International Petroleum Corp.

International Petroleum Corporation

Annual Information Form

For the year ended December 31, 2021

Dated: March 25, 2022

AIF
2021

Contents

GLOSSARY OF TERMS

"**AIF**" or "**Annual Information Form**" means this Annual Information Form of IPC prepared for the year ended December 31, 2021 and dated March 25, 2022.

"**Audited Financial Statements**" means the audited consolidated financial statements of the Corporation for the year ended December 31, 2021.

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

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

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook Consolidated Third Edition prepared by the Society of Petroleum Evaluation Engineers (Calgary Chapter), 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.

"**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 8, 2022 filed by the Corporation in respect of certain reserves and resource information.

"**MD&A**" means the Management's Discussion and Analysis of the Corporation for the year ended December 31, 2021.

"**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.

"**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
Bcf	Billion cubic feet
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
GJ	Gigajoules
Mbbl	Thousand barrels
MMbbl	Million barrels
Mboe	Thousand barrels of oil equivalents
Mboepd	Thousand barrels of oil equivalents per day
Mbopd	Thousand barrels of oil per day
MMboe	Million barrels of oil equivalents
Mcf	Thousand cubic feet
MMcf	Million 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.

The Covid-19 virus and the restrictions and disruptions related to it have had a material 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. Although demand, commodity prices and share prices have recovered, there can be no assurance that these effects will not continue or that commodity prices will not decrease or remain volatile in the future. 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 IPC's 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:

- IPC's ability to maximize liquidity and financial flexibility in connection with the current and any future Covid-19 outbreaks;
- the potential for an improved future economic environment, including resulting from a lack of capital investment and drilling in the oil and gas industry;
- 2022 production range, operating costs and capital and decommissioning expenditure estimates;
- estimates of future production, cash flows, operating costs and capital expenditures that are based on IPC's current business plans and assumptions regarding the business environment, which are subject to change;
- IPC's financial and operational flexibility to continue to react to recent events and navigate the Corporation through periods of volatile commodity prices;
- IPC's continued access to its existing credit facilities, including current financial headroom, on terms acceptable to the Corporation;
- the ability to fully fund 2022 expenditures from cash flows and current borrowing capacity;
- IPC's ability to maintain operations, production and business in light of the current and any future Covid-19 outbreaks and the restrictions and disruptions related thereto, including risks related to production delays and interruptions, changes in laws and regulations and reliance on third-party operators and infrastructure;
- IPC's intention and ability to continue to implement our strategies to build long-term shareholder value;
- the ability of IPC's portfolio of assets to provide a solid foundation for organic and inorganic growth;
- the continued facility uptime and reservoir performance in IPC's areas of operation;
- future development potential of the Suffield and Ferguson operations in Canada, including the timing and success of future oil and gas drilling and optimization programs;
- development of the Blackrod project in Canada, including estimates of resource volumes, future production, timing, breakeven prices and net present value;
- current and future drilling pad production and timing and success of facility upgrades, tie-in work and infill drilling at Onion Lake Thermal;
- the potential improvement in the Canadian oil egress situation and IPC's ability to benefit from any such improvements;
- the timing and success of the future development projects and other organic growth opportunities in France;
- the ability to maintain current and forecast production in France;
- the ability of IPC to achieve and maintain current and forecast production in Malaysia;
- the success of the drilling of the A15 sidetrack well and of the production well pump rate optimization project 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;
- the ability of IPC to implement further shareholder distributions in addition to the share repurchase program;
- IPC's ability to implement its greenhouse gas (GHG) emissions intensity and climate strategies and to achieve its net GHG emissions intensity reduction targets;
- estimates of reserves and contingent resources;

- the ability to generate free cash flows and use that cash to repay debt;
- IPC's ability to identify and complete future acquisitions; 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;
- Interest rate and exchange rate fluctuations;
- Marketing and transportation;
- Loss of markets;
- Environmental and climate-related 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" 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 that may be used by other public companies. Management believes that FCF, OCF, EBITDA, operating costs and net debt 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, 2021, 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, 2021 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, 2021, 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, 2021 price forecasts.

The price forecasts used in the Sproule and ERCE reports are available on the website of Sproule (sproule.com) and are contained in "Statement of Reserves Data and Other Oil and Gas Information – Part III Pricing Assumptions" below. These price forecasts are as at December 31, 2021 and may not be reflective of current and future forecast commodity prices. The product types comprising the 2P reserves described in this AIF are contained in "Statement of Reserves Data and Other Oil and Gas Information" below. See also "Supplemental Information regarding Product Types" 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 the best estimate of the quantity that will be actually recovered; it is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability that the quantities actually recovered will equal or exceed the best estimate.

Contingent resources are further classified based on project maturity. The project maturity subclasses include development pending, development on hold, development unclarified and development not viable. All of the Corporation's contingent resources are classified as either development on hold or development unclarified. Development on hold is defined as a contingent resource where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator. Development unclarified is defined as a contingent resource that requires further appraisal to clarify the potential for development and has been assigned a lower chance of development until commercial considerations 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 chance of commerciality. In accordance with the COGE Handbook guidance for contingent resources, the chance of commerciality is solely based on the chance of development associated with resolution of all contingencies required for the re-classification of the contingent resources as reserves. Reported unrisked 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. Estimates of reserves, resources and future net revenue for individual properties may not reflect the same level of confidence as estimates of reserves, resources and future net revenue for all properties, due to the effects of aggregation. This AIF contains estimates of the net present value of the future net revenue from IPC's reserves and resources. 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 reserves and resources evaluations will be attained and variances could be material.

References to "contingent resources" do not constitute, and should be distinguished from, references to "reserves".

Supplemental Information regarding Product Types

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

	Heavy Crude Oil (Mbopd)	Light and Medium Crude Oil (Mbopd)	Conventional Natural Gas (per day)	Total (Mboepd)
Three months ended				
December 31, 2020	19.2	8.2	104.7 MMcf (17.4 Mboe)	44.9
December 31, 2021	21.7	8.5	100.2 MMcf (16.7 Mboe)	46.8
Year ended				
December 31, 2020	16.5	8.5	103.1 MMcf (17.2 Mboe)	42.1
December 31, 2021	20.4	8.4	99.9 MMcf (16.7 Mboe)	45.5

This AIF also makes reference to IPC's forecast total average daily production of 46,000 to 48,000 boepd for 2022. IPC estimates that approximately 46% of that production will be comprised of heavy oil, approximately 21% will be comprised of light and medium crude oil and approximately 33% will be comprised of conventional natural gas.

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, 2021, 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, 2021.

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.

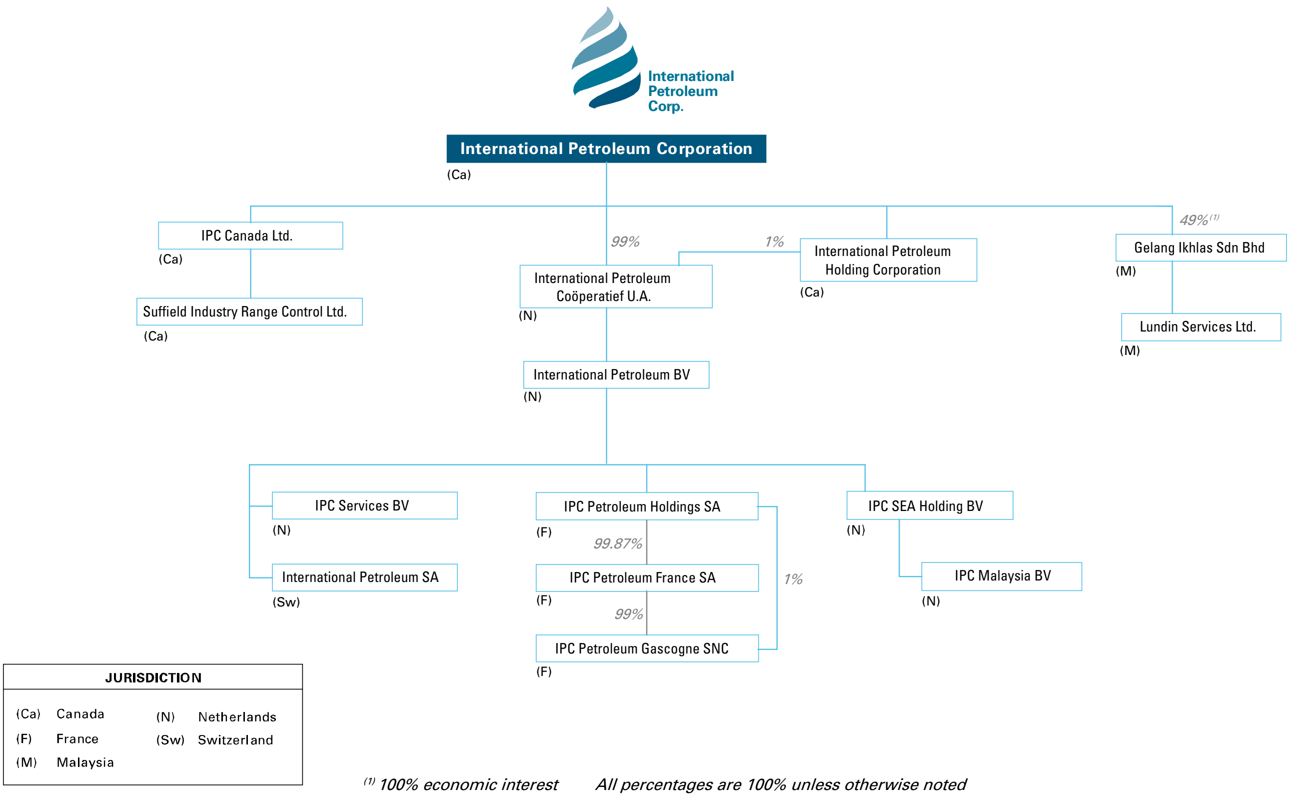
CORPORATE STRUCTURE

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:



GENERAL DEVELOPMENT OF THE BUSINESS

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. IPC is 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, by acquiring and growing a significant resource base.

The following provides a summary of how our business has developed over the last three years.

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.

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 encountered in the A-15 area and poorer than expected results 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 was 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.

Year ended December 31, 2020

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

IPC announced that as at March 31, 2020, following the cancellation of a further 42,336 Common Shares repurchased by IPC under the share repurchase program, the total number of issued and outstanding Common Shares was 155,342,757 Common Shares. IPC suspended further share repurchases and the share repurchase program expired in early November 2020.

In April 2020, IPC announced that following the extraordinary economic and Covid-19 pandemic-related developments since the release of IPC's 2020 budget and production guidance in February 2020, IPC was taking decisive action to reset the 2020 expenditure plans in order to maximise the financial flexibility of the Corporation. IPC revised its forecasts to reduce total forecast 2020 expenditure by between USD 125 and 190 million, with IPC's revised total estimated 2020 capital and decommissioning expenditures accounting for approximately USD 85 million of the total forecast reduction. IPC's total forecast 2020 operating costs were revised downwards by between USD 40 and 105 million, depending on production levels and commodity prices. All remaining discretionary 2020 expenditures were deferred or cancelled and IPC determined to temporarily curtail certain oil production from those fields that were not expected to generate positive cash flows. IPC announced a revised 2020 net average production forecast in the range of 30,000 to 45,000 boepd.

IPC announced in May 2020 that further operational decisions resulted in a revision of the forecast 2020 expenditure reductions to between USD 175 and 190 million as compared to estimates provided in February 2020. IPC revised its forecast 2020 net average production guidance range to 30,000 to 37,000 boepd. IPC's announced its estimated 2020 capital and decommissioning expenditures of USD 77 million and IPC's forecast 2020 operating costs in the range of USD 140 to 155 million, resulting in estimated 2020 unit operating costs in the range of USD 12 to 13 per boe. IPC confirmed its flexibility to resume production during the second half of 2020 should market conditions improve. IPC also announced an unsecured French Government backed loan of MEUR 13.

In August 2020, IPC announced that following the strengthening of oil prices, in particular Canadian crude oil pricing, it had decided to progressively bring back on stream oil production at Suffield and Onion Lake Thermal. As a result of this and other factors, IPC revised its 2020 forecast net average production to be above the upper end of our previous guidance with a new range of 37,000 to 40,000 boepd. IPC also announced that its estimated 2020 capital and decommissioning expenditures were marginally increased to MUSD 80. IPC also confirmed that it had concluded discussions with its banking partners regarding the refinancing of its reserve-based lending facilities (RBL).

In August 2020, IPC announced the appointment of William Lundin to the position of Chief Operating Officer as of December 2020.

In November 2020, IPC announced its forecast full year 2020 average net production at approximately 41,000 boepd. IPC also presented its inaugural Sustainability Report, detailing the Corporation's environmental, social and governance (ESG) performance. IPC confirmed its target to reduce net GHG emissions intensity to the global average by the end of 2025, which would represent a 50% reduction relative to the Corporation's 2019 baseline.

Year ended December 31, 2021

In February 2021, IPC announced its initial 2021 capital expenditure budget of USD 37 million and its initial 2021 production guidance of between 41,000 and 43,000 boepd. IPC also announced its 2020 year-end 2P reserves and best estimate contingent resources (unrisked) of respectively 272 MMboe and 1,102 MMboe. IPC's net debt was confirmed as USD 321 million as at December 31, 2020. At that time, IPC stated that uncertainties regarding the Covid-19 pandemic remained and as a result, IPC set a limited capital budget for 2021 with a focus on free cash flow generation and debt reduction. IPC's 2021 capital expenditure budget includes continued Onion Lake Thermal Pad D' completion work, gas optimization activities in the Suffield area, well conversions at the Ferguson asset and Blackrod project activities in Canada. IPC planned limited capital activities in France and Malaysia for 2021, with flexibility to amend plans based on commodity prices.

IPC announced that as at February 26, 2021, following the exercise of stock options, the total number of issued and outstanding Common Shares increased by 25,000 to 155,367,757 Common Shares.

In May 2021, IPC announced that as a result of exceptional operational performance and high uptimes recorded across IPC's portfolio, full year 2021 average net production was expected to be towards the high end of the forecast 41,000 to 43,000 boepd range. IPC also announced that during April 2021, IPC acquired an additional 25% interest in the Bertam field, Malaysia, taking IPC's interest in the field to 100% effective from April 10, 2021.

IPC announced in August 2021 that its full year 2021 average net production forecast was revised upwards to above 44,000 boepd. In addition, the 2021 capital expenditure budget was increased to MUSD 73 from MUSD 37 following the addition of drilling projects in Malaysia and Canada in the second half of 2021. IPC also published its second Sustainability Report, detailing the Corporation's ESG performance.

In December 2021, IPC announced the launch of a share repurchase program under which IPC was authorized to repurchase through the facilities of the TSX, Nasdaq Stockholm and/or alternative Canadian trading systems, up to approximately 11.1 million Common Shares, over the twelve month period to December 2022.

IPC announced that as at December 31, 2021, following the cancellation of 169,652 Common Shares repurchased by IPC under the share repurchase program, the total number of issued and outstanding Common Shares was 155,198,105 Common Shares.

Subsequent to the year ended December 31, 2021

In January 2022, IPC announced that international credit rating agencies Moody's and S&P Global Ratings have assigned corporate credit ratings to IPC. Moody's has assigned a credit rating of B1 with stable outlook and S&P Global Ratings has assigned a credit rating of B with Stable Outlook.

IPC announced that in January 2022, it cancelled a further 1,160,651 common shares repurchased under the share repurchase program during December 2021.

In January 2022, IPC announced that it successfully completed a private placement of USD 300 million of senior unsecured bonds. The bonds have a tenor of five years and a fixed coupon rate of 7.25 percent per annum, with interest payable in semi-annual instalments. The bond issue was rated B+ by S&P Global Ratings and B1 by Moody's. In early February 2022, IPC used a portion of the proceeds of the bond to fully repay and cancel existing reserve-based lending facilities and, at the same time, IPC put in place a new CAD 75 million revolving credit facility for financial flexibility in Canada.

IPC announced that as at January 31, 2022, following the cancellation of 726,676 Common Shares repurchased by IPC under the share repurchase program, the total number of issued and outstanding Common Shares was 153,310,778 Common Shares.

In February 2022, IPC announced its 2022 capital expenditure budget of USD 127 million and its 2022 production guidance of between 46,000 and 48,000 boepd. IPC also announced its 2021 year-end 2P reserves and best estimate contingent resources (unrisked) of respectively 270 MMboe and 1,410 MMboe. IPC's net debt was confirmed as USD 94 million as at December 31, 2021. IPC's 2022 capital expenditure budget includes the commencement of investment at Onion Lake Thermal on the next sustaining Pad L as well as further infill drilling, Suffield oil N2N drilling, Phase I development at the Ferguson asset and Blackrod FEED studies as well as continued production from Well Pair 3 in Canada. IPC also stated its plans to complete the A15 sidetrack well and ESP pump upsizing campaign in Malaysia as well as to start the Phase I development of the Villeperdue West project in France. IPC also stated that based on current business plans and assumptions, IPC plans to distribute to shareholders up to 40% of the free cash flow generated by IPC above achieved average Brent oil prices of USD 55 per barrel, provided that IPC's net debt to EBITDA ratio is at or below 1 time.

IPC announced that as at February 28, 2022, following the cancellation of 1,564,178 Common Shares repurchased by IPC under the share repurchase program, the total number of issued and outstanding Common Shares was 151,746,600 Common Shares.

Significant Acquisitions in the year ended December 31, 2021

IPC did not complete any acquisitions requiring the filing of a business acquisition report under applicable Canadian securities regulations during the year ended December 31, 2021.

DESCRIPTION OF THE BUSINESS

Summary

As at December 31, 2021, 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 2021, IPC reported average daily production of 45,500 boepd (45% heavy crude oil, 18% light and medium crude oil and 37% natural gas).

During 2021, IPC's operating cash flow was approximately USD 337 million and IPC's total year end net debt was USD 94 million.

As at the end of December 2021, IPC's 2P reserves were 270 MMboe, with a reserves life index of 16 years. The product types comprising the 2P reserves described in this AIF are contained in "Statement of Reserves Data and Other Oil and Gas Information" below. See also "Supplemental Information regarding Product Types" above.

In addition, IPC had best estimate contingent resources (unrisked) as at the end of December 2021 of 1,410 MMboe. 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 asset in Malaysia is a 100% working interest in the offshore Bertam Field, where production is light, high quality oil. IPC acquired the remaining 25% working interest in the Bertam Field in April 2021, previously having held operatorship and a 75% working interest. 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, 2021 unless otherwise indicated.

Canada

2021 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 2021 was 38.1 Mboepd.

At Onion Lake Thermal, new production sustaining Pad D' was brought online in Q3 2021. As of the end of Q4 2021, all six production wells had been successfully brought online with initial production in line with pre sanction expectations. During Q4 2021, a five well infill drilling campaign was successfully completed at Onion Lake Thermal. All five production wells had been brought online by year-end 2021.

Suffield Area

Overview

The 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. EOR techniques are deployed by IPC on appropriate reservoirs with a view to increasing recoverable oil.

Sweet natural gas production in the Suffield area is via shallow vertical wells producing from multiple formations. These low pressure wells flow naturally into the pipeline gathering system. Natural gas production is compressed and exported via 16 strategically located compressor stations.

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.

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.

Following the acquisition by IPC in 2018, oil drilling commenced for the first time since 2014 on these assets. This drilling program continued through 2019 and into the first quarter of 2020. By the end of 2020, twenty-five oil wells from the drilling program had been drilled and brought online.

In 2019, the N2N field ASP EOR development project was sanctioned, commissioned and brought online. By the end of 2020, six new oil wells were online. During 2021, ASP injection rate optimization and oil production ramp up continued.

In addition, since acquisition, IPC has implemented a multi-year gas optimization program with a ramp up in well swabbing activity and an extensive well recompletion program targeting underdeveloped production zones. In 2021, swabbing activity had reached the highest levels since 2014, significantly offsetting the historical field decline rate.

In 2021, IPC originally forecast a limited capital expenditure plan. Following the operational success and improvement in commodity prices, IPC increased its capital expenditure activities in Canada, including at Suffield.

Abandonment Obligations

Abandonment consists of permanent capping of 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 expenditure budget. The Group follows the applicable Alberta regulations and reports regularly to the Alberta regulator on its abandonment activities in respect of Suffield. On this basis, uneconomic wells and/or non-producing wells are regularly abandoned as a part of ongoing business.

IPC is committed to responsibly managing its abandonment risks and liabilities in Canada, in compliance with applicable regulations. In determining abandonment strategy and budget for all of its assets in Canada, IPC takes into account several factors with respect to the asset, including remaining economic life, safety and environment risks, regulatory compliance, and cost and time efficient abandonment operations. Since 2020, in Alberta, IPC has elected to participate in the Alberta Energy Regulator's Area Based Closure Program, enabling IPC to pursue abandonment activities on the basis of internal risk evaluation and operational efficiencies. This program requires a commitment to spend a percentage of deemed asset liability over the course of the year. IPC remained in compliance with these requirements in 2021.

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 2021, there were 25 conventional primary producing wells (20 net wells) and 39 thermal producing wells on the property.

History

Up to 2020, 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 bopd 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 bopd. 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 bopd.

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

In early 2019, a steam optimization project was completed at the processing facility lifting Onion Lake Thermal name-plate production processing capacity to 14,000 bopd.

In 2021, the Onion Lake Thermal production growth story continued in line with the field development plan. Production sustaining Pad D' and its six production wells successfully brought online. Furthermore, during Q4 2021, a five well infill drilling campaign was successfully completed and all five production wells had been brought online by year-end 2021.

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 metres 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 metres 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 metres 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 oil 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. Produced water is then trucked and disposed of at IPC's deep water disposal well, with sand being trucked to third party disposal sites. Much of the solution gas is utilized to drive the progressive 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 via deep well disposal. The sales oil is then trucked to various delivery points surrounding the Lloydminster area.

Abandonment Obligations

Abandonment and reclamation consists of permanent capping 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 activities are revised and included in the capital expenditure budget. The appropriate Saskatchewan regulations are followed and reports are filed regularly in respect of Onion Lake. Uneconomic 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 abandoned and the pad is no longer in use, it is then available to be abandoned.

See also "Canada -- Suffield – Abandonment Obligations" above in respect of IPC's abandonment strategy.

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 became operational in the first quarter of 2022 with the potential for enhanced operational reliability and efficiencies in bringing oil to market.

Development Plans

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

Ferguson

Summary

The Ferguson field, acquired by IPC in March 2020, produces 29° API oil from an oil pool which extends over a 50 kilometre fairway. The Ferguson field acquisition also included existing infrastructure to enable the 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 2021, there were 53 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 gas injection facilities at the central oil battery with a current capacity of approximately 20,000 Mcf per day. IPC also owns 100% of a natural gas plant and processing facility that has a capacity of 7,000 Mcf per day of gas.

Abandonment Obligations

Abandonment consists of permanent capping of 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 expenditure budget. The Group follows the applicable Alberta regulations and reports regularly to the Alberta regulator their abandonment activities in respect of Ferguson. On this basis, uneconomic wells and/or non-producing wells are regularly abandoned as a part of ongoing business.

See also "Canada – Suffield – Abandonment Obligations" above in respect of IPC's abandonment strategy.

Development Plans

IPC plans to commence oil drilling, conversion of oil wells to gas injectors and upgrade of gas compression capacity at the Ferguson assets during 2022.

Mooney

Summary

Mooney is located in north-central Alberta, Canada and is a conventional heavy crude oil property with an EOR flood scheme, on a portion of the lands. There are 32 active production wells on the Mooney field.

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). During 2021, the Mooney field resumed production following improved commodity prices.

Geology

The Mooney field produces from the Bluesky formation, which is found at approximately 900 metres TVD and was deposited in a broad coastline setting with a consistent orientation and a predictable thickness trend. Generally, 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 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.

Abandonment Obligations

Abandonment and reclamation consists of permanent capping 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 are filed regularly in respect of Mooney. Uneconomic 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 abandoned and the pad is no longer in use, it is then available to be decommissioned and reclaimed.

See also "Canada -- Suffield – Abandonment Obligations" above in respect of IPC's abandonment strategy.

Infrastructure and Marketing

Production from the Mooney area is currently trucked to third party sales points.

Blackrod

Summary

Blackrod is an in situ (SAGD) heavy oil project located south of Fort McMurray about 20 kilometres north of Wandering River, in the Athabasca 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. The Blackrod asset is located in the Athabasca oil sands area and represents an attractive SAGD heavy oil development opportunity. IPC is the operator of a successful pilot at Blackrod, having recorded positive results from the production testing phases of the first two pilot well pairs. In 2020, Well Pair 3 was successfully brought online with steam conformance optimization, production ramp up and well rate testing continuing through 2021.

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 metres to 30 metres, 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 with API gravity ranging 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 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. 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 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 produced in excess of 900,000 bbls to the end of 2020.

Drilling of the third well pair at the Blackrod SAGD pilot project was completed in the third quarter of 2019, with the horizontal section of the well reaching approximately 1400 meters in length. Steam injection commenced in Well Pair 3 in 2019, with conversion to SAGD production operations completed in 2020. Well Pair 3 steam conformance optimization, production ramp up and well rate testing continued through 2021.

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 commercial 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 initial production rates of 20,000 bopd increasing to 30,000 bopd.

During 2021, IPC commissioned a third party independent qualified reserves evaluator report from Sproule Associates Ltd. (Sproule) on the contingent resources at Blackrod Phase I as at December 31, 2021. Full field best estimate contingent resources (unrisked) increased from 987 MMboe as at end December 2020 to 1,283 MMboe as at end December 2021. Phase I best estimate contingent resources (unrisked) increased from 178 MMboe to 217 MMboe as at end December 2021. IPC plans to mature the Blackrod Phase I project during 2022 through FEED studies in parallel with the continuation of production from Well Pair 3. See Schedule B for further information.

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 and expects to begin Front End Engineering Design during 2022.

Other Properties in Canada

IPC also holds interests and has ongoing operations and production in several other areas of Alberta and Saskatchewan, including John Lake, Reita Lake, Portage and Graindale.

Malaysia

2021 Summary

Net production from the Bertam field on Block PM307 (IPC working interest (WI) 100% from April 20, 2021, WI 75% previously) during 2021 was at 4.4 Mboepd. Reservoir performance for the Bertam field was in line with expectation and facility uptime during 2021 was in excess of 99 percent (excluding planned shutdowns).

In 2021, the water handling capacity of the Bertam FPSO was successfully increased from 17,000 to 24,000 barrels of water per day. At the end of Q4 2021, A15 sidetrack drilling operations commenced with first oil from the well being delivered in March 2022. The production well pump rate optimization project is underway as at the date of this AIF.

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 100% WI from April 20, 2021.

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, 2021, 14 active 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, 2021, reservoir access was through 16 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 until April 2023, with two further one-year options available from April 2023. 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. 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 cleaned and returned to the Group as owner of the vessel. 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.

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 crude is delivered directly from the FPSO Bertam into the buyer's vessel.

Petronas, IPC SEA Holding BV, 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, IPC SEA Holding BV and IPC Malaysia BV appoint Petco as an exclusive marketing agent to sell Petronas', IPC SEA Holding BV'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 program of highly successful infill well drilling campaigns commenced in 2016 at Bertam field, and have continued in 2021 with the fourth phase of infill well drilling undertaken. Drilling of the A15 sidetrack well commenced in December 2021 and was completed in Q1 2022. One additional infill drilling location has been identified and booked as contingent resources. Further technical work is planned during 2022.

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 from fields operated by Vermilion Energy Inc., where IPC holds a 50% working interest.

2021 Summary

Net production in France during 2021 was 3.0 Mboepd. IPC continues to review 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.

Assets Description

The Group was the operator during 2021 of ten oil field licenses and one exploration permit 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 reports 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 storage at the main Villeperdue gathering centre and then to a third party storage facility at Le Havre, France. IPC's Paris Basin production is sold to Total under a sales contract to end 2026.

Development Plans

IPC plans to commence the first phase of the Villeperdue West development in 2022, including the drilling of three new horizontal production wells in the field.

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. 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, previously held an interest in the Gurita Block PSC which has been terminated. 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 Energy 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, 2021, IPC had a total of 258 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 maintains a corporate and financing office in The Netherlands.

The following table summarizes IPC's full-time equivalent employees as at December 31, 2021:

	December 31, 2021
Canada	127
Malaysia	64
France	46
Switzerland	21
Number of employees	258

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 substantial oil and gas industry experience, including 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.

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 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 seeks 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".

Climate Regulations

Climate change regulation at international, national and regional levels has the potential to significantly affect the regulatory environment of the oil and natural gas industry where we operate.

In general, there is some uncertainty with regard to the impacts of changes in climate change and environmental laws and regulations globally, as countries aim to fulfill their commitments under the Paris Agreement. 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. 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.

The Corporation's Sustainability Policy is articulated around 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.

In 2021, IPC presented its second annual Sustainability Report, detailing the Corporation's environmental, social and governance (ESG) performance. IPC confirmed its target to reduce net GHG emissions intensity to the global average by the end of 2025, which will represent a 50% reduction relative to the Corporation's 2019 baseline. IPC's Sustainability Report may be accessed on IPC's website at www.international-petroleum.com.

In 2020, IPC joined the United Nations Global Compact, a leading global initiative for good corporate citizenship. IPC supports and is committed to upholding the 10 Principles of the UN Global Compact on human rights, labour, environment and anti-corruption, and reports on progress on an annual basis.

INDUSTRY CONDITIONS

Oil and Gas Market Overview

Global energy consumption is driven by world population, economic growth and availability of resources. Oil is used for a wide array of purposes including transportation, petrochemical processes, pharmaceuticals, power generation and agriculture.

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 past. 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.

Enbridge Inc. Line 3 Replacement from Alberta to Wisconsin came into service in October 2021. The Line 3 Replacement, originally expected to be in-service in late 2019, faced significant permitting difficulties in the United States, resulting in the two-year delay. The pipeline provides an incremental 370,000 bbls/d of export capacity from Western Canada into the United States.

The TransMountain Pipeline expansion received federal government approval in 2016 and was acquired by the federal government in August 2018. Following the resolution of a number of legal challenges and a second regulatory hearing, construction on the TransMountain Pipeline expansion commenced in late 2019. The pipeline is expected to be in service in the third quarter of 2023.

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 meeting a minimum level of production (MLP), or by paying an escalating rental in lieu of achieving the 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. Based on these factors, the base royalty rate ranges from 5% - 20% and the marginal royalty rate ranges from 25% - 45%. The Crown royalty payable on natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type and classification of the natural gas, the finished drilling date of the well and certain price adjustment factors. Based on these factors, the base royalty rate ranges from 0% - 20% and the marginal royalty rate ranges from 30% - 45%.

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

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, emissions management, 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.

In 2019, the *Impact Assessment Act* (the "IAA") replaced the *Canadian Environmental Assessment Act, 2012* (the "CERA"). The CERA and the IAA introduced a number of important changes to the regulation of federally regulated major projects and their associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer manage strategic, administrative and policy considerations while adjudicative functions fall to independent commissioners. The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and certain offshore renewable energy projects. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

The IAA relies on a designated project list as a trigger for a federal assessment. Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the IA Agency or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the IAA. The impact assessment requires consideration of the project's potential adverse effects and the overall societal impact that a project may have, both of which may include a consideration of, among other items, environmental, biophysical and socio-economic factors, climate change, and impacts to Indigenous rights. It also requires an expanded public interest assessment. Designated projects specific to the oil and gas industry include pipelines that require more than 75 km of new right of way and pipelines located in national parks, large scale in situ oil sands projects not regulated by provincial GHG emissions caps and certain refining, processing and storage facilities.

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process.

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 "**SKOGCA**"), including *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 Program - Alberta

The AER administers the Liability Management Framework (the "**LM Framework**") and the Liability Management Rating Program (the "**LMR Program**") to manage liability for most conventional upstream oil and natural gas wells, facilities and pipelines in Alberta. The AER is in the process of replacing the LMR Program with the LM Framework. This change was effected under key new AER directives in 2021. Broadly, the LM Framework is intended to provide a more holistic approach to liability management in Alberta, as the AER found that the more formulaic approach under the LMR Program did not necessarily indicate whether a company could meet its liability obligations. New developments under the LM Framework include a new Licensee Capability Assessment System (the "**LCA**"), a new Inventory Reduction Program (the "**IR Program**"), and a new Licensee Management Program ("**LM Program**"). Meanwhile, some programs under the LMR Program remain in effect, including the Oilfield Waste Liability Program (the "**OWL Program**"), the Large Facility Liability Management Program (the "**LF Program**") and elements of the Licensee Liability Rating Program (the "**LLR Program**"). The mix between active programs under the LM Framework and the LMR Program highlights the transitional and dynamic nature of liability management in Alberta. While the province is moving towards the LM Framework and a more holistic approach to liability management, the AER has noted that this will be a gradual process that will take time to complete. In the meantime, the LMR Program continues to play an important role in Alberta's liability management scheme.

Complementing the LM Framework and the LMR Program, Alberta's *Oil and Gas Conservation Act* (the "**OGCA**") establishes an orphan fund (the "**Orphan Fund**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the LLR Program and the OWL Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. Licensees in the LLR Program and the OWL Program fund the Orphan Fund through a levy administered by the AER. However, given the increase in orphaned oil and natural gas assets, the Government of Alberta has loaned the Orphan Fund approximately CA$335 million to carry out abandonment and reclamation work. In response to the COVID-19 pandemic, the Government of Alberta also covered CA$113 million in levy payments that licensees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. A separate orphan levy applies to persons holding licences subject to the LF Program. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

An important step in the shift to the LM Framework has been amendments to *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* ("**Directive 067**"), which deals with licensee eligibility to operate wells and facilities. All licence transfers and granting of new well, facility and pipeline licences in Alberta are subject to AER approval. Previously under the LMR Program, as a condition of transferring existing AER licences, approvals and permits, all transfers required transferees to demonstrate that they had a liability management rating ("**LMR**") of 2.0 or higher immediately following the transfer. If transferees did not have the required rating, they would have to otherwise prove to the satisfaction of the AER that they could meet their abandonment and reclamation obligations, through means such as posting security or reducing their existing obligations. However, amendments from April 2021 to Directive 067 expanded the criteria for assessing licensee eligibility. Notably, the recent amendments increase requirements for financial disclosure, detail new requirements for when a licensee poses an "unreasonable risk" of orphaning assets, and adds additional general requirements for maintaining eligibility.

Alongside changes to Directive 067, the AER also introduced *Directive 088: Licensee Life-Cycle Management* ("**Directive 088**") in December 2021 under the LM Framework. Directive 088 replaces, to an extent, the LLR Program with the LCA. Whereas the LLR Program previously assessed a licensee based on a liability rating determined by the ratio of a licensee's deemed asset value relative to the deemed liability value of its oil and gas wells and facilities, the LCA now considers a wider variety of factors and is intended to be a more comprehensive assessment of corporate health. The liability management rating under the LLR Program is still in effect for other liability management programs such as the OWL Program and the LF Program, and will remain in effect until a broadened scope of Directive 088 is phased in over time.

In addition to the LCA, Directive 088 also implemented other new liability management programs under the LM Framework. These include the LM Program and the IR Program. Under the LM Program the AER will continuously monitor licensees over the life-cycle of a project. If, under the LM Program, the AER identifies a licensee as high risk, the regulator may employ various tools to ensure that a licensee meets its regulatory and liability obligations. In addition, under the IR Program the AER sets industry wide spending targets for abandonment and reclamation activities. Licensees are then assigned a mandatory licensee specific target based on the licensee's proportion of provincial inactive liabilities and the licensee's level of financial distress. Certain licensees may also elect to provide the AER with a security deposit in place of their closure spend target.

IPC continues to monitor the development of these changes to the liability management regulations in Alberta and is committed to responsibly managing its abandonment risks and liabilities, in compliance with these regulations. See also "**Description of the Business – Description of the Group's Oil and Gas Assets – Canada – Suffield – Abandonment Obligations**" with respect to IPC's abandonment strategy in Canada. Since 2020, IPC has elected to participate in the AER's Area Based Closure Program. This program requires a commitment to spend a percentage of deemed asset liability over the course of the year. IPC remained in compliance with these requirements in 2021.

Liability Management Program - Saskatchewan

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "**SK LLR Program**"), which was updated in May 2020. The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund takes on the obligation of carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when the Saskatchewan Ministry of Energy and Resources confirms there is no legally responsible or financially able party to deal with the abandonment and/or reclamation responsibilities. The SK LLR Program also outlines requirements for security deposits and licence transfers. If a licence holder wishes to transfer a licence, then the transferee will be required to provide a security deposit if their licensee liability rating ("**LLR**") is not greater than 1.0. Other factors aside from the licensee's LLR may be considered when assessing the amount of the required security deposit.

In February 2021, the Energy Regulation Division of the Ministry of Energy and Resources announced that it was consulting with stakeholders on proposed regulatory enhancements intended to strengthen Saskatchewan's oil and gas liability management framework and reduce the prospect of new orphan oil and gas wells and facilities in Saskatchewan. This process led to the development of the new *Financial Security and Site Closure Regulations,* which were published in June 2021, but are not yet in force.

IPC continues to monitor the development of these changes to the liability management regulations in Saskatchewan and is committed to responsibly managing its abandonment risks and liabilities, in compliance with these regulations. See also "**Description of the Business – Description of the Group's Oil and Gas Assets – Canada – Suffield – Abandonment Obligations**" with respect to IPC's abandonment strategy in Canada. IPC remained in compliance with the Saskatchewan regulations in 2021.

Federal and Provincial Support for Liability Management

As part of an announcement of federal relief for Canada's oil and gas industry in response to the Covid-19 pandemic, the federal government pledged CA$1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. The funds are being administered by regulatory authorities in each province. The majority of these funds have now been allocated and disbursed.

Climate Change Regulation

Climate change regulation at international, federal and provincial levels 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, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**") in 2016. 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. On December 11, 2020, however, the federal Government announced its intention to continue the annual price increases beyond 2022, such that, commencing in 2023, the benchmark price per tonne of CO2e will increase by CAD 15 per year until it reaches CAD 170/tonne of CO2e in 2030. Starting April 1, 2022, the minimum price permissible under the GGPPA is CAD 50/tonne of CO2e. In addition, on March 5, 2021, the federal government introduced for comment the Greenhouse Gas Offset Credit System Regulations (Canada) (the "**Federal Offset Credit Regulations**"). The proposed Federal Offset Credit Regulations are intended to establish a regulatory framework to allow certain kinds of projects to generate and sell offset credits for use in the federal OBPS. The final Federal Offset Credit Regulations are currently targeted for publication in mid-2022.

The 2018 federal *Greenhouse Gas Pollution Pricing Act* (the “**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 (the “**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.

The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030. Both Alberta and Saskatchewan have implemented methane regulations which have been granted equivalency by the federal government.

In the November 23, 2021 Speech from the Throne, the federal government restated its commitment to achieve net-zero emission by 2050. In pursuit of this objective, the government's proposed actions include: (i) moving to cap and cut oil and gas sector emissions; (ii) investing in public transit and mandating the sale of zero-emission vehicles; (iii) increasing the federally imposed price on pollution; (iv) investing in the production of cleaner steel, aluminum, building products, cars, and planes; (v) addressing the loss of biodiversity by continuing to strengthen partnerships with First Nations, Inuit, and Métis, to protect nature and the traditional knowledge of those groups; (vi) creating a Canada Water Agency to safeguard water as a natural resource and support Canadian farmers; (vii) strengthening action to prevent and prepare for floods, wildfires, droughts, coastline erosion, and other extreme weather worsened by climate change; and (viii) helping build back communities impacted by extreme weather events through the development of Canada's first-ever National Adaptation Strategy.

The *Canadian Net-Zero Emissions Accountability Act* (the "CNEAA") received royal assent on June 29, 2021, and came into force on the same day. The CNEAA binds the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It establishes rolling five-year emissions-reduction targets and requires the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body. The CNEAA also requires the federal government to publish annual reports that describe how departments and crown corporations are considering the financial risks and opportunities of climate change in their decision-making. A comprehensive review of the CNEAA is required every five years from the date the CNEAA came into force.

The Government of Canada is also in the midst of developing a carbon capture utilization and storage ("CCUS") strategy. CCUS is a technology that captures carbon dioxide from facilities, including industrial or power applications, or directly from the atmosphere. The captured carbon dioxide is then compressed and transported for permanent storage in underground geological formations or used to make new products such as concrete. The federal government has indicated that urgent steps are necessary to ramp up CCUS in Canada, as this will be a critical element of the plan to reach net-zero by 2050.

Alberta

On April 1, 2022, the carbon tax payable in Alberta will increase from CA$40 to CA$50 per tonne of CO2e, and will continue to increase at a rate of CA$15 per year until it reaches CA$170 per tonne in 2030. In December 2019, the federal government approved Alberta's *Technology Innovation and Emissions Reduction* ("TIER") regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 and replaces the previous *Carbon Competitiveness Incentives Regulation*. The TIER regulation meets the federal benchmark stringency requirements for emissions sources covered in the regulation, but the federal backstop continues to apply to emissions sources not covered by the regulation.

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 until it reaches the high-performance benchmark; 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 rolling 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 a price set by the Alberta government.

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. In November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Alberta. IPC has been active in implementing methane reduction strategies in respect of its assets as further detailed in its Sustainability Report.

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

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 is 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.

To facilitate its emissions reduction efforts, the Government of Saskatchewan has implemented Directive PNG017: Measurement Requirements for Oil and Gas Operations, which came into force in December 2019 and was amended in April 2020, and Directive PNG036: Venting and Flaring Requirements, which came into force in April 2020. Together with the Saskatchewan O&G Emissions Regulations, these directives enable the Government of Saskatchewan to regulate emissions reductions within the province. In November 2020, the Government of Canada and the Government of Saskatchewan announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the CGPPA will not apply in Saskatchewan.

In January 2021, the Government of Saskatchewan announced support for three projects expected to reduce methane emissions, including a new flare-gas-to-power project, an expansion of gas processing facilities, and a new gas fractionation plant. The Saskatchewan Petroleum Innovation Incentive ("**SPII**") and Oil and Gas Processing Investment Incentive ("**OGPII**") give this support. The SPII and OGPII provide a percentage of transferable royalty credits after private funding has been obtained and the facilities have been built.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, the rights of Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the United Nations Declaration of the Rights of Indigenous Peoples ("**UNDRIP**") and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. For example, in November 2019, the *Declaration on the Rights of Indigenous Peoples Act* ("**DRIPA**") became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In June 2021, the *United Nations Declaration on the Rights of Indigenous Peoples Act* ("**UNDRIP Act**") came into force in Canada. Similar to British Columbia's DRIPA, the UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as DRIPA and UNDRIP Act are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines. The Government of Canada has expressed that implementation of the UNDRIP Act has the potential to make meaningful change in how Indigenous peoples collaborate in impact assessment moving forward, but has confirmed that the current IAA already establishes a framework that aligns with UNDRIP and does not need to be changed in light of the UNDRIP Act.

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 the 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, 2021 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.

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 share 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 Malaysian 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. The bulk of current oil production in France comes from the Paris Basin.

Regulatory Regime Summary

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 2021, the corporate tax rate was 26.5% 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 27.37%.

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 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 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 decided to stop granting future petroleum exploration permits in France and to cease the production of oil and gas under existing production licenses in France from 2040.

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 Transition. The local mining tax is payable in arrears (production of 2020 is reported in 2021 and the corresponding tax is paid, after receipt of the notice of payment, generally end 2021 or beginning 2022), is ring-fenced by well. For 2021, the RCDM was set at EUR 30.135 per net tonne of oil equivalent.

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.

Pandemic: The Covid-19 virus and the restrictions and disruptions related to it had a material 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. There can be no assurance that these effects will not continue or that commodity prices will not decrease or remain volatile in the future. 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 IPC's 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.

The current and any future Covid-19 outbreaks may increase IPC's exposure to, and magnitude of, each of the risks and uncertainties identified below that result from, for example, a reduction in demand for oil and gas consumption, lower or volatile commodity prices, reliance on third parties, operational risks and costs and changes in government regulation. The extent to which Covid-19 impacts IPC's business, results of operations and financial condition will depend on future developments, which are highly uncertain and are difficult to predict, including, but not limited to, the duration and spread of any Covid-19 outbreaks, their severity, the actions taken to contain such outbreaks or treat their impact, and how quickly and to what extent normal economic and operating conditions resume and their impacts to IPC's business, results of operations and financial condition which could be more significant in upcoming periods as compared with previous periods. Even after the Covid-19 outbreaks have subsided, IPC may continue to experience materially adverse impacts to IPC's business as a result of the global economic impact of the pandemic.

Exploration, Development and Production Risks: Oil and 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 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 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 Covid-19 virus, 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 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, hydrocarbon releases and spills, each of which could result in substantial damage to oil and 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 and Price Differentials: The marketability and price of oil and 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 gas may depend upon its ability to access space on pipelines that deliver oil and 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 gas and many other aspects of the oil and 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 and OPEC+, governmental regulation, political instability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports, the availability of alternative fuel sources and the potential for increased supply of oil and gas for unconventional shale oil and shale gas and other services.

Oil and 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 (GHG) 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.

The Group's facilities and operations, and the oil and gas that the Group markets, result in the emission of GHGs which makes the Group subject to GHG emissions legislation and regulation. 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 GHGs could have a material impact on the operations and financial condition of the Corporation.

In addition, concerns about climate change and public discussion that climate change may be associated with extreme weather conditions 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 GHGs and resulting requirements, it is not possible to predict the impact on the Group and its operations and financial condition.

Emission and carbon tax regulations in Canada federally and regionally are evolving and as these regulations are established or amended, they may have an impact on organizations involved in heavy oil production. As a signatory to the United Nations Framework Convention on Climate Change and a party to the Paris Agreement, the Government of Canada committed to a 30% reduction in GHG emissions below 2005 levels by 2030; one of the policies announced to date by the Government of Canada to reduce GHG emission is the implementation of a nation-wide price on carbon emissions. 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 Covid-19 virus, 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 its oil and gas reserves.

Uncertainties Associated with Estimating Reserves and Resources Volumes: There are numerous uncertainties inherent in estimating quantities of oil and 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 disclosure 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 gas, curtailments or increases in consumption by oil and 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 and resources. 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 reserves and resource 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 intends to use the SAGD process at the Blackrod project. The SAGD recovery process requires a significant amount of 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 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 gas. The implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could reduce demand for crude oil and 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 licences in France and to restrict the production of oil and gas under existing production licences in France from 2040. There is a risk that France could implement further legislative changes and that the licence regime in France could become more onerous. In Canada, the oil and gas regulatory authorities have implemented regulations regarding the ability to transfer leases, licences, permits, wells and facilities between parties. These authorities have increased the minimum abandonment liability rating of the buyer before they will accept a transfer of oil and gas assets. These regulations may make it difficult and costly for producers, such as IPC, to transfer or sell assets to other parties.

Aboriginal Land Claims in Canada: In Canada, aboriginal groups have filed claims in respect of their aboriginal and treaty rights against the federal and certain provincial governments 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. 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 some of the licence and concession 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 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 Covid-19 virus, 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, most of which it does not own. The amount of oil and 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, Total is ceasing crude oil transportation and storage operations at the Grandpuits refinery in the Paris Basin, France), could ceased refining and 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 or increased operating or transportation costs. 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 Covid-19 virus, 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 and Bonds: The Group is, and may in the future become, party to credit facilities with international financial institutions. The Corporation has also issued bonds and may issue further bonds in the future. The terms of these facilities and bonds may 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 and bonds 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 may be 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 credit facilities, the Group may be required to repay all or a portion of the amounts owing thereunder.

If the Group fails to comply with the covenants in these facilities and bonds, is unable to repay or refinance amounts owned at maturity or pay the debt service charges or otherwise commit an event of default, such as bankruptcy, it could result in the seizure and/or sale of the Group's assets by the creditors. The proceeds from any sale of our assets would be applied to satisfy amounts owed to the secured creditors and then unsecured creditors. Only after the proceeds of that sale were applied towards the Group's debt would the remainder, if any, be available for the benefit of shareholders.

Credit Ratings: Credit ratings affect the Corporation's ability to obtain short term and long term financing and the cost of such financing. A reduction in the current rating or a negative change in the rating outlook could adversely affect the cost of financing and access to sources of liquidity and capital. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant. Credit ratings are not recommendations to buy, sell or hold any of the Corporation's securities.

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 gas properties and in the marketing of oil and gas. The Corporation's competitors include oil and 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 gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources and renewable energies.

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 (for example, the Total-operated Grandpuits facility which ceased refining and is ceasing crude oil transportation and storage operations) 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 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 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 production sharing contracts (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 Covid-19 virus), which could have a negative impact on the Group.

In response to the Covid-19 virus, 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 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., an investment company wholly owned by a Lundin family trust ("Nemesia"), owns approximately 27 percent of the aggregate voting shares of the Corporation. Nemesia's holdings may allow it to significantly affect substantially all the actions to be taken by the shareholders of the Corporation, including the election of directors. As long as Nemesia maintains a significant interest in the Corporation, it is likely that Nemesia 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 and may also discourage acquisition bids for the Corporation. There is a risk that the interests of Nemesia may 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 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. 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 Further 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 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.

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 25, 2022.

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, 2021, 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, 2021 price forecasts. The reserves report by Sproule is dated January 31, 2022 and the contingent resource report by Sproule is dated February 4, 2022.

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, 2021, 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, 2021 price forecasts. The report by ERCE is dated January 27, 2022.

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 Schedules A and 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, 2021 and may not be reflective of current and future forecast commodity prices.

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. 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	MMbbl	MMbbl	MMbbl	MMbbl	Bscf	Bscf	MMboe	MMboe
Proved Developed Producing												
Canada	-	-	45.3	38.3	3.9	3.3	0.0	0.0	311.6	295.5	101.2	90.9
France	-	-	-	-	6.1	5.4	-	-	-	-	6.1	5.4
Malaysia	-	-	-	-	3.3	2.8	-	-	-	-	3.3	2.8
IPC Total	-	-	45.3	38.3	13.4	11.5	0.0	0.0	311.6	295.5	110.6	99.1
Proved Developed Non-Producing												
Canada	-	-	2.8	2.6	0.5	0.4	0.0	0.0	15.3	14.5	5.8	5.4
France	-	-	-	-	0.0	0.0	-	-	-	-	0.0	0.0
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-
IPC Total	-	-	2.8	2.6	0.5	0.5	0.0	0.0	15.3	14.5	5.8	5.4
Proved Undeveloped												
Canada	-	-	70.2	55.7	6.2	5.3	0.0	0.0	0.5	0.5	76.5	61.1
France	-	-	-	-	0.8	0.7	-	-	-	-	0.8	0.7
Malaysia	-	-	-	-	1.4	1.2	-	-	-	-	1.4	1.2
IPC Total	-	-	70.2	55.7	8.4	7.2	0.0	0.0	0.3	0.3	78.7	63.0
Total Proved (1P)												
Canada	-	-	118.3	96.6	10.6	9.0	0.0	0.0	327.4	310.5	183.5	157.4
France	-	-	-	-	7.0	6.1	-	-	-	-	7.0	6.1
Malaysia	-	-	-	-	4.7	4.1	-	-	-	-	4.7	4.1
IPC Total	-	-	118.3	96.6	22.4	19.2	0.0	0.0	327.4	310.5	195.2	167.6

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	MMbbl	MMbbl	Bscf	Bscf	MMboe	MMboe
Proved plus Probable Developed Producing												
Canada	-	-	61.0	50.6	4.7	3.9	0.0	0.0	384.1	364.3	129.7	115.2
France	-	-	-	-	9.4	8.2	-	-	-	-	9.4	8.2
Malaysia	-	-	-	-	4.0	3.4	-	-	-	-	4.0	3.4
IPC Total	-	-	61.0	50.6	18.0	15.5	0.0	0.0	384.1	364.3	143.1	126.8
Proved plus Probable Developed Non-Producing												
Canada	-	-	6.8	6.0	0.4	0.3	0.0	0.0	41.5	39.4	14.1	12.9
France	-	-	-	-	0.1	0.1	-	-	-	-	0.1	0.1
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-
IPC Total	-	-	6.8	6.0	0.5	0.5	0.0	0.0	41.5	39.4	14.3	13.0
Proved plus Probable Undeveloped												
Canada	-	-	100.6	78.4	7.9	6.7	0.0	0.0	0.7	0.7	108.7	85.3
France	-	-	-	-	2.0	1.7	-	-	-	-	2.0	1.7
Malaysia	-	-	-	-	2.0	1.8	-	-	-	-	2.0	1.8
IPC Total	-	-	100.6	78.4	12.0	10.2	0.0	0.0	0.7	0.7	112.7	88.8
Total Proved plus Probable (2P)												
Canada	-	-	168.5	135.1	13.0	10.9	0.0	0.0	426.3	404.4	252.5	213.5
France	-	-	-	-	11.5	10.0	-	-	-	-	11.5	10.0
Malaysia	-	-	-	-	6.0	5.2	-	-	-	-	6.0	5.2
IPC Total	-	-	168.4	146.0	30.6	26.2	0.0	0.0	426.3	404.4	270.1	228.6
Total Probable (PB)												
Canada	-	-	50.2	38.5	2.4	1.9	0.0	0.0	99.0	93.9	69.1	56.0
France	-	-	-	-	4.5	3.9	-	-	-	-	4.5	3.9
Malaysia	-	-	-	-	1.3	1.1	-	-	-	-	1.3	1.1
IPC Total	-	-	50.2	49.4	8.2	6.9	0.0	0.0	99.0	93.9	74.9	61.0

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%	
Proved Developed Producing													
Canada	1160.7	1170.7	1104.6	1056.1	941.8	846.3	1044.6	1084.8	1031.8	990.6	890.8	805.8	11.6
France	81.2	111.4	111.3	108.7	99.5	90.2	38.0	75.9	79.0	78.3	72.7	66.2	20.3
Malaysia	50.1	49.9	49.6	49.4	48.7	47.8	48.6	48.5	48.3	48.1	47.5	46.8	17.4
IPC Total	1291.9	1332.0	1265.4	1214.1	1089.9	984.3	1131.2	1209.1	1159.1	1117.0	1011.1	918.8	12.2
Proved Developed Non-Producing													
Canada	90.1	66.8	56.5	50.7	39.6	31.6	68.8	50.5	42.4	38.0	29.3	23.2	9.4
France	0.5	0.2	0.1	0.1	-0.1	-0.1	0.4	0.1	0.0	0.0	-0.1	-0.2	2.1
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-
IPC Total	90.6	67.1	56.6	50.8	39.5	31.4	69.1	50.7	42.4	37.9	29.2	23.0	9.3
Proved Undeveloped													
Canada	1865.3	971.4	680.4	545.2	330.3	213.5	1385.5	714.5	494.9	393.1	232.1	145.4	8.9
France	1.8	-1.6	-3.4	-4.5	-6.5	-8.0	0.8	-2.0	-3.6	-4.5	-6.4	-7.7	-6.4
Malaysia	69.7	63.0	59.4	57.2	52.1	47.8	69.4	62.7	59.1	56.9	51.9	47.6	46.9
IPC Total	1936.8	1032.8	736.3	597.9	375.9	253.3	1455.8	775.2	550.4	445.5	277.6	185.2	9.5
Total Proved													
Canada	3116.1	2208.9	1841.4	1652.0	1311.7	1091.3	2498.9	1849.8	1569.1	1421.7	1152.3	974.4	10.5
France	83.5	110.1	108.0	104.3	92.9	82.1	39.2	74.0	75.5	73.7	66.2	58.3	17.1
Malaysia	119.8	112.8	109.0	106.5	100.8	95.6	118.0	111.2	107.4	105.0	99.4	94.3	26.2
IPC Total	3319.4	2431.8	2058.3	1862.8	1505.4	1269.0	2656.1	2035.0	1752.0	1600.5	1317.9	1127.0	11.1

All figures in the above table are in USD millions, unless otherwise indicated. Unit values are calculated based on net reserves volumes.

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%	
Proved plus Probable Developed Producing													
Canada	1696.6	1586.5	1448.3	1361.1	1176.6	1035.9	1465.6	1418.8	1307.2	1234.4	1077.8	956.9	11.8
France	194.8	191.1	177.6	167.9	145.8	127.8	122.0	135.3	128.7	122.9	107.8	94.9	20.5
Malaysia	93.2	89.1	86.8	85.3	81.8	78.5	91.5	87.6	85.3	83.9	80.5	77.3	25.0
IPC Total	1984.6	1866.7	1712.6	1614.4	1404.2	1242.2	1679.2	1641.7	1521.3	1441.2	1266.1	1129.1	12.7
Proved plus Probable Developed Non-Producing													
Canada	262.3	175.8	142.4	125.0	92.9	71.6	201.6	133.9	107.8	94.4	69.7	53.3	9.7
France	1.7	2.1	2.1	2.1	2.0	1.8	1.2	1.6	1.6	1.6	1.5	1.4	16.9
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-
IPC Total	264.0	177.9	144.5	127.1	94.9	73.4	202.8	135.4	109.5	96.0	71.2	54.7	9.8
Proved plus Probable Undeveloped													
Canada	3109.4	1560.6	1078.3	857.8	511.4	325.1	2292.0	1142.4	783.4	619.4	362.5	225.0	10.1
France	50.7	33.2	25.7	21.7	14.0	8.7	37.1	23.9	18.1	15.0	9.0	4.8	12.8
Malaysia	117.9	106.5	100.6	96.9	88.6	81.5	104.1	94.4	89.3	86.2	79.1	73.0	55.3
IPC Total	3277.9	1700.3	1204.6	976.4	614.1	415.4	2433.2	1260.7	890.8	720.6	450.7	302.8	11.0
Total Proved plus Probable (2P)													
Canada	5068.4	3322.9	2669.0	2343.9	1781.0	1432.6	3959.2	2695.1	2198.4	1948.2	1510.0	1235.2	11.0
France	247.2	226.4	205.5	191.8	161.8	138.3	160.3	160.7	148.5	139.5	118.3	101.1	19.2
Malaysia	211.1	195.7	187.4	182.2	170.4	160.0	195.6	182.0	174.7	170.1	159.6	150.3	35.3
IPC Total	5526.6	3744.9	3061.8	2717.9	2113.2	1731.0	4315.1	3037.8	2521.6	2257.8	1788.0	1486.6	11.9
Total Probable (PB)													
Canada	1952.3	1113.9	827.6	691.8	469.3	341.3	1460.3	845.2	629.3	526.5	357.7	260.8	12.3
France	163.7	116.3	97.5	87.5	68.9	56.3	121.1	86.7	73.0	65.7	52.1	42.8	22.4
Malaysia	91.3	82.8	78.4	75.7	69.6	64.4	77.6	70.8	67.3	65.1	60.2	56.0	68.3
IPC Total	2207.2	1313.1	1003.5	855.1	607.8	462.0	1659.1	1002.8	769.6	657.3	470.1	359.6	14.0

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	8357	1360	2718	668	494	3116	617	2499
France	535	69	251	33	99	83	44	39
Malaysia	413	38	189	24	42	120	2	118
IPC Total	9305	1467	3158	725	635	3319	663	2656
Total Proved plus Probable								
Canada	11 999	2122	3508	747	554	5068	1109	3959
France	905	119	406	33	100	247	87	160
Malaysia	513	49	195	24	34	211	15	196
IPC Total	13 417	2290	4109	803	689	5527	1211	4315

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	-	1231	350	1	280	1863
Total Proved and Probable (2P) Reserves	-	1812	547	1	358	2718
USD per boe by product type	USD/bbl	USD/bbl	USD/bbl	USD/bbl	USD/Mscf	USD/boe
Total Proved Reserves	-	12.7	18.2	23.4	0.9	11.1
Total Proved and Probable (2P) Reserves	-	13.4	20.9	23.4	0.9	11.9

All figures in the above table are in USD millions, unless otherwise indicated. Unit values are calculated based on net reserves volumes.

Part III – Pricing Assumptions

Forecast prices used in this document are sourced from the Sproule forecasts effective December 31, 2021. [(1)]

Item 3.2 – Forecast Prices Used in Estimates

	Brent (U.S.$/bbl)	WTI Crude Oil (U.S.$/bbl)	Canadian Light Sweet Crude ($Cdn/bbl)	Western Canadian Select ($Cdn/bbl)	Natural Gas AECO ($Cdn/mmbtu)	Natural Gas Empress ($Cdn/ mmbtu)	Capital Cost Inflation Rate (%/yr)	USD/CAD Exchange Rate ($US/$Cdn)
Historical								
2017	54.83	50.95	61.85	50.24	2.19	2.73	2.4%	0.77
2018	71.53	64.77	68.49	52.34	1.53	3.10	4.2%	0.77
2019	64.17	57.02	68.87	58.77	1.80	2.51	0.4%	0.75
2020	43.21	39.40	45.39	35.59	2.24	2.23	-5.0%	0.75
2021	70.79	67.91	80.31	68.73	3.64	3.90	6.6%	0.80
Forecast								
2022	75.00	73.00	86.25	75.63	3.88	4.55	0.0%	0.80
2023	72.00	70.00	82.40	71.56	3.36	3.92	2.0%	0.80
2024	70.00	68.00	79.80	68.74	3.02	3.59	2.0%	0.80
2025	71.40	69.36	81.39	70.12	3.08	3.67	2.0%	0.80
2026	72.83	70.75	83.02	71.52	3.14	3.74	2.0%	0.80
2027	74.28	72.16	84.68	72.95	3.21	3.81	2.0%	0.80
2028	75.77	73.61	86.38	74.41	3.27	3.89	2.0%	0.80
2029	77.29	75.08	88.10	75.90	3.34	3.97	2.0%	0.80
2030	78.83	76.58	89.87	77.42	3.40	4.05	2.0%	0.80
2031	80.41	78.11	91.66	78.96	3.47	4.13	2.0%	0.80
2032	82.02	79.67	93.50	80.54	3.54	4.21	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	2021	2022	2023	2024	2025 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

(1) Realized pricing will reflect these reference prices with further adjustments for quality and transportation to point of sale.

Part IV – Reconciliation of Changes in Reserves

Item 4.1 – Reserves Reconciliation Company Gross Volumes

	Malaysia Light & Medium Oil MMbbl	France Light & Medium Oil MMbbl	Canada Light & Medium Oil MMbbbl	Canada Heavy Oil MMbbl	Canada NGL's MMbbl	Canada Conventional Natural Gas MMboe	IPC Total Oil Equivalent MMboe
Proved Reserves							
Opening Balance Dec 31, 2020	3.5	6.6	10.2	113.2	0.0	58.8	**192.4**
Extensions and improved recovery	0	0.3	0.9	0.6	0.0	0.0	2.3
Technical revisions	1.4	-0.1	-0.9	10.0	-0.0	1.3	11.2
Acquisitions	1.2	-	-	-	-	-	1.2
Dispositions	-	-	-	-	-	-	-
Economic factors	0.2	1.3	0.7	1.7	0.0	0.1	4.0
Production	-1.6	-1.1	-0.4	-7.2	-0.0	-5.6	-15.9
Closing Balance Dec 31, 2021	4.7	7.0	10.6	118.3	0.0	54.6	**195.2**
Probable Reserves							
Opening Balance Dec 31, 2020	1.9	4.8	2.3	53.5	0.0	16.7	**79.2**
Extensions and improved recovery	-	0.3	0.3	0.1	-0.0	0.0	0.7
Technical revisions	-0.7	0.4	-	-3.2	-0.0	-0.2	-3.7
Acquisitions	0.3	-	-	-	-	-	0.3
Dispositions	-	-	-	-	-	-	-
Economic factors	-0.2	-1.1	-0.3	-0.2	0.0	-	-1.8
Production	-	-	-	-	-	-	-
Closing Balance Dec 31, 2021	1.3	4.5	2.4	50.2	0.0	16.5	**74.9**
Proved plus Probable Reserves							
Opening Balance Dec 31, 2020	5.4	11.4	12.5	166.7	0.1	75.4	**271.5**
Extensions and improved recovery	-	0.7	1.2	0.7	0.0	-	2.6
Technical revisions	0.7	0.3	-0.9	6.8	-0.0	1.1	8.0
Acquisitions	1.5	-	-	-	-	-	1.5
Dispositions	-	-	-	-	-	-	-
Economic factors	-	0.2	0.5	1.5	0.0	0.1	2.3
Production	-1.6	-1.1	-0.4	-7.2	-0.0	-5.6	-15.9
Closing Balance Dec 31, 2021	6.0	11.5	13.0	168.5	0.0	71.1	**270.1**

Technical revision volumes include amounts associated with changes in operating costs, capital costs and commodity price offsets. Infill drilling adds are captured within the extensions and improved recovery category. Alterations to the year end 2021 reserves are driven by:

- The reserves base in Malaysia reflecting an additional 25% equity from April 2021 and good reservoir performance overall.
- Continued good performance from the Vert La Gravelle field, the maturation of the Dommartin Lettree development to reserves in France and economic adjustments to reflect 2021 operational results.
- A net pay revision in the Onion Lake Thermal field and reservoir performance from the southern oil and gas assets in Canada. The Ferguson field development was sanctioned in 2021 and expanded to include additional well targets. Economic adjustments have been made throughout the asset base to reflect 2021 operational results.

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	
Proved Undeveloped	First Attributed MMbbl	YE Total MMbbl	First Attributed MMbbl	YE Total MMbbl	First Attributed Bscf	YE Total Bscf	First Attributed MMbbl	YE Total MMbbl	First Attributed MMboe	YE Total MMboe
December 31, 2019	0.0	1.4	0.2	63.5	0.0	0.1	0.0	0.0	0.2	64.9
December 31, 2020	6.9	7.5	0.00	66.9	0.0	0.3	0.0	0.0	6.9	74.4
December 31, 2021	1.2	8.4	0.6	70.2	0.0	0.5	0.0	0.0	1.9	78.7
Probable Undeveloped										
December 31, 2019	0.0	3.3	0.0	46.0	0.0	0.1	0.0	0.0	0.0	49.3
December 31, 2020	3.1	5.1	0.0	30.4	0.0	0.2	0.0	0.0	3.1	35.5
December 31, 2021	1.0	5.8	0.1	30.4	0.0	0.3	0.0	0.0	1.1	36.2

Reserves development forecasts documented in this disclosure 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) for the large heavy oil thermal project in the Onion Lake area future development has been scheduled to optimize operations and deliver supply at design capacity for the life of the central processing facility.

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 continued effectiveness of the polymer injection in mobilizing bypassed oil. At Onion Lake Thermal, the main uncertainties include the performance of future drilling pads and the effectiveness of steam propagation. These uncertainties are captured in the 1P to 2P range of estimates. Other uncertainties that affect the Canadian properties include weather related downtime, facility performance, effectiveness of Suffield gas optimization investments and performance of development drilling at Ferguson. The abandonment liability beyond what has been considered in the reserve assessment is not material to the Canadian asset valuation. These assets are not expected to have higher than reported costs or onerous contractual obligations that would impair the Group's realized values.

In France, the main uncertainties are the reservoir performance in the water flooded Triassic formation pools and results of the Villeperdue West development wells. These uncertainties have been captured in the 1P to 2P range of estimates. There are no material abandonment costs, excessive costs or contractual obligations, other than what has been considered in the reserves assessment, that would impair the Group's realized values. 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 and probable reserves assume a cessation of production as at year end 2039, to reflect the uncertainties regarding the application of this new legislation.

In Malaysia, the main uncertainties, which have been captured in the 1P to 2P range of estimates, include, performance of the A15ST development well, water cut performance of recently drilled wells, facility uptime performance, electric submersible pump performance and operating cost performance. There are no material abandonment costs, excessive costs or contractual obligations, other than what has been considered in the reserves assessment, that would impair the Group's realized values.

Item 5.3 Future Development Costs MM U.S.$

	2022	2023	2024	2025	2026	2027 on	Total for all years undiscounted	Total for all years discounted at 10% p.a.
Total Proved								
France	12.2	19.6	0.8	-	-	-	32.6	29.2
Malaysia	23.9	-	-	-	-	-	23.9	23.6
Canada	61.4	49.0	45.7	14.3	48.4	449.5	668.4	320.7
Total	97.5	68.7	46.5	14.3	48.4	449.5	724.9	373.5
Total Proved Plus Probable								
France	12.2	19.6	0.8	-	-	-	32.6	29.2
Malaysia	23.9	-	-	-	-	-	23.9	23.6
Canada	63.2	52.4	104.1	45.2	25.3	456.3	746.6	383.9
Total	99.3	72.1	104.9	45.2	25.3	456.3	803.2	436.7

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 (as at December 31, 2021)

	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	13	4	4	-	-	-	-
France	111	105	-	-	-	-	-	-
Canada	712	701	876	865	10 535	10 510	305	291

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 2022 Towards Commitments	Amount planned after 2022 Towards Commitments	End of Commitment Period
					ha	Ha			EUR	USD	USD	
France	Plivot	IPC	100%	Onshore	19 800	19 800	None	-	-	-	-	-
Canada	Blackrod	IPC	100%	Onshore	23 208	23 208	None	-	-	-	-	-
	Portage	IPC	62%	Onshore	36 608	22 594	None	-	-	-	-	-
	Fishing Lake	IPC	98%	Onshore	3904	3828	None	-	-	-	-	-
	Salt Lake	IPC	100%	Onshore	210	210	None	-	-	-	-	-
	Unity	IPC	100%	Onshore	10 617	10 593	None	-	-	-	-	-

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

IPC have a single exploration license in France with no attributed reserves. This property does not have significant abandonment and reclamation costs, unusually high expected development or operating costs, or onerous contractual obligations.

In Canada, approximately 19 462 gross hectares of land are subject to expiry in 2022. None of the properties listed with no attributed reserves have significant abandonment and reclamation costs, unusually high expected development or operating costs, or onerous contractual obligations.

Item 6.5 – Tax Horizon

In Canada, as of January 1, 2022, IPC has depreciable tax pools brought forward of CAD 633 million as well as tax loss carry forward balances of CAD 543 million. Based on current assumptions and forecasts, IPC expects no cash taxes to be paid in Canada until approximately 2024.

In Malaysia, the Corporation has a significant cost recovery balance of USD 433 million as of January 1, 2022. IPC has depreciable tax pools of USD 56 million and Petroleum Income Tax loss carryforwards of USD 71 million as of January 1, 2022. Management expects, based on current assumptions and forecasts, to utilize the benefits of these tax positions and then commence paying taxes in Malaysia in 2023.

IPC pays current taxes in France. The tax rate is 26.5%.

Item 6.6 – Costs Incurred

2021 Costs Incurred, in USD millions

	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
France	-	-	0.0	2.5
Malaysia	-	-	0.5	10.3
Canada	-	-	-2.7 *	33.4
Total	**-**	**-**	**- 2.2**	**46.2**

* Net revenues of million U.S.$ 11.9 have been offset against exploration costs in respect of the Blackrod appraisal project

Item 6.7.1 – Exploration and Development Activity

2021 Exploration Activity Summary, wells completed

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

2021 Development Activity Summary, wells completed

	France		Malaysia		Canada	
	gross	net	gross	net	gross	net
Wells completed	-	-	-	-	5	5
Completed as						
Oil well	-	-	-	-	5	5
Gas well	-	-	-	-	-	-
Service well	-	-	-	-	-	-
Stratigraphic test well	-	-	-	-	-	-
Dry hole	-	-	-	-	-	-

The recent development activity by field is summarised below. Where additional development potential has been identified it is discussed further in the Statement of Contingent Resources Data contained in **Schedule A** of this AIF.

Malaysia

No wells were drilled or completed during 2021. The A15ST well spudded in December and went on production in Q1 2022.

France

No wells were drilled during 2021 however planning continues for the Villerperdue West development which is expected to spud in 2023.

Canada

Suffield Area

Development plans in the Suffield property include development drilling in the glauconitic oil pools, and optimization of the existing gas well inventory.

The glauconitic development drilling consists of a combination of infill and step-out drilling of horizontal producers. The wells are generally 1000 metre 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.

Further drilling is planned associated with enhanced oil recovery expansion in the N2N pool, which was initiated in 2019 and has exceeded original expectations.

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

Onion Lake

In 2021, in line with the field development plan, the next production sustaining Pad D' development project entered production with performance in line with expectations. In 2021 infill wells were also drilled, they were brought onto production in December 2021. Facility upgrades and tie-in works as scheduled were executed in 2021 and continue into 2022. The next production sustaining Pad L has allocated funds for 2022 when drilling will begin. First oil is expected in 2023.

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 came online in March 2022. This will bring enhanced operational reliability and efficiencies in bringing oil to market.

Mooney

Mooney production recommenced in 2021, following shut in due to the pandemic. Facilities upgrades are ongoing with a plan to sanction a polymer only EOR flood in 2022.

Blackrod

Well Pair 3 continues to perform ahead of expectations. IPC continues work on an optimized field development plan, optimization work matured through 2021 and an economic assessment is presented in Schedule B.

Ferguson

Ferguson development was planned and sanctioned in 2021. Drilling will commence in Q1 2022. A thirteen well initial programme is planned for 2022.

Item 6.8 – 2022 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 (Mbbl/d)	Total (Mboe/d)
Total Proved (1P) Scenario						
France	-	2.5	-	-	-	2.5
Malaysia	-	4.7	-	-	-	4.7
Canada	-	1.7	19.7	14.4	0.01	36.0
Total	-	8.9	19.7	14.4	0.01	43.2
Total Proved plus Probable (2P) Scenario						
France	-	3.0	-	-	-	3.0
Malaysia	-	4.4	-	-	-	4.4
Canada	-	1.1	20.4	16.7	-	38.1
Total	-	**8.5**	**20.4**	**16.7**	-	**45.5**

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

Canada – Light and Medium Crude Oil	Q1'21	Q2 '21	Q3 '21	Q4 '21	2021
Production, Mbopd	1.2	1.1	1.1	1.1	1.1
Unit Volume Average (US$/bbl)					
Prices received	37.63	44.26	54.98	57.42	48.37
Royalties paid	5.54	11.95	14.18	15.73	11.75
Production costs	18.84	13.90	19.59	18.95	17.81
Netback	13.25	18.41	21.21	22.74	18.81

Canada - Heavy Crude Oil	Q1'21	Q2 '21	Q3 '21	Q4 '21	2021
Production, Mbopd	19.4	18.7	21.7	21.6	20.3
Unit Volume Average (US$/bbl)					
Prices received	45.32	52.30	56.04	60.71	53.91
Royalties paid	3.37	4.64	5.67	6.00	4.98
Production costs	26.16	30.68	26.16	29.44	28.07
Netback	15.80	16.97	24.21	25.27	20.85

Canada – Conventional Natural Gas	Q1 '21	Q2 '21	Q3 '21	Q4 '21	2021
Production, Mboepd	16.2	17.0	16.8	16.7	16.7
Unit Volume Average (US$/boe)					
Prices received	13.98	13.48	15.08	21.17	15.95
Royalties paid	0.45	0.66	0.43	0.83	0.60
Production costs	6.59	6.93	5.71	6.42	6.41
Netback	6.94	5.89	8.94	13.91	8.95

Canada – (Oil & Gas)	Q1 '21	Q2 '21	Q3 '21	Q4 '21	2021
Production, Mboepd	36.7	36.7	39.6	39.4	38.1
Unit Volume Average (US$/bbl)					
Prices received	31.81	34.82	39.26	44.47	37.78
Royalties paid	2.20	3.10	3.77	4.16	3.34
Production costs	17.64	19.62	17.62	19.75	18.66
Netback	11.97	12.10	17.88	20.56	15.79

Malaysia – Light & Medium Crude Oil	Q1 '21	Q2 '21	Q3 '21	Q4 '21	2021
Production, Mboepd	4.0	4.8	4.2	4.5	4.4
Unit Volume Average (US$/bbl)					
Prices received	47.53	41.67	57.40	113.31	65.42
Royalties paid	0.00	0.00	0.00	0.00	0.00
Production costs	-7.17	0.88	19.26	48.01	15.77
Netback	54.70	40.79	38.14	65.30	49.64

France – Light & Medium Crude Oil	Q1 '21	Q2 '21	Q3 '21	Q4 '21	2021
Production, Mboepd	3.0	3.0	3.0	2.9	3.0
Unit Volume Average (US$/bbl)					
Prices received	72.12	72.09	76.09	81.69	75.48
Royalties paid	0.00	0.00	0.00	0.00	0.00
Production costs	36.85	36.90	32.53	40.79	36.74
Netback	35.27	35.18	43.57	40.90	38.74

IPC Total – Oil Equivalent	Q1 '21	Q2 '21	Q3 '21	Q4 '21	2021
Production, Mboepd	43.7	44.6	46.8	46.8	45.5
Unit Volume Average (US$/bbl)					
Prices received	35.99	38.10	43.25	53.45	42.92
Royalties paid	1.85	2.55	3.19	3.49	2.80
Production costs	16.69	18.78	18.72	23.80	19.57
Netback	17.46	16.77	21.35	26.16	20.56

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

DIVIDENDS AND DISTRIBUTIONS

The Corporation does not currently pay cash dividends on the Common Shares.

In 2021, the Corporation implemented a share repurchase program, because IPC believes that such program represents an effective use of IPC's capital and an efficient way to return value to IPC's shareholders. A maximum of 11,097,074 Common Shares may be repurchased over the period of twelve months commencing December 3, 2021 and ending December 2, 2022, or until such earlier date as the share repurchase program is completed or terminated by IPC. Under the share repurchase program, a total of 1,330,303 Common Shares were repurchased up to December 31, 2021 and a further 3,071,441 Common Shares were repurchased from January 1, 2022 up to March 23, 2022. All Common Shares repurchased by IPC under the share repurchase program have been, or will be, cancelled.

In February 2022, IPC announced its 2022 capital allocation plans. Based on IPC's current business plans and assumptions, IPC plans to distribute to shareholders up to 40% of the free cash flow generated by IPC above achieved average Brent oil prices of USD 55 per barrel, provided that IPC's net debt to EBITDA ratio is at or below 1 time. These shareholder distributions are planned to be implemented by continued share repurchases under the previously announced share repurchase program as well as the consideration by IPC of other forms of shareholder distributions, subject to further applicable regulatory and corporate approvals.

Any decision to pay cash dividends on the Common Shares in the future will be made by the Board on the basis of the Corporation's earnings and financial requirements as well as other conditions existing at such time. Unless the Corporation commences the payment of dividends, holders of Common Shares will not be able to receive a return on their Common Shares unless they sell them.

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

The Corporation is authorized to issue an unlimited number of Common Shares without par value, of which 155,342,757 were issued and outstanding as at December 31, 2021 and of which 151,746,600 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, 2021 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 share unit plan ("**Share Unit 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**"); and a stock option plan ("**Stock Option Plan**").

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. As at the date of this AIF, no stock options are outstanding under the Stock Option Plan.

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 5,279,308awards of IPC PSUs and IPC RSUs outstanding as at December 31, 2021.

Bonds

In February 2022, IPC completed a private placement of USD 300 million of senior unsecured bonds. The bonds have a tenor of five years and a fixed coupon rate of 7.25 percent per annum, with interest payable in semi-annual instalments. The bond issue was rated B+ by S&P Global Ratings and B1 by Moody's. In early February 2022, IPC used a portion of the proceeds of the bond to fully repay and cancel existing reserve-based lending facilities and, at the same time, IPC put in place a new CAD 75 million revolving credit facility for financial flexibility in Canada.

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 2021	3.60	1.81	956,762
February 2021	4.35	3.11	2,159,688
March 2021	4.47	4.04	1,121,969
April 2021	4.46	3.74	478,293
May 2021	5.23	4.36	2,295,298
June 2021	5.91	5.25	1,064,950
July 2021	6.18	5.44	890,443
August 2021	6.05	5.02	318,076
September 2021	6.67	5.50	1,990,553
October 2021	7.55	6.66	1,051,917
November 2021	7.38	6.32	1,010,953
December 2021	7.28	6.48	1,018,806

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 2021	23.40	18.23	12,118,743
February 2021	28.68	20.50	19,923,125
March 2021	29.82	26.90	16,872,603
April 2021	30.50	25.76	10,302,873
May 2021	36.10	29.96	18,011,362
June 2021	40.44	36.00	13,454,259
July 2021	42.70	37.36	11,948,157
August 2021	42.18	34.40	10,618,023
September 2021	46.02	37.46	12,095,374
October 2021	52.75	45.66	11,217,578
November 2021	51.10	43.80	13,962,575
December 2021	51.90	46.62	10,185,076

Prior Sales

In 2021, in connection with the exercise of Stock Options, the Corporation issued an aggregate of 25,000 Common Shares at CAD 4.77 per Common Share.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

As at December 31, 2021 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.

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)
Mike Nicholson *Switzerland*	President and CEO, Director	500,000	President and CEO of the Corporation since April 2017; CFO, Lundin Petroleum until April 2017
C. Ashley Heppenstall[1][4] *United Kingdom*	Chair of the Board, Director	1,127,501[6]	Corporate Director
Donald Charter[1][2][4] *Ontario, Canada*	Director	72,333	Business executive
Chris Bruijnzeels[1][3][4] *The Netherlands*	Director	50,000	Corporate Director; President and CEO, ShaMaran Petroleum Corp. until May 2019
Torstein Sanness[2] *Norway*	Director	25,037	Corporate Director
Emily Moore[2][3] *Ontario, Canada*	Director	4,333 Director RSUs	Associate Professor and Director, Troost Institute for Leadership Education in Engineering (ILead), University of Toronto Faculty of Applied Science and Engineering since October 2018; Managing Director, Water and Innovation of Hatch Ltd. until 2018
L.H. (Harry) Lundin[3] *Ontario, Canada*	Director	185,100[7]	Chief Executive Officer of Bromma Asset Management inc. since October 2016; Analyst at Sprott Inc. from March 2015 to September 2016
Christophe Nerguararian *Switzerland*	Chief Financial Officer	164,335	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
William Lundin Switzerland	Chief Operating Officer	275,000	COO of the Corporation since December 2020; Project management positions at IPC Canada Ltd. until 2020; Operations positions at BlackPearl Resources Inc. from 2016
Jeffrey Fountain *Switzerland*	General Counsel	211,723	General Counsel of the Corporation since April 2017; Vice President Legal, Lundin Petroleum until April 2017
Rebecca Gordon *Switzerland*	Vice President Corporate Planning and Investor Relations	14,000	Vice President Corporate Planning and Investor Relations of the Corporation since April 2017; Group Manager Economics and Planning, Lundin Petroleum until April 2017

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)
Chris Hogue *Alberta, Canada*	Senior Vice President Canada	1,074,454	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

Notes:

(1) Member of Audit Committee.
(2) Member of Compensation Committee.
(3) Member of Reserves and Sustainability 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 2021 for a term until the next Annual General Meeting of Shareholders, to be held in May 2022, unless the directorship is earlier vacated in accordance with the Articles of the Corporation or the *Business Corporations Act* (British Columbia) or he or she becomes disqualified to act as a director.
(6) Rojafi, an investment company owned by Mr. Heppenstall and his family, holds 1,127,501 Common Shares.
(7) Bromma Asset Management Inc., of which Mr. Lundin is majority owner and CEO, has control and direction over 185,100 Common Shares.

As at March 25, 2022, the directors and executive officers of the Corporation, as a group, beneficially owned, or directed or controlled, directly or indirectly, including through investment or controlled companies as noted above, approximately 3.7 million Common Shares or approximately 2.4% of the total number of issued and outstanding 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.

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.

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, other than in respect of L.H. (Harry) Lundin and William Lundin. The Board believes that their family relationship as brothers does not adversely affect the proper functioning and independence of the Board as a whole.

As at December 31, 2021 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 currently comprised of C. Ashley Heppenstall (Chair), Donald Charter and Chris Bruijnzeels, 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.

Mr. Bruijnzeels has experience as an officer and director of public companies in the oil and gas industry with responsibility for managerial, operational and financial functions. He is experienced in analyzing the financial statements of public companies and has a degree in Mining Engineering.

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, 2020 and 2021.

MUSD

Financial Year Ending	Audit Fees (1)	Audit Related Fees (2)	Tax Fees (3)	All Other Fees (4)
2020	624	195	17	-
2021	556	151	-	-

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.

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

During the year ended December 31, 2021 and until the date of this AIF, 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. See also "Description of the Business – Discontinued Operations".

Regulatory actions

During the year ended December 31, 2021 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.

TRANSFER AGENTS AND REGISTRARS

The transfer agent and registrar for the Common Shares in Canada is Computershare Investor Services Inc., and the Common Shares are 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 are 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 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, 2021, 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, 2021 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, 2021, 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, 2021 price forecasts.

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

	Technology	Light Crude Oil & Medium Crude Oil (Mbbl)			Heavy Crude Oil (Mbbl)			Bitumen (Mbbl)			Conventional Natural Gas (MMscf)			NGL (Mbbl)			Total Oil Equivalent (Mboe)			Chance of Development	Economic Sub Class	Project Maturity	Project Evaluation	Working Interest
		1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C					
Malaysia Bertam																								
NFA and 2022 Activities Post PSC	Established	2,352	3,857	4,249	-	-	-	-	-	-	-	-	-	-	-	-	2,352	3,857	4,249	50%	Economic	Development on Hold	Advanced	100%
Development Drilling Pre PSC	Established	1,516	2,278	2,844	-	-	-	-	-	-	-	-	-	-	-	-	1,516	2,278	2,844	50%	Economic	Development Unclarified	Conceptual	100%
Development Drilling Post PSC	Established	848	962	1,285	-	-	-	-	-	-	-	-	-	-	-	-	848	962	1,285	50%	Economic	Development Unclarified	Conceptual	100%
France Paris Basin																								
Amaltheus	Established	165	671	1,206	-	-	-	-	-	-	-	-	-	-	-	-	165	671	1,206	50%	not determined	Development Unclarified	Conceptual	100%
Amaltheus Post 2040	Established	8	18	54													8	18	54	45%	not determined	Development on Hold	Advanced	100%
Courdemanges	Established	390	1,597	2,716	-	-	-	-	-	-	-	-	-	-	-	-	390	1,597	2,716	50%	not determined	Development Unclarified	Conceptual	100%
Courdemanges Post 2040	Established	10	69	201	-	-	-	-	-	-	-	-	-	-	-	-	10	69	201	45%	not determined	Development on Hold	Advanced	100%
Dommartin Lettree	Established	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50%	not determined	Development Unclarified	Conceptual	43.01%
Dommartin Lettree Post 2040	Established	22	40	184	-	-	-	-	-	-	-	-	-	-	-	-	22	40	184	45%	not determined	Development on Hold	Advanced	100%
Genievre	Established	-	68	237	-	-	-	-	-	-	-	-	-	-	-	-	-	68	237	50%	not determined	Development Unclarified	Conceptual	100%
Geniervre Post 2040	Established	6	10	30													6	10	30	45%	not determined	Development on Hold	Advanced	100%
Grandville	Established	-	1,035	1,380	-	-	-	-	-	-	-	-	-	-	-	-	-	1,035	1,380	50%	not determined	Development Unclarified	Conceptual	100%
Grandville Post 2040	Established	198	711	1,285	-	-	-	-	-	-	-	-	-	-	-	-	198	711	1,285	45%	not determined	Development on Hold	Advanced	100%
Hautefeuille	Established	54	52	56	-	-	-	-	-	-	-	-	-	-	-	-	54	52	56	45%	not determined	Development on Hold	Advanced	100%
La Motte Noir	Established	24	50	56													24	50	56	45%	not determined	Development on Hold	Advanced	100%
Merisier	Established	607	2,566	4,008	-	-	-	-	-	-	-	-	-	-	-	-	607	2,566	4,008	50%	not determined	Development Unclarified	Conceptual	100%
Merisier Post 2040	Established	52	78	90													52	78	90	45%	not determined	Development on Hold	Advanced	100%
Soudron	Established	819	1,647	2,692	-	-	-	-	-	-	-	-	-	-	-	-	819	1,647	2,692	50%	not determined	Development Unclarified	Conceptual	100%
Soudron Post 2040	Established	224	588	976	-	-	-	-	-	-	-	-	-	-	-	-	224	588	976	45%	not determined	Development on Hold	Advanced	100%
Vert La Gravelle	Established	250	500	1,000	-	-	-	-	-	-	-	-	-	-	-	-	250	500	1,000	50%	not determined	Development Unclarified	Conceptual	100%
Vert La Gravelle Post 2040	Established	169	261	347	-	-	-	-	-	-	-	-	-	-	-	-	169	261	347	45%	not determined	Development on Hold	Advanced	100%
Villeperdue	Established	2,279	3,845	5,353	-	-	-	-	-	-	-	-	-	-	-	-	2,279	3,845	5,353	30%	not determined	Development on Hold	Conceptual	100%
Villerperdue Post 2040	Established	1,762	2,237	3,040	-	-	-	-	-	-	-	-	-	-	-	-	1,762	2,237	3,040	45%	not determined	Development on Hold	Advanced	100%
Villeseneux	Established	1	327	421	-	-	-	-	-	-	-	-	-	-	-	-	1	327	421	50%	not determined	Development Unclarified	Conceptual	100%
Villeseneux Post 2040	Established	11	82	196	-	-	-	-	-	-	-	-	-	-	-	-	11	82	196	45%	not determined	Development on Hold	Conceptual	100%
France Aquitaine Basin																								
Courbey	Established	1,300	2,150	3,700	-	-	-	-	-	-	-	-	-				1,300	2,150	3,700	50%	not determined	Development Unclarified	Conceptual	50%
Courbey Post 2040	Established	267	498	709	-	-	-	-	-	-	-	-	-				267	498	709	45%	not determined	Development on Hold	Advanced	50%
Les Arbousiers Post 2040	Established	79	177	212	-	-	-	-	-	-	-	-	-				79	177	212	45%	not determined	Development on Hold	Advanced	50%
Les Mimosas Post 2040	Established	6	44	138	-	-	-	-	-	-	-	-	-				6	44	138	45%	not determined	Development on Hold	Advanced	50%
Les Pins Post 2040	Established	51	155	262	-	-	-	-	-	-	-	-	-				51	155	262	45%	not determined	Development on Hold	Advanced	50%
Tamaris Post 2040	Established	15	46	76	-	-	-	-	-	-	-	-	-				15	46	76	45%	not determined	Development on Hold	Advanced	50%
Canada South																								
Suffield Oil	Established	-	-	-	2,533	3,500	4,468	-	-	-	258	355	448	2	2	3	2,578	3,561	4,545	70%	not determined	Development On Hold	Level II/III	100%
Ferguson	Established	1,717	3,012	4,971	302	478	644	-	-	-	8,400	12,000	15,600	193	276	359	3,612	5,766	8,574	70%	Economic	Development Unclarified	Level III	100%
Suffield Gas	Established	-	-	-	-	-	-	-	-	-	125,580	229,312	333,044	-	-	-	20,930	38,219	55,507	50%	not determined	Development On Hold	Level II	100%
Canada North																								
Blackrod - Phase I	Established	-	-	-	-	-	-	196,849	217,175	237,421	-	-	-	-	-	-	196,849	217,175	237,421	94%	Economic	Development On Hold	Level III	100%
Blackrod - Phase II and III	Established	-	-	-	-	-	-	967,524	1,065,608	1,163,693	-	-	-	-	-	-	967,524	1,065,608	1,163,693	77%	Economic	Development On Hold	Level II/III	100%
Mooney	Established	-	-	-	14,188	20,048	26,236	-	-	-	-	-	-	-	-	-	14,188	20,048	26,236	71%	Economic	Development On Hold	Level III	100%
Onion Lake Thermal	Established	-	-	-	22,911	30,365	45,798	-	-	-	-	-	-	-	-	-	22,911	30,365	45,798	85%	Economic	Development On Hold	Level III	100%
Onion Lake Primary	Established				2,375	2,900	3,580	-	-	-	-	-	-	-	-	-	2,375	2,900	3,580	90%	Economic	Development On Hold	Level III	100%
John Lake	Established				145	195	265							-	-	-	145	195	265	70%	Economic	Development On Hold	Level III	100%

Working Interest Contingent Resource

Development Unclarified status

	Light & Medium Oil Mbbl			Heavy Crude Oil Mbbl			Bitumen Mbbl			Conventional Natural Gas Bscf			NGL Mbbl			Total Oil Equivalent Mboe		
	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C				1C	2C	3C
Subtotal by Country																		
Unrisked																		
Malaysia	2,364	3,240	4,130	-	-	-	-	-	-	-	-	-	-	-	-	2,364	3,240	4,130
France	3,533	10,561	17,361	-	-	-	-	-	-	-	-	-	-	-	-	3,533	10,561	17,361
Canada	1,717	3,012	4,971	302	478	644	-	-	-	8,400	12,000	15,600	193	276	359	3,612	5,766	8,574
Total Unrisked	7,614	16,813	26,462	302	478	644	-	-	-	8,400	12,000	15,600	193	276	359	9,509	19,567	30,064
Subtotal by Country																		
Risked by Chance of Development																		
Malaysia	1,182	1,620	2,065	-	-	-	-	-	-	-	-	-	-	-	-	1,182	1,620	2,065
France	1,766	5,281	8,680	-	-	-	-	-	-	-	-	-	-	-	-	1,766	5,281	8,680
Canada	1,202	2,108	3,480	211	334	451	-	-	-	5,880	8,400	10,920	135	193	251	2,529	4,036	6,002
Total Risked	4,150	9,009	14,225	211	334	451	-	-	-	5,880	8,400	10,920	135	193	251	5,477	10,937	16,747

Working Interest Contingent Resource

Development On-hold status

	Light & Medium Oil Mbbl			Heavy Mbbl			Bitumen Mbbl			Conventional Bscf			NGL Mbbl			Total Oil Equivalent Mboe		
	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C
Subtotal by Country Unrisked																		
Malaysia	2,352	3,857	4,249	-	-	-	-	-	-	-	-	-	-	-	-	2,352	3,857	4,249
France	5,236	8,960	13,264	-	-	-	-	-	-	-	-	-	-	-	-	5,236	8,960	13,264
Canada	-	-	-	42,152	57,007	80,348	1,164,372	1,282,784	1,401,114	125,838	229,667	333,492	2	2	3	1,227,499	1,378,071	1,537,047
Total Unrisked	7,588	12,817	17,513	42,152	57,007	80,348	1,164,372	1,282,784	1,401,114	125,838	229,667	333,492	2	2	3	1,235,086	1,390,888	1,554,559
Subtotal by Country Risked by Chance of Development																		
Malaysia	1,176	1,929	2,124	-	-	-	-	-	-	-	-	-	-	-	-	1,176	1,929	2,124
France	2,014	3,455	5,166	-	-	-	-	-	-	-	-	-	-	-	-	2,014	3,455	5,166
Canada	-	-	-	33,560	45,240	64,091	930,031	1,024,663	1,119,220	62,971	114,905	166,836	1	2	2	974,087	1,089,056	1,211,119
Total Risked	3,190	5,384	7,290	33,560	45,240	64,091	930,031	1,024,663	1,119,220	62,971	114,905	166,836	1	2	2	977,277	1,094,439	1,218,409

Working Interest Contingent Resource

Total

	Light & Medium Oil Mbbl			Heavy Mbbl			Bitumen Mbbl			Conventional Bscf			NGL Mbbl			Total Oil Equivalent Mboe		
	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C
Subtotal by Country Unrisked																		
Malaysia	4,716	7,097	8,379	-	-	-	-	-	-	-	-	-	-	-	-	4,716	7,097	8,379
France	8,768	19,521	30,625	-	-	-	-	-	-	-	-	-	-	-	-	8,768	19,521	30,625
Canada	1,717	3,012	4,971	42,454	57,485	80,991	1,164,372	1,282,784	1,401,114	134,238	241,667	349,092	195	278	362	1,231,111	1,383,837	1,545,621
IPC Total	15,202	29,630	43,975	42,454	57,485	80,991	1,164,372	1,282,784	1,401,114	134,238	241,667	349,092	195	278	362	1,244,596	1,410,455	1,584,624
Subtotal by Country Risked by Chance of Development																		
Malaysia	2,358	3,549	4,189	-	-	-	-	-	-	-	-	-	-	-	-	2,358	3,549	4,189
France	3,781	8,736	13,846	-	-	-	-	-	-	-	-	-	-	-	-	3,781	8,736	13,846
Canada	1,202	2,108	3,480	33,772	45,574	64,542	930,031	1,024,663	1,119,220	68,851	123,305	177,756	136	195	253	976,616	1,093,092	1,217,121
IPC Total	7,341	14,393	21,516	33,772	45,574	64,542	930,031	1,024,663	1,119,220	68,851	123,305	177,756	136	195	253	982,754	1,105,376	1,235,156

The volumes in the table above are arithmetic sums of multiple estimates of contingent resources, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of contingent resources and appreciate the differing probabilities of recovery associated with each class.

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, waterflood optimization opportunities and volumes produced beyond the economic life time and/or December 31, 2039 in the relevant forecasts. In all cases, the product type is light crude oil. The technical risks and uncertainties associated with the Contingent Resources in France relate to limited seismic coverage and understanding of the structural extent of the fields. To recover the Contingent Resources, the drilling of development wells and, in some instances, the modification of existing production facilities would be required. Project development timing for the highest ranked opportunities will potentially be in the next two to five years with the remaining within the next ten years. In all cases, the Contingent Resources require a definitive development plan and approval of the plan to mature from Contingent Resources to Reserves. For those Contingent Resources associated with the petroleum law to become Reserves, it would be necessary for the government to issue a repeal, or for the appeal of an operator to be won, or for new projects to be identified to accelerate hydrocarbon recovery. Economics have not been run on forecasts after December 31, 2039 and so those volumes may include a portion that is sub-economic to produce.

Malaysia

The Contingent Resource estimates for Malaysia relate to the drilling of three infill wells in Bertam and to the extension of the production sharing contract (PSC) beyond 2025. The decision to drill the Bertam wells will be contingent on the performance of the A15-ST infill well plus economic and technical feasibility studies. Project development timing will be within the next five years. Extension of the PSC beyond 2025 is contingent on regulatory approval and economic conditions at the time. Contingent resources are assigned to all economic volumes produced in the period following the licence expiry up until end 2029, which is consistent with IPC cut-offs.

Canada
Suffield Area

The contingent shallow gas resources in the Suffield area of Alberta are attributed to development drilling. The development is expected to be phased and consists of drilling vertical commingled wells. IPC's gas production in the Suffield area is established and therefore infrastructure investment is expected to be minimal and commercial well recovery can be demonstrated. Sanction of these developments is sensitive to natural gas pricing.

Key positive factors relevant to the contingent resource estimates for Suffield and Alderson shallow gas include:

- established recovery technology, including demonstration of commercial production rates in the subject reservoir;
- available facilities and infrastructure currently in place from the Corporation's existing operations in the subject areas; and
- ongoing and continual operational activity in the areas by the Corporation.

Key negative factors relevant to the contingent resource estimates for Suffield and Alderson shallow gas include:

- economic sensitivity to future gas pricing; and
- the limited economic value of shallow gas opportunities in the context of the Corporation's broader asset portfolio in the current commodity pricing environment.

Two contingencies are identified for Suffield shallow gas contingent resource development:

Timing of Production and Development

The Corporation's lands in Suffield and Alderson are well defined and largely developed. The primary contingency for the shallow gas contingent resource locations is a lack of corporate commitment to developing the wells within the five year timeframe recommended by COGEH for reserves assignments.

Economic Viability

Based on offsetting well performance in these areas, it is likely that a portion of the shallow gas contingent resource opportunities will be economic and a portion will be sub-economic. Further review of operating costs, capital costs, royalties and incentives would need to be completed for this contingency to be lifted.

The contingent heavy oil resources in the Suffield area are attributed to development drilling. The development is expected to be phased and consists of drilling horizontal wells targeting Mannville and Detrital reservoirs. IPC's oil production in the Suffield area is established therefore infrastructure investment is expected to be minimal commercial well recovery can be demonstrated. Sanction of these developments is sensitive to oil pricing.

Key positive factors relevant to the contingent resource estimates for Suffield heavy oil include:

- established recovery technology, including widespread successful implementation in the subject reservoir;
- available facilities and infrastructure currently in place from the Corporation's existing operations in the subject area; and
- active and continual implementation of development drilling in the subject area by the Corporation.

Key negative factors relevant to the contingent resource estimates for development for Suffield heavy oil include:

- economic sensitivity to future oil pricing; and
- highly variable range of well productivity.

Three contingencies are identified for Suffield heavy oil contingent resource development:

Evaluation Drilling

In the Detrital opportunities there is a requirement for more evaluation drilling to better establish commercial reservoir productivity. The Detrital has producing wells, though mapping of opportunities is largely seismic driven as it is not a continuous reservoir. As a result, additional drilling to establish commercial productivity within each Detrital pool is necessary to satisfy COGEH prerequisites for reserves assignment, at which time this contingency would be removed. The Mannville resources in the Falcon area will also require additional evaluation drilling before recoverable volumes can be classified as reserves due to limited wells and relatively poor existing production performance.

Timing of Production and Development

The Corporation's lands in the Mannville formation in the Suffield area are well delineated and largely developed. The primary contingency for the Mannville locations is a lack of corporate commitment to developing the wells within the five year timeframe.

Economic Viability

Based on offsetting well performance in these areas it is likely that a portion of the heavy oil contingent resource opportunities will be economic and a portion will be sub-economic. Further review of operating costs, capital costs, royalties and incentives would need to be completed for this contingency to be lifted.

Blackrod

See Schedule B of this document for further information with respect to the Blackrod project.

Onion Lake Thermal

The thermal contingent heavy oil resources in the Onion Lake area of Saskatchewan are attributed to a thermal enhanced oil recovery project. Commercial production is demonstrated from earlier and ongoing phases and IPC has existing operational experience at this site. Sanction of this expansion is sensitive to oil pricing and potential regulatory changes that could be related to future First Nations leases.

Key positive factors relevant to the contingent resource estimates for the Onion Lake thermal project 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
- existing fully operational central processing facility infrastructure in place.

Key negative factors relevant to the contingent resource estimate for the Onion Lake thermal project include:

- economic sensitivity to future oil pricing; and
- potential for IOGC to introduce policy changes for First Nations leases which could impact future lease agreements.

Three contingencies are identified for the Onion Lake thermal contingent resource development:

Evaluation Drilling

There is a requirement for more evaluation drilling to confirm the reservoir characteristics needed for the successful implementation and operation of the modified SAGD recovery process. Delineation through primary development drilling is currently ongoing and it is expected that the delineation necessary for adequate reservoir evaluation within the project area will be met prior to the first Phase Three well pad being drilled, at which time this contingency would be lifted.

Regulatory Approval

The Corporation's lands in the Onion Lake area are leased from the Onion Lake Cree Nation (OLCN), are subject to Indian Oil and Gas Canada (IOGC) policies and approvals, as well as approvals from Saskatchewan Energy and Resources (SER). An application to expand the commercial modified SAGD development beyond the existing OLCN/OLE approved thermal EOR development area and facility capacities has not been submitted by the Corporation. It is expected that as the Corporation nears a final investment decision for developing additional acreage, OLCN/OLE agreements will be affirmed and further expansion applications will be submitted, at which point this contingency would be lifted. Within the thermal EOR development area is a sub-area where the Corporation has received regulatory approval for Phases One and Two of the Onion Lake thermal project from OLCN/OLE, SER and IOGC. Reserves were assigned to this area. Reserves were also assigned to the lands where the Corporation and OLCN/OLE have a thermal EOR development agreement in place that are outside of the existing SER/IOGC approval area based on the expectation that these lands will receive SER/IOGC approval as the Corporation expands the commercial project and submits an application to include this area. These reserves volumes have been excluded from the contingent resources volumes.

Timing of Production and Development

The timing of production and development is estimated to commence beyond reasonable time periods as described in COGEH as a requirement for classification as reserves. It is expected that as development planning continues, the timing of production and development will fall within the timeframes and certainty required for reserves classification, at which time this contingency would be lifted.

Onion Lake Primary

The primary contingent heavy oil resources in the Onion Lake area of Saskatchewan are attributed to development drilling. The production mechanism would be vertical Cold Heavy Oil Production with Sand (CHOPS). Drilling and production has been proven from the targeted reservoir and IPC has existing operational experience at this site. Sanction of these development wells is sensitive to oil price and potential regulatory changes that could be related to future First Nations leases.

Key positive factors relevant to the contingent resource estimates for primary development in the Onion Lake area include:

- established recovery technology, including widespread successful implementation in the subject reservoir;
- available facilities and infrastructure currently in place from the Companies existing operations in the subject area;
- established relationship with the Onion Lake Cree Nation (lessor); and
- active pursuit by the Corporation of expanded reservoir development using CHOPS.

Key negative factors relevant to the contingent resource estimate for primary well development in the Onion Lake area include:

- economic sensitivity to future oil pricing; and
- potential for IOGC to introduce policy changes for First Nations leases which could impact future lease agreements.

Two contingencies are identified for Onion Lake primary heavy oil contingent resource development:

Evaluation Drilling

There is a requirement for more evaluation drilling to confirm the geological continuity of the reservoir and reduce the distance from proven productivity. It is anticipated that as the Corporation continues to pursue primary development of the reservoir, commercial productivity will be established closer to and within the primary production contingent resource areas, at which time this contingency would be removed.

Regulatory Approval

The Corporation's lands in the Onion Lake area are leased from the Onion Lake Cree Nation (OLCN) and are subject to Indian Oil and Gas Canada (IOGC) policies and approvals. As the Corporation continues primary development within the Onion Lake leases, agreements between the Corporation and OLCN may be subject to renegotiation due to changes imposed by IOGC. It is expected that as the Corporation nears a final investment decision for developing additional acreage, the OLCN/IOGC agreements will be reaffirmed, at which point this contingency would be lifted.

Mooney

The contingent heavy oil resource estimates in the Mooney area of Alberta are attributed to deploying an Alkaline Surfactant Polymer Enhanced Oil Recovery project to the existing development and areas immediately offsetting existing development. The development plan is well defined and the operating facility is in place. Sanction of this project is dependent on future oil and chemical prices and predicted flood performance in the reservoir. The Corporation includes reserve estimates for Phases One and Two of the Mooney project; the contingent resource estimates relate to the future potential development of Phases Three and Four.

Key positive factors relevant to the contingent resource estimate for Mooney Phases Three and Four include:

- established recovery technology, including successful implementation in the subject reservoir;
- regulatory approval obtained for Phases One and Two of the project;
- well defined development plan; and
- fully operational injection and production facility and surface infrastructure in place.

Key negative factors relevant to the contingent resource estimate for Mooney Phases Three and Four include:

- economics highly sensitive to future oil and chemical pricing;
- flood performance susceptible to reservoir heterogeneities; and
- comparatively limited resource base within the Corporation's broader asset portfolio.

Four contingencies are identified for the Mooney Phases Three and Four contingent resources:

Evaluation Drilling

There is a requirement for more evaluation drilling to confirm the reservoir characteristics needed for the implementation and operation of the ASP or Polymer recovery process. Certain portions of the reservoir, specifically stepping out southwards and eastwards of current productive development, are not sufficiently delineated and reservoir properties such as oil viscosity, presence of free gas, and formation heterogeneities need to be further defined. It is anticipated that the reservoir characteristics pertinent to ASP and polymer flood performance will become better understood as the Corporation continues to delineate the reservoir with primary production wells, at which time this contingency would be lifted.

Regulatory Approval

There is a requirement for the submission of an application to expand the commercial EOR development beyond the Phase One and Two project areas. The Corporation has obtained regulatory approval for Phases One and Two of the Mooney project, but no expansion application currently exists for the Phases Three and Four contingent resource volumes.

Corporate Commitment

The final investment decision and endorsement from the Corporation to move forward with development of Phases Three and four has not been made. The Corporation has historically focused development efforts towards its other major assets. For year-end 2021 this focus is much the same. The Mooney property was shut in in 2020 and reactivated in 2021 due to challenging economics. Mooney Phases Three and Four represent some of the lowest materiality projects in the Corporation's portfolio in terms of resource base and expected value. It is likely that a final investment decision to approve these Phases Three and Four will not occur for several years, and as a result there is potential for delays or revisions to the development plan.

Timing of Production and Development

The timing of production and development of the flood patterns detailed in this report is estimated to commence beyond the five year time period deemed reasonable for classification as proved or probable reserves. The strategic goals of the Corporation in managing its asset portfolio result in the need for a phased development plan executed over an extended time period to fully develop the Mooney resources.

John Lake

The primary contingent heavy oil resources in the John Lake area Alberta are attributed to the drilling of vertical and horizontal heavy oil wells. Drilling and production has been proven from the targeted reservoir and IPC has existing operational experience at this site.

Key positive factors relevant to the contingent resource estimates for John Lake include:

- established recovery technology, including widespread successful implementation in the subject reservoir; and
- available facilities and infrastructure currently in place from the Companies existing operations in the subject area.

Key negative factors relevant to the contingent resource estimates for John Lake include:

- economic sensitivity to future oil pricing; and
- lack of commitment and internal approvals to actively pursue the identified development opportunities at this time.

One contingency is identified for John Lake contingent resource development:

Corporate Commitment

The Corporation has indicated they are not committed to proceeding with the development opportunities classified as contingent resources until they can further assess the opportunities, clarify the development plan and compare the identified opportunities to other Corporation investment opportunities.

Ferguson

The contingent resources at the Ferguson field are a combination of oil and gas resources. The oil resources are attributed to development drilling, re fracturing of existing wells and the optimization of the field's gas flood. The gas resources are attributed to blowdown associated with the gas flood reservoir.

Key positive factors relevant to the contingent resource estimates for Ferguson include:

- established recovery technologies, including widespread successful implementation in the subject reservoir; and
- available facilities and infrastructure currently in place from the Companies existing operations in the subject area.

Key negative factors relevant to the contingent resource estimates for Ferguson include:

- economic sensitivity to future oil and gas pricing; and
- lack of commitment and internal approvals to actively pursue the identified development opportunities at this time.

One contingency is identified for Ferguson contingent resource development:

Corporate Commitment

The Corporation has indicated they are not committed to proceeding with the development opportunities classified as contingent resources in the Ferguson area until they can further assess the opportunities, clarify the development plan and compare the identified opportunities to other Corporation investment opportunities.

SCHEDULE B – FURTHER CONTINGENT RESOURCE DATA WITH RESPECT TO BLACKROD

Blackrod Project Summary

The contingent bitumen resources outlined in this document are attributed to a thermal enhanced oil recovery project in the Blackrod area of Alberta. IPC holds a 100 percent working interest in the Blackrod project, with production volumes subject to Alberta oil sands royalties. The resources would be recovered using Steam Assisted Gravity Drainage (SAGD); SAGD is an established technology in the heavy oil regions of Western Canada.

The Blackrod development concept proposed by IPC is to develop the project in three separate phases. Phase One includes a 30,000 barrel per day eleven pad development project; Phase Two includes an expansion to a 50,000 barrels per day; and Phase Three includes expansion to 80,000 barrels per day.

See also "Description of the Business – Description of the Group's Oil and Gas Assets – Canada – Blackrod" above.

Blackrod Phase One

IPC commissioned an independent qualified reserves evaluator report from Sproule assessing the contingent resources of the Blackrod Phase One development as at December 31, 2021, including an economic assessment of the best estimate case. This Schedule summarises certain information contained in that report. Contingent resource estimates and estimates of future net revenue in respect of Blackrod Phase One are effective as of December 31, 2021, and the report by Sproule was prepared in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2021 price forecasts.

The Blackrod thermal pilot project began in 2011, three pilot well pairs have been drilled to date. The third pilot pair is currently on production. Phase One includes a 20,000 bopd facility, rising to 30,000 bopd as production matures. The design of future phases would be optimized based on Phase One performance.

IPC plans to mature the Blackrod Phase One project through 2022 with Front End Engineering Design (FEED) studies in parallel with the continuation of production from well pair three. The current iteration of the Blackrod Phase One development plan assumes first steam in 2025 and commercial production commencing in 2026. It is acknowledged that a final investment decision has not yet been sanctioned and there is therefore potential for delays and/or revisions to the proposed development plan. It is anticipated that as development planning continues, internal approvals to proceed are likely.

Estimates of Blackrod unrisked and risked contingent resource volumes are presented in Schedule A Contingent Resources; Phase One best estimate (2C) unrisked and risked volumes are also summarised below on a Gross and Net basis, along with risked and unrisked estimates of net present values and estimated total cost required to achieve commercial production. The pricing information shown in Part III of this document was used as the basis for these estimates.

The risked volumes and estimates of net present value are risked by chance of development. Chance of development is defined as the probability of a project being commercially viable. Risked amounts represent unrisked values multiplied by the chance of development.

All contingent resource volumes for Blackrod Phase One outlined in this document are classified as Economically Viable, Development on Hold and have a high probability of becoming a commercial development. In recognition of the risk of achieving commerciality for 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 three contingencies identified for the project (Regulatory Approval, 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.

Key positive factors relevant to the contingent resource estimates for the Blackrod Phase One include:

- established recovery technology, including a successful pilot in the subject reservoir;
- extensive regulatory application filed and approved for Phase One; and
- well defined development plan; and well delineated relatively homogeneous in-place-bitumen resource volume.

Key negative factors relevant to the contingent resource estimates for the Blackrod Phase One include:

- economic sensitivity to future oil pricing;
- potential for Alberta Government policy changes regarding carbon emissions to impact project viability;
- potential lack of available pipeline capacity with which to access bitumen markets; and
- bitumen market may be sensitive to the number of other oil sands projects that come on-stream in the same timeframe.

Three contingencies are identified for Blackrod Phase One:

Corporate Commitment

While the Corporation has demonstrated commitment through recent commencement of detailed Phase One pre-development characterizations and workflow and continues to actively work towards commercialization of the Blackrod project, it is acknowledged that a final investment decision to approve Phase One may not occur in the immediate term. As a result, there is potential for delays or revisions to the development plan.

Timing of Production and Development

Current IPC plans indicate that the timing of significant capital spending, production and development of Phase One will commence towards the latter end of the reasonable time periods required for classification as proved and probable reserves by COGEH. Given the uncertainty surrounding a final investment decision and internal approvals to proceed and the preliminary nature of the current development scheduling, it is acknowledged that currently proposed scheduling is tentative and there is potential for delays in project timing that may exceed the reasonable time periods described in COGEH for reserves assignments. It is expected that the timing of significant capital spending, production and development will fall within the reasonable timeframes required for reserves classification as development planning continues and timelines become firm, at which time this contingency would be removed.

Regulatory Approval

Based on the current layout of Phase One development pads proposed by the Corporation, there is a small portion of Phase One contingent resource assignments that fall outside the boundaries of the currently approved project area. The Corporation has submitted a regulatory application for Phase One and received approval from the AER and Alberta government in September 2016. No application currently exists for the areas identified as Phases Two and Three. In addition, changes in Alberta Government carbon emission policies could impede the approval of large-scale heavy oil projects in the future. It is expected that as the Company moves forward with Phase One (with completion of central facilities construction and first production) the Company will either have sufficient information to move forward with expansion of the application area to a larger scale project or will adjust their pad layouts to coincide with the current approval area, at which time this contingency would be removed.

Blackrod Phases Two and Three

Phase Two includes an expansion of Phase One to a 50,000 barrel per day development project. Phase Three further expands the facility to an 80,000 barrel per day development project.

Four contingencies are identified for the contingent resources related to Blackrod Phases Two and Three:

Evaluation Drilling

There is a requirement for more evaluation drilling to confirm the reservoir characteristics needed for the implementation and operation of the SAGD recovery process. AER regulations generally require 8 delineation wells per section (or lower density delineation drilling combined with 3D seismic data) within the project area for Grand Rapids project applications. It is expected that the delineation well density and seismic data acquisition requirements for the majority of the project area will be met prior to commencement of development of Phases Two and Three, at which time this contingency would be lifted.

Regulatory Approval

An application to expand the SAGD development beyond the Phase One project area has not yet been made. The Corporation has submitted a regulatory application for the large majority of Phase One and received approval from the AER and Alberta government in September 2016. No application currently exists for the areas identified as Phases Two and Three. In addition, changes in Alberta Government carbon emission policies could impede the approval of large-scale oil sands projects in the future. It is expected that as the Corporation moves forward with Phase One (with completion of central facilities construction and first production) the Corporation will have sufficient information to move forward with expansion of the application area to a larger scale project, at which time this contingency would be removed.

Corporate Commitment

The final investment decision and endorsement from the Corporation to move forward with development of Phases Two and Three has not been made. While the Corporation has consciously demonstrated a strong focus on its major assets and continues to actively work towards commercialization of the Blackrod project, it is acknowledged that Blackrod Phases Two and Three represent the largest project in the Corporation portfolio both in terms of capital requirements and resource base. It is likely that a final investment decision to approve Phases Two and Three will not occur for several years and as a result there is potential for delays or revisions to the development plan.

Timing of Production and Development

The timing of significant capital spending, production and development of Phases Two and Three is estimated to commence beyond the five year reasonable time periods recommended in COGEH for classification as proved and probable reserves. The large size of the resource base at Blackrod presents the need for a phased development plan executed over an extended time period to fully develop the resources.

An estimate of risked net present value of future net revenue of contingent resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of IPC proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

Breakdown of Blackrod Phase One Contingent Resources
(Unrisked and Risked by Chance of Development Forecast Cases)

	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	MMbbl	MMbbl	Bscf	Bscf	MMboe	MMboe
Unrisked												
2C	217.2	174.6	-	-	-	-	-	-	-	-	217.2	174.6
Risked												
2C	204.1	164.1	-	-	-	-	-	-	-	-	204.1	164.1

Net Present Value of Future Net Revenue of Blackrod Phase One Contingent Resources
(Unrisked and Risked by Chance of Development Forecast Cases) 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%	
Unrisked													
2C	4443.1	1914.7	1179.5	855.3	369.9	130.8	3402.0	1433.8	861.4	609.2	232.9	49.1	4.9
Risked													
2C	4176.6	1799.8	1108.8	804.0	347.7	123.0	3197.9	1347.8	809.7	572.7	218.9	46.1	4.9

Blackrod Phase One Contingent Resources Future Development Costs MM U.S.$

	2022	2023	2024	2025	2026	2027 on	Total for all years undiscounted	Total for all years discounted at 10% p.a.
Unrisked								
2C	13.6	87.6	211.0	230.2	50.6	960.9	1553.9	783.9
Risked								
2C	12.8	82.4	198.4	216.4	47.6	903.1	1460.7	736.8

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 Corporation (the "Company"):

1. We have evaluated the Company's Canadian assets reserves data as at December 31, 2021. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2021, estimated using forecast prices and costs in U.S. Dollars.

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).

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.

Sproule

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, 2021, 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, 2021	Canada				
Total			**Nil**	**2,343,855**	**Nil**	**2,343,855**

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 IPC Canada Ltd. (As of December 31, 2021)".

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

Sproule

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta

PROFESSIONAL ENGINEER
JASON ROBOTTOM
ALBERTA
ID 92046

Jan. 31, 2022
Jason E. Robottom, P.Eng., CFA
Manager, Reserves Certification

Sproule Associates Limited
APEGA Permit Number 00417

Douglas McNichol, P.Eng.
Senior Manager, Engineering
DATE: Jan. 31, 2022 **RM APEGA ID #:** 30528

Alec Kovaltchouk, P.Geo.
VP, Geoscience
DATE: Jan. 31, 2022 **RM APEGA ID #:** 72150

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, 2021. The Reserves data are estimates of Proved Reserves and Probable Reserves and related future net revenue as at December 31, 2021, estimated using forecast prices and costs. The Contingent Resources have been estimated using data as at December 31, 2021.

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, 2021, 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, 2021	France	$191,791,328	$0	$0	$191,791,328
ERC Equipoise	Dec 31, 2021	Malaysia	$182,217,872	$0	$0	$182,217,872
Totals			**$374,009,199**	**$0**	**$0**	**$374,009,199**

6. The following tables set forth the risked volume of Contingent 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	ERC Equipoise Ltd	Dec 31, 2020	France	8,735.6
Unclarified/Development On Hold (2C)	ERC Equipoise Ltd	Dec 31, 2020	Malaysia	3,548.6

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.

Executed as to our report referred to above:

ERC Equipoise Limited, London, United Kingdom, March 01, 2022

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 and Sustainability Committee of the Board of Directors of the Corporation has

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

(b) met with the independent qualified reserves auditors and evaluators to determine whether any restrictions affected the ability of the independent qualified reserves auditors and evaluators to report without reservation; and

(c) reviewed the reserves data and contingent resources data, as applicable, with management and the independent qualified reserves auditors and evaluators.

The Reserves and Sustainability 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 and Sustainability 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 auditors and evaluators on the reserves data and contingent resources data; and

(c) the content and filing of this report.

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.

"Mike Nicholson"	*"William Lundin"*
Mike Nicholson, Chief Executive Officer	William Lundin, Chief Operating Officer
"Chris Bruijnzeels"	*"Emily Moore"*
Chris Bruijnzeels, Director	Emily Moore, Director

Date: March 25, 2022

SCHEDULE F – AUDIT COMMITTEE MANDATE

Audit Committee Mandate

Amended as of March 25, 2019 and March 24, 2021, ratified as of March 18, 2022

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.

Auditors

(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.

Risk Management

The Audit Committee shall coordinate with the Reserves and Sustainability Committee (as it relates to ESG (environmental, social and governance), sustainability and climate-related risks) and with the Compensation Committee (as it relates to compensation-related risks) and review with management:

(i) the effectiveness of the Company's procedures with respect to risk identification, assessment and management;

(ii) the Company's major risk exposures;

(iii) the steps management has taken to monitor and control such exposures; and

(iv) the effect of relevant regulatory initiatives and trends.

The Audit Committee, with the assistance of management, shall periodically report to the Board on these matters in support of the Board's responsibility for the management of the principal risks associated with the Company's business and operations.

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

C. Ashley Heppenstall
Director, Chair of the Board
London, England

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

Donald K. Charter
Director
Toronto, Ontario

Chris Bruijnzeels
Director
Abcoude, The Netherlands

Torstein Sanness
Director
Oslo, Norway

Emily Moore
Director
Toronto, Ontario

L.H. (Harry) Lundin
Director
Toronto, Ontario

OFFICERS

Christophe Nerguararian
Chief Financial Officer
Geneva, Switzerland

William Lundin
Chief Operating Officer
Geneva, Switzerland

Jeffrey Fountain
General Counsel and Corporate Secretary
Geneva, Switzerland

Rebecca Gordon
VP Corporate Planning and Investor Relations
Geneva, Switzerland

Chris Hogue
Senior Vice President Canada
Calgary, Alberta

Ryan Adair
Vice President Asset Management and Corporate Planning
Canada
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INDEPENDENT AUDITORS

PricewaterhouseCoopers SA, Switzerland

TRANSFER AGENT

Computershare Investor Services Inc.
Calgary, Alberta and Toronto, Ontario

STOCK EXCHANGE LISTINGS

Toronto Stock Exchange and NASDAQ Stockholm
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