International Petroleum Corp.

Operations and Financial Update
Second Quarter 2019

Mike Nicholson, CEO
Christophe Nerguararian, CFO
August 6, 2019
International Petroleum Corp.

Corporate Strategy

- Deliver operational excellence
- Maintain financial resilience
- Maximize the value of our resource base
- Grow through M&A
# Q2 2019 Highlights

| **Production Guidance** | - Q2 production at **46,100** boepd  
- Expect to be toward lower end of **46,000 to 50,000** boepd full year guidance  
- 2019 forecast exit rate **>50,000** boepd |
|--------------------------|-------------------------------------------------------------------------------------------------------------------------------------|
| **Operating Costs**(1)   | - Q2 operating costs of **12.6** USD/boe; ahead of guidance  
- Full year guidance of 12.9 USD/boe retained |
| **Organic Growth**       | - Capital expenditure guidance retained at **188** MUSD  
- Drilling operations ongoing in Canada, France & Malaysia |
| **Operating Cash Flow**(1) | - Strong cash flow generation  
- Full year 2019 OCF forecast of **163 to 330** MUSD  
- 1H OCF of **160** MUSD, **48%** of high end guidance at **70** USD/bbl Brent (Brent avg 66 USD/bbl) |
| **Liquidity**            | - Capital programme remains fully funded from cash flow |
| **Resource Base**(2)     | - **>2x** increase to 288 MMboe; >1.3 billion boe 2P+2C; 16 yr RLI |
| **Shareholder Value**(2)  | - **37%** increase in NAV per share to **12.40** USD, IPC trading at **68%** discount |
| **Business Development** | - Opportunistic approach to further acquisitions |
| **HSE**                  | - No material incidents |

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(1) Non-IFRS measure, see MD&A  
(2) As at December 31, 2018, see Reader Advisory and MD&A
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Production Growth

- Expect full year production toward lower end of 46,000 to 50,000 boepd range
- Onion Lake delayed ramp up -> lower end of guidance range for Q3
- Q4 ramp up with Malaysia infills, France and Onion Lake F-Pad
- Exit rate of 50,000 boepd retained
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2019 Production - Q2 Performance

- Q2 production ~1,400 boepd (3%) below mid-point guidance
- Most assets in line with Q2 guidance
- **Canada - Onion Lake Thermal**
  - Delayed ramp up due to water intake rates (abnormally cold weather)
  - Start-up of new F-Pad production platform rescheduled to Q4 2019
- **France - Paris Basin - Grandpuits refinery**
  - Total refinery shutdown from March to July
  - Full expedition and production restarted in July
  - Alternative export solutions utilised to minimise Q2 impact
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2019 Capital Programme - International

- **2019 Malaysia drilling programme commenced in Q2**
  - 3 well infill campaign on track for 2019 start-up
  - 2 appraisal pilots completed -> results favour A20 over A14 location
  - Keruing exploration well completed in early August
    - Good quality reservoir at target depth
    - Water bearing

- **VGR well VGR113 drilling in France**
  - On track for a Q3 start-up
  - Reservoir properties in line with expectations
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2019 Capital Programme - Canada

- **Suffield**
  - Oil drilling ahead of expectations
  - Accelerated N2N enhanced oil recovery (EOR) project on track for a Q4 start-up
  - Enhanced gas optimisation programme with 50 recompletions and ~5,000 swabs to date

- **Onion Lake Thermal Water Intake Enhancements**
  - 2 direct intake hoses and facilities installed
  - Produced water recycle skid installed and commissioning ongoing

- **Blackrod project**
  - Third well pair drilling commenced early July 2019
  - Full field development optimisation ongoing
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Operating Cash Flow (MUSD)\(^{(1)}\)

\(^{(1)}\) Non-IFRS measure, See MD&A

\(^{2}\) Including OCF related to Netherlands assets disposed in December 2018

\(^{3}\) At mid-point of 2019 production guidance
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Net Asset Value (MUSD)\(^{(1)}\)

<table>
<thead>
<tr>
<th>Year</th>
<th>Net Debt(^{(2)})</th>
<th>NAV(^{(1)})</th>
<th>IPCO Market Cap(^{(3)})</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>543</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2018</td>
<td>1,151</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2019</td>
<td>2,314</td>
<td>526</td>
<td>645</td>
</tr>
</tbody>
</table>

With YE 2017 Pricing

- 68% discount to NAV

1) As at December 31, 2018, see Reader Advisory and MD&A
2) Non-IFRS measure, see MD&A
3) Based on the price of IPC shares as at August 5\(^{th}\), 2019, converted to USD (SEK 37.80; SEK/USD 9.61)
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Net Asset Value Per Share vs Share Price\(^{(1)}\)

\(\text{USD per share} \begin{array}{cccccccccccccc}
\text{May} & \text{Jun} & \text{Jul} & \text{Aug} & \text{Sep} & \text{Oct} & \text{Nov} & \text{Dec} \\
10 & 11 & 12 & 13 & 14 & 9 & 8 & 7 & 6 & 5 & 4 & 3 & 2 & 1 & 0
\end{array}\)

\(\text{USD per share} \begin{array}{cccccccccccccc}
\text{2017} & \text{2018} & \text{2019} \\
01/01/17 & 01/01/18 & 01/01/19 \\
USD 4.8 & USD 9.1 & USD 12.4
\end{array}\)

\(\text{~68% discount to NAV}\)

\(\text{~26% discount to NAV}\)

\(\text{1) As at December 31, 2018, see Reader Advisory and MD&A}\)
Second Quarter 2019
Financial Highlights
## First Six Months 2019

### Financial Highlights

<table>
<thead>
<tr>
<th></th>
<th>Second Quarter 2019</th>
<th>First Six Months 2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production (boepd)</td>
<td>46,100</td>
<td>45,200</td>
</tr>
<tr>
<td>Average Dated Brent Oil Price (USD/boe)</td>
<td>68.9</td>
<td>66.0</td>
</tr>
<tr>
<td>Operating costs (USD/boe) ((^{(1)}))</td>
<td>12.6</td>
<td>12.9</td>
</tr>
<tr>
<td>Operating cash flow (MUSD) ((^{(1)}))</td>
<td>76.5</td>
<td>159.6</td>
</tr>
<tr>
<td>EBITDA (MUSD) (^{(1)})</td>
<td>74.6</td>
<td>156.3</td>
</tr>
<tr>
<td>Net result (MUSD)</td>
<td>25.7</td>
<td>58.9</td>
</tr>
</tbody>
</table>

\(^{(1)}\) Non-IFRS Measures, see MD&A
Second Quarter 2019
Realised Oil Prices

<table>
<thead>
<tr>
<th>Country</th>
<th>2018</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Malaysia</td>
<td>76.20</td>
<td>73.42</td>
</tr>
<tr>
<td>France</td>
<td>45.85</td>
<td>68.28</td>
</tr>
<tr>
<td>Suffield</td>
<td>37.20</td>
<td>51.44</td>
</tr>
<tr>
<td>Onion Lake</td>
<td>21.30</td>
<td>42.37</td>
</tr>
</tbody>
</table>

Brent Spot
WTI Spot
WTI - 10 days differential (month -1)
Second Quarter 2019
Realised Gas Prices

<table>
<thead>
<tr>
<th>Month</th>
<th>Realised Price CAD/Mcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan</td>
<td>2.70</td>
</tr>
<tr>
<td>Feb</td>
<td>2.11</td>
</tr>
<tr>
<td>Mar</td>
<td>2.29</td>
</tr>
<tr>
<td>Apr</td>
<td>3.07</td>
</tr>
<tr>
<td>May</td>
<td>3.86</td>
</tr>
<tr>
<td>Jun</td>
<td>2.43</td>
</tr>
</tbody>
</table>

- **Empress / AECO differential**
- **AECO Day Ahead Index**

![Chart showing realised gas prices for the second quarter of 2019 with specific values for each month from January to July.](chart.png)
First Six Months 2019

Financial Results – Operating Cash Flow\(^{(1)}\) and EBITDA\(^{(1)}\)

\(^{(1)}\) Non-IFRS Measures, see MD&A
First Six Months 2019

Operating Costs (1)

USD/boe

Q1 2019 Actual
Q2 2019 Actual
Q3 2019 Forecast
Q4 2019 Forecast

12.9 USD/boe guidance unchanged

(1) Non-IFRS Measure, see MD&A
### First Six Months 2019

**Netback**\(^{(1)}\) (USD/boe)

<table>
<thead>
<tr>
<th></th>
<th>Second Quarter 2019</th>
<th>First Six Months 2019</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Average Dated Brent oil price</strong></td>
<td>(68.9 USD/bbl)</td>
<td>(66.0 USD/bbl)</td>
</tr>
<tr>
<td><strong>Revenue</strong></td>
<td>30.8</td>
<td>33.8</td>
</tr>
<tr>
<td><strong>Cost of operations</strong></td>
<td>-10.7</td>
<td>-11.0</td>
</tr>
<tr>
<td><strong>Tariff and transportation</strong></td>
<td>-1.5</td>
<td>-1.5</td>
</tr>
<tr>
<td><strong>Production taxes</strong></td>
<td>-0.4</td>
<td>-0.4</td>
</tr>
<tr>
<td><strong>Operating costs</strong>(^{(2)})</td>
<td>-12.6</td>
<td>-12.9</td>
</tr>
<tr>
<td><strong>Cost of blending</strong></td>
<td>-1.5</td>
<td>-1.4</td>
</tr>
<tr>
<td><strong>Inventory movements</strong></td>
<td>1.6</td>
<td>0.3</td>
</tr>
<tr>
<td><strong>Revenue – production costs</strong></td>
<td>18.3</td>
<td>19.8</td>
</tr>
<tr>
<td><strong>Cash taxes</strong></td>
<td>-0.1</td>
<td>-0.3</td>
</tr>
<tr>
<td><strong>Operating cash flow</strong>(^{(2)})</td>
<td>18.2</td>
<td>19.5</td>
</tr>
<tr>
<td><strong>General and administration costs(^{(3)})</strong></td>
<td>-0.6</td>
<td>-0.7</td>
</tr>
<tr>
<td><strong>EBITDA</strong>(^{2})</td>
<td>17.7</td>
<td>19.1</td>
</tr>
</tbody>
</table>

\(^{(1)}\) Based on production volumes

\(^{(2)}\) Non-IFRS Measures, see MD&A

\(^{(3)}\) Adjusted for depreciation
First Six Months 2019

Net Debt\(^{(1)}\)

Opening Net Debt
1 Jan 2019
MUSD -276.8

Closing Net Debt
30 Jun 2019
MUSD -239.3

Operating Cash Flow
MUSD 159.6

Development
MUSD -47.5

Exploration & evaluation
MUSD -13.9

G&A
MUSD -5.3

LUPE working capital repayment
MUSD -14.2

Financial
MUSD -12.5

Working capital & other
MUSD -28.7

\(^{(1)}\) Non-IFRS Measures, see MD&A
<table>
<thead>
<tr>
<th></th>
<th>MUSD</th>
<th>Second Quarter 2019</th>
<th>First Six Months 2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>G&amp;A</td>
<td>2.3</td>
<td>5.3</td>
<td></td>
</tr>
<tr>
<td>G&amp;A – Depreciation</td>
<td>0.4</td>
<td>0.7</td>
<td></td>
</tr>
<tr>
<td><strong>G&amp;A Expense</strong></td>
<td><strong>2.7</strong></td>
<td><strong>6.0</strong></td>
<td></td>
</tr>
<tr>
<td>Interest expense</td>
<td>7.3</td>
<td>11.6</td>
<td></td>
</tr>
<tr>
<td>Loan facility commitment fees</td>
<td>0.4</td>
<td>0.8</td>
<td></td>
</tr>
<tr>
<td>Amortisation of loan fees</td>
<td>0.6</td>
<td>1.2</td>
<td></td>
</tr>
<tr>
<td>Foreign exchange loss (gain), net(^{(1)})</td>
<td>-5.0</td>
<td>-8.9</td>
<td></td>
</tr>
<tr>
<td>Unwinding of asset retirement obligation</td>
<td>2.6</td>
<td>5.3</td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>0.2</td>
<td>0.2</td>
<td></td>
</tr>
<tr>
<td><strong>Net Finance Costs</strong></td>
<td><strong>6.1</strong></td>
<td><strong>10.2</strong></td>
<td></td>
</tr>
</tbody>
</table>

\(^{(1)}\) Mainly non-cash, driven by the revaluation of intra-group loans
First Six Months 2019

Financial Results

- Revenue: MUSD 276.8, 45,200 boepd
- Production costs: MUSD 115.2, Operating costs 12.9 USD/boe
- Depletion: MUSD 75.1
- Exploration and business development costs: MUSD 0.3
- G&A: MUSD 6.0
- Financial Items: MUSD 10.2
- Tax: MUSD 11.1
- Net result: MUSD 58.9

Cash Margin: MUSD 161.6

Gross profit: MUSD 86.2
First Six Months 2019

Balance Sheet

<table>
<thead>
<tr>
<th></th>
<th>MUSD</th>
<th>30 Jun 2019</th>
<th>31 Dec 2018</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Assets</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil and gas properties</td>
<td>1,062.0</td>
<td>1,014.8</td>
<td></td>
</tr>
<tr>
<td>Other non-current assets</td>
<td>169.1</td>
<td>185.2</td>
<td></td>
</tr>
<tr>
<td>Current assets</td>
<td>103.7</td>
<td>98.9</td>
<td></td>
</tr>
<tr>
<td><strong>Total Assets</strong></td>
<td>1,334.8</td>
<td>1,298.9</td>
<td></td>
</tr>
<tr>
<td><strong>Liabilities</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Financial liabilities</td>
<td>245.5</td>
<td>283.7</td>
<td></td>
</tr>
<tr>
<td>Provisions</td>
<td>177.0</td>
<td>167.3</td>
<td></td>
</tr>
<tr>
<td>Other non-current liabilities</td>
<td>59.2</td>
<td>55.8</td>
<td></td>
</tr>
<tr>
<td>Current liabilities</td>
<td>86.0</td>
<td>96.3</td>
<td></td>
</tr>
<tr>
<td>Equity</td>
<td>767.1</td>
<td>695.8</td>
<td></td>
</tr>
<tr>
<td><strong>Total Liabilities</strong></td>
<td>1,334.8</td>
<td>1,298.9</td>
<td></td>
</tr>
</tbody>
</table>
First Six Months 2019
Hedging and Liquidity

- **Credit Facilities**
  - Two revolving credit facilities: International (200 MUSD) and Canadian (375 MCAD)
  - IPC amalgamated the two Canadian credit facilities into a single facility in Q2
  - Second lien notes repaid (75 MCAD) in June 2019
  - Lower cost of debt going forward

- **Hedging**

<table>
<thead>
<tr>
<th></th>
<th>bbl/d</th>
<th>Floor (WTI in USD)</th>
<th>Cap (WTI in USD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q3 2019</td>
<td>7,500</td>
<td>50.00</td>
<td>72.88</td>
</tr>
<tr>
<td>Q4 2019</td>
<td>3,000</td>
<td>49.45</td>
<td>68.15</td>
</tr>
<tr>
<td>Q1 2020</td>
<td>3,500</td>
<td>50.00</td>
<td>77.50</td>
</tr>
<tr>
<td>Q2 2020</td>
<td>6,150</td>
<td>35.00</td>
<td>71.74</td>
</tr>
</tbody>
</table>

- No further hedging obligations following the refinancing of the Canadian financing facilities
## International Petroleum Corp.  
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| Resource Base<sup>(2)</sup> | - **>2x** increase to 288 MMboe; >1.3 billion boe 2P+2C; 16 yr RLI  
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| Business Development | - Opportunistic approach to further acquisitions  
| HSE | - No material incidents  

<sup>(1)</sup> Non-IFRS measure, see MD&A  
<sup>(2)</sup> As at December 31, 2018, see Reader Advisory and MD&A
Disclosure of Oil and Gas Information

This presentation contains references to estimates of 2P reserves and resources attributed to the Corporation's oil and gas assets. Gross reserves/resources are the total working interest (operating or non-operating) share reserves before the deduction of any royalties and without including any royalty interests receivable.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in the Saffield area of Canada are effective as of December 31, 2018, and are included in the report prepared by McDaniel & Associates Consultants Ltd. (McDaniel), 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 CEGE Handbook), and using McDaniel’s January 1, 2019, price forecasts.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC’s oil and gas assets in the Blackrod area of Canada are effective as of December 31, 2018, and are included in the report prepared by Sproule Associates Consultants Ltd. (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 CEGE Handbook, and using Sproule’s January 1, 2019, price forecasts.

Reserves estimates, contingent resource estimates, prospective 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, 2018, and are included in the report prepared by ERCO Equipe Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the CEGE Handbook, and using McDaniel’s January 1, 2019, price forecasts.

The contingent resource estimates in respect of the oil and gas assets acquired in May 2019, in the Blackrod area of Canada, are effective as of December 31, 2018, and are included in the report prepared by Sproule, in accordance with NI 51-101 and the CEGE Handbook. The lands acquired will be part of the planned SAGD development at Blackrod and have the same classification (Development on Hold) as the other Blackrod lands. The same change of development risk (77%) has been applied to the acquired lands as was used for Phase 2 and Phase 3 of the Blackrod project. These lands will be incorporated into the Phase 2 and Phase 3 development plan going forward. Additional details regarding the planned development at Blackrod, including an assessment of the contingencies, timing and economics for the proposed development, are available in the AIF.

Non-IFRS Measures

References are made in this press release 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. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS.

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. Management also uses non-IFRS measures internally in order to facilitate operating performance comparisons from period to period, to prepare annual operating budgets and assess the Corporation’s ability to meet its future capital expenditure and working capital requirements. Management believes these non-IFRS measures are important supplemental measures of operating performance because they highlight trends in the core business that may not otherwise be apparent when relying solely on IFRS financial measures. Management believes such measures allow for assessment of the Corporation’s operating performance and financial condition on a basis that is more consistent and comparable between reporting periods. The Corporation also believes that securities analysts, investors and other parties frequently use non-IFRS measures in the evaluation of issuers. The definition and reconciliation of each non-IFRS measure is presented in the Corporation’s MD&A (See “Non-IFRS Measures” therein).
The price forecasts used in the reserve reports are available on the website of McDaniel (www.mcdan.com), and are contained in the MCR.

The reserves life index (RLI) is calculated by dividing the 2P reserves of 288 MMboe as at December 31, 2018, by the mid-point of the initial 2019 production guidance of 48,000 to 50,000 boepd. The reserves replacement ratio is based on 2P reserves of 129.1 MMboe as at December 31, 2017 (including the 2P reserves attributable to the acquisition of the Suffield area assets which completed on January 5, 2018), production during 2018 of 12.4 MMboe, additions to 2P reserves during 2018 of 12.7 MMboe, disposals of 2P reserves related to the disposal of the Netherlands assets of 1.6 MMboe and 2P reserves of 128.0 MMboe as at December 31, 2018 (excluding the 2P reserves attributable to the acquisition of BlackPearl which completed on December 14, 2018).

“2P reserves” means IPC’s gross 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.

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 reserves described in the CGOE 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 either development on hold or development unclarified. Development on hold is defined as a contingent resource where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator. Development unclarified is defined as a contingent resource that requires further appraisal to clarify the potential for development and has been assigned a lower chance of development until contingencies can be clearly defined. Chance of development is the probability of a project being commercially viable.

References to “unrisked” contingent resources volumes means that the reported volumes of contingent resources have not been risked (or adjusted) based on the probability of commerciality of such resources. In accordance with the CGOE 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 this presentation 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 presentation.

2P reserves and contingent resources included in the reports of McDaniel, Sproule and ERCE have been aggregated in this presentation by IPC. Estimates of reserves, resources and future net revenue for individual properties may not reflect the same level of confidence as estimates of reserves, resources and future net revenue for all properties, due to aggregation. This presentation 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 presentation do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material.

References to “contingent resources” do not constitute, and should be distinguished from, references to “reserves”. References to "prospective resources” do not constitute, and should be distinguished from, references to "contingent resources” and "reserves”. This presentation includes oil and gas metrics including "cash margin netback", "taxation netback", "operating cash flow netback", "cash taxes", "EBITDA netback" and "profit netback". Such metrics do not have a standardized meaning under IFRS or otherwise, and as such may not be reliable. This information should not be used to make comparisons.

"Cash margin netback" is calculated on a per boe basis as oil and gas sales, less operating, tariff/transportation and production tax expenses. Netback is a common metric used in the oil and gas industry and is used by management to measure operating results on a per boe basis to better analyze performance against prior periods on a comparable basis.

"Taxation netback" is calculated on a per boe basis as current tax charge/credit less deferred tax charge/credit. Taxation netback is used to measure taxation on a per boe basis.

"Operating cash flow netback" is calculated as cash margin netback less cash taxes. Operating cash flow netback is used to measure operating results on a per boe basis of cash flow.

"Cash taxes" is calculated as taxes payable in cash, and not only for accounting purposes. Cash taxes is used to measure cash flow.

"EBITDA netback" is calculated as cash margin netback less general and administration expenses. EBITDA netback is used by management to measure operating results on a per boe basis.

"Profit netback" is calculated as cash margin netback less depletion/depreciation, general and administration expenses and financial items. Profit netback is used by management to measure operating results on a per boe basis.

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.

Currency
All dollar amounts in this presentation are expressed in United States dollars, except where otherwise noted. References herein to USD mean United States dollars. References herein to CAD mean Canadian dollars.