Supplementary Information:
- to accompany 21-22 Jun-2016 Upstream investor presentation

The information below has been provided to enhance understanding of the terminology and performance measures that have been used in the accompanying presentations.

Resources and production

Total resources – Total resources are the estimated quantities of crude oil, condensate, natural gas liquids, bitumen and natural gas likely to be produced in the fullness of time from fields in which BP has current entitlement. The estimation, categorization and progression of total resources is founded on a discrete deterministic base case informed by interpretation and integration of the relevant data.

Total resources are divided into reserves and contingent resources and are evaluated using existing economic conditions.

Non-proved resources – that portion of our total resources that has not yet been categorized within our proved reserves.

Proved oil and gas reserves – Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:
  (A) The area identified by drilling and limited by fluid contacts, if any; and
  (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
  (A) Successful testing by a pilot project in an area of the reservoir with properties no more favourable than in the reservoir as a whole, the operation of an installed programme in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the

reasonable certainty of the engineering analysis on which the project or programme was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Production – Crude oil, condensate, natural gas liquids (NGLs), bitumen and natural gas produced by subsidiaries and equity-accounted entities. Converted to barrels of oil equivalent (boe) at 1 barrel of NGL = 1 boe and 5,800 standard cubic feet of natural gas = 1 boe.

Average reserves to production ratio (R/P) – The amount of a remaining reserves divided by the current rate of production of those reserves. The metric is typically represented in units of years, and is an indicator of the remaining life of the reserves.

Financial and operating measures

Cash costs – Non-GAAP measure. Cash costs are a subset of production and manufacturing expenses plus distribution and administration expenses and excludes costs that are classified as non-operating items. They represent the substantial majority of the remaining expenses in these line items but exclude certain costs that are variable, primarily with volumes (such as freight costs). Management believes that the presentation of cash costs is a performance measure that provides investors with useful information regarding the company's financial condition because it considers these expenses to be the principal operating and overhead expenses that are most directly under their control although they also include certain foreign exchange and commodity price effects.

<u>Development costs per barrel of oil equivalent (boe)</u> – Development costs per boe equals development costs divided by the expected ultimate recovery in boe. Development costs are costs incurred after a decision has been taken to develop a reservoir area, including the costs of: (a) drilling, equipping and testing development wells; (b) production platforms, downhole and wellhead equipment, pipelines, production and initial treatment and storage facilities and utility and waste disposal systems; and (c) improved recovery systems and equipment.

<u>Loss of primary containment (LOPC)</u> – LOPC is the number of unplanned or uncontrolled releases of oil, gas or other hazardous materials from a tank, vessel, pipe, railcar or other equipment used for containment or transfer.

<u>Net debt and net debt ratio (Gearing)</u> – Non-GAAP measures. Net debt is calculated as gross finance debt, as shown in the balance sheet, plus the fair value of associated derivative financial instruments that are used to hedge foreign currency exchange and interest rate risks relating to finance debt, for which hedge accounting is applied, less cash and cash equivalents. The net debt ratio is defined as the ratio of net debt to the total of net debt plus shareholders' equity. All components of equity are included in the denominator of the calculation. BP believes these measures provide useful information to investors. Net debt enables investors to see the economic effect of gross debt, related hedges and cash and cash equivalents in total. The net debt ratio enables investors to see how significant net debt is relative to equity from shareholders. The derivatives are reported on the balance sheet within the headings 'Derivative financial instruments'.

<u>Operating cash</u> – Net cash provided by (used in) operating activities as stated in the group cash flow statement. When used in the context of a segment rather than the group, the terms refer to the segment's share thereof, including an estimate of segment's share of group's income taxes paid.

<u>Operating cash margin</u> – Operating cash margin is operating cash divided by the applicable number of barrels of oil equivalent produced.

<u>Operating efficiency</u> – Operating efficiency (OE) is the amount of actual production expressed as a percentage of the installed production capacity (IPC). IPC is the agreed rate achievable (measured at the export end of the system) when the existing production system (reservoir, wells, plant and export) is operated at full rate with no planned or unplanned deferrals.

<u>Organic free cash flow</u> – Non-GAAP measure. Organic free cash flow is operating cash flow less organic capital expenditure. Organic free cash flow excludes any impacts from the Gulf of Mexico oil spill.

<u>Organic sources and uses of cash</u> – Non-GAAP measure. Organic sources of cash are net cash provided by operating activities, excluding the impact of Gulf of Mexico oil spill. Organic uses of cash are the cash flow effects of organic capital expenditure, dividends paid

as stated in the condensed group cash flow statement, and the value of shares issued as scrip dividends.

Plant reliability – Plant reliability is calculated taking 100% less the ratio of total unplanned plant deferrals divided by installed production capacity. Unplanned plant deferrals are associated with the topside plant and where applicable the subsea equipment (excluding wells and reservoir). Unplanned plant deferrals include breakdowns and weather

Post-tax operating cash per barrel of oil equivalent – See Operating cash margin above.

Production costs per barrel of oil equivalent (boe) – Non-GAAP measure. Production cost is a subset of production and manufacturing expenses. It includes the costs incurred to operate and maintain wells and related equipment and facilities, excluding ad valorem and severance taxes. Production cost per boe is calculated as production costs divided by production volumes in the relevant period.

Reported recordable injury frequency – The number of reported work-related employee and contractor incidents that result in a fatality or injury (apart from minor first aid cases) per 200,000 hours worked.

Tier 1 process safety events – Losses of primary containment from a process of greatest consequence – causing harm to a member of the workforce or costly damage to equipment or exceeding defined quantities.

Upstream free cash flow (proxy) – Non-GAAP measure. Upstream's free cash flow (proxy) is Upstream's underlying replacement cost profit before interest and tax, adding back Upstream's depreciation, depletion and amortization, and exploration write-offs, less Upstream's share of capital expenditure.