Supplementary Information – 4 March 2014 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.

Group Measures

Net debt (Gearing) – Ratio of net debt (finance debt, including the fair value of associated derivative financial instruments that are used to hedge foreign exchange and interest rate risks relating to finance debt, for which hedge accounting is claimed, less cash and cash equivalents) to net debt plus equity.

The table below presents BP's debt to debt plus equity ratio on a gross basis as net debt is not a recognized GAAP measure:

$million	2009	2010	2011	2012	2013
Gross debt	34,627	45,336	44,208	48,800	48,192
Less: Fair value asset (liability) of hedges related to finance debt	127	916	1,133	1,700	477
	34,500	44,420	43,075	47,100	47,715
Less: Cash and cash equivalents	8,339	18,556	14,177	19,635	22,520
Net debt	26,161	25,864	28,898	27,465	25,195
Equity	102,113	95,891	112,585	119,752	130,407
Gross debt to gross debt-plus-equity ratio	25.3%	32.1%	28.2%	29.0%	27.0%
Net debt to net debt-plus-equity ratio	20.4%	21.2%	20.4%	18.7%	16.2%

Cash costs – Cash costs are a subset of production and manufacturing expenses plus distribution and administration expenses. They represent the substantial majority of the expenses in these line items but exclude certain costs that are variable, primarily with volumes (such as freight costs). They are the principal operating and overhead costs that management considers to be most directly under their control although they include certain foreign exchange and commodity price effects.

Underlying cash costs – Underlying Cash costs are cash costs excluding any cash flows associated with non-operating items.

Operating cash flow – Operating cash flow is net cash provided by operating activities, as presented in the group cash flow statement.

Free cash flow – Free cash flow is net cash provided by operating activities less net cash used in investing activities..

Inorganic capital expenditure – (Inorganic Capex) is equal to acquisitions, asset exchanges and certain other inorganic capital expenditure. See page 18 of our fourth-quarter 2013 results announcement.

Organic capital expenditure – (Organic Capex) is equal to total capital expenditure and acquisitions less inorganic capital expenditure.

Upstream:

Production – Crude oil, condensate, natural gas liquids (NGLs) 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.

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.

Operating cash pre-tax per barrel of oil equivalent – Operating cash per barrel is net cash provided by operating activities by the Upstream segment, divided by the total number of barrels of oil equivalent produced. It excludes dividends and production for TNK-BP and Rosneft.

Operating cash margin – Operating cash margin is net cash provided by operating activities by the relevant projects in our Upstream segment, divided by the total number of barrels of oil equivalent produced for the relevant projects.

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.

Upstream operating efficiency – Operating efficiency is the actual production of an asset expressed as a percentage of the total achievable installed production capacity of the asset including the reservoir, well, plant and export systems.

Plant efficiency – Plant efficiency is the actual production of a plant facility expressed as a percentage of the total achievable installed production capacity of the asset including the reservoir, well, plant and export systems.

Downstream:

Operating cash pre-tax per barrel – This is the cash generated by operating activities for the Downstream segment before interest and tax, divided by the Downstream's total refining capacity.

Operating cash margin – The operating cash margin for the Downstream segment is the Net operating cash flow for the segment divided by the total refining capacity.

Refining availability – Refining availability represents Solomon Associates' operational availability, which is defined as the percentage of the year that a unit is available for processing after subtracting the annualized time lost due to turnaround activity and all planned mechanical, process and regulatory maintenance downtime.

Post tax operating cash flow – This is operating cash flow for the Downstream segment

Post tax free cash flow – This is free cash flow for the Downstream segment

Marketing Refining ratio (Marketing cover) – This is the ratio of the marketing sales volumes over the refining capacity.

Reinvestment ratio – Organic capital expenditure divided by net cash provided by operating activities.

Pretax underlying replacement cost profit – This is the segment underlying replacement cost profit before interest and tax.

Underlying Net Income per barrel – Downstream's underlying net income per barrel is calculated by taking Downstream's underlying replacement cost profit before interest and tax, deducting tax at the group effective tax rate on underlying replacement cost profit and then dividing this notional post tax underlying replacement cost profit by the Downstream segment's total refining capacity.

Underlying post-tax return on average capital employed (ROACE) for Downstream segment

- *Numerator* – Underlying replacement cost profit. The numerator is tax effected using the BP group effective tax rate on underlying replacement cost profit.
- *Denominator* – Annual average capital employed, which equals the average of the operating capital employed for the Downstream segment (excluding goodwill) on 1 January and 31 December of each year, including liabilities for current and deferred taxation allocated on the basis of the segment's relative percentage of the group's operating capital employed.

Downstream underlying replacement cost profit before interest and tax and ROACE

					$ million
	2009	**2010**	**2011**	**2012**	**2013**
Underlying replacement cost profit before interest and tax	3,607	4,883	6,009	6,463	3,632
Taxation*	(1,117)	(1,554)	(1,968)	(1,960)	(1,286)
Downstream underlying replacement cost profit after tax	**2,490**	**3,329**	**4,041**	**4,503**	**2,346**

Downstream ROACE					$million
Denominator for ROACE	**2009**	**2010**	**2011**	**2012**	**2013**
Operating Capital Employed (excluding goodwill)	46,501	48,422	51,084	50,323	49,515
Liabilities for current and deferred taxation**	(6,399)	(6,857)	(7,184)	(5,640)	(5,300)
Capital Employed for Downstream (excluding goodwill)	40,102	41,565	43,900	44,683	44,215
Average capital employed		**40,834**	**42,733**	**44,291**	**44,449**
Downstream Underlying ROACE		**8.2%**	**9.5%**	**10.2%**	**5.3%**

*BP does not present post-tax segment results. For the purposes of comparison with competitors, tax has been applied using the BP group effective tax rate on underlying replacement cost profit.

** Liabilities for current and deferred taxation have been allocated to Downstream on the basis of the segment's relative percentage share of the group's operating capital employed.

Group effective tax rate on underlying replacement cost profit	31%	32%	33%	30%	35%

Return on sales – This is calculated as pre-tax underlying replacement cost profit divided by third party sales and other operating revenues.