Operations and Financial Update
Second Quarter 2020

Mike Nicholson, CEO
Christophe Nerguararian, CFO
August 4, 2020
## International Petroleum Corp.
### Q2 2020 Highlights

| Production | - Q2 average net production of **35,700** boepd  
| - Commenced progressive increase of curtailed Canadian oil production  
| - Revising full year guidance upwards to **37,000** to **40,000** boepd [Previously **30,000** to **37,000** boepd] |
| Operating Costs | - Q2 opex per bbl USD **10.7**  
| - Full year USD **12** to **13** per bbl [unchanged] |
| Capex & Decommissioning | - Marginal increase of MUSD **3** to MUSD **80** for the full year |
| Liquidity | - International and Canadian RBL refinancings completed and new French facility secured  
| - Q2 OCF of MUSD **14.7**  
| - Free cash flow **neutral** in Q2 2020  
| - Net debt increased from MUSD **302.5** to **341.4** (exchange rate and working capital movements) |
| Hedging | - Additional Canadian oil hedges put in place  
| - Average WCS price of **28** USD/bbl for Q3 (67% forecast Canadian production)  
| - Average WCS price of **25** USD/bbl for Q4 (50% forecast Canadian production) |
| Financial Headroom | - Forecast financial headroom of MUSD **>100** by year end  
| - Assumes **35** USD/bbl Brent and **22** USD/bbl WCS for the second half of 2020  
| - Significant improvement from Q1 guidance (up to 40% draw down) |
| ESG | - **No** material incidents to report / COVID protection measures in place / 2020 Carbon offset project secured |

1) See Reader Advisory and MD&A  
2) Non-IFRS measure, see MD&A
International Petroleum Corp.

2020 Investment Strategy - Q2 Update\(^{(1)}\)

**CAPEX & Decommissioning**

- Marginal increase of MUSD 3
  - Onion Lake Thermal D’ drilling completion
  - Progressive increase of Suffield N2N production
  - Minor capital activities across various assets

**OPEX**

- No change to Q1 OPEX guidance
- Progressive production increases at major oil assets in Canada

\(^{(1)}\) See Reader Advisory. Non-IFRS measures, see MD&A. Reductions are as compared to 2020 CMD estimates.
International Petroleum Corp.  
Production - Q2 Update

Q1 Results
- 2020 guidance of 30,000 to 37,000 boepd\(^{(1)}\)
  - Low side: Canada oil fully curtailed
  - High side: Canada oil partially curtailed 2H 2020

Q2 Results
- 2020 guidance increased to 37,000 to 40,000 boepd\(^{(1)}\)
  - Significant improvement in Canadian oil prices
  - Increasing production at Suffield oil and Onion Lake Thermal assets
  - Paired with additional WCS hedges put in place
  - France back to pre curtailment levels: Grandpuits refinery restart

Capital Projects
- Production growth from capital projects remains on hold

\(^{(1)}\) See Reader Advisory.
International Petroleum Corp.
2020 Production – Year to Date

- Q2 2020 production of 35,700 boepd
  - Canada
    - Q2 production impacted by voluntary curtailments
    - Production increases through Q3 2020
  - International
    - Paris Basin impacted by temporary Grandpuits refinery outage
    - Production back to full rates in June
International Petroleum Corp.
Maximising Liquidity Headroom\(^{(1)}\)

- **RBL facilities**
  - International facility increased from 125 to 140 MUSD; maturity extended to December 2024
  - Canadian facility refinanced to 350 MCAD; maturity extended to May 2022
  - No leverage covenants
  - French 13 MEUR facility secured
  - Net increase of ~10 MUSD in available financial flexibility

- **Hedging update**
  - Additional oil hedges for second half executed in Canada
    - 67% of forecast Q3 production hedged at average 28 USD/bbl WCS
    - 50% of forecast Q4 production hedged at average 25 USD/bbl WCS

- **Significant improvement in 2020 funding requirement**

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**Q1 Liquidity Forecast**

<table>
<thead>
<tr>
<th>Funding requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brent: 25 USD/bbl</td>
</tr>
<tr>
<td>WCS: 0 USD/bbl</td>
</tr>
</tbody>
</table>

MUSD

- Headroom for remainder of 2020: >100
- Headroom end Q2: 90
- FCF positive 2H 2020: 35 USD/bbl
- WCS: 22 USD/bbl

**Q2 Liquidity Forecast**

- Headroom for remainder of 2020: >100

\(^{(1)}\) See Reader Advisory and MD&A
IPC Canada
Suffield Asset(1)

- Continued optimisation of Suffield gas production
- Progressive ramp up of production at Suffield oil 2H 2020
- 2020 development activity on hold due to low pricing in Q1/Q2 2020
- Mature and high grade 2021 organic growth programme for both oil and gas assets

<table>
<thead>
<tr>
<th>Canada Suffield Gas Production</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production (Mscf/d)</td>
</tr>
<tr>
<td>Jan</td>
</tr>
<tr>
<td>80,000</td>
</tr>
</tbody>
</table>

| Winter freeze-offs |

<table>
<thead>
<tr>
<th>Canada Suffield Oil Production</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production (boepd)</td>
</tr>
<tr>
<td>2016</td>
</tr>
<tr>
<td>8,000</td>
</tr>
</tbody>
</table>

1) See Reader Advisory.
IPC Canada
Onion Lake Thermal

- Facility upgrades completed in 2019
- F Pad online, field production ~ 12,000 bopd capacity
- Progressive production ramp up 2H 2020 with improved WCS pricing
- D’ pad drilling in 2020 -> positioned for 2021 start-up
- No reservoir impact due to production curtailment

1) See Reader Advisory.
IPC Malaysia
Operations Update\(^{(1)}\)

- A15 activity suspended in 2020, side track planned for 2021
- Maturing additional production opportunities
  - Additional drilling target identification and maturation
  - Base well rate optimisation

Bertam Field Gross Production

- **A15 potential**
- **Phase 3 infill**
- **Phase 2 infill**
- **Phase 1 infill (A15)**
- **Base**

\(^{(1)}\) See Reader Advisory.
IPC France
Operations Update\(^{(1)}\)

- All development activity on hold due to low pricing environment in 2020
- Production increased to pre-curtailment rates post Grandpuits refinery outage
- Proven track record of resource growth
- Horizontal wells unlock further potential

\(^{(1)}\) See Reader Advisory.
Second Quarter 2020
Financial Highlights
First Six Months 2020
Financial Highlights

<table>
<thead>
<tr>
<th></th>
<th>Second Quarter 2020</th>
<th>First Six Months 2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production (boepd)</td>
<td>35,700</td>
<td>40,900</td>
</tr>
<tr>
<td>Average Dated Brent Oil Price (USD/boe)</td>
<td>29.6</td>
<td>40.1</td>
</tr>
<tr>
<td>Operating costs (USD/boe) (¹)</td>
<td>10.7</td>
<td>11.7</td>
</tr>
<tr>
<td>Operating cash flow (MUSD) (¹)</td>
<td>14.7</td>
<td>36.2</td>
</tr>
<tr>
<td>EBITDA (MUSD) (¹)</td>
<td>12.2</td>
<td>31.2</td>
</tr>
<tr>
<td>Net result (MUSD)</td>
<td>-1.5</td>
<td>-41.5</td>
</tr>
</tbody>
</table>

(¹) Non-IFRS Measure, see MD&A
# First Six Months 2020

## Realised Oil Prices

<table>
<thead>
<tr>
<th></th>
<th>Q2 2020</th>
<th>Q1 2020</th>
<th>Full Year 2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brent</td>
<td>29.6</td>
<td>50.1</td>
<td>64.2</td>
</tr>
<tr>
<td>Malaysia</td>
<td>31.6 (+2.0)</td>
<td>48.9 (-1.2)</td>
<td>69.9 (+5.7)</td>
</tr>
<tr>
<td>France</td>
<td>24.1 (-5.5)</td>
<td>33.6 (-16.5)</td>
<td>63.5 (-0.7)</td>
</tr>
<tr>
<td>WTI</td>
<td>28.3</td>
<td>46.1</td>
<td>57.0</td>
</tr>
<tr>
<td>WCS (calculated)</td>
<td>16.9</td>
<td>25.5</td>
<td>44.2</td>
</tr>
<tr>
<td>Suffield</td>
<td>13.3 (-3.6)</td>
<td>27.0 (+1.5)</td>
<td>45.6 (+1.4)</td>
</tr>
<tr>
<td>Onion Lake</td>
<td>9.9 (-7.0)</td>
<td>18.6 (-6.9)</td>
<td>37.8 (-6.4)</td>
</tr>
</tbody>
</table>

- **Q2 2020:** Malaysia -> 2 cargoes were lifted in the quarter => 1 in April and 1 in June  
  France -> pricing is based on month + 1 and 1 Aquitaine cargo was lifted in April  
- **Q1 2020:** Malaysia -> 3 cargoes were lifted in the quarter => 1 in February and 2 in March  
  France -> pricing is based on month + 1
First Six Months 2020
Realised Gas Prices

<table>
<thead>
<tr>
<th></th>
<th>Q2 2020</th>
<th>Q1 2020</th>
<th>Full Year 2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>AECO</td>
<td>1.99</td>
<td>2.03</td>
<td>1.80</td>
</tr>
<tr>
<td>Empress</td>
<td>1.99</td>
<td>2.03</td>
<td>2.49</td>
</tr>
<tr>
<td>Realised</td>
<td>1.93 (-0.06)</td>
<td>2.28 (+0.25)</td>
<td>2.77 (+0.28)</td>
</tr>
</tbody>
</table>

- Realised Price CAD/Mcf
- Empress / AECO differential
- AECO Day Ahead Index
Second Quarter 2020

Financial Results – Operating Cash Flow & EBITDA (1)

Operating Cash Flow (1)  EBITDA (1)

<table>
<thead>
<tr>
<th>Quarter</th>
<th>2020</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q2</td>
<td>14.7</td>
<td>76.5</td>
</tr>
<tr>
<td>Q2</td>
<td>12.2</td>
<td>74.6</td>
</tr>
</tbody>
</table>

(1) Non-IFRS Measure, see MD&A
First Six Months 2020

Operating Costs (1)

2020 Operating Costs: 12-13 USD/boe guidance

USD/boe

Q1 2020 Actual
Q2 2020 Actual
Q3 2020 Forecast
Q4 2020 Forecast

(1) Non-IFRS Measure, see MD&A
## First Six Months 2020

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

<table>
<thead>
<tr>
<th></th>
<th>Second Quarter 2020</th>
<th>First Six Months 2020</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Average Dated Brent oil price</strong></td>
<td>(29.6 USD/bbl)</td>
<td>(40.1 USD/bbl)</td>
</tr>
<tr>
<td>Revenue</td>
<td>13.8</td>
<td>16.9</td>
</tr>
<tr>
<td>Cost of operations</td>
<td>-9.1</td>
<td>-10.0</td>
</tr>
<tr>
<td>Tariff and transportation</td>
<td>-1.3</td>
<td>-1.3</td>
</tr>
<tr>
<td>Production taxes</td>
<td>-0.3</td>
<td>-0.4</td>
</tr>
<tr>
<td>Operating costs(^{(2)})</td>
<td>-10.7</td>
<td>-11.7</td>
</tr>
<tr>
<td>Cost of blending</td>
<td>-0.6</td>
<td>-0.8</td>
</tr>
<tr>
<td>Inventory movements</td>
<td>2.1</td>
<td>0.5</td>
</tr>
<tr>
<td><strong>Revenue – production costs</strong></td>
<td><strong>4.6</strong></td>
<td><strong>4.9</strong></td>
</tr>
<tr>
<td>Cash taxes</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td><strong>Operating cash flow(^{(2)})</strong></td>
<td><strong>4.6</strong></td>
<td><strong>4.9</strong></td>
</tr>
<tr>
<td>General and administration costs(^{(3)})</td>
<td>-0.8</td>
<td>-0.7</td>
</tr>
<tr>
<td><strong>EBITDA(^{(2)})</strong></td>
<td><strong>3.8</strong></td>
<td><strong>4.2</strong></td>
</tr>
</tbody>
</table>

\(^{(1)}\) Based on production volumes  \(^{(2)}\) Non-IFRS Measure, see MD&A  \(^{(3)}\) Adjusted for depreciation
First Six Months 2020
Cash Flows and Closing Net Debt\(^{(1)}\) (MUSD)

Opening Net Debt
1 Jan 2020
MUSD -304.5\(^{(2)}\)

Closing Net Debt
30 Jun 2020
MUSD -341.4

Operating Cash Flow
MUSD 36.2

Development capex
MUSD -59.4

Exploration & evaluation
MUSD -3.2

G&A
MUSD -5.1

Fx on net debt
MUSD 10.4

Abandonment/
Farm in payments
MUSD -3.3

Change in
working capital & other
MUSD -3.5

Financial items
MUSD -9.0

\(^{(1)}\) Non-IFRS Measure, see MD&A

\(^{(2)}\) Opening net debt including Granite acquisition (55.4 MUSD) and share repurchase (17.6 MUSD)
## First Six Months 2020

### G&A / Financial Items

<table>
<thead>
<tr>
<th></th>
<th>MUSD</th>
<th>Q2 2020</th>
<th>First Six Months 2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>G&amp;A</td>
<td></td>
<td>2.7</td>
<td>5.1</td>
</tr>
<tr>
<td>G&amp;A – Depreciation</td>
<td></td>
<td>0.4</td>
<td>0.8</td>
</tr>
<tr>
<td><strong>G&amp;A Expense</strong></td>
<td></td>
<td>3.1</td>
<td>5.9</td>
</tr>
<tr>
<td>Interest expense</td>
<td></td>
<td>2.6</td>
<td>6.4</td>
</tr>
<tr>
<td>Loan facility commitment fees</td>
<td></td>
<td>0.2</td>
<td>0.5</td>
</tr>
<tr>
<td>Amortisation of loan fees</td>
<td></td>
<td>0.4</td>
<td>0.8</td>
</tr>
<tr>
<td>Foreign exchange loss (gain), net(^{(1)})</td>
<td></td>
<td>-12.4</td>
<td>9.5</td>
</tr>
<tr>
<td>Unwinding of asset retirement obligation</td>
<td></td>
<td>2.6</td>
<td>5.2</td>
</tr>
<tr>
<td>Other</td>
<td></td>
<td>0.2</td>
<td>0.4</td>
</tr>
<tr>
<td><strong>Net Financial Items</strong></td>
<td></td>
<td>-6.4</td>
<td>22.8</td>
</tr>
</tbody>
</table>

\(^{(1)}\) Mainly non-cash, driven by the revaluation of external and intra-group loans
First Six Months 2020

Financial Results

- Revenue: MUSD 125.4, 40,900 boepd
- Cash Margin: MUSD 36.2
- Production costs: MUSD -89.2, Operating costs (\textsuperscript{1}) 11.7 USD/boe
- Depletion: MUSD -59.6
- Exploration costs: MUSD -5.6
- G&A: MUSD -5.9
- Financial items: MUSD -22.7
- Tax: MUSD 16.1
- Net result: MUSD -41.5
- Gross result: MUSD -29.0

\textsuperscript{1} Non-IFRS Measure, see MD&A
## First Six Months 2020

### Balance Sheet

<table>
<thead>
<tr>
<th></th>
<th>MUSD</th>
<th>30 Jun 2020</th>
<th>31 Dec 2019</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>1,114.6</td>
<td>1,105.5</td>
<td></td>
</tr>
<tr>
<td>Other non-current assets</td>
<td>166.8</td>
<td>147.1</td>
<td></td>
</tr>
<tr>
<td>Current assets</td>
<td>75.9</td>
<td>112.0</td>
<td></td>
</tr>
<tr>
<td><strong>Total Assets</strong></td>
<td>1,357.3</td>
<td>1,364.6</td>
<td></td>
</tr>
<tr>
<td><strong>Liabilities</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Financial liabilities</td>
<td>319.8</td>
<td>244.7</td>
<td></td>
</tr>
<tr>
<td>Provisions</td>
<td>185.5</td>
<td>180.0</td>
<td></td>
</tr>
<tr>
<td>Other non-current liabilities</td>
<td>44.1</td>
<td>49.5</td>
<td></td>
</tr>
<tr>
<td>Current liabilities</td>
<td>95.4</td>
<td>99.6</td>
<td></td>
</tr>
<tr>
<td>Equity</td>
<td>712.5</td>
<td>790.8</td>
<td></td>
</tr>
<tr>
<td><strong>Total Liabilities</strong></td>
<td>1,357.3</td>
<td>1,364.6</td>
<td></td>
</tr>
</tbody>
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International Petroleum Corp.

Maximising Liquidity Headroom\(^{(1)}\)

- **RBL facilities**
  - International facility increased from 125 to 140 MUSD; maturity extended to December 2024
  - Canadian facility refinanced to 350 MCAD; maturity extended to May 2022
  - No leverage covenants
  - French 13 MEUR facility secured

  Net increase of ~10 MUSD in available financial flexibility

- **Hedging update**
  - Additional oil hedges for second half executed in Canada
    - 67% of forecast Q3 production hedged at average 28 USD/bbl WCS
    - 50% of forecast Q4 production hedged at average 25 USD/bbl WCS

- **Significant improvement in 2020 funding requirement**

### Q1 Liquidity Forecast

**Headroom for remainder of 2020**

- Funding requirement
  - Brent: 25 USD/bbl
  - WCS: 0 USD/bbl

**Q2 Liquidity Forecast**

**Headroom end Q2**

- 90 MUSD

**Headroom for remainder of 2020**

- FCF positive 2H 2020
  - Brent: 35 USD/bbl
  - WCS: 22 USD/bbl

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\(^{(1)}\) See Reader Advisory and MD&A
30 June 2020
Oil Hedging in Canada

Weighted average WCS price of 28 USD/bbl for Q3 (67% forecast Canadian production) and 25 USD/bbl for Q4 (50% forecast Canadian production)

<table>
<thead>
<tr>
<th>Period</th>
<th>Volumes per day</th>
<th>Type</th>
<th>Weighted average</th>
</tr>
</thead>
<tbody>
<tr>
<td>July 1, 2020 - September 30, 2020</td>
<td>700</td>
<td>SWAP</td>
<td>70.67</td>
</tr>
<tr>
<td>October 1, 2020 - December 31, 2020</td>
<td>350</td>
<td>SWAP</td>
<td>71.25</td>
</tr>
<tr>
<td>July 1, 2020 - July 31, 2020</td>
<td>6,600</td>
<td>SWAP</td>
<td>37.58</td>
</tr>
<tr>
<td>August 1, 2020 - August 31, 2020</td>
<td>8,700</td>
<td>SWAP</td>
<td>26.43</td>
</tr>
<tr>
<td>September 1, 2020 - September 30, 2020</td>
<td>9,200</td>
<td>SWAP</td>
<td>25.76</td>
</tr>
<tr>
<td>October 1, 2020 - December 31, 2020</td>
<td>7,550</td>
<td>SWAP</td>
<td>24.22</td>
</tr>
<tr>
<td>January 1, 2021 - March 31, 2021</td>
<td>200</td>
<td>SWAP</td>
<td>23.37</td>
</tr>
</tbody>
</table>

Oil hedges post 30 June 2020

<table>
<thead>
<tr>
<th>Period</th>
<th>Volumes per day</th>
<th>Type</th>
<th>Weighted average</th>
</tr>
</thead>
<tbody>
<tr>
<td>August 1, 2020 - August 31, 2020</td>
<td>600</td>
<td>SWAP</td>
<td>40.65</td>
</tr>
<tr>
<td>September 1, 2020 - September 30, 2020</td>
<td>700</td>
<td>SWAP</td>
<td>29.80</td>
</tr>
<tr>
<td>October 1, 2020 - December 31, 2020</td>
<td>500</td>
<td>SWAP</td>
<td>27.20</td>
</tr>
</tbody>
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### Operating Costs
- Q2 opex per bbl USD **10.7**
- Full year USD **12** to **13** per bbl [unchanged]

### Capex & Decommissioning
- Marginal increase of MUSD **3** to MUSD **80** for the full year

### Liquidity
- International and Canadian RBL refinancings completed and new French facility secured
- Q2 OCF of MUSD **14.7**
- Free cash flow neutral in Q2 2020
- Net debt increased from MUSD **302.5** to **341.4** (exchange rate and working capital movements)

### Hedging
- Additional Canadian oil hedges put in place
- Average WCS price of **28 USD/bbl** for Q3 (67% forecast Canadian production)
- Average WCS price of **25 USD/bbl** for Q4 (50% forecast Canadian production)

### Financial Headroom
- Forecast financial headroom of MUSD **>100** by year end
- Assumes **35 USD/bbl** Brent and **22 USD/bbl** WCS for the second half of 2020
- Significant improvement from Q1 guidance (up to 40% draw down)

### ESG
- No material incidents to report / COVID protection measures in place / 2020 Carbon offset project secured

---

1) See Reader Advisory and MD&A  
2) Non-IFRS measure, see MD&A
The Covid-19 virus and the restrictions and disruptions related to it, as well as the actions of certain oil and gas producing nations, had a drastic adverse effect in 2020 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, including the Corporation’s common shares. During Q2 2020, commodity prices improved although such prices are subject to change and there can be no assurance 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 presentation, 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 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 replacement; 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 globally; the availability and cost of financing, labor 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 associated with the oil and gas industry in general such as operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of estimates and projections relating to reserves, resources, production, revenues, costs and expenses; health, safety and environmental risks; commodity price fluctuations, including those experienced in 2020; exchange rate and 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.

Additional information on these and other factors that could affect IPC’s results, or its operations or financial position, is included in the Corporation’s unaudited interim consolidated condensed financial statements and management discussion and analysis for the six months ended June 30, 2020 (See “Cautionary Statement Regarding Forward-Looking Information”), the Corporation’s Annual Information Form (AIF) for the year ended December 31, 2019 (See “Cautionary Statement Regarding Forward-Looking Information”, “Reserves and Resources Advisory” and “Risk Factors”) 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).

The current and any future Covid-19 outbreaks may increase IPC’s exposure to, and magnitude of, each of the risks and uncertainties described above. If any of these events should occur, their severity, the actions taken to contain such outbreaks or treat their impact, and how quickly and to what extent 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 the first half of 2020. 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.

Non-IFRS Measures

References are made in this presentation to “operating cash flow” (OCF), “free cash flow” (FCF), “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 similar measures presented by other public companies. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS.
The Corporation uses non-IFRS measures to provide investors with supplemental measures to assess cash generated by the Corporation and its financial performance and condition. Management also utilizes non-IFRS measures internally in order to facilitate operating performance comparisons from period to period, prepare annual operating budgets and assess the Corporation's ability to meet its future capital expenditure and working capital requirements. Management believes these non-IFRS measures are important supplemental measures of operating performance because they highlight trends in the core business that may not otherwise be apparent when relying solely on IFRS financial measures. Management believes such measures allow for assessment of the Corporation's operating performance and financial condition on a basis that is more consistent and comparable between reporting periods. The Corporation also believes that securities analysts, investors and other interested parties frequently use non-IFRS measures in the evaluation of issuers. Forward-looking statements are provided for the purpose of presenting information about management’s current expectations and plans relating to the future and readers are cautioned that such statements may not be appropriate for other purposes.

The definition and reconciliation of each non-IFRS measure is presented in the Corporation’s MD&A (See “Non-IFRS Measures” therein). Actual results may differ materially from forward-looking estimates and forecasts. See “Forward-Looking Statements” above.

Disclosure of Oil and Gas Information

This presentation 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 (including oil and gas assets acquired in the acquisition of the Granite Acquisition) are effective as of December 31, 2019, and are included in reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) for the year ended December 31, 2019.

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

The price forecasts used in the Sproule and ERCE reports are available on the website of Sproule (sproule.com) and are contained in the AIF. These price forecasts are as at December 31, 2019, and may not be reflective of current and future forecast commodity prices.

“2P reserves” means proved plus probable reserves. “Proved reserves” are those reserves that can be estimated with a high degree of certainty. 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 into 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 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 reserve 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 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 contingent resource classification (proved, probable, probable) to which they are assigned. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated developed plus undeveloped reserves.

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 equal or exceed the best estimate. Probable methods are used, but 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 no defined development plan, 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 level of development until contingencies can be clearly defined. Contingent reserves that have not been assigned a level of development at the end of the reporting period are classified as “undeveloped reserves.”

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. References to “contingent resources” do not constitute, and should be distinguished from, references to “reserves.”
Reader Advisory

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

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.

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.

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.