International Petroleum Corporation

Annual Information Form

For the year ended December 31, 2019

Dated: March 24, 2020

International Petroleum Corp.

Contents

GLOSSARY OF TERMS

"**AIF**" or "**Annual Information Form**" means this Annual Information Form prepared for the year ended December 31, 2019 and dated March 24, 2020.

"**Audited Financial Statements**" means the audited consolidated financial statements of the Corporation for the year ended December 31, 2019.

"**BlackPearl**" means BlackPearl Resources Inc.

"**BlackPearl Acquisition**" means the acquisition by way of plan of arrangement between IPC and BlackPearl by which IPC acquired all of the issued and outstanding shares of BlackPearl.

"**Board**" means the Corporation's Board of Directors.

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time.

"**Common Shares**" means the common shares in the capital of International Petroleum Corporation.

"**ERCE**" means ERC Equipoise Ltd.

"**FPSO**" means floating production storage and offloading vessel.

"**Granite**" means Granite Oil Corp.

"**Granite Acquisition**" means the acquisition by way of plan of arrangement between IPC and Granite by which IPC acquired all of the issued and outstanding shares of Granite.

"**Group**" means International Petroleum Corporation and its subsidiaries, or any one or more of them.

"**IFRS**" means the International Financial Reporting Standards as issued by the International Accounting Standards Board and the IFRS Interpretations Committee.

"**IPC**" or the "**Corporation**" means International Petroleum Corporation.

"**MCR**" means the material change report dated February 11, 2020 filed by the Corporation in respect of certain reserves and resource information, including reserves and resources attributable to the Granite Acquisition.

"**MD&A**" means the Management's Discussion and Analysis of the Corporation for the year ended December 31, 2019.

"**NASDAQ Stockholm**" means the Nasdaq Stockholm Stock Exchange in Sweden.

"**NI 51-101**" means National Instrument 51-101 — Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators.

"**PSC**" means production sharing contract.

"**SEDAR**" means the Canadian Securities Administrator's System for Electronic Document Analysis and Retrieval.

"**Spin-Off**" means the transaction in 2017 under which Lundin Petroleum AB spun-off its oil and gas assets in Malaysia, France and the Netherlands into the Corporation and distributed the Common Shares, on a pro-rata basis, to Lundin Petroleum shareholders.

"**Sproule**" means Sproule Associates Limited.

"**TSX**" means the Toronto Stock Exchange in Canada.

OTHER SUPPLEMENTARY INFORMATION

Abbreviations

CAD or CA$	Canadian dollar
EUR or €	Euro
USD or US$	United States dollar

Oil related terms and measurements

AECO	The daily average benchmark price for natural gas at the AECO hub in southeast Alberta
°API	An indication of the specific gravity of crude oil measured on the API (American Petroleum Institute) gravity scale
ASP	Alkaline surfactant polymer (an EOR process)
bbl	Barrel (1 barrel = 159 litres)
boe[(1)]	Barrels of oil equivalents
boepd	Barrels of oil equivalents per day
bopd	Barrels of oil per day
Bscf	Billion standard cubic feet
CHOPS	Cold heavy oil production with sand
Empress	The benchmark price for natural gas at the Empress point at the Alberta/Saskatchewan border
EOR	Enhanced oil recovery
Mbbl	Thousand barrels
MMbbl	Million barrels
Mboe	Thousand barrels of oil equivalents
Mboepd	Thousand barrels of oil equivalents per day
Mbopd	Thousand barrels of oil per day
MMboe	Million barrels of oil equivalents
Mcf	Thousand cubic feet
NGL	Natural gas liquid
SAGD	Steam assisted gravity drainage (a thermal recovery process)
WTI	West Texas Intermediate (a light oil reference price)
WCS	Western Canadian Select (a heavy oil reference price)

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

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This AIF 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 AIF are expressly qualified by this cautionary statement. Forward-looking statements speak only as of the date made, 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.

In 2020, the Coronavirus (Covid-19) and the restrictions and disruptions related to it, as well as the actions of producers such as Saudi Arabia and Russia, have had a drastic adverse effect on the world demand for, and prices of, oil and gas as well as the market price of the shares of oil and gas companies generally. These factors are beyond the control of the Corporation and it is difficult to assess how these, and other factors, will continue to affect the Corporation and the market price of the Common Shares. In light of the current situation, as at the date of this AIF, the Corporation continues to review and assess its business plans and assumptions regarding the business environment, as well as its estimates of future production, cash flows, operating costs and capital expenditures.

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:

- The intention and ability to continue to implement our strategies to build long-term shareholder value;
- The intention to review future potential growth opportunities;
- The ability of our portfolio of assets to provide a solid foundation for organic and inorganic growth;
- The contingent resource base in place to provide the feedstock to add to reserves in the future;
- The continued facility uptime and reservoir performance in our areas of operation;
- Future development potential of the Suffield operations, including future oil drilling and gas optimization programs, the ability to offset natural declines and the N2N EOR development project;
- Further conventional oil drilling in Canada, including the ability of such drilling to identify further drilling or development opportunities;
- Development of the Blackrod project in Canada, including continued current operations at the project and steam injection in the third well pair;
- The results of the facility optimization program, the work to debottleneck the facilities and injection capability and the F-Pad production, as well as water intake and steam generation issues, at Onion Lake Thermal;
- Addition of another drilling pad at Onion Lake Thermal and the production resulting from such pad;
- The ability of IPC to achieve and maintain current and forecast production and take advantage of production growth and development upside opportunities related to the assets acquired in the Granite Acquisition;
- The ability of existing infrastructure acquired in the Granite Acquisition to enable EOR projects, as well as capacity to allow for potential further field development opportunities;
- The timing and success of the Villeperdue West development project, including drilling and related production rates as well as future phases of the Vert La Gravelle redevelopment project, and other organic growth opportunities in France;
- Future development potential of Triassic reservoirs in France and the ability to maintain current and forecast production in France;
- The ability of IPC to achieve and maintain current and forecast production in Malaysia and the ability to identify, mature and drill additional infill drilling locations;
- The success and timing of remedial works in respect of the A-15 well in Malaysia;
- The ability of IPC to acquire further Common Shares under the share repurchase program, including the timing of any such purchases;
- The return of value to IPC’s shareholders as a result of the share repurchase program;
- 2020 production range, operating costs and capital expenditure estimates;
- Estimates of future production, cash flows, operating costs and capital expenditures that are based on IPC’s current business plans and assumptions regarding the business environment, which are subject to change;
- Potential further acquisition opportunities;
- Estimates of reserves;
- Estimates of contingent resources;
- The ability to generate free cash flows and use that cash to repay debt and to continue to deleverage; and
- Future drilling and other exploration and development activities.

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

The forward-looking statements are based on certain key expectations and assumptions made by IPC, including expectations and assumptions concerning: prevailing commodity prices and currency exchange rates; applicable royalty rates and tax laws; interest rates; future well production rates and reserve and contingent resource volumes; operating costs; the timing of receipt of regulatory approvals; the performance of existing wells; the success obtained in drilling new wells; anticipated timing and results of capital expenditures; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the successful completion of acquisitions and dispositions; the benefits of acquisitions; the state of the economy and the exploration and production business in the jurisdictions in which IPC operates and globally; the availability and cost of financing, 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 fluctuations, including those experienced in 2020;
- Interest rate and exchange 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. See also “Risk Factors”.

References may be made in this AIF to “free cash flow” (FCF), “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 FCF, OCF, EBITDA, operating costs and net debt/net cash that may be used by other public companies. Management believes that FCF, OCF, EBITDA, operating costs and net debt/net cash are useful supplemental measures that may assist shareholders and investors in assessing the cash generated by and the financial performance and position of the Corporation. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-IFRS measure is presented in the MD&A under “Non-IFRS Measures”.

Additional information on these and other factors that could affect IPC, or its operations or financial results, are included in the Audited Financial Statements, the MCR, the MD&A and other reports on file with applicable securities regulatory authorities, including previous financial reports, management’s discussion and analysis and material change reports, which may be accessed through the SEDAR website (www.sedar.com) or IPC's website (www.international-petroleum.com).

RESERVES AND RESOURCE ADVISORY

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

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC’s oil and gas assets in Canada are effective as of December 31, 2019, and are included in reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Sproule’s December 31, 2019 price forecasts.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC’s oil and gas assets in France and Malaysia are effective as of December 31, 2019, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule’s December 31, 2019 price forecasts.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of the oil and gas assets acquired in the Granite Acquisition are effective as of December 31, 2019, and are included in reports prepared by Sproule on behalf of IPC, in accordance with NI 51-101 and the COGE Handbook, and using Sproule’s December 31, 2019 price forecasts. The Granite Acquisition was completed on March 5, 2020.

The price forecasts used in the Sproule and ERCE reports are available on the website of Sproule (sproule.com) and are contained in “Statement of Reserves Data and Other Oil and Gas Information – Part III Pricing Assumptions” below. These price forecasts are as at December 31, 2019 and may not be reflective of current and future forecast commodity prices.

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

The product types comprising the 2P reserves described in this AIF are contained in the MCR and in “Statement of Reserves Data and Other Oil and Gas Information” below. Light, medium and heavy crude oil reserves/resources disclosed in this AIF include solution gas and other by-products.

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

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

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

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

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

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

2P reserves and contingent resources included in the reports prepared by Sproule and ERCE in respect of IPC's oil and gas assets in Canada, France and Malaysia have been aggregated by IPC and may also be aggregated by IPC with the 2P reserves and contingent resources attributable to the Granite Acquisition. 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 AIF 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 AIF 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".

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.

INTRODUCTION

The information set out in this AIF is stated as at December 31, 2019, unless otherwise indicated.

Reserves and contingent resources included in the reports prepared by Sproule and ERCE have been aggregated in this document by IPC as at December 31, 2019.

The MCR, the MD&A and the Audited Financial Statements are incorporated by reference and 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. See "**Cautionary Statement Regarding Forward-Looking Information**" and in particular, note that forward-looking statements speak only as of the date made, unless otherwise indicated, and IPC does not intend, and does not assume any obligation, to update these forward-looking statements, except as required by applicable laws.

Capitalized terms used but not defined, are defined in the Glossary of Terms.

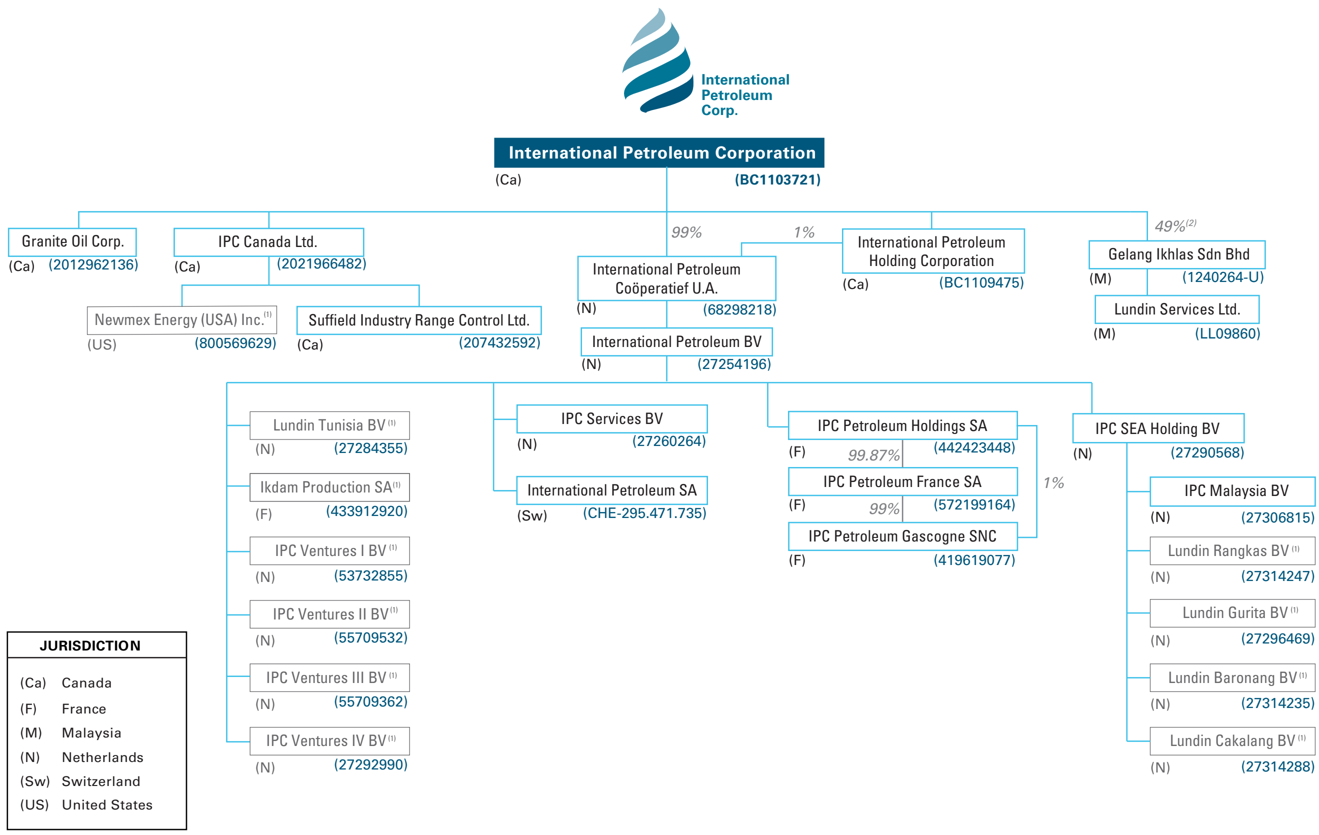
CORPORATE STRUCTURE

The full corporate 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 British Columbia, Alberta, Saskatchewan, Manitoba and Ontario. The Common Shares trade on the TSX and NASDAQ Stockholm 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.

Substantially all of the Corporation's business is carried on through its various subsidiaries. The following chart illustrates, as at the date of this AIF, 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:



(1) *Inactive and/or under liquidation*

(2) *100% economic interest*

All percentages are 100% unless otherwise noted

GENERAL DEVELOPMENT OF THE BUSINESS

Year ended December 31, 2017

In February 2017, Lundin Petroleum AB announced its intention to spin-off its oil and gas assets in Malaysia, France and the Netherlands into a newly formed company called International Petroleum Corporation and to distribute the Common Shares, on a pro-rata basis, to Lundin Petroleum shareholders.

IPC acquired the Malaysian, French and Dutch oil and gas assets of Lundin Petroleum through a series of reorganization transactions completed on April 7, 2017. All of the shares of International Petroleum BV (then known as Lundin Petroleum BV) 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.

On April 24, 2017, the Spin-Off was completed and IPC's Common Shares commenced trading on the TSX and the Nasdaq First North stock exchange under the ticker symbol "IPCO".

In May 2017, IPC 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 Equinor ASA (a shareholder of Lundin Petroleum) as a large non-core shareholder of IPC. In June 2017, 25,540,302 Common Shares were purchased under the share purchase offer for a consideration of approximately USD 90 million. These Common Shares were subsequently cancelled through an internal reorganization. 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 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 the acquisition of the Suffield area oil and gas assets in southern Alberta, Canada. 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 was made in June 2018. 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.

Year ended December 31, 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 the 2018 production guidance of 30,000 to 34,000 boepd, with operating costs for 2018 forecast to be USD 12.6 per boe. IPC's 2018 capital expenditure budget was announced at USD 32 million, primarily targeting production growth in Canada and Malaysia. The Group 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 prospect, subject to Petronas approval and rig contracting.

In June 2018, IPC announced that the Common Shares ceased trading on the Nasdaq First North stock exchange and commenced trading on Nasdaq Stockholm.

In August 2018, IPC announced a revised 2018 production guidance of 32,500 to 34,000 boepd following strong first half 2018 performance. IPC also increased the 2018 capital expenditure budget to USD 44 million, mainly related to increased gas optimization in Canada. IPC also announced that net debt reduced to USD 255 million as at June 30, 2018 and that the CAD 60 million second lien credit facility was fully repaid.

In October 2018, IPC and BlackPearl announced that IPC had agreed to acquire, by way of plan of arrangement, all of the issued and outstanding shares of BlackPearl. The BlackPearl Acquisition was completed on December 14, 2018 and IPC acquired all of the issued and outstanding shares of BlackPearl on the basis of 0.22 of a Common Share for each share of BlackPearl. IPC issued 75,798,219 Common Shares in connection with the BlackPearl Acquisition and, following completion of the BlackPearl Acquisition, 163,720,065 Common Shares were issued and outstanding.

In November 2018, IPC announced that net debt reduced to USD 213 million as at September 30, 2018.

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

Year ended December 31, 2019

In February 2019, IPC announced the 2019 production guidance of 46,000 to 50,000 boepd, with operating costs for 2019 forecast to be USD 12.9 per boe. IPC's 2019 capital expenditure budget range was announced at between USD 146 and 166 million. The budget included the proposed 2019 infill drilling campaign, the Keruing exploration well and other optimization work in Malaysia, and the Vert La Gravelle development project and other project maturation activities in France. The budget also included continued Suffield area oil drilling and gas optimization, Onion Lake Thermal facilities and well work, and Blackrod project activities in Canada.

In April 2019, IPC announced the appointment of Daniel Fitzgerald, formerly IPC's Vice President Operations, to the position of Chief Operating Officer. At the same time, Ryan Adair assumed a senior role in the Canadian management team as Vice President Asset Management and Corporate Planning of IPC Canada.

In May 2019, IPC reported that the 2019 capital expenditure budget was revised from USD 166 million to USD 188 million, including the enhanced oil recovery (EOR) development project at the Suffield N2N oil field and further conventional oil drilling in Alberta. In addition, IPC reported the acquisition of a significant land and contingent resource position adjacent to the Blackrod property. The acquired lands are 100% working interest to IPC and include best estimate contingent resources (unrisked) of 243 MMboe, increasing IPC's total contingent resources at the Blackrod project to 987 MMboe.

In June 2019, IPC announced the commencement of the drilling program on Block PM 307 in Malaysia. The PM307 drilling program was to consist of two infill landing pilot wells, followed by the Keruing exploration well and three Bertam field infill wells. In August 2019, IPC reported that the drilling of two infill landing pilots had been completed, with better than expected results were encountered in the A-15 area and poorer than expected results were encountered in the A-14 area. As a result, the third infill well (A-20) was planned for the A-15 area. The Keruing exploration well was drilled in the third quarter of 2019 and the well was plugged and abandoned after the reservoir was found to be water-bearing.

In November 2019, IPC announced that the first horizontal development well at the Vert La Gravelle field in France commenced production in mid-September 2019. In addition, IPC announced the launch of a share repurchase program under which IPC is authorized to repurchase through the facilities of the TSX, Nasdaq Stockholm and/or alternative Canadian trading systems, up to approximately 11.5 million Common Shares, over the twelve month period to November 2020.

IPC announced that as at December 31, 2019, following the cancellation of 3,929,196 Common Shares repurchased by IPC under the share repurchase program, the total number of issued and outstanding Common Shares was 159,790,869 Common Shares.

Subsequent to the year ended December 31, 2019

In January 2020, IPC announced the agreement to acquire Granite for total equity and debt consideration of approximately CAD 77.2 million. The Granite Acquisition includes total 2P reserves of 14.0 MMboe and 6.2 MMboe of unrisked contingent resources (best estimate) as at December 31, 2019. The Granite Acquisition includes current production with further potential for light oil production and development upside, close to IPC's current area of operations in southern Alberta. The Granite Acquisition was completed on March 5, 2020.

IPC announced that as at January 31, 2020, following the cancellation of 2,540,000 Common Shares repurchased by IPC under the share repurchase program, the total number of issued and outstanding Common Shares was 157,250,869 Common Shares.

In February 2020, IPC announced the estimated production guidance and forecast operating costs for 2020. IPC's estimated 2020 capital expenditure budget was also announced, with discretion to reduce such expenditure based on commodity prices. IPC operates the majority of its oil and gas assets and has the ability to manage and control work scope and expenditures as deemed appropriate. IPC also reported that productivity was lost on the A-15 well that has been on production since 2016 and such well is expected to require remedial works in order to recommence production.

IPC announced that as at February 28, 2020, following the cancellation of a further 1,865,776 Common Shares repurchased by IPC under the share repurchase program, the total number of issued and outstanding Common Shares was 155,385,093 Common Shares.

Significant Acquisitions in the year ended December 31, 2019

IPC did not complete any significant acquisitions during the year ended December 31, 2019.

DESCRIPTION OF THE BUSINESS

Summary

The main business of IPC is exploring for, developing and producing oil and gas. IPC holds a portfolio of oil and gas production assets and development projects in Canada, Malaysia and France with exposure to growth opportunities. Since listing the Common Shares in April 2017, 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 has been 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 December 31, 2019, the Group operated its produced volumes in Canada, France (Paris Basin) and Malaysia and owned non-operated interests in France (Aquitaine Basin). As operator of its oil and gas assets, 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.

For the full year 2019, IPC reported average daily production of 45,800 boepd (43% heavy crude oil, 18% light and medium crude oil and 18% natural gas).

During 2019, IPC's operating cash flow was in excess of USD 308 million and net debt reduction was close to USD 46 million. IPC's total year end net debt was USD 231.5 million.

As at the end of December 2019, IPC's 2P reserves have increased more than tenfold from inception to 300 MMboe. (including the 2P reserves acquired in the Granite Acquisition). This included a reserves replacement ratio of 89 percent in 2019, excluding acquisition additions, following upgrades predominantly in Canada. The product types comprising the 2P reserves described in this AIF are contained in the MCR and in "Statement of Reserves Data and Other Oil and Gas Information" below.

In addition, IPC has increased its best estimate contingent resources (unrisked) as at the end of December 2019 to 1,089 MMboe (including the contingent resources acquired in the Granite Acquisition). The largest single addition to the contingent resource base is the Blackrod land acquisition that was completed in Q2 2019. IPC is confident that it has a solid contingent resource base in place that can provide the feedstock to add to IPC's reserves in the future.

IPC's oil and gas assets in Canada are located in Alberta and Saskatchewan. In January 2018, IPC completed the acquisition of the Suffield area oil and gas assets in Alberta, Canada. The Suffield area oil and gas assets are high quality conventional assets. In December 2018, IPC completed the acquisition of BlackPearl, including the interests in the Onion Lake, Mooney and Blackrod projects in Alberta and Saskatchewan, Canada. In March 2020, IPC completed the acquisition of Granite, including the interests in the Ferguson assets in Alberta, Canada.

IPC's oil and gas assets in Malaysia are offshore assets where production is light, high quality oil that attracts a premium to Brent crude pricing. The Corporation also indirectly holds a 100% economic interest in the FPSO Bertam operating in Malaysia.

IPC's 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 a subsidiary of Vermilion Energy Inc. 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.

Description of the Group's Oil and Gas Assets

The following is a description of the properties comprising the Group's oil and gas assets in Canada, Malaysia and France. The following property descriptions are as at December 31, 2019 unless otherwise indicated.

Canada

2019 Summary

In January 2018, IPC completed the acquisition of the Suffield area oil and gas assets in Alberta, Canada. In December 2018, IPC completed the acquisition of BlackPearl, including the interests in the Onion Lake, Mooney and Blackrod projects. In March 2020, IPC completed the acquisition of Granite, including the interests in the Ferguson assets in Alberta, Canada. Net production in Canada during 2019 was 37.5 Mboepd.

Suffield Area

Overview

The onshore Suffield Area oil and gas assets in Canada are situated in southeast Alberta 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.

Asset Description

Oil is produced primarily from open-hole horizontal wells pumped with progressive cavity pumps, gathered and processed at a central 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 three 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 conventional shallow natural gas production is from a combination of three shallow horizons produced via vertical production wells. These low pressure wells flow naturally into the pipeline gathering system.

Geologic Overview

The main oil producing horizon is the Cretaceous age Glauconitic (Mannville 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 Mannville Ellerslie, and Lower Mannville Detrital. Three 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 sufficient oil processing capacity to accommodate existing and future planned production.

During the fourth quarter of 2018, oil drilling commenced for the first time since 2014 on these assets. This drilling program continued through 2019.

By the end of 2019, eighteen oil wells from the 2018/19 drilling programme (including one additional well accelerated from 2020) had been drilled and brought online with initial rates in line with expectations. The accelerated construction and start-up of the N2N EOR development project at Suffield was completed and commissioned in 2019, with minor carry-over extending into early 2020. Gas optimization activity also continued at Suffield throughout 2019, with completion of over 9,150 swabs and execution of 150 well recompletions by the end of 2019.

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 central 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 the Empress pricing reference point.

Onion Lake

Summary

Onion Lake is located in Saskatchewan, Canada and is a conventional heavy crude oil property with thermal development on a portion of the lands.

Overview

IPC holds working interests, ranging from 50% to 100%, in approximately 17 net sections of land (11,496 net acres) located in the Onion Lake area of Saskatchewan. IPC is the operator of the field which is located on the Onion Lake Cree Nation reserve, along the Saskatchewan/Alberta border near Lloydminster. At Onion Lake, the field produces primarily heavy crude oil with an API gravity between 10° and 11°. As of December 2019, there were 39 conventional primary producing wells (31.3 net wells) and 34 thermal producing wells on the property.

History

Up to 2019, IPC and its predecessor companies drilled over 300 conventional primary wells on the Onion Lake property. In addition to conventional primary drilling, due to reservoir thickness, a portion of the lands at Onion Lake are amenable to thermal development in the Cummings formation. The reservoir in this area of the Onion Lake lands ranges between 8 and 25 metres thick, which makes it suitable for thermal development.

In 2011, a 12,000 boepd modified SAGD (horizontal producer wells and vertical steam injection wells) commercial thermal development application was filed with Saskatchewan Energy and Resources and Indian Oil and Gas Canada. The application was amended in 2012 to include additional lands for development. In 2013, the thermal development application was approved.

In order to manage capital spending on the thermal project, it was determined to develop the project in phases; the first phase of the thermal project was designed for oil production of approximately 6,000 boepd. During the second quarter of 2015, construction of the first phase of the Onion Lake thermal project was completed with initial steam injection occurring in May 2015. Commercial thermal production commenced in 2015 and during the second quarter of 2016, reached its productive design capacity of 6,000 boepd.

The second 6,000 boepd phase was completed and commenced steam injection during the first quarter of 2018, reaching capacity of 12,000 boepd in September 2018.

Production commenced from sustaining well F-Pad in the third quarter of 2019. At the end of 2019, seven production wells had been brought online and ramped up, with Onion Lake Thermal production averaging slightly below 12,000 boepd in December 2019.

Geology

The geological formation of interest is the Cretaceous Cummings formation. The Cummings reservoir is divided into a Lower and Upper sequence throughout Onion Lake.

In the Onion Lake area, the Lower Cummings formation occurs at approximately 625 m true vertical depth (TVD) and consists of a variable succession of blocky, clean sandstones interlaminated with siltstones, mudstones and breccias that were deposited in an overall transgressive estuarine environment. The stacked estuarine deposits have coalesced to form vertically continuous sand bodies that are oil saturated and comprise the main reservoir target for thermal development. The Lower Cummings is 75% to 90% oil saturated and has an average API gravity of 10.5º. Permeability ranges from 3 to 10 Darcy, net pay ranges from 8 to 25 m and viscosities average about 50,000 centipoise. The Lower Cummings reservoir is currently being targeted on primary using CHOPS and thermally using modified SAGD in a phased approached.

The Upper Cummings Reservoir at Onion Lake is interpreted to have been deposited in a tidally influenced marginal marine shoreface environment. Separating the Upper Cummings from the Lower Cummings is a regional shale, interpreted to be a flooding surface. The Upper Cummings is 65% to 75% oil saturated and oil quality is approximately 11° API. Permeability ranges from 1 to 4 Darcy, net pay ranges from 5 to 12 m and viscosities average about 40,000 centipoise. The Upper Cummings reservoir is currently being targeted on primary using CHOPS.

Production Operations

Conventional production is from conventional wells drilled on pads with one to eight wells per pad. Wells are equipped with progressive cavity pumps feeding to single well batteries. At each battery, water and sand are separated in production tanks and the remaining crude oil emulsion is trucked to sales. The water is then trucked and disposed of at IPC's deep water disposal well and sand is trucked to third party disposal sites. Much of the solution gas is utilized to drive the progress cavity pumps and to heat the production tanks at the single well batteries.

The modified SAGD scheme involves production pad drilling with 6 to 8 horizontal production wells per pad complemented by injection pads with 3 to 8 vertical directional injection wells per pad. Steam is generated at a Central Processing Facility (CPF) utilizing fuel gas purchased from the Saskatchewan gas utility system supplemented with produced gas from the production wells. Steam travels via above ground pipelines to the steam injection wells. Rotaflex pumps are used to pump the emulsion from the production wells which is then shipped via above ground pipelines connected to CPF. At the CPF, oil, water and gas are conserved and separated. Some produced water is recycled; the remaining is disposed of down deep well disposal. The sales oil is then trucked to various delivery points surrounding the Lloydminster area.

Abandonment and Reclamation Obligations

Abandonment and reclamation consists of permanent plugging of wells, decommissioning of facilities and pipelines and site restoration. Each year, reviews of the pipelines, wells and facilities are completed and annual provisions for abandonment and reclamations activities are revised and included in the capital budget. The appropriate Saskatchewan and Alberta regulations are followed and reports filed regularly. Non economic wells and/or non producing wells without a future potential use (such as a vertical production well that could be used as a future thermal injection well or as an observation well) are then regularly abandoned as a part of ongoing business. Once all of the wells on a pad have been reclaimed and the pad is no longer in use, it is then available to be decommissioned and reclaimed.

Infrastructure and Marketing

Production from the Onion Lake area is currently trucked to third party sales points including pipeline facilities and rail terminals. IPC Canada entered into a Transportation Services Agreement which provides firm transportation from its Onion Lake Thermal facility and enables IPC Canada to have pipeline access to key sales points, including Hardisty. The pipeline is expected to be completed at the end of 2021 and may reduce trucking costs currently being incurred in order to bring oil to market.

Development Plans

IPC may consider further expansion phases to the thermal project, depending on current and forecast commodity prices.

Mooney

Summary

Mooney is located in north-central Alberta, Canada and is a conventional heavy crude oil property with an EOR scheme, an ASP flood, on a portion of the lands.

Overview

IPC has a 100% working interest in 28 sections (7,296 hectares) in the Mooney field located in the Slave Lake area of Alberta. IPC is the operator of the Mooney field which is located on the south shore of Lesser Slave Lake to the west of the town of Slave Lake. The Mooney field produces oil from horizontal production wells, a portion of which are produced utilizing an ASP flood (phase one) and a portion of which are produced conventionally (phases two and three). As at December 2019, there were 17 horizontal wells producing from the phase one ASP flood and 15 horizontal conventional wells producing from phase two.

History

The Mooney field was initially developed for conventional production using horizontal wells. A water flood pilot was implemented in 2006 which increased the oil recoveries by an additional 2% to 3% of the oil in place.

A three well polymer pilot, initiated in 2008 and operated for approximately 14 months, was undertaken prior to proceeding to commercial development. During the term of the pilot overall oil recoveries increased to approximately 18% of the oil in place. Conventional recovery rates without ASP flooding are estimated to be 3% to 7%. As a result of the polymer pilot success, in late 2009, a development application was filed with the Alberta regulatory body to commence a commercial ASP flood at Mooney.

Government approval to proceed with phase one of the commercial ASP flood was received in late 2010 and field construction of the chemical and water handling facilities commenced immediately thereafter. During the implementation of phase one, twenty five of the existing wells were shut-in and converted to ASP injectors. ASP injection commenced in the third quarter of 2011.

In 2012, a new heavy crude oil processing facility was constructed to handle the increased fluid volumes from the area.

Geology

The Mooney field produces from the Bluesky formation, which is found at approximately 900 m TVD and was deposited in a broad coastline setting with a consistent orientation and a predictable thickness trend. The Bluesky reservoir is a homogeneous sandstone deposit with both vertical and lateral consistency. In the Mooney area, the Bluesky formation represents a shoreface deposit that consists of two coarsening upward parasequences, interpreted to have been deposited in a shallowing-up marginal marine environment.

The oil quality at Mooney ranges from 12° to 19° API, with an average of approximately 16° API. The viscosity of the oil ranges from 150 centipoise to 5,000 centipoise, with an average of 300 centipoise. Permeability ranges from 0.3 Darcy to 10 Darcy with an average of 3 Darcy and the reservoir has average oil saturations of 70%.

Production Operations

At Mooney, all production and injection volumes are pipelined from a centralized site. Injection water for the ASP flood is sourced from a downhole saline sources, which is then softened prior to the ASP injection. Clean oil is pipelined from our central battery to a trucking terminal. Produced water is pumped to deep well water disposal. Solution gas is captured, conserved and used to run IPC's facilities and downhole pumps. Surplus gas can be processed and sold through IPC's own infrastructure onto a third party pipeline system.

Royalties

The Alberta government has programs that encourage EOR developments by reducing royalties on fields with tertiary recovery programs. Mooney is eligible for the Enhanced Hydrocarbon Recovery Program (EHRP). EHRP royalty status has been received for phase one of the Mooney ASP flood.

Abandonment Obligations

Abandonment and reclamation consists of permanent plugging of wells, decommissioning of facilities and pipelines and site restoration. Each year, reviews of the pipelines, wells and facilities are completed and annual provisions for abandonment and reclamations activities are revised and included in the capital budget. The appropriate Alberta regulations are followed and reports filed regularly. Non economic wells and/or non producing wells without a future potential use are then regularly abandoned as a part of ongoing business. Once all of the wells on a pad have been reclaimed and the pad is no longer in use, it is then available to be decommissioned and reclaimed.

Infrastructure and Marketing

Production from the Mooney area is currently trucked to third party sales points including pipeline facilities and rail terminals.

Blackrod

Summary

Blackrod is an in situ (SAGD) oil sands project located south of Fort McMurray about 20 km north of Wandering River, in the Athabasca oil sands region of northern Alberta.

Overview

IPC holds a 100% working interest in approximately 87 net sections (22,184 net hectares) of oil sands leases in the Blackrod area, including a strategic acquisition in 2019 of approximately 12 net sections to the north and south of the existing Blackrod area. The Blackrod asset is located in the Athabasca oil sands area and represents an attractive SAGD oil sands development opportunity. IPC is the operator of a successful pilot at Blackrod, with the most recent SAGD well pair, Well Pair 2, having produced over 900,000 bbls.

Geology

The geological formation of interest at Blackrod is the Cretaceous Lower Grand Rapids (L.GR) at a depth of approximately 300 metres. The thick, laterally extensive, stacked shoreface sandstones of the L.GR formation are interpreted to have been deposited in a shallowing-upward, marginal-marine environment. At Blackrod, the L.GR formation consists of three parasequences which have been informally named from top to bottom as L.GR 1, L.GR 2 and L.GR 3. Each parasequence ranges in thickness from 5 meters to 30 meters, with the thickest and cleanest parasequence being observed in L.GR 1. It is this uppermost parasequence that is bitumen bearing.

The depositional setting allowed for the creation of a large, regionally consistent L.GR 1 reservoir with the reservoir ranging in thickness from 8 to 28 metres. Bitumen saturation within the L.GR 1 reservoir varies between 50% and 75%, averaging approximately 60%. Reservoir permeability averages 3 Darcy. The viscosity of the bitumen ranges from approximately 150,000 centipoise at the top of the reservoir, increasing with depth to greater than 1,000,000 centipoise and the API gravity of between 8° and 10°.

Pilot History and Production Operations

A 35% working interest in the Blackrod lands was initially acquired in 2007. In 2008 and 2009, the working interest in Blackrod was increased to 80% as a result of acquiring interests from joint venture partners. In 2010, the remaining 20% interest in the Blackrod lands was acquired, as well as operatorship of the project. In 2013, an additional 10 sections were acquired contiguous to its existing oil sands leases. In May 2019, an additional 12 sections were acquired to the north and south of the existing Blackrod area.

In 2009, an application was filed with regulatory authorities to undertake a single well pair SAGD pilot on the property. The purpose of the pilot was to demonstrate the use of SAGD technology to produce bitumen from the L.GR formation on the Blackrod lands. The pilot data was used to better understand the reservoir deliverability and optimum operating methods. BlackPearl's SAGD recovery scheme was approved by the Alberta government in late 2010.

The original horizontal well pair was drilled in 2010 and construction of the pilot facilities was completed early in 2011. Steam injection was initiated in 2011 and following a warm-up period, the well was converted to SAGD operation. The pilot consisted of a single SAGD horizontal well pair, water source and disposal wells, observation wells, water monitoring wells and a central facility consisting of water treatment and steam generation equipment and other associated facilities. In order to access the pilot lands, an existing logging road was acquired and upgraded to facilitate oil and gas operations. Non-potable water to generate steam comes from the Grosmont formation. Emulsion (raw crude bitumen and water) produced from the pilot is trucked from the central facility location to third party oil processing facilities and pipeline terminals.

In 2012, approval from the Alberta government to expand the pilot was received. In 2013, Well Pair 2 and two observations wells were drilled and the existing processing facilities were modified. Well Pair 2 was drilled slightly deeper in the reservoir and was drilled longer than the original pilot well pair, with the horizontal section of the well reaching approximately 950 metres in length. Steam injection was commenced in Well Pair 2 late in 2013 and it was converted to SAGD operation in March 2014. The objective of the second well pair was to continue to refine several operating strategies, including well start-up procedures, steam distribution and sand control methods. Well Pair 2 had produced in excess of 900,000 bbls to the end of 2019. Drilling of the third well pair at the BlackRod SAGD pilot project was completed in the third quarter of 2019.

Royalties

Blackrod is located in a designated oil sands region and approval was received for oil sands royalty treatment for the Blackrod pilot. The government of Alberta's royalty share from oil sands production is price-sensitive. The royalty range applicable to price sensitivities changes depending on whether the project's status is pre-payout or post-payout. "Payout" is generally defined as the point in time when a project has generated enough net revenue to recover its costs and provide a designated return allowance. The base pre-payout royalty rate starts at 1% of gross revenue and increases for every dollar that the world oil price, as reflected by the WTI crude oil price in Canadian dollars, is priced above CA$55 per barrel, to a maximum of 9% when the WTI crude oil price is CA$120 per barrel or higher. The post-payout royalty rate is based on net revenue; it starts at 25% and increases for every dollar the WTI crude oil price is above CA$55 per barrel to a maximum of 40% when the WTI crude oil price is CA$120 per barrel or higher. Specified capital and operating costs may be deducted to arrive at net revenue for this calculation. Additional regulatory approvals for oilsands royalty treatment will be required when development of Blackrod is initiated.

Commercial Application and Development

In 2012, a development application was filed on the Blackrod lands. In 2016, the Project received regulatory and environmental approval from the AER and Alberta government for its 80,000 bopd Blackrod SAGD development application. The project is expected to be developed in phases. The first phase of this project would target production rates of 20,000 bopd.

Infrastructure and Marketing

Two major sales oil and diluent pipeline systems are in close proximity to the Blackrod lands.

Development Plans

IPC continues work on cost optimization with respect to the project.

Ferguson

Summary

IPC completed the acquisition of Granite in March 2020. The producing Ferguson field is the main asset acquired through this acquisition. The field produces 29° API oil, from an oil pool which extends over a 50 kilometre fairway. The assets acquired in the Granite Acquisition include existing infrastructure to enable the current gas injection EOR scheme, with capacity to allow for potential further field development opportunities.

Overview

IPC operates and holds a 100% working interest in approximately 57 sections in the Ferguson oil field located in southern Alberta, 70 kilometres south of Lethbridge. The Ferguson field produces oil from horizontal wells using a gas flood EOR scheme.

As at December 2019, there were 60 horizontal wells producing from the Ferguson pool. IPC also owns 100% of the central oil battery and associated facilities that have a capacity of 8,000 bopd and 20,000 bbls of storage, as well as a natural gas plant with a capacity of 7,000 Mcf per day of gas.

Development Plans

IPC continues to integrate the Ferguson assets into its existing business, and to assess the potential of further development, depending on current and forecast commodity prices.

Malaysia

2019 Summary

Net production from the Bertam field on Block PM307 (IPC working interest (WI) 75%) during 2019 was at 5.8 Mboepd. Reservoir performance for the Bertam field was in line with expectation and facilities uptime during 2019 was in excess of 99 percent (excluding planned shutdowns).

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.

Bertam Field (Block PM307)

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, 2019, 13 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 1,600 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 to 25% and permeability is 80 to 300 milliDarcies.

Production Operations

The reservoir recovery mechanism is moderate to strong aquifer drive. As at December 31, 2019, reservoir access was through 12 horizontal producer wells placed close to the top of the K10.1 structure and 1 horizontal producing well close to the top of the K10.2 reservoir. 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 – Floating Production Storage and Offloading (FPSO) Unit

In 2013, development plan approval was received for the Bertam oil field on Block PM307 which integrated an unmanned wellhead platform tied to a floating production, storage and offloading vessel. An extensive upgrade and life extension program was completed 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 (excluding planned shutdowns).

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.

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, 2024. 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

A infill drilling program was completed in 2019. Two additional infill drilling locations have been identified and booked as contingent resources in the A-15/A-20 area. Further technical work is planned on these locations during 2020, for potential drilling in 2021, depending on current and forecast commodity prices. Productivity was lost on the A-15 well that has been on production since 2016 and such well is expected to require remedial works in order to recommence production.

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

The Tembakau-1 exploration well was drilled in 2012 and was a natural gas discovery in two Miocene sandstone intervals. The discovery was successfully appraised with the Tembakau-2 well in 2014. Subsequently, the Mengkuang-1 well 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. Potential future development options are being assessed, depending on current and forecast commodity prices.

France

In France, the Group's oil and gas assets are situated in the Paris Basin and the Aquitaine Basin. The majority of the production and reserves of the Group's oil and gas assets comes from the operated fields in the Paris Basin. In the Aquitaine Basin, production comes fields operated by Vermilion Energy Inc., where IPC holds a 50% working interest.

2019 Summary

Net production in France during 2019 was 2.5 Mboepd. IPC continues to work its undeveloped resource base in the Paris Basin.

France – 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 ten oil field licenses and three 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 nine of the ten producing fields (43.01% working interest in Dommartin Lettrée field).

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 Villeperdue production centre where separation takes place. Produced water is reinjected into the reservoirs for pressure support.

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 Group's 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 fields 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

Phase 1 of the Vert La Gravelle redevelopment project was completed in 2019 with two new horizontal wells added to the well count. Future phases of the Vert La Gravelle redevelopment project, if any, will depend on current and forecast commodity prices. In addition, IPC continues to review the potential Villeperdue West development project, which may be commenced depending on current and forecast commodity prices.

France – The Aquitaine Basin

Assets Description

The Group has a 50% working interest in five production licenses in the Aquitaine Basin. All licenses associated with the Group's 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.

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 28 to 34°API gravity. Oil and water produced from Les Pins and Les Mimosas is transported by a pipeline network to Les Arbousiers where water/oil separation takes place, then the oil is sent via a pipeline to Les Mimosas where all the oil is trucked to the Vermilion 100% owned and operated Cazaux field. The Group has a 50% interest in the pipelines connecting the fields. Concerning the Tamaris field oil and water produced areoil/water separation takes place. From Cazaux, oil is transported via a Vermilion owned and operated pipeline into the Ambes terminal, north of Bordeaux.

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 operator 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 operator 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. The Group charters a 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.

Discontinued Operations

The Corporation indirectly owns certain other oil and gas assets, which are 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.

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. 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.

Employees

As of December 31, 2019, IPC had a total of 285 employees located in Canada, Malaysia, France and Switzerland providing the Group with the managerial, operational, technical, financial and locally specific knowledge and experience to ensure effective and efficient management of IPC's 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 Canada, Malaysia and France. The Group also maintain a corporate and financing office in The Netherlands.

The following table summarizes IPC's full-time equivalent employees as at December 31, 2019:

	December 31, 2019
Canada	156
Malaysia	62
France	47
Switzerland	20
Number of employees	**285**

Specialized Skill and Knowledge

The Corporation relies on the specialized skills and knowledge required to explore for, develop and produce oil and natural gas. These skills include: (a) gathering, interpreting and processing technical data (such as geological and geophysical information); (b) designing, drilling and completing wells; (c) marketing oil and natural gas production; and (d) analyzing potential acquisition or development opportunities.

The Group employs teams of technical, commercial, financial and management staff in each of its areas of operations. In addition, various specialized consultants are available to assist in areas where the Group does not require full time employees.

The Corporation is led by an experienced management team with a successful track record in the oil and gas industry. Each individual on the Corporation's management team has 10 to 25 years of oil and gas industry experience, including substantial experience working directly with the Group's oil and gas assets and in jurisdictions worldwide. In addition, the Board is comprised of individuals with substantial oil and gas and natural resources industry experience in very senior positions and a proven track record of creating value for shareholders, both organically and inorganically.

Competitive Conditions

The oil and gas industry is very competitive in the areas where the Corporation currently operates and may operate in the future. The Corporation competes for reserve acquisitions, licences and concessions, and skilled technical personnel with a substantial number of other oil and gas companies, many of which may have greater technical or financial resources.

The Group attempts to mitigate the risks associated with competition in exploration, production and marketing by operating in areas where IPC believes that its technical and commercial personnel have in-depth knowledge and understanding, for example in Canada, Malaysia and France. In respect of the acquisition of the Suffield area assets and of BlackPearl in Canada, an important factor for IPC was the availability of skilled and experienced personnel to transition across to the Group, for the current operations as well as for the future development of those and potentially other assets.

Cyclical Nature of Operations

IPC's business and operations are generally not cyclical. However, operational results and financial condition are dependent on prices received for oil and natural gas production. Oil and natural gas prices have been volatile and are determined by a number of factors, including global and local supply and demand factors, weather, general economic conditions as well as conditions in other oil and natural gas producing and consuming regions.

In 2020, the Coronavirus (Covid-19) and the restrictions and disruptions related to it, as well as the actions of producers such as Saudi Arabia and Russia, have had a drastic adverse effect on the world demand for, and prices of, oil and gas as well as the market price of the shares of oil and gas companies generally. These factors are beyond the control of the Corporation and it is difficult to assess how these, and other factors, will continue to affect the Corporation and the market price of the Common Shares. In light of the current situation, as at the date of this AIF, the Corporation continues to review and assess its business plans and assumptions regarding the business environment, as well as its estimates of future production, cash flows, operating costs and capital expenditures.

In addition, the production of oil and natural gas is dependent on access to areas where development of reserves is to be conducted. Seasonal weather variations, including "freeze-up" and "break-up" in Canada, could affect access in certain circumstances. See also "Risk Factors".

Environmental Regulations

The Group's oil and gas operations are in regions where there are environmental regulations including restrictions on where and when oil and gas operations can occur, releases to the atmosphere and surface land and the potential routing of pipelines or location of production facilities. IPC attempts to mitigate the risk of inheriting environmental liabilities when conducting due diligence on acquisition opportunities. The Group will insure against such liabilities in accordance with industry practice. The Group will not fully insure against all of these risks, nor are all such risks insurable. Compliance with applicable environmental regulations may require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on IPC's financial position. See also "Industry Conditions" and "Risk Factors".

Social and Environmental Policies – Sustainability

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 Guidelines 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.

In 2019, the Corporation adopted a Sustainability Policy articulating the approach around three components: people, environment and ethics. The Corporation recognizes that people are key to IPC's success and confirms the commitment to ensure health, safety and well-being at work. In respect of the environment, the Corporation seeks to conserve ecosystems and living organisms and aims to avoid, minimize, restore or offset potential impacts resulting from operations. The Corporation is also driven by values of fairness and transparency and adopts high standards of professional integrity and ethics at all times.

INDUSTRY CONDITIONS

Oil and Gas Market Overview

Global energy consumption is driven by world population, economic growth and availability of resources. According to BP's 2019 Statistical Review of World Energy, oil is the most consumed energy source with an annual consumption of almost 100 million barrels per day in 2018. Oil is used for a wide array of purposes including transportation, petrochemical processes, power generation and agriculture.

Oil is found in large quantities on most continents of the world. The largest producers are the United States, Russia and Saudi Arabia. Going forward, oil production growth is expected to be dependent on increased output from the OPEC, as well as increased unconventional oil production, 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 ICE Futures 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 ICE Futures. In recent years, Brent price has emerged as the benchmark price of oil sales in global markets.

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.

Industry Overviews and Regulatory Regimes in Canada, Malaysia and France

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 provinces of Alberta and Saskatchewan, 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 generally in 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 western Canada 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 western Canada, 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 western Canada 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 western Canada may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in western Canada 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 western Canada may be further exacerbated by natural gas storage limitations.

Land Tenure

Crown

Rights are granted to energy companies to explore for and produce oil, bitumen and natural gas pursuant to leases, licenses, permits and regulations as legislated by the respective provincial and federal governments. Lease terms vary in length and incorporate terms and conditions as set forth in legislation, including continuation requirements, obligations to perform specific work, or make payments.

Lands in oil and natural gas leases are continued beyond their primary term by drilling a well(s) where certain minimum thresholds of production have been reached, all lease rental payments have been made on time and certain other conditions have been met. A lease is proven productive at the end of its primary term by drilling, producing, mapping (Alberta), being part of a unit agreement or by paying offset compensation. If a lease is proven productive, it will continue indefinitely beyond the initial term of the lease until the lease holder can no longer prove the lands are capable of producing oil or gas.

Oil sands leases are continued beyond their primary term by performing a minimum level of evaluation (MLE) by drilling and coring all potential producing hydrocarbon bearing zones or by meeting a minimum level of production (MLP).

Many jurisdictions in Canada, including the provinces of Alberta and Saskatchewan have legislation in place for mineral rights reversion to the Crown where stratigraphic formations cannot be shown to be capable of production at the end of their primary lease term. Such legislation may also include mechanisms available to energy companies to "continue" lease terms for non-producing lands, having met certain criteria as laid out in the relevant legislation.

Freehold

In addition, to Crown ownership, oil and natural gas can also be privately owned (freehold). Rights to explore for and produce such oil and natural gas are granted by leases on such terms and conditions as may be negotiated between the mineral holder and oil and natural gas producers.

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). Indian Oil and Gas Canada ("IOGC"), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable indigenous peoples, for exploration and production of crude oil and natural gas on indigenous reservations.

Royalties and Incentives - Alberta

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 50%. 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.

Royalties - Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. Each month, royalty rates are adjusted using a "crude oil royalty/tax factor" established by the Province for each type of oil. For Crown royalty purposes, crude oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil", depending on the area in which it is produced. Within these three geographic classifications, oil will be classified as either fourth tier oil, third tier oil, new oil or old oil, depending on when the well was originally drilled. The government establishes separate reference prices for each type of oil based on the average wellhead price received by producers during the month for sales of that oil type in Saskatchewan.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil. If average wellhead prices fall below the established base prices of CA$100 per cubic metre ($m^3$) for third and fourth tier oil and CA$50/$m^3$ for new oil and old oil, base royalty rates are applied. Base rates are: 5% for all fourth tier oil; 10% for heavy crude oil that is third tier oil or new oil; 12.5% for southwest designated oil that is third tier oil or new oil; 15% for non-heavy crude oil other than southwest designated oil that is third tier or new oil; and 20% for old oil. If average wellhead prices move above the established base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price.

Marginal rates are: 30% for all fourth tier oil; 25% for heavy crude oil that is third tier oil or new oil; 35% for southwest designated oil that is third tier oil or new oil; 35% for non-heavy crude oil other than southwest designated oil that is third tier or new oil; and 45% for old oil.

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 are required to pay freehold mineral taxes or production taxes levied by the provincial government on oil and natural gas production from lands where the provincial government does not hold the mineral rights.

Aboriginal Lands

Indian Oil and Gas Canada (IOGC) administers the oil and gas royalty regime for petroleum production on aboriginal lands. Royalties payable on aboriginal lands are prescribed under the *Indian Oil and Gas Regulations*, *1995*; however, IOGC has the authority to enter into a special agreement with the lessee to reduce, increase or vary the basis of calculations of royalties prescribed from time to time by regulations.

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 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.

Saskatchewan

Environmental compliance in Saskatchewan is governed by *The Oil and Gas Conservation Act* (Saskatchewan) (the "**OGC Act**"). On April 1, 2012, a bill enacting changes to the OGC Act was proclaimed into force in conjunction with the release of *The Oil and Gas Conservation Regulations*, *2012* (Saskatchewan) (the "**OGC Regulations**") and *The Petroleum Registry and Electronic Documents Regulations* (the "**Registry Regulations**"). With the enactment of the Registry Regulations and the

OGC Regulations, Saskatchewan implemented a number of operational matters, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers, and procedural matters including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Environmental compliance in Saskatchewan is also subject to the *Environmental Management and Protection Act, 2010* and the *Environmental Management and Protection (Saskatchewan Environmental Code Adoption) Regulations*. The environmental laws take a results-based approach which incorporates the required outcomes into regulations, and leaves the specific methods on how to achieve that outcome up to the resource company. The Government of Saskatchewan also established a set of oil and gas operating directives and environmental standards, including environmental site assessment guidelines, acknowledgement of reclamation requirements and incident reporting requirements.

Liability Management Rating Program - Alberta

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. Each company may access its liability management rating on a monthly basis by accessing the AER's Digital Data Submission 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.

Liability Management Program - Saskatchewan

Saskatchewan has developed a liability management program designed to prevent taxpayers from incurring costs associated with the suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct, known as the Licensee Liability Rating program. It is part of the Saskatchewan Oil and Gas Orphan Fund. The Licensee Liability Rating program involves an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. Separately, any changes to the values used to calculate each industry participant's share of the total decommissioning liabilities may also result in increases to the security that must be posted.

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.

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. The 2018 federal *Greenhouse Gas Pollution Pricing Act* (GGPPA) establishes the federal carbon price on GHG emissions applicable as of January 2019. The GGPPA reinforces the approach taken in the Framework and is only intended to serve as a regulatory carbon pricing ''backstop'' to any province or territory that have not otherwise implemented a compliant provincial or territorial pricing regime.

Both Alberta and Saskatchewan have carbon pricing systems in place that have been determined to meet Federal standards and have been granted equivalency by the Federal government.

In addition to the GGPPA's carbon pricing, a Clean Fuel Standard (CFS) is being developed by the federal government with an aim of reducing emissions of methane from various sectors, including oil and natural gas production. As part of the CFS, the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector), became effective on January 1, 2020 in order to fulfill Canada's commitment to reduce emissions of methane from the oil and gas sector by 40% to 45% below 2012 levels by 2025. The regulations require certain oil and natural gas producers to measure, manage and reduce key fugitive and venting emission sources, including those from pneumatic devices, compressors and other equipment.

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 *Technology Incentive and Emissions Regulation* ("**TIER**") replaced the *Carbon Competitiveness Incentives Regulation* (the "**CCIR**") on January 1, 2020. Similar to the CCIR, TIER imposes an output-based benchmark on competitors in the same emitting industry for regulated facilities that emit more than 100,000 tonnes of carbon dioxide equivalent in any year from 2016 onwards, or those facilities that elect to opt-in to the program after meeting certain criteria. In addition, TIER provides the option for conventional oil and gas producers to aggregate facilities.

Large emitters and opted-in facilities are required to establish facility-specific benchmarks which are verified by an independent third party. Under the facility-specific benchmark methodology, a facility is required to reduce its emissions intensity by 10 per cent relative to the facility's historical production weighted average emissions intensity. High performance benchmarks are set to the average emissions intensity of the most emissions efficient facilities (performers in the top 10 percent) producing each benchmarked product over reference years. If there are fewer than ten facilities producing a product, the high-performance benchmark for a product is then set based on the emissions intensity of the best-performing facility. In most cases, a regulated facility is subject to the less stringent of the high performance benchmark and the facility-specific benchmark. The stringency of facility-specific benchmarks will increase by 1 per cent annually beginning in 2021; so, a facility with a 90 per cent free emissions allocation (or a 10 per cent emissions intensity reduction requirement) in 2020 would receive 89 per cent free allocation in 2021, 88 per cent in 2022, and so on.

Conventional oil and natural gas producers have the ability to aggregate some or all facilities located in Alberta and to be regulated under TIER. Once aggregated, the facilities are treated as a single facility under TIER as long as these facilities emit less than 100,000 tonnes carbon dioxide equivalent and share the same responsible person. An aggregate facility has different treatment than other types of regulated facilities under TIER (large emitters or opted-in facilities). Emissions for aggregate facilities include stationary fuel combustion emissions only and the annual one per cent tightening rate does not apply to aggregate facility benchmarks. Currently, an aggregate facility will be required to reduce its emission intensity of stationary fuel combustion emissions by 10 per cent relative to the aggregate facility's historical baseline. An aggregate facility's reduction target will stay at 10 per cent and will not become more stringent over time. Alberta Environment and Parks will also develop high performance benchmarks for the sector at a later date.

Under TIER, companies have a variety of compliance options including implementing emissions reductions, use of emissions performance credits and Alberta-based emissions offsets and payment into the TIER compliance fund at the same rate as the carbon price applicable in the year of compliance.

On January 1, 2020, the AER's Directive 060 following by Directive 017 came into force giving effect to the Government of Alberta's direction to lower annual methane emissions by 45% by 2025. The requirements address the primary sources of methane emissions from Alberta's upstream oil and gas industry: fugitive emissions and venting, which includes emissions from compressors, pneumatic devices, and glycol dehydrators. The requirements also focus on improved measurement, monitoring, and reporting of methane emissions.

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.

Saskatchewan

On June 22, 2011, the government of Saskatchewan released the *Upstream Petroleum Industry Associated Gas Conservation Directive*, which aims to reduce emissions resulting from the flaring and venting of associated gas. The Directive requires producers in Saskatchewan to conserve associated gas on all wells producing more than 900 cubic metres per day if conservation is determined to be economic by any method under the Directive. An associated gas conservation project is considered economic if the gas conservation generates a net present value ("**NPV**"), before-tax, of greater than CA$50,000. If an associated gas conservation project has an NPV, before-tax, of less than CA$50,000, then there will be no conservation requirement, but the project must be re-evaluated annually using updated prices, costs, and forecast. NPV is measured on a per project basis, meaning gas conservation economics will be enhanced for larger multi-well projects. The Directive was fully implemented for all wells as of July 1, 2015.

In 2010, Saskatchewan passed the *Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**"). Under the MRGGA, persons that emit more than 1,500,000 tonnes of GHG per year due to gas or coal-fired electricity generation are subject to reporting requirements and are required to reduce annual emissions in accordance with emissions reduction targets set forth in the MRGGA. Portions of the MRGGA came into force on January 1, 2018.

In December 2017, Saskatchewan introduced Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy, which was fully implemented in 2019. This strategy includes reporting requirements and emissions reduction targets for the upstream oil and gas industry and output-based performance standards for aggregated conventional facilities and large facilities emitting more than 25,000 tonnes of carbon dioxide equivalent per year. Large emitters and aggregated facilities are required to establish a facility-specific benchmark which are verified by an independent third party. Under the facility-specific benchmark methodology, a facility (large emitter or aggregated) is required to reduce its emissions intensity by 15 percent over a 12-year period (annually by 1.25 percent) relative to the facility's historical production-weighted average emissions intensity. Similar to the TIER in Alberta, emitters will have various compliance options, including making improvements at facilities to reduce emissions intensity, purchasing a carbon offset, using best performance credits, paying into a technology fund and using market mechanisms outlined in the Paris Agreement.

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, 2019 will be available on the Corporation's website at www.international-petroleum.com.

Malaysia Country Overview

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 bopd 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**") 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. All of IPC's material 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 2019, the corporate tax rate was 28% on the first EUR 500,000 then 31%with a social surtax of 3.3% on the amount of tax paid in excess of EUR 763,000, resulting in a marginal tax rate of up to 31.70%.

French law prohibits the use of certain techniques, including hydraulic fracturing, which 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 Mining Code allows the government to delegate to companies the right to explore the subsoil and produce oil and gas. The 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. From a law 2017-1839 dated December 30, 2017 (the "Hydrocarbon law"), new exploration permits (*permis exclusifs de recherches*) can no longer be granted and production licenses (*concessions*) can be granted and renewed only under certain conditions.

Regulatory Body

The Minister for the Ecological and Solidary Transition (acting as the Ministry of the Environment), together with the Minister for the Economy and Finance, 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 Energy Department (*Bureau des ressources énergétiques du sous-sol*) of the Ministry for the Ecological and Solidary Transition. Regulation and administration of the mining activities are carried out through the local state representatives.

Exploration Permits (permis exclusif de recherches)

From the Hydrocarbon law, new exploration permits (*permis exclusifs de recherches*) can no longer be granted in France. Exploration permits granted prior to December 30, 2017 were awarded for an initial period of five years or less, with a financial commitment referring to an agreed work programme. These permits have not been affected by the Hydrocarbon law and may be renewed twice, each time for five years or less. Applications for extension of exploration permits granted prior to December 30, 2017 are submitted to the Minister in charge of mining. If the work programme requirements for the current period 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. From the Hydrocarbon law, no new production license can be granted, except when the production license is to cover a discovery made under an exploration permit granted prior to December 30, 2017. The initial period of the concession is flexible and is generally shorter for smaller developments. It should be noted that production can commence from a new field on an exploration permit prior to the award of a concession.

The award of concessions is subject to a specific procedure and to certain conditions. In the case where the applicant has already been granted an exploration permit on the corresponding area prior to December 30, 2017, a production license can be awarded for a period that cannot extend beyond January 1, 2040, except if it can be demonstrated that the costs incurred have not been recovered by this date. The procedure of granting involves in particular a public enquiry *(enquete publique*). The concession is granted by decree (*décret en Conseil d'Etat*).

Production licenses granted prior to December 30, 2017 can be renewed for 25 years or less but, as per the Hydrocarbon law, they cannot be renewed for a duration extending beyond January 1, 2040.

French Decree 2006-648 dated June 2, 2006 relating to mining licences provides, 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.

With the Hydrocarbon law, the French government has expressed the will to cease future petroleum exploration 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 license must pay the French tax authorities a royalty proportional to the value of the products extracted. This royalty is paid starting from production. Under the current French Mining Code, the royalty payable for a concession is 8% of the portion of the annual production above 1,500 tonnes/year extracted from that concession .

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 for the Ecological and Solidary Transition. The local mining tax is payable in arrears (production of 2018 is reported in 2019 and the corresponding tax is paid, after receipt of the notice of payment, generally end 2019 or beginning 2020), is ring-fenced by well. For 2019, the RCDM was set at EUR 27.12 per net tonne of oil equivalent.

From January 1, 2018, a tax on exploration permits is payable every year for each permit existing at January 1, and is set at EUR 5/km^2 for the initial period, EUR 10/km^2 for the second period and EUR 30/km^2 for the third period.

RISK FACTORS

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

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

Future oil and gas development may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. Production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees. **In addition, the Coronavirus (Covid-19), and the restrictions and disruptions related to it, may cause production delays and interruptions which could have adverse effects on the Corporation, its revenues and cash flows and the market price of the Common Shares.**

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

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

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

In 2020, the Coronavirus (Covid-19) and the restrictions and disruptions related to it, as well as the actions of producers such as Saudi Arabia and Russia, have had a drastic adverse effect on the world demand for, and prices of, oil and gas as well as the market price of the shares of oil and gas companies generally. These factors are beyond the control of the Corporation and it is difficult to assess how these, and other factors, will continue to affect the Corporation and the market price of the Common Shares.

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

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

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

Climate Change: Physical climate change related risks can be event-driven with increased severity of extreme weather events, such as cyclones, hurricanes, or floods, or long-term shifts in climate patterns with sustained higher temperatures or sea level rise. These physical risks may have financial and operational implications for the Corporation, such as direct damage to assets and indirect impacts from supply chain disruption.

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

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

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

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

Operational Risks Relating to Facilities and Pipelines: The pipelines and facilities associated with the Group's assets, including the FPSO Bertam, are exposed to operational risks that can lead to hydrocarbon releases, production interruptions and unplanned outages. Other operating risks relating to the facilities and pipelines associated with the Group's assets include: the breakdown or failure of equipment; 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. **In addition, the Coronavirus (Covid-19), and the restrictions and disruptions related to it, may cause production delays and interruptions which could have adverse effects on the Corporation, its revenues and cash flows and the market price of the Common Shares.** The occurrence or continuance of any of these or other operational events could curtail sales or production or materially increase the cost of operating the facilities and pipelines associated with the Group's oil and gas assets and reduce revenues accordingly.

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

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

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

References to "contingent resources" do not constitute, and should be distinguished from, references to "reserves". References to "prospective resources" do not constitute, and should be distinguished from, references to "contingent resources" and "reserves". This AIF 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 AIF do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material. See also "Reserves and Resource Advisory" above.

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

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

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

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

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

In 2020, in response to the Coronavirus (Covid-19), there are public health restrictions and other related disruptions which could have adverse effects on the business and operations of the Corporation, including production delays or interruptions. These factors are beyond the control of the Corporation and it is difficult to assess how these, and other factors, will continue to affect the Corporation and the market price of the Common Shares. In light of the current situation, as at the date of this AIF, the Corporation continues to review and assess its business plans and assumptions

regarding the business environment, as well as its estimates of future production, cash flows, operating costs and capital expenditures.

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

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

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

Reliance on Third-Party Operators: The Group has partners in many of the licence, lease and PSC areas associated with the Group's assets. In some cases, including in the Aquitaine Basin in France, the Group is not the operator of the licence and concession areas and must depend on the competence, expertise, judgment and financial resources (in addition to those of its own and, where relevant, other partnership and joint venture companies) of the partner operator and the operator's compliance with the terms of the licences, leases, PSCs and contractual arrangements. Mismanagement of licence areas by the Group's partner operators or defaults by them in meeting required obligations may result in significant exploration, production or development delays, losses or increased costs to the Group. **In addition, the Coronavirus (Covid-19), and the restrictions and disruptions related to it, may adversely affect third-party operators which could have adverse effects on the Corporation, its revenues and cash flows and the market price of the Common Shares.**

Reliance on Third-Party Infrastructure: The Group delivers the products associated with the Group's assets by gathering, processing and pipeline systems, some of which it does not own. The amount of oil and natural gas that the Group is able to produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities (for example, the Total-operated Grandpuits refinery in the Paris Basin, France), could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Group's business financial condition, results of operations, cash flows and future prospects. **In addition, the Coronavirus (Covid-19), and the restrictions and disruptions related to it, may adversely affect third-party infrastructure which could have adverse effects on the Corporation, its revenues and cash flows and the market price of the Common Shares.**

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

In addition, the maximum amount that the Group is permitted to borrow under its credit facilities is subject to periodic review by the lenders. The Group's lenders generally review its oil and gas production and reserves, forecast oil and gas prices, general business environment and other factors to establish the amount which the Group is entitled to borrow. In the event the lenders decide to reduce the amount of credit available under the senior credit facilities, the Group may be required to repay all or a portion of the amounts owing thereunder. **In 2020, the Coronavirus (Covid-19) and the restrictions and disruptions related to it, as well as the actions of producers such as Saudi Arabia and Russia, have had a drastic** adverse effect on the world demand for, and prices of, oil and gas. These factors are beyond the control of the Corporation and it is difficult to assess how these, and other factors, will affect the Corporation and its access to credit facilities and other debt instruments.

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

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

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

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

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

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

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

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

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

Economic and Political Developments in Countries in which the Group Operates: International operations are subject to political, economic and other uncertainties. The Group's assets could also be adversely affected by changes in applicable laws and policies of Canada, Malaysia and France (including relating to the Coronavirus (Covid-19)), which could have a negative impact on the Group.

In 2020, in response to the Coronavirus (Covid-19), there are public health restrictions and other related disruptions which could have adverse effects on the business and operations of the Corporation, including production delays or interruptions. These factors are beyond the control of the Corporation and it is difficult to assess how these, and other factors, will continue to affect the Corporation and the market price of the Common Shares. In light of the current situation, as at the date of this AIF, the Corporation continues to review and assess its business plans and assumptions regarding the business environment, as well as its estimates of future production, cash flows, operating costs and capital expenditures.

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

Information Security: The Group is heavily dependent on its information systems and computer based programs. Failure, malfunction or security breaches by computer hackers and cyberterrorists of any such systems or programs may have a material adverse effect on the Group's business and systems, potentially affecting network assets and people's privacy. The Group manages cyber security risk by ensuring appropriate technologies, processes and practices are effectively designed and implemented to help prevent, detect and respond to threats as they emerge and evolve. The primary risks to the Group include, loss of data, destruction or corruption of data, compromising of confidential customer or employee information, leaked information, disruption of business, theft or extortion of funds, regulatory infractions, loss of competitive advantage and reputational damage.

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

Significant Shareholder: Nemesia S.à.r.l. and Zebra Holdings and Investments S.à.r.l., investment companies wholly owned by a Lundin family trust (the "**Trust Entities**"), own approximately 26 percent of the aggregate voting shares of the Corporation. The Trust Entities' holdings may allow them to significantly affect substantially all the actions taken by the shareholders of the Corporation, including the election of directors. As long as the Trust Entities maintain a significant interest in the Corporation, it is likely that the Trust Entities will exercise significant influence on the ability of the Corporation to, among other things, amend the articles of the Corporation, enter into a change in control transaction of the Corporation that might otherwise be beneficial to its shareholders and may also discourage acquisition bids for the Corporation. There is a risk that the interests of the Trust Entities will not be aligned with the interests of other shareholders.

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

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

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

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

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

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

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

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

Financial markets can experience significant price and volume fluctuations that may particularly affect the market prices of equity securities of companies and that may be unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the Common Shares may decline even if the Corporation's operating results, underlying asset values or prospects have not changed. These factors, as well as other related factors, may cause decreases in asset values, which may result in impairment losses. **In 2020, the Coronavirus (Covid-19) and the restrictions and disruptions related to it, as well as the actions of producers such as Saudi Arabia and Russia, have had a drastic adverse effect on the world demand for, and prices of, oil and gas as well as the market price of the shares of oil and gas companies generally. These factors are beyond the control of the Corporation and it is difficult to assess how these, and other factors, will continue to affect the Corporation and the market price of the Common Shares.**

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Part I - Date of Statement

The Statement of Reserves Data and Other Oil and Gas Information is prepared as at March 24, 2020.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada are effective as of December 31, 2019, and are included in reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Sproule's December 31, 2019 price forecasts. The reserves report by Sproule is dated January 27, 2020 and the contingent resource reports by Sproule are dated January 30, 2020.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France and Malaysia are effective as of December 31, 2019, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2019 price forecasts. The report by ERCE is dated February 3, 2020.

The reserve estimates, contingent resource estimates and estimate of future net revenue, and related information, including product types, in respect of IPC's oil and gas assets in Canada, France and Malaysia, based on the above-mentioned Sproule and ERCE reports, are contained in Parts II to VI below and in Schedule A.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of the oil and gas assets acquired in the Granite Acquisition are effective as of December 31, 2019, and are included in reports prepared by Sproule on behalf of IPC, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2019 price forecasts. The reports by Sproule are dated January 15, 2020. The Granite Acquisition was completed on March 5, 2020.

The reserves estimates, contingent resource estimates and estimate of future net revenue, and related information, including product types, in respect of the oil and gas assets acquired in the Granite Acqusition, based on the above-mentioned Sproule reports, are contained in Schedule B.

The price forecasts used in the reserve reports are available on the website of Sproule (sproule.com), and are provided below in "Part III – Pricing Assumptions". These price forecasts are as at December 31, 2019 and may not be reflective of current and future forecast commodity prices.

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

2P reserves and contingent resources included in the reports prepared by Sproule and ERCE in respect of IPC's oil and gas assets in Canada, France and Malaysia have been aggregated in this document by IPC and may also be aggregated by IPC with the 2P reserves and contingent resources attributable to the Granite Acquisition. Estimates of reserves and future net revenue for individual properties may not reflect the same level of confidence as estimates of reserves and future net revenue for all properties, due to aggregation. This document 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 document do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material.

See "Reserves and Resource Advisory" above.

The Form 51-101F2 Report on Reserves Data, Contingent Resources Data and Prospective Resources Data by Independent Qualified Reserves Evaluator or Auditor (Sproule), the Form 51-101F2 Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor (ERCE) and the Form 51-101F3 Report of Management are attached to this AIF as Schedules C, D and E.

Part II - Disclosure of Reserves Data

The tables below set out the reserves volumes and net present values by country. IPC's working interest volumes are reported herein as the gross reserves. The reserves adjusted for royalties or similar are reported as net reserves.

Item 2.1.1a – Breakdown of Proved Reserves (Forecast Case)
Breakdown of Reserves by Product Type

	Bitumen		Heavy Crude Oil		Light & Medium Oil		Natural Gas Liquids		Conventional Natural Gas (Non-Associated & Associated)		Oil Equivalent	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	MMbbl	MMbbl	MMbbl	MMbbl	MMboe	MMboe	MMboe	MMboe	Bscf	Bscf	MMboe	MMboe
Proved Developed Producing												
Canada	-	-	41.7	36.4	-	-	0.0	0.0	370.4	351.1	103.4	94.9
France	-	-	-	-	7.6	6.7	-	-	-	-	7.6	6.7
Malaysia	-	-	-	-	4.4	3.8	-	-	-	-	4.4	3.8
IPC Total	-	-	41.7	36.4	12.0	10.5	0.0	0.0	370.4	351.1	115.5	105.4
Proved Developed Non-Producing												
Canada	-	-	2.9	2.6	-	-	0.0	0.0	18.8	17.8	6.0	5.6
France	-	-	-	-	0.0	0.0	-	-	-	-	0.0	0.0
Malaysia	-	-	-	-	1.4	1.2	-	-	-	-	1.4	1.2
IPC Total	-	-	2.9	2.6	1.4	1.2	0.0	0.0	18.8	17.8	7.4	6.8
Proved Undeveloped												
Canada	-	-	63.5	51.4	-	-	0.0	0.0	0.1	0.1	63.5	51.5
France	-	-	-	-	1.4	1.2	-	-	-	-	1.4	1.2
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-
IPC Total	-	-	63.5	51.4	1.4	1.2	0.0	0.0	0.1	0.1	64.9	52.6
Total Proved (1P)												
Canada	-	-	108.0	90.5	-	-	0.0	0.0	389.3	369.0	172.9	152.0
France	-	-	-	-	9.0	7.9	-	-	-	-	9.0	7.9
Malaysia	-	-	-	-	5.8	5.0	-	-	-	-	5.8	5.0
IPC Total	-	-	108.0	90.5	14.8	12.9	0.0	0.0	389.3	369.0	187.7	164.9

Item 2.1.1b – Breakdown of Proved and Probable Reserves (Forecast Case)
Breakdown of Reserves by Product Type

	Bitumen		Heavy Crude Oil		Light & Medium Oil		Natural Gas Liquids		Conventional Natural Gas (Non-Associated & Associated)		Oil Equivalent	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	MMbbl	MMbbl	MMbbl	MMbbl	MMbbl	MMbbl	MMboe	MMboe	Bscf	Bscf	MMboe	MMboe
Proved plus Probable Developed Producing												
Canada	-	-	62.4	52.8	-	-	0.0	0.0	444.6	421.4	136.5	123.0
France	-	-	-	-	14.3	12.6	-	-	-	-	14.3	12.6
Malaysia	-	-	-	-	5.3	4.6	-	-	-	-	5.3	4.6
IPC Total	-	-	-	-	19.6	17.2	0.0	0.0	444.6	421.4	156.0	140.2
Proved plus Probable Developed Non-Producing												
Canada	-	-	7.5	6.6	-	-	0.0	0.0	45.3	43.0	15.0	13.8
France	-	-	-	-	0.0	0.0	-	-	-	-	0.0	0.0
Malaysia	-	-	-	-	2.3	1.8	-	-	-	-	2.3	1.8
IPC Total	-	-	7.5	6.6	2.3	1.9	0.0	0.0	45.3	43.0	17.3	15.6
Proved plus Probable Undeveloped												
Canada	-	-	109.5	87.3	-	-	0.0	0.0	0.3	0.2	109.5	87.4
France	-	-	-	-	3.3	2.8	-	-	-	-	3.3	2.8
Malaysia	-	-	-	-	0.0	0.0	-	-	-	-	0.0	0.0
IPC Total	-	-	109.5	87.3	3.3	2.8	0.0	0.0	0.3	0.2	112.8	90.2
Total Proved plus Probable (2P)												
Canada	-	-	179.3	146.7	-	-	0.0	0.0	490.2	464.7	261.0	224.1
France	-	-	-	-	17.6	15.4	-	-	-	-	17.6	15.4
Malaysia	-	-	-	-	7.6	6.4	-	-	-	-	7.6	6.4
IPC Total	-	-	179.3	146.7	25.1	21.8	0.0	0.0	490.2	464.7	286.2	246.0
Total Probable (PB)												
Canada	-	-	71.3	56.2	-	-	0.0	0.0	100.9	95.6	88.1	72.2
France	-	-	-	-	8.5	7.5	-	-	-	-	8.5	7.5
Malaysia	-	-	-	-	1.8	1.4	-	-	-	-	1.8	1.4
IPC Total	-	-	71.3	56.2	10.3	8.9	0.0	0.0	100.9	95.6	98.4	81.1

Item 2.1.2a – Net Present Value of Future Net Revenue (Forecast Case), Proved Reserves
Breakdown of NPV by country and in aggregate MM U.S.$

	Before Deducting Income Tax, Discounted at						After Deducting Income Tax, Discounted at						Unit Value Before Income Tax, discounted at 10%
	0%	5%	8%	10%	15%	20%	0%	5%	8%	10%	15%	20%	US$/boe
Proved Developed Producing													
Canada	809.1	879.7	837.3	801.5	712.0	634.8	735.5	826.3	792.8	761.9	682.0	611.6	8.4
France	151.7	144.8	135.7	129.2	113.9	100.7	103.5	108.2	103.9	99.9	89.3	79.5	19.3
Malaysia	145.6	137.4	132.9	130.0	123.3	117.2	145.6	137.4	132.9	130.0	123.3	117.2	34.3
IPC Total	1 106.4	1 161.9	1 105.9	1 060.8	949.2	852.7	984.5	1 072.0	1 029.5	991.8	894.6	808.3	10.1
Proved Developed Non-Producing													
Canada	69.1	47.4	38.4	33.6	24.3	18.0	52.9	35.4	28.3	24.4	17.3	12.4	6.0
France	0.1	0.2	0.2	0.2	0.3	0.3	0.1	0.1	0.1	0.2	0.2	0.3	24.7
Malaysia	86.4	75.6	70.2	66.9	59.9	54.1	76.8	67.5	62.8	60.0	53.9	48.9	57.5
IPC Total	155.6	123.2	108.8	100.7	84.6	72.5	129.8	103.0	91.2	84.6	71.4	61.6	14.9
Proved Undeveloped													
Canada	1104.3	618.9	444.8	360.6	221.6	142.8	803.7	447.2	317.6	255.1	152.5	95.0	7.0
France	13.5	9.1	5.7	3.5	-1.3	-5.1	9.0	5.9	3.0	1.2	-3.0	-6.4	2.9
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-
IPC Total	1 117.8	628.1	450.5	364.1	220.3	137.7	812.7	453.2	320.7	256.3	149.5	88.6	6.9
Total Proved													
Canada	1 982.6	1 546.0	1 320.5	1 195.7	958.0	795.6	1 592.1	1 309.0	1 138.7	1041.5	851.8	718.9	7.9
France	165.3	154.1	141.6	133.0	112.9	96.0	112.6	114.3	107.0	101.2	86.5	73.4	16.8
Malaysia	231.9	213.0	203.1	196.9	183.2	171.4	222.4	204.9	195.7	190.0	177.2	166.2	39.7
IPC Total	2 379.8	1 913.1	1 665.1	1 525.6	1 254.1	1 063.0	1 927.1	1 628.2	1 441.5	1 332.8	1 115.5	958.5	9.3

All figures in the above table are in USD millions, unless otherwise indicated.

Item 2.1.2b – Net Present Value of Future Net Revenue (Forecast Case), Proved and Probable Reserves
Breakdown of NPV by country and in aggregate MM U.S.$

	Before Deducting Income Tax, Discounted at						After Deducting Income Tax, Discounted at						Unit Value Before Income Tax, discounted at 10%
	0%	5%	8%	10%	15%	20%	0%	5%	8%	10%	15%	20%	US$/boe
Proved plus Probable Developed Producing													
Canada	1 359.1	1 290.5	1 176.8	1 103.0	943.7	820.2	1 152.3	1 142.9	1 053.9	993.6	860.2	754.9	9.0
France	358.5	275.0	235.5	214.1	174.1	146.8	250.4	207.4	180.4	165.0	135.2	114.4	17.0
Malaysia	204.8	188.4	179.7	174.4	162.4	152.0	201.7	185.8	177.5	172.3	160.7	150.6	38.3
IPC Total	1 922.4	1 753.9	1 591.9	1 491.5	1 280.2	1 119.0	1 604.3	1 536.1	1 411.8	1 330.9	1 156.1	1 019.9	10.6
Proved plus Probable Developed Non-Producing													
Canada	221.9	136.1	104.7	88.7	60.3	42.4	171.5	103.4	78.8	66.3	44.4	30.7	6.4
France	1.2	1.1	1.0	1.0	0.9	0.8	0.9	0.8	0.7	0.7	0.6	0.5	55.7
Malaysia	134.3	118.8	110.9	106.2	95.8	87.2	103.7	92.0	86.1	82.5	74.7	68.3	57.8
IPC Total	357.4	256.0	216.6	195.9	157.0	130.3	276.1	1961.	165.5	149.5	119.7	99.5	12.5
Proved plus Probable Undeveloped													
Canada	2 458.1	1 212.1	820.2	641.8	364.9	219.1	1 800.8	883.5	592.1	459.5	254.3	147.0	7.3
France	87.8	60.0	46.0	38.6	25.2	16.4	62.2	44.0	33.1	27.2	16.5	9.5	13.7
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-
IPC Total	2 545.9	1 272.2	866.2	680.5	390.1	235.6	1 862.9	927.5	625.2	486.8	270.8	156.4	7.5
Total Proved plus Probable (2P)													
Canada	4 039.1	2 638.7	2 101.6	1 833.6	1 368.9	1 081.7	3 124.6	2 129.8	1 724.8	1 519.5	1 158.9	932.5	8.2
France	447.4	336.1	282.5	253.7	200.2	164.1	313.4	252.2	214.2	192.9	152.3	124.4	16.4
Malaysia	339.1	307.2	290.6	280.5	258.2	239.1	305.4	277.8	263.5	254.8	235.4	218.8	43.9
IPC Total	4 825.7	3 282.0	26 74.8	2 367.8	1 827.2	1 484.9	3 743.4	2 659.7	2 202.5	1 967.3	1 546.7	1 275.8	9.6
Total Probable (PB)													
Canada	2 056.5	1 092.7	781.2	637.9	410.9	286.1	1 532.5	820.8	586.1	478.0	307.2	213.6	8.8
France	282.2	182.0	140.9	120.7	87.3	68.0	200.8	137.9	107.1	91.7	65.9	51.0	16.1
Malaysia	107.2	94.2	87.6	83.6	74.9	67.8	83.0	72.9	67.8	64.8	58.2	52.7	58.4
IPC Total	2 445.9	1 368.9	1 009.6	842.2	573.1	421.9	1 816.3	1 031.5	761	634.5	431.2	317.3	10.4

All figures in the above table are in USD millions, unless otherwise indicated.

Item 2.1.3b – Elements of Future Net Revenue (Forecast Case)
Undiscounted

	Revenue MM U.S.$	Royalties MM U.S.$	Operating Costs MM U.S.$	Development Costs MM U.S.$	Abandonment Costs MM U.S.$	Future Net Revenue Before Income Taxes MM U.S.$	Income Taxes MM U.S.$	Future Net Revenue After Income Taxes MM U.S.$
Total Proved								
Canada	6 501	913	2 381	684	541	1 983	390	1 592
France	696	82	315	48	86	165	53	113
Malaysia	548	45	242	4	25	232	10	222
IPC Total	7 745	1 040	2 938	735	652	2 380	453	1 927
Total Proved plus Probable								
Canada	11 017	1 788	3 763	807	620	4 039	915	3 125
France	1 541	180	747	48	119	447	134	313
Malaysia	678	59	251	4	25	339	34	305
IPC Total	13 236	2 027	4 760	859	765	4 826	1 082	3 743

All figures in the above table are in USD millions, unless otherwise indicated.

Item 2.1.3c – Net Present Value of Future Net Revenue (Forecast Case)
By product type, in each case including associated by-products

	Primary Product Type					
Future Net Revenue BTAX at 10% Discount	Bitumen	Heavy Crude Oil	Light & Medium Crude Oil	Natural Gas Liquids	Conventional Natural Gas	Total
Total Proved Reserves	-	944	330	-	252	1 526
Total Proved and Probable (2P) Reserves	-	1 523	535	-	311	2 368
USD per boe by product type	USD/bbl	USD/bbl	USD/bbl	USD/bbl	USD/Mscf	USD/boe
Total Proved Reserves	-	10.5	26.0	-	0.7	8.7
Total Proved and Probable (2P) Reserves	-	10.3	24.0	-	0.7	9.2

All figures in the above table are in USD millions, unless otherwise indicated.

Part III – Pricing Assumptions

Forecast prices used in this document are sourced from the Sproule forecasts published December 31, 2019.

Item 3.2 – Forecast Prices Used in Estimates

	Brent (U.S.$/bbl)	WTI Crude Oil (U.S.$/bbl)	Edmonton Pentanes Plus (U.S.$/bbl)	Western Canadian Select (U.S.$/bbl)	Natural Gas AECO ($US/mmbtu)	Natural Gas Empress ($US/ mmbtu)	Capital Cost Inflation Rate (%/yr)	USD/CAD Exchange Rate ($US/$Cdn)
Historical								
2015	53.64	48.80	48.12	35.10	2.11	2.26	(18.7%)	0.78
2016	45.04	43.32	42.06	29.36	1.65	1.78	(9.7%)	0.76
2017	54.83	50.95	51.82	38.74	1.69	2.10	2.4%	0.77
2018	71.53	64.77	61.23	40.41	1.18	2.39	4.2%	0.77
2019	64.17	57.02	53.83	44.31	1.36	1.89	0.7%	0.75
Forecast								
2020	65.00	61.00	58.00	45.46	1.55	2.19	0.0	0.76
2021	68.00	65.00	62.00	49.26	1.75	2.39	1.0	0.77
2022	70.00	67.00	64.00	51.02	2.25	2.61	2.0	0.80
2023	71.40	68.34	65.34	52.03	2.31	2.67	2.0	0.80
2024	72.83	69.71	66.70	53.07	2.38	2.74	2.0	0.80
2025	74.28	71.10	68.10	54.14	2.45	2.81	2.0	0.80
2026	75.77	72.52	69.52	55.22	2.52	2.88	2.0	0.80
2027	77.29	73.97	70.98	56.32	2.59	2.95	2.0	0.80
2028	78.83	75.45	72.46	57.45	2.66	3.02	2.0	0.80
2029	80.41	76.96	73.96	58.60	2.74	3.10	2.0	0.80
2030	82.02	78.50	75.50	59.77	2.81	3.17	2.0	0.80
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.80

International Currency Exchange Rate Assumptions

Rate	2020	2021	2022	2023	2024 on
USD/EUR	1.15	1.15	1.15	1.15	1.15
MYR/USD	4.20	4.20	4.20	4.20	4.20

Part IV – Reconciliation of Changes in Reserves

Item 4.1 – Reserves Reconciliation

	Malaysia Light & Medium Oil MMboe	France Light & Medium Oil MMboe	Canada Heavy Oil MMboe	Canada Conven-tional Natural Gas MMboe	IPC Total Oil Equivalent MMboe
Proved Reserves					
Opening Balance Dec 31, 2018	6.5	9.8	112.4	61.6	**190.3**
Extensions and improved recovery	-	-	+0.1	0	**+0.1**
Technical revisions	+1.4	+0.1	+3.0	+9.4	**+13.9**
Acquisitions	-	-	-	-	**-**
Dispositions	-	-	-	-	**-**
Economic factors	-	-0.0	-0.1	+0.2	**+0.1**
Production	-2.1	-0.9	-7.5	-6.2	**-16.7**
Closing Balance Dec 31, 2019	5.8	9.0	108	64.9	**187.7**
Probable Reserves					
Opening Balance Dec 31, 2018	2.8	8.5	73.4	13.0	**97.6**
Extensions and improved recovery	-	-	+0.1	+1.1	**+1.2**
Technical revisions	-1.0	+0.3	-2.1	+2.7	**-0.1**
Acquisitions	-	-	-	-	**-**
Dispositions	-	-	-	-	**-**
Economic factors	-	-0.2	-	-	**-0.2**
Production	-	-	-	-	**-**
Closing Balance Dec 31, 2019	1.8	8.5	71.3	16.8	**98.4**
Proved plus Probable Reserves					
Opening Balance Dec 31, 2018	9.3	18.3	185.8	74.6	**288.0**
Extensions and improved recovery	-	-	+0.2	+1.1	**+1.3**
Technical revisions	+0.4	+0.4	+0.9	+12.1	**+13.7**
Acquisitions	-	-	-	-	**-**
Dispositions	-	-	-	-	**-**
Economic factors	-	-0.2	-0.1	+0.2	**-0.1**
Production	-2.1	-0.9	-7.5	-6.2	**-16.7**
Closing Balance Dec 31, 2019	7.6	17.6	179.3	81.7	**286.2**

Technical revisions for 2019 are driven by:

- The drilling of a pilot and production well in the K10.2 reservoir in the north east of the Bertam field in Malaysia
- Adjusted sanction volumes for the Villerperdue West development in France
- For Canada positive technical revisions were realized for both TP (+7.2%) and TPP (+5.0%) reserves, essentially offsetting production. Most of the positive revisions were in the Suffield area (due to positive performance of both the shallow gas assets and Mannville oil assets) with some additional positive revisions due to performance realized for the Onion Lake thermal project.

Part V – Additional Information Relating to Reserves Data

Item 5.1.1a, 5.1.2a – Undeveloped Reserves First Attributed by Product Type

	Light & Medium Crude Oil		Heavy Crude Oil		Conventional Natural Gas		Natural Gas Liquids		Total	
	First Attributed MMbbl	YE Total MMbbl	First Attributed MMbbl	YE Total MMbbl	First Attributed MMboe	YE Total MMboe	First Attributed MMboe	YE Total MMboe	First Attributed MMboe	YE Total MMboe
December 31, 2017	0.7	2.2	-	-	-	-	-	-	0.7	2.2
December 31, 2018	2.4	1.4	67.2	67.2	1.1	1.1	0.0	0.0	70.7	69.7
December 31, 2019	0.0	1.4	0.2	63.5	-	0.1	-	0.0	0.2	65.0
December 31, 2017	0.8	1.7	-	-	-	-	-	-	0.8	1.7
December 31, 2018	2.0	1.9	47.6	47.6	0.7	0.7	0.0	0.0	50.3	50.2
December 31, 2019	-	1.9	-	46.0	-	0.1	-	0.0	-	48.0

Development forecasts documented in this report are consistent with COGE Handbook recommended guidance regarding the development of undeveloped petroleum and natural gas volumes as follows:

1) three years for the assignment of proved reserves and five years for the assignment of probable reserves in conventional development properties,

2) five years for the assignment of proved reserves and ten years for the assignment of probable reserves in resource play development properties, and

3) heavy oil and bitumen thermal projects are not constrained by the above timing rules and are included on a "drill to fill the facility" timing basis.

In some situations, development forecasts of undeveloped petroleum and natural gas volumes have extended beyond the development timing guidance identified above, as the result of other factors which are not contingencies. This delay has no consequent impact on the confidence level associated with the reserves estimate in each category, and the Company has provided assurance of their corporate commitment for development. In the following section, the properties, the timing for the extended development plan and the rationale is documented.

The following table lists the properties with future development plan timing that differ from the COGE Handbook guidance listed above.

Properties	Final Year of Development Plan		Rational for Development Timing
	Proved	Probable	
Mooney	2026	2026	An ASP Project with ongoing, extensive development opportunity. Development deferral is designed to align future capital investments with estimated future cash flow.

Item 5.2 – Significant Factors or Uncertainties Affecting Reserves Data

See "**Cautionary Statement regarding Forward-Looking Information**","**Reserves and Resource Advisory**" and "**Risk Factors**" above.

In Canada, the main uncertainties at Suffield relate to performance of future infill wells and the effectiveness of the alkaline-surfactant-polymer injection in mobilizing bypassed oil. At Onion Lake Thermal, the main uncertainties include the performance of future drilling pads and the steam generation capabilities and effectiveness. These uncertainties are captured in the 1P to 2P range of estimates. Other uncertainties include weather related downtime and facility performance and effectiveness of Suffield 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.

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 2P range of estimates. The performance of the recent and future development wells at Vert La Gravelle is also an uncertainty considered in the estimates. Villeperdue West development performance is an uncertainty captured in the 1P to 2P range. 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, given the uncertainties regarding the application of this new legislation, the reported probable and possible reserves do not assume cessation at such date.

In Malaysia, the main uncertainties relate to rate of water cut build of the recent 2019/Q120 infill wells. This uncertainty has been captured in the 1P to 2P range of estimates. Other uncertainties include, but are not limited to, facility uptime performance, electric submersible pump performance 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.

Also note that in December 2019, a mechanical issue detrimentally impacted the productivity of the A15 well in Malaysia. This has resulted in the need to perform well remediation works on the A15 well. The impact on production or costs has not been accounted for in the values and production forecasts stated in this report.

Item 5.3 Future Development Costs MM U.S.$

	2020	2021	2022	2023	2024	2025 on	Total for all years undiscounted	Total for all years discounted at 10% p.a.
Total Proved								
France	47.6	-	-	-	-	-	47.6	45.4
Malaysia	4.0	-	-	-	-	-	4.0	3.9
Canada	50.0	60.8	29.0	10.3	29.6	503.9	683.7	329.8
Total	101.6	60.8	29.0	10.3	29.6	503.9	735.3	379.1
Total Proved Plus Probable								
France	47.6	-	-	-	-	-	47.6	45.4
Malaysia	4.0	-	-	-	-	-	4.0	3.9
Canada	51.7	97.5	47.2	24.7	45.1	540.7	807.0	391.9
Total	103.3	97.5	47.2	24.7	45.1	540.7	858.6	441.2

All figures in the above table are in USD millions, unless otherwise indicated.

IPC'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 document. 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.

Part VI – Other Oil and Gas Information

Item 6.1 – Oil and Gas Properties and Wells

The assets described in this report are located in Canada, France and Malaysia. The Canadian assets are located in Alberta and Saskatchewan. The French and Canadian assets are exclusively located onshore. The Malaysian asset is located offshore.

Item 6.1.2. Producing and non-producing well counts

	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	13	10	4	3	-	-	-	-
France	116	109	1	1	-	-	-	-
Canada	859	841	1 263	1 214	10 181	10 171	718	706

Item 6.2 – Properties with no attributed reserves

							Outstanding Work Commitments					
Country	Property	Operator	W.I.	Location	Gross Area	Net Area	Nature of Outstanding Commitment	Detail of Work Commitment	Gross Amount	Amount planned in 2019 Towards Commitments	Amount planned after 2019 Towards Commitments	End of Commitment Period
					ha	Ha			EUR	USD	USD	
France	Est-Champagne	IPC	100%	Onshore	99 100	13 1800	None	-	-4 000 000	-	-	-2024
	Estheria	IPC	100%	Onshore	4 300	4 300	None	-	-1 200 000	-	-	-2020
	Plivot	IPC	100%	Onshore	19 800	19 800	None	-	-870 755	-	-	-2020
Malaysia	PM307 GHA	IPC	75.0%	Offshore	10800	8100	None	-	-	-	-	-

Item 6.2.1 –Significant factors or uncertainties relevant to properties with no attributed reserves

IPC's properties with no attributed reserves include three exploration licenses in France and a Gas Holding Area (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.

PM307 GHA in Malaysia includes the Tembakau gas discovery which is currently being reviewed for commerciality.

In Canada, approximately 1,571 hectares of land are subject to expiry in 2020.

Item 6.5 – Tax Horizon

In Canada, as of January 1, 2020, IPC has depreciable tax pools brought forward of CAD 730 million as well as tax loss carry forward balances of CAD 469 million. IPC expects no cash taxes to be paid in Canada for several years.

In Malaysia, the Corporation has a significant cost recovery balance of USD 285 million as of January 1, 2020. IPC has depreciable tax pools of USD 70 million and Petroleum Income Tax loss carryforwards of USD 16 million as of January 1, 2020. Management expects to utilize the benefits of these tax positions and expects to pay insignificant taxes in Malaysia in the next few years.

IPC pays current taxes in France. The tax rate steps down from 28% in 2020 to 25% by 2022.

Item 6.6 – Costs Incurred

2019 Costs Incurred, in USD millions

	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
France	-	-	0.5	39.7
Malaysia	-	-	17.3	36.7
Canada	-	3.8	9.8	72.7
Total	**-**	**3.8**	**27.6**	**149.1**

Item 6.7.1 – Exploration and Development Activity

2019 Exploration Activity Summary, wells completed

	France		Malaysia		Canada	
	gross	net	gross	net	gross	net
Wells completed	-	-	1	0.75	1	1
Completed as						
Oil well	-	-	-	-	1	1
Gas well	-	-	-	-	-	-
Service well	-	-	-	-	-	-
Stratigraphic test well	-	-	-	-	-	-
Dry hole	-	-	1	0.75	-	-

2019 Development Activity Summary, wells completed

	France		Malaysia		Canada	
	gross	net	gross	net	gross	net
Wells completed	2	2	2	1.5	39	33
Completed as						
Oil well	1	1	2	1.5	33	30
Gas well	-	-	-	-	-	-
Service well	-	-	-	-	5	1
Stratigraphic test well	1	1	-	-	-	2
Dry hole	-	-	-	-	1	-

Malaysia

A three well infill campaign, A18, A19 and A20, was completed successfully during 2019 and Q1 2020.

Additional development potential has been identified in the field which is discussed further in the Statement of Contingent Resources Data contained in **Schedule A** of this AIF.

France

A three well development Vert La Gravelle drilling campaign was completed successfully during 2019 and Q1 2020.

In addition to the general maintenance programme, infrastructure investments in the short term will include well work in the Les Arbousiers field in the Aquitaine Basin and preparation for possible future development activities in the western part of the Villeperdue field.

Canada

Suffield Area

Development plans in the Suffield property 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 1,000 metres dual leg horizontal producers although the length varies according to the reservoir and in some instances 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 was completed in 2019. Activity in 2019 included commissioning the already installed facilities to inect an alkaline-surfactant-polymer water solution into the reservoir to mobilize oil that would not be recoverable with water-flooding alone. The existing producing and injection wells were supplemented by drilling another six producers and two injectors. This method has been applied in the nearby and geologically analogous UU and YYY pools with positive reservoir response.

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

Onion Lake

During 2019, work continued on a facility optimization program of the thermal facilities. This optimization work was completed in 2019 with a resulting increase in steam generation capacity which will enable an increase to thermal production

Construction of a river water intake project and the second sustaining well pad commenced in 2019.

IPC Canada entered into a Transportation Services Agreement which provides firm transportation from its Onion Lake Thermal facility and enables IPC Canada to have pipeline access to key sales points, including Hardisty. The pipeline is expected to be completed at the end of 2021 and may reduce trucking costs currently being incurred in order to bring oil to market.

Mooney

Primary development of the phase two and phase three lands at Mooney is continuing. As of December 2019, a total of 35 horizontal wells have been drilled on the phase two lands and six horizontal wells have been drilled on phase three lands. In 2013, regulatory approval was applied for and received to expand the existing ASP flood to the phase two lands. Due to low oil prices over the last several years, the expansion of the ASP flood to phase two lands was deferred.

Blackrod

In 2019, a third pilot well pair, Well Pair 3 was drilled Well Pair 3 was designed to incorporate recently proven technologies and was drilled longer than the first two well pairs with the horizontal section of the well reaching approximately 1,400 metres in length, as well as incorporating inflow control technology.

Item 6.8 – 2020 Forecast Saleable Production Estimates in Reserves Report

	Bitumen (Mbbl/d)	Light & Medium Crude Oil (Mbbl/d)	Heavy Crude Oil (Mbbl/d)	Convent-Ional Natural Gas (Mboe/d)	Natural Gas Liquids (Mboe/d)	Total (Mboe/d)
Total Proved (1P) Scenario						
France	-	2.9	-	-	-	2.9
Malaysia	-	4.6	-	-	-	4.6
Canada	-	-	18.8	16.3	-	35.1
Total	-	-7.5	-18.8	-16.3	-	-42.6
Total Proved plus Probable (2P) Scenario						
France	-	3.4	-	-	-	3.4
Malaysia	-	5.4	-	-	-	5.4
Canada	-	-	20.4	16.6	-	36.9
Total	-	8.8	20.4	16.6	-	45.8

Item 6.9 – Production history by quarter for most recent financial year split by product type and average netbacks

Canada - Heavy Crude Oil	Q1 '19	Q2 '19	Q3 '19	Q4 '19	2019
Production, Mbopd	19.1	18.9	19.4	20.5	**19.5**
Unit Volume Average (US$/bbl)					
Prices received	42.81	45.52	41.14	38.22	**41.83**
Royalties paid	3.18	4.43	3.91	3.21	**3.67**
Production costs	20.65	20.54	18.05	19.13	**19.57**
Netback	18.99	20.56	19.18	15.88	**18.59**

Canada – Conventional Natural Gas	Q1 '19	Q2 '19	Q3 '19	Q4 '19	2019
Production, Mboepd	16.4	19.0	18.4	18.1	**18.0**
Unit Volume Average (US$/boe)					
Prices received	16.30	10.31	9.62	11.71	**11.83**
Royalties paid	0.31	0.41	0.04	0.21	**0.24**
Production costs	6.82	5.91	5.69	4.98	**5.82**
Netback	9.18	3.99	3.89	6.51	**5.77**

Canada – (Oil & Gas)	Q1 '19	Q2 '19	Q3 '19	Q4 '19	2019
Production, Mboepd	35.5	37.9	37.8	38.7	**37.5**
Unit Volume Average (US$/bbl)					
Prices received	30.58	27.86	25.83	25.78	**27.44**
Royalties paid	1.85	2.41	2.03	1.81	**2.03**
Production costs	14.27	13.20	12.05	12.49	**12.97**
Netback	14.46	12.25	11.76	11.48	**12.44**

Malaysia – Light & Medium Crude Oil	Q1 '19	Q2 '19	Q3 '19	Q4 '19	2019
Production, Mboepd	6.4	6.2	5.1	5.4	**5.8**
Unit Volume Average (US$/bbl)					
Prices received	69.34	56.64	69.10	82.16	**68.89**
Royalties paid	0.00	0.00	0.00	0.00	**0.00**
Production costs	17.32	2.51	20.41	24.91	**15.83**
Netback	52.02	54.13	48.69	57.25	**53.06**

France – Light & Medium Crude Oil	Q1 '19	Q2 '19	Q3 '19	Q4 '19	2019
Production, Mboepd	2.4	2.0	2.5	3.2	**2.5**
Unit Volume Average (US$/bbl)					
Prices received	70.16	53.11	68.97	66.46	**65.38**
Royalties paid	0.00	0.00	0.00	0.00	**0.00**
Production costs	32.72	30.43	38.19	29.28	**32.55**
Netback	37.44	22.68	30.77	37.18	**32.83**

IPC Total – Oil Equivalent	Q1 '19	Q2 '19	Q3 '19	Q4 '19	2019
Production, Mboepd	44.4	46.1	45.4	47.2	**45.8**
Unit Volume Average (US$/bbl)					
Prices received	38.39	32.83	33.15	34.98	**34.80**
Royalties paid	1.48	1.99	1.69	1.48	**1.66**
Production costs	15.72	12.49	14.43	15.04	**14.41**
Netback	21.19	18.35	17.03	18.46	**18.73**

Netbacks reflected in the table above are with respect to production volumes.

DIVIDENDS AND DISTRIBUTIONS

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. In addition, in 2019, the Corporation implemented a share repurchase program, stating that IPC believes that such program represents an effective use of IPC's capital and an efficient way to return value to IPC's shareholders.

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, including compliance with banking or other contractual covenants. 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.

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

The Corporation is authorized to issue an unlimited number of Common Shares without par value, of which 159,790,869 were issued and outstanding as at December 31, 2019 and of which 155,385,093 are issued and outstanding as at the date of this AIF.

All of the Common Shares outstanding 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 therefor.

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 are issued and outstanding at December 31, 2019 and at the date of the AIF, 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 IPC'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.

Share-based plans

The Group has the following share-based compensation plans for its employees, consultants and directors: a stock option plan ("**Stock Option Plan**"); and a performance and restricted share plan, under which awards have been made, and are expected to be made in the future, in performance share units ("**IPC PSU**") or in restricted share units ("**IPC RSU**").

The Stock Option Plan gives the participants a right to buy Common Shares of IPC at an exercise price equal to the market value at the date of grant. The Board granted stock options under the Stock Option Plan on February 21, 2017 with a three year vesting period and a four year term, whereby the stock options vest equally in three tranches: one third after one year, one third after two years and the final third after three years. The plan is effective from February 21, 2017 and the total outstanding number of stock options as at the date of this AIF was 1,808,566, with an exercise price of CAD 4.77.

Under the IPC PSU plan, awards are subject to continued employment and to certain performance conditions being met. The IPC PSUs will vest after three years based wholly or partly on a calculation of comparative total shareholder return (TSR) relative to a peer group of international oil and gas companies. Under the IPC RSU plan, awards to employees are subject to continued employment. The awards which vest over three years as to one-third each year. In addition, non-employee directors of the Corporation can elect for awards of IPC RSUs for all or a portion of the fee payable for services performed as a director and otherwise payable in cash. These awards vest immediately at the time of grant, although these awards may not be redeemed before the end of service as a director of the Corporation. IPC had an aggregate of 3,951,183 awards of IPC PSUs and IPC RSUs outstanding at the date of this AIF.

MARKET FOR SECURITIES

Trading price and volume

The Common Shares are listed for trading on the TSX in Canada and the NASDAQ Stockholm in Sweden under the trading symbol "IPCO".

The following table sets out, for the calendar periods indicated, the high and low closing prices and aggregate trading volumes for the Common Shares as reported on the TSX.

Month	High (CA$)	Low (CA$)	Volume
January 2019	5.04	4.35	1,733,434
February 2019	6.28	4.69	4,299,155
March 2019	6.42	5.96	2,079,195
April 2019	7.31	6.23	997,919
May 2019	6.93	5.79	1,395,670
June 2019	6.09	5.47	488,464
July 2019	6.14	5.51	1,239,736
August 2019	5.60	4.16	1,009,245
September 2019	5.47	4.50	1,064,777
October 2019	4.83	4.41	885,367
November 2019	5.80	4.59	708,137
December 2019	5.79	5.44	3,055,410

The following table sets out, for the calendar periods indicated, the high and low closing prices and aggregate trading volumes for the Common Shares as reported on the Nasdaq Stockholm.

Month	High (SEK)	Low (SEK)	Volume
January 2019	34.30	29.20	9,518,055
February 2019	44.70	32.30	17,037,211
March 2019	46.40	41.50	13,568,479
April 2019	50.90	44.05	9,705,111
May 2019	50.00	41.70	10,198,045
June 2019	43.00	39.60	9,125,680
July 2019	43.22	39.60	8,472,657
August 2019	41.06	30.66	17,167,089
September 2019	40.20	33.64	13,421,990
October 2019	35.70	33.02	8,897,995
November 2019	42.34	33.18	12,678,747
December 2019	42.14	39.40	11,942,797

Prior Sales

In December 2018, in connection with the completion of the acquisition of BlackPearl, the Corporation issued an aggregate of 75,798,219 Common Shares to the former BlackPearl shareholders.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

As at December 31, 2019 and as at the date of this AIF, the Corporation does not have any securities in escrow or that are subject to a contractual restriction on transfer, other than as described as follows.

DIRECTORS AND OFFICERS

Name and Province and Country of Residence	Position with the Corporation[5]	Number of Common Shares Beneficially Owned or Controlled	Principal Occupation (for last 5 years)
Lukas H. Lundin *Switzerland*	Chairman, Director	3,092,549	Corporate Director
Mike Nicholson *Switzerland*	President and CEO, Director	459,891	President and CEO of the Corporation since April 2017; CFO, Lundin Petroleum until April 2017
C. Ashley Heppenstall[1] *United Kingdom*	Lead Director	Nil[6]	Corporate Director; President and CEO, Lundin Petroleum until 2015
Donald Charter[1][2][4] *Ontario, Canada*	Director	72,333	Corporate Director
Chris Bruijnzeels[3][4] *The Netherlands*	Director	50,000	Corporate Director; President and CEO, ShaMaran Petroleum Corp. from 2015 to May 2019
Torstein Sanness[2][3] *Norway*	Director	25,037	Corporate Director; Managing Director then Chairman of Lundin Norway until 2015
Daniella Dimitrov[1][2][4] *Ontario, Canada*	Director	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
John Festival[3] *Alberta, Canada*	Director	2,027,371	Corporate Director; President and CEO, BlackPearl Resources Inc. until December 2018
Christophe Nerguararian *Switzerland*	CFO	129,475	CFO of the Corporation since April 2017; Vice President Corporate Finance, Lundin Petroleum until April 2017; Head of Corporate Debt and Commercial Manager, Lundin Petroleum, until December 2015
Jeffrey Fountain *Switzerland*	General Counsel	193,723	General Counsel of the Corporation since April 2017; Vice President Legal, Lundin Petroleum until April 2017
Daniel Fitzgerald *Switzerland*	Chief Operating Officer	15,000	Chief Operating Officer of the Corporation since April 2019; Vice President Operations of the Corporation from April 2017 to March 2019; Group Operations Manager, Lundin Petroleum until April 2017
Rebecca Gordon *Switzerland*	Vice President Corporate Planning and	14,000	Vice President Corporate Planning and Investor Relations of the Corporation since April 2017; Group Manager

Name and Province and Country of Residence	Position with the Corporation[5]	Number of Common Shares Beneficially Owned or Controlled	Principal Occupation (for last 5 years)
	Investor Relations		Economics and Planning, Lundin Petroleum until April 2017
Chris Hogue *Alberta, Canada*	Senior Vice President Canada	1,274,454	Senior Vice President Canada of the Corporation since December 2018; Vice President Operations, BlackPearl Resources Inc. until December 2018
Ryan Adair *Alberta, Canada*	Vice President Asset Management and Corporate Planning Canada	Nil	Vice President Asset Management and Corporate Planning Canada since April 2019; Vice President Reservoir Development of the Corporation from April 2017 to March 2019; Group Subsurface Manager, Lundin Petroleum until April 2017
Ed Sobel *Alberta, Canada*	Vice President Exploration	1,762,876	Vice President Exploration of the Corporation since December 2018; Vice President Exploration, BlackPearl Resources Inc. until December 2018

Notes:

(1) Member of Audit Committee.
(2) Member of Compensation Committee.
(3) Member of Reserves and HSE Committee.
(4) Member of Nominating and Corporate Governance Committee.
(5) Each of the Directors was appointed at the Annual General Meeting of Shareholders in May 2019 for a term until the next Annual General Meeting of Shareholders, to be held in May 2020.
(6) Rojafi, an investment company owned by Mr Heppenstall and his family, holds 1,127,501 Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

No current or proposed director or executive officer or securityholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation has, within the last 10 years prior to the date of this AIF, 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 or securityholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation 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 current or proposed director or officer or securityholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation has, within the last 10 years prior to the date of this AIF, 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 current or proposed director or executive officer or securityholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation has, within the last 10 years prior to the date of this AIF, 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 current or proposed director or executive officer or securityholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation 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 of the Corporation or any of the executive officers 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 evicted of any fraudulent acts.

Conflicts of Interest

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.

There is no family relationship between any of the individuals who will be members of the Board or executive officers of the Corporation.

As at December 31, 2019 and as at the date of this AIF, the Group was not aware of any existing or potential material conflicts of interest between the Group and a subsidiary of the Group and a director or officer of the Group or of a subsidiary of the Group.

AUDIT COMMITTEE

Audit Committee Mandate

The Audit Committee Mandate of the Corporation is attached hereto as Schedule F.

Composition of the Audit Committee

The Audit Committee is comprised of C. Ashley Heppenstall (Chair), Donald Charter and Daniella Dimitrov, each of whom is considered "independent" and "financially literate" within the meaning of Multilateral Instrument 52-110 – Audit Committees.

Mr. Heppenstall has extensive experience in finance and in the mining, oil and gas and renewable energy industries. He has a degree in Mathematics from Durham University. He worked as a commercial bank executive, following which he served as Chief Financial Officer then Chief Executive Officer of Lundin Petroleum from 1997 to 2015. He is a director on the boards of several public companies.

Mr. Charter has experience as a corporate director and officer of public companies, including in the financial services, natural resource and real estate industries. He has degrees in Economics and Law from McGill University. In addition to his senior executive leadership experience, he has extensive board level experience, including audit, compensation and governance committee chair and member status. He is a member of the Institute of Corporate Directors.

Ms. Dimitrov has experience as a corporate and securities lawyer and as a corporate executive, acting as President and CEO, CFO and COO of public companies. Ms. Dimitrov has chaired or been on the audit committee of a number of companies in the natural resources sector. Ms. Dimitrov is a Partner at Sprott Capital Partners where she regularly reviews the financial statements and other financial and operational disclosures of natural resource issuers.

Pre-Approval of Policies and Procedures

In accordance with the Audit Committee Mandate, the Audit Committee shall approve in advance any retainer of the external auditor to provide any non-audit service to the Corporation (together with all non-audit service fees) that it deems advisable in accordance with applicable requirements and Board-approved policies and procedures. The Audit Committee shall consider the impact of such service and fees on the independence of the external auditor.

Audit Committee Oversight

Since the commencement of the Corporation's most recently completed financial year, there has not been a recommendation of the Audit Committee to nominate or compensate an external auditor that was not adopted by the Board of Directors.

External Auditor Services Fees

The following table discloses the fees billed to the Corporation by PricewaterhouseCoopers SA, Licensed Public Accountants, in the years ended December 31, 2018 and 2019.

MUSD

Financial Year Ending	Audit Fees (1)	Audit Related Fees (2)	Tax Fees (3)	All Other Fees (4)
2018	556	160	17	248
2019	609	190	17	-

Notes:
(1) The aggregate fees billed for audit services.
(2) The aggregate fees billed for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not disclosed in the audit fees column.
(3) The aggregate fees billed for tax compliance, tax advice, and tax planning services.
(4) The aggregate fees billed for professional services other than those listed in the other three columns. In 2018, these fees related to the listing of the Common Shares on the Nasdaq Stockholm and the acquisitions of the Suffield assets and of BlackPearl.

PROMOTERS

The Corporation has had no promoters within the two most recently completed financial years or during the current financial year.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal proceedings

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. See also "Description of the Business – Discontinued Operations".

Regulatory actions

For the period beginning on the date of incorporation of the Corporation until the date of this AIF, 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 AIF.

In respect of the acquisition of BlackPearl by the Corporation in 2018, Mr. Lukas H. Lundin and Mr. C. Ashley Heppenstall held respectively approximately 3.81% and 0.9% of the issued and outstanding common shares of BlackPearl as at November 9, 2018, the date of the joint management information circular prepared in respect the Special Meetings of the shareholders of IPC and BlackPearl held on December 7, 2018 to approve the transaction. Nemesia S.à.r.l. ("**Nemesia**"), Lorito Holdings S.a.r.l. ("**Lorito**") and Zebra Holdings and Investments S.a.r.l. ("**Zebra**") are private companies ultimately controlled by a trust settled by the late Adolf H. Lundin. As at November 9, 2018, Nemesia held approximately 31.92% of the issued and outstanding Common Shares of the Corporation and Lorito and Zebra held approximately 11.93% of the issued and outstanding common shares of BlackPearl. John Festival was a director and the President and CEO of BlackPearl and he was a party to a transitional services agreement with the Corporation from December 2018 to June 2019.

TRANSFER AGENTS AND REGISTRARS

The transfer agent and registrar for the Common Shares in Canada is Computershare Investor Services Inc., and the Common Shares will be transferable at the offices of Computershare (Canada) in Toronto and Calgary. The transfer agent and registrar for the Common Shares in Sweden is Computershare AB, and the Common Shares will be transferable at the offices of Computershare (Sweden) in Stockholm.

MATERIAL CONTRACTS

There are no material contracts, other than those contracts entered into in the ordinary course of business, which the Corporation has entered into since the beginning of the last financial year before the date of this AIF, or entered into prior to such date but which contracts are still in effect.

NAMES AND INTERESTS OF EXPERTS

This AIF contains references to estimates of reserves, contingent resources, prospective resources and estimates of future net revenue attributed to the Corporation's oil and gas assets.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC’s oil and gas assets in Canada are effective as of December 31, 2019, and are included in reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Sproule’s December 31, 2019 price forecasts.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC’s oil and gas assets in France and Malaysia are effective as of December 31, 2019, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule’s December 31, 2019 price forecasts.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of the oil and gas assets acquired in the Granite Acquisition are effective as of December 31, 2019, and are included in reports prepared by Sproule on behalf of IPC, in accordance with NI 51-101 and the COGE Handbook, and using Sproule’s December 31, 2019 price forecasts. The Granite Acquisition was completed on March 5, 2020.

Neither of ERCE and Sproule, nor any directors, officers, employees or consultants of such firms, 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 linked to the value of the Corporation.

In addition, none of the officers, directors, employees or consultants of the aforementioned firms is currently expected to be elected, appointed or employed as a director, officer or employee of the Corporation or any of its associates or affiliates.

PricewaterhouseCoopers SA, Chartered Accountants, is the Corporation’s auditor and such firm has advised they are independent in accordance with the auditor’s rules of professional conduct in Canada. PricewaterhouseCoopers AS is a member of EXPERTsuisse – Swiss Expert Association for Audit, Tax and Fiduciary.

ADDITIONAL INFORMATION

Additional information, including directors’ and officers’ remuneration and indebtedness, principal holders of the Corporation’s securities, options to purchase securities and interests of insiders in material transactions, where applicable, will be contained in the Corporation’s management information circular for its Annual Meeting of Shareholders that will involve the election of directors.

Additional financial information is provided in the Corporation’s Audited Financial Statements and MD&A.

Additional information relating to the Group may be found under the Corporation’s profile on SEDAR at www.sedar.com and on the Corporation’s website at www.international-petroleum.com.

SCHEDULE A – STATEMENT OF CONTINGENT RESOURCES (UNRISKED) DATA

Working Interest Contingent Resources	Project Type	Technology	Economic Sub Class	Project Maturity	Project Evaluation	WI	Light Crude Oil & Medium Crude Oil Mbbl 1C	2C	3C	Heavy Crude Oil Mbbl 1C	2C	3C	Bitumen Mbbl 1C	2C	3C	Conventional Natural Gas MMscf 1C	2C	3C	Total Oil Equivalent Mboe 1C	2C	3C	Chance of Development
Malaysia																						
Bertam Field	Development Drilling	Established	not determined	Development Unclarified	Conceptual	75%	710	1 063	1 502	-	-	-	-	-	-	-	-	-	710	1 063	1 502	50%
France Paris Basin																						
Amaltheus	Development Drilling, Improved Water Injection	Established	not determined	Development Unclarified	Conceptual	100%	185	696	1 229	-	-	-	-	-	-	-	-	-	185	696	1 229	50%
Courdemanges	Development Drilling, Improved Water Injection	Established	not determined	Development Unclarified	Conceptual	100%	443	1 682	2 773	-	-	-	-	-	-	-	-	-	443	1 682	2 773	50%
Dommartin Lettree	Development Drilling, Improved Water Injection	Established	not determined	Development Unclarified	Conceptual	43.01%	433	951	1 263	-	-	-	-	-	-	-	-	-	433	951	1 263	50%
Genievre	Improved water injection	Established	not determined	Development Unclarified	Conceptual	100%	-	92	266	-	-	-	-	-	-	-	-	-	-	92	266	50%
Grandville	Development Drilling	Established	not determined	Development Unclarified	Conceptual	100%	-	1 218	1 603	-	-	-	-	-	-	-	-	-	-	1 218	1 603	50%
Mersier	Development Drilling	Established	not determined	Development Unclarified	Conceptual	100%	679	2 728	4 261	-	-	-	-	-	-	-	-	-	679	2 728	4 261	50%
Soudron	Development Drilling, Improved Water Injection	Established	not determined	Development Unclarified	Conceptual	100%	1 168	1 654	2 631	-	-	-	-	-	-	-	-	-	1 168	1 654	2 631	50%
Vert La Gravelle	Development Drilling	Established	not determined	Development Unclarified	Conceptual	100%	-	104	1 010	-	-	-	-	-	-	-	-	-	-	104	1010	50%
Villeperdue	Development Drilling, Improved Water Injection	Established	not determined	Development On-hold	Conceptual	100%	2 369	3 350	4 832	-	-	-	-	-	-	-	-	-	2 369	3 350	4 832	30%
Villeseneux	Development Drilling	Established	not determined	Development Unclarified	Conceptual	100%	165	540	578	-	-	-	-	-	-	-	-	-	165	540c	578	50%
France Aquitaine Basin																						
Courbey	Development Drilling	Established	not determined	Development Unclarified	Conceptual	50%	1 300	2 150	3 700	-	-	-	-	-	-	-	-	-	1 300	2 150	3 700	50%
Subtotal France							6 741	15 164	24 146	-	-	-	-	-	-	-	-	-	6 741	15 164	24 146	
Canada Southern																						
Oil Development Drilling																						
Mannville	Development Drilling	Established	not determined	Development On-hold	Pre- Development Study Level II/III	100%	-	-	-	2 283	3 130	3 978	-	-	-	236	323	406	2 324	3 186	4 048	70%
Detrital	Development Drilling	Established	not determined	Development On-hold	Pre- Development Study Level II/III	100%	-	-	-	350	500	650	-	-	-	32	45	59	356	508	660	70%
Gas Development Drilling																						
Alderson	Development Drilling	Established	not determined	Development On-hold	Pre- Development Study Level II	100%	-	-	-	-	-	-	-	-	-	20 513	34 188	47 863	3 419	5 698	7 977	50%
Suffield	Development Drilling	Established	not determined	Development On-hold	Pre- Development Study Level II	100%	-	-	-	-	-	-	-	-	-	105 067	195 124	285 181	17 511	32 521	47 530	50%
Subtotal Southern							-	-	-	2 633	3 630	4 628	-	-	-	125 848	229 680	333 509	23 609	41 912	60 215	
Canada - Northern																						
Blackrod - Phase I	Field Development	Established	Economic	Development On-hold	Development Study Level III	100%	-	-	-	-	-	-	159 177	177 514	196 385	-	-	-	159 177	177 514	196 385	94%
Blackrod-Phase II and III	Field Development Expansion	Established	Economic	Development On-hold	Pre-Development Study Level II/III	100%	-	-	-	-	-	-	723 242	809 481	895 721	-	-	-	723 242	809 481	895 721	77%
Mooney Phase II	Development Drilling and ASP	Established	Economic	Development On-hold	Development Study Level III	100%	-	-	-	12 378	15 904	20 841	-	-	-	-	-	-	12 378	15 904	20 841	71%
Onion Lake Thermal	Field Development Expansion	Established	Economic	Development On-hold	Development Study Level III	100%	-	-	-	14 772	20 029	26 334	-	-	-	-	-	-	14 772	20 029	26 334	85%
Onion Lake Primary	Development Drilling (28)	Established	Economic	Development On-hold	Development Study Level III	100%	-	-	-	1 179	1 447	1 788	-	-	-	-	-	-	1 179	1 447	1 788	90%
Subtotal Northern							-	-	-	28 329	37 380	48 963	882 419	986 995	1 092 106		-	-	910 748	1 024 375	1 141 069	

Working Interest Contingent Resource

Development Unclarified status

Working Interest Contingent Resource	Light Crude Oil & Medium Crude Oil Mbbl			Heavy Crude Oil Mbbl			Bitumen Mbbl			Conventional Natural Gas MMscf			Total Oil Equivalent Mboe		
	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C
Subtotal by Country															
Un-risked															
Malaysia	710	1 063	1 502	-	-	-	-	-	-	-	-	-	710	1 063	1 502
France	4 372	11 815	19 315	-	-	-	-	-	-	-	-	-	4 372	11 815	19 315
Canada	-	-	-	-	-	-	-	-	-	-	-	-			
Total Unrisked	5 082	12 878	20 817	-	-	-	-	-	-	-	-	-	5 082	12 878	20 817
Subtotal by Country															
Risked by Chance of Development															
Malaysia	355	531	751	-	-	-	-	-	-	-	-	-	355	531	751
France	2 186	5 907	9 657	-	-	-	-	-	-	-	-	-	2 186	5 907	9 657
Canada	-	-	-	-	-	-	-	-	-						
Total Risked	2 541	6 439	10 408	-	-	-	-	-	-				2 541	6 439	10 408

Working Interest Contingent Resource

Development On-hold status

Working Interest Contingent Resource	Light Crude Oil & Medium Crude Oil Mbbl			Heavy Crude Oil Mbbl			Bitumen Mbbl			Conventional Natural Gas MMscf			Total Oil Equivalent Mboe		
	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C
Subtotal by Country															
Un-risked															
Malaysia				-	-	-	-	-	-	-	-	-	-	-	-
France	2 369	3 350	4 832	-	-	-	-	-	-	-	-	-	2 369	3 350	4 832
Canada	-	-	-	30 962	41 010	53 591	882 419	986 995	1 092 106	125 847	229 680	333 509	934 357	1 066 287	1 201 285
Total Unrisked	2 369	3 350	4 832	30 962	41 010	53 591	882 419	986 995	1 092 106	125 847	229 680	333 509	936 726	1 069 637	1 206 217
Subtotal by Country															
Risked by Chance of Development															
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
France	711	1 005	1 450	-	-	-	-	-	-	-	-	-	711	1 005	1450
Canada	-	-	-	24 249	32 160	42 029	706 523	790 164	874 307	62 977	114 913	166 847	741 269	841 477	944 146
Total Risked	711	1 005	1 450	24 249	32 160	42 029	706 523	790 164	874 307	62 977	114 913	166 847	741 980	842 482	945 596

Working Interest Contingent Resource

Total

Working Interest Contingent Resource	Light Crude Oil & Medium Crude Oil Mbbl			Heavy Crude Oil Mbbl			Bitumen Mbbl			Conventional Natural Gas MMscf			Total Oil Equivalent Mboe		
	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C
Subtotal by Country															
Un-risked															
Malaysia	710	1 063	1 502	-	-	-	-	-	-	-	-	-	710	1 063	1 502
France	6 741	15 164	24 146	-	-	-	-	-	-	-	-	-	6 741	15 164	24 146
Canada	-	-	-	30 962	41 010	53 591	882 419	986 995	1 092 106	125 847	229 680	333 509	934 357	1 066 287	1 201 285
Total Unrisked	7 451	16 227	25 649	30 962	41 010	53 591	882 419	986 995	1 092 106	125 847	229 680	333 509	941 808	1 082 513	1 226 930
Subtotal by Country															
Risked by Chance of Development															
Malaysia	355	531	751	-	-	-	-	-	-	-	-	-	355	531	751
France	2 897	6 912	11 107	-	-	-	-	-	-	-	-	-	2 897	6 912	11 107
Canada	-	-	-	24 249	32 160	42 029	706 523	790 164	874 307	62 977	114 913	166 847	741 269	841 477	944 146
Total Risked	3 252	7 444	11 858	24 249	32 160	42 029	706 523	790 164	874 307	62 977	114 913	166 847	744 521	848 921	956 004

Project descriptions for IPC's contingent resource estimates are provided as follows, noting that in respect of all statements with respect to future potential activities and estimated costs and timing, see "Cautionary Statement regarding Forward-Looking Information", "Reserves and Resource Advisory" and "Risk Factors" above:

France

The contingent resource estimates reported for France relate to development drilling and water-flood optimization opportunities. 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.

Malaysia

The contingent resource estimates reported for Malaysia relate to development drilling in the north east of the Bertam field. The product type is light crude oil. The risk and uncertainty associated with the contingent resources in Malaysia is largely due to the subsurface understanding of the north east of the Bertam field. To recover the contingent resources, the drilling of a development well or wells would be required.

Canada

Suffield Area

The contingent resources reported for the Suffield area of Alberta are consolidated into two project categories: shallow gas development drilling and oil development drilling. In each case, the recovery of the resources would be via established technology, is based upon conceptual development plans and is discussed below.

The contingent shallow gas resources in the Suffield area of Alberta are attributable to a shallow gas drilling project that is estimated to require an estimated CAD 350 to 450 million. Timing of first commercial production, should the project proceed, is expected to be in the 2025 to 2030 horizon. The project would likely be approved and implemented in several stages. The project is primarily drilling and completion scope, using vertical commingled wells, with minimal infrastructure investment required. Positive factors include established recovery technology with demonstrated commercial rates, IPC's available facilities/infrastructure and IPC's ongoing activity in the area. Negative factors include economic sensitivity to future natural gas pricing and materiality in respect of IPC's capital allocation priorities.

All of the Suffield area contingent gas resource volumes are classified as "Economics Undetermined" and "Development On-Hold" and in Sproule's opinion, have a reasonable probability of becoming a commercial development. Sproule has classified the project evaluation status to be Project Evaluation Level II. In recognition of the risk of commerciality of the shallow gas contingent resource volumes, a 50 percent chance of development risk factor has been applied to the total recoverable volumes. This chance of development risk factor is an aggregation of risk factors attributable to the two contingencies identified for the project ("Timing of Production and Development" and "Economic Viability") and has been incorporated as a 50 percent chance of occurrence applied to all contingent resource inputs.

The contingent heavy oil resources in the Suffield area of Alberta are attributable to an oil development drilling project that is estimated to require CAD 75 to 100 million. Timing of first commercial production, should the project proceed, is expected to be in the 2023 to 2030 horizon. The heavy oil locations would likely be approved and implemented in groups over several stages. The heavy oil locations largely consist of drilling and completion scope, using horizontal multi-leg laterals in the Mannville reservoir and single leg horizontal wells in the Detrital reservoir, with minor facility and infrastructure investments. Positive factors include established recovery technology with widespread successful implementation, IPC's available facilities/infrastructure and IPC's active development drilling in the area. Negative factors include economic sensitivity to future oil pricing and a variable range of well productivity.

All of the Suffield area contingent heavy oil resource volumes are classified as "Economics Undetermined" and "Development On-Hold" and in Sproule's opinion, have a reasonable probability of becoming a commercial development. Sproule has classified the project evaluation status to be Project Evaluation Level II and Level III. In recognition of the risk of commerciality of the heavy oil contingent resource volumes, a 70 percent chance of development risk factor has been applied to the total recoverable volumes. This chance of development risk factor is an aggregation of risk factors attributable to the three contingencies identified for the project ("Timing of Production and Development", "Evaluation Drilling" and "Economic Viability") and has been incorporated as a 70 percent chance of occurrence applied to all contingent resource inputs.

Blackrod

The contingent bitumen resources reported for the Blackrod area of Alberta are attributed to a thermal enhanced oil recovery project. All contingent bitumen resources contained in this project are to be recovered using Steam Assisted Gravity Drainage (SAGD) technology. The Blackrod thermal pilot project began in 2011 and consisted of two pilot well pairs. A third well pair was drilled in 2019. The overall development concept is to develop the Blackrod leases in three separate phases. Phase One includes a 20,000 barrel per day five-section development project with production scheduled to start in the 2025 to 2029 horizon. Phase Two includes an expansion to a 50,000 barrel per day development project with production scheduled to start in the 2029 to 2033 horizon; and Phase Three includes expansion to an 80,000 barrel per day development project with production scheduled to commence in the 2033 to 2037 horizon. The Corporation continues work to assess estimated costs to first commercial production for each Phase.

Phase One

All of the Blackrod Phase One contingent bitumen resource volumes are classified as "Economically Viable" and "Development On–Hold" and in Sproule's opinion, have a high probability of becoming a commercial development. Sproule has classified the project evaluation status to be Project Evaluation Level III. Positive factors include established recovery technology with a successful pilot in the subject reservoir, extensive regulatory application filed and approved for Phase One, well-defined development plan, and well-delineated relatively homogeneous in-place-bitumen resource volume. Negative factors include economic sensitivity to future oil pricing, potential for regulatory changes, potential lack of available pipeline capacity and competition from other projects. In recognition of the risk of commerciality of the Blackrod Phase One contingent bitumen resource volumes, a 94 percent chance of development risk factor has been applied to the total recoverable volumes. This chance of development risk factor is an aggregation of risk factors attributable to the two contingencies identified for the project ("Corporate Commitment" and "Timing of Production and Development") and has been incorporated as a 94 percent chance of occurrence applied to all contingent resource inputs.

Phases Two and Three

All of the Blackrod Phases Two and Three contingent bitumen resource volumes are classified as "Economically Viable" and "Development On–Hold" and in Sproule's opinion have a high probability of becoming a commercial development. Sproule has classified the project evaluation status to be Project Evaluation Level II/III. Positive factors include established recovery technology with a successful pilot in the subject reservoir, well-defined development plan, and well-delineated relatively homogeneous in-place-bitumen resource volume. Negative factors include economic sensitivity to future oil pricing, potential for regulatory changes, potential lack of available pipeline capacity, access to capital and competition from other industry oil sands projects. In recognition of the risk of commerciality of the Blackrod Phase Two and Three contingent bitumen resource volumes, a 77 percent chance of development risk factor has been applied to the total recoverable volumes. This chance of development risk factor is an aggregation of risk factors attributable to the four contingencies identified for the project ("Evaluation Drilling", "Regulatory Approval", "Corporate Commitment" and "Timing of Production and Development") and has been incorporated as a 77 percent chance of occurrence applied to all contingent resource inputs.

Onion Lake

At the Onion Lake property in Saskatchewan, the recovery of the Company's Onion Lake contingent heavy oil resources is expected to use a combination of production processes: the modified SAGD process, Onion Lake Thermal; and the Cold Heavy Oil Production with Sand (CHOPS) process, Onion Lake Primary.

Onion Lake Thermal: Phase IV

The thermal contingent heavy oil resources in the Onion Lake area of Saskatchewan are attributed to a thermal enhanced oil recovery project . The overall development concept proposed is to thermally develop the Onion Lake leases in four phases. Of the development phases, Phase Four is classified as contingent resources and is planned to include a facility expansion of 3,000 barrels of oil per day to bring the total project capacity to 19,000 barrels of oil per day with incremental production beginning in the 2025 to 2030 horizon (estimated to require CAD 50 to 60 million to first commercial production). All Phases classified as reserves are separate from the volumes included in the contingent resource tables. Positive factors include established recovery technology, including demonstration of commercial production rates in the subject reservoir, full regulatory approval received for the first and second phases of the project, well-defined development plan and fully operational central processing facility infrastructure in place. Negative factors include economic sensitivity to future oil pricing and potential regulatory changes including related to future First Nations leases.

All of the Onion Lake Thermal: Phase IV contingent heavy oil resource volumes are classified as "Economically Viable" and "Development On–Hold" and in Sproule's opinion, have a high probability of becoming a commercial development. Sproule has classified the project evaluation status to be Project Evaluation Level III. In recognition of the risk of commerciality of the Onion Lake contingent Phase Four heavy oil thermal resource volumes, an 85 percent chance of development risk factor has been applied to the total recoverable volumes. This chance of development risk factor is an aggregation of risk factors attributable to the three contingencies identified for the project ("Evaluation Drilling", "Regulatory Approval" and "Timing of Production and Development") and has been incorporated as an 85 percent chance of occurrence applied to all contingent resource inputs.

Onion Lake Primary

The primary contingent heavy oil resources in the Onion Lake area of Saskatchewan are attributable to primary development in areas of the reservoir more than two drill spacing units apart from current production. These locations offset spacing units with reserves assignments and are a continuation of the primary production development strategy for the reservoir and would be developed using existing technology. These 37 locations are estimated to require CAD 15 to 18 million to develop and will likely be developed in the 2023 to 2030 horizon. The heavy oil locations largely consist of drilling and completion scope, using vertical CHOPS wells, with minor facility and infrastructure investments. Positive factors include established recovery technology, including widespread successful implementation in the subject reservoir, established relationship with the Onion Lake Cree Nation (lessor), and active pursuit by IPC of expanded reservoir development using CHOPS. Negative factors include economic sensitivity to future oil pricing and and potential regulatory changes including related to future First Nations leases.

All of the Onion Lake Primary contingent heavy oil resource volumes are classified as "Economically Viable" and "Development On–Hold" and in Sproule's opinion, have a high probability of becoming a commercial development. Sproule has classified the project evaluation status to be Project Evaluation Level III. In recognition of the risk of commerciality of the Onion Lake primary contingent heavy oil resource volumes, a 90 percent chance of development risk factor has been applied to the total recoverable volumes. This chance of development risk factor is an aggregation of risk factors attributable to the two contingencies identified for the project ("Evaluation Drilling" and "Regulatory Approval") and has been incorporated as a 90 percent chance of occurrence applied to all contingent resource inputs.

Mooney

The contingent heavy oil resources in the Mooney area of Alberta are attributed to an alkaline-surfactant-polymer (ASP) Enhanced Oil Recovery project. The overall development concept proposed is to develop the Mooney leases in four distinct phases. Phase One began in 2008 with a polymer injection pilot project, with positive results leading to a large scale ASP flood commencing in 2011 with twenty-three flood patterns. Phase One also included construction of an injection facility capable of handling 27,000 barrels of fluid per day and a production facility capable of handling 20,000 barrels of fluid per day. Phase Two expands the flood area with an additional seventeen flood patterns. Phase Three includes a 7,500 and 11,250 (Best and High Estimate cases, respectively) barrel per day expansion of production fluid capacity coinciding with the implementation of eighteen additional flood patterns. Phase Four encompasses the remaining 12 flood patterns. The majority of Phases One and Two are classified as reserves and separate from the volumes included in the contingent resources, while Phases Three and Four are classified as contingent resources and detailed in this document. Positive factors include established recovery technology, including successful implementation in the subject reservoir, regulatory approval received for the first and second phases of the project, well-defined development plan and fully operational injection and production facility infrastructure in place. Negative factors include economics highly sensitive to future oil and chemical pricing, flood performance susceptible to reservoir heterogeneities and materiality in respect of IPC's capital allocation priorities.

All of the Mooney contingent heavy oil resource volumes are classified as "Economically Viable" and "Development On–Hold" and in Sproule's opinion, have a reasonable probability of becoming a commercial development. Sproule has classified the project evaluation status to be Project Evaluation Level III. In recognition of the risk of commerciality of the Mooney contingent heavy oil resource volumes, a 71 percent chance of development risk factor has been applied to the total recoverable volumes. This chance of development risk factor is an aggregation of risk factors attributable to the four contingencies identified for the project ("Evaluation Drilling", "Regulatory Approval", "Corporate Commitment" and "Timing of Production and Development") and has been incorporated as a 71 percent chance of occurrence applied to all contingent resource inputs.

SCHEDULE B – RESERVES AND RESOURCES ACQUIRED IN THE GRANITE ACQUISITION

Part II - Disclosure of Reserves Data

On January 20, 2020, IPC announced that it had agreed to acquire Granite under a plan of arrangement. The Granite Acquisition was completed on March 5, 2020. This Appendix includes reserves estimates, contingent resource estimates and estimates of future net revenue in respect of the oil and gas assets acquired in the Granite Acquisition effective as of December 31, 2019, and included in reports prepared by Sproule on behalf of IPC, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2019 price forecasts. These price forecasts are as at December 31, 2019 and may not be reflective of current and future forecast commodity prices. The reports by Sproule are dated January 15, 2020.

The working interest volumes are reported herein as the gross reserves, the reserves adjusted for royalties or similar are reported as net reserves.

Item 2.1.1a – Breakdown of Proved Reserves (Forecast Case)
Breakdown of Reserves by Product Type

	Bitumen		Heavy Crude Oil		Light & Medium Oil		Natural Gas Liquids		Conventional Natural Gas (Non-Associated & Associated)		Oil Equivalent	
	Gross MMbbl	Net MMbbl	Gross MMbbl	Net MMbbl	Gross MMbbl	Net MMbbl	Gross MMboe	Net MMboe	Gross Bscf	Net Bscf	Gross MMboe	Net MMboe
Proved Developed Producing												
Ferguson	-	-	0.0	0.0	6.0	5.3	-	-	-	-	6.0	5.4
Proved Developed Non-Producing												
Ferguson	-	-	0.0	0.0	0.2	0.2	-	-	-	-	0.2	0.2
Proved Undeveloped												
Ferguson	-	-	-	-	5.2	4.3	-	-	-	-	5.2	4.3
Total Proved (1P)												
Ferguson	-	-	0.0	0.0	11.4	9.8	-	-	-	-	11.4	9.8

Item 2.1.1b – Breakdown of Proved and Probable Reserves (Forecast Case)
Breakdown of Reserves by Product Type

	Bitumen		Heavy Crude Oil		Light & Medium Oil		Natural Gas Liquids		Conventional Natural Gas (Non-Associated & Associated)		Oil Equivalent	
	Gross MMbbl	Net MMbbl	Gross MMbbl	Net MMbbl	Gross MMbbl	Net MMbbl	Gross MMboe	Net MMboe	Gross Bscf	Net Bscf	Gross MMboe	Net MMboe
Proved plus Probable Developed Producing												
Ferguson	-	-	0.0	0.0	7.2	6.3	-	-	-	-	7.2	6.3
Proved plus Probable Developed Non-Producing												
Ferguson	-	-	0.0	0.0	0.3	0.2	-	-	-	-	0.3	0.3
Proved plus Probable Undeveloped												
Ferguson	-	-	-	-	6.5	5.3	-	-	-	-	6.5	5.3
Total Proved plus Probable (2P)												
Ferguson	-	-	0.1	0.1	13.9	11.8	-	-	-	-	14.0	11.9

Item 2.1.2a – Net Present Value of Future Net Revenue (Forecast Case), Proved Reserves
Breakdown of NPV by country and in aggregate MM U.S. $

	Before Deducting Income Tax, Discounted at						After Deducting Income Tax, Discounted at						Unit Value Before Income Tax, discounted at 10%
	0%	5.0%	8.0%	10.0%	15.0%	20.0%	0%	5.0%	8.0%	10.0%	15.0%	20.0%	US$/boe
Proved Developed Producing													
Ferguson	159.4	133.2	113.7	103.0	83.1	69.9	144.6	127.0	109.9	100.2	81.8	69.2	19.2
Proved Developed Non-Producing													
Ferguson	8.3	6.1	5.2	4.8	3.9	3.3	6.4	5.0	4.5	4.2	3.6	3.1	23.5
Proved Undeveloped													
Ferguson	172.8	101.0	77.2	65.7	45.9	33.7	132.7	78.6	60.7	51.9	36.8	27.4	15.4
Total Proved													
Ferguson	340.5	240.2	196.2	173.5	133.0	106.9	283.6	210.6	175.0	156.3	122.1	99.7	17.7

All figures in the above table are in USD millions, unless otherwise indicated.

Item 2.1.2b – Net Present Value of Future Net Revenue (Forecast Case), Proved and Probable Reserves
Breakdown of NPV by country and in aggregate MM U.S. $

	Before Deducting Income Tax, Discounted at						After Deducting Income Tax, Discounted at						Unit Value Before Income Tax, discounted at 10%
	0%	5.0%	8.0%	10.0%	15.0%	20.0%	0%	5.0%	8.0%	10.0%	15.0%	20.0%	US$/boe
Proved plus Probable Developed Producing													
Ferguson	218.7	159.3	132.1	118.2	93.5	77.6	192.6	148.1	125.0	112.8	90.6	76.0	18.8
Proved plus Probable Developed Non-Producing													
Ferguson	11.2	7.6	6.4	5.8	4.7	3.9	8.6	6.2	5.3	4.9	4.1	3.5	22.2
Proved plus Probable Undeveloped													
Ferguson	226.9	130.3	99.5	84.7	59.5	44.0	174.1	100.8	77.3	66.1	46.8	35.0	16.0
Total Probable (PB)													
Ferguson	116.3	57.0	41.8	35.1	24.7	18.6	91.8	44.4	32.6	27.5	19.5	14.9	17.3
Total Proved plus Probable (2P)													
Ferguson	456.8	297.2	238.0	208.7	157.7	125.5	375.4	255.0	207.6	183.8	141.6	114.5	17.6

All figures in the above table are in USD millions, unless otherwise indicated.

Item 2.1.3b – Elements of Future Net Revenue (Forecast Case)
Undiscounted

	Revenue MM U.S.$	Royalties MM U.S.$	Operating Costs MM U.S.$	Development Costs MM U.S.$	Abandonment Costs MM U.S.$	Future Net Revenue Before Income Taxes MM U.S.$	Income Taxes MM U.S.$	Future Net Revenue After Income Taxes MM U.S.$
Total Proved								
Ferguson	757.5	107.4	237.0	53.8	18.7	340.5	56.9	283.6
Total Proved plus Probable								
Ferguson	947.2	145.5	266.1	58.6	20.2	456.8	81.4	375.4

All figures in the above table are in USD millions, unless otherwise indicated.

Part V – Additional Information Relating to Reserves Data

Item 5.3 Future Development Costs

	2020	2021	2022	2023	2024	2025 on	Total for all years undiscounted	Total for all years discounted at 10% p.a.
Total Proved								
Ferguson	6.1	7.3	12.4	14.6	10.4	3.0	53.8	39.4
Total Proved Plus Probable								
Ferguson	6.1	7.3	12.4	14.6	15.3	3.0	58.6	42.6

All figures in the above table are in USD millions, unless otherwise indicated.

Part VI – Other Oil and Gas Information

Item 6.1.2. Producing and non-producing well counts

	Oil				Gas			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Ferguson	69	69	7	7	23	21	88	85

Item 6.8 – 2020 Forecast Saleable Production Estimates in Reserves Report

	Bitumen (Mbbl/d)	Light & Medium Crude Oil (Mbbl/d)	Heavy Crude Oil (Mboe/d)	Convent-Ional Natural Gas (Mboe/d)	Natural Gas Liquids (Mboe/d)	Total (Mboe/d)
Total Proved (1P) Scenario						
Ferguson	-	1 909	29	-	-	1 938
Total Proved plus Probable (2P) Scenario						
Ferguson	-	2 014	29	-	-	2 043

APPENDIX 1 to Schedule B

Contingent Resources Unrisked

Working Interest Contingent Resources		Project Type	Technology	Economic Sub Class	Project Maturity	Project Evaluation	WI	Light Oil & Medium Oil Mbbl			Heavy Oil Mbbl			Sales Gas (MMCF)			NGL (Mbbl)			BOE (Mboe)			Chance of Development
								1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	
Canada																							
Ferguson	Bow Island	Shallow Gas Reactivations	Established	Economic	Development Unclarified	Development Study	100	-	-	-	-	-	-	1 898	2 764	3 593	-	-	-	316.3	460.7	598.9	70%
	Bakken	Refracs (15)	Established	Economic	Development Unclarified	Development Study	100	748.9	985.6	1 425.0	-	-	-	-	-	-	-	-	-	748.9	985.6	1 425.0	70%
	Bakken	Gas Flood Optimization	Established	Economic	Development Unclarified	Development Study	100	968.1	2 026.5	3 546.4	-	-	-	-	-	-	-	-	-	968.1	2 026.5	3 546.4	70%
	Bakken	Gas Flood Blowdown	Established	Economic	Development Unclarified	Development Study	100	-	-	-	-	-	-	8 400	12 000	15 600	193.2	276.0	358.8	1 593.2	2 276.0	2 958.8	70%
	Sunburst	Locations (7)	Established	Economic	Development Unclarified	Development Study	100	-	-	-	302.1	477.6	643.7	-	-	-	-	-	-	302.1	477.6	643.7	70%
Total								1 717.0	3 012.1	4 971.4	302.1	477.6	643.7	10 298	14 764	19 193	193.2	276.0	358.8	3 928.6	6 226.4	9 172.8	

Contingent Table Risked

Working Interest Contingent Resources		Project Type	Technology	Economic Sub Class	Project Maturity	Project Evaluation	WI	Light Oil & Medium Oil Mbbl			Heavy Oil Mbbl			Sales Gas (MMCF)			NGL (Mbbl)			BOE (Mboe)			Chance of Development
								1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	
Canada																							
Ferguson	Bow Island	Shallow Gas Reactivations	Established	Economic	Development Unclarified	Development Study	100	-	-	-	-	-	-	1 329	1 935	2 515	-	-	-	221.4	322.5	419.2	70%
	Bakken	Refracs (15)	Established	Economic	Development Unclarified	Development Study	100	524.2	689.9	997.5	-	-	-	-	-	-	-	-	-	524.2	689.9	997.5	70%
	Bakken	Gas Flood Optimization	Established	Economic	Development Unclarified	Development Study	100	677.7	1 418.6	2 482.5	-	-	-	-	-	-	-	-	-	677.7	1 418.6	2 482.5	70%
	Bakken	Gas Flood Blowdown	Established	Economic	Development Unclarified	Development Study	100	-	-	-	-	-	-	5 880	8 400	10 920	135.2	193.2	251.2	1 115.2	1 593.2	2 071.2	70%
	Sunburst	Locations (7)	Established	Economic	Development Unclarified	Development Study	100	-	-	-	211.5	334.3	450.6	-	-	-	-	-	-	211.5	334.3	450.6	70%
Total								1 201.9	2 108.5	3 480.0	211.5	334.3	450.6	7 209	10 335	13 435	135.2	193.2	251.2	2 750.0	4 358.5	6 421.0	

All of the contingent resources are classified as Development Unclarified. The chance of development risk of 70% has been applied to all of these contingent resources. The contingency for all of the unrisked best estimate contingent resources is the corporate commitment whether to proceed with the specific opportunities.

SCHEDULE C – FORM 51-101 F2 (SPROULE)

Form 51-101F2

Report on Reserves Data
by Independent Qualified Reserves Evaluator or Auditor

To the Board of Directors of International Petroleum Corp. Canada (the "Company"):

1. We have evaluated the Company's Canadian assets reserves data as at December 31, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, estimated using forecast prices and costs in USD.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook"), maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter). Note that, as requested by the Company, the evaluation includes ADR costs only for wells assigned reserves and related material dedicated facilities and excludes ADR costs for uneconomic wells, shut-in and suspended wells, and some facilities within active properties and also excludes ADR costs for inactive properties.

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs in USD and calculated using a discount rate of 10 percent, included in the reserves data of the Company for Canadian properties evaluated for the year ended December 31, 2019, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$US)	Evaluated (M$US)	Reviewed (M$US)	Total (M$US)
Sproule	December 31, 2019	Canada				
Total			**Nil**	**1,833,574**	**Nil**	**1,833,574**

6. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report, entitled "Evaluation of the P&NG Reserves of International Petroleum Corporation Corp. Canada in Canada (As of December 31, 2019)".

8. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
Jan / 27 /2020 mmm/dd/yyyy

Original Signed by Charles Wong, P.Eng.
Charles Wong P.Eng.
Petroleum Engineer

Original Signed by Stephanie D. Brunt, P.Eng.
Stephanie D. Brunt, P.Eng.
Petroleum Engineer

Original Signed by Jeffrey A. McKeeman, P.Eng.
Jeffrey A. McKeeman, P.Eng.
Petroleum Engineer

Original Signed by Victor Verkhogliad, Ph.D., P.Geol.
Victor Verkhogliad, Ph.D., P.Geol.
Manager, Geoscience

Original Signed by Cameron P. Six, P.Eng.
Cameron P. Six, P.Eng.
CEO

SCHEDULE D – FORM 51-101 F2 (ERCE)

NI 51-101 F2
Report on Reserves Data, Contingent Resources Data and Prospective Resources Data by Independent Qualified Reserves Evaluator or Auditor

To the board of directors of International Petroleum Corporation (the "Company"):

1. We have audited the Company's Reserves data and certain Contingent Resources data as at December 31, 2019. The Reserves data are estimates of Proved Reserves and Probable Reserves and related future net revenue as at December 31, 2019, estimated using forecast prices and costs. The Contingent Resources have been estimated using data as at December 31, 2019.

2. The Reserves data and Contingent Resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the Reserves data and Contingent Resources data based on our audit.

3. We carried out our audit in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an audit to obtain reasonable assurance as to whether the Reserves data and Contingent Resources data are free of material misstatement. An audit also includes assessing whether the Reserves data and Contingent Resources data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to Proved plus Probable Reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Reserves data of the Company audited for the year ended December 31, 2019, and identifies the respective portions thereof that we have audited and reported on to the Company's management:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of [Audit/Evaluation/ Review] Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue in USD (before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
ERC Equipoise	Dec 31, 2019	France	$253,728,177	$0	$0	$253,728,177
ERC Equipoise	Dec 31, 2019	Malaysia	$280,544,241	$0	$0	$280,544,241
Totals			**$534,272,418**	**$0**	**$0**	**$534,272,418**

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6. The following tables set forth the risked volume of Contingent Resources and prospective resources included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the Contingent Resources data that we have audited and reported on to the Company's management:

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of [Audit/ Evaluation] Report	Location of Resources Other than Reserves (Country or Foreign Geographic Area)	Risked Gross Working Interest Volume Oil (MMstb)
Contingent Resources, Development Unclarified (2C)	ERC Equipoise Ltd	Dec 31, 2019	France	7,582.2
	ERC Equipoise Ltd	Dec 31, 2019	Malaysia	531.4

7. In our opinion, the Reserves data and Contingent Resources data respectively audited by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the Reserves data and Contingent Resources data that we reviewed but did not audit or evaluate.

8. We have no responsibility to update our reports referred to in paragraphs 5 and 6 for events and circumstances occurring after the effective date of our reports.

9. Because the Reserves data and Contingent Resources data are based on judgements regarding future events, actual results will vary and the variations may be material.

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Executed as to our report referred to above:

ERC Equipoise Limited, London, United Kingdom, February 03, 2020

Paul Chernik, P.Eng
Director, ERC Equipoise Ltd.

SCHEDULE E – FORM 51-101 F3

Form 51-101F3

Report of Management and Directors on Reserves Data and Other Information

Management of International Petroleum Corp. (the "Corporation") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This includes reserves data and other information such as contingent resources data or prospective resources data.

Sproule Associates Ltd. and ERC Equipoise Ltd., independent qualified reserves auditors or evaluators, have, as applicable, audited, evaluated and reviewed the Corporation's reserves data and contingent resources data. The reports of the independent qualified reserves auditors and evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Corporation has

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves auditor and the independent qualified reserves evaluator;

(b) met with, or otherwise confirmed with, the independent qualified reserves auditor and the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves auditor and the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data, contingent resources data and prospective resources data, as applicable, with management and the independent qualified reserves auditor and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data, contingent resources data and other oil and gas information;

(b) the filing of Forms 51-101F2, which are the reports of the independent qualified reserves auditor and the independent qualified reserves evaluator on the reserves data and contingent resources data; and

(c) the content and filing of this report.

Because the reserves data, contingent resources data and prospective resources data are based on judgements regarding future events, actual results will vary and the variations may be material.

"Mike Nicholson"
Mike Nicholson, Chief Executive Officer

"Daniel Fitzgerald"
Daniel Fitzgerald, Chief Operating Officer

"Chris Bruijnzeels"
Chris Bruijnzeels, Director

"Torstein Sanness"
Torstein Sanness, Director

Date: March 24, 2020

SCHEDULE F – AUDIT COMMITTEE MANDATE

Audit Committee Mandate

As of March 25, 2019

1. Introduction

The Audit Committee (the "Committee" or the "Audit Committee") of International Petroleum Corporation (the "Company") is a committee of the board of directors (the "Board"). The Committee shall oversee the accounting and financial reporting practices of the Company and the audits of the Company's financial statements and exercise the responsibilities and duties set out in this Mandate.

2. Membership

Number of Members

The Committee shall be composed of three or more members of the Board.

Independence of Members

Each member of the Committee must be independent. "Independent" shall have the meaning, as the context requires, given to it in National Instrument 52-110 Audit Committees, as may be amended from time to time.
Chair

The members of the Committee shall elect a Chair of the Committee from among their number by majority vote of the full Committee membership. The Chair shall preside over all Audit Committee meetings, coordinate the Audit Committee's compliance with this Mandate, work with management to develop the Audit Committee's annual work-plan and provide reports of the Audit Committee to the Board.

Financial Literacy of Members

At the time of his or her appointment to the Committee, each member of the Committee shall have, or shall acquire within a reasonable time following appointment to the Committee, the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Company's financial statements.

Term of Members

The members of the Committee shall be appointed annually by the Board. Each member of the Committee shall serve at the pleasure of the Board until the member resigns, is removed, or ceases to be a member of the Board.

3. Meetings

Number of Meetings

The Committee may meet as many times per year as necessary to carry out its responsibilities.

Quorum

No business may be transacted by the Committee at a meeting unless a quorum of the Committee is present. A majority of members of the Committee shall constitute a quorum.

Calling of Meetings

The Chair, any member of the Audit Committee, the external auditor, the Chair of the Board, the Lead Director, the Chief Executive Officer or the Chief Financial Officer may call a meeting of the Audit Committee by notifying the Company's Corporate Secretary, who will notify the members of the Audit Committee. The Chair shall chair all Audit Committee meetings that he or she attends, and in the absence of the Chair, the members of the Audit Committee present may appoint a chair from their number for a meeting.

Minutes; Reporting to the Board

The Committee shall maintain minutes or other records of meetings and activities of the Committee in sufficient detail to convey the substance of all discussions held. Upon approval of the minutes by the Committee, the minutes shall be circulated to the members of the Board. However, the Chair may report orally to the Board on any matter in his or her view requiring the immediate attention of the Board.

Attendance of Non-Members

The external auditor is entitled to attend and be heard at, and shall be given reasonable notice of, each Audit Committee meeting. In addition, the Committee may invite to a meeting any officers or employees of the Company, legal counsel, advisors and other persons whose attendance it considers necessary or desirable in order to carry out its responsibilities. At least once per year, the Committee shall meet with the internal auditor and management in separate sessions to discuss any matters that the Committee or such individuals consider appropriate.

Meetings without Management

The Committee shall hold unscheduled or regularly scheduled meetings, or portions of meetings, at which management is not present.

Procedure

The procedures for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those applicable to meetings of the Board.

Access to Management

In discharging its duties and responsibilities, the Committee shall have unrestricted access to the Company's management and employees and to the relevant books, records and systems of the Company as it considers appropriate.

4. Duties and Responsibilities

The Committee shall have the functions and responsibilities set out below as well as any other functions that are specifically delegated to the Committee by the Board and that the Board is authorized to delegate by applicable laws and regulations. In addition to these functions and responsibilities, the Committee shall perform the duties required of an audit committee by any exchange upon which securities of the Company are traded, or any governmental or regulatory body exercising authority over the Company, as are in effect from time to time (collectively, the "Applicable Requirements").

Financial Reports

(a) General

The Audit Committee is responsible for overseeing the Company's financial statements and financial disclosures. Management is responsible for the preparation, presentation and integrity of the Company's financial statements and financial disclosures and for the appropriateness of the accounting principles and the reporting policies used by the Company. The external auditor is responsible for auditing the Company's annual consolidated financial statements and for reviewing the Company's unaudited interim financial statements.

(b) Review of Annual Financial Reports

The Audit Committee shall review the annual consolidated audited financial statements of the Company, the external auditor's report thereon and the related management's discussion and analysis of the Company'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 of Interim Financial Reports

The Audit Committee shall review the interim consolidated financial statements of the Company, 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. Unless determined otherwise by the Audit Committee in consultation with the Chair of the Board, the Audit Committee will formally approve for release the interim financial statements and related MD&A for the first and third quarters of each fiscal year, and will recommend for Board approval the interim financial statements and related MD&A for the second quarter of each financial year.

(d) Review Considerations

In conducting its review of the annual financial statements or the interim financial statements, the Audit Committee shall:

(i) meet with management and the external auditor to discuss the financial statements and MD&A;

(ii) review the disclosure in the financial statements;

(iii) review the audit report or review report prepared by the external auditor;

(iv) discuss with management, the external auditor and internal legal counsel, as requested, any litigation claim or other contingency that could have a material effect on the financial statements;

(v) review the accounting policies followed and critical accounting and other significant estimates and judgements underlying the financial statements as presented by management;

(vi) review any material effects of regulatory accounting initiatives or off-balance sheet structures on the financial statements as presented by management, including requirements relating to complex or unusual transactions, significant changes to accounting principles and alternative treatments under Canadian generally accepted accounting principles applicable to publicly accountable enterprises;

(vii) review any material changes in accounting policies and any significant changes in accounting practices and their impact on the financial statements as presented by management;

(viii) review management's report on the effectiveness of internal controls over financial reporting;

(ix) review the factors identified by management as factors that may affect future financial results;

(x) review results of the Company's audit committee whistleblowing program; and

(xi) review any other matters related to the financial statements that are brought forward by the external auditor or management or that are required to be communicated to the Audit Committee under accounting policies, auditing standards or Applicable Requirements.

(e) Review of Other Financial Disclosures

The Audit Committee shall review and, if advisable, recommend for Board approval financial disclosure in a prospectus or other securities offering document of the Company, press releases disclosing, or based upon, financial results of the Company, financial guidance provided to analysts or rating agencies or otherwise publicly disseminated and any other material financial disclosure.

(f) Review of Future-Oriented Financial Information or Financial Outlook

The Committee shall 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.

<u>Auditors</u>

(a) General

The Audit Committee shall be responsible for 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. The external auditor will report directly to the Committee.

(b) Nomination and Compensation

The Audit Committee shall review and, if advisable, select and recommend for Board approval the external auditor to be nominated and the compensation of such external auditor. The Audit Committee shall have ultimate authority to approve all audit engagement terms and fees, including the external auditor's audit plan.

(c) Resolution of Disagreements

The Audit Committee shall resolve any disagreements between management and the external auditor as to financial reporting matters brought to its attention.

(d) Discussions with External Auditor

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.

(e) Audit Plan

At least annually, the Audit Committee shall review a summary of the external auditor's annual audit plan. The Audit Committee shall consider and review with the external auditor any material changes to the scope of the plan.

(f) Quarterly Review Report

The Audit Committee shall review a report prepared by the external auditor in respect of each of the interim financial statements of the Company.

(g) Independence of Auditors

At least annually, and before the external auditor issues its report on the annual financial statements, the Audit Committee shall: obtain from the external auditor a formal written statement describing all relationships between the external auditor and the Company; discuss with the external auditor any disclosed relationships or services that may affect the objectivity and independence of the external auditor; and obtain written confirmation from the external auditor that it is objective and independent within the meaning of the applicable Rules of Professional Conduct/Code of Ethics adopted by the provincial institute or order of chartered accountants to which the external auditor belongs and other Applicable Requirements. The Audit Committee shall take appropriate action to oversee the independence of the external auditor.

(h) Evaluation and Rotation of Lead Partner

At least annually, the Audit Committee shall review the qualifications and performance of the lead partner(s) of the external auditor and determine whether it is appropriate to adopt or continue a policy of rotating lead partners of the external auditor.

(i) Requirement for Pre-Approval of Non-Audit Services

The Audit Committee shall approve in advance any retainer of the external auditor to provide any non-audit service to the Company (together with all non-audit service fees) that it deems advisable in accordance with Applicable Requirements and Board-approved policies and procedures. The Audit Committee shall consider the impact of such service and fees on the independence of the external auditor. The Audit Committee may delegate pre-approval authority to a member of the Audit Committee. The decisions of any member of the Audit Committee to whom this authority has been delegated must be presented to the full Audit Committee at its next scheduled Audit Committee meeting.

(j) Approval of Hiring Policies

The Audit Committee shall review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Company and the Committee shall be responsible for any specified reporting and pre-approval functions thereunder.

(k) Communication with Internal Auditor

The internal auditor shall report regularly to the Committee. The Committee shall review with the internal auditor any problem or difficulty the internal auditor may have encountered including, without limitation, any restrictions on the scope of activities or access to required information, and any significant reports to management prepared by the internal auditing department and management's responses thereto. The Committee shall periodically review and approve the mandate, plan, budget and staffing of the internal audit department. The Committee shall direct management to make changes it deems advisable in respect of the internal audit function.

The Committee shall review the appointment, performance and replacement of the senior internal auditing executive and the activities, organization structure and qualifications of the persons responsible for the internal audit function.

(l) Financial Executives

The Committee shall review and discuss with management the appointment of key financial executives and recommend qualified candidates to the Board, as appropriate.

<u>Internal Controls</u>

(a) General

The Audit Committee shall review the Company's system of internal controls.

(b) Establishment, Review and Approval

The Audit Committee shall require management to implement and maintain appropriate systems of internal controls in accordance with Applicable Requirements, including internal controls over financial reporting and disclosure and to review, evaluate and approve these procedures. At least annually, the Audit Committee shall consider and review with management and the external auditor:

(i) the effectiveness of, or weaknesses or deficiencies in: the design or operation of the Company's internal controls (including computerized information system controls and security); the overall control environment for managing business risks; and accounting, financial and disclosure controls (including, without limitation, controls over financial reporting), non-financial controls, and legal and regulatory controls and the impact of any identified weaknesses in internal controls on management's conclusions;

(ii) any significant changes in internal controls over financial reporting that are disclosed, or considered for disclosure, including those in the Company's periodic regulatory filings;

(iii) any material issues raised by any inquiry or investigation by regulators;

(iv) the Company's fraud prevention and detection program, including deficiencies in internal controls that may impact the integrity of financial information, or may expose the Company to other significant internal or external fraud losses and the extent of those losses and any disciplinary action in respect of fraud taken against management or other employees who have a significant role in financial reporting; and

(v) any related significant issues and recommendations of the external auditor together with management's responses thereto, including the timetable for implementation of recommendations to correct weaknesses in internal controls over financial reporting and disclosure controls.

Hedging Strategy

The Audit Committee shall be responsible, on behalf of the Board, for approving the hedging strategy of the Company from time to time, including with respect to commodity price, foreign exchange and interest rate hedging, financial or physical, intended to manage, mitigate or eliminate risks relation to commodity price, foreign exchange and interest rate fluctuations. The Company shall report to the Audit Committee at each Audit Committee meeting regarding hedges placed under the approved hedging strategy. The Audit Committee shall regularly report to the Board on the approved hedging strategy and on hedges placed under such strategy.

Compliance with Legal and Regulatory Requirements

The Audit Committee shall review reports from the Company's Corporate Secretary and other management members on: legal or compliance matters that may have a material impact on the Company; the effectiveness of the Company's compliance policies; and any material communications received from regulators. The Audit Committee shall review management's evaluation of and representations relating to compliance with specific applicable law and guidance, and management's plans to remediate any deficiencies identified.

Audit Committee Whistleblowing Procedures

The Audit Committee shall establish procedures for (a) the receipt, retention, and treatment of complaints received by the Company regarding accounting, internal accounting controls, or auditing matters; and (b) the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters. Any such complaints or concerns that are received shall be reviewed by the Audit Committee and, if the Audit Committee determines that the matter requires further investigation, it will direct the Chair of the Audit Committee to engage outside advisors, as necessary or appropriate, to investigate the matter and will work with management and the general counsel to reach a satisfactory conclusion.

Audit Committee Disclosure

The Audit Committee shall prepare, review and approve any audit committee disclosures required by Applicable Requirements in the Company's disclosure documents.

Delegation

The Audit Committee may, to the extent permitted by Applicable Requirements, designate a sub-committee to review any matter within this mandate as the Audit Committee deems appropriate.

5. Outside Advisors

The Committee shall have the authority to retain external legal counsel, consultants or other advisors to assist it in fulfilling its responsibilities and to set and pay the respective compensation for these advisors. The Company shall provide appropriate funding, as determined by the Committee, for the services of these advisors.

6. No Rights Created

This Mandate is a statement of broad policies and is intended as a component of the flexible governance framework within which the Audit Committee functions. While it should be interpreted in the context of all applicable laws, regulations and listing requirements, as well as in the context of the Company's articles, it is not intended to establish any legally binding obligations.

7. Mandate Review

The Committee shall review and update this Mandate annually and present it to the Board for approval.

DIRECTORS

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Director, Chairman
Geneva, Switzerland

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

C. Ashley Heppenstall
Lead Director
London, England

Donald K. Charter
Director
Toronto, Ontario

Chris Bruijnzeels
Director
Abcoude, The Netherlands

Torstein Sanness
Director
Oslo, Norway

Daniella Dimitrov
Director
Toronto, Ontario

John Festival
Director
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Geneva, Switzerland

Daniel Fitzgerald
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MEDIA RELATIONS

Robert Eriksson
Stockholm, Sweden

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