International Petroleum Corporation

Business Acquisition Report

April 5, 2018

International Petroleum Corp.

FORM 51-102F4

BUSINESS ACQUISITION REPORT

Item 1 Identity of Company

1.1 Name and Address of Company

International Petroleum Corporation ("IPC" or the "Corporation")
Suite 2000
885 West Georgia Street
Vancouver, BC
V6C 3E8, Canada

1.2 Executive Officer

Mr. Jeffrey Fountain, General Counsel of IPC, is knowledgeable about the acquisition in respect of which this business acquisition report ("Report") has been filed. Mr. Fountain may be reached by telephone at +41 22 595 1050.

Item 2 Details of Acquisition

2.1 Nature of Business Acquired

In September 2017, IPC announced the transformational acquisition (the "Acquisition") of the Suffield area oil and gas assets in Alberta, Canada from Cenovus Energy Inc. ("Cenovus").

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

On September 25, 2017, the Corporation reported that the Suffield area oil and gas assets were forecast to produce an average of approximately 6,900 barrels of oil per day and approximately 102 million standard cubic feet of natural gas per day during 2017, for a total average of approximately 24,000 barrels of oil equivalent per day (boepd).

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

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

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

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

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

Overview

The onshore Suffield Area oil and gas assets are situated in southeast Alberta and are operated by IPC. The oil assets are 100% working interest and gas assets are 99.6% working interest. These assets are characterized as having a high number of wells with low production decline rates. The oil quality is 13°API and is produced via conventional, non-thermal methods. The assets are well-known to the operational team in Redcliff, Alberta and to the asset management team in Calgary, Alberta, many of whom have been working the assets for many years as Cenovus employees.

Asset Description

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

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

Geologic Overview

The main oil producing horizon is the Cretaceous age Glauconitic (Manville group) sand. The sand was deposited in a shoreline / Aeolian environment and is generally of very high reservoir quality. Reservoir depth is approximately 1000 metres and oil is produced via water drive. The oil is viscous however with the good reservoir quality it can be produced via conventional, non-thermal methods.

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

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

Production Operations

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

Abandonment Obligations

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

Infrastructure and Marketing

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

RESERVES AND RESOURCE ADVISORY

This Report 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. Unless otherwise indicated, reserves / resource volumes are presented on a gross basis.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada are effective as of January 5, 2018, being the completion date for the acquisition of these assets by IPC, and were evaluated by McDaniel & Associates Consultants Ltd. (McDaniel), an independent qualified reserves evaluator, in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's January 1, 2018 price forecasts. The volumes are reported by IPC in this Report as being as at December 31, 2017.

The price forecasts used in the reserve audit / evaluation are available on the website of McDaniel (www.mcdan.com), and are contained in the "Statement of Reserves Data and Other Oil and Gas Information" below.

Light and medium crude oil reserves/resources disclosed in this Report include solution gas and other by-products.

"2P reserves" means proved plus probable reserves. "Proved reserves" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. "Probable reserves" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. "Possible reserves" are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

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

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

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

Contingent resources are further classified based on project maturity. The project maturity subclasses include development pending, development on hold, development unclarified and development not viable. All of the Corporation's contingent resources are classified as development unclarified. Development unclarified is defined as a contingent resource that requires further appraisal to clarify the potential for development and has been assigned a lower chance of development until contingencies can be clearly defined. Chance of development is the probability of a project being commercially viable.

References to "unrisked" contingent resources volumes means that the reported volumes of contingent resources have not been risked (or adjusted) based on the chance of commerciality of such resources. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore unrisked reported volumes of contingent resources do not reflect the risking (or adjustment) of such volumes based on the chance of development of such resources.

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

This Report 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 Report do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material.

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

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 thousand cubic feet (Mcf) per 1 barrel (bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a 6:1 conversion basis may be misleading as an indication of value.

Oil and Gas Reserves – Based on Forecast Prices and Costs

Proved Reserves

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

Proved plus Probable Reserves

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

Proved plus Probable plus Possible Reserves

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

Net Present Value of Future Net Revenue – Proved Reserves

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

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

Net Present Value of Future Net Revenue – Proved plus Probable Reserves

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

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

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

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

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

Elements of Future Net Revenue

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

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

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

Net Present Value by Product Type

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

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

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

Forecast Prices used in Estimates

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

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

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

Exchange rate Assumptions

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

Reconciliation of Changes in Reserves

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

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

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

Undeveloped Reserves

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

Development Projects

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

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

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

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

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

Significant Factors or Uncertainties Affecting Reserves Data

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

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

Future Development Costs

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

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

Expectations of Sources and Costs of Funding

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 Corporation will allocate funds to develop the reserves as represented in this Report. The Corporation may choose to delay or cancel discretionary development projects depending on economic factors, strategy and priorities. Equally, the Corporation may choose to accelerate activity where possible should circumstances allow.

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

Producing and Non-Producing Well Counts

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

Properties with No Attributed Reserves

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

Tax Horizon

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

Production Forecast Estimates

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

Contingent Resources

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

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

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

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

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

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

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

2.2 Acquisition Date

IPC completed the Acquisition on January 5, 2018.

2.3 Consideration

In September 2017, IPC announced the proposed acquisition from Cenovus of the Suffield Area Assets for a total consideration of CAD 512 million, subject to closing adjustments and to certain additional contingent payments.

The consideration paid on closing on January 5, 2018, net of closing adjustments, was CAD 449 million. A further amount of CAD 12 million will become payable at end of June 2018.

In addition, certain capped, additional contingent payments may become payable based on oil and gas prices. These contingent purchase price payments may become payable based on actual average monthly oil and natural gas prices during 2018 and 2019. Payments are due for each month when the average daily price of West Texas Intermediate (WTI) is above USD 55 bbl or natural gas prices at the Henry Hub are above USD 3.50 per million British thermal units (MMBtu). These payments are capped for each commodity on a per month basis (CAD 375,000 per month for oil and CAD 1,125,000 per month for gas) with a maximum combined payment of CAD 36 million in aggregate. The Corporation paid Cenovus CAD 375,000 in February and March 2018 related to oil prices realized in January and February 2018 respectively, with no amount owing related to January or February 2018 gas production.

The Corporation funded the Acquisition with internally generated cash flows and bank lending facilities. In connection with the completion of the Acquisition, IPC entered into an amendment to the existing reserve-based lending credit facility on December 20, 2017 to increase such facility from USD 100 million to USD 200 million and IPC entered into a CAD 250 million reserve-based lending credit facility and a CAD 60 million second lien facility in Canada on January 5, 2018. The amendment to the existing reserve-based lending credit facility was signed on December 20, 2017 and became effective on January 3, 2018.

2.4 Effect on Financial Position

Except as may be described elsewhere in this Report, the Corporation does not have any current plans or proposals for material changes in the Corporation's business affairs or the affairs of the acquired business which may have a significant effect on the financial performance and financial position of the Corporation.

2.5 Prior Valuations

No valuation required by securities legislation or a Canadian stock exchange or market to support the consideration payable by the Corporation pursuant to the Acquisition has been obtained within the past 12 months by IPC.

2.6 Parties to Transaction

The Acquisition is not a transaction with an "informed person", "associate" or "affiliate" of the Corporation.

2.7 Date of Report

April 5, 2018

Item 3 Financial Statements

The following financial statements required by Part 8 of National Instrument 51-102 *Continuous Disclosure Obligations* are included in this Report:

Schedule A Unaudited Condensed Pro Forma Operating Statement of IPC that gives effect to the Acquisition, for the financial year ended December 31, 2017, and together with the notes thereto.

Schedule B Audited Operating Statements in respect of the Suffield Assets for the financial years ended December 31, 2017 and December 31, 2016, together with the notes thereto.

The unaudited pro forma operating statements are not necessarily indicative of either the financial position or results of operations that actually would have occurred if the events reflected therein had been in effect on the dates indicated or of the results that may be obtained in the future.

OTHER SUPPLEMENTARY INFORMATION

Abbreviations

CAD or CA$	Canadian dollar
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
bbl	Barrel (1 barrel = 159 litres)
boe[1]	Barrels of oil equivalents
boepd	Barrels of oil equivalents per day
bopd	Barrels of oil per day
Empress	The benchmark price for natural gas at the Empress point at the Alberta/Saskatchewan border
Mbbl	Thousand barrels
MMbbl	Million barrels
Mboe	Thousand barrels of oil equivalents
Mboepd	Thousand barrels of oil equivalents per day
Mbopd	Thousand barrels of oil per day
MMboe	Million barrels of oil equivalents
Mcf	Thousand cubic feet
Bscf	Billion standard cubic feet
NGL	Natural gas liquid

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

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This document 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 document are expressly qualified by this cautionary statement. Forward-looking statements speak only as of the date of this document, unless otherwise indicated. IPC does not intend, and does not assume any obligation, to update these forward-looking statements, except as required by applicable laws.

All statements other than statements of historical fact may be forward-looking statements. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, forecasts, guidance, budgets, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", “forecast”, "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", "budget" and similar expressions) are not statements of historical fact and may be "forward-looking statements".

Forward-looking statements include, but are not limited to, statements with respect to:

- Our intention to continue to implement our strategies to build long-term shareholder value;
- The benefits of the Suffield acquisition;
- IPC's intention to review future potential growth opportunities;
- The ability of our high quality portfolio of assets to provide a solid foundation for organic and inorganic growth;
- The integration of the Suffield-related operations into IPC;
- Potential future growth opportunities in North America;
- Future development potential of the Suffield operations;
- Potential acquisition opportunities;
- Estimates of reserves;
- Estimates of contingent resources;
- Estimates of prospective resources; 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.

The forward-looking statements are based on certain key expectations and assumptions made by IPC, including expectations and assumptions concerning: prevailing commodity prices and currency exchange rates; applicable royalty rates and tax laws; interest rates; future well production rates and reserve and contingent resource volumes; operating costs; the timing of receipt of regulatory approvals; the performance of existing wells; the success obtained in drilling new wells; anticipated timing and results of capital expenditures; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the successful completion of acquisitions and dispositions; the benefits of acquisitions; the state of the economy and the exploration and production business in the jurisdictions in which IPC operates and globally; the availability and cost of financing, labour and services; and the ability to market crude oil, natural gas and natural gas liquids successfully.

Although IPC believes that the expectations and assumptions on which such forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because IPC can give no assurances that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks.

These include, but are not limited to:

- The risks associated with the oil and gas industry in general such as operational risks in development, exploration and production;
- Delays or changes in plans with respect to exploration or development projects or capital expenditures;
- The uncertainty of estimates and projections relating to reserves, resources, production, revenues, costs and expenses;
- Health, safety and environmental risks;
- Commodity price and exchange rate fluctuations;
- Interest rate fluctuations;
- Marketing and transportation;
- Loss of markets;
- Environmental risks;
- Competition;
- Incorrect assessment of the value of acquisitions;
- Failure to complete or realize the anticipated benefits of acquisitions or dispositions;
- The ability to access sufficient capital from internal and external sources;
- Failure to obtain required regulatory and other approvals; and
- Changes in legislation, including but not limited to tax laws, royalties, environmental and abandonment regulations.

Readers are cautioned that the foregoing list of factors is not exhaustive.

References may be made in this Report to “operating cash flow” (OCF), “Earnings Before Interest, Tax, Depreciation and Amortization” (EBITDA), “operating costs” and “net debt”/”net cash” which are not generally accepted accounting measures under International Financial Reporting Standards (IFRS) and do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with definitions of OCF, EBITDA, operating costs and net debt/net cash that may be used by other public companies. Management believes that OCF, EBITDA, operating costs and net debt/net cash are useful supplemental measures that may assist shareholders and investors in assessing the cash generated by and the financial performance and position of the Corporation. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-IFRS measure is presented in 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 annual information form prepared for the year ended December 31, 2017 and dated March 30, 2018, the audited consolidated financial statements of the Corporation for the years ended December 31, 2017 and 2016, the material change report dated February 26, 2018 filed by the Corporation in respect of certain reserves and resource information, the MD&A (See "Cautionary Statement Regarding Forward-Looking Information" therein), the Corporation's Non-Offering Prospectus dated April 17, 2017 (See "Risk Factors" and "Forward-Looking Information" therein) and other reports on file with applicable securities regulatory authorities, which may be accessed through the SEDAR website (www.sedar.com) or IPC's website (www.international-petroleum.com).

SCHEDULE A

Unaudited Condensed Pro Forma Operating Statement of IPC

IPC Unaudited Condensed Pro Forma Operating Statement for the year ended December 31, 2017

USD Thousands	IPC information (audited)	Suffield Assets information* (audited)	Pro Forma adjustments (unaudited)	**IPC Condensed Pro Forma Operating Statement (unaudited)**
Sales of oil and gas	185,182	185,659	-	**370,841**
Change in under/over lift position	(613)	-	-	**(613)**
Other Revenue	18,432	-	-	**18,432**
Royalties	-	(7,183)	-	**(7,183)**
Total Revenue	**203,001**	**178,476**	**-**	**381,477**
Cost of operations	(53,389)	(54,984)	-	**(108,373)**
Tariff and transportation expenses	(3,361)	(36,202)	24,172	**(15,391)**
Direct production taxes	(3,999)	(112)	-	**(4,111)**
Change in inventory position	(3,688)	-	-	**(3,688)**
Other costs	-	-	(24,172)	**(24,172)**
Operating expenses	**(64,437)**	**(91,298)**	**-**	**(155,735)**
Operating income	**138,564**	**87,178**	**-**	**225,742**

**Translated from CAD to USD - See the accompanying notes to the Unaudited Condensed Pro Forma Operating Statement*

Basis of Presentation

The accompanying Unaudited Condensed Pro Forma Operating Statement of IPC (the "Company") for the year ended December 31, 2017 has been prepared by management of the Company for illustrative purposes only and gives effect to the Company's acquisition (the "Acquisition") of certain oil and gas properties ("The Suffield Assets") in Canada. The Unaudited Condensed Pro Forma Operating Statement has been prepared using International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, on a basis consistent with the Company's accounting policies.

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

- the audited consolidated financial statements of the Company as at and for the year ended December 31, 2017; and
- the audited operating statements for the Suffield Assets for the year ended December 31, 2017 and December 31, 2016.

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

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

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

The Unaudited Condensed Pro Forma Operating Statement is prepared in accordance with the International Financial Reporting Standards ("IFRS") as applied by IPC.

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

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

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

The Unaudited Condensed Pro Forma Operating Statement does not include any provision for depletion, depreciation and amortization, general, administration and depreciation expenses, share-based compensation, asset retirement obligation accretion, interest and other financing expense, or income taxes.

SCHEDULE B

Operating Statements of the Suffield Assets

February 23, 2018

Independent Auditor's Report

To the Directors of Cenovus Energy Inc.

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

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

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

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

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

PricewaterhouseCoopers LLP
111 5 Avenue SW, Suite 3100, Calgary, Alberta, Canada T2P 5L3
T: +1 403 509 7500, F: +1 403 781 1825, www.pwc.com/ca

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

PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, Alberta

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

($ Canadian thousands)

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

See accompanying Notes to Operating Statements

Suffield Assets

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

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

1. Basis of presentation

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

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

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

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

2. Significant accounting policies

(A) Joint Operations

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

(B) Revenue Recognition

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

(C) Royalties

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

(D) Transportation and Blending

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

(E) Operating Expenses

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

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

(F) Use of Estimates

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

3. Commitments and contingencies

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

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

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

International Petroleum Corp

Corporate Office:
Suite 2000
885 West Georgia Street
Vancouver, BC V6C 3E8
Canada
Tel. +1 604 689 7842
E-mail : info@international-petroleum.com
Web : www.international-petroleum.com