Base salary

An officer's base salary will be based on market conditions, will be competitive and will take into account the scope and responsibilities associated with the position, as well as the skills, experience and performance of the officer. Each officer's base salary, as well as the other elements of the officer's compensation, will be reviewed annually to ensure that such compensation remains competitive and in line with market conditions. As part of this assessment process, the Compensation Committee will undertake periodic benchmarking studies in respect of the Corporation's compensation policy and practices, as described above.

(b) Annual bonus

The annual bonus will be an important part of an officer's compensation. Through its performance management process, the Corporation will set predetermined and measurable performance criteria for each officer, aimed at promoting long-term value creation for the Corporation's shareholders. The performance conditions for the Corporation's 2017 annual bonus were (i) 50% linked to the Corporation's strategic and operational targets, including production, exploration, financial and health and safety targets, evaluated against stretching quantitative targets, and (ii) 50% linked to a mix of quantitative and qualitative targets related to the individual officer's responsibilities and evaluated on a discretionary basis by the Board.

The annual bonus opportunity is based upon a predetermined limit between 0% and 100% of salary, determined by performance against the performance conditions outlined in the previous paragraph. However, the Compensation Committee may exercise discretion and recommend to the Board for approval an annual bonus outside of this range in circumstances, or in respect of performance, that the Compensation Committee considers to be exceptional.

(c) Long-term incentive plans

The Corporation believes that it is appropriate to structure its long-term incentive plans to align its officers' incentives with shareholder interests. Compensation that is linked to the share price should result in a greater personal commitment to the Corporation. The Corporation's long-term incentive plans, on an ongoing basis, consist of the Stock Option Plan and, as part of the Spin-Off only, the IPC Transitional PSP, the IPC Transitional RSP and the proposed 2018 Plan. See "*Equity-Based Compensation Arrangements – The Corporation's Stock Option Plan*", "*Transitional Equity-Based Compensation Arrangements – One-Time Transitional Performance Share Plan*", *"Transitional Equity-Based Compensation Arrangements – One-Time Transitional Restricted Share Plan*" and "*Performance and Restricted Share Plan"*.

All equity-based incentive plans of the Corporation have a maximum number of shares issuable for awards in accordance with applicable stock exchange rules.

In the event of a change of control of the Corporation, all awards under the relevant plan will vest in full.

If, during the performance or restricted period, the share capital of the Corporation is materially changed, or if there is a dividend in kind, a split, reverse split, bonus issue, delisting or similar major corporate event, the Board will seek to recalculate awards (and any performance conditions) to achieve a neutral outcome for both participants and the Corporation. All recalculations will be done at the discretion of the Board.

(d) Other benefits

Any other benefits will be based on market terms and will facilitate the discharge of each officer's duties. Such benefits include defined contribution pension plans, as well as certain housing allowances, education expenses and health-care limited in time and/or amount.

Officer Compensation

The table below reflects the fair value of the compensation that was earned by, paid to or awarded to the officers for the fiscal year ending December 31, 2017, based on a start date of April 24, 2017.

Name and Principal Position	Year	Salary (2) (CAD)	Share-Based Awards (3) (CAD)	Option-Based Awards (4) (CAD)	Annual Incentive Plans (5) (CAD)	Pension Value (6) (CAD)	All Other Compensation (7) (CAD)	Total Compensation (CAD)
Mike Nicholson, CEO	2017	463,989	1,842,795	1,002,208	548,351	174,283	75,023	4,106,649
The other officers of the Corporation (1), in aggregate	2017	1,368,057	1,368,057	1,302,872	1,084,095	286,190	139,858	5,521,458

Notes:

(1) i.e., the CFO, the General Counsel and Corporate Secretary, the VP Corporate Planning and Investor Relations, the VP Operations and the VP Reservoir Development.

(2) Salaries were paid in Swiss Francs and have been converted based on the daily average exchange rate as reported by the Bank of Canada on December 31, 2017 of C$1.00 equals 0.7779 Swiss Francs. The salaries have been further pro-rated based on a start date of April 24, 2017.

(3) These figures represent the fair value estimated of awards under the IPC Transitional PSP and the IPC Transitional RSP. These awards will vest in 2018 and 2019, respectively. See "*Equity-Based Compensation Arrangements – Transitional Equity-Based Compensation Arrangements – One-Time Transitional Performance Share Plan*" and "*One-Time Transitional Restricted Share Plan*". Each PSP was fair valued at the date of grant at C$2.50 (for awards vesting in 2018) and C$2.79 (for awards vesting in 2019) using an adjusted share price calculated with a hybrid valuation model based on the Monte Carlo simulation. The assumptions used in the calculation of the adjusted share price were a risk free rate of 0.76%, expected volatility of 52.80%, a dividend yield rate of 0% and an exercise price of nil. Each RSP was fair valued at the date of grant at C$4.77. It should be recognized that the actual future value will be based on the market value of the common shares at the time of vesting. Therefore, the value attributed to the share-based awards does not necessarily correspond to that actual future value that will be realized.

(4) These figures represent the fair value of stock options granted over Common Shares. These options were granted at an exercise price of CAD 4.77 on February 21, 2017 and will vest in three equal tranches on the first, second and third anniversaries of their award. The overall option life will be four years. Each original stock-option was fair valued at the date of grant at C$2.01 using a Black-Scholes option pricing model. The assumptions used in the calculation were a risk free rate of 1.02%, expected volatility of 53.70% and dividend yield rate of 0%. It should be recognized that the actual future value will be based on the difference between the market value of the common shares at the time of exercise and the exercise price of the stock options. Therefore, the value attributed to the option based-awards does not necessarily correspond to that actual future value that will be realized.

(5) These figures represent the annual bonus for the nine month period until December 31, 2017. Bonuses are paid in Swiss Francs and have been converted based on the daily average exchange rate as reported by the Bank of Canada on December 31, 2017 of C$1.00 equals 0.7779 Swiss Francs.

(6) Pension contributions are paid in Swiss Francs and have been converted based on the daily average exchange rate as reported by the Bank of Canada on December 31, 2017 of C$1.00 equals 0.7779 Swiss Francs.

(7) The amounts include housing allowances, health-care and school fees. Benefits are denominated in Swiss Francs and have been converted based on the daily average exchange rate as reported by the Bank of Canada on December 31, 2017 of C$1.00 equals 0.7779 Swiss Francs.

Director Compensation

All directors who are not officers receive a basic annual retainer of USD 50,000. In addition, those directors who are not officers and were appointed in connection with the Spin-Off in 2017 received a grant of 25,000 stock options under the Stock Option Plan for 2017, described above.

In addition, Chairs of the Audit Committee and the Compensation Committee receive annual fees of USD 20,000 and members of the Audit Committee and the Compensation Committee receive annual fees of USD 10,000 per committee. Chairs of the Nominating and Corporate Governance Committee and the Reserves Committee receive annual fees of USD 10,000 and members of the Nominating and Corporate Governance Committee and the Reserves and HSE Committee receive annual fees of USD 5,000. In addition, the Chairman of the Board receives an annual fee of USD 100,000 and the Lead Director receives an annual fee of USD 75,000. There will be no meeting fees.

Termination and Change of Control Provisions

Other than as described below, there are no agreements, compensation plans, contracts or arrangements whereby an officer is entitled to receive payments from the Corporation in the event of the termination of the officer's employment with the Corporation. The employment agreements with the officers provide for a mutual notice period of between one and 12 months, depending on the duration of the officer's employment with the Corporation, recognizing prior employment with Lundin Petroleum. In addition, severance terms in the employment contracts for officers will give rise to compensation of up to one to two years' base salary, in the event of termination of employment due to, or within a year of, a change of control of the Corporation. In addition, the Board is authorized, in individual cases, to approve severance arrangements where employment is terminated by the Corporation without cause or in other circumstances at the discretion of the Board.

In addition to the termination and change of control provisions in employment agreements, the Corporation's equity incentive plans also contain provisions relating to termination of employment and change of control, including expiry or accelerated vesting in certain circumstances.

INDEBTEDNESS OF DIRECTORS AND OFFICERS

At no time since incorporation of the Corporation has there been any indebtedness, other than routine indebtedness, of any director or officer of the Corporation, any proposed directors of the Corporation, or any associate or affiliate of any such director or officer, to the Corporation or to any other entity which is, or at any time since the beginning of the most recently completed financial period has been, the subject of a guarantee, support agreement, letter of agreement or other similar arrangement or understanding provided by the Corporation.

CORPORATE GOVERNANCE

The Corporation discloses its corporate governance practices pursuant to the disclosure requirements in National Instrument 58-101 – Disclosure of Corporate Governance Practices (the "**Governance Disclosure Rule**") that apply to issuers listed on the TSX. The Corporation's governance practices are made with reference to National Policy 58-201, Corporate Governance Guidelines (the "**Governance Guidelines**"). The Governance Disclosure Rule and the Governance Guidelines are initiatives of the Canadian Securities Administrators ("**CSA**").

The Governance Guidelines are not intended to be prescriptive, but are to be used as guidelines in developing corporate governance practices. The Governance Guidelines deal with matters such as the constitution and independence of corporate boards, their functions, the effectiveness and education of board members and other items dealing with sound corporate governance practices. The Governance Disclosure Rule requires that, if management of an issuer solicits proxies from its shareholders for the purpose of electing directors, specified disclosure of its corporate governance practices must be included in its management information circular.

The Corporation complies with the corporate governance regime in British Columbia, Canada.

Further details regarding rules in relation to corporate governance are set forth in Section "*Summary of Shareholder Rights*".

The Board of Directors

The Board is primarily responsible for supervising the management of the Corporation's business and affairs. Its authority is determined by the provisions of the BCBCA and by the Corporation's articles. In addition, the Board's activities are governed by a set of procedural rules which are adopted by the Board. The Board regularly reviews its guidelines and policies and, not less than annually, considers how its corporate governance practices align with guidelines established by the Canadian regulatory authorities having authority, including the TSX.

The Board meets as required to conduct its business, which includes the approval of the quarterly and annual audited consolidated financial statements of the Corporation.

The Board's Chairman, together with the Lead Director, is responsible for the management, development and effective performance of the Board, for monitoring the Corporation's development through regular contact with the President and CEO, and for ensuring that the Board regularly receives reports concerning the development of the Corporation's business and operations, including progress in respect of profits, liquidity and significant contractual matters.

Committees

Audit Committee

The Audit Committee consists of four Board members, each of whom is independent and financially literate. The Audit Committee reviews and reports to the Board on the integrity of the consolidated financial statements of the Corporation. The Audit Committee ensures the Corporation has designed and implemented effective internal financial controls and reviews the compliance with regulatory and statutory requirements as they related to the financial statements, taxation matters and disclosure of material facts.

The Audit Committee has the functions and responsibilities as set out below, among others:

(a) overseeing the Corporation's financial statements and financial disclosures;

(b) review the annual consolidated audited financial statements of the Corporation, the external auditor's report thereon and the related management's discussion and analysis of the Corporation's financial condition and results of operation ("**MD&A**"). After completing its review, if advisable, the Audit Committee shall approve and recommend for Board approval the annual financial statements and the related MD&A;

(c) review the interim consolidated financial statements of the Corporation, the external auditor's review report thereon, if any, and the related MD&A. After completing its review, if advisable, the Audit Committee shall either: (i) formally approve (such approval to include the authorization for public release) or (ii) recommend for Board approval, the interim financial statements and the related MD&A;

(d) review and, if advisable, recommend for Board approval financial disclosure in a prospectus or other securities offering document of the Corporation, press releases disclosing, or based upon, financial results of the Corporation, financial guidance provided to analysts or rating agencies or otherwise publicly disseminated and any other material financial disclosure;

(e) review and, if advisable, recommend for Board approval any material future oriented financial information or financial outlook and endeavour to ensure that there is a reasonable basis for drawing any conclusions or making any forecasts and projections set out in such disclosures;

(f) oversight of the work of the external auditor, including the external auditor's work in preparing or issuing an audit report, performing other audit, review or attest services or any other related work;

(g) review and, if advisable, select and recommend for Board approval the external auditor to be nominated and the compensation of such external auditor;

(h) at least annually, the Audit Committee shall discuss with the external auditor such matters as are required by applicable auditing standards to be discussed by the external auditor with the Audit Committee;

(i) at least annually, the Audit Committee shall review a summary of the external auditor's annual audit plan;

(j) at least annually, and before the external auditor issues its report on the annual financial statements, the Audit Committee shall take appropriate action to oversee the independence of the external auditor;

(k) review the Corporation's system of internal controls;

(l) review reports from the Corporation's Corporate Secretary and other management members on: legal or compliance matters that may have a material impact on the Corporation; the effectiveness of the Corporation's compliance policies; and any material communications received from regulators; and

(m) establish procedures for (a) the receipt, retention, and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters; and (b) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

Audit Committee members: C. Ashley Heppenstall (Chair), Donald K. Charter, Chris Bruijnzeels and Daniella Dimitrov

Nominating and Corporate Governance Committee

This Committee is comprised of three non-executive Board members and assists the Board in identifying qualified individuals for Board membership, develops and implements corporate governance guidelines, and reports annually to the Corporation's shareholders on the Corporation's system of corporate governance.

The Nominating and Corporate Governance Committee (the "**N&CG Committee**") mandate adopted by the Board provides that the N&CG Committee is responsible for, among other things:

(a) developing and updating a long-term plan for the composition of the Board that takes into consideration the current strengths, competencies, skills and experience of the Board members, retirement dates and the strategic direction of the Corporation, and reporting to the Board thereon at least annually;

(b) periodically undertaking an examination of the size of the Board, with a view to determining the impact of the number of directors on the effectiveness of the Board, and recommending to the Board, if necessary, a reduction or increase in the size of the Board;

(c) recommending to the Board the remuneration to be paid to and the benefits to be provided to directors;

(d) endeavouring, in consultation with the Chair or Lead Director, to ensure that an appropriate system is in place to evaluate the effectiveness of the Board as a whole, each of the committees of the Board and each individual director of the Board with a view to ensuring that they are fulfilling their respective responsibilities and duties;

(e) in consultation with the Chair and the CEO, annually or as required, recruiting and identifying individuals qualified to become new Board members and recommending to the Board new director nominees for the next annual meeting of shareholders;

(f) in consultation with the Chair or Lead Director, annually or as required, recommending to the Board, the individual directors to serve on the various committees;

(g) conducting a periodic review of the Corporation's corporate governance policies and making policy recommendations aimed at enhancing Board and committee effectiveness;

(h) reviewing overall governance principles, monitoring disclosure and best practices of comparable and leading companies, and bringing forward to the Board a list of corporate governance issues for review, discussion or action by the Board or its committees;

(i) reviewing the disclosure in the Corporation's public disclosure documents relating to corporate governance practices and preparing recommendations to the Board regarding any other reports required or recommended on corporate governance;

(j) proposing agenda items and content for submission to the Board related to corporate governance issues and providing periodic updates on recent developments in corporate governance to the Board;

(k) conducting a periodic review of the relationship between management and the Board, particularly in connection with a view to ensuring effective communication and the provision of information to directors in a timely manner;

(l) monitoring and making recommendations regarding new director orientation and the ongoing development of existing directors;

(m) reviewing annually the Board Mandate and the mandates for each committee of the Board, together with the position descriptions, if any, of each of the Chair of the Board, the CEO, lead director, director and committee chairs, and where necessary, recommending changes to the Board;

(n) reviewing and recommending the appropriate structure, size, composition, mandate and members for the committees, and recommending for Board approval the appointment of each to Board committees;

(o) recommending procedures to ensure that the Board and each of its committees function independently of management;

(p) monitoring conflicts of interest (real or perceived) of both the Board and management in accordance with the Corporation's Code of Business Conduct and Ethics; and

(q) receiving reports from the CEO and reporting to the Board regarding breaches of the Code of Business Conduct and Ethics and reviewing investigations and any resolutions of complaints received under the Code of Business Conduct and Ethics and reporting annually to the Board thereon.

Nominating and Corporate Governance Committee members: Donald K. Charter (Chair), Chris Bruijnzeels and Daniella Dimitrov.

Compensation Committee

The Compensation Committee is comprised of three non-executive members of the Board. The Compensation Committee is responsible for administering the Corporation's executive compensation program and implements and oversees and compensation policies approved by the Board.

In order for the Board to determine the compensation for the Corporation's Directors and executive officers, the Compensation Committee receives information and makes recommendations to the Board and, if applicable, shareholders, on matters relating to the principles of compensation, as well as all compensation and other terms of employment of officers. Following the Board's approval of the executive compensation plan, the Compensation Committee will propose to the Board for approval the compensation and other terms of employment of the CEO. The CEO, in turn, will propose to the Compensation Committee, for approval by the Board, the compensation and other terms of employment of senior management reporting directly to the CEO and any other officers appointed by the Board. This will include any award of annual bonus and long-term incentives. To ensure that the Corporation's compensation packages remain competitive and in line with market conditions, the Compensation Committee will undertake periodic benchmarking studies. The Compensation Committee will also consider any risks associated with compensation policies and practices, including possible material adverse effects on the Corporation.

The Compensation Committee mandate adopted by the Board provides that the Compensation Committee is responsible for, among other things:

(a) reviewing and approving corporate goals and objectives relevant to CEO compensation;

(b) evaluating the CEO's performance in light of those corporate goals and objectives, and making recommendations to the Board with respect to the CEO's compensation level based on its evaluation;

(c) reviewing the recommendations to the Compensation Committee of the CEO respecting the appointment, compensation and other terms of employment of the Chief Financial Officer, all senior management reporting directly to the CEO and all other officers appointed by the Board and, if advisable, approving and recommending for Board approval, with or without modifications, any such appointment, compensation and other terms of employment;

(d) reviewing executive compensation disclosure before the Corporation publicly discloses this information;

(e) submitting a report to the Board on human resources matters; and

(f) preparing an annual report for inclusion in the Corporation's management information circular to shareholders respecting the process undertaken by the Committee in its review.

Compensation Committee members: Donald K. Charter (Chair), Lukas H. Lundin and Torstein Sanness

Reserves and HSE Committee

The Reserves and HSE Committee is comprised of three independent directors. The Reserves Committee has the responsibility in general for developing the Corporation's approach to the reporting of oil and gas reserves and other oil and gas information required to be publicly disclosed. The Reserves Committee's mandate prescribes the methodology that the Corporation and the independent evaluator selected by management and approved by the Reserves Committee will adhere to in the calculation of oil and gas reserves and the valuation of those reserves. The Reserves and HSE Committee also is responsible for environmental, health and safety oversight.

The specific responsibilities of the Reserves and HSE Committee are set out in the Reserves and HSE Committee Mandate. The primary role of the Reserves and HSE Committee is to:

(a) act in an advisory capacity to the Board;

(b) review the Corporation's procedures relating to disclosure of information with respect to crude oil, natural gas and NGL reserves and resources data;

(c) annually review the selection of the qualified reserves evaluators or auditors chosen to report to the Board on the Corporation's crude oil, natural gas and NGL reserves and resources data;

(d) review the Corporation's annual reserves and resources estimates prior to public disclosure; and

(e) review the Corporation's material compliance with applicable HSE policies, standards and applicable laws, note any material non-compliance and monitor efforts to remedy such non-compliance.

<u>Reserves and HSE Committee members</u>: Chris Bruijnzeels (Chair), Torstein Sanness and C. Ashley Heppenstall

ESCROWED SECURITIES

As at the date hereof, the Corporation does not have any securities in escrow or that are subject to a contractual restriction on transfer.

LEGAL PROCEEDINGS

Other than as stated in section "The Oil and Gas Assets" – "Discontinued Operations", there are no material legal proceedings against the Corporation or any of its subsidiaries, the Corporation is not a party to any material legal proceedings and the Corporation is not aware of any contemplated proceedings. The Corporation has not in the past twelve months been involved in any governmental, legal or arbitrational proceedings which have had, or may have, significant effect on the Corporation's financial position or profitability. The Corporation is not aware of any such pending or threatened proceedings.

REGULATORY ACTIONS

For the period beginning on the date of incorporation of the Corporation until the date of this prospectus, there were (i) no penalties or sanctions imposed against the Corporation or by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements the Corporation entered into before a court relating to a securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Management is not aware of any material interest, direct or indirect, of any director or officer of the Corporation, any person beneficially owning, directly or indirectly, more than 10% of the Corporation's voting securities, or any associate or affiliate of such person in any transaction within the last three years or in any proposed transaction which in either case has materially affected or will materially affect the Corporation or its subsidiaries, other than as disclosed in this prospectus.

MATERIAL CONTRACTS

The Reorganization

Under the Contribution and Transfer Agreements, all of the shares of IPBV and all of the shares of Lundin Services Ltd. were transferred to the Corporation in exchange for the issuance by the Corporation to Lundin Petroleum of an aggregate of 113,462,147 Common Shares based on a price of CAD $4.77 per Common Share, for aggregate consideration of USD 410 million plus working capital as at the effective date.

The Reorganization was completed on April 7, 2017, with an effective date of January 1, 2017. The Contribution and Transfer Agreements provide for a working capital adjustment. For more information on the Contribution and Transfer Agreements and the Reorganization please refer to "The Corporation".

Credit Facilities

The Corporation and certain of the IPC Subsidiaries have entered into the Credit Facilities which are described under "Capital Structure, Indebtedness and Related Information" – "Financing and Credit Facilities".

The Material Contracts and Licenses in relation to the Material Oil and Gas Assets

In respect of the FPSO Bertam operating in Malaysia, a bareboat charter agreement dated August 13, 2014 is in place between IPC Malaysia BV (formerly Lundin Malaysia BV), on behalf of the PM307 joint venture, and Lundin Services Limited, under which the charterer (IPC Malaysia BV (formerly Lundin Malaysia BV)) pays a fixed lease rate over a six-year period starting April 2015, with four one-year options for renewal after the fixed period, at the option of IPC Malaysia BV (formerly Lundin Malaysia BV), as charterer. The parties comprising the PM307 joint venture are IPC Malaysia BV (formerly Lundin Malaysia BV) with a 75% interest and PCSB with a 25% interest. The PM307 joint venture is governed by a farmout agreement with an effective date of May 1, 2011 and by a joint operating agreement dated May 1, 2011. Costs incurred within the licence are apportioned in proportion to each party's interest. Lundin Services Limited is paid the complete lease by IPC Malaysia BV (formerly Lundin Malaysia BV), and PCSB reimburses its share to IPC Malaysia BV (formerly Lundin Malaysia BV) in accordance with its proportionate interest in the PM307 joint venture, resulting in an additional stream of revenue for the Corporation.

All of the Corporation's production and reserves in Malaysia come from the Bertam oil field located offshore Peninsular Malaysia. In addition to the Bertam field area, block PM307 contains the two Gas Holding Areas for Tembakau and Mengkuang. Under a PSC, IPC Malaysia BV (formerly Lundin Malaysia BV) is the operator of Block PM307 with a 75% working interest, with Petronas holding the remaining 25% through its wholly owned subsidiary PCSB.

IPC Malaysia BV's interest in block PM307 is governed by a PSC. The terms and scope of the rights granted are entirely contained in the PSC and such rights are enforceable under Malaysian law. The terms of the PSC provide that the party to the PSC (the PSC Contractor) is solely responsible for the provision of all funds required directly or indirectly for petroleum operations. The PSC Contractor is then entitled to recover costs related to petroleum operations and a share of profits from the production of crude oil or natural gas in kind, based on a defined formula contained in the PSC.

In France, all mining resources from the subsoil, including oil and gas, belong to the state. The 2011 Mining Code, which came into force on March 1, 2011, allows the government to delegate to companies the right to explore the subsoil and produce oil and gas. Certain provisions of the Mining Code that were in effect prior to the 2011 Mining Code remain in force until the publication of the regulatory provisions of the 2011 Mining Code. The 2011 Mining Code defines the process by which exploration permits (*permis exclusifs de recherches*) and production licences (*concessions*) may be granted and how royalties should be set. In addition, the General Code of Taxation (*Code general des impots*) details how Communal and Departmental taxes, as well as corporate income tax payable to the state, are calculated.

The Corporation is the operator of the oil production licenses (‘concessions’) for Vert-La-Gravelle, Villeperdue and Grandville and holds a 100% working interest in these producing fields. The concessions are granted for a period of not more than 50 years and could be renewed several times for 25 years or less. However, the initial period of the concession is flexible and is generally shorter for smaller developments, it being specified that the maximum duration of the concession shall not exceed 50 years. The Corporation’s current concessions for Vert-La-Gravelle, Villeperdue and Grandville will expire in August 2038 (Grandville), September 2028 (Vert-La-Gravelle) and January 2037 (Villeperdue).

Mineral rights in France belong to the French State, and production of hydrocarbons occurs under a concession regime. Holders of a concession or production licence must pay the French tax authorities a royalty proportional to the value of the products extracted. This royalty is paid starting from production. Local mining taxes, or RCDM (*redevance communale et départementale des mines*), are also payable to the applicable administrative French country and municipality on whose territory the oil is produced.

On September 22, 2017, the Corporation’s wholly-owned subsidiary IPC Alberta Ltd. entered into an asset sale and purchase agreement regarding the purchase of the Suffield Assets, covering a land position of 800,000 net acres of shallow natural gas rights and 100,000 net acres of oil rights in southern Alberta, Canada, at a purchase price of CAD 512 million (subject to closing adjustments) from Cenovus Energy Inc. The purchase had an economic effect as of April 1, 2017, i.e. IPC Alberta Ltd. assumed all benefits, obligations and risks associated with the assets as of that date.

For more information on the regulatory framework regarding the Oil and Gas Assets, see “The Canadian, Malaysian, French and Dutch Industry Overviews and Regulatory Regimes”.

EXPERTS

ERC Equipoise Limited, with a business address at: 6th Floor Stephenson House, 2 Cherry Orchard Road, Croydon CR0 6BA, London U.K., is one of the Corporation’s independent qualified reserves auditors and has prepared the ERCE Report. The team responsible for the audit from ERCE have the following qualifications:

- Simon McDonald is a UK Chartered Engineer, registered with the Energy Institute (#580340) and a Member of the Society of Petroleum Evaluation Engineers (#714). He has over 40 years’ experience in engineering studies related to International oil and gas fields.

- Paul Chernik is a Canadian Professional Engineer, registered with APEGA (#66938) and a Member of the Society of Petroleum Evaluation Engineers (#776). He has over 13 years’ experience in engineering studies related to International oil and gas fields.

McDaniel & Associates Consultants Ltd., with a business address at: 2200, 255 – 5th Avenue SW, Bow Valley Square 3, Calgary, Alberta, T2P 3G6 Canada, is one of the Corporation’s independent qualified reserves evaluators and has prepared the McDaniel Report. The team responsible for the evaluation from McDaniel have the following qualifications:

- Michael J. Verney is a Professional Engineer, registered with the Association of Professional Engineers and Geoscientists of Alberta (APEGA), a member of the Society of Petroleum Enginners and a member of the Society of Petroleum Evaluation Engineers. He has over 10 years’ experience in the evaluation of oil and gas reserves in Canada.

None of ERCE, McDaniel or their respective officers, directors, employees or consultants beneficially owns, directly or indirectly, any of the outstanding Common Shares, nor have any economic or beneficial interest in the Corporation or in any of its assets, nor are they remunerated by way of a fee that is lined to the admission or corporate value of the Corporation.

INDEPENDENT ACCOUNTANTS / AUDITOR

PricewaterhouseCoopers AG, independent auditors, with Steve Johnson as the auditor in charge, is the Corporation's auditor and has audited the financial statements for the special-purpose combined carve-out financial statements of the Malaysia, France and the Netherlands Oil and Gas Businesses (a carve-out of Lundin Petroleum AB) for the years ended December 31, 2015 and 2016, and the consolidated financial statements of the Corporation for the years ended December 31, 2016 and 2017, each incorporated into this prospectus by reference, as stated in their audit opinions also incorporated by reference into this prospectus. PricewaterhouseCoopers AG has its registered office at St. Jakobs-Strasse 25, 4002 Basel, Switzerland. PricewaterhouseCoopers AG is a member of EXPERTsuisse – Swiss Expert Association for Audit, Tax and Fiduciary.

CERTAIN TAX CONSIDERATIONS IN SWEDEN

Below is a summary of certain Swedish tax consequences that may arise for individuals and limited liability companies in relation to the market listing of Common Shares. The summary is based on current legislation and is intended only as general information for shareholders who are subject to unlimited tax liability in Sweden, unless otherwise stated. The analysis does not address securities held as current assets in business operations or by a partnership. Moreover, it does not address the special rules regarding tax-free capital gains (including a non-deductible capital loss) and dividends in the corporate sector that may be applicable when a shareholder holds securities of the Corporation that are considered to be shares held for business purposes (participation exemption). Nor does it cover the special rules that may apply to holdings in companies that are or have been so-called closely-held companies or securities acquired on the basis of so-called qualified shares in closely-held companies. Furthermore, the summary does not cover shares or other securities held in a so-called investment savings account. Finally, the summary does not cover matters related to credit of foreign taxes. The tax treatment of individual shareholders depends on their particular circumstances. It is therefore recommended that shareholders consult a tax advisor for information on the specific implications that may arise in the individual case, including the applicability and effect of foreign rules and tax treaties.

Shareholders who have unlimited tax liability in Sweden

In this case, "unlimited tax liability" refers to holders of shares or other securities who are (i) a natural person who is resident or is permanently living in Sweden or who has been resident in Sweden and has an essential connection with Sweden, or (ii) any legal entity registered in Sweden or whose board of directors is domiciled in Sweden if registration has not taken place.

Taxation on the divestment of shares

Natural persons who have unlimited tax liability in Sweden

Natural persons and estates who have unlimited tax liability in Sweden are taxed on the sale of Common Shares for any profit as income from capital at a rate of 30%. Capital gains or capital loss is calculated as the difference between the sales proceeds, after deduction of any sales expenses, and the tax base value of the divested Common Shares (acquisition cost). The tax base value comprises the acquisition price plus brokerage fees.

The average method is used when calculating the capital gains. According to this method, the tax base value of one Common Share comprises the average tax base value of all shares of the same class and type. Upon the sale of listed shares, such as Common Shares, the tax base value may alternatively be determined according to the standard method at a rate of 20% of the sales proceeds after deducting sales costs.

A capital loss on listed shares and other listed securities may be fully offset against taxable capital gains the same year on shares and other listed securities, except for shares in investment funds that only contain

Swedish receivables (fixed income funds). Capital losses on shares that cannot be offset in this way are 70% deductible against other income from capital. To the extent a capital loss cannot be offset against capital gains, a tax reduction is allowed against municipal and state income tax, as well as property tax and municipal property tax. A tax reduction is allowed at a rate of 30% of the portion of the loss that is not greater than SEK 100,000 and 21% of the remaining portion. Such a loss cannot be carried forward to future tax years.

Legal entities who have unlimited tax liability in Sweden

For limited liability companies and other legal entities other than estates, taxable capital gains are taxed as income from business operations at a tax rate of 22%. Capital gains and losses are calculated in essentially the same manner as described above with respect to natural persons. A deduction for capital losses on shares or other securities is allowed only against taxable capital gains on such securities. If certain conditions are fulfilled, such capital losses may also be offset against capital gains in companies within the same group. Capital losses that cannot be utilized in a given year may be carried forward and deducted against taxable capital gains on shares and other securities in subsequent years without limitation in time.

Special tax rules apply to certain categories of companies, such as investment funds, investment companies and insurance companies.

Shareholders who have limited tax liability in Sweden

Shareholders who have limited tax liability in Sweden and whose holdings are not attributable to a permanent establishment in Sweden are usually not taxed in Sweden for capital gains on the disposal of shares or subscription rights. However, shareholders may be subject to taxation in their country of residence. According to a special rule, however, natural persons with limited tax liability in Sweden may be subject to Swedish taxation upon the sale of certain foreign securities (such as shares and warrants) if at any time during the year of sale, or any of the ten (10) previous calendar years, the shareholder has been resident or lived permanently in Sweden. In order for this rule to apply, the foreign security must have been acquired at the time the shareholder was unlimited tax liable in Sweden. Applicability of this rule may be limited by tax treaties between Sweden and other countries.

Taxation of dividends

Dividends on shares are usually taxable. Natural persons and estates who have unlimited tax liability in Sweden are taxed as income from capital at a rate of 30%. For limited liability companies and other legal entities, dividends are taxed as income from business operations at a rate of 22%.

Canadian withholding tax

Since the Common Shares are shares in a Canadian company, dividends paid to a non-resident Canadian shareholder (e.g. unlimited tax liable person in Sweden) will be subject to a Canadian withholding tax. According to the tax treaty between Canada and Sweden, the withholding tax rate will generally be limited to 15%. Where the beneficial owner is a corporation that directly controls at least 10% of the voting rights or holds directly at least 25% of the capital in the company, the withholding tax rate will be reduced to 5%. Unless the dividend is tax-exempt for the Swedish shareholder, the Canadian tax withheld can generally be credited against Swedish tax.

SUMMARY OF SHAREHOLDER RIGHTS

This summary sets out certain differences between the rights of shareholders in the Corporation based upon current British Columbia legislation and other applicable corporate governance rules in Canada and the Corporation’s current articles, as compared with the rights of shareholders generally under Swedish corporate law (in those parts applicable to public limited liability companies whose shares are subject to trading on a regulated market and Swedish corporate governance principles.

Unless expressly stated otherwise Swedish law and corporate governance rules are not applicable on the Corporation. The summary should therefore only serve as an overview of the main differences between Canadian and Swedish law and rules as per the date hereof.

The summary is of a general nature and it is not an exhaustive review of all potentially relevant differences between Canadian and Swedish law and corporate governance requirements.

The Business of the Corporation

British Columbia

Under the BCBCA, the articles set the rules of a company's conduct and set out every restriction, if any, on (i) the business that may be carried on by the company and (ii) the powers that the company may exercise. The articles of the Corporation do not include any restrictions on the Corporation's business.

Sweden

Under the *Swedish Companies Act*, the objectives of a Swedish company must be set out in the articles of association. These objectives set out the limits within which a company can operate.

Shares

British Columbia

The shares have been issued in accordance with the BCBCA. The capital structure of the Corporation is composed of an unlimited number of Common Shares without par value and an unlimited number of Preferred Shares, issuable in series.

Sweden

Under the *Swedish Companies Act*, a company may issue different classes of shares only if such share classes are specified in a company's articles of association. The articles shall also contain limitations on the minimum and maximum number of shares of each share class.

Voting rights

British Columbia

Under the BCBCA, every company having more than 100 shareholders must, unless the central securities register is in a form constituting in itself an index, keep an index of the names of the shareholders of the company as a part of its central securities register, and, within 14 days after the date on which an alteration is made in the central securities register, make any necessary alteration in the index. The index of shareholders must be so kept as to enable particulars with respect to every shareholder to be readily ascertained. A shareholder has one vote in respect of each share held by that shareholder and is entitled to vote in person or by proxy. A registered shareholder can either attend the meeting and vote him or herself or appoint someone else to vote his or her Common Shares (a "proxy holder"). A shareholder appoints a proxy holder to attend and act on the shareholder's behalf at a meeting of shareholders by giving the proxy holder a completed and executed form of proxy. A proxy holder is required to vote the Common Shares in accordance with the shareholder's instructions.

Under ordinary principles of property and trust law a non-registered shareholder has beneficial ownership of the shares, but a trustee, person or other legal representative, agent or other intermediary (an "intermediary") is the registered holder that holds the Common Shares on behalf of the beneficial owner. The intermediary cannot vote the Common Shares registered in its name unless it receives written voting instructions from the beneficial owner. If the beneficial owner requests and provides an intermediary with appropriate documentation, the intermediary must appoint the beneficial owner or nominee of the beneficial owner as proxy holder.

Unless the memorandum or by-laws otherwise provide, any meeting of shareholders may be held entirely by means of telephone or other communications medium, provided all shareholders and proxy holders participating in the meeting are able to communicate with each other.

Sweden

Under the *Swedish Companies Act*, all shares carry one vote unless different share classes with different voting rights are provided for in the articles of association of the company. No share may however have a voting right which exceeds ten times the voting rights of any other share.

Shareholders registered in the share register as of the record date for a general meeting are entitled to vote at such general meeting (in person or by appointing a proxy holder). Shareholders with shares registered through a nominee must request to be temporarily registered as a shareholder of record on the record date in order to participate in a general meeting. The share register is kept by Euroclear Sweden and the record date for a general meeting shall be the fifth business day prior to the date of the meeting. Shareholders must also, if provided for in the articles of association, give notice of their intention to attend a shareholder meeting.

Shareholder meetings

British Columbia

Under the BCBCA, the directors of the Corporation must call an annual meeting of shareholders not later than 18 months after the date on which it was recognized, and subsequently, at least once in each calendar year and not more than 15 months after the annual reference date for the preceding calendar year. Meetings of shareholders of a corporation shall be held in British Columbia, or may be held at a location outside British Columbia if the location for the meeting is approved by the resolution required by the articles for that purpose or approved by ordinary resolution, as applicable, or the location for the meeting is approved in writing by the registrar before the meeting is held.

The holders of at least 1/20 of the issued Common Shares may also requisition the directors to call a meeting of the shareholders for the purposes stated in the requisition, provided that the business may be transacted at a general meeting. Subject to certain exemptions, on receiving the requisition, the directors shall call a general meeting to be held not more than four months after the date on which the requisition is received. If the directors fail to send notice of a general meeting within 21 days after the date on which the requisition is received, any shareholder who signed the requisition holding more than 1/40 of the issued Common Shares may call the meeting.

Under the articles of the Corporation the directors, president (if any), the secretary (if any), the assistant secretary (if any), any lawyer of the Corporation, the auditor of the Corporation and any other person invited by the directors are entitled to attend any meeting of shareholders, but are not to be counted in the quorum and is not entitled to vote at the meeting unless that person is a shareholder or proxy holder entitled to vote at the meeting.

Under the BCBCA, a consent resolution of shareholders is deemed to be a proceeding at a meeting of those shareholders and to be as valid and effective as if it had been passed at a meeting of shareholders.

Sweden

An annual general meeting must be held within six months from the end of each financial year at which the board of directors must present the annual report and auditor's report. Resolutions on the following matters must be passed at the annual general meeting: (i) adoption of the profit and loss account and balance sheet, (ii) allocation of the company's profit or loss as set out on the adopted balance sheet, (iii) discharge from liability for directors and the managing director and (iv) other matters to be dealt with under the *Swedish Companies Act* or the articles of association of the company. For a company with shares listed on a regulated market a resolution must also be passed on guidelines for remuneration payable to senior executives.

Under the *Swedish Companies Act*, the board of directors is responsible for convening general meetings but holders of not less than 10% of all shares in the company may in writing demand that an extraordinary general meeting is convened. In such case, notice to attend the meeting shall be issued by the board within two weeks of receipt of the demand therefor. When a general meeting is not convened in the prescribed manner, the Swedish Companies Registration Office shall, following notification, convene the general meeting. General meetings shall be held in the municipality in which the board of directors holds its registered office or in another municipality in Sweden if specified in the articles of association.

The general meeting shall be opened by the chairman of the board or such person as the board has decided. Moreover, the Swedish corporate governance code stipulates that the chairman of the board of directors together with a quorum of directors, as well as the chief executive officer, shall attend general meetings. The chairman of the general meeting shall be nominated by the nomination committee and elected by the general meeting.

Minutes from general meetings shall be available on the company’s website no later than two weeks after the meeting.

Notices

British Columbia

The Corporation must send notice of the date, time and location of a general meeting of the Corporation at least the prescribed number of days but not more than two months before the meeting to each shareholder entitled to attend the meeting.

Under its articles the Corporation must send notice of the date, time and location of any meeting of shareholders, in the manner provided in the articles or in such other manner, if any, as may be prescribed by ordinary resolution, to each shareholder entitled to attend the meeting, to each director and to the auditor, unless the articles of the Corporation otherwise provide, at least 21 days before the meeting.

Sweden

Under the *Swedish Companies Act*, a general meeting of shareholders must be preceded by a notice. The notice of the annual general meeting of shareholders must be given no sooner than six weeks and no later than four weeks before the date of the meeting. In general, notice of extraordinary general meetings must be given no sooner than six weeks and no later than three weeks before the meeting. The notice shall be announced in a press release, published in the Swedish Official Gazette and on the company’s website. The company must also publish in a daily newspaper with nationwide circulation a short form message containing information regarding the notice and where it can be found. The notice shall include an agenda listing each item that the meeting is to resolve upon and the main content of the proposed resolutions.

Pursuant to the Swedish corporate governance code, a company shall, as soon as the time and venue of a general meeting have been decided publish such information on the company’s website. With respect to annual general meetings, such publication shall be made no later than in conjunction with the third quarterly report.

Record date

British Columbia

The directors of the Corporation may set a date as the record date for any purpose, including for the purpose of determining shareholders entitled to notice of or entitled to vote at a meeting of shareholders. Under the BCBCA, the record date must not precede the date of the meeting by more than two months (or, in the case of a requisitioned meeting, four months). Under Canadian securities laws, the record date for notice of the meeting shall be no fewer than 30 days and no more than 60 days before the meeting date. Further, under the Corporation's articles, the record date must not precede the date on which the meeting is held by fewer than 21 days.

Sweden

Under the *Swedish Companies Act* the record date for a general meeting is the fifth work day (i.e., not a holiday) prior to the date of the meeting. In connection with other events such as inter alia rights issues of new shares, the record date may be determined by the board of directors within certain time frames stipulated by, inter alia, the *Swedish Companies Act*.

Issue of shares

British Columbia

Under the BCBCA:

(1) subject to the notice of articles and the Corporation's articles, shares may be issued at the times and to the persons as the directors may determine, and for such consideration as set by a directors' resolution; and

(2) a share must not be issued until (i) it is fully paid in money or in property or past services performed for the Corporation, and (ii) the valuation of the consideration received by the Corporation equals or exceeds, to the satisfaction of the directors, the issue price as determined by the directors.

Sweden

Under the *Swedish Companies Act*, resolutions on new share issues are as a main rule passed by the shareholders at a general meeting. A general meeting may also authorize the board of directors to issue new shares for a period no longer than until the next annual general meeting. Furthermore, the board of directors may also resolve to issue new shares without such authorization, provided that the resolution is conditioned upon the shareholders' subsequent approval at a general meeting.

New shares may be issued against payment in cash, in kind or by way of set-off. As a main rule, the shareholders have pre-emption rights to new shares issued (see "Pre-emption rights").

When issuing new shares the limitations on maximum number of shares and share capital set out in the company's articles of association need to be adhered to, unless a general meeting decides to amend the articles of association.

Pre-emption rights

British Columbia

The articles of incorporation of the Corporation are not required to and do not contain any pre-emption rights.

Sweden

Under the *Swedish Companies Act*, shareholders have pre-emption rights ("*företrädesrätt*") to subscribe for new shares issued *pro rata* to their shareholdings as of a certain record date for the new share issue. Pre-emption rights to subscribe for new shares do not apply in respect of shares issued for consideration in kind or shares issued pursuant to convertibles or warrants previously granted by the company. The pre-emption rights to subscribe for new shares may also be set aside by a resolution passed by two thirds of the votes cast and shares represented at the general meeting resolving upon the issue. The corresponding majority threshold applies to a decision by a general meeting to authorize the board to decide upon new share issues with deviation from shareholders' pre-emption rights.

Dividends

British Columbia

Under the BCBCA, the Corporation may declare and pay a dividend in property, including in money, or by issuing shares or warrants of the Corporation. The Corporation must not declare or pay a dividend in property, including in money, if there are reasonable grounds for believing that (a) the Corporation is insolvent, or (b) the payment of the dividend would render the Corporation insolvent.

Sweden

Under the *Swedish Companies Act*, resolutions on payments of dividends must be passed at a general meeting. A resolution to pay dividends may, with some exceptions, not exceed the amount recommended by the board of directors. Dividends may only be made if, after the payment of the dividend, there is sufficient coverage for the company's restricted equity and the payment of dividends is justified, taking into consideration the equity required for the type of operations, the company's (or the group's when applicable) need for consolidation and liquidity as well as the company's (or the group's when applicable) financial position in general. The assessment shall be based on the most recently adopted balance sheet taking into consideration changes in the restricted equity which have occurred subsequent to the balance sheet date.

Each shareholder appearing in share register as of the record date for the dividend is entitled to receive the dividend distribution. Dividends are normally distributed to the shareholders through Euroclear Sweden.

Distribution of assets on liquidation

British Columbia

Under the BCBCA, the Corporation may apply to the court to supervise a voluntary liquidation. After the final accounts have been approved by the court, the liquidator will distribute any remaining assets of the Corporation, after paying or making provision for all the Corporation's liabilities, among the shareholders according to their respective rights.

Swedish

Under the *Swedish Companies Act*, a company can enter into voluntary liquidation following a resolution passed at the general meeting by a simple majority of the votes cast, unless otherwise provided in the articles of association of the company. All shares carry equal rights in a liquidation procedure unless otherwise provided for in the company's articles of association.

The *Swedish Companies Act* also stipulates that a company shall enter into compulsory liquidation procedure in a capital deficiency situation and in certain other situations.

Certain extraordinary corporate actions

British Columbia

Under the BCBCA, certain extraordinary corporate actions, such as certain amalgamations and continuations, and other extraordinary corporate actions, such as liquidations, dissolutions and arrangements, are required to be approved by special resolution. A special resolution is a resolution passed at a meeting by not less than two-thirds of the votes cast on the resolution or a resolution signed by all of the shareholders entitled to vote on that resolution. In certain cases, a special separate resolution to approve an extraordinary corporate action is also required to be approved separately by the holders of a separate class or series of shares.

Sweden

Under the *Swedish Companies Act*, a statutory merger requires a shareholder resolution passed at a general meeting. The majority requirements for a valid resolution depends on the type of companies involved, however never less than two-thirds of the votes cast and the shares represented at the meeting. A material change of the operations conducted by the company may require a change of the company's objects and purposes in the articles of association. See "Amendment to the articles".

Change of Control Restrictions

British Columbia

British Columbia law does not impose any change of control restrictions on the Corporation.

Sweden

Not applicable for Swedish companies with shares listed on a regulated market.

Mandatory takeover bids/squeeze-out rules

British Columbia

Under British Columbia law, an acquisition offer (defined as an offer made by a person or persons acting jointly or in concert to acquire shares of a company) is accepted if, within 4 months after the making of the offer, the offer is accepted regarding the shares by shareholders who, in the aggregate, hold at least 9/10 of those shares (other than shares already held at the date of the offer by the acquiring person or its affiliate). In such a case, the acquiring person may, within five months of making the offer, send written notice to any offeree who did not accept the offer that the acquiring person wants to acquire the offeree's shares.

Where such a notice is sent to an offeree, the acquiring person is entitled and bound to acquire all the offeree's shares involved in the offer for the same price and on the same terms contained in the acquisition offer (unless the court orders otherwise) on an application made by that offeree within two months of the date of the notice.

If a notice has been sent by an acquiring person and the court has not ordered otherwise, the acquiring person must, no earlier than two months after the date of the notice, send a copy of the notice to the subject company, and pay to the subject company the amount representing the price payable by the acquiring person for the shares referred to in the notice. On receiving a copy of the notice and such consideration, the subject company must register the acquiring person as a shareholder with respect to those shares.

If the acquiring person has not sent the notice within one month after becoming entitled to do so, the acquiring person must send a written notice to each offeree stating that the offeree, within 3 months after receiving the notice, may require the acquiring person to acquire that offeree's shares involved in the acquisition offer. If an offeree requires the acquiring person to acquire the offeree's shares, the acquiring person must acquire those shares for the same price and on the same terms contained in the acquisition offer.

Every acquisition offer for shares of more than one class of shares is deemed to be a separate acquisition offer for shares of each class of shares.

Sweden

Under Swedish law an obligation to launch a mandatory take-over bid applies when a party becomes the owner of 30% or more of the votes in a company with shares listed on a regulated market.

Under the *Swedish Companies Act*, a shareholder holding more than 90% of the shares in a company (majority shareholder) is entitled, on a compulsory basis, to buy-out the remaining shares of the other shareholders of the company. On the other hand, a minority shareholder is also, in such situation, entitled to compel the majority shareholder to purchase his or her shares.

Redemption provisions

British Columbia

Under the BCBCA, the Corporation may liquidate by a special resolution of the shareholders.

After giving the appropriate notice and adequately providing for the payment or discharge of all its obligations, the Corporation will distribute its remaining property, either in money or in kind, among its shareholders according to their respective rights.

Subject to the conditions in the BCBCA and the Corporation's articles, the Corporation may purchase or otherwise acquire any of its shares. The Corporation must not make a payment or provide any other consideration to purchase or otherwise acquire any of its shares if there are reasonable grounds for believing that (a) the Corporation is insolvent, or (b) making the payment would render the Corporation insolvent.

Notwithstanding this, but subject to the conditions in the BCBCA and the Corporation's articles, the Corporation may redeem, on the terms and in the manner provided in its articles, any of its shares that has a right of redemption attached to it. The Corporation must not make a payment or provide any other consideration to redeem any of its shares if there are reasonable grounds for believing that (a) the Corporation is insolvent, or (b) making the payment or providing the consideration would render the Corporation insolvent.

Sweden

Under the *Swedish Companies Act*, a company with shares listed on a regulated market is permitted to repurchase a maximum of 10% of all outstanding shares in the company. A resolution to repurchase shares must be taken either by shareholders holding not less than two-thirds of both the votes cast and the shares represented at the general meeting or, following authorization from the general meeting with same majority vote, by the board of directors.

A general meeting may also resolve upon the redemption of the company's shares through which the share capital of the company will be reduced. This is a formal and complex process, which as a main rule involves also notice to the company's creditors.

Amendment to the articles

British Columbia

Under the BCBCA and the articles of the Corporation, any amendment to the articles generally requires approval by special resolution, which is a resolution passed by not less than two-thirds of the votes cast on the resolution or a resolution signed by all of the shareholders entitled to vote on that resolution.

Sweden

Under the *Swedish Companies Act*, an amendment of the articles of association requires a shareholder resolution at a general meeting. The majority requirement for a valid resolution depends on the type of alteration. However, not less than two-thirds of the votes cast and of the shares represented at the meeting will be required. The board of directors is not allowed to make amendments to the articles of association. Any amendment to the articles will have to be registered with the Swedish Companies Registration Office.

Directors and the board of directors

Number of directors

British Columbia

Under the BCBCA, a public company must have at least three directors. The first directors of a company hold office as directors from the recognition of the company until they cease to hold office upon expiry of term, death or resignation of the director or removal by a special resolution of the shareholders.

Under the BCBCA and the articles of the Corporation, the directors may also appoint one or more additional directors, who shall also hold office for a term expiring at the end of the next annual meeting, provided that the total number of directors so elected shall not exceed one-third of the number of directors elected at the previous annual meeting.

Sweden

Under the *Swedish Companies Act*, the board of directors in a public company shall comprise not less than three members and the chairman of the board of directors may not be the managing director of the company. At least half of the directors shall be resident within the European Economic Area, unless otherwise approved by the Swedish Companies Registration Office. The actual number of board members shall be determined by a shareholders' meeting, within the limits set out in the company's articles of association.

For companies to which the Swedish corporate governance code applies, not more than one director may also be a senior executive of the relevant company or a subsidiary. In addition, a majority of the board members shall be independent of the company and its management and two of these members shall also be independent of major shareholders in the company.

Nomination, appointment and removal of directors

British Columbia

At every annual general meeting, the shareholders entitled to vote at the annual general meeting for the election of directors must elect a board of directors consisting of the number of directors set under the Corporation's articles. All the directors cease to hold office immediately before the election or appointment of directors at the next annual general meeting, but are eligible for re-election.

Under the BCBCA, the Corporation may remove a director before the expiration of the director's term in office by a special resolution, which is a resolution passed by not less than two-thirds of the votes cast on the resolution or a resolution signed by all of the shareholders entitled to vote on that resolution. However, there are a couple of exceptions. If the shareholders holding shares of a class or series of Common Shares have the exclusive right to elect or appoint one or more directors, a director so elected or appointed may only be removed by a special separate resolution of those shareholders. In addition, the articles of the Corporation provide that the directors may remove any director before the expiration of his or her term if the director is convicted of an indictable offence, or if the director ceases to be qualified to act as a director and does not promptly resign.

Sweden

Under Swedish law, the board of directors shall, except for any employee representatives, be elected by the shareholders at a general meeting, unless the articles of association provide otherwise. The members of the board of directors are usually elected for the period until the end of the first annual general meeting held after the year in which the directors were elected, unless a longer term of up to four financial years is set out in the articles of association. It is possible for a board member to be re-elected for a new term of office.

Companies to which the Swedish corporate governance code applies shall have a nomination committee. In addition to nominating directors, the nomination committee shall nominate the chairman of the board of directors and the auditors and shall also propose fees to each director and to the auditors. The nomination committee's proposals are to be presented in the notice of the general meeting and on the company's website. At the same time, the nomination committee is to issue a statement on the company's website explaining its proposals and providing more information about the candidates proposed for election or re-election. The statement is also to include an account of how the nomination committee has conducted its work and, for certain companies, a description of the diversity policy applied by the nomination committee in its work.

Under the Swedish corporate governance code, the annual general meeting of shareholders shall either appoint the members of a nomination committee or pass a resolution specifying how the members are to be appointed. The nomination committee shall have at least three members, one of whom is to be appointed committee chair. The majority of the members are to be independent of the company and its executive management. One of the independent members shall also be independent of the company and one shall be independent of the largest shareholders. Members of the board of directors may be members of the nomination committee but may not constitute a majority thereof. The chief executive officer and other senior executives may not be members of the nomination committee. Regardless of how they are appointed, members of the nomination committee are to promote the common interests of all shareholders in the company.

Remuneration

British Columbia

According to the articles of the Corporation, the directors are entitled to the remuneration for acting as directors, if any, as the directors may determine from time to time. That remuneration may be in addition to any salary or other remuneration paid to any officer or employee of the Corporation as such, who is also a director. The Corporation must reimburse each director for the reasonable expenses that he or she may incur in and about the business of the Corporation. If any director performs any professional or other services for the Corporation that in the opinion of the directors are outside the ordinary duties of a director, or if any director is otherwise specially occupied in or about the Corporation's business, he or she may be paid remuneration fixed by the directors, and such remuneration may be either in addition to, or in substitution for, any other remuneration that he or she may be entitled to receive.

Sweden

Under the *Swedish Companies Act*, the remuneration to the board of directors shall be determined by the general meeting of shareholders, specifying the amount for each director. For companies complying with the Swedish corporate governance code, the nomination committee's proposal to the general meeting of shareholders shall include a proposal regarding the remuneration to each member of the board.

In addition, the board of directors shall, pursuant to the Swedish corporate governance code, have a remuneration committee. The remuneration committee shall prepare the board of directors' resolutions regarding executive compensation and shall monitor and evaluate the company's principles and levels of remuneration to the executive management, including programs for variable compensation. The code also stipulates that variable compensation paid in cash to the executive management shall be subject to predetermined limits regarding the total outcome and that the board of directors in such cases shall consider (i) to make payment conditional on the performance proving to be sustainable over time, and (ii) to introduce the right to reclaim remuneration that has been paid on the basis of information which later proves to be manifestly misstated. Furthermore, all share and share-price related incentive schemes for the executive management shall be approved by a general meeting. The board of directors should not participate in such share and share-price related incentive schemes.

Powers of the board of directors

British Columbia

Subject to the BCBCA and the Corporation's articles, the directors of the Corporation must manage or supervise the management of the business and affairs of the Corporation. Directors of corporations governed by the BCBCA have fiduciary obligations to the corporation. Under the BCBCA, directors must act honestly and in good faith with a view to the best interests of the Corporation, exercise the care, diligence and skill that a reasonably prudent individual would exercise in comparable circumstances, act in accordance with the BCBCA and the regulations, and, subject to the preceding duties, act in accordance with the articles of the Corporation.

Sweden

Under the *Swedish Companies Act*, the board of directors is responsible for the organization of the company and the management of the company's affairs. The board of directors shall regularly assess the financial position of the company and ensure that the company's organization is structured in such a manner that accounting, management of funds and the company's finances in general are monitored in a satisfactory manner. Further, the board shall appoint a managing director and issue instructions to such managing director setting out the responsibilities of the board and managing director. The board shall also issue instructions in reporting obligations in order for the board to fulfill its duties.

The managing director is responsible for the day-to-day management of the company pursuant to guidelines and instructions issued by the board of directors. In addition, the managing director may, without authorization by the board of directors, take measures which, in light of the scope and nature of the company's operations, are of an unusual nature or of great significance, provided a decision by the board of directors cannot be awaited without significant prejudice to the company's operations. In such cases, the board of directors shall be notified as soon as possible of any measures taken. The managing director shall be resident within the European Economic Area, unless otherwise approved by the Swedish Companies Registration Office.

Right to indemnification

British Columbia

Under the BCBCA, the Corporation may indemnify a director or officer, a former director or officer, or another individual who acts or acted at the Corporation's request as a director or officer, or an individual acting in a similar capacity, of another entity (an "**Eligible Party**"), against all costs, charges and expenses, including an amount paid to settle an action or satisfy a judgment, actually and reasonably incurred by the individual in respect of a proceeding in which the individual is joined as a party or liable by reason of the Eligible Party's association with the Corporation or other entity. The Corporation must not indemnify an Eligible Party if (a) the Eligible Party did not act honestly and in good faith with a view to the best interests of the Corporation or the associated corporation; or (b) in the case of a proceeding other than a civil proceeding, the Eligible Party did not have reasonable grounds for believing that the Eligible Party's conduct in respect of which the proceeding was brought was lawful.

The BCBCA also allows the Corporation to pay the expenses actually and reasonably incurred by an Eligible Party, as they are incurred in advance of the final disposition of an eligible proceeding. The Corporation must not make such payments unless the Corporation receives a written undertaking from the Eligible Party that, if the Eligible Party does not fulfill the conditions noted in (a) and (b) above, the Eligible Party will repay the amounts advanced.

Under the articles of the Corporation, the Corporation may, subject to the BCBCA, indemnify any person and further must, subject to the BCBCA, indemnify a director or former director of the Corporation and his or her heirs and legal personal representatives against all judgments, penalties or fines awarded or imposed in, or an amount paid in settlement of, a legal proceeding or investigative action, whether current, threatened, pending or completed, in which a director or former director of the Corporation or any of the heirs and legal personal representatives of the director or former director, by reason of the director or former director being or having been director of the Corporation, is or may be joined as a party, or, is or may be liable for or in respect of a judgment, penalty or fine in, or expenses related to, the proceeding.

Sweden

The *Swedish Companies Act* does not contain any specific provisions requiring that the articles of association provide for indemnification of board members, officers or other persons. Instead, Swedish companies can have professional indemnity insurance in place for its board members and officers.

The annual general meeting of shareholders shall resolve on the discharge of the board of directors and managing director from liability. An action for damages on behalf of the company may be available in certain circumstances against a founder, board member, managing director, auditor or shareholder of the company. Such action may be brought if the majority, or a minority comprising owners of at least one-tenth of all shares in the company, has supported a general meeting resolution to bring an action for damages or, in the case of a director or managing director, have voted against a resolution on discharge from liability. The action for damages in favor of a company may also be conducted by owners (in their own name) of at least one-tenth of all shares.

A settlement on liability for damages for the company may be concluded only at a general meeting and only if owners of at least one-tenth of all shares in the company do not vote against the settlement proposed. However, if an action for damages is brought by a shareholder on behalf of the company, a settlement may not be reached without his or her consent.

Financial statements, auditor's reports, auditors and audit committee

British Columbia

Under the BCBCA, the directors of the Corporation must place before the shareholders at every annual general meeting: (a) comparative financial statements as prescribed, relating separately to the period that began on the date the corporation came into existence and ended not more than six months before the annual meeting or, if the corporation has completed a financial year, the period that began immediately after the end of the last completed financial year and ended not more than six months before the annual meeting, and the immediately preceding financial year; (b) any auditor's report on those financial statements; and (c) any further information respecting the financial position of the Corporation and the results of its operations required by the articles or any unanimous shareholder agreement.

A reporting issuer that is listed on the TSX is required to prepare and file on SEDAR its annual financial statements an annual MD&A, along with the report of the auditor, if any, on or before the earlier of (a) the 90th day after its financial year-end; and (b) the date of filing, in a foreign jurisdiction, its annual financial statements for the most recently completed financial year. A reporting issuer that is listed on the TSX is required to prepare and file on SEDAR its quarterly financial statements and interim MD&A on or before the earlier of (a) the 45th day after the interim period; and (b) the date of filing, in a foreign jurisdiction, its interim financial statements for the most recently completed interim period.

Under the BCBCA, a public company or financial institution must, at the first meeting held on or after each annual reference date, elect an audit committee from among their number. An audit committee must be composed of at least three directors, and a majority of the members of the committee must not be officers or employees of the company or an affiliate of the company. The primary responsibility for the Corporation's financial reporting, accounting systems and internal controls is vested in senior management and is overseen by the directors of the Corporation. The audit committee is a standing committee of the board, established to assist it in fulfilling its responsibilities in this regard. The audit committee must, in addition to or as part of any responsibilities assigned to it under the BCBCA, review and report to the directors on (a) the annual or interim financial statements of the company; and (b) the auditor's report if any, prepared in relation to those financial statements, before any of the preceding documents are published. While it is management's responsibility to design and implement an effective system of internal control, it is the responsibility of the audit committee to ensure that management has done so.

Sweden

Under the *Swedish Companies Act*, the annual general meeting shall adopt the balance sheet and the profit and loss statement. Further, it makes decisions in respect of the disposition of the company's profit or loss (such as payment of dividends). A company with shares listed on a regulated market is required to make its annual reports public not later than four months after the end of each financial year.

The annual report, together with the auditor's report, must be presented at the annual general meeting which according to the *Swedish Companies* Act is to be held within six months after the end of the financial year.

Auditors are appointed by the general meeting of shareholders, whereby a registered accounting firm may be appointed as auditor. The Swedish corporate governance code requires that the board of directors shall at least once annually meet the company's auditor without any member of the executive management present.

Companies with shares listed on a regulated market must have an audit committee, unless the assignments of such committee are carried out by the board of directors. The members of the committee may not be employees of the company. At least one member must be independent and have accounting or auditing proficiency. The audit committee shall appoint one of its members as chairperson. The audit committee shall, without any impact otherwise on the responsibility and tasks of the board of directors (i) monitor the company’s financial reporting and provide recommendations and proposals to ensure the reliability of the reporting; (ii) in respect of the financial reporting, monitor the efficiency of the company’s internal controls, internal audits, and risk management; (iii) keep itself informed regarding audit of the annual report and group accounts as well as regarding the conclusions of the Supervisory Board of Public Accountants quality controls; (iv) inform the board of directors of the result of the audit and the way in which the audit contributed to the reliability of the financial reporting, as well as the function filled by the committee; (v) review and monitor the impartiality and independence of the auditor and, in conjunction therewith, pay special attention to whether the auditor provides the company with services other than auditing services; and (vi) assist in conjunction with preparation of proposals to the general meeting’s resolution regarding election of an auditor. Where the company has a nominating committee in which the shareholders have a significant influence, the company may instead instruct the nominating committee to submit a proposal to the general meeting regarding the election of an auditor.

Corporate governance reports and website

British Columbia

If management of a company listed on the TSX solicits a proxy from a security holder of the company for the purpose of electing directors to the company’s board of directors, the company must provide corporate governance information in its management information circular (usually referred to as a proxy circular). The circular is distributed together with the notice of the relevant shareholders’ meeting and is filed on SEDAR. There is no requirement to include the circular on the company’s website, unless the company is relying on certain notice-and-access provisions in *National Instrument 54-101 – Communication with Beneficial Owners of Securities of a Reporting Issuer*, nor is there a requirement to have the circular reviewed by the company’s auditors. The content of the circular is regulated by Canadian securities laws, and the circular must, among other things, include a discussion of the company’s compliance with Canadian corporate governance principles.

The Corporation may include information useful to investors on its website; however, all such information must comply with relevant securities laws regarding permitted, required and restricted disclosure.

Sweden

Swedish companies with shares listed on a regulated market are obliged by law to prepare an annual corporate governance report with information about, among other things, the key elements of the internal control systems, information about major shareholders, information about the board of directors and its committees and any mandates for the board of directors to issue new shares or acquire treasury shares.

The boards of certain companies are also to prepare an annual sustainability report with information to shareholders and the capital market on sustainability issues that is necessary for an understanding of the company’s development, position and results, as well as the environmental impact of its operations.

The Swedish corporate governance code requires that the company clearly (i) states which rules of the Swedish corporate governance code it has not complied with, (ii) explains the reasons for each case of non-compliance and (iii) describes the solution it has adopted instead. The company must also have a section of its website devoted to corporate governance matters, where the company’s 10 most recent corporate governance reports are to be posted, together with, among other things, the articles of association, information about upcoming shareholders’ meetings and minutes from general meetings held during the past three years. Companies that publish a sustainability report must make available on their websites the ten most recent years’ sustainability reports, along with the part of the auditor’s report which covers the sustainability report or the auditor’s written statement on the sustainability report.

Shareholder remedies and special audit rights

British Columbia

The most common shareholder remedies under the BCBCA are the oppression remedy, derivative actions, dissent rights and court-appointed inspections.

Oppression Remedy

A shareholder may apply to the court for an order on the ground (a) that the affairs of the company are being or have been conducted, or that the powers of the directors are being or have been exercised, in a manner oppressive to one or more of the shareholders, including the applicant, or (b) that some act of the company has been done or is threatened, or that some resolution of the shareholders has been passed or is proposed, that is unfairly prejudicial to one or more of the shareholders, including the applicant. In this case, a "shareholder" means (a) a registered or beneficial owner of a share of the company; and (b) any other person whom the court considers to be an appropriate person to make such an application.

In connection with such an application, the court may make any interim or final order it considers appropriate, subject to the conditions in the BCBCA, including an order (a) directing or prohibiting any act; (b) regulating the conduct of the company's affairs; (c) appointing a receiver or receiver manager; (d) directing an issue or conversion or exchange of shares; (e) appointing directors in place of or in addition to all or any of the directors then in office; (f) removing any director: (g) directing the company to purchase some or all of the shares of a shareholder and, if required, to reduce its capital in the manner specified by the court; (h) directing a shareholder to purchase some or all of the shares of any other shareholder; (i) directing the company or any other person to pay to a shareholder all or any part of the money paid by that shareholder for shares of the company;(j) varying or setting aside a transaction to which the company is a party and directing any party to the transaction to compensate any other party to the transaction; (k) varying or setting aside a resolution; (l) requiring the company, within a time specified by the court, to produce to the court or to an interested person financial statements or an accounting in any form the court may determine; (m) directing the company to compensate an aggrieved person; (n) directing correction of the registers or other records of the company; (o) directing that the company be liquidated and dissolved, and appointing one or more liquidators, with or without security; (p) directing that an investigation be made under the BCBCA; (q) requiring the trial of any issue; or (r) authorizing or directing that legal proceedings be commenced in the name of the company against any person on the terms the court directs.

Derivative Actions

A "complainant", which includes any individual described as a "shareholder" above as well as any director of the Corporation, may, with leave of the court, prosecute a legal proceeding in the name and on behalf of the Corporation to enforce a right, duty or obligation owed to the company or to obtain damages for any breach of such right, duty or obligation. With leave of the court, a complainant may also, in the name and on behalf of the Corporation, defend a legal proceeding brought against the Corporation. In connection with such an action brought or defended, the court may grant leave where reasonable efforts have been made, notice of the application for leave has been given to the company and to any other appropriate party, the complainant is acting in good faith and it appears to the court that it is in the best interests of the Corporation. In connection with such an action brought or defended, the court may make any order it considers appropriate, including an order that a person to whom costs are paid repay to the Corporation some or all of those costs; the Corporation or any other party to the proceeding indemnify the complainant or the person controlling the conduct of the legal proceeding; or the complainant indemnify one or more of the Corporation, a director of the Corporation and an officer of the Corporation for expenses, including legal costs, that they incurred as a result of the legal proceeding.

Dissent Rights

In certain circumstances, shareholders of a BCBCA company are entitled to dissent from some fundamental action undertaken by the company and demand to be paid fair value for their shares. Examples of these circumstances include amalgamations, resolutions to authorize or ratify the sale, lease or other disposition of all or substantially all of the company's undertaking, continuation of the company into a jurisdiction other than British Columbia or a resolution to alter the articles of the company to add, change or remove any restriction on the business or businesses that the corporation may carry on. Procedures for dissenting are complex and failure to strictly comply with the procedures may result in the loss of all dissent rights. If the procedures are followed, the dissenter's shares must then be purchased by the corporation at fair market value. In the event that the parties cannot agree on what constitutes fair market value, either the company or the dissenter can apply to court to determine the appropriate fair market value.

Inspections

One or more shareholders who, in the aggregate, hold at least one-fifth of the issued Common Shares may apply to the court to appoint an inspector to conduct an investigation of the Corporation and determine the manner and extent of the investigation. The court may make such an order if it appears to the court that there are reasonable grounds for believing that (a) the affairs of the company are being or have been conducted, or the powers of the directors are being or have been exercised, in a manner that is oppressive or unfairly prejudicial to one or more shareholders, including the applicant, (b) the business of the company is being or has been carried on with intent to defraud any person, (c) the Corporation was formed for a fraudulent or unlawful purpose or is to be dissolved for a fraudulent or unlawful purpose, or (d) persons concerned with the formation, business or affairs of the Corporation have, in connection with it, acted fraudulently or dishonestly. The powers of the inspector will be set out in the enabling court order, such powers including the power to examine under oath any person who is or was a director, receiver, receiver manager, officer, employee, banker, auditor or agent of the Corporation or any of its affiliates in relation to the affairs, management, accounts and records of or relating to the Corporation. In addition, a person so described must, on the request of an inspector so appointed, (a) produce, for the examination of the inspector, each accounting record and each other record relating to the Corporation or any of its affiliates that is in the custody or control of that person, and give to the inspector every assistance in connection with the investigation that that person is reasonably able to give.

Sweden

Special examination

Under the *Swedish Companies Act*, a shareholder may submit a proposal for an examination through a special examiner. The proposal shall be submitted to an annual general meeting, or to any general meeting for which the matter is included in the notice to attend the general meeting. The scope of the examination shall be defined in the proposal, and may relate to the company's management and accounts during a specific period of time in the past, or certain measures or circumstances within the company. If the proposal is supported by owners of at least one-tenth of all shares, or at least one-third of the shares represented at the general meeting, the Swedish Companies Registration Office shall appoint one or more examiners. The Swedish Companies Registration Office shall give the company's board of directors the opportunity to submit its comments prior to the appointment of a special examiner. The examiner shall submit a report regarding the examination, which shall be made available to the shareholders and presented at the general meeting. Persons who are no longer shareholders, but who were included in the voting register prepared for the general meeting at which the issue of the appointment of a special examiner was addressed, shall also have the right to read the report.

Minority shareholders' auditor

A shareholder may propose that a minority shareholders' auditor shall be appointed. The proposal shall be submitted to a general meeting at which the election of auditors is to take place, or at a general meeting where the proposal is included in the notice to attend the general meeting. The Swedish Companies

Registration Office shall appoint such auditor upon the request of any shareholder, if the proposal is supported by at least one-tenth of all shares in the company, or at least one-third of the shares represented at the general meeting. The company's board of directors shall be afforded the opportunity to comment prior to the appointment of an auditor. The appointment shall relate to the period of time up to and including the next annual general meeting. The auditor shall participate in the audit together with the other auditors.

Corporation's obligation to disclose changes in its share capital

British Columbia

The Corporation is required to file a report with the TSX within 10 days at the end of each month in which any change to the number of outstanding or reserved listed securities has occurred (including a reduction in such number that results from a cancellation or redemption of securities).

Sweden

The Corporation is required, under Swedish law, to report any changes in the number of shares or votes. Such disclosure shall be made on the last trading day of the calendar month in which the increase or decrease of shares or votes occurred.

Distribution of information to the Canadian and Swedish markets

The content and format of the disclosure obligations of Canadian reporting issuers is mandated under National Instrument 51-102 – *Continuous Disclosure Obligations* and other regulations under Canadian securities laws, as well as the regulations applicable to TSX-listed issuers. The Canadian Securities Administrators have implemented National Policy 51-201 – *Disclosure Standards* to provide guidance on best disclosure practices in order that everyone investing in securities will have equal access to information that may affect their investment decisions. Canadian securities legislation prohibits a reporting issuer from selective disclosure or informing any person or company in a special relationship with a reporting issuer, other than in the necessary course of business, of a material fact or a material change before that material information has been generally disclosed. Securities legislation also prohibits anyone in a special relationship with a reporting issuer from purchasing or selling securities of the reporting issuer with knowledge of a material fact or material change about the issuer that has not been generally disclosed.

The Corporation maintains a disclosure policy to ensure that communications to the investing public about the Corporation are timely, factual, accurate, complete, broadly disseminated and, where necessary, filed with regulators in accordance with applicable securities laws. The disclosure policy applies to all directors, officers and employees of the Corporation, including those individuals authorized to speak on behalf of the Corporation.

The Corporation will be subject to the rules on disclosure of the Nasdaq Rulebook for Issuers and MAR. The Corporation will be required to handle inside information in accordance with MAR and disclose inside information as soon as possible, but, if some conditions are met, the disclosure may be delayed. If the Corporation delays the disclosure of inside information, the Corporation must document when the inside information arose and when the decision to delay the disclosure was taken. The reasons for the delay must also be documented. When the inside information is later made public, the Corporation must inform the Swedish Financial Supervisory Authority (the "**SFSA**") of the decision to delay the disclosure and, upon request by the SFSA, provide an explanation of the reasons for the delay.

Financial reports and press releases will be published on the Corporation's website at www.international-petroleum.com and by its news distributors. Financial reports and press releases are also filed under the corporation's profile on SEDAR at www.sedar.com. The information will be in English only.

Swedish insider reporting rules

In addition to any reporting requirements under applicable Canadian laws, persons discharging managerial responsibilities in a company whose shares are subject to trading on a regulated market (or for which a request for admission to trading on a regulated market has been made), and persons closely associated to such persons, are required to report their transactions of shares and other financial instruments to the SFSA as well as to the company. Such reporting shall be made in accordance with MAR. In addition, MAR stipulates a trading ban for persons discharging managerial responsibilities in such companies during a closed period of 30 calendar days before the announcement of an interim financial report or a year-end report.

Furthermore, a shareholder in a company with shares listed on a regulated market must notify the company and the SFSA of a change in a holding if the change involves the percentage of all shares in the listed company or of the votes for all shares in the listed company to which the holding corresponds, reaches or exceeds limits of 5%, 10%, 15%, 20%, 25%, 30%, 50%, 66 2/3% and 90%, or falls below any of these limits. Should such a company hold shares in itself, the company must notify the stock exchange in the event of it transferring its shares and also publish information thereof under certain circumstances.

DOCUMENTS INCORPORATED BY REFERENCE

The following documents form part of the prospectus and are incorporated by reference:

- the audited combined carve-out from Lundin Petroleum financial statements for the Oil and Gas Assets for the financial years ended December 31, 2015 and 2016, together with the auditor's report thereon, included in the Corporation's company description for the listing on Nasdaq First North as Appendix "B" (pages B1 – B30);[2]

- the Corporation's audited consolidated financial statements for the financial years ended December 31, 2017 and 2016, together with the auditor's report thereon;[3]

- the Corporation's year end 2017 MD&A;[4]

- the Corporation's unaudited interim condensed consolidated financial statements for the three months ended March 31, 2018 (including prior period comparative information), together with the auditor's review report thereon;[5] and

- the Corporation's Q1 2018 MD&A.[6]

Copies of the documents incorporated herein by reference may be obtained on request without charge from the Corporation at 5, chemin de la Pallanterie, 1222 Vésenaz, Switzerland, and is also available electronically on the Corporation's website at www.international-petroleum.com and/or at www.sedar.com.

DOCUMENTS AVAILABLE FOR INSPECTION

The following documents are also available for inspection by physical means at the Corporation's office (see "*Addresses*"):

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[2] www.international-petroleum.com/investors/corporate-filings-sedar/

[3] https://www.international-petroleum.com/investors/financial-statements/

[4] https://www.international-petroleum.com/investors/financial-statements/

[5] https://www.international-petroleum.com/investors/financial-statements/

[6] https://www.international-petroleum.com/investors/financial-statements/

- the Corporation's articles of incorporation and certificate of incorporation; and
- historical financial information for the Corporation's subsidiaries for the financial years 2015, 2016 and 2017.

GLOSSARY

In this prospectus, unless otherwise indicated or the context otherwise requires, the following terms shall have the meaning set forth below:

Selected Defined Terms

"**2018 Plan**" means the proposed Performance and Restricted Share Plan

"**Acquisition**" means the Corporation's acquisition of the Suffield Assets.

"**affiliate**" has the meaning ascribed thereto in MI 62-104.

"**BCBCA**" means the *Business Corporations Act* (British Columbia), as amended, including the regulations promulgated thereunder.

"**Board**" means the board of directors of the Corporation.

"**Brent crude**" is a global market benchmark price for light sweet crude oil.

"**Cenovus**" means Cenovus Energy Inc., the holder of the Suffield Assets prior to the completion of the Acquisition.

"**CEO**" means Chief Executive Officer.

"**CFO**" means Chief Financial Officer.

"**Class A Preferred Shares**" means the Class A Preferred Shares.

"**Class B Preferred Shares**" means the Class B Preferred Shares.

"**Common Shares**" means common shares of the Corporation.

"**Contribution and Transfer Agreements**" means the contribution and transfer agreements between Lundin Petroleum, the Corporation and certain affiliates, pursuant to which the Oil and Gas Assets will be transferred to the Corporation.

"**Corporate Governance Guidelines**" means the series of guidelines for effective corporate governance set forth in National Policy 58-201 — *Corporate Governance Guidelines*.

"**Corporation**" means International Petroleum Corporation, and references to the "Corporation" include the IPC Subsidiaries where the context requires.

"**Credit Facilities**" means the credit facilities entered into by the Corporation and certain of the IPC Subsidiaries, generally on the terms set out in this prospectus.

"**Discontinued Operations**" means the discontinued operations owned by the Corporation located in Indonesia, Tunisia, Cambodia and the Republic of Congo.

"**ERCE**" means ERC Equipoise Limited, independent petroleum consultants.

"**ERCE Report**" means the reserves and resource report relating to the Oil and Gas Assets in France, Malaysia and the Netherlands, dated February 21, 2018, by ERCE.

"**Euroclear Sweden**" means Euroclear Sweden AB, the entity which keeps the CSD register in Sweden.

"**FPSO**" means floating, production, storage and offloading.

"**FPSO Bertam**" means the FPSO used in the Bertam field, Malaysia.

"**Group**" means IPC (as parent company) and its subsidiaries.

"**IAS**" means the International Accounting Standards.

"**IASB**" means the International Accounting Standards Board.

"**ISA**" means the International Standards on Auditing.

"**IFRS**" means the International Financial Reporting Standards, as issued by the IASB.

"**Initial Oil and Gas Assets**" means the oil and gas exploration and production properties and related assets formerly of Lundin Petroleum located in Malaysia, France and the Netherlands.

"**IPC**" means International Petroleum Corporation.

"**IPC Alberta Credit Facilities**" means credit facilities entered into by IPC Alberta Ltd., generally on the terms set out in this prospectus.

"**IPC Subsidiaries**" means each of International Petroleum SA, International Petroleum Holding Corporation, International Petroleum Cooperatief U.A., Lundin Services Ltd., IPBV, IPC Services BV (formerly Lundin Services BV), Ikdam Production SA, Jet Arrow SA (now liquidated), IPC Ventures I BV (formerly Lundin Ventures XVII BV), IPC Ventures II BV (formerly Lundin Ventures XVIII BV), IPC Ventures III BV (formerly Lundin Ventures XIX BV), IPC Petroleum Holdings SA (formerly Lundin Holdings SA), IPC Petroleum France SA (formerly Lundin International SA), IPC Petroleum Gascogne SNC (formerly Lundin Gascogne SNC), IPC Netherlands BV (formerly Lundin Netherlands BV), IPC Netherlands Facilities BV (formerly Lundin Netherlands Facilities BV), Lundin Marine BV, Lundin Marine SARL (now liquidated), Lundin Tunisia BV, IPC SEA Holding BV (formerly Lundin SEA Holding BV), IPC Malaysia BV (formerly Lundin Malaysia BV), IPC Venturs IV BV (formerly Lundin Cambodia BV), Lundin Rangkas BV, Lundin Gurita BV, Lundin Baronang BV and Lundin Cakalang BV.

"**IPC Transitional PSP**" means a one-time transitional performance share plan implemented by the Corporation in connection with the Spin-Off incorporating the terms described herein.

"**IPC Transitional RSP**" means a one-time transitional restricted share plan implemented by the Corporation incorporating the terms described herein.

"**ISIN**" means International Securities Identification Number.

"**Lundin Petroleum**" means Lundin Petroleum AB.

"**Lundin Petroleum PSP**" means the Lundin Petroleum Performance Share Plan.

"**Lundin Petroleum Unit Bonus Plan**" means the Lundin Petroleum unit bonus plan.

"**MAR**" means Regulation (EU) no 596/2014 of the European Parliament and of the Council of April 16, 2014 on market abuse (market abuse regulation) and repealing Directive 2003/6/EC of the European Parliament and of the Council and Commission Directives 2003/124/EC, 2003/125/EC and 2004/72/EC.

"**McDaniel**" means McDaniel & Associates Consultants Ltd.

"**McDaniel Report**" means the reserves and resource report relating to the Oil and Gas Assets in Canada, dated February 22, 2018, by McDaniel.

"**MD&A**" means management's discussion and analysis.

"**MI 62-104**" means Multilateral Instrument 62-104 – *Take-Over Bids and Issuer Bids*, as amended from time to time.

"**Nasdaq First North**" means the multilateral trading facility Nasdaq First North operated by Nasdaq Stockholm AB.

"**Nasdaq Stockholm**" means the regulated market Nasdaq Stockholm operated by Nasdaq Stockholm AB.

"**NI 58-101**" means National Instrument 58-101 – *Disclosure of Corporate Governance Practices*, as amended from time to time.

"**Oil and Gas Assets**" means the oil and gas exploration and production properties and related assets formerly of Lundin Petroleum located in Malaysia, France and the Netherlands and the oil and gas exploration and production properties and related assets owned by IPC in Canada.

"**OPEC**" means the Organization of the Petroleum Exporting Countries.

"**Preferred Shares**" means preferred shares in the capital of the Corporation.

"**PSC**" means production sharing contract.

"**PSC Contractor**" means the party to a PSC.

"**PSU**" means performance share units under the 2018 Plan.

"**proxy holder**" means, in relation to voting rights under the BCBCA, someone appointed by a registered shareholder to vote his or her shares.

"**Redemption Amount**" means a redemption price or retraction price (as applicable) of $1.00 per share (as adjusted in accordance with the articles of the Corporation).

"**Reorganization**" means the internal reorganization of Lundin Petroleum pursuant to which, among other things, the Corporation became the direct or indirect owner of a number of the subsidiaries of Lundin Petroleum.

"**RSU**" means restricted share units under the 2018 Plan.

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval.

"**SFSA**" means the Swedish Financial Supervisory Authority.

"**Spin-Off**" means the distribution of all of the Common Shares by Lundin Petroleum on a *pro rata* basis to all of its shareholders which was completed with a record date of April 24, 2017.

“**Stock Option Plan**” means the Corporation’s stock option plan.

“**Suffield Assets**” or the “**Oil and Gas Assets in Canada**” means the acquired Suffield area oil and gas assets in southern Alberta, Canada.

“**TSX**” means the Toronto Stock Exchange.

“**TTF**” means the Title Transfer Facility.

“**US**” means the United States of America.

Selected Defined Oil and Gas Terms

“**AECO**” means the daily average benchmark price for natural gas at the AECO hub in southeast Alberta.

“**API**” means the American Petroleum Institute.

“**API gravity**” or “**ºAPI**” means the American Petroleum Institute gravity expressed in degrees in relation to liquids, which is a measure of how heavy or light a petroleum liquid is compared to water. If a petroleum liquid’s API gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier than water and sinks. API gravity is thus a measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids.

“**Best Estimate**” means the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50% confidence level that the actual quantities recovered will equal or exceed the estimate.

“**COGE Handbook**” means the Canadian Oil Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum.

“**Cumulative Production**” means the cumulative quantity of petroleum that has been recovered at a given date.

“**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.

“**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 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.

“**development costs**” means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"**Discovered Petroleum Initially-In-Place**" or "**DPIIP**" means that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially-in-place includes production, reserves, and contingent resources; the remainder is categorized as unrecoverable.

"**Empress**" means the benchmark price for natural gas at the Empress point at the Alberta/Saskatchewan border.

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

"**gross**" means:

(a) in relation to an entity's interest in production and reserves, its "company gross reserves", which are such entity's working interest (operating and non-operating) before deduction of royalties and without including any royalty interest of such entity;

(b) in relation to wells, the total number of wells in which an entity has an interest; and

(c) in relation to properties, the total area of properties in which an entity has an interest.

"**natural gas liquids**" or "**NGLs**" means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

"**net**" means:

(a) in relation to an entity's interest in production and reserves, such entity's interest (operating and non-operating) after deduction of royalties obligations, plus the entity's royalty interest in production or reserves;

(b) in relation to wells, the number of wells obtained by aggregating an entity's working interest in each of its gross wells; and

(c) in relation to the Corporation's interest in a property, the total area in which an entity has an interest multiplied by the working interest owned by it.

"**Netback**" means all revenues derived from bringing one unit of oil to the marketplaces less all costs associated therewith and has been calculated by subtracting royalties and "operating costs" (as defined in the COGE Handbook).

"**NI 51-101**" means National Instrument 51-101 – *Standards of Disclosure for Oil Activities*.

"**51-101CP**" means Companion Policy 51-101 – *Standards of Disclosure for Oil and Gas Activities*.

"**PDP Reserves**" means proved developed producing 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 2P 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.

"**Reserve Life Index**" or "**RLI**" is calculated by dividing year-end reserves by annual production.

"**Reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.

"**resource play**" refers to drilling programmes targeted at regionally distributed crude oil or natural gas accumulations; successful exploitation of these reservoirs is dependent upon technologies such as horizontal drilling and multi-stage fracture stimulation to access large rock volumes in order to produce economic quantities of oil or natural gas.

"**Total Petroleum Initially-in-Place**" means that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered.

"**undeveloped reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

"**Unrecoverable Discovered Petroleum Initially-In-Place**" or "**Unrecoverable DPIIP**" is that portion of DPIIP quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

"**Working Interest"** or **"WI**" means the Corporation's total working interest share before deduction of royalties and including any royalty interests.

"**2P Reserves**" means Proved plus Probable Reserves.

"**3P Reserves**" means Proved plus Probable plus Possible Reserves.

ADDRESSES

The Corporation	International Petroleum Corporation Suite 2000, 885 West Georgia Street Vancouver, BC V6C 3E8 Canada Tel +1 604 689 7842
The Corporation's statutory auditor	PricewaterhouseCoopers AG St Jakobs-Strasse 25 Postfach, CH-4002 Basel, Switzerland
Swedish legal counsel	Gernandt & Danielsson Advokatbyrå KB Hamngatan 2, P.O. Box 5747 114 87 Stockholm Sweden
Central securities depositories	Euroclear Sweden AB P.O. Box 191 Klarabergsviadukten 63 Stockholm 101 23 Sweden
The Corporation's independent qualified reserves and resource evaluator (for the Initial Oil and Gas Assets)	ERC Equipoise Ltd. 6th Floor Stephenson House 2 Cherry Orchard Road London, Croydon CR0 6BA United Kingdom
The Corporation's independent qualified reserves and resource evaluator (for the Oil and Gas Assets in Canada)	McDaniel & Associates Consultants Ltd. 2200, 255 – 5th Avenue SW Bow Valley Square 3 Calgary, Alberta T2P 3G6