26. Financial instruments and financial risk factors

The accounting classification of each category of financial instruments, and their carrying amounts, are set out below.

At 31 December	Note	Loans and receivables	Available-for-sale financial assets	At fair value through profit or loss	Derivative hedging instruments	Financial liabilities measured at amortized cost	Total carrying amount
							$ million
							2011
Financial assets							
Other investments – equity shares	**27**	**–**	**1,128**	**–**	**–**	**–**	**1,128**
– other	**27**	**–**	**1,277**	**–**	**–**	**–**	**1,277**
Loans		**1,128**	**–**	**–**	**–**	**–**	**1,128**
Trade and other receivables	**29**	**36,879**	**–**	**–**	**–**	**–**	**36,879**
Derivative financial instruments	**33**	**–**	**–**	**7,188**	**1,707**	**–**	**8,895**
Cash and cash equivalents	**30**	**9,750**	**4,317**	**–**	**–**	**–**	**14,067**
Financial liabilities							
Trade and other payables	**32**	**–**	**–**	**–**	**–**	**(50,651)**	**(50,651)**
Derivative financial instruments	**33**	**–**	**–**	**(6,436)**	**(557)**	**–**	**(6,993)**
Accruals		**–**	**–**	**–**	**–**	**(6,321)**	**(6,321)**
Finance debt	**34**	**–**	**–**	**–**	**–**	**(44,183)**	**(44,183)**
		47,757	**6,722**	**752**	**1,150**	**(101,155)**	**(44,774)**

At 31 December	Note	Loans and receivables	Available-for-sale financial assets	At fair value through profit or loss	Derivative hedging instruments	Financial liabilities measured at amortized cost	Total carrying amount
							$ million
							2010
Financial assets							
Other investments – equity shares	27	–	1,191	–	–	–	1,191
– other	27	–	1,532	–	–	–	1,532
Loans		1,141	–	–	–	–	1,141
Trade and other receivables	29	32,380	–	–	–	–	32,380
Derivative financial instruments	33	–	–	7,222	1,344	–	8,566
Cash and cash equivalents	30	13,462	5,094	–	–	–	18,556
Financial liabilities							
Trade and other payables	32	–	–	–	–	(56,499)	(56,499)
Derivative financial instruments	33	–	–	(7,254)	(279)	–	(7,533)
Accruals		–	–	–	–	(6,249)	(6,249)
Finance debt	34	–	–	–	–	(39,139)	(39,139)
		46,983	7,817	(32)	1,065	(101,887)	(46,054)

The fair value of finance debt is shown in Note 34. For all other financial instruments, the carrying amount is either the fair value, or approximates the fair value.

Financial risk factors

The group is exposed to a number of different financial risks arising from natural business exposures as well as its use of financial instruments including: market risks relating to commodity prices, foreign currency exchange rates, interest rates and equity prices; credit risk; and liquidity risk.

The group financial risk committee (GFRC) advises the group chief financial officer (CFO) who oversees the management of these risks. The GFRC is chaired by the CFO and consists of a group of senior managers including the group treasurer and the heads of the group finance, tax and the integrated supply and trading functions. The purpose of the committee is to advise on financial risks and the appropriate financial risk governance framework for the group. The committee provides assurance to the CFO and the group chief executive (GCE), and via the GCE to the board, that the group’s financial risk-taking activity is governed by appropriate policies and procedures and that financial risks are identified, measured and managed in accordance with group policies and group risk appetite.

The group’s trading activities in the oil, natural gas and power markets are managed within the integrated supply and trading function, while the activities in the financial markets are managed by the integrated supply and trading function, on behalf of the treasury function. All derivative activity is carried out by specialist teams that have the appropriate skills, experience and supervision. These teams are subject to close financial and management control.

The integrated supply and trading function maintains formal governance processes that provide oversight of market risk associated with trading activity. These processes meet generally accepted industry practice and reflect the principles of the Group of Thirty Global Derivatives Study recommendations. A policy and risk committee monitors and validates limits and risk exposures, reviews incidents and validates risk-related policies, methodologies and procedures. A commitments committee approves value-at-risk delegations, the trading of new products, instruments and strategies and material commitments.

In addition, the integrated supply and trading function undertakes derivative activity for risk management purposes under a separate control framework as described more fully below.

26. Financial instruments and financial risk factors continued

(a) Market risk

Market risk is the risk or uncertainty arising from possible market price movements and their impact on the future performance of a business. The primary commodity price risks that the group is exposed to include oil, natural gas and power prices that could adversely affect the value of the group's financial assets, liabilities or expected future cash flows. The group enters into derivatives in a well-established entrepreneurial trading operation. In addition, the group has developed a control framework aimed at managing the volatility inherent in certain of its natural business exposures. In accordance with the control framework the group enters into various transactions using derivatives for risk management purposes.

The group measures market risk exposure arising from its trading positions using value-at-risk techniques. These techniques are based on Monte Carlo simulation and make a statistical assessment of the market risk arising from possible future changes in market prices over a one-day holding period. The calculation of the range of potential changes in fair value takes into account a snapshot of the end-of-day exposures and the history of one-day price movements, together with the correlation of these price movements. The value-at-risk measure is supplemented by stress testing.

The value-at-risk table does not incorporate any of the group's natural business exposures or any derivatives entered into to risk manage those exposures. Market risk exposure in respect of embedded derivatives is also not included in the value-at-risk table.

Value-at-risk limits are in place for each trading activity and for the group's trading activity in total. The board has delegated a limit of $100 million value at risk in support of this trading activity. The high and low values at risk indicated in the table below for each type of activity are independent of each other. Through the portfolio effect the high value at risk for the group as a whole is lower than the sum of the highs for the constituent parts. The potential movement in fair values is expressed to a 95% confidence interval. This means that, in statistical terms, one would expect to see a decrease in fair values greater than the trading value at risk on one occasion per month if the portfolio were left unchanged.

								$ million
Value at risk for 1 day at 95% confidence interval				**2011**				2010
	High	**Low**	**Average**	**Year end**	High	Low	Average	Year end
Group trading	**83**	**28**	**42**	**28**	70	15	34	33
Oil price trading	**84**	**23**	**39**	**27**	39	10	19	25
Gas and power trading	**20**	**6**	**11**	**7**	62	7	27	18

The major components of market risk are commodity price risk, foreign currency exchange risk, interest rate risk and equity price risk, each of which is discussed below.

(i) Commodity price risk

The group's integrated supply and trading function uses conventional financial and commodity instruments and physical cargoes available in the related commodity markets. Oil and natural gas swaps, options and futures are used to mitigate price risk. Power trading is undertaken using a combination of over-the-counter forward contracts and other derivative contracts, including options and futures. This activity is on both a standalone basis and in conjunction with gas derivatives in relation to gas-generated power margin. In addition, NGLs are traded around certain US inventory locations using over-the-counter forward contracts in conjunction with over-the-counter swaps, options and physical inventories. Trading value-at-risk information in relation to these activities is shown in the table above.

As described above, the group also carries out risk management of certain natural business exposures using over-the-counter swaps and exchange futures contracts. Together with certain physical supply contracts that are classified as derivatives, these contracts fall outside of the value-at-risk framework. For these derivative contracts the sensitivity of the net fair value to an immediate 10% increase or decrease in all reference prices would have been $23 million at 31 December 2011 (2010 $104 million). This figure does not include any corresponding economic benefit or disbenefit that would arise from the natural business exposure which would be expected to offset the gain or loss on the over-the-counter swaps and exchange futures contracts mentioned above.

In addition, the group has embedded derivatives relating to certain natural gas contracts. The net fair value of these contracts was a liability of $1,417 million at 31 December 2011 (2010 liability of $1,607 million). Key information on the natural gas contracts is given below.

At 31 December	**2011**	2010
Remaining contract terms	**3 years and 5 months to 6 years and 9 months**	4 years and 5 months to 7 years and 9 months
Contractual/notional amount	**952 million therms**	1,688 million therms

For these embedded derivatives the sensitivity of the net fair value to an immediate 10% favourable or adverse change in the key assumptions is as follows.

								$ million
At 31 December				**2011**				2010
	Gas price	**Oil price**	**Power price**	**Discount rate**	Gas price	Oil price	Power price	Discount rate
Favourable 10% change	**100**	**74**	**4**	**5**	145	48	10	10
Unfavourable 10% change	**(109)**	**(77)**	**(4)**	**(5)**	(180)	(68)	(10)	(10)

26. Financial instruments and financial risk factors continued

The sensitivities for risk management activity and embedded derivatives are hypothetical and should not be considered to be predictive of future performance. In addition, for the purposes of this analysis, in the above table, the effect of a variation in a particular assumption on the fair value of the embedded derivatives is calculated independently of any change in another assumption. In reality, changes in one factor may contribute to changes in another, which may magnify or counteract the sensitivities. Furthermore, the estimated fair values as disclosed should not be considered indicative of future earnings on these contracts.

(ii) Foreign currency exchange risk

Where the group enters into foreign currency exchange contracts for entrepreneurial trading purposes the activity is controlled using trading value-at-risk techniques as explained above. This activity is included within oil price trading in the value-at-risk table above.

Since BP has global operations, fluctuations in foreign currency exchange rates can have significant effects on the group's reported results. The effects of most exchange rate fluctuations are absorbed in business operating results through changing cost competitiveness, lags in market adjustment to movements in rates and translation differences accounted for on specific transactions. For this reason, the total effect of exchange rate fluctuations is not identifiable separately in the group's reported results. The main underlying economic currency of the group's cash flows is the US dollar. This is because BP's major product, oil, is priced internationally in US dollars. BP's foreign currency exchange management policy is to minimize economic and material transactional exposures arising from currency movements against the US dollar. The group co-ordinates the handling of foreign currency exchange risks centrally, by netting off naturally-occurring opposite exposures wherever possible, and then dealing with any material residual foreign currency exchange risks.

The group manages these exposures by constantly reviewing the foreign currency economic value at risk and aims to manage such risk to keep the 12-month foreign currency value at risk below $200 million. At 31 December 2011, the foreign currency value at risk was $100 million (2010 $81 million). At no point over the past three years did the value at risk exceed the maximum risk limit. The most significant exposures relate to capital expenditure commitments and other UK and European operational requirements, for which a hedging programme is in place and hedge accounting is claimed as outlined in Note 33.

For highly probable forecast capital expenditures the group locks in the US dollar cost of non-US dollar supplies by using currency forwards and futures. The main exposures are sterling, euro, Norwegian krone, Australian dollar and Korean won and at 31 December 2011 open contracts were in place for $1,242 million sterling, $158 million euro, $118 million Norwegian krone, $210 million Australian dollar and $230 million Korean won capital expenditures maturing within five years, with over 69% of the deals maturing within two years (2010 $989 million sterling, $115 million euro, $212 million Norwegian krone and $143 million Australian dollar capital expenditures maturing within five years, with over 80% of the deals maturing within two years).

For other UK, European and Australian operational requirements the group uses cylinders and currency forwards to hedge the estimated exposures on a 12-month rolling basis. At 31 December 2011, the open positions relating to cylinders consisted of receive sterling, pay US dollar, purchased call and sold put options (cylinders) for $2,683 million (2010 $1,340 million); receive euro, pay US dollar cylinders for $1,304 million (2010 $650 million); receive Australian dollar, pay US dollar cylinders for $312 million (2010 $286 million). At 31 December 2011 there were no open positions relating to currency forwards (2010 buy sterling, sell US dollar currency forwards for $925 million; buy euro, sell US dollar currency forwards for $630 million; buy Canadian dollar, sell US dollar currency forwards for $162 million).

In addition, most of the group's borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2011, the total foreign currency net borrowings not swapped into US dollars amounted to $371 million (2010 $278 million). Of this total, $129 million was denominated in currencies other than the functional currency of the individual operating unit being entirely Canadian dollars (2010 $125 million, being entirely Canadian dollars). It is estimated that a 10% change in the corresponding exchange rates would result in an exchange gain or loss in the income statement of $13 million (2010 $12 million).

(iii) Interest rate risk

Where the group enters into money market contracts for entrepreneurial trading purposes the activity is controlled using value-at-risk techniques as described above. This activity is included within oil price trading in the value-at-risk table above.

BP is also exposed to interest rate risk from the possibility that changes in interest rates will affect future cash flows or the fair values of its financial instruments, principally finance debt.

While the group issues debt in a variety of currencies based on market opportunities, it uses derivatives to swap the debt to a floating rate exposure, mainly to US dollar floating, but in certain defined circumstances maintains a US dollar fixed rate exposure for a proportion of debt. The proportion of floating rate debt net of interest rate swaps and excluding disposal deposits at 31 December 2011 was 65% of total finance debt outstanding (2010 62%). The weighted average interest rate on finance debt at 31 December 2011 is 2% (2010 2%) and the weighted average maturity of fixed rate debt is five years (2010 five years).

The group's earnings are sensitive to changes in interest rates on the floating rate element of the group's finance debt. If the interest rates applicable to floating rate instruments were to have increased by 1% on 1 January 2012, it is estimated that the group's profit before taxation for 2012 would decrease by approximately $289 million (2010 $241 million decrease in 2011). This assumes that the amount and mix of fixed and floating rate debt, including finance leases, remains unchanged from that in place at 31 December 2011 and that the change in interest rates is effective from the beginning of the year. Where the interest rate applicable to an instrument is reset during a quarter it is assumed that this occurs at the beginning of the quarter and remains unchanged for the rest of the year. In reality, the fixed/floating rate mix will fluctuate over the year and interest rates will change continually. Furthermore, the effect on earnings shown by this analysis does not consider the effect of any other changes in general economic activity that may accompany such an increase in interest rates.

(iv) Equity price risk

The group holds equity investments, typically made for strategic purposes, that are classified as non-current available-for-sale financial assets and are measured initially at fair value with changes in fair value recognized in other comprehensive income. Accumulated fair value changes are recycled to the income statement on disposal, or when the investment is impaired. No impairment losses have been recognized for the years presented relating to listed non-current available-for-sale investments. For further information see Note 27.

At 31 December 2011, it is estimated that an increase of 10% in quoted equity prices would result in an immediate credit to other comprehensive income of $87 million (2010 $95 million credit to other comprehensive income), while a decrease of 10% in quoted equity prices would result in an immediate charge to other comprehensive income of $87 million (2010 $95 million charge to other comprehensive income).

26. Financial instruments and financial risk factors continued

At 31 December 2011, 77% (2010 80%) of the carrying amount of non-current available-for-sale equity financial assets represented the group's stake in Rosneft, thus the group's exposure is concentrated on changes in the share price of this equity investment in particular.

(b) Credit risk

Credit risk is the risk that a customer or counterparty to a financial instrument will fail to perform or fail to pay amounts due causing financial loss to the group and arises from cash and cash equivalents, derivative financial instruments and deposits with financial institutions and principally from credit exposures to customers relating to outstanding receivables.

The group has a credit policy, approved by the CFO, that is designed to ensure that consistent processes are in place throughout the group to measure and control credit risk. Credit risk is considered as part of the risk-reward balance of doing business. On entering into any business contract the extent to which the arrangement exposes the group to credit risk is considered. Key requirements of the policy are formal delegated authorities to the sales and marketing teams to incur credit risk and to a specialized credit function to set counterparty limits; the establishment of credit systems and processes to ensure that counterparties are rated and limits set; and systems to monitor exposure against limits and report regularly on those exposures, and immediately on any excesses, and to track and report credit losses. The treasury function provides a similar credit risk management activity with respect to group-wide exposures to banks and other financial institutions.

The global credit environment exhibited deterioration in 2011, suffering not only from continuing economic and political uncertainties but also from key event risks, causing the group to further heighten awareness, discussion and co-ordination around the material credit risks arising from its activities.

Before trading with a new counterparty can start, its creditworthiness is assessed and a credit rating is allocated that indicates the probability of default, along with a credit exposure limit. The assessment process takes into account all available qualitative and quantitative information about the counterparty and the group, if any, to which the counterparty belongs. The counterparty's business activities, financial resources and business risk management processes are taken into account in the assessment, to the extent that this information is publicly available or otherwise disclosed to BP by the counterparty, together with external credit ratings. Creditworthiness continues to be evaluated after transactions have been initiated and a watchlist of higher-risk counterparties is maintained.

The group does not aim to remove credit risk but expects to experience a certain level of credit losses. The group attempts to mitigate credit risk by entering into contracts that permit netting and allow for termination of the contract on the occurrence of certain events of default. Depending on the creditworthiness of the counterparty, the group may require collateral or other credit enhancements such as cash deposits, letters of credit, trade credit insurance, liens, third-party guarantees and other forms of credit mitigation. Trade receivables and payables, and derivative assets and liabilities, are presented on a net basis where unconditional netting arrangements are in place with counterparties and where there is an intent to settle amounts due on a net basis. The maximum credit exposure associated with financial assets is equal to the carrying amount. Collateral received and recognized in the balance sheet at the year end was $273 million (2010 $313 million) and collateral held off balance sheet was $6 million (2010 $52 million). As at 31 December 2011, the group had in place other credit enhancements designed to mitigate approximately $8.6 billion of credit risk (2010 $7.0 billion). Credit exposure exists in relation to guarantees issued by group companies under which amounts outstanding at 31 December 2011 were $415 million (2010 $404 million) in respect of liabilities of jointly controlled entities and associates and $1,430 million (2010 $1,339 million) in respect of liabilities of other third parties.

Notwithstanding the processes described above, significant unexpected credit losses can occasionally occur. Exposure to unexpected losses increases with concentrations of credit risk that exist when a number of counterparties are involved in similar activities or operate in the same industry sector or geographical area, which may result in their ability to meet contractual obligations being impacted by changes in economic, political or other conditions. The group's principal customers, suppliers and financial institutions with which it conducts business are located throughout the world. In addition, these risks are managed by maintaining a group watchlist and aggregating multi-segment exposures to ensure that a material credit risk is not missed.

Reports are regularly prepared and presented to the GFRC that cover the group's overall credit exposure and expected loss trends, exposure by segment, and overall quality of the portfolio. The reports also include details of the largest counterparties by exposure level and expected loss, and details of counterparties on the group watchlist.

For the contracts comprising derivative financial instruments in an asset position at 31 December 2011, it is estimated that over 76% (2010 over 80%) of the unmitigated credit exposure is to counterparties of investment grade credit quality.

For cash and cash equivalents, the treasury function dynamically manages bank deposit limits to ensure cash is well-diversified and to reduce concentration risks. At 31 December 2011, 98% of the cash and cash equivalents balance was deposited with financial institutions rated at least A by Standard & Poor's and A2 by Moody's. Direct cash and cash equivalent exposures to Greek, Italian, Irish, Portuguese and Spanish financial institutions totalled less than 1% of total cash and cash equivalents.

Trade and other receivables of the group are analysed in the table below. By comparing the BP credit ratings to the equivalent external credit ratings, it is estimated that approximately 70-80% (2010 approximately 50-60%) of the unmitigated trade receivables portfolio exposure is of investment grade credit quality. With respect to the trade and other receivables that are neither impaired nor past due, there are no indications as of the reporting date that the debtors will not meet their payment obligations.

		$ million
Trade and other receivables at 31 December	**2011**	2010
Neither impaired nor past due	**34,563**	30,181
Impaired (net of valuation allowance)	**33**	67
Not impaired and past due in the following periods		
within 30 days	**1,263**	1,358
31 to 60 days	**250**	249
61 to 90 days	**132**	101
over 90 days	**638**	424
	36,879	32,380

26. Financial instruments and financial risk factors continued

The movement in the valuation allowance for trade receivables is set out below.

	2011	2010
		$ million
At 1 January	**428**	430
Exchange adjustments	**(16)**	(9)
Charge for the year	**115**	150
Utilization	**(124)**	(143)
Write-back	**(71)**	–
At 31 December	**332**	428

(c) Liquidity risk

Liquidity risk is the risk that suitable sources of funding for the group's business activities may not be available. The group's liquidity is managed centrally with operating units forecasting their cash and currency requirements to the central treasury function. Unless restricted by local regulations, subsidiaries pool their cash surpluses to treasury, which will then arrange to fund other subsidiaries' requirements, or invest any net surplus in the market or arrange for necessary external borrowings, while managing the group's overall net currency positions.

In managing its liquidity risk, the group has access to a wide range of funding at competitive rates through capital markets and banks. The group's treasury function centrally co-ordinates relationships with banks, borrowing requirements, foreign exchange requirements and cash management. The group believes it has access to sufficient funding through its own current cash holdings and future cash generation including disposal proceeds, the commercial paper markets and by using undrawn committed borrowing facilities to meet foreseeable liquidity requirements.

The group has in place a European Debt Issuance Programme (DIP) under which the group may raise up to $20 billion of debt for maturities of one month or longer. At 31 December 2011, the amount drawn down against the DIP was $11,582 million (2010 $12,272 million). In addition, the group has in place an unlimited US Shelf Registration under which it may raise debt with maturities of one month or longer.

The group has long-term debt ratings of A2 (stable outlook) assigned by Moody's consistently throughout the year, and A (stable outlook) assigned by Standard & Poor's since July 2011, strengthened from A (negative outlook) in force at the start of the year.

During 2011 $10.7 billion of long-term taxable bonds were issued with tenors of between 18 months and 10 years, and $0.8 billion of US Industrial/Municipal bonds were re-issued in term-out mode of between three and ten years. Flexible commercial paper is issued at competitive rates to meet short-term borrowing requirements as and when needed.

As a further liquidity measure, the group continues to maintain suitable levels of cash and cash equivalents, invested with highly rated banks or money market funds and readily accessible at immediate and short notice ($14.1 billion at the end of 2011; $18.6 billion at the end of 2010).

At 31 December 2011, the group had substantial amounts of undrawn borrowing facilities available, consisting of $6,925 million of standby facilities (of which $6,825 million is available to draw and repay until mid-March 2014, and the equivalent of $100 million is available to draw and repay in Chinese yuan with half expiring in mid-September 2012 and half in December 2012). These facilities were renegotiated during 2011 across 25 international banks, and borrowings under them would be at pre-agreed rates.

The group also has committed letter of credit (LC) facilities totalling $5,125 million with a number of banks for a one-year duration, allowing LCs to be issued to a maximum one-year duration. There were also uncommitted secured LC evergreen facilities in place at the year end for $2,160 million, secured against inventories or receivables when utilized.

The amounts shown for finance debt in the table below include expected interest payments on borrowings and the future minimum lease payments with respect to finance leases.

Current finance debt on the group balance sheet at 31 December 2011 includes $30 million (2010 $6,197 million) in respect of cash deposits received for disposals expected to complete in 2012, which will be considered extinguished on completion of the transactions. This amount is excluded from the table below.

The table also shows the timing of cash outflows relating to trade and other payables and accruals.

						$ million
			2011			2010
	Trade and other payables[a]	Accruals	Finance debt	Trade and other payables[a]	Accruals	Finance debt
Within one year	**47,678**	**5,933**	**10,024**	42,691	5,612	9,353
1 to 2 years	**1,605**	**137**	**7,866**	6,549	278	6,816
2 to 3 years	**569**	**55**	**7,311**	6,242	125	7,542
3 to 4 years	**449**	**26**	**5,487**	411	42	6,105
4 to 5 years	**259**	**49**	**4,634**	365	28	5,494
5 to 10 years	**31**	**82**	**12,381**	323	110	6,642
Over 10 years	**72**	**39**	**573**	25	54	724
	50,663	**6,321**	**48,276**	56,606	6,249	42,676

[a] Trade and other payables at 31 December 2011 includes the Gulf of Mexico oil spill trust fund liability which is payable as follows: $4,884 million within one year (2010 $5,008 million within one year, $5,000 million payable in 1 to 2 years and $5,000 million payable in 2 to 3 years).

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26. Financial instruments and financial risk factors continued

The group manages liquidity risk associated with derivative contracts, other than derivative hedging instruments, based on the expected maturities of both derivative assets and liabilities as indicated in Note 33. Management does not currently anticipate any cash flows that could be of a significantly different amount, or could occur earlier than the expected maturity analysis provided.

The table below shows cash outflows for derivative hedging instruments based upon contractual payment dates. The amounts reflect the maturity profile of the fair value liability where the instruments will be settled net, and the gross settlement amount where the pay leg of a derivative will be settled separately from the receive leg, as in the case of cross-currency interest rate swaps hedging non-US dollar finance debt. The swaps are with high investment-grade counterparties and therefore the settlement day risk exposure is considered to be negligible. Not shown in the table are the gross settlement amounts for the receive leg of derivatives that are settled separately from the pay leg, which amount to $9,099 million at 31 December 2011 (2010 $6,725 million) to be received on the same day as the related cash outflows.

		$ million
	2011	2010
Within one year	**1,738**	986
1 to 2 years	**1,372**	1,682
2 to 3 years	**1,115**	1,358
3 to 4 years	**298**	1,124
4 to 5 years	**1,262**	295
5 to 10 years	**3,459**	947
	9,244	6,392

The group has issued third-party guarantees, as described above under credit risk. These amounts represent the maximum exposure of the group, substantially all of which could be called within one year.

27. Other investments

				$ million
		2011		2010
	Current	**Non-current**	Current	Non-current
Equity investments – listed	**–**	**876**	–	953
– unlisted	**–**	**252**	–	238
Repurchased gas pre-paid bonds	**288**	**989**	1,532	–
	288	**2,117**	1,532	1,191

Equity investments have no fixed maturity date or coupon rate, and are classified as available-for-sale financial assets. As such they are recorded at fair value with the gain or loss arising as a result of changes in fair value recorded directly in other comprehensive income. Accumulated fair value changes are recycled to the income statement on disposal, or when the investment is impaired.

The fair value of listed investments has been determined by reference to quoted market bid prices and as such are in level 1 of the fair value hierarchy. Unlisted investments are stated at cost less accumulated impairment losses.

The most significant listed investment is the group's stake in Rosneft which had a fair value of $873 million at 31 December 2011 (2010 $948 million). The fair value loss arising on revaluation of this investment during 2011 has been recorded within other comprehensive income.

In 2011, impairment losses of $12 million were incurred relating to unlisted investments; there were no impairment losses relating to listed investments. In 2010, no impairment losses were incurred relating to either unlisted investments or listed investments.

BP has entered into long-term gas supply contracts which are backed by gas pre-paid bonds. In 2010, BP was unsuccessful in the remarketing of these bonds and repurchased them. The outstanding bonds associated with these long-term gas supply contracts held by BP are recorded within other investments, with the related liability recorded within other payables on the balance sheet. The fair value of the gas pre-paid bonds is the same as the carrying amount, as the bonds are based on floating rate interest with weekly market re-set, and as such are in Level 1 of the fair value hierarchy.

BP has no investments pledged as security for liabilities as at 31 December 2011. As at 31 December 2010, BP had pledged listed equity investments with a carrying value of $948 million as part of a financing arrangement. As BP had retained substantially all the risks and rewards associated with the shares, they continued to be reflected as an asset on the balance sheet, with a liability being reflected within finance debt. The terms of the arrangement meant that BP could request to have the shares returned at any time with 20 days notice, up to the date of maturity (in three tranches, up to December 2013), subject to repayment of the outstanding loan. The financing arrangement was terminated during 2011.

28. Inventories

		$ million
	2011	2010
Crude oil	**7,702**	8,969
Natural gas	**178**	112
Refined petroleum and petrochemical products	**14,909**	13,997
	22,789	23,078
Supplies	**2,057**	1,669
	24,846	24,747
Trading inventories	**815**	1,471
	25,661	26,218
Cost of inventories expensed in the income statement	**285,618**	216,211

29. Trade and other receivables

	2011 Current	2011 Non-current	2010 Current	2010 Non-current
				$ million
Financial assets				
Trade receivables	**27,929**	**508**	24,255	–
Amounts receivable from jointly controlled entities	**1,004**	**612**	751	601
Amounts receivable from associates	**492**	**159**	448	220
Other receivables	**5,429**	**746**	4,763	1,342
	34,854	**2,025**	30,217	2,163
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset[a]	**8,233**	**1,642**	5,943	3,601
Other receivables	**439**	**670**	389	534
	8,672	**2,312**	6,332	4,135
	43,526	**4,337**	36,549	6,298

[a] See Note 2 for further information.

Trade and other receivables are predominantly non-interest bearing. See Note 26 for further information.

30. Cash and cash equivalents

	2011	2010
		$ million
Cash at bank and in hand	**4,872**	8,209
Term bank deposits	**4,878**	5,253
Cash equivalents	**4,317**	5,094
	14,067	18,556

Cash and cash equivalents comprise cash in hand; current balances with banks and similar institutions; term deposits of three months or less with banks and similar institutions; and short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and have a maturity of three months or less from the date of acquisition. The carrying amounts of cash at bank and in hand and term bank deposits approximate their fair values. All of the other cash equivalents are categorized within level 1 of the fair value hierarchy.

Cash and cash equivalents at 31 December 2011 includes $901 million (2010 $982 million) that is restricted. This relates principally to amounts required to cover initial margins on trading exchanges.

See Note 26 for further information.

31. Valuation and qualifying accounts

	2011 Doubtful debts	2011 Fixed assets – investments	2010 Doubtful debts	2010 Fixed assets – investments	2009 Doubtful debts	2009 Fixed assets – investments
						$ million
At 1 January	**428**	**540**	430	349	391	935
Charged to costs and expenses	**115**	**111**	150	376	157	66
Charged to other accounts[a]	**(16)**	**(3)**	(9)	(3)	12	6
Deductions	**(195)**	**(5)**	(143)	(182)	(130)	(658)
At 31 December	**332**	**643**	428	540	430	349

[a] Principally currency transactions.

Valuation and qualifying accounts are deducted in the balance sheet from the assets to which they apply.

Financial statements

32. Trade and other payables

	2011 Current	2011 Non-current	2010 Current	2010 Non-current
				$ million
Financial liabilities				
Trade payables	**29,830**	**–**	27,510	–
Amounts payable to jointly controlled entities	**1,578**	**1,047**	1,361	1,905
Amounts payable to associates	**876**	**159**	712	220
Gulf of Mexico oil spill trust fund liability[a]	**4,872**	**–**	5,002	9,899
Other payables	**10,510**	**1,779**	8,100	1,790
	47,666	**2,985**	42,685	13,814
Non-financial liabilities				
Other payables	**4,739**	**452**	3,644	471
	52,405	**3,437**	46,329	14,285

[a] See Note 2 for further information.

Trade and other payables are predominantly interest free, however the Gulf of Mexico oil spill trust fund liability is recorded on a discounted basis. See Note 26 for further information.

33. Derivative financial instruments

An outline of the group's financial risks and the objectives and policies pursued in relation to those risks is set out in Note 26.

In the normal course of business the group enters into derivative financial instruments (derivatives) to manage its normal business exposures in relation to commodity prices, foreign currency exchange rates and interest rates, including management of the balance between floating rate and fixed rate debt, consistent with risk management policies and objectives. Additionally, the group has a well-established entrepreneurial trading operation that is undertaken in conjunction with these activities using a similar range of contracts.

IAS 39 prescribes strict criteria for hedge accounting, whether as a cash flow or fair value hedge or a hedge of a net investment in a foreign operation, and requires that any derivative that does not meet these criteria should be classified as held for trading and fair valued, with gains and losses recognized in the income statement.

The fair values of derivative financial instruments at 31 December are set out below.

	2011 Fair value asset	2011 Fair value liability	2010 Fair value asset	2010 Fair value liability
				$ million
Derivatives held for trading				
Currency derivatives	**217**	**(217)**	194	(280)
Oil price derivatives	**823**	**(536)**	1,099	(877)
Natural gas price derivatives	**5,305**	**(3,603)**	5,350	(3,951)
Power price derivatives	**843**	**(663)**	561	(432)
	7,188	**(5,019)**	7,204	(5,540)
Embedded derivatives				
Commodity price contracts	**–**	**(1,417)**	18	(1,625)
Other embedded derivatives	**–**	**–**	–	(89)
	–	**(1,417)**	18	(1,714)
Cash flow hedges				
Currency forwards, futures and cylinders	**25**	**(159)**	134	(124)
Cross-currency interest rate swaps	**–**	**–**	101	(1)
	25	**(159)**	235	(125)
Fair value hedges				
Currency forwards, futures and swaps	**842**	**(398)**	772	(80)
Interest rate swaps	**840**	**–**	337	(74)
	1,682	**(398)**	1,109	(154)
	8,895	**(6,993)**	8,566	(7,533)
Of which – current	**3,857**	**(3,220)**	4,356	(3,856)
– non-current	**5,038**	**(3,773)**	4,210	(3,677)

33. Derivative financial instruments continued

Derivatives held for trading

The group maintains active trading positions in a variety of derivatives. The contracts may be entered into for risk management purposes, to satisfy supply requirements or for entrepreneurial trading. Certain contracts are classified as held for trading, regardless of their original business objective, and are recognized at fair value with changes in fair value recognized in the income statement. Trading activities are undertaken by using a range of contract types in combination to create incremental gains by arbitraging prices between markets, locations and time periods. The net of these exposures is monitored using market value-at-risk techniques as described in Note 26.

The following tables show further information on the fair value of derivatives and other financial instruments held for trading purposes. Derivative assets held for trading have the following fair values and maturities.

							$ million
							2011
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**194**	**18**	**5**	**–**	**–**	**–**	**217**
Oil price derivatives	**573**	**135**	**77**	**25**	**10**	**3**	**823**
Natural gas price derivatives	**2,493**	**1,160**	**597**	**346**	**207**	**502**	**5,305**
Power price derivatives	**498**	**160**	**101**	**54**	**30**	**–**	**843**
	3,758	**1,473**	**780**	**425**	**247**	**505**	**7,188**

							$ million
							2010
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	124	41	18	11	–	–	194
Oil price derivatives	797	128	82	64	21	7	1,099
Natural gas price derivatives	2,591	1,100	652	375	231	401	5,350
Power price derivatives	389	125	35	11	1	–	561
	3,901	1,394	787	461	253	408	7,204

Derivative liabilities held for trading have the following fair values and maturities.

							$ million
							2011
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**(168)**	**(49)**	**–**	**–**	**–**	**–**	**(217)**
Oil price derivatives	**(483)**	**(37)**	**(7)**	**(4)**	**(3)**	**(2)**	**(536)**
Natural gas price derivatives	**(1,696)**	**(876)**	**(347)**	**(197)**	**(102)**	**(385)**	**(3,603)**
Power price derivatives	**(328)**	**(176)**	**(89)**	**(46)**	**(24)**	**–**	**(663)**
	(2,675)	**(1,138)**	**(443)**	**(247)**	**(129)**	**(387)**	**(5,019)**

							$ million
							2010
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(228)	(6)	(46)	–	–	–	(280)
Oil price derivatives	(794)	(76)	(6)	(1)	–	–	(877)
Natural gas price derivatives	(2,174)	(741)	(484)	(161)	(114)	(277)	(3,951)
Power price derivatives	(287)	(103)	(32)	(9)	(1)	–	(432)
	(3,483)	(926)	(568)	(171)	(115)	(277)	(5,540)

If at inception of a contract the valuation cannot be supported by observable market data, any gain or loss determined by the valuation methodology is not recognized in the income statement but is deferred on the balance sheet and is commonly known as ‘day-one profit or loss’. This deferred gain or loss is recognized in the income statement over the life of the contract until substantially all of the remaining contract term can be valued using observable market data at which point any remaining deferred gain or loss is recognized in the income statement. Changes in valuation from this initial valuation are recognized immediately through the income statement.

33. Derivative financial instruments continued

The following table shows the changes in the day-one profits and losses deferred on the balance sheet.

				$ million
		2011		2010
	Power price	Natural gas price	Oil price	Natural gas price
Fair value of contracts not recognized through the income statement at 1 January	–	69	21	33
Fair value of new contracts at inception not recognized in the income statement	9	51	–	39
Fair value recognized in the income statement	–	(6)	(21)	(3)
Fair value of contracts not recognized through profit at 31 December	9	114	–	69

The following table shows the fair value of derivative assets and derivative liabilities held for trading, analysed by maturity period and by methodology of fair value estimation.

IFRS 7 'Financial Instruments: Disclosures' sets out a fair value hierarchy which consists of three levels that describe the methodology of estimation as follows:

Level 1 –using quoted prices in active markets for identical assets or liabilities.

Level 2 –using inputs for the asset or liability, other than quoted prices, that are observable either directly (i.e. as prices) or indirectly (i.e. derived from prices).

Level 3 –using inputs for the asset or liability that are not based on observable market data such as prices based on internal models or other valuation methods.

This information is presented on a gross basis, that is, before netting by counterparty.

							$ million
							2011
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Fair value of derivative assets							
Level 1	229	18	5	–	–	–	252
Level 2	7,225	2,725	1,123	269	81	8	11,431
Level 3	310	284	253	221	170	500	1,738
	7,764	3,027	1,381	490	251	508	13,421
Less: netting by counterparty	(4,006)	(1,554)	(601)	(65)	(4)	(3)	(6,233)
	3,758	1,473	780	425	247	505	7,188
Fair value of derivative liabilities							
Level 1	(168)	(49)	–	–	–	–	(217)
Level 2	(6,323)	(2,479)	(887)	(163)	(21)	(7)	(9,880)
Level 3	(190)	(164)	(157)	(149)	(112)	(383)	(1,155)
	(6,681)	(2,692)	(1,044)	(312)	(133)	(390)	(11,252)
Less: netting by counterparty	4,006	1,554	601	65	4	3	6,233
	(2,675)	(1,138)	(443)	(247)	(129)	(387)	(5,019)
Net fair value	1,083	335	337	178	118	118	2,169

							$ million
							2010
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Fair value of derivative assets							
Level 1	122	36	12	5	–	–	175
Level 2	7,132	1,928	639	239	109	–	10,047
Level 3	341	314	296	267	165	410	1,793
	7,595	2,278	947	511	274	410	12,015
Less: netting by counterparty	(3,694)	(884)	(160)	(50)	(21)	(2)	(4,811)
	3,901	1,394	787	461	253	408	7,204
Fair value of derivative liabilities							
Level 1	(239)	(6)	(46)	–	–	–	(291)
Level 2	(6,733)	(1,685)	(617)	(107)	(44)	–	(9,186)
Level 3	(205)	(148)	(125)	(114)	(92)	(279)	(963)
	(7,177)	(1,839)	(788)	(221)	(136)	(279)	(10,440)
Less: netting by counterparty	3,694	884	160	50	21	2	4,811
	(3,483)	(955)	(628)	(171)	(115)	(277)	(5,629)
Net fair value	418	439	159	290	138	131	1,575

33. Derivative financial instruments continued

The following table shows the changes during the year in the net fair value of derivatives held for trading purposes within level 3 of the fair value hierarchy.

	Oil price	Natural gas price	Power price	Total
				$ million
Net fair value of contracts at 1 January 2011	**164**	**667**	**(1)**	**830**
Gains (losses) recognized in the income statement	**69**	**129**	**11**	**209**
Settlements	**(71)**	**(110)**	**3**	**(178)**
Transfers out of level 3	**–**	**(278)**	**–**	**(278)**
Net fair value of contracts at 31 December 2011	**162**	**408**	**13**	**583**

	Oil price	Natural gas price	Power price	Total
				$ million
Net fair value of contracts at 1 January 2010	215	72	(1)	286
Gains (losses) recognized in the income statement	21	637	(1)	657
Settlements	(54)	(11)	1	(64)
Transfers out of level 3	(18)	(38)	–	(56)
Transfers into level 3	–	4	–	4
Exchange adjustments	–	3	–	3
Net fair value of contracts at 31 December 2010	164	667	(1)	830

Transfers out of level 3 of the fair value hierarchy in 2011 relate primarily to the delivery dates for a number of natural gas forward contracts moving into a time period where market observable prices are available, and therefore being reclassified to level 2 of the fair value hierarchy.

The amount recognized in the income statement for the year relating to level 3 held for trading derivatives still held at 31 December 2011 was a $204 million gain (2010 $651 million gain relating to derivatives still held at 31 December 2010).

Gains and losses relating to derivative contracts are included either within sales and other operating revenues or within purchases in the income statement depending upon the nature of the activity and type of contract involved. The contract types treated in this way include futures, options, swaps and certain forward sales and forward purchases contracts, and relate to both currency and commodity trading activities. Gains or losses arise on contracts entered into for risk management purposes, optimization activity and entrepreneurial trading. They also arise on certain contracts that are for normal procurement or sales activity for the group but that are required to be fair valued under accounting standards. Also included within sales and other operating revenues are gains and losses on inventory held for trading purposes. The total amount relating to all of these items was a net loss of $934 million (2010 $1,738 million net gain and 2009 $4,046 million net gain).

Embedded derivatives

The group has embedded derivatives relating to certain natural gas contracts. Prior to the development of an active gas trading market, UK gas contracts were priced using a basket of available price indices, primarily relating to oil products, power and inflation. After the development of an active UK gas market, certain contracts were entered into or renegotiated using pricing formulae not directly related to gas prices, for example, oil product and power prices. In these circumstances, pricing formulae have been determined to be derivatives, embedded within the overall contractual arrangements that are not clearly and closely related to the underlying commodity. The resulting fair value relating to these contracts is recognized on the balance sheet with gains or losses recognized in the income statement.

All the commodity price embedded derivatives relate to natural gas contracts, are categorized in level 3 of the fair value hierarchy and are valued using inputs that include price curves for each of the different products that are built up from active market pricing data. Where necessary, these are extrapolated to the expiry of the contracts (the last of which is in 2018) using all available external pricing information. Additionally, where limited data exists for certain products, prices are interpolated using historic and long-term pricing relationships.

In addition, at 31 December 2010, BP was party to a collar-backed financing arrangement involving an available-for-sale investment held by the group. This arrangement contained an embedded derivative whose fair value was related to the equity price of the investment and was categorized in level 2 of the fair value hierarchy. The arrangement was terminated in 2011.

33. Derivative financial instruments continued

Embedded derivative assets and liabilities have the following fair values and maturities.

							$ million
							2011
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Liabilities – commodity price contracts	**(347)**	**(319)**	**(306)**	**(236)**	**(134)**	**(75)**	**(1,417)**
Net fair value	**(347)**	**(319)**	**(306)**	**(236)**	**(134)**	**(75)**	**(1,417)**

							$ million
							2010
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Assets – commodity price contracts	18	–	–	–	–	–	18
Liabilities – commodity price contracts	(325)	(326)	(285)	(281)	(212)	(196)	(1,625)
– other embedded derivatives	–	(29)	(60)	–	–	–	(89)
Net fair value	(307)	(355)	(345)	(281)	(212)	(196)	(1,696)

The following table shows the changes during the year in the net fair value of embedded derivatives, within level 3 of the fair value hierarchy.

		$ million
	2011	2010
	Commodity price	Commodity price
Net fair value of contracts at 1 January	**(1,607)**	(1,331)
Settlements	**301**	37
Losses recognized in the income statement	**(106)**	(350)
Exchange adjustments	**(5)**	37
Net fair value of contracts at 31 December	**(1,417)**	(1,607)

The amount recognized in the income statement for the year relating to level 3 embedded derivatives still held at 31 December 2011 was a $106 million loss (2010 $350 million loss relating to embedded derivatives still held at 31 December 2010).

The fair value gain (loss) on embedded derivatives is shown below.

			$ million
	2011	2010	2009
Commodity price embedded derivatives	**190**	(309)	607
Other embedded derivatives	**(122)**	–	–
Fair value gain (loss)	**68**	(309)	607

Cash flow hedges

At 31 December 2011, the group held currency forwards and futures contracts and cylinders that were being used to hedge the foreign currency risk of highly probable forecast transactions. Note 26 outlines the management of risk aspects for currency risk. For cash flow hedges the group only claims hedge accounting for the intrinsic value on the currency with any fair value attributable to time value taken immediately to the income statement. There were no highly probable transactions for which hedge accounting has been claimed that have not occurred and no significant element of hedge ineffectiveness requiring recognition in the income statement. For cash flow hedges the pre-tax amount removed from equity during the period and included in the income statement is a gain of $195 million (2010 gain of $25 million and 2009 loss of $366 million). The entire gain of $195 million is included in production and manufacturing expenses (2010 $25 million gain in production and manufacturing expense; 2009 $332 million loss in production and manufacturing expense and $34 million loss in finance costs). The amount removed from equity during the period and included in the carrying amount of non-financial assets was a gain of $13 million (2010 $53 million loss and 2009 $136 million loss).

The amounts retained in equity at 31 December 2011 consist of deferred losses of $78 million maturing in 2012, deferred losses of $39 million maturing in 2013 and deferred losses of $30 million maturing in 2014 and beyond.

Fair value hedges

At 31 December 2011, the group held interest rate and cross-currency interest rate swap contracts as fair value hedges of the interest rate risk on fixed rate debt issued by the group. The effectiveness of each hedge relationship is quantitatively assessed and demonstrated to continue to be highly effective. The gain on the hedging derivative instruments taken to the income statement in 2011 was $328 million (2010 $563 million gain and 2009 $98 million loss) offset by a loss on the fair value of the finance debt of $327 million (2010 $554 million loss and 2009 $117 million gain).

The interest rate and cross-currency interest rate swaps mature within one to 10 years, with an average maturity of four to five years (2010 four to five years) and are used to convert sterling, euro, Swiss franc, Australian dollar, Japanese yen and Hong Kong dollar denominated borrowings into US dollar floating rate debt. Note 26 outlines the group’s approach to interest rate and currency risk management.

34. Finance debt

						$ million
			2011			2010
	Current	**Non-current**	**Total**	Current	Non-current	Total
Borrowings	**8,675**	**34,816**	**43,491**	8,312	30,017	38,329
Net obligations under finance leases	**339**	**353**	**692**	117	693	810
	9,014	**35,169**	**44,183**	8,429	30,710	39,139
Disposal deposits	**30**	**–**	**30**	6,197	–	6,197
	9,044	**35,169**	**44,213**	14,626	30,710	45,336

Current finance debt includes the portion of long-term borrowings and net obligations under finance leases that will mature in the next 12 months, amounting to $5,214 million (2010 $6,976 million).

The main elements of current borrowings are the current portion of long-term bonds of $4,875 million (2010 $6,859 million) and issued commercial paper of $3,635 million (2010 $1,025 million).

Deposits for disposal transactions expected to complete in 2012 of $30 million are also included in current finance debt (2010 $6,197 million for transactions expected to complete in 2011). This debt will be considered extinguished on completion of the transactions.

At 31 December 2011, $131 million (2010 $790 million) of finance debt was secured by the pledging of assets, and no finance debt was secured in connection with deposits received relating to certain disposal transactions expected to complete in subsequent periods (2010 $4,780 million). In addition, in connection with $2,344 million (2010 $4,588 million) of finance debt, BP has entered into crude oil sales contracts in respect of oil produced from certain fields in offshore Angola and Azerbaijan to provide security to the lending banks. The remainder of finance debt was unsecured.

The following table shows, by major currency, the group's finance debt at 31 December and the weighted average interest rates achieved at those dates through a combination of borrowings and derivative financial instruments entered into to manage interest rate and currency exposures. The disposal deposits noted above are excluded from this analysis.

			Fixed rate debt		Floating rate debt	Total
	Weighted average interest rate %	**Weighted average time for which rate is fixed Years**	**Amount $ million**	**Weighted average interest rate %**	**Amount $ million**	**Amount $ million**
						2011
US dollar	**4**	**5**	**15,016**	**1**	**27,285**	**42,301**
Euro	**5**	**3**	**25**	**3**	**1,575**	**1,600**
Other currencies	**4**	**12**	**240**	**3**	**42**	**282**
			15,281		**28,902**	**44,183**
						2010
US dollar	4	5	14,797	1	21,076	35,873
Euro	4	3	53	2	2,988	3,041
Other currencies	6	18	140	4	85	225
			14,990		24,149	39,139

The euro debt not swapped to US dollar is naturally hedged for the foreign currency risk by holding equivalent euro cash and cash equivalent amounts.

Finance leases

The group uses finance leases to acquire property, plant and equipment. These leases have terms of renewal but no purchase options and escalation clauses. Renewals are at the option of the lessee. The terms and conditions of these finance leases do not impose any significant financial restrictions on the group. Future minimum lease payments under finance leases are set out below.

		$ million
	2011	2010
Future minimum lease payments payable within		
1 year	**454**	153
2 to 5 years	**200**	535
Thereafter	**380**	438
	1,034	1,126
Less: finance charges	**342**	316
Net obligations	**692**	810
Of which – payable within 1 year	**339**	117
– payable within 2 to 5 years	**99**	404
– payable thereafter	**254**	289

34. Finance debt continued

Fair values

The estimated fair value of finance debt is shown in the table below together with the carrying amount as reflected in the balance sheet.

Long-term borrowings in the table below include the portion of debt that matures in the year from 31 December 2011, whereas in the balance sheet the amount would be reported within current finance debt. The disposal deposits noted above are excluded from this analysis.

The carrying amount of the group's short-term borrowings, comprising mainly commercial paper, approximates their fair value. The fair value of the group's long-term borrowings and finance lease obligations is estimated using quoted prices or, where these are not available, discounted cash flow analyses based on the group's current incremental borrowing rates for similar types and maturities of borrowing.

				$ million
		2011		2010
	Fair value	Carrying amount	Fair value	Carrying amount
Short-term borrowings	**3,800**	**3,800**	1,453	1,453
Long-term borrowings	**40,606**	**39,691**	37,258	36,876
Net obligations under finance leases	**776**	**692**	928	810
Total finance debt	**45,182**	**44,183**	39,639	39,139

35. Capital disclosures and analysis of changes in net debt

The group defines capital as total equity. The group's approach to managing capital is set out in its financial framework which BP continues to refine to support the pursuit of value growth for shareholders, while maintaining a secure financial base. We intend to maintain a significant liquidity buffer and to reduce our net debt ratio to the lower half of the 10-20% gearing range over time as our disposal programme progresses.

The group monitors capital on the basis of the net debt ratio, that is, the ratio of net debt to net debt plus equity. 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 exchange and interest rate risks relating to finance debt, for which hedge accounting is applied, less cash and cash equivalents. Net debt and net debt ratio are non-GAAP measures. 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'. All components of equity are included in the denominator of the calculation. At 31 December 2011 the net debt ratio was 20.5% (2010 21.2%).

During 2011 and 2010, the company did not repurchase any of its own shares, other than to satisfy the requirements of certain employee share-based payment plans.

		$ million
At 31 December	2011	2010
Gross debt	**44,213**	45,336
Less: Cash and cash equivalents	**14,067**	18,556
Less: Fair value asset of hedges related to finance debt	**1,133**	916
Net debt	**29,013**	25,864
Equity	**112,482**	95,891
Net debt ratio	**20.5%**	21.2%

An analysis of changes in net debt is provided below.

						$ million
			2011			2010
Movement in net debt	Finance debt[a]	Cash and cash equivalents	Net debt	Finance debt[a]	Cash and cash equivalents	Net debt
At 1 January	**(44,420)**	**18,556**	**(25,864)**	(34,500)	8,339	(26,161)
Exchange adjustments	**30**	**(492)**	**(462)**	194	(279)	(85)
Net cash flow	**(4,725)**	**(3,997)**	**(8,722)**	(3,613)	10,496	6,883
Movement in finance debt relating to investing activities[b]	**6,167**	**–**	**6,167**	(6,197)	–	(6,197)
Other movements	**(132)**	**–**	**(132)**	(304)	–	(304)
At 31 December	**(43,080)**	**14,067**	**(29,013)**	(44,420)	18,556	(25,864)

[a] Including fair value of associated derivative financial instruments.
[b] See Note 34 for further information.

36. Provisions

$ million

	Decommissioning	Environmental	Spill response	Litigation and claims	Clean Water Act penalties	Other	Total
At 1 January 2011	**10,544**	**2,465**	**1,043**	**11,967**	**3,510**	**2,378**	**31,907**
Exchange adjustments	**(27)**	**(4)**	**–**	**(13)**	**–**	**(12)**	**(56)**
Acquisitions	**163**	**–**	**–**	**9**	**–**	**118**	**290**
New or increased provisions	**4,596**	**1,677**	**586**	**3,821**	**–**	**1,145**	**11,825**
Write-back of unused provisions	**(1)**	**(140)**	**–**	**(92)**	**–**	**(416)**	**(649)**
Unwinding of discount	**195**	**27**	**–**	**15**	**–**	**6**	**243**
Change in discount rate	**3,211**	**90**	**–**	**45**	**–**	**10**	**3,356**
Utilization	**(342)**	**(840)**	**(1,293)**	**(4,715)**	**–**	**(876)**	**(8,066)**
Reclassified as liabilities directly associated with assets held for sale	**(51)**	**–**	**–**	**–**	**–**	**–**	**(51)**
Deletions	**(1,048)**	**(11)**	**–**	**(61)**	**–**	**(37)**	**(1,157)**
At 31 December 2011	**17,240**	**3,264**	**336**	**10,976**	**3,510**	**2,316**	**37,642**
Of which – current	**596**	**1,375**	**282**	**8,518**	**–**	**467**	**11,238**
– non-current	**16,644**	**1,889**	**54**	**2,458**	**3,510**	**1,849**	**26,404**

$ million

	Decommissioning	Environmental	Spill response	Litigation and claims	Clean Water Act penalties	Other	Total
At 1 January 2010	9,020	1,719	–	1,076	–	2,815	14,630
Exchange adjustments	(114)	–	–	(7)	–	(50)	(171)
Acquisitions	188	–	–	2	–	15	205
New or increased provisions	1,800	1,290	10,883	15,171	3,510	808	33,462
Write-back of unused provisions	(12)	(120)	–	(51)	–	(466)	(649)
Unwinding of discount	168	29	–	18	–	19	234
Change in discount rate	444	22	–	9	–	(6)	469
Utilization	(164)	(460)	(9,840)	(4,250)	–	(755)	(15,469)
Reclassified as liabilities directly associated with assets held for sale	(381)	(1)	–	–	–	(1)	(383)
Deletions	(405)	(14)	–	(1)	–	(1)	(421)
At 31 December 2010	10,544	2,465	1,043	11,967	3,510	2,378	31,907
Of which – current	432	635	982	7,011	–	429	9,489
– non-current	10,112	1,830	61	4,956	3,510	1,949	22,418

The group makes full provision for the future cost of decommissioning oil and natural gas wells, facilities and related pipelines on a discounted basis upon installation. The provision for the costs of decommissioning these wells, production facilities and pipelines at the end of their economic lives has been estimated using existing technology, at current prices or future assumptions, depending on the expected timing of the activity, and discounted using a real discount rate of 0.5% (2010 1.5%). These costs are generally expected to be incurred over the next 30 years. While the provision is based on the best estimate of future costs and the economic lives of the facilities and pipelines, there is uncertainty regarding both the amount and timing of these costs.

Provisions for environmental remediation are made when a clean-up is probable and the amount of the obligation can be estimated reliably. Generally, this coincides with commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites. The provision for environmental liabilities has been estimated using existing technology, at current prices and discounted using a real discount rate of 0.5% (2010 1.5%). The majority of these costs are expected to be incurred over the next 10 years. The extent and cost of future remediation programmes are inherently difficult to estimate. They depend on the scale of any possible contamination, the timing and extent of corrective actions, and also the group’s share of the liability.

The litigation category includes provisions for matters related to, for example, commercial disputes, product liability, and allegations of exposures of third parties to toxic substances. Included within the other category at 31 December 2011 are provisions for deferred employee compensation of $666 million (2010 $728 million). These provisions are discounted using either a nominal discount rate of 2.5% (2010 3.75%) or a real discount rate of 0.5% (2010 1.5%), as appropriate.

Provisions relating to the Gulf of Mexico oil spill

The Gulf of Mexico oil spill is described on pages 76 to 79 and in Note 2. Provisions relating to the Gulf of Mexico oil spill, included in the table above, are separately presented below:

$ million

	Environmental	Spill response	Litigation and claims	Clean Water Act penalties	Total
At 1 January 2011	**809**	**1,043**	**10,973**	**3,510**	**16,335**
New or increased provisions	**1,167**	**586**	**3,430**	**–**	**5,183**
Unwinding of discount	**6**	**–**	**–**	**–**	**6**
Change in discount rate	**17**	**–**	**–**	**–**	**17**
Utilization	**(482)**	**(1,293)**	**(4,433)**	**–**	**(6,208)**
At 31 December 2011	**1,517**	**336**	**9,970**	**3,510**	**15,333**
Of which – current	**961**	**282**	**8,194**	**–**	**9,437**
– non-current	**556**	**54**	**1,776**	**3,510**	**5,896**
Of which – payable from the trust fund	**1,066**	**–**	**8,809**	**–**	**9,875**

36. Provisions continued

					$ million
	Environmental	Spill response	Litigation and claims	Clean Water Act penalties	Total
At 1 January 2010	–	–	–	–	–
New or increased provisions	929	10,883	14,939	3,510	30,261
Unwinding of discount	4	–	–	–	4
Change in discount rate	5	–	–	–	5
Utilization	(129)	(9,840)	(3,966)	–	(13,935)
At 31 December 2010	809	1,043	10,973	3,510	16,335
Of which – current	314	982	6,642	–	7,938
– non-current	495	61	4,331	3,510	8,397
Of which – payable from the trust fund	382	–	9,162	–	9,544

As described in Note 2, BP has recorded provisions at 31 December 2011 relating to the Gulf of Mexico oil spill including amounts in relation to environmental expenditure, spill response costs, litigation and claims, and Clean Water Act penalties, each of which is described below. The total amounts that will ultimately be paid by BP are subject to significant uncertainty as described in Note 2.

Subsequent to BP releasing its preliminary announcement of the fourth quarter 2011 results on 7 February 2012, BP announced on 3 March 2012 that it had reached a proposed settlement with the Plaintiffs' Steering Committee (PSC), subject to final written agreement and court approvals, to resolve the substantial majority of legitimate economic loss and medical claims stemming from the Deepwater Horizon accident and oil spill. The proposed settlement has been reflected in the financial statements for 2011 included in this report.

Certain items are subject to settlement discussions or may be subject to settlement discussions in the future. Any further settlements which may be reached relating to the Deepwater Horizon accident and oil spill could impact the amount and timing of any future payments.

Environmental

The amounts committed by BP for a 10-year research programme to study the impact of the incident on the marine and shoreline environment of the Gulf of Mexico have been provided for. BP's commitment is to provide $500 million of funding, and the remaining commitment, on a discounted basis, of $421 million was included in provisions at 31 December 2011. This amount is expected to be spent over the remaining life of the programme.

As a responsible party under the Oil Pollution Act of 1990 (OPA 90), BP faces claims by the United States, as well as by State, tribal, and foreign trustees, if any, for natural resource damages ("Natural Resource Damages claims"). These damages include, among other things, the reasonable costs of assessing the injury to natural resources as well as some emergency restoration projects which are expected to occur over the next two years. BP has been incurring natural resource damage assessment costs and a provision has been made for the estimated costs of the assessment phase. The assessment covers a large area of potential impact and will take some time to complete in order to determine both the severity and duration of the impact of the oil spill. The process of interpreting the large volume of data collected is expected to take at least several months and, in order to determine potential injuries to certain animal populations, data will need to be collected over one or more reproductive cycles. This expected assessment spend is based upon past experience as well as identified projects. During 2011, BP entered a framework agreement with natural resource trustees for the United States and five Gulf Coast states, providing for up to $1 billion to be spent on early restoration projects to address natural resource injuries resulting from the Gulf of Mexico oil spill. Funding for these projects will come from the $20-billion trust fund. The total amount provided for these items was $1,096 million at 31 December 2011. Until the size, location and duration of the impact is assessed, it is not possible to estimate reliably either the amounts or timing of the remaining Natural Resource Damages claims other than the emergency and early restoration agreements noted above, therefore no amounts have been provided for these items and they are disclosed as a contingent liability. See Note 43 for further information.

Spill response

Further amounts were provided relating to the spill response during 2011, totalling $0.6 billion. This primarily reflected increased costs of shoreline clean-up, patrolling and maintenance and vessel decontamination. The majority of the active clean-up of the shorelines had been completed by the end of the year.

Litigation and claims

Individual and Business Claims, and State and Local Claims under the Oil Pollution Act of 1990 (OPA 90) and claims for personal injury

BP faces claims under OPA 90 by individuals and businesses for removal costs, damage to real or personal property, lost profits or impairment of earning capacity, loss of subsistence use of natural resources and for personal injury ("Individual and Business Claims") and by state and local government entities for removal costs, physical damage to real or personal property, loss of government revenue and increased public services costs ("State and Local Claims").

The estimated future cost of settling Individual and Business Claims, State and Local Claims under OPA 90 and claims for personal injuries, both reported and unreported, has been provided for. Claims administration costs and legal fees have also been provided for.

Subsequent to BP releasing its preliminary announcement of the fourth quarter 2011 results on 7 February 2012, BP announced on 3 March 2012 that it had reached a proposed settlement with the PSC, subject to final written agreement and court approvals, to resolve the substantial majority of legitimate economic loss and medical claims stemming from the Deepwater Horizon accident and oil spill. The details of the proposed settlement agreement are explained in Legal proceedings on pages 160 to 164.

In 2010 and for the 2011 preliminary results, BP believed that the history of claims received, and settlements made, provided sufficient data to enable the company to use an approach based on a combination of actuarial methods and management judgements to estimate IBNR (Incurred But Not Reported) claims to determine a reliable best estimate of BP's exposure for claims not yet reported in relation to Individual and Business claims, and State and Local claims under OPA 90. The amount provided for these claims was determined in accordance with IFRS and represented BP's best estimate of the expenditure required to settle its obligations at the balance sheet date.

In estimating the amount of the provision, BP determined a range of possible outcomes for Individual and Business Claims, and State and Local Claims. As disclosed in the preliminary announcement of the fourth quarter 2011 results, BP had concluded that a reasonable range of possible outcomes for the amount of the provision as at 31 December 2011 was $4.1 billion to $8.3 billion. This range was for claims payable through the Gulf Coast Claims Facility and State and Local Claims only.

36. Provisions continued

Following the proposed settlement agreement entered into with the PSC, subject to final written agreement and court approvals, BP reviewed the amount of the provision for the items covered by the proposed settlement based upon information available at the time that the consolidated financial statements were approved. The provision for these items at 31 December 2011 is now $7.8 billion which represents a reliable best estimate of the liability under the proposed settlement agreement which, under accounting standards, is the amount that BP would rationally pay to settle the obligation. Substantially all of this amount is included as payable from the trust fund under Litigation and claims in the table above. Future claims administration costs are expected to be paid from the trust fund. However, at this time, the provision for these costs is shown as payable from outside the trust fund, consistent with how the administration costs associated with the GCCF were treated, as the proposed settlement is subject to final written agreement and court approvals. Further information on the proposed settlement with the PSC is included in Legal proceedings on pages 160 to 164.

The provision is in addition to the $6.3 billion of claims paid in total ($2.9 billion in 2011 and $3.4 billion in 2010). Of this total paid, $6.1 billion is included within utilization of provision in the table ($2.9 billion in 2011 and $3.2 billion in 2010), and the remaining $0.2 billion was a period expenditure prior to the recognition of the provision at the end of the second quarter 2010. Also included within the utilization of the provision of $4.4 billion (2010 $4.0 billion) under Litigation and claims in the table are amounts relating to claims administration costs, legal fees and other settlements. Of the total payments of $6.3 billion, $5.9 billion was paid out of the trust fund ($2.9 billion in 2011 and $3.0 billion in 2010) and $0.4 billion was paid by BP in 2010.

Many key assumptions underlie and influence the reliable best estimates of total expenditures derived for both categories of claims. The amount provided for Individual and Business Claims is based upon the expected terms of the proposed settlement with the PSC, which is subject to final written agreement and court approvals. Other key assumptions include the amounts that will ultimately be paid in relation to current claims, the number, type and amounts for claims not yet reported, the outcomes of any further litigation through potential opt-outs from the proposed settlement and the amount of administration and other costs associated with the proposed settlement. While BP has determined a reliable best estimate of the cost of the proposed settlement with the PSC, it is possible that the actual cost could be higher or lower than this estimate.

The outcomes of claims and litigation are likely to be paid out over many years to come. BP will re-evaluate the assumptions underlying this analysis on a quarterly basis as more information becomes available and the claims process matures.

BP also faces other litigation for which no reliable estimate of the cost can currently be made. Therefore no amounts have been provided for these items. See Note 43 for further information.

Clean Water Act penalties

A provision has been made for the estimated penalties for strict liability under Section 311 of the Clean Water Act. Such penalties are subject to a statutory maximum calculated as the product of a per-barrel maximum penalty rate and the number of barrels of oil spilled. Uncertainties currently exist in relation to both the per-barrel penalty rate that will ultimately be imposed and the volume of oil spilled.

A charge for potential Clean Water Act Section 311 penalties was first included in BP’s second-quarter 2010 interim financial statements. At the time that charge was taken, the latest estimate from the intra-agency Flow Rate Technical Group created by the National Incident Commander in charge of the spill response was between 35,000 and 60,000 barrels per day. The mid-point of that range, 47,500 barrels per day, was used for the purposes of calculating the charge. For the purposes of calculating the amount of the oil flow that was discharged into the Gulf of Mexico, the amount of oil that had been or was projected to be captured in vessels on the surface was subtracted from the total estimated flow up until when the well was capped on 15 July 2010. The result of this calculation was an estimate that approximately 3.2 million barrels of oil had been discharged into the Gulf. This estimate of 3.2 million barrels was calculated using a total flow of 47,500 barrels per day multiplied by the 85 days from 22 April 2010 through 15 July 2010 less an estimate of the amount captured on the surface (then estimated at approximately 850,000 barrels).

This estimated discharge volume was then multiplied by $1,100 per barrel – the maximum amount the statute allows in the absence of gross negligence or wilful misconduct – for the purposes of estimating a potential penalty. This resulted in a provision of $3,510 million for potential penalties under Section 311.

In utilizing the $1,100 per-barrel input, BP took into account that the actual per-barrel penalty a court may impose, or that the Government might agree to in settlement, could be lower than $1,100 per barrel if it were determined that such a lower penalty was appropriate based on the factors a court is directed to consider in assessing a penalty. In particular, in determining the amount of a civil penalty, Section 311 directs a court to consider a number of enumerated factors, including “the seriousness of the violation or violations, the economic benefit to the violator, if any, resulting from the violation, the degree of culpability involved, any other penalty for the same incident, any history of prior violations, the nature, extent, and degree of success of any efforts of the violator to minimize or mitigate the effects of the discharge, the economic impact of the penalty on the violator, and any other matters as justice may require.” Civil penalties above $1,100 per barrel up to a statutory maximum of $4,300 per barrel of oil discharged would only be imposed if gross negligence or wilful misconduct were alleged and subsequently proven. BP expects to seek assessment of a penalty lower than $1,100 per barrel based on several of these factors. However, the $1,100 per-barrel rate was utilized for the purposes of calculating a charge after considering and weighing all possible outcomes and in light of: (i) BP’s conclusion that it did not act with gross negligence or engage in wilful misconduct; and (ii) the uncertainty as to whether a court would assess a penalty below the $1,100 statutory maximum.

On 2 August 2010, the United States Department of Energy and the Flow Rate Technical Group had issued an estimate that 4.9 million barrels of oil had flowed from the Macondo well, and 4.05 million barrels had been discharged into the Gulf (the difference being the amount of oil captured by vessels on the surface as part of BP’s well containment efforts).

It was and remains BP’s view, that the 2 August 2010 Government estimate and other similar estimates are not reliable estimates because they are based on incomplete or inaccurate information, rest in large part on assumptions that have not been validated, and are subject to far greater uncertainties than have been acknowledged. As BP has publicly asserted, including at a 22 October 2010 meeting with the staff of the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, BP believes that the 2 August 2010 discharge estimate and similar estimates are overstated by a significant amount, and that the flow rate is potentially in the range of 20–50% lower. If the flow rate is 50% lower than the 2 August 2010 estimate, then the amount of oil that flowed from the Macondo well would be approximately 2.5 million barrels, and the amount discharged into the Gulf would be approximately 1.6 million barrels. If the flow rate is 20% lower than the 2 August 2010 estimate, then the amount of oil that flowed from the Macondo well would be approximately 3.9 million barrels and the amount discharged into the Gulf would be approximately 3.1 million barrels, which is not materially different from the amount we used for our original estimate at the second quarter of 2010.

36. Provisions continued

Therefore, for the purposes of calculating a provision for fines and penalties under Section 311 of the Clean Water Act, BP has continued to use an estimate of 3.2 million barrels of oil discharged to the Gulf of Mexico as its current best estimate, as defined in paragraphs 36-40 of IAS 37 'Provisions, contingent liabilities and contingent assets', of the amount which may be used in calculating the penalty under Section 311 of the Clean Water Act. This reflects an estimate of total flow from the well of approximately 4 million barrels, and an estimate of barrels captured by vessels on the surface, currently estimated at 811,000 barrels. In utilizing this estimate, BP has taken into consideration not only its own analysis of the flow and discharge issue, but also the analyses and conclusions of other parties, including the US government. The estimate of BP and of other parties as to how much oil was discharged to the Gulf of Mexico may change, perhaps materially, over time. Changes in estimates as to flow and discharge could affect the amount actually assessed for Clean Water Act fines and penalties. The year-end provision continued to be based on a per-barrel penalty of $1,100 for the reasons discussed above, including BP's continued conclusion that it did not act with gross negligence or engage in wilful misconduct.

The amount and timing of these costs will depend upon what is ultimately determined to be the volume of oil spilled and the per-barrel penalty rate that is imposed. It is not currently practicable to estimate the timing of expending these costs and the provision has been included within non-current liabilities on the balance sheet. No other amounts have been provided as at 31 December 2011 in relation to other potential fines and penalties because it is not possible to measure the obligation reliably. Fines and penalties are not covered by the trust fund.

37. Pensions and other post-retirement benefits

Most group companies have pension plans, the forms and benefits of which vary with conditions and practices in the countries concerned. Pension benefits may be provided through defined contribution plans (money purchase plans) or defined benefit plans (final salary and other types of plans with committed pension payments). For defined contribution plans, retirement benefits are determined by the value of funds arising from contributions paid in respect of each employee. For defined benefit plans, retirement benefits are based on such factors as the employees' pensionable salary and length of service. Defined benefit plans may be externally funded or unfunded. The assets of funded plans are generally held in separately administered trusts.

In particular, the primary pension arrangement in the UK is a funded final salary pension plan under which retired employees draw the majority of their benefit as an annuity. With effect from 1 April 2010, BP closed its UK plan to new joiners other than some of those joining the North Sea business. The plan remains open to ongoing accrual for those employees who had joined BP on or before 31 March 2010. The majority of new joiners in the UK have the option to join a defined contribution plan.

In the US, a range of retirement arrangements is provided. This includes a funded final salary pension plan for certain heritage employees and a cash balance arrangement for new hires. Retired US employees typically take their pension benefit in the form of a lump sum payment. US employees are also eligible to participate in a defined contribution (401k) plan in which employee contributions are matched with company contributions.

The level of contributions to funded defined benefit plans is the amount needed to provide adequate funds to meet pension obligations as they fall due. During 2011, contributions of $429 million (2010 $411 million and 2009 $9 million) and $777 million (2010 $694 million and 2009 $795 million) were made to the UK plans and US plans respectively. In addition, contributions of $223 million (2010 $188 million and 2009 $204 million) were made to other funded defined benefit plans. The aggregate level of contributions in 2012 is expected to be approximately $1,250 million, and includes contributions in all countries that we expect to be required to make by law or under contractual agreements as well as an allowance for discretionary funding.

Certain group companies, principally in the US, provide post-retirement healthcare and life insurance benefits to their retired employees and dependants. The entitlement to these benefits is usually based on the employee remaining in service until retirement age and completion of a minimum period of service.

The obligation and cost of providing pensions and other post-retirement benefits is assessed annually using the projected unit credit method. The date of the most recent actuarial review was 31 December 2011. The group's principal plans are subject to a formal actuarial valuation every three years in the UK, with valuations being required more frequently in many other countries. The most recent formal actuarial valuation of the UK pension plans was as at 31 December 2008.

The material financial assumptions used for estimating the benefit obligations of the various plans are set out below. The assumptions are reviewed by management at the end of each year, and are used to evaluate accrued pension and other post-retirement benefits at 31 December. The same assumptions are used to determine pension and other post-retirement benefit expense for the following year, that is, the assumptions at 31 December 2011 are used to determine the pension liabilities at that date and the pension expense for 2012.

									%
			UK			US			Other
Financial assumptions	**2011**	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Discount rate for pension plan liabilities	**4.8**	5.5	5.8	**4.3**	4.7	5.4	**4.7**	5.3	5.8
Discount rate for other post-retirement benefit plans	**n/a**	n/a	n/a	**4.5**	5.3	5.8	**n/a**	n/a	n/a
Rate of increase in salaries	**5.1**	5.4	5.3	**3.7**	4.1	4.2	**3.7**	3.8	3.8
Rate of increase for pensions in payment	**3.2**	3.5	3.4	**–**	–	–	**1.7**	1.8	1.8
Rate of increase in deferred pensions	**3.2**	3.5	3.4	**–**	–	–	**1.2**	1.3	1.2
Inflation	**3.2**	3.5	3.4	**1.9**	2.3	2.4	**2.2**	2.3	2.3

Our discount rate assumptions are based on third-party AA corporate bond indices and for our largest plans in the UK, US and Germany we use yields that reflect the maturity profile of the expected benefit payments. The inflation rate assumptions for our UK and US plans are based on the difference between the yields on index-linked and fixed-interest long-term government bonds. In other countries we use either this approach, or the central bank inflation target, or advice from the local actuary depending on the information that is available to us. The inflation rate assumptions are used to determine the rate of increase for pensions in payment and the rate of increase in deferred pensions where there is such an increase.

37. Pensions and other post-retirement benefits continued

Our assumptions for the rate of increase in salaries are based on our inflation rate assumption plus an allowance for expected long-term real salary growth. These include allowance for promotion-related salary growth, of between 0.3% and 0.4% depending on country.

In addition to the financial assumptions, we regularly review the demographic and mortality assumptions. The mortality assumptions reflect best practice in the countries in which we provide pensions, and have been chosen with regard to the latest available published tables adjusted where appropriate to reflect the experience of the group and an extrapolation of past longevity improvements into the future. BP's most substantial pension liabilities are in the UK, the US and Germany where our mortality assumptions are as follows:

									Years
Mortality assumptions		UK			US				Germany
	2011	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Life expectancy at age 60 for a male currently aged 60	**27.6**	26.1	26.0	**24.8**	24.7	24.6	**23.5**	23.3	23.2
Life expectancy at age 60 for a male currently aged 40	**30.5**	29.1	29.0	**26.3**	26.2	26.1	**26.3**	26.2	26.1
Life expectancy at age 60 for a female currently aged 60	**29.3**	28.7	28.6	**26.4**	26.3	26.3	**28.0**	27.9	27.8
Life expectancy at age 60 for a female currently aged 40	**32.0**	31.6	31.5	**27.3**	27.2	27.2	**30.7**	30.6	30.4

Our assumption for future US healthcare cost trend rate for the first year after the reporting date reflects the rate of actual cost increases seen in recent years. The ultimate trend rate reflects our long-term expectations of the level at which cost inflation will stabilize based on past healthcare cost inflation seen over a longer period of time. The assumed future US healthcare cost trend rate assumptions are as follows:

			%
	2011	2010	2009
First year's US healthcare cost trend rate	**7.6**	7.8	8.0
Ultimate US healthcare cost trend rate	**5.0**	5.0	5.0
Year in which ultimate trend rate is reached	**2020**	2018	2016

Pension plan assets are generally held in trusts. The primary objective of the trusts is to accumulate pools of assets sufficient to meet the obligations of the various plans. The assets of the trusts are invested in a manner consistent with fiduciary obligations and principles that reflect current practices in portfolio management.

A significant proportion of the assets are held in equities, owing to a higher expected level of return over the long term with an acceptable level of risk. In order to provide reasonable assurance that no single security or type of security has an unwarranted impact on the total portfolio, the investment portfolios are highly diversified. The long-term asset allocation policy for the major plans is as follows:

	UK	**US**	**Other**
Asset category	**%**	**%**	**%**
Total equity	**73**	**70**	**17-63**
Bonds/cash	**20**	**30**	**25-75**
Property/real estate	**7**	**–**	**0-10**

Some of the group's pension plans use derivative financial instruments as part of their asset mix and to manage the level of risk. The group's main pension plans do not invest directly in either securities or property/real estate of the company or of any subsidiary.

Return on asset assumptions reflect the group's expectations built up by asset class and by plan. The group's expectation is derived from a combination of historical returns over the long term and the forecasts of market professionals. Our assumption for return on equities is based on a long-term view, and the size of the resulting equity risk premium over government bond yields is reviewed each year for reasonableness. Our assumption for return on bonds reflects the portfolio mix of government fixed-interest, index-linked and corporate bonds.

37. Pensions and other post-retirement benefits continued

The expected long-term rates of return and market values of the various categories of assets held by the defined benefit plans at 31 December are set out below. The market values shown include the effects of derivative financial instruments. The amounts classified as equities include investments in companies listed on stock exchanges as well as unlisted investments. Movements in the value of plan assets during the year are shown in detail in the table on page 238.

		2011		2010		2009
	Expected long-term rate of return	**Market value**	Expected long-term rate of return	Market value	Expected long-term rate of return	Market value
	%	**$ million**	%	$ million	%	$ million
UK pension plans						
Equities[a]	**8.0**	**17,202**	8.0	18,546	8.0	16,945
Bonds	**4.4**	**4,141**	5.0	3,866	5.3	3,701
Property/real estate	**6.5**	**1,710**	6.5	1,462	6.5	1,269
Cash	**1.7**	**534**	1.4	406	1.1	634
	7.0	**23,587**	7.2	24,280	7.3	22,549
US pension plans						
Equities[a]	**9.0**	**5,034**	9.1	5,058	9.0	4,326
Bonds	**4.0**	**2,022**	4.5	1,419	4.8	1,218
Property/real estate	**8.0**	**4**	8.0	7	8.0	8
Cash	**0.2**	**144**	0.3	165	0.9	271
	7.4	**7,204**	8.0	6,649	8.0	5,823
US other post-retirement benefit plans						
Equities	**–**	**–**	–	–	8.5	8
Bonds	**–**	**–**	–	–	4.8	4
Cash	**0.2**	**4**	0.3	8	–	–
	0.2	**4**	0.3	8	7.6	12
Other plans						
Equities	**7.9**	**831**	8.0	1,182	8.6	1,091
Bonds	**3.3**	**1,951**	4.2	1,874	4.4	1,651
Property/real estate	**6.2**	**117**	6.3	83	6.5	82
Cash	**2.2**	**387**	2.7	155	2.0	245
	4.7	**3,286**	5.4	3,294	5.9	3,069

[a] The amounts classified as equities include investments in companies listed on stock exchanges as well as private equity investments which are substantially all unlisted. The market value of private equity investments at 31 December 2011 was $4,099 million (2010 $3,348 million and 2009 $2,956 million). The equity return assumption shown above is the weighted average of the assumed returns for listed and private equity investments in each fund. Comparative return assumptions for the US pension plans' equities have been restated to reflect this. Equity return assumptions previously disclosed reflected the assumption for listed equities only.

37. Pensions and other post-retirement benefits continued

The assumed rate of investment return, discount rate, inflation, US healthcare cost trend rate and the mortality assumptions all have a significant effect on the amounts reported.

A one-percentage point change in the following assumptions for the group’s plans would have had the effects shown in the table below. The effects shown for the expense in 2012 include current service cost and interest on plan liabilities.

		$ million
	One percentage point	
	Increase	Decrease
Investment return		
Effect on pension and other post-retirement benefit expense in 2012	**(351)**	**351**
Discount rate		
Effect on pension and other post-retirement benefit expense in 2012	**(78)**	**101**
Effect on pension and other post-retirement benefit obligation at 31 December 2011	**(5,585)**	**7,285**
Inflation rate		
Effect on pension and other post-retirement benefit expense in 2012	**494**	**(381)**
Effect on pension and other post-retirement benefit obligation at 31 December 2011	**5,323**	**(4,301)**
US healthcare cost trend rate		
Effect on US other post-retirement benefit expense in 2012	**27**	**(22)**
Effect on US other post-retirement obligation at 31 December 2011	**350**	**(290)**

One additional year of longevity in the mortality assumptions would have the effects shown in the table below. The effect shown for the expense in 2012 includes current service cost and interest on plan liabilities.

				$ million
	UK pension plans	US pension plans	US other post-retirement benefit plans	German pension plans
One additional year’s longevity				
Effect on pension and other post-retirement benefit expense in 2012	**44**	**5**	**4**	**9**
Effect on pension and other post-retirement benefit obligation at 31 December 2011	**609**	**111**	**73**	**166**

Financial statements

37. Pensions and other post-retirement benefits continued

	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
					$ million
					2011
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	383	280	53	133	849
Past service cost	–	184	–	7	191
Settlement, curtailment and special termination benefits	3	–	–	40	43
Payments to defined contribution plans	5	199	–	41	245
Total operating charge[b]	391	663	53	221	1,328
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	1,799	518	–	185	2,502
Interest on plan liabilities	(1,263)	(369)	(163)	(444)	(2,239)
Other finance income (expense)	536	149	(163)	(259)	263
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	(1,990)	10	(1)	(61)	(2,042)
Change in assumptions underlying the present value of the plan liabilities	(2,680)	(512)	39	(642)	(3,795)
Experience gains and losses arising on the plan liabilities	(84)	(102)	89	(26)	(123)
Actuarial (loss) gain recognized in other comprehensive income	(4,754)	(604)	127	(729)	(5,960)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	22,363	7,988	3,157	8,404	41,912
Exchange adjustments	(137)	–	–	(326)	(463)
Current service cost[a]	383	280	53	133	849
Past service cost	–	184	–	7	191
Interest cost	1,263	369	163	444	2,239
Curtailment	–	–	–	(1)	(1)
Settlement	–	–	–	4	4
Special termination benefits[c]	3	–	–	37	40
Contributions by plan participants[d]	33	–	–	10	43
Benefit payments (funded plans)[e]	(993)	(750)	(3)	(226)	(1,972)
Benefit payments (unfunded plans)[e]	(4)	(68)	(181)	(405)	(658)
Disposals	–	–	–	(20)	(20)
Actuarial loss (gain) on obligation	2,764	614	(128)	668	3,918
Benefit obligation at 31 December[a f]	25,675	8,617	3,061	8,729	46,082
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	24,280	6,649	8	3,294	34,231
Exchange adjustments	29	–	–	(123)	(94)
Expected return on plan assets[a g]	1,799	518	–	185	2,502
Contributions by plan participants[d]	33	–	–	10	43
Contributions by employers (funded plans)	429	777	–	223	1,429
Benefit payments (funded plans)[e]	(993)	(750)	(3)	(226)	(1,972)
Disposals	–	–	–	(16)	(16)
Actuarial gain (loss) on plan assets[g]	(1,990)	10	(1)	(61)	(2,042)
Fair value of plan assets at 31 December	23,587	7,204	4	3,286	34,081
Deficit at 31 December	(2,088)	(1,413)	(3,057)	(5,443)	(12,001)
Represented by					
Asset recognized	–	–	–	17	17
Liability recognized	(2,088)	(1,413)	(3,057)	(5,460)	(12,018)
	(2,088)	(1,413)	(3,057)	(5,443)	(12,001)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	(1,852)	(784)	(41)	(492)	(3,169)
Unfunded	(236)	(629)	(3,016)	(4,951)	(8,832)
	(2,088)	(1,413)	(3,057)	(5,443)	(12,001)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(25,439)	(7,988)	(45)	(3,778)	(37,250)
Unfunded	(236)	(629)	(3,016)	(4,951)	(8,832)
	(25,675)	(8,617)	(3,061)	(8,729)	(46,082)

[a] The costs of managing the plan's investments are treated as being part of the investment return, the costs of administering our pension plan benefits are generally included in current service cost and the costs of administering our other post-retirement benefit plans are included in the benefit obligation.
[b] Included within production and manufacturing expenses and distribution and administration expenses.
[c] The charge for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes.
[d] Most of the contributions made by plan participants after 1 January 2010 into UK pension plans were made under salary sacrifice arrangements.
[e] The benefit payments amount shown above comprises $2,576 million benefits plus $54 million of plan expenses incurred in the administration of the benefit.
[f] The benefit obligation for other plans includes $3,909 million for the German plan, which is largely unfunded.
[g] The actual return on plan assets is made up of the sum of the expected return on plan assets and the actuarial gain on plan assets as disclosed above.

37. Pensions and other post-retirement benefits continued

	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
					$ million
					2010
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	393	241	48	120	802
Past service cost	–	–	–	3	3
Settlement, curtailment and special termination benefits	24	–	–	161	185
Payments to defined contribution plans	1	187	–	35	223
Total operating charge[b]	418	428	48	319	1,213
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	1,580	465	1	178	2,224
Interest on plan liabilities	(1,183)	(396)	(169)	(429)	(2,177)
Other finance income (expense)	397	69	(168)	(251)	47
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	1,577	425	(1)	36	2,037
Change in assumptions underlying the present value of the plan liabilities	(1,144)	(498)	(132)	(489)	(2,263)
Experience gains and losses arising on the plan liabilities	12	(167)	(8)	69	(94)
Actuarial (loss) gain recognized in other comprehensive income	445	(240)	(141)	(384)	(320)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	21,425	7,519	2,996	8,133	40,073
Exchange adjustments	(835)	–	–	(269)	(1,104)
Current service cost[a]	393	241	48	120	802
Past service cost	–	–	–	3	3
Interest cost	1,183	396	169	429	2,177
Curtailment	–	–	–	4	4
Settlement	11	–	–	18	29
Special termination benefits[c]	13	–	–	139	152
Contributions by plan participants[d]	39	–	–	13	52
Benefit payments (funded plans)[e]	(952)	(758)	(4)	(192)	(1,906)
Benefit payments (unfunded plans)[e]	(3)	(75)	(192)	(387)	(657)
Acquisitions	–	–	–	2	2
Disposals	(43)	–	–	(29)	(72)
Actuarial (gain) loss on obligation	1,132	665	140	420	2,357
Benefit obligation at 31 December[a f]	22,363	7,988	3,157	8,404	41,912
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	22,549	5,823	12	3,069	31,453
Exchange adjustments	(881)	–	–	29	(852)
Expected return on plan assets[a g]	1,580	465	1	178	2,224
Contributions by plan participants[d]	39	–	–	13	52
Contributions by employers (funded plans)	411	694	–	187	1,292
Benefit payments (funded plans)[e]	(952)	(758)	(4)	(192)	(1,906)
Acquisitions	–	–	–	2	2
Disposals	(43)	–	–	(28)	(71)
Actuarial gain (loss) on plan assets[g]	1,577	425	(1)	36	2,037
Fair value of plan assets at 31 December	24,280	6,649	8	3,294	34,231
Surplus (deficit) at 31 December	1,917	(1,339)	(3,149)	(5,110)	(7,681)
Represented by					
Asset recognized	2,120	–	–	56	2,176
Liability recognized	(203)	(1,339)	(3,149)	(5,166)	(9,857)
	1,917	(1,339)	(3,149)	(5,110)	(7,681)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	2,115	(838)	(39)	(223)	1,015
Unfunded	(198)	(501)	(3,110)	(4,887)	(8,696)
	1,917	(1,339)	(3,149)	(5,110)	(7,681)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(22,165)	(7,487)	(47)	(3,517)	(33,216)
Unfunded	(198)	(501)	(3,110)	(4,887)	(8,696)
	(22,363)	(7,988)	(3,157)	(8,404)	(41,912)

[a] The costs of managing the plan's investments are treated as being part of the investment return, the costs of administering our pension plan benefits are generally included in current service cost and the costs of administering our other post-retirement benefit plans are included in the benefit obligation.
[b] Included within production and manufacturing expenses and distribution and administration expenses.
[c] The charge for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes.
[d] Most of the contributions made by plan participants after 1 January 2010 into UK pension plans were made under salary sacrifice arrangements.
[e] The benefit payments amount shown above comprises $2,507 million benefits plus $56 million of plan expenses incurred in the administration of the benefit.
[f] The benefit obligation for other plans includes $3,871 million for the German plan, which is largely unfunded.
[g] The actual return on plan assets is made up of the sum of the expected return on plan assets and the actuarial gain on plan assets as disclosed above.

37. Pensions and other post-retirement benefits continued

	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
					$million
					2009
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	311	243	48	117	719
Past service cost	–	–	(22)	1	(21)
Settlement, curtailment and special termination benefits	37	–	–	53	90
Payments to defined contribution plans	–	205	–	28	233
Total operating charge[b]	348	448	26	199	1,021
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	1,426	405	1	147	1,979
Interest on plan liabilities	(1,112)	(456)	(183)	(420)	(2,171)
Other finance income (expense)	314	(51)	(182)	(273)	(192)
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	1,761	617	2	169	2,549
Change in assumptions underlying the present value of the plan liabilities	(2,217)	(501)	(50)	(42)	(2,810)
Experience gains and losses arising on the plan liabilities	(141)	(229)	71	(122)	(421)
Actuarial (loss) gain recognized in other comprehensive income	(597)	(113)	23	5	(682)

[a] The costs of managing the plan's investments are treated as being part of the investment return, the costs of administering our pension plan benefits are generally included in current service cost and the costs of administering our other post-retirement benefit plans are included in the benefit obligation.
[b] Included within production and manufacturing expenses and distribution and administration expenses.

At 31 December 2011, reimbursement balances due from or to other companies in respect of pensions amounted to $546 million reimbursement assets (2010 $483 million) and $13 million reimbursement liabilities (2010 $13 million). These balances are not included as part of the pension surpluses and deficits, but are reflected within other receivables and other payables in the group balance sheet.

					$ million
	2011	2010	2009	2008	2007
History of surplus (deficit) and of experience gains and losses					
Benefit obligation at 31 December	**46,082**	41,912	40,073	34,847	43,100
Fair value of plan assets at 31 December	**34,081**	34,231	31,453	26,154	42,799
Deficit	**(12,001)**	(7,681)	(8,620)	(8,693)	(301)
Experience losses on plan liabilities	**(123)**	(94)	(421)	(178)	(200)
Actual return less expected return on pension plan assets	**(2,042)**	2,037	2,549	(10,253)	302
Actual return on plan assets	**460**	4,261	4,528	(7,331)	3,157
Actuarial (loss) gain recognized in other comprehensive income	**(5,960)**	(320)	(682)	(8,430)	1,717
Cumulative amount recognized in other comprehensive income	**(9,902)**	(3,942)	(3,622)	(2,940)	5,490

Estimated future benefit payments

The expected benefit payments, which reflect expected future service as appropriate, but exclude plan expenses, up until 2021 are as follows:

	UK pension plans	**US pension plans**	**US other post-retirement benefit plans**	**Other plans**	**Total**
					$ million
2012	**998**	**743**	**181**	**619**	**2,541**
2013	**1,031**	**756**	**183**	**588**	**2,558**
2014	**1,068**	**766**	**186**	**592**	**2,612**
2015	**1,109**	**778**	**188**	**583**	**2,658**
2016	**1,154**	**776**	**190**	**567**	**2,687**
2017-2021	**6,476**	**3,721**	**955**	**2,728**	**13,880**

38. Called-up share capital

The allotted, called up and fully paid share capital at 31 December was as follows:

	2011		2010		2009	
	Shares thousand	**$ million**	Shares thousand	$ million	Shares thousand	$ million
8% cumulative first preference shares of £1 each[a]	**7,233**	**12**	7,233	12	7,233	12
9% cumulative second preference shares of £1 each[a]	**5,473**	**9**	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
At 1 January	**20,647,160**	**5,162**	20,629,665	5,158	20,618,458	5,155
Issue of new shares for the scrip dividend programme	**165,601**	**41**	–	–	–	–
Issue of new shares for employee share plans[b]	**649**	**–**	17,495	4	11,207	3
At 31 December	**20,813,410**	**5,203**	20,647,160	5,162	20,629,665	5,158
		5,224		5,183		5,179

[a] The nominal amount of 8% cumulative first preference shares and 9% cumulative second preference shares that can be in issue at any time shall not exceed £10,000,000 for each class of preference shares.
[b] The nominal value of new shares issued for the employee share plans in 2011 amounted to $162,000. Consideration received relating to the issue of new shares for employee share plans amounted to $4 million (2010 $138 million and 2009 $84 million).

Voting on substantive resolutions tabled at a general meeting is on a poll. On a poll, shareholders present in person or by proxy have two votes for every £5 in nominal amount of the first and second preference shares held and one vote for every ordinary share held. On a show-of-hands vote on other resolutions (procedural matters) at a general meeting, shareholders present in person or by proxy have one vote each.

In the event of the winding up of the company, preference shareholders would be entitled to a sum equal to the capital paid up on the preference shares, plus an amount in respect of accrued and unpaid dividends and a premium equal to the higher of (i) 10% of the capital paid up on the preference shares and (ii) the excess of the average market price of such shares on the London Stock Exchange during the previous six months over par value.

Treasury shares

	2011		2010		2009	
	Shares thousand	**Nominal value $ million**	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million
At 1 January	**1,850,699**	**462**	1,869,777	467	1,888,151	472
Shares gifted to ESOPs	**–**	**–**	–	–	(1,265)	(1)
Shares transferred to ESOPs at market price	**–**	**–**	(7,125)	(2)	–	–
Shares re-issued for employee share plans	**(13,191)**	**(3)**	(11,953)	(3)	(17,109)	(4)
At 31 December	**1,837,508**	**459**	1,850,699	462	1,869,777	467

For each year presented, the balance at 1 January represents the maximum number of shares held in treasury during the year, representing 9.0% (2010 9.1% and 2009 9.2%) of the called-up ordinary share capital of the company.

During 2011, the movement in treasury shares represented less than 0.1% (2010 less than 0.1% and 2009 less than 0.1%) of the ordinary share capital of the company.

39. Capital and reserves

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2011	**5,183**	**9,987**	**1,072**	**27,206**	**43,448**
Currency translation differences (including recycling)	**–**	**–**	**–**	**–**	**–**
Actuarial loss relating to pensions and other post-retirement benefits	**–**	**–**	**–**	**–**	**–**
Available-for-sale investments (including recycling)	**–**	**–**	**–**	**–**	**–**
Cash flow hedges (including recycling)	**–**	**–**	**–**	**–**	**–**
Share of equity-accounted entities' other comprehensive income, net of tax	**–**	**–**	**–**	**–**	**–**
Profit for the year	**–**	**–**	**–**	**–**	**–**
Total comprehensive income	**–**	**–**	**–**	**–**	**–**
Dividends	**41**	**(41)**	**–**	**–**	**–**
Share-based payments[a]	**–**	**6**	**–**	**–**	**6**
Transactions involving minority interests	**–**	**–**	**–**	**–**	**–**
At 31 December 2011	**5,224**	**9,952**	**1,072**	**27,206**	**43,454**
At 1 January 2010	5,179	9,847	1,072	27,206	43,304
Currency translation differences (including recycling)	–	–	–	–	–
Actuarial loss relating to pensions and other post-retirement benefits	–	–	–	–	–
Available-for-sale investments (including recycling)	–	–	–	–	–
Cash flow hedges (including recycling)	–	–	–	–	–
Profit (loss) for the year	–	–	–	–	–
Total comprehensive income	–	–	–	–	–
Dividends	–	–	–	–	–
Share-based payments[a]	4	140	–	–	144
Transactions involving minority interests	–	–	–	–	–
At 31 December 2010	5,183	9,987	1,072	27,206	43,448
At 1 January 2009	5,176	9,763	1,072	27,206	43,217
Currency translation differences (including recycling)	–	–	–	–	–
Actuarial loss relating to pensions and other post-retirement benefits	–	–	–	–	–
Available-for-sale investments (including recycling)	–	–	–	–	–
Cash flow hedges (including recycling)	–	–	–	–	–
Profit for the year	–	–	–	–	–
Total comprehensive income	–	–	–	–	–
Dividends	–	–	–	–	–
Share-based payments[a]	3	84	–	–	87
Changes in associates' equity	–	–	–	–	–
Transactions involving minority interests	–	–	–	–	–
At 31 December 2009	5,179	9,847	1,072	27,206	43,304

[a] Includes new share issues and movements in own shares and treasury shares where these relate to employee share-based payment plans.

$ million

Own shares	Treasury shares	Total own shares and treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Total fair value reserves	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
(126)	**(21,085)**	**(21,211)**	**4,937**	**463**	**6**	**469**	**1,586**	**65,758**	**94,987**	**904**	**95,891**
–	**–**	**–**	**(515)**	**–**	**(1)**	**(1)**	**–**	**–**	**(516)**	**(10)**	**(526)**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(4,321)**	**(4,321)**	**(3)**	**(4,324)**
–	**–**	**–**	**–**	**(74)**	**–**	**(74)**	**–**	**–**	**(74)**	**–**	**(74)**
–	**–**	**–**	**–**	**–**	**(127)**	**(127)**	**–**	**–**	**(127)**	**–**	**(127)**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(57)**	**(57)**	**–**	**(57)**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**25,700**	**25,700**	**397**	**26,097**
–	**–**	**–**	**(515)**	**(74)**	**(128)**	**(202)**	**–**	**21,322**	**20,605**	**384**	**20,989**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(4,072)**	**(4,072)**	**(245)**	**(4,317)**
(262)	**150**	**(112)**	**–**	**–**	**–**	**–**	**(4)**	**102**	**(8)**	**–**	**(8)**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(47)**	**(47)**	**(26)**	**(73)**
(388)	**(20,935)**	**(21,323)**	**4,422**	**389**	**(122)**	**267**	**1,582**	**83,063**	**111,465**	**1,017**	**112,482**
(214)	(21,303)	(21,517)	4,811	754	22	776	1,584	72,655	101,613	500	102,113
–	–	–	126	–	2	2	–	–	128	3	131
–	–	–	–	–	–	–	–	(418)	(418)	–	(418)
–	–	–	–	(291)	–	(291)	–	–	(291)	–	(291)
–	–	–	–	–	(18)	(18)	–	–	(18)	–	(18)
–	–	–	–	–	–	–	–	(3,719)	(3,719)	395	(3,324)
–	–	–	126	(291)	(16)	(307)	–	(4,137)	(4,318)	398	(3,920)
–	–	–	–	–	–	–	–	(2,627)	(2,627)	(315)	(2,942)
88	218	306	–	–	–	–	2	(113)	339	–	339
–	–	–	–	–	–	–	–	(20)	(20)	321	301
(126)	(21,085)	(21,211)	4,937	463	6	469	1,586	65,758	94,987	904	95,891
(326)	(21,513)	(21,839)	2,353	63	(866)	(803)	1,295	67,080	91,303	806	92,109
–	–	–	2,458	(2)	(37)	(39)	–	–	2,419	(56)	2,363
–	–	–	–	–	–	–	–	(478)	(478)	–	(478)
–	–	–	–	693	–	693	–	–	693	–	693
–	–	–	–	–	925	925	–	–	925	–	925
–	–	–	–	–	–	–	–	16,578	16,578	181	16,759
–	–	–	2,458	691	888	1,579	–	16,100	20,137	125	20,262
–	–	–	–	–	–	–	–	(10,483)	(10,483)	(416)	(10,899)
112	210	322	–	–	–	–	289	23	721	–	721
–	–	–	–	–	–	–	–	(43)	(43)	–	(43)
–	–	–	–	–	–	–	–	(22)	(22)	(15)	(37)
(214)	(21,303)	(21,517)	4,811	754	22	776	1,584	72,655	101,613	500	102,113

39. Capital and reserves continued

Share capital
The balance on the share capital account represents the aggregate nominal value of all ordinary and preference shares in issue, including treasury shares.

Share premium account
The balance on the share premium account represents the amounts received in excess of the nominal value of the ordinary and preference shares.

Capital redemption reserve
The balance on the capital redemption reserve represents the aggregate nominal value of all the ordinary shares repurchased and cancelled.

Merger reserve
The balance on the merger reserve represents the fair value of the consideration given in excess of the nominal value of the ordinary shares issued in an acquisition made by the issue of shares.

Own shares
Own shares represent BP shares held in Employee Share Ownership Plan Trusts (ESOPs) to meet the future requirements of the employee share-based payment plans, as discussed in Note 40. At 31 December 2011, a further 21,420,000 ordinary share equivalents were held by the group in the form of ADSs to meet the requirements of employee share-based payment plans in the US.

Treasury shares
Treasury shares represent BP shares repurchased and available for re-issue.

Foreign currency translation reserve
The foreign currency translation reserve is used to record exchange differences arising from the translation of the financial statements of foreign operations. Upon disposal of foreign operations, the related accumulated exchange differences are recycled to the income statement. This reserve is also used to record the effect of hedging net investments in foreign operations.

Available-for-sale investments
This reserve records the changes in fair value of available-for-sale investments. On disposal or impairment, the cumulative changes in fair value are recycled to the income statement.

Cash flow hedges
This reserve records the portion of the gain or loss on a hedging instrument in a cash flow hedge that is determined to be an effective hedge. When the hedged transaction occurs, the gain or loss on the hedging instrument is transferred out of equity to either profit or loss or the carrying value of assets, as appropriate. If the forecast transaction is no longer expected to occur the gain or loss recognized in equity is transferred to profit or loss.

Share-based payment reserve
This reserve represents cumulative amounts charged to profit in respect of employee share-based payment plans where the scheme has not yet been settled by means of an award of shares to an individual.

Profit and loss account
The balance held on this reserve is the accumulated retained profits of the group.

39. Capital and reserves continued

The pre-tax amounts of each component of other comprehensive income, and the related amounts of tax, are shown in the table below.

			$ million
			2011
	Pre-tax	**Tax**	**Net of tax**
Currency translation differences (including recycling)	**(512)**	**(14)**	**(526)**
Actuarial loss relating to pensions and other post-retirement benefits	**(5,960)**	**1,636**	**(4,324)**
Available-for-sale investments (including recycling)	**(74)**	**–**	**(74)**
Cash flow hedges (including recycling)	**(164)**	**37**	**(127)**
Share of equity-accounted entities' other comprehensive income	**(57)**	**–**	**(57)**
Other comprehensive income	**(6,767)**	**1,659**	**(5,108)**

			$ million
			2010
	Pre-tax	Tax	Net of tax
Currency translation differences (including recycling)	239	(108)	131
Actuarial loss relating to pensions and other post-retirement benefits	(320)	(98)	(418)
Available-for-sale investments (including recycling)	(341)	50	(291)
Cash flow hedges (including recycling)	(37)	19	(18)
Other comprehensive income	(459)	(137)	(596)

			$ million
			2009
	Pre-tax	Tax	Net of tax
Currency translation differences (including recycling)	1,799	564	2,363
Actuarial loss relating to pensions and other post-retirement benefits	(682)	204	(478)
Available-for-sale investments (including recycling)	707	(14)	693
Cash flow hedges (including recycling)	1,154	(229)	925
Other comprehensive income	2,978	525	3,503

40. Share-based payments

Effect of share-based payment transactions on the group's result and financial position

			$million
	2011	2010	2009
Total expense recognized for equity-settled share-based payment transactions	**579**	577	506
Total expense (credit) recognized for cash-settled share-based payment transactions	**5**	(1)	15
Total expense recognized for share-based payment transactions	**584**	576	521
Closing balance of liability for cash-settled share-based payment transactions	**12**	16	32
Total intrinsic value for vested cash-settled share-based payments	**1**	1	7

For ease of presentation, options and shares detailed in the tables within this note are stated as UK ordinary share equivalents in US dollars. US employees are granted American Depositary Shares (ADSs) or options over the company's ADSs (one ADS is equivalent to six ordinary shares). The main share-based payment plans that existed during the year are detailed below.

Plans for executive directors

For further information on the Executive Directors' Incentive Plan (EDIP) see the Directors' remuneration report on pages 139 to 151.

Plans for senior employees

The group operates a number of equity-settled share plans under which share units are granted to its senior leaders and certain other employees. These plans typically have a three-year performance or restricted period during which the units accrue net notional dividends which are treated as having been reinvested. Leaving employment will normally preclude the conversion of units into shares, but special arrangements apply for participants that leave for qualifying reasons. Grants are settled in cash where the regulatory environment prohibits participants to hold BP shares.

Performance unit plans

The number of units granted is related to the level of seniority of employees. The number of units converted to shares is determined by reference to performance measures over the three-year performance period. The main performance measure used is BP's total shareholder return (TSR) compared to the other oil majors. Plans included in this category are the Competitive Performance Plan (CPP) and, in part, the Performance Share Plan (PSP).

Restricted share unit plans

Share unit grants under BP's restricted plans typically take into account the employee's performance in either the current or the prior year, track record of delivery, business and leadership skills and potential. One restricted share unit plan for senior employees, used in special circumstances such as recruitment and retention, normally has no performance conditions. Plans included in this category are the Executive Performance Plan (EPP), the Restricted Share Plan (RSP), the Deferred Annual Bonus Plan (DAB) and, in part, the Performance Share Plan (PSP).

BP Share Option Plan (BPSOP)

Share options with an exercise price equivalent to the market price of a BP share immediately preceding the date of grant were granted to participants annually until 2006. These options are not subject to any performance conditions and are exercisable between the third and tenth anniversaries of the grant date.

BP Plan 2011

Share options with an exercise price equivalent to the market price of a BP share immediately preceding the date of grant were granted to participants in 2011. These options are not subject to any performance conditions and will be exercisable between the third and tenth anniversaries of the grant date.

Share Value Plan

In 2012, the group will launch a new performance plan known as the Share Value Plan (SVP) which will grant restricted share units with a three-year performance period. The number of units granted is dependent on grade and country of operation. The performance measures are grade specific and include individual rating, balanced scorecard and TSR criteria. For the 2012 performance year, no further grants will be made under DAB; and from 1 January 2012, no further grants will be made under CPP, EPP or PSP.

Other plans

For further information on BP's savings and matching plans, including the BP ShareMatch plans and the BP ShareSave Plan, see page 158.

40. Share-based payments continued

Share option transactions

Details of share option transactions for the year under the share options plans are as follows:

Share option transactions	2011		2010		2009	
	Number of options	**Weighted average exercise price $**	Number of options	Weighted average exercise price $	Number of options	Weighted average exercise price $
Outstanding at 1 January	**263,306,722**	**8.75**	295,895,357	8.73	326,254,599	8.70
Granted[a]	**152,472,556**	**6.03**	10,420,287	6.08	9,679,836	6.55
Forfeited	**(9,058,406)**	**7.22**	(9,499,661)	7.88	(5,954,325)	8.81
Exercised	**(2,502,306)**	**7.64**	(31,839,034)	7.97	(21,293,871)	7.53
Expired	**(29,717,854)**	**8.26**	(1,670,227)	8.71	(12,790,882)	8.01
Outstanding at 31 December	**374,500,712**	**7.73**	263,306,722	8.75	295,895,357	8.73
Exercisable at 31 December	**209,776,014**	**9.01**	242,530,635	8.90	274,685,068	8.80

[a] Share options granted during 2011 include 142.5 million options awarded under the BP Plan 2011 with a fair value of $1.02 per option at the date of grant, determined using a binomial option pricing model including assumptions for share price volatility, dividends and cancellations.

The weighted average share price at the date of exercise was $7.71 (2010 $9.54 and 2009 $9.10).

For options outstanding at 31 December 2011, the exercise price ranges and weighted average remaining contractual lives were as shown below:

	Options outstanding[a]			**Options exercisable**	
Range of exercise prices	**Number of shares**	**Weighted average remaining life Years**	**Weighted average exercise price $**	**Number of shares**	**Weighted average exercise price $**
$5.66 – $ 7.22	**199,571,741**	**7.51**	**6.11**	**37,283,772**	**6.37**
$7.23 – $ 8.79	**81,608,110**	**1.21**	**8.13**	**81,608,110**	**8.13**
$8.80 – $ 10.35	**22,264,187**	**2.73**	**9.83**	**19,827,458**	**9.92**
$10.36 – $ 11.92	**71,056,674**	**3.81**	**11.14**	**71,056,674**	**11.14**
	374,500,712	**5.15**	**7.73**	**209,776,014**	**9.01**

[a] Included within options outstanding at 31 December 2011 are options granted under the BPSOP of 208 million options (2010 239 million options).

Fair values and associated details for restricted share units granted

For restricted share units granted in 2011, the number of units and weighted average fair value at the date of grant were as shown below:

Restricted share units granted in 2011	**CPP**	**EPP**	**RSP**	**DAB**	**PSP**
Number of restricted share units granted (million)	**1.4**	**8.9**	**20.0**	**17.5**	**19.2**
Weighted average fair value	**$11.99**	**$7.51**	**$6.86**	**$7.51**	**$7.51**
Fair value measurement basis	**Monte Carlo**	**Market value**	**Market value**	**Market value**	**Market value**

Restricted share units granted in 2010	CPP	EPP	RSP	DAB	PSP
Number of restricted share units granted (million)	1.3	7.6	21.4	24.5	16.0
Weighted average fair value	$19.81	$9.43	$6.78	$9.43	$9.43
Fair value measurement basis	Monte Carlo	Market value	Market value	Market value	Market value

Restricted share units granted in 2009	CPP	EPP	RSP	DAB	PSP
Number of restricted share units granted (million)	1.4	7.6	2.4	38.9	16.5
Weighted average fair value	$9.76	$6.56	$8.76	$6.56	$8.32
Fair value measurement basis	Monte Carlo	Market value	Market value	Market value	Monte Carlo

The group uses the observable market price for ordinary shares at the date of grant to determine the fair value of non-TSR restricted share units.

The group used a Monte Carlo simulation to determine the fair values of the TSR elements of the 2011, 2010 and 2009 CPP and EDIP grants and the 2009 PSP grant. In accordance with the plans' rules, the model simulates BP's TSR and compares it against its principal strategic competitors over the three-year period of the plans. The model takes into account the historical dividends, share price volatilities and covariances of BP and each comparator company to produce a predicted distribution of relative share performance. This is applied to the reward criteria to give an expected value of the TSR element.

Accounting expense does not necessarily represent the actual value of share-based payments made to recipients, which are determined by the remuneration committee according to established criteria.

Employee Share Ownership Plan Trusts (ESOPs)

ESOPs have been established to acquire BP shares to satisfy any awards made to participants under the BP share plans as required. The ESOPs have waived their rights to dividends on shares held for future awards and are funded by the group. Until such time as the company's own shares held by the ESOPs vest unconditionally to employees, the amount paid for those shares is shown as a reduction in shareholders' equity (see Note 39). Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

At 31 December 2011, the ESOPs held 27,784,503 shares (2010 11,477,253 shares and 2009 18,062,246 shares) for potential future awards, which had a market value of $197 million (2010 $82 million and 2009 $174 million).

41. Employee costs and numbers

Employee costs	2011	2010	2009
			$ million
Wages and salaries[a]	**9,827**	9,242	9,702
Social security costs	**851**	789	780
Share-based payments	**584**	576	521
Pension and other post-retirement benefit costs	**1,065**	1,166	1,213
	12,327	11,773	12,216

Number of employees at 31 December	2011	2010	2009
Exploration and Production	**22,200**	21,100	21,500
Refining and Marketing[b]	**51,000**	52,300	51,600
Other businesses and corporate	**10,100**	6,200	7,200
Gulf Coast Restoration Organization	**100**	100	–
	83,400	79,700	80,300
By geographical area			
US	**22,900**	22,100	22,800
Non-US[b]	**60,500**	57,600	57,500
	83,400	79,700	80,300

		2011			2010			2009	
Average number of employees	US	Non-US	Total	US	Non-US	Total	US	Non-US	Total
Exploration and Production	**8,500**	**13,200**	**21,700**	8,100	13,500	21,600	7,900	13,800	21,700
Refining and Marketing	**12,300**	**39,200**	**51,500**	12,600	38,300	50,900	14,700	40,700	55,400
Other businesses and corporate	**1,700**	**6,500**	**8,200**	1,900	5,000	6,900	2,300	5,800	8,100
Gulf Coast Restoration Organization	**100**	**–**	**100**	–	–	–	–	–	–
	22,600	**58,900**	**81,500**	22,600	56,800	79,400	24,900	60,300	85,200

[a] Includes termination payments of $126 million (2010 $166 million and 2009 $945 million).
[b] Includes 14,600 (2010 15,200 and 2009 13,900) service station staff.

42. Remuneration of directors and senior management

Remuneration of directors

	2011	2010	2009
			$ million
Total for all directors			
Emoluments	**10**	15	19
Gains made on exercise of share options	**–**	2	2
Amounts awarded under incentive schemes	**1**	4	2

Emoluments
These amounts comprise fees paid to the non-executive chairman and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus bonuses awarded for the year. There was no compensation for loss of office in 2011 (2010 $3 million and 2009 nil).

Pension contributions
During 2011 one executive director participated in a non-contributory pension plan established for UK employees by a separate trust fund to which contributions are made by BP based on actuarial advice. Two US executive directors participated in the US BP Retirement Accumulation Plan during 2011.

Office facilities for former chairmen and deputy chairmen
It is customary for the company to make available to former chairmen and deputy chairmen, who were previously employed executives, the use of office and basic secretarial facilities following their retirement. The cost involved in doing so is not significant.

Further information
Full details of individual directors' remuneration are given in the directors' remuneration report on pages 139 to 151.

Remuneration of directors and senior management

Total for all senior management	2011	2010	2009
			$ million
Total for all senior management			
Short-term employee benefits	**34**	25	36
Post-retirement benefits	**3**	3	3
Share-based payments	**27**	29	20

42. Remuneration of directors and senior management continued

Senior management, in addition to executive and non-executive directors, includes other senior managers who are members of the executive management team.

Short-term employee benefits

In addition to fees paid to the non-executive chairman and non-executive directors, these amounts comprise, for executive directors and senior managers, salary and benefits earned during the year, plus cash bonuses awarded for the year. Deferred annual bonus awards, to be settled in shares, are included in share-based payments. Short-term employee benefits includes compensation for loss of office of $9 million (2010 $3 million and 2009 $6 million).

Post-retirement benefits

The amounts represent the estimated cost to the group of providing defined benefit pensions and other post-retirement benefits to senior management in respect of the current year of service measured in accordance with IAS 19 'Employee Benefits'.

Share-based payments

This is the cost to the group of senior management's participation in share-based payment plans, as measured by the fair value of options and shares granted accounted for in accordance with IFRS 2 'Share-based Payments'. The main plans in which senior management have participated are the EDIP, DAB and RSP. For details of these plans refer to Note 40.

43. Contingent liabilities

Contingent liabilities relating to the Gulf of Mexico oil spill

As a consequence of the Gulf of Mexico oil spill, as described on pages 76 to 79, BP has incurred costs during the year and recognized provisions for certain future costs. Further information is provided in Note 2 and Note 36.

BP has provided for its best estimate of amounts expected to be paid from the $20-billion trust fund. This includes certain amounts expected to be paid pursuant to the Oil Pollution Act of 1990 (OPA 90), as well as the increased estimate of the cost of individual and business claims as a result of the proposed settlement with the PSC announced on 3 March 2012 as described in Note 2 and Note 36. It is not possible, at this time, to measure reliably any other items that will be paid from the trust fund, namely any obligation in relation to Natural Resource Damages claims other than the emergency and early restoration costs as described in Note 36, and claims asserted in civil litigation, including any further litigation through potential opt-outs from the proposed settlement agreement, nor is it practicable to estimate their magnitude or possible timing of payment.

Natural resource damages resulting from the oil spill are currently being assessed (see Note 36 for further information). BP and the federal and state trustees are collecting extensive data in order to assess the extent of damage to wildlife, shoreline, near shore and deepwater habitats, and recreational uses, among other things. Because the affected areas and their uses vary by seasons, we are continuing our work to complete a full assessment of the natural resource damages. In addition, as and when early restoration projects are undertaken, these projects could mitigate the total damages resulting from the incident. Accordingly, until the size, location and duration of the impact have been fully determined and the effects of early restoration projects are fully assessed, or other actions such as potential future settlement discussions occur, it is not possible to obtain a range of outcomes or to estimate reliably either the amounts (other than the amounts previously provided for emergency and early restoration projects) or timing of the remaining Natural Resource Damages claims.

BP is named as a defendant in approximately 600 civil lawsuits brought by individuals, corporations and governmental entities in US federal and state courts resulting from the Gulf of Mexico oil spill. Additional lawsuits are likely to be brought. The lawsuits assert, among others, claims for personal injury in connection with the incident itself and the response to it, and wrongful death, commercial or economic injury, securities and shareholder claims, breach of contract and violations of statutes. The lawsuits, many of which purport to be class actions, seek various remedies including compensation to injured workers and families of deceased workers, recovery for commercial losses and property damage, claims for environmental damage, remediation costs, injunctive relief, treble damages and punitive damages. Most of these lawsuits have been consolidated into one of two multi-district litigation (MDL) proceedings. On 3 March 2012, BP announced that it had reached a proposed settlement with the Plaintiffs' Steering Committee (PSC), subject to final written agreement and court approvals, to resolve the substantial majority of legitimate economic loss and medical claims stemming from the Deepwater Horizon accident and oil spill. The PSC acts on behalf of individual and business plaintiffs in the MDL 2179 and the estimated cost of the proposed settlement has been reflected in the financial statements. While BP announced that it had reached a proposed settlement with the PSC, a trial of liability issues in the MDL 2179 is, at this time, still expected to go ahead. Damage issues will be scheduled for trial thereafter. Until further fact and expert disclosures occur, court rulings clarify the issues in dispute, liability and damage trial activity nears, or other actions such as possible settlements occur, it is not possible given these uncertainties to arrive at a range of outcomes or a reliable estimate of the liability other than the estimated cost of the proposed settlement with the PSC. See Legal proceedings on pages 160 to 164 for further information.

Therefore, with the exception of the estimated costs of the proposed settlement agreement with the PSC, no amounts have been provided for these items as of 31 December 2011. Although these items, which will be paid through the trust fund, have not been provided for at this time, BP's full obligation under the $20-billion trust fund has been expensed in the income statement, taking account of the time value of money. The aggregate of amounts paid and provided for items to be settled from the trust fund currently falls within the amount committed by BP to the trust fund.

For those items not covered by the trust fund it is not possible to measure reliably any obligation in relation to other litigation or potential fines and penalties except, subject to certain assumptions detailed in Note 36, for those relating to the Clean Water Act. There are a number of federal and state environmental and other provisions of law, other than the Clean Water Act, under which one or more governmental agencies could seek civil fines and penalties from BP. For example, a complaint filed by the United States sought to reserve the ability to seek penalties and other relief under a number of other laws. Given the large number of claims that may be asserted, it is not possible at this time to determine whether and to what extent any such claims would be successful or what penalties or fines would be assessed. Therefore no amounts have been provided for these items.

Under the settlement agreements with Anadarko and MOEX, BP has agreed to indemnify Anadarko and MOEX for certain claims arising from the accident (excluding civil, criminal or administrative fines and penalties, claims for punitive damages, and certain other claims). Under the settlement agreement entered into with M-I L.L.C. (M-I) (see Legal proceedings on pages 160 to 164), BP agreed to indemnify M-I for certain claims resulting from the accident. M-I was contracted by BP to provide specialized drilling mud and mud engineering services for the Macondo well. It is therefore possible that BP may face claims under these indemnities, but it is not currently possible to reliably measure any obligation in relation to such claims and therefore no amount has been provided as at 31 December 2011.

43. Contingent liabilities continued

The magnitude and timing of possible obligations in relation to the Gulf of Mexico oil spill are subject to a very high degree of uncertainty as described further in Risk factors on pages 59 to 63. Any such possible obligations are therefore contingent liabilities and, at present, it is not practicable to estimate their magnitude or possible timing of payment. Certain items are subject to settlement discussions or may be subject to settlement discussions in the future. Any settlements which may be reached relating to the Deepwater Horizon accident and oil spill could impact the amount and timing of any future payments. Furthermore, other material unanticipated obligations may arise in future in relation to the incident.

Other contingent liabilities

There were contingent liabilities at 31 December 2011 in respect of guarantees and indemnities entered into as part of the ordinary course of the group's business. No material losses are likely to arise from such contingent liabilities. Further information is included in Note 26.

Lawsuits arising out of the Exxon Valdez oil spill in Prince William Sound, Alaska, in March 1989 were filed against Exxon (now ExxonMobil), Alyeska Pipeline Service Company (Alyeska), which operates the oil terminal at Valdez, and the other oil companies that own Alyeska. Alyeska initially responded to the spill until the response was taken over by Exxon. BP owns a 46.9% interest (reduced during 2001 from 50% by a sale of 3.1% to Phillips) in Alyeska through a subsidiary of BP America Inc. and briefly indirectly owned a further 20% interest in Alyeska following BP's combination with Atlantic Richfield Company (Atlantic Richfield). Alyeska and its owners have settled all the claims against them under these lawsuits. Exxon has indicated that it may file a claim for contribution against Alyeska for a portion of the costs and damages that Exxon has incurred. BP will defend any such claims vigorously. It is not possible to estimate any financial effect.

In the normal course of the group's business, legal proceedings are pending or may be brought against BP group entities arising out of current and past operations, including matters related to commercial disputes, product liability, antitrust, premises-liability claims, general environmental claims and allegations of exposures of third parties to toxic substances, such as lead pigment in paint, asbestos and other chemicals. BP believes that the impact of these legal proceedings on the group's results of operations, liquidity or financial position will not be material.

With respect to lead pigment in paint in particular, Atlantic Richfield, a subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property. Although it is not possible to predict the outcome of the legal proceedings, Atlantic Richfield believes it has valid defences that render the incurrence of a liability remote; however, the amounts claimed and the costs of implementing the remedies sought in the various cases could be substantial. The majority of the lawsuits have been abandoned or dismissed against Atlantic Richfield. No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgment in any proceeding. Atlantic Richfield intends to defend such actions vigorously.

The group files income tax returns in many jurisdictions throughout the world. Various tax authorities are currently examining the group's income tax returns. Tax returns contain matters that could be subject to differing interpretations of applicable tax laws and regulations and the resolution of tax positions through negotiations with relevant tax authorities, or through litigation, can take several years to complete. While it is difficult to predict the ultimate outcome in some cases, the group does not anticipate that there will be any material impact upon the group's results of operations, financial position or liquidity.

The group is subject to numerous national and local environmental laws and regulations concerning its products, operations and other activities. These laws and regulations may require the group to take future action to remediate the effects on the environment of prior disposal or release of chemicals or petroleum substances by the group or other parties. Such contingencies may exist for various sites including refineries, chemical plants, oilfields, service stations, terminals and waste disposal sites. In addition, the group may have obligations relating to prior asset sales or closed facilities. The ultimate requirement for remediation and its cost are inherently difficult to estimate. However, the estimated cost of known environmental obligations has been provided in these accounts in accordance with the group's accounting policies. While the amounts of future costs could be significant and could be material to the group's results of operations in the period in which they are recognized, it is not practical to estimate the amounts involved. BP does not expect these costs to have a material effect on the group's financial position or liquidity.

The group also has obligations to decommission oil and natural gas production facilities and related pipelines. Provision is made for the estimated costs of these activities, however there is uncertainty regarding both the amount and timing of these costs, given the long-term nature of these obligations. BP believes that the impact of any reasonably foreseeable changes to these provisions on the group's results of operations, financial position or liquidity will not be material.

The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. This is because external insurance is not considered an economic means of financing losses for the group. Losses will therefore be borne as they arise rather than being spread over time through insurance premiums with attendant transaction costs. The position is reviewed periodically.

44. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been placed at 31 December 2011 amounted to $12,517 million (2010 $11,279 million). In addition, at 31 December 2011, the group had contracts in place for future capital expenditure relating to investments in jointly controlled entities of $296 million (2010 $437 million) and investments in associates of $36 million (2010 $80 million).

BP's share of capital commitments of jointly controlled entities amounted to $1,244 million (2010 $1,117 million).

45. Subsidiaries, jointly controlled entities and associates

The more important subsidiaries, jointly controlled entities and associates of the group at 31 December 2011 and the group percentage of ordinary share capital or joint venture interest (to nearest whole number) are set out below. Those held directly by the parent company are marked with an asterisk (*), the percentage owned being that of the group unless otherwise indicated. A complete list of investments in subsidiaries, jointly controlled entities and associates will be attached to the parent company's annual return made to the Registrar of Companies.

Subsidiaries	%	Country of incorporation	Principal activities
International			
*BP Corporate Holdings	100	England & Wales	Investment holding
BP Europa SE	100	Germany	Refining and marketing and petrochemicals
BP Exploration Operating Company	100	England & Wales	Exploration and production
*BP Global Investments	100	England & Wales	Investment holding
*BP International	100	England & Wales	Integrated oil operations
BP Oil International	100	England & Wales	Integrated oil operations
*BP Shipping	100	England & Wales	Shipping
*Burmah Castrol	100	Scotland	Lubricants
Jupiter Insurance	100	Guernsey	Insurance
Algeria			
BP Amoco Exploration (In Amenas)	100	Scotland	Exploration and production
BP Exploration (El Djazair)	100	Bahamas	Exploration and production
Angola			
BP Exploration (Angola)	100	England & Wales	Exploration and production
Australia			
BP Australia Capital Markets	100	Australia	Finance
BP Developments Australia	100	Australia	Exploration and production
BP Finance Australia	100	Australia	Finance
BP Oil Australia	100	Australia	Integrated oil operations
Azerbaijan			
Amoco Caspian Sea Petroleum	100	British Virgin Islands	Exploration and production
BP Exploration (Caspian Sea)	100	England & Wales	Exploration and production
Brazil			
BP Energy do Brazil	100	Brazil	Exploration and production
Canada			
BP Canada Energy	100	Canada	Exploration and production
BP Canada Finance	100	Canada	Finance
Egypt			
BP Egypt Company	100	US	Exploration and production
India			
BP Exploration (Alpha)	100	England & Wales	Exploration and production
Indonesia			
BP Berau	100	US	Exploration and production
New Zealand			
BP Oil New Zealand	100	New Zealand	Marketing
Norway			
BP Norge	100	Norway	Exploration and production
Spain			
BP España	100	Spain	Refining and marketing
South Africa			
*BP Southern Africa	75	South Africa	Refining and marketing
Trinidad & Tobago			
BP Trinidad and Tobago	70	US	Exploration and production
UK			
BP Capital Markets	100	England & Wales	Finance
BP Oil UK	100	England & Wales	Marketing
Britoil	100	Scotland	Exploration and production
US			
*BP Holdings North America	100	England & Wales	Investment holding
Atlantic Richfield Company	100	US	
BP America	100	US	
BP America Production Company	100	US	
BP Amoco Chemical Company	100	US	
BP Company North America	100	US	
BP Corporation North America	100	US	Exploration and production, refining and marketing, pipelines and petrochemicals
BP Exploration & Production	100	US	
BP Exploration (Alaska)	100	US	
BP Products North America	100	US	
BP West Coast Products	100	US	
Standard Oil Company	100	US	
Verano Collateral Holdings	100	US	
BP Capital Markets America	100	US	Finance

45. Subsidiaries, jointly controlled entities and associates continued

Jointly controlled entities	%	Country of incorporation	Principal activities
Angola			
Angola LNG Supply Services	14	US	LNG processing and transportation
Argentina			
Pan American Energy[a]	60	US	Exploration and production
Canada			
Sunrise Oil Sands	50	Canada	Exploration and production
China			
Shanghai SECCO Petrochemical Company	50	China	Petrochemicals
Germany			
Ruhr Oel	50	Germany	Refining and petrochemicals
Trinidad & Tobago			
Atlantic 4 Holdings	38	US	LNG manufacture
Atlantic LNG 2/3 Company of Trinidad and Tobago	43	Trinidad & Tobago	LNG manufacture
Taiwan			
China American Petrochemical Company[a]	61	Taiwan	Petrochemicals
UK			
Vivergo Fuels	46	England & Wales	Biofuels
US			
BP-Husky Refining	50	US	Refining
Watson Cogeneration[a b]	51	US	Power generation

[a] The entity is not controlled by BP as certain key business decisions require joint approval of both BP and the minority partner. It is therefore classified as a jointly controlled entity rather than a subsidiary.
[b] As at 31 December 2011 the group's interests in Watson Cogeneration have been classified as assets held for sale. See Note 4 for further information.

Associates	%	Country of incorporation	Principal activities
Abu Dhabi			
Abu Dhabi Gas Liquefaction Company	10	United Arab Emirates	Crude oil production
Abu Dhabi Marine Areas	33	England & Wales	Crude oil production
Abu Dhabi Petroleum Company	24	England & Wales	Crude oil production
Azerbaijan			
The Baku-Tbilisi-Ceyhan Pipeline Company	30	Cayman Islands	Pipelines
South Caucasus Pipeline Company	26	Cayman Islands	Pipelines
Russia			
TNK-BP	50	British Virgin Islands	Integrated oil operations

46. Condensed consolidating information on certain US subsidiaries

BP p.l.c. fully and unconditionally guarantees the payment obligations of its 100%-owned subsidiary BP Exploration (Alaska) Inc. under the BP Prudhoe Bay Royalty Trust. The following financial information for BP p.l.c., BP Exploration (Alaska) Inc. and all other subsidiaries on a condensed consolidating basis is intended to provide investors with meaningful and comparable financial information about BP p.l.c. and its subsidiary issuers of registered securities and is provided pursuant to Rule 3-10 of Regulation S-X in lieu of the separate financial statements of each subsidiary issuer of public debt securities. Investments include the investments in subsidiaries recorded under the equity method for the purposes of the condensed consolidating financial information. Equity income of subsidiaries is the group's share of profit related to such investments. The eliminations and reclassifications column includes the necessary amounts to eliminate the intercompany balances and transactions between BP p.l.c., BP Exploration (Alaska) Inc. and other subsidiaries. The financial information presented in the following tables for BP Exploration (Alaska) Inc. for all years includes equity income arising from subsidiaries of BP Exploration (Alaska) Inc., some of which operate outside of Alaska and excludes the BP group's midstream operations in Alaska that are reported through different legal entities and that are included within the 'other subsidiaries' column in these tables. BP p.l.c. also fully and unconditionally guarantees securities issued by BP Capital Markets p.l.c. and BP Capital Markets America Inc. These companies are 100%-owned finance subsidiaries of BP p.l.c.

Income statement

					$ million
For the year ended 31 December					**2011**
	Issuer	**Guarantor**			
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Sales and other operating revenues	6,159	–	375,517	(6,159)	375,517
Earnings from jointly controlled entities – after interest and tax	–	–	1,304	–	1,304
Earnings from associates – after interest and tax	–	–	4,916	–	4,916
Equity-accounted income of subsidiaries – after interest and tax	313	26,158	–	(26,471)	–
Interest and other revenues	10	242	664	(320)	596
Gains on sale of businesses and fixed assets	–	1	4,129	–	4,130
Total revenues and other income	6,482	26,401	386,530	(32,950)	386,463
Purchases	978	–	290,799	(6,159)	285,618
Production and manufacturing expenses	1,280	–	22,865	–	24,145
Production and similar taxes	1,684	–	6,596	–	8,280
Depreciation, depletion and amortization	335	–	10,800	–	11,135
Impairment and losses on sale of businesses and fixed assets	–	–	2,058	–	2,058
Exploration expense	4	–	1,516	–	1,520
Distribution and administration expenses	27	1,048	12,992	(109)	13,958
Fair value gain on embedded derivatives	–	–	(68)	–	(68)
Profit before interest and taxation	2,174	25,353	38,972	(26,682)	39,817
Finance costs	32	47	1,378	(211)	1,246
Net finance (income) expense relating to pensions and other post-retirement benefits	–	(533)	270	–	(263)
Profit before taxation	2,142	25,839	37,324	(26,471)	38,834
Taxation	729	139	11,869	–	12,737
Profit for the year	1,413	25,700	25,455	(26,471)	26,097
Attributable to					
BP shareholders	1,413	25,700	25,058	(26,471)	25,700
Minority interest	–	–	397	–	397
	1,413	25,700	25,455	(26,471)	26,097

46. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

$ million

For the year ended 31 December					2010
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	4,793	–	297,107	(4,793)	297,107
Earnings from jointly controlled entities – after interest and tax	–	–	1,175	–	1,175
Earnings from associates – after interest and tax	–	–	3,582	–	3,582
Equity-accounted income of subsidiaries – after interest and tax	620	(3,567)	–	2,947	–
Interest and other revenues	–	188	714	(221)	681
Gains on sale of businesses and fixed assets	–	260	6,376	(253)	6,383
Total revenues and other income	5,413	(3,119)	308,954	(2,320)	308,928
Purchases	637	–	220,367	(4,793)	216,211
Production and manufacturing expenses	966	–	63,649	–	64,615
Production and similar taxes	998	–	4,246	–	5,244
Depreciation, depletion and amortization	351	–	10,813	–	11,164
Impairment and losses on sale of businesses and fixed assets	1,524	–	1,689	(1,524)	1,689
Exploration expense	–	–	843	–	843
Distribution and administration expenses	16	673	11,975	(109)	12,555
Fair value loss on embedded derivatives	–	–	309	–	309
Profit (loss) before interest and taxation	921	(3,792)	(4,937)	4,106	(3,702)
Finance costs	2	31	1,249	(112)	1,170
Net finance (income) expense relating to pensions and other post-retirement benefits	4	(388)	337	–	(47)
Profit (loss) before taxation	915	(3,435)	(6,523)	4,218	(4,825)
Taxation	143	31	(1,675)	–	(1,501)
Profit (loss) for the year	772	(3,466)	(4,848)	4,218	(3,324)
Attributable to					
BP shareholders	772	(3,466)	(5,243)	4,218	(3,719)
Minority interest	–	–	395	–	395
	772	(3,466)	(4,848)	4,218	(3,324)

46. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

					$ million
For the year ended 31 December					2009
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	4,189	–	239,272	(4,189)	239,272
Earnings from jointly controlled entities – after interest and tax	–	–	1,286	–	1,286
Earnings from associates – after interest and tax	–	–	2,615	–	2,615
Equity-accounted income of subsidiaries – after interest and tax	838	17,315	–	(18,153)	–
Interest and other revenues	17	144	832	(201)	792
Gains on sale of businesses and fixed assets	–	9	2,173	(9)	2,173
Total revenues and other income	5,044	17,468	246,178	(22,552)	246,138
Purchases	510	–	167,451	(4,189)	163,772
Production and manufacturing expenses	970	–	22,232	–	23,202
Production and similar taxes	602	–	3,150	–	3,752
Depreciation, depletion and amortization	424	–	11,682	–	12,106
Impairment and losses on sale of businesses and fixed assets	–	–	2,333	–	2,333
Exploration expense	–	–	1,116	–	1,116
Distribution and administration expenses	27	1,145	12,974	(108)	14,038
Fair value gain on embedded derivatives	–	–	(607)	–	(607)
Profit before interest and taxation	2,511	16,323	25,847	(18,255)	26,426
Finance costs	22	26	1,155	(93)	1,110
Net finance (income) expense relating to pensions and other post-retirement benefits	10	(310)	492	–	192
Profit before taxation	2,479	16,607	24,200	(18,162)	25,124
Taxation	583	20	7,762	–	8,365
Profit for the year	1,896	16,587	16,438	(18,162)	16,759
Attributable to					
BP shareholders	1,896	16,587	16,257	(18,162)	16,578
Minority interest	–	–	181	–	181
	1,896	16,587	16,438	(18,162)	16,759

Financial statements

46. Condensed consolidating information on certain US subsidiaries continued

Balance Sheet

At 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2011 BP group
Non-current assets					
Property, plant and equipment	8,653	–	110,561	–	119,214
Goodwill	–	–	12,100	–	12,100
Intangible assets	456	–	20,646	–	21,102
Investments in jointly controlled entities	–	–	15,518	–	15,518
Investments in associates	–	2	13,289	–	13,291
Other investments	–	–	2,117	–	2,117
Subsidiaries – equity-accounted basis	4,802	129,042	–	(133,844)	–
Fixed assets	13,911	129,044	174,231	(133,844)	183,342
Loans	46	38	5,113	(4,313)	884
Other receivables	–	–	4,337	–	4,337
Derivative financial instruments	–	–	5,038	–	5,038
Prepayments	–	–	1,255	–	1,255
Deferred tax assets	–	–	611	–	611
Defined benefit pension plan surpluses	–	–	17	–	17
	13,957	129,082	190,602	(138,157)	195,484
Current assets					
Loans	–	–	244	–	244
Inventories	167	–	25,494	–	25,661
Trade and other receivables	4,109	17,698	49,753	(28,034)	43,526
Derivative financial instruments	–	–	3,857	–	3,857
Prepayments	7	–	1,279	–	1,286
Current tax receivable	–	–	235	–	235
Other investments	–	–	288	–	288
Cash and cash equivalents	(1)	–	14,068	–	14,067
	4,282	17,698	95,218	(28,034)	89,164
Assets classified as held for sale	–	–	8,420	–	8,420
	4,282	17,698	103,638	(28,034)	97,584
Total assets	18,239	146,780	294,240	(166,191)	293,068
Current liabilities					
Trade and other payables	5,035	2,390	73,014	(28,034)	52,405
Derivative financial instruments	–	–	3,220	–	3,220
Accruals	–	28	5,904	–	5,932
Finance debt	–	–	9,044	–	9,044
Current tax payable	287	–	1,654	–	1,941
Provisions	–	–	11,238	–	11,238
	5,322	2,418	104,074	(28,034)	83,780
Liabilities directly associated with assets classified as held for sale	–	–	538	–	538
	5,322	2,418	104,612	(28,034)	84,318
Non-current liabilities					
Other payables	9	4,264	3,477	(4,313)	3,437
Derivative financial instruments	–	–	3,773	–	3,773
Accruals	–	35	354	–	389
Finance debt	–	–	35,169	–	35,169
Deferred tax liabilities	1,966	–	13,112	–	15,078
Provisions	1,620	–	24,784	–	26,404
Defined benefit pension plan and other post-retirement benefit plan deficits	–	2,088	9,930	–	12,018
	3,595	6,387	90,599	(4,313)	96,268
Total liabilities	8,917	8,805	195,211	(32,347)	180,586
Net assets	9,322	137,975	99,029	(133,844)	112,482
Equity					
BP shareholders' equity	9,322	137,975	98,012	(133,844)	111,465
Minority interest	–	–	1,017	–	1,017
Total equity	9,322	137,975	99,029	(133,844)	112,482

46. Condensed consolidating information on certain US subsidiaries continued

Balance Sheet continued

$ million

At 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries[a]	Eliminations and reclassifications	BP group[a]
					2010
Non-current assets					
Property, plant and equipment	7,679	–	102,484	–	110,163
Goodwill	–	–	8,598	–	8,598
Intangible assets	425	–	13,873	–	14,298
Investments in jointly controlled entities	–	–	14,927	–	14,927
Investments in associates	–	2	13,333	–	13,335
Other investments	–	–	1,191	–	1,191
Subsidiaries – equity-accounted basis	4,489	112,227	–	(116,716)	–
Fixed assets	12,593	112,229	154,406	(116,716)	162,512
Loans	–	38	5,161	(4,305)	894
Other receivables	–	–	6,298	–	6,298
Derivative financial instruments	–	–	4,210	–	4,210
Prepayments	–	–	1,432	–	1,432
Deferred tax assets	–	–	528	–	528
Defined benefit pension plan surpluses	–	1,870	306	–	2,176
	12,593	114,137	172,341	(121,021)	178,050
Current assets					
Loans	–	–	247	–	247
Inventories	244	–	25,974	–	26,218
Trade and other receivables	3,173	14,444	42,783	(23,851)	36,549
Derivative financial instruments	–	–	4,356	–	4,356
Prepayments	6	–	1,568	–	1,574
Current tax receivable	–	–	693	–	693
Other investments	–	–	1,532	–	1,532
Cash and cash equivalents	(1)	4	18,553	–	18,556
	3,422	14,448	95,706	(23,851)	89,725
Assets classified as held for sale	–	–	4,487	–	4,487
	3,422	14,448	100,193	(23,851)	94,212
Total assets	16,015	128,585	272,534	(144,872)	272,262
Current liabilities					
Trade and other payables	4,931	2,362	62,887	(23,851)	46,329
Derivative financial instruments	–	–	3,856	–	3,856
Accruals	–	23	5,589	–	5,612
Finance debt	–	–	14,626	–	14,626
Current tax payable	182	–	2,738	–	2,920
Provisions	–	–	9,489	–	9,489
	5,113	2,385	99,185	(23,851)	82,832
Liabilities directly associated with assets classified as held for sale	–	–	1,047	–	1,047
	5,113	2,385	100,232	(23,851)	83,879
Non-current liabilities					
Other payables	9	4,258	14,323	(4,305)	14,285
Derivative financial instruments	–	–	3,677	–	3,677
Accruals	–	35	602	–	637
Finance debt	–	–	30,710	–	30,710
Deferred tax liabilities	2,026	410	8,472	–	10,908
Provisions	958	–	21,460	–	22,418
Defined benefit pension plan and other post-retirement benefit plan deficits	–	–	9,857	–	9,857
	2,993	4,703	89,101	(4,305)	92,492
Total liabilities	8,106	7,088	189,333	(28,156)	176,371
Net assets	7,909	121,497	83,201	(116,716)	95,891
Equity					
BP shareholders' equity	7,909	121,497	82,297	(116,716)	94,987
Minority interest	–	–	904	–	904
Total equity	7,909	121,497	83,201	(116,716)	95,891

[a] Adjusted following the termination of the Pan American Energy LLC sale agreement as described in Note 4.

Financial statements

46. Condensed consolidating information on certain US subsidiaries continued

Cash flow statement

$ million

For the year ended 31 December					2011
	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Net cash provided by operating activities	661	8,321	25,114	(11,942)	22,154
Net cash used in investing activities	(661)	(3,710)	(22,262)	–	(26,633)
Net cash (used in) provided by financing activities	–	(4,615)	(6,845)	11,942	482
Currency translation differences relating to cash and cash equivalents	–	–	(492)	–	(492)
Decrease in cash and cash equivalents	–	(4)	(4,485)	–	(4,489)
Cash and cash equivalents at beginning of year	(1)	4	18,553	–	18,556
Cash and cash equivalents at end of year	(1)	–	14,068	–	14,067

$ million

For the year ended 31 December					2010
	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Net cash provided by (used in) operating activities	829	32,111	(4,584)	(14,740)	13,616
Net cash (used in) provided by investing activities	(752)	(29,325)	26,117	–	(3,960)
Net cash (used in) provided by financing activities	(56)	(2,810)	(11,034)	14,740	840
Currency translation differences relating to cash and cash equivalents	–	–	(279)	–	(279)
Increase (decrease) in cash and cash equivalents	21	(24)	10,220	–	10,217
Cash and cash equivalents at beginning of year	(22)	28	8,333	–	8,339
Cash and cash equivalents at end of year	(1)	4	18,553	–	18,556

$ million

For the year ended 31 December					2009
	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Net cash provided by operating activities	1,022	14,514	47,466	(35,286)	27,716
Net cash used in investing activities	(935)	(4,227)	(12,971)	–	(18,133)
Net cash used in financing activities	(99)	(10,270)	(34,468)	35,286	(9,551)
Currency translation differences relating to cash and cash equivalents	–	–	110	–	110
(Decrease) increase in cash and cash equivalents	(12)	17	137	–	142
Cash and cash equivalents at beginning of year	(10)	11	8,196	–	8,197
Cash and cash equivalents at end of year	(22)	28	8,333	–	8,339

Supplementary information on oil and natural gas (unaudited)

The regional analysis presented below is on a continent basis, with separate disclosure for countries that contain 15% or more of the total proved reserves (for subsidiaries plus equity-accounted entities), in accordance with SEC and FASB requirements.

Oil and gas reserves – certain definitions

Unless the context indicates otherwise, the following terms have the meanings shown below:

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.

For details on BP's proved reserves and production compliance and governance processes, see pages 90 to 91.

Oil and natural gas exploration and production activities

	Europe: UK	Europe: Rest of Europe	North America: US	North America: Rest of North America	South America	Africa	Asia: Russia	Asia: Rest of Asia	Australasia	Total
										$ million
										2011
Subsidiaries[a]										
Capitalized costs at 31 December[b j]										
Gross capitalized costs										
Proved properties	37,491	8,994	73,626	182	7,471	29,358	–	14,833	3,370	175,325
Unproved properties	368	180	6,198	1,471	2,986	3,689	–	4,495	1,279	20,666
	37,859	9,174	79,824	1,653	10,457	33,047	–	19,328	4,649	195,991
Accumulated depreciation	26,953	3,715	36,009	139	3,839	14,595	–	6,235	1,294	92,779
Net capitalized costs	10,906	5,459	43,815	1,514	6,618	18,452	–	13,093	3,355	103,212
Costs incurred for the year ended 31 December[b j]										
Acquisition of properties[c k]										
Proved	–	–	1,178	8	237	–	–	1,733	–	3,156
Unproved	–	1	418	–	2,592	679	–	3,008	–	6,698
	–	1	1,596	8	2,829	679	–	4,741	–	9,854
Exploration and appraisal costs[d]	211	1	566	117	271	490	6	511	225	2,398
Development	1,361	889	3,016	–	405	2,933	–	1,340	251	10,195
Total costs	1,572	891	5,178	125	3,505	4,102	6	6,592	476	22,447
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	1,997	–	751	25	2,263	3,353	–	1,450	1,611	11,450
Sales between businesses	3,495	1,273	19,089	20	1,409	4,858	–	10,811	967	41,922
	5,492	1,273	19,840	45	3,672	8,211	–	12,261	2,578	53,372
Exploration expenditure	37	1	1,065	9	35	163	6	134	70	1,520
Production costs	1,372	230	3,402	66	503	1,146	4	787	194	7,704
Production taxes	72	–	1,854	–	278	–	–	5,956	147	8,307
Other costs (income)[f]	(1,357)	101	4,688	49	935	215	72	118	257	5,078
Depreciation, depletion and amortization	874	199	2,980	6	523	1,668	–	1,692	172	8,114
Impairments and (gains) losses on sale of businesses and fixed assets	26	(64)	(492)	15	(1,085)	18	(1)	(537)	–	(2,120)
	1,024	467	13,497	145	1,189	3,210	81	8,150	840	28,603
Profit (loss) before taxation[g]	4,468	806	6,343	(100)	2,483	5,001	(81)	4,111	1,738	24,769
Allocable taxes	2,483	384	2,152	(159)	1,205	2,184	(21)	1,001	677	9,906
Results of operations	1,985	422	4,191	59	1,278	2,817	(60)	3,110	1,061	14,863
Exploration and Production segment replacement cost profit before interest and tax										
Exploration and production activities –subsidiaries (as above)	4,468	806	6,343	(100)	2,483	5,001	(81)	4,111	1,738	24,769
Midstream activities – subsidiaries[h]	(118)	29	(157)	299	(58)	(4)	(1)	42	284	316
Equity-accounted entities[i]	–	12	10	58	598	69	4,095	573	–	5,415
Total replacement cost profit before interest and tax	4,350	847	6,196	257	3,023	5,066	4,013	4,726	2,022	30,500

[a] These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries. They do not include any costs relating to the Gulf of Mexico oil spill. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia and BP is also investing in the LNG business in Angola.

[b] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

[c] Includes costs capitalized as a result of asset exchanges.

[d] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[e] Presented net of transportation costs, purchases and sales taxes.

[f] Includes property taxes, other government take and the fair value gain on embedded derivatives of $191 million. The UK region includes a $1,442 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme. The South America region includes a charge of $700 million associated with the termination of the agreement to sell our 60% interest in Pan American Energy LLC to Bridas Corporation (see page 85).

[g] Excludes the unwinding of the discount on provisions and payables amounting to $352 million which is included in finance costs in the group income statement.

[h] Midstream activities exclude inventory holding gains and losses.

[i] The profits of equity-accounted entities are included after interest and tax.

[j] Excludes balances associated with assets held for sale.

[k] Excludes goodwill associated with business combinations.

Oil and natural gas exploration and production activities continued

$ million

2011	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Equity-accounted entities (BP share)[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	–	–	–	168	6,562	–	16,214	3,571	–	26,515
Unproved properties	–	–	–	1,510	19	–	652	9	–	2,190
	–	–	–	1,678	6,581	–	16,866	3,580	–	28,705
Accumulated depreciation	–	–	–	–	2,644	–	6,978	3,017	–	12,639
Net capitalized costs	–	–	–	1,678	3,937	–	9,888	563	–	16,066
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved	–	–	–	–	–	–	–	46	–	46
Unproved	–	–	–	–	6	–	37	–	–	43
	–	–	–	–	6	–	37	46	–	89
Exploration and appraisal costs[d]	–	–	–	–	2	–	167	9	–	178
Development	–	–	–	251	587	–	1,862	435	–	3,135
Total costs	–	–	–	251	595	–	2,066	490	–	3,402
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	–	–	–	–	2,381	–	7,380	3,828	–	13,589
Sales between businesses	–	–	–	–	–	–	5,149	23	–	5,172
	–	–	–	–	2,381	–	12,529	3,851	–	18,761
Exploration expenditure	–	–	–	–	10	–	72	1	–	83
Production costs	–	–	–	–	459	–	1,846	212	–	2,517
Production taxes	–	–	–	–	1,098	–	5,000	3,125	–	9,223
Other costs (income)	–	–	–	–	(239)	–	2	(1)	–	(238)
Depreciation, depletion and amortization	–	–	–	–	329	–	988	431	–	1,748
Impairments and (gains) losses on sale of businesses and fixed assets	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	1,657	–	7,908	3,768	–	13,333
Profit (loss) before taxation	–	–	–	–	724	–	4,621	83	–	5,428
Allocable taxes	–	–	–	–	294	–	806	19	–	1,119
Results of operations	–	–	–	–	430	–	3,815	64	–	4,309
Exploration and production activities – equity-accounted entities after tax (as above)	–	–	–	–	430	–	3,815	64	–	4,309
Midstream and other activities after tax[f]	–	12	10	58	168	69	280	509	–	1,106
Total replacement cost profit after interest and tax	–	12	10	58	598	69	4,095	573	–	5,415

[a] These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. They do not include amounts relating to assets held for sale. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation as well as downstream activities of TNK-BP are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.
[b] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.
[c] Includes costs capitalized as a result of asset exchanges.
[d] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
[e] Presented net of transportation costs and sales taxes.
[f] Includes interest, minority interest and the net results of equity-accounted entities of equity-accounted entities, and excludes inventory holding gains and losses.

Oil and natural gas exploration and production activities continued

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		$ million 2010
Subsidiaries[a]										
Capitalized costs at 31 December[b j]										
Gross capitalized costs										
Proved properties	36,161	7,846	67,724	278	6,047	27,014	–	11,497	3,088	159,655
Unproved properties	787	179	5,968	1,363	220	2,694	–	1,113	1,149	13,473
	36,948	8,025	73,692	1,641	6,267	29,708	–	12,610	4,237	173,128
Accumulated depreciation	27,688	3,515	33,972	216	3,282	13,893	–	4,569	1,205	88,340
Net capitalized costs	9,260	4,510	39,720	1,425	2,985	15,815	–	8,041	3,032	84,788
Costs incurred for the year ended 31 December[b j]										
Acquisition of properties[c]										
Proved	–	–	655	1	–	–	–	1,121	–	1,777
Unproved	–	519	1,599	1,200	–	–	–	151	–	3,469
	–	519	2,254	1,201	–	–	–	1,272	–	5,246
Exploration and appraisal costs[d]	401	13	1,096	78	68	607	7	316	120	2,706
Development	726	816	3,034	251	414	3,003	–	1,244	187	9,675
Total costs	1,127	1,348	6,384	1,530	482	3,610	7	2,832	307	17,627
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	1,472	58	1,148	90	1,896	3,158	–	1,272	1,398	10,492
Sales between businesses	3,405	1,134	18,819	453	1,574	4,353	–	6,697	929	37,364
	4,877	1,192	19,967	543	3,470	7,511	–	7,969	2,327	47,856
Exploration expenditure	82	(2)	465	25	9	189	7	51	17	843
Production costs	1,018	152	2,867	240	445	938	9	365	124	6,158
Production taxes	52	–	1,093	2	249	–	–	3,764	109	5,269
Other costs (income)[f]	(316)	76	3,502	129	209	130	76	90	195	4,091
Depreciation, depletion and amortization	897	209	3,477	95	575	1,771	–	829	168	8,021
Impairments and (gains) losses on sale of businesses and fixed assets	(1)	–	(1,441)	(2,190)	(3)	(427)	341[k]	–	–	(3,721)
	1,732	435	9,963	(1,699)	1,484	2,601	433	5,099	613	20,661
Profit (loss) before taxation[g]	3,145	757	10,004	2,242	1,986	4,910	(433)	2,870	1,714	27,195
Allocable taxes	1,333	530	3,504	610	1,084	1,771	(23)	813	410	10,032
Results of operations	1,812	227	6,500	1,632	902	3,139	(410)	2,057	1,304	17,163
Exploration and Production segment replacement cost profit before interest and tax										
Exploration and production activities – subsidiaries (as above)	3,145	757	10,004	2,242	1,986	4,910	(433)	2,870	1,714	27,195
Midstream activities – subsidiaries[h]	23	42	(347)	3	49	(26)	4	(23)	(13)	(288)
Equity-accounted entities[i]	–	4	27	171	614	63	2,613	487	–	3,979
Total replacement cost profit before interest and tax	3,168	803	9,684	2,416	2,649	4,947	2,184	3,334	1,701	30,886

[a] These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries. They do not include any costs relating to the Gulf of Mexico oil spill. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia and BP is also investing in the LNG business in Angola.

[b] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

[c] Includes costs capitalized as a result of asset exchanges.

[d] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[e] Presented net of transportation costs, purchases and sales taxes.

[f] Includes property taxes, other government take and the fair value loss on embedded derivatives of $309 million. The UK region includes a $822 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.

[g] Excludes the unwinding of the discount on provisions and payables amounting to $313 million which is included in finance costs in the group income statement.

[h] Midstream activities exclude inventory holding gains and losses.

[i] The profits of equity-accounted entities are included after interest and tax.

[j] Excludes balances associated with assets held for sale.

[k] This amount represents the write-down of our investment in Sakhalin. A portion of these costs was previously reported within capitalized costs of equity-accounted entities with the remainder previously reported as a loan, which was not included in the disclosures of oil and natural gas exploration and production activities.

Oil and natural gas exploration and production activities continued

$ million

	Europe		North America		South America	Africa	Asia		Australasia	2010 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Equity-accounted entities (BP share)[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	–	–	–	142	5,778	–	14,486	3,192	–	23,598
Unproved properties	–	–	–	1,284	163	–	652	–	–	2,099
	–	–	–	1,426	5,941	–	15,138	3,192	–	25,697
Accumulated depreciation	–	–	–	–	2,250	–	6,300	2,674	–	11,224
Net capitalized costs	–	–	–	1,426	3,691	–	8,838	518	–	14,473
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved	–	–	–	–	–	–	–	–	–	–
Unproved	–	–	–	–	9	–	66	–	–	75
	–	–	–	–	9	–	66	–	–	75
Exploration and appraisal costs[d]	–	–	–	–	2	–	94	–	–	96
Development	–	–	–	49	549	–	1,416	355	–	2,369
Total costs	–	–	–	49	560	–	1,576	355	–	2,540
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	–	–	–	–	2,268	–	5,610	2,557	–	10,435
Sales between businesses	–	–	–	–	–	–	3,432	19	–	3,451
	–	–	–	–	2,268	–	9,042	2,576	–	13,886
Exploration expenditure	–	–	–	–	22	–	40	–	–	62
Production costs	–	–	–	–	316	–	1,602	184	–	2,102
Production taxes	–	–	–	–	911	–	3,567	2,029	–	6,507
Other costs (income)	–	–	–	67	75	–	3	(2)	–	143
Depreciation, depletion and amortization	–	–	–	–	269	–	954	363	–	1,586
Impairments and losses on sale of businesses and fixed assets	–	–	–	–	–	–	43	–	–	43
	–	–	–	67	1,593	–	6,209	2,574	–	10,443
Profit (loss) before taxation	–	–	–	(67)	675	–	2,833	2	–	3,443
Allocable taxes	–	–	–	–	260	–	475	33	–	768
Results of operations	–	–	–	(67)	415	–	2,358	(31)	–	2,675
Exploration and production activities –equity-accounted entities after tax (as above)	–	–	–	(67)	415	–	2,358	(31)	–	2,675
Midstream and other activities after tax[f]	–	4	27	238	199	63	255	518	–	1,304
Total replacement cost profit after interest and tax	–	4	27	171	614	63	2,613	487	–	3,979

[a] These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. They do not include amounts relating to assets held for sale. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation as well as downstream activities of TNK-BP are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.
[b] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.
[c] Includes costs capitalized as a result of asset exchanges.
[d] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
[e] Presented net of transportation costs and sales taxes.
[f] Includes interest, minority interest and the net results of equity-accounted entities of equity-accounted entities.

Oil and natural gas exploration and production activities continued

$ million

2009

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	35,096	6,644	64,366	3,967	8,346	24,476	–	10,900	2,894	156,689
Unproved properties	752	–	5,464	147	198	2,377	–	733	1,039	10,710
	35,848	6,644	69,830	4,114	8,544	26,853	–	11,633	3,933	167,399
Accumulated depreciation	26,794	3,306	31,728	2,309	4,837	12,492	–	4,798	1,038	87,302
Net capitalized costs	9,054	3,338	38,102	1,805	3,707	14,361	–	6,835	2,895	80,097
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved	179	–	(17)	–	–	–	–	306	–	468
Unproved	(1)	–	370	1	–	18	–	–	10	398
	178	–	353	1	–	18	–	306	10	866
Exploration and appraisal costs[d]	183	–	1,377	79	78	712	8	315	53	2,805
Development	751	1,054	4,208	386	453	2,707	–	560	277	10,396
Total costs	1,112	1,054	5,938	466	531	3,437	8	1,181	340	14,067
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	2,239	68	972	99	1,525	1,846	–	636	785	8,170
Sales between businesses	2,482	809	15,100	484	1,409	5,313	–	6,257	726	32,580
	4,721	877	16,072	583	2,934	7,159	–	6,893	1,511	40,750
Exploration expenditure	59	–	663	80	16	219	8	49	22	1,116
Production costs	1,243	164	2,821	284	395	908	15	361	70	6,261
Production taxes	(3)	–	649	1	220	–	–	2,854	72	3,793
Other costs (income)[f]	(1,259)	51	2,353	145	184	144	76	967	178	2,839
Depreciation, depletion and amortization	1,148	185	3,857	170	697	2,041	–	757	96	8,951
Impairments and (gains) losses on sale of businesses and fixed assets	(122)	(7)	(208)	–	(11)	(1)	–	(702)[j]	–	(1,051)
	1,066	393	10,135	680	1,501	3,311	99	4,286	438	21,909
Profit (loss) before taxation[g]	3,655	484	5,937	(97)	1,433	3,848	(99)	2,607	1,073	18,841
Allocable taxes	1,568	76	1,902	(58)	916	1,517	(25)	682	2	6,580
Results of operations	2,087	408	4,035	(39)	517	2,331	(74)	1,925	1,071	12,261
Exploration and Production segment replacement cost profit before interest and tax										
Exploration and production activities –subsidiaries (as above)	3,655	484	5,937	(97)	1,433	3,848	(99)	2,607	1,073	18,841
Midstream activities – subsidiaries[h j]	925	17	719	833	17	(27)	(37)	518	(315)	2,650
Equity-accounted entities[i]	–	5	29	134	630	56	1,924	531	–	3,309
Total replacement cost profit before interest and tax	4,580	506	6,685	870	2,080	3,877	1,788	3,656	758	24,800

[a] These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia and BP is also investing in the LNG business in Angola.

[b] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

[c] Includes costs capitalized as a result of asset exchanges.

[d] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[e] Presented net of transportation costs, purchases and sales taxes. Sales between businesses and third party sales have been amended in the US without net effect to total sales.

[f] Includes property taxes, other government take and the fair value gain on embedded derivatives of $663 million. The UK region includes a $783 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.

[g] Excludes the unwinding of the discount on provisions and payables amounting to $308 million which is included in finance costs in the group income statement.

[h] Midstream activities exclude inventory holding gains and losses.

[i] The profits of equity-accounted entities are included after interest and tax.

[j] Includes the gain on disposal of upstream assets associated with our sale of our 46% stake in LukArco (see Note 5).

Oil and natural gas exploration and production activities continued

$ million

	Europe		North America		South America	Africa	Asia		Australasia	2009 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Equity-accounted entities (BP share)[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	–	–	–	–	5,789	–	13,266	2,259	–	21,314
Unproved properties	–	–	–	1,378	197	–	737	–	–	2,312
	–	–	–	1,378	5,986	–	14,003	2,259	–	23,626
Accumulated depreciation	–	–	–	–	2,084	–	5,550	1,739	–	9,373
Net capitalized costs	–	–	–	1,378	3,902	–	8,453	520	–	14,253
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved	–	–	–	–	–	–	–	–	–	–
Unproved	–	–	–	–	31	–	10	–	–	41
	–	–	–	–	31	–	10	–	–	41
Exploration and appraisal costs[d]	–	–	–	–	21	–	77	3	–	101
Development	–	–	–	30	538	–	1,182	246	–	1,996
Total costs	–	–	–	30	590	–	1,269	249	–	2,138
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	–	–	–	–	1,977	–	4,919	1,874	–	8,770
Sales between businesses	–	–	–	–	–	–	2,838	–	–	2,838
	–	–	–	–	1,977	–	7,757	1,874	–	11,608
Exploration expenditure	–	–	–	–	23	–	37	–	–	60
Production costs	–	–	–	–	354	–	1,428	159	–	1,941
Production taxes	–	–	–	–	702	–	2,597	1,523	–	4,822
Other costs (income)	–	–	–	–	(69)	–	12	(2)	–	(59)
Depreciation, depletion and amortization	–	–	–	–	281	–	1,073	274	–	1,628
Impairments and losses on sale of businesses and fixed assets	–	–	–	–	–	–	72	–	–	72
	–	–	–	–	1,291	–	5,219	1,954	–	8,464
Profit (loss) before taxation	–	–	–	–	686	–	2,538	(80)	–	3,144
Allocable taxes	–	–	–	–	270	–	501	–	–	771
Results of operations	–	–	–	–	416	–	2,037	(80)	–	2,373
Exploration and production activities –equity-accounted entities after tax (as above)	–	–	–	–	416	–	2,037	(80)	–	2,373
Midstream and other activities after tax[f]	–	5	29	134	214	56	(113)	611	–	936
Total replacement cost profit after interest and tax	–	5	29	134	630	56	1,924	531	–	3,309

a These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation as well as downstream activities of TNK-BP are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.
b Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.
c Includes costs capitalized as a result of asset exchanges.
d Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
e Presented net of transportation costs, purchases and sales taxes.
f Includes interest, minority interest and the net results of equity-accounted entities of equity-accounted entities.

Movements in estimated net proved reserves

million barrels

Crude oil[a]	Europe		North America		South America	Africa	Asia		Australasia	2011 Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2011										
Developed	364	77	1,729	–	44	371	–	269	48	2,902
Undeveloped	431	221	1,190	–	58	374	–	325	58	2,657
	795	298	2,919	–	102	745	–	594	106	5,559
Changes attributable to										
Revisions of previous estimates	(1)	5	27	–	6	(68)	–	(131)	3	(159)
Improved recovery	14	8	97	–	1	10	–	70	6	206
Purchases of reserves-in-place	–	–	10	–	7	–	–	4	–	21
Discoveries and extensions	–	–	1	–	1	19	–	–	–	21
Production[b]	(41)	(12)	(162)	–	(13)	(68)	–	(50)	(9)	(355)
Sales of reserves-in-place	(34)	–	(34)	–	(29)	(12)	–	(31)	–	(140)
	(62)	1	(61)	–	(27)	(119)	–	(138)	–	(406)
At 31 December 2011[c]										
Developed	288	69	1,685	–	27	311	–	177	59	2,616
Undeveloped	445	230	1,173	–	48	315	–	279	47	2,537
	733	299	2,858	–	75	626	–	456	106	5,153
Equity-accounted entities (BP share)[f]										
At 1 January 2011										
Developed	–	–	–	–	408	–	2,388	370	–	3,166
Undeveloped	–	–	–	–	407	12	1,362	24	–	1,805
	–	–	–	–	815	12	3,750	394	–	4,971
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(12)	2	677	(5)	–	662
Improved recovery	–	–	–	–	70	–	73	–	–	143
Purchases of reserves-in-place	–	–	–	–	98	–	–	1	–	99
Discoveries and extensions	–	–	–	–	–	–	25	–	–	25
Production	–	–	–	–	(30)	–	(316)	(76)	–	(422)
Sales of reserves-in-place	–	–	–	–	(244)	–	–	–	–	(244)
	–	–	–	–	(118)	2	459	(80)	–	263
At 31 December 2011[d g]										
Developed	–	–	–	–	349	–	2,596	256	–	3,201
Undeveloped	–	–	–	–	348	14	1,613	58	–	2,033
	–	–	–	–	697	14	4,209	314	–	5,234
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2011										
Developed	364	77	1,729	–	452	371	2,388	639	48	6,068
Undeveloped	431	221	1,190	–	465	386	1,362	349	58	4,462
	795	298	2,919	–	917	757	3,750	988	106	10,530
At 31 December 2011										
Developed	288	69	1,685	–	376	311	2,596	433	59	5,817
Undeveloped	445	230	1,173	–	396	329	1,613	337	47	4,570
	733	299	2,858	–	772	640	4,209	770	106	10,387

[a] Crude oil includes NGLs and condensate. Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Excludes NGLs from processing plants in which an interest is held of 28 thousand barrels per day.
[c] Includes 616 million barrels of NGLs. Also includes 20 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 19 million barrels of NGLs. Also includes 310 million barrels of crude oil in respect of the 7.37% minority interest in TNK-BP.
[e] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 82 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[g] Total proved liquid reserves held as part of our equity interest in TNK-BP is 4,305 million barrels, comprising 95 million barrels in Venezuela, one million barrels in Vietnam and 4,209 million barrels in Russia. In 2011, BP aligned its reporting with TNK-BP by moving to a life of field reporting basis. Reasonable certainty of licence renewals is demonstrated by evidence of Russian subsoil law, track record of renewals within the industry and track record of success in obtaining renewals by TNK-BP. This has resulted in an increase in proved liquid reserves of 221 million barrels.

Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a]	Europe		North America		South America	Africa	Asia		Australasia	2011 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2011										
Developed	1,416	40	9,495	58	3,575	1,329	–	1,290	3,563	20,766
Undeveloped	829	430	4,248	–	6,575	2,351	–	268	2,342	17,043
	2,245	470	13,743	58	10,150	3,680	–	1,558	5,905	37,809
Changes attributable to										
Revisions of previous estimates	169	30	–	(9)	202	(206)	–	69	299	554
Improved recovery	56	1	597	–	84	15	–	28	22	803
Purchases of reserves-in-place	8	–	93	7	–	–	–	310	–	418
Discoveries and extensions	–	–	219	–	47	–	–	–	–	266
Production[b]	(146)	(8)	(737)	(5)	(811)	(232)	–	(244)	(291)	(2,474)
Sales of reserves-in-place	(12)	–	(363)	(23)	(274)	–	–	(323)	–	(995)
	75	23	(191)	(30)	(752)	(423)	–	(160)	30	(1,428)
At 31 December 2011[c]										
Developed	1,411	43	9,721	28	2,869	1,224	–	1,034	3,570	19,900
Undeveloped	909	450	3,831	–	6,529	2,033	–	364	2,365	16,481
	2,320	493	13,552	28	9,398	3,257	–	1,398	5,935	36,381
Equity-accounted entities (BP share)[e]										
At 1 January 2011										
Developed	–	–	–	–	1,075	–	1,900	71	–	3,046
Undeveloped	–	–	–	–	1,192	175	459	19	–	1,845
	–	–	–	–	2,267	175	2,359	90	–	4,891
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(75)	20	683	(3)	–	625
Improved recovery	–	–	–	–	190	–	–	12	–	202
Purchases of reserves-in-place	–	–	–	–	31	–	–	76	–	107
Discoveries and extensions	–	–	–	–	–	–	–	–	–	–
Production[b]	–	–	–	–	(167)	–	(264)	(20)	–	(451)
Sales of reserves-in-place	–	–	–	–	(96)	–	–	–	–	(96)
	–	–	–	–	(117)	20	419	65	–	387
At 31 December 2011[d] [f]										
Developed	–	–	–	–	1,144	–	2,119	104	–	3,367
Undeveloped	–	–	–	–	1,006	195	659	51	–	1,911
	–	–	–	–	2,150	195	2,778	155	–	5,278
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2011										
Developed	1,416	40	9,495	58	4,650	1,329	1,900	1,361	3,563	23,812
Undeveloped	829	430	4,248	–	7,767	2,526	459	287	2,342	18,888
	2,245	470	13,743	58	12,417	3,855	2,359	1,648	5,905	42,700
At 31 December 2011										
Developed	1,411	43	9,721	28	4,013	1,224	2,119	1,138	3,570	23,267
Undeveloped	909	450	3,831	–	7,535	2,228	659	415	2,365	18,392
	2,320	493	13,552	28	11,548	3,452	2,778	1,553	5,935	41,659

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Includes 196 billion cubic feet of natural gas consumed in operations, 155 billion cubic feet in subsidiaries, 41 billion cubic feet in equity-accounted entities and excludes 14 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.
[c] Includes 2,759 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 174 billion cubic feet of natural gas in respect of the 6.27% minority interest in TNK-BP.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Total proved gas reserves held as part of our equity interest in TNK-BP is 2,881 billion cubic feet, comprising 30 billion cubic feet in Venezuela, 73 billion cubic feet in Vietnam and 2,778 billion cubic feet in Russia. In 2011, BP aligned its reporting with TNK-BP by moving to a life of field reporting basis. Reasonable certainty of licence renewals is demonstrated by evidence of Russian subsoil law, track record of renewals within the industry and track record of success in obtaining renewals by TNK-BP. This has resulted in an increase in proved gas reserves of 185 billion cubic feet.

Movements in estimated net proved reserves continued

Bitumen[a]		million barrels
		2011
	Rest of North America	Total
Equity-accounted entities (BP share)		
At 1 January 2011		
Developed	–	–
Undeveloped	179	179
	179	179
Changes attributable to		
Revisions of previous estimates	(1)	(1)
Improved recovery	–	–
Purchases of reserves-in-place	–	–
Discoveries and extensions	–	–
Production	–	–
Sales of reserves-in-place	–	–
	(1)	(1)
At 31 December 2011		
Developed	–	–
Undeveloped	178	178
	178	178

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

Movements in estimated net proved reserves continued

Total hydrocarbons[a]	Europe		North America		South America	Africa	Asia		Australasia	Total
										million barrels of oil equivalent
										2011
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2011										
Developed	608	84	3,366	10	660	600	–	491	662	6,481
Undeveloped	574	295	1,923	–	1,192	779	–	371	462	5,596
	1,182	379	5,289	10	1,852	1,379	–	862	1,124	12,077
Changes attributable to										
Revisions of previous estimates	28	10	27	(2)	41	(103)	–	(119)	55	(63)
Improved recovery	24	8	200	–	15	12	–	75	10	344
Purchases of reserves-in-place	1	–	26	2	7	–	–	58	–	94
Discoveries and extensions	–	–	39	–	9	19	–	–	–	67
Production[b f]	(66)	(13)	(289)	(1)	(153)	(108)	–	(92)	(59)	(781)
Sales of reserves-in-place	(36)	–	(97)	(4)	(76)	(12)	–	(87)	–	(312)
	(49)	5	(94)	(5)	(157)	(192)	–	(165)	6	(651)
At 31 December 2011[c]										
Developed	531	76	3,362	5	522	522	–	355	675	6,048
Undeveloped	602	308	1,833	–	1,173	665	–	342	455	5,378
	1,133	384	5,195	5	1,695	1,187	–	697	1,130	11,426
Equity-accounted entities (BP share)[g]										
At 1 January 2011										
Developed	–	–	–	–	593	–	2,716	382	–	3,691
Undeveloped	–	–	–	179	613	43	1,441	27	–	2,303
	–	–	–	179	1,206	43	4,157	409	–	5,994
Changes attributable to										
Revisions of previous estimates	–	–	–	(1)	(25)	5	795	(5)	–	769
Improved recovery	–	–	–	–	103	–	73	2	–	178
Purchases of reserves-in-place	–	–	–	–	103	–	–	14	–	117
Discoveries and extensions	–	–	–	–	–	–	25	–	–	25
Production[b f]	–	–	–	–	(59)	–	(362)	(80)	–	(501)
Sales of reserves-in-place	–	–	–	–	(260)	–	–	–	–	(260)
	–	–	–	(1)	(138)	5	531	(69)	–	328
At 31 December 2011[d h]										
Developed	–	–	–	–	546	–	2,961	274	–	3,781
Undeveloped	–	–	–	178	522	48	1,727	66	–	2,541
	–	–	–	178	1,068	48	4,688	340	–	6,322
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2011										
Developed	608	84	3,366	10	1,253	600	2,716	873	662	10,172
Undeveloped	574	295	1,923	179	1,805	822	1,441	398	462	7,899
	1,182	379	5,289	189	3,058	1,422	4,157	1,271	1,124	18,071
At 31 December 2011										
Developed	531	76	3,362	5	1,068	522	2,961	629	675	9,829
Undeveloped	602	308	1,833	178	1,695	713	1,727	408	455	7,919
	1,133	384	5,195	183	2,763	1,235	4,688	1,037	1,130	17,748

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Excludes NGLs from processing plants in which an interest is held of 28 thousand barrels of oil equivalent per day.
[c] Includes 616 million barrels of NGLs. Also includes 496 million barrels of oil equivalent in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 19 million barrels of NGLs. Also includes 340 million barrels of oil equivalent in respect of the minority interest in TNK-BP.
[e] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 82 million barrels of oil equivalent upon which a net profits royalty will be payable.
[f] Includes 34 million barrels of oil equivalent of natural gas consumed in operations, 27 million barrels of oil equivalent in subsidiaries, seven million barrels of oil equivalent in equity-accounted entities and excludes two million barrels of oil equivalent of produced non-hydrocarbon components which meet regulatory requirements for sales.
[g] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[h] Total proved reserves held as part of our equity interest in TNK-BP is 4,802 million barrels of oil equivalent, comprising 100 million barrels of oil equivalent in Venezuela, 14 million barrels of oil equivalent in Vietnam and 4,688 million barrels of oil equivalent in Russia. In 2011, BP aligned its reporting with TNK-BP by moving to a life of field reporting basis. Reasonable certainty of licence renewals is demonstrated by evidence of Russian subsoil law, track record of renewals within the industry and track record of success in obtaining renewals by TNK-BP. This has resulted in an increase in proved reserves of 253 million barrels of oil equivalent.

Movements in estimated net proved reserves continued

Crude oil[a]	Europe		North America		South America	Africa	Asia		Australasia	2010 Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		million barrels
Subsidiaries										
At 1 January 2010										
Developed	403	83	1,862	11	49	422	–	182	58	3,070
Undeveloped	291	184	1,211	1	56	454	–	334	57	2,588
	694	267	3,073	12	105	876	–	516	115	5,658
Changes attributable to										
Revisions of previous estimates	20	3	(45)	1	(1)	(62)	–	(62)	–	(146)
Improved recovery	100	9	133	–	17	14	–	145	3	421
Purchases of reserves-in-place	–	33	6	–	–	–	–	38	–	77
Discoveries and extensions	31	1	80	–	–	19	–	–	–	131
Production[b j]	(50)	(15)	(211)	(2)	(19)	(87)	–	(43)	(12)	(439)
Sales of reserves-in-place	–	–	(117)	(11)	–	(15)	–	–	–	(143)
	101	31	(154)	(12)	(3)	(131)	–	78	(9)	(99)
At 31 December 2010[c g]										
Developed	364	77	1,729	–	44	371	–	269	48	2,902
Undeveloped	431	221	1,190	–	58	374	–	325	58	2,657
	795	298	2,919	–	102	745	–	594	106	5,559
Equity-accounted entities (BP share)[f]										
At 1 January 2010										
Developed	–	–	–	–	407	–	2,351	363	–	3,121
Undeveloped	–	–	–	–	405	9	1,198	120	–	1,732
	–	–	–	–	812	9	3,549	483	–	4,853
Changes attributable to										
Revisions of previous estimates	–	–	–	–	4	3	248	(20)	–	235
Improved recovery	–	–	–	–	33	–	269	–	–	302
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	1	–	–	–	–	1
Production	–	–	–	–	(35)[i k]	–	(313)	(69)	–	(417)
Sales of reserves-in-place	–	–	–	–	–	–	(3)	–	–	(3)
	–	–	–	–	3	3	201	(89)	–	118
At 31 December 2010[d]										
Developed	–	–	–	–	408	–	2,388	370	–	3,166
Undeveloped	–	–	–	–	407	12	1,362	24	–	1,805
	–	–	–	–	815[h]	12	3,750	394	–	4,971
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2010										
Developed	403	83	1,862	11	456	422	2,351	545	58	6,191
Undeveloped	291	184	1,211	1	461	463	1,198	454	57	4,320
	694	267	3,073	12	917	885	3,549	999	115	10,511
At 31 December 2010										
Developed	364	77	1,729	–	452	371	2,388	639	48	6,068
Undeveloped	431	221	1,190	–	465	386	1,362	349	58	4,462
	795	298	2,919	–	917	757	3,750	988	106	10,530

a Crude oil includes NGLs and condensate. Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
b Excludes NGLs from processing plants in which an interest is held of 29 thousand barrels per day.
c Includes 643 million barrels of NGLs. Also includes 22 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
d Includes 18 million barrels of NGLs. Also includes 254 million barrels of crude oil in respect of the 7.03% minority interest in TNK-BP.
e Proved reserves in the Prudhoe Bay field in Alaska include an estimated 78 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
f Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
g Includes 70 million barrels relating to assets held for sale at 31 December 2010. Amounts by region are: 6 million barrels in US; 30 million barrels in South America; and 34 million barrels in Rest of Asia.
h Includes 213 million barrels relating to assets held for sale at 31 December 2010.
i Includes 2 million barrels of crude oil sold relating to production since classification of equity-accounted entities as held for sale.
j Includes 15 million barrels of crude oil sold relating to production from assets held for sale at 31 December 2010. Amounts by region are: 2 million barrels in US; 6 million barrels in South America; and 7 million barrels in Rest of Asia.
k Includes 9 million barrels of crude oil sold relating to production from assets held for sale at 31 December 2010.

Movements in estimated net proved reserves continued

Natural gas[a]	Europe		North America		South America	Africa	Asia		Australasia	Total
billion cubic feet, 2010	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2010										
Developed	1,602	49	9,583	716	3,177	1,107	–	1,579	3,219	21,032
Undeveloped	670	397	5,633	453	7,393	1,454	–	249	3,107	19,356
	2,272	446	15,216	1,169	10,570	2,561	–	1,828	6,326	40,388
Changes attributable to										
Revisions of previous estimates	(8)	(5)	(1,854)	(11)	2	3	–	(142)	(191)	(2,206)
Improved recovery	152	6	830	–	512	18	–	83	58	1,659
Purchases of reserves-in-place	–	31	97	1	–	–	–	17	–	146
Discoveries and extensions	26	–	739	9	19	1,378	–	–	–	2,171
Production[b i]	(191)	(8)	(861)	(77)	(953)	(229)	–	(228)	(288)	(2,835)
Sales of reserves-in-place	(6)	–	(424)	(1,033)	–	(51)	–	–	–	(1,514)
	(27)	24	(1,473)	(1,111)	(420)	1,119	–	(270)	(421)	(2,579)
At 31 December 2010[c f]										
Developed	1,416	40	9,495	58	3,575	1,329	–	1,290	3,563	20,766
Undeveloped	829	430	4,248	–	6,575	2,351	–	268	2,342	17,043
	2,245	470	13,743	58	10,150	3,680	–	1,558	5,905	37,809
Equity-accounted entities (BP share)[e]										
At 1 January 2010										
Developed	–	–	–	–	1,252	–	1,703	80	–	3,035
Undeveloped	–	–	–	–	1,010	165	519	13	–	1,707
	–	–	–	–	2,262	165	2,222	93	–	4,742
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(141)	10	382	2	–	253
Improved recovery	–	–	–	–	291	–	–	12	–	303
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	23	–	–	–	–	23
Production[b]	–	–	–	–	(168)[h j]	–	(244)	(17)	–	(429)
Sales of reserves-in-place	–	–	–	–	–	–	(1)	–	–	(1)
	–	–	–	–	5	10	137	(3)	–	149
At 31 December 2010[d]										
Developed	–	–	–	–	1,075	–	1,900	71	–	3,046
Undeveloped	–	–	–	–	1,192	175	459	19	–	1,845
	–	–	–	–	2,267[g]	175	2,359	90	–	4,891
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2010										
Developed	1,602	49	9,583	716	4,429	1,107	1,703	1,659	3,219	24,067
Undeveloped	670	397	5,633	453	8,403	1,619	519	262	3,107	21,063
	2,272	446	15,216	1,169	12,832	2,726	2,222	1,921	6,326	45,130
At 31 December 2010										
Developed	1,416	40	9,495	58	4,650	1,329	1,900	1,361	3,563	23,812
Undeveloped	829	430	4,248	–	7,767	2,526	459	287	2,342	18,888
	2,245	470	13,743	58	12,417	3,855	2,359	1,648	5,905	42,700

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Includes 204 billion cubic feet of natural gas consumed in operations, 166 billion cubic feet in subsidiaries, 38 billion cubic feet in equity-accounted entities and excludes 14 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.
[c] Includes 2,921 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 137 billion cubic feet of natural gas in respect of the 5.89% minority interest in TNK-BP.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Includes 740 billion cubic feet relating to assets held for sale at 31 December 2010. Amounts by region are: 158 billion cubic feet in US; 205 billion cubic feet in South America; and 377 billion cubic feet in Rest of Asia.
[g] Includes 50 billion cubic feet relating to assets held for sale at 31 December 2010.
[h] Includes 1 billion cubic feet of gas sales relating to production since classification of equity-accounted entities as held for sale.
[i] Includes 133 billion cubic feet of gas (excluding gas consumed in operations) relating to production from assets held for sale at 31 December 2010. Amounts by region are: 23 billion cubic feet in US; 27 billion cubic feet in South America; and 83 billion cubic feet in Rest of Asia.
[j] Includes 3 billion cubic feet of gas (excluding gas consumed in operations) relating to production from assets held for sale at 31 December 2010.

Movements in estimated net proved reserves continued

Bitumen[a]		million barrels
		2010
	Rest of North America	Total
Equity-accounted entities (BP share)		
At 1 January 2010		
Developed	–	–
Undeveloped	–	–
	–	–
Changes attributable to		
Revisions of previous estimates	–	–
Improved recovery	–	–
Purchases of reserves-in-place	–	–
Discoveries and extensions	179	179
Production	–	–
Sales of reserves-in-place	–	–
	179	179
At 31 December 2010		
Developed	–	–
Undeveloped	179	179
	179	179

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

Movements in estimated net proved reserves continued

million barrels of oil equivalent

Total hydrocarbons[a]	Europe		North America		South America	Africa	Asia		Australasia	2010 Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2010										
Developed	680	91	3,514	135	596	613	–	455	612	6,696
Undeveloped	406	253	2,183	79	1,331	704	–	376	593	5,925
	1,086	344	5,697	214	1,927	1,317	–	831	1,205	12,621
Changes attributable to										
Revisions of previous estimates	18	2	(364)	(2)	(1)	(61)	–	(87)	(33)	(528)
Improved recovery	126	10	276	–	105	17	–	160	13	707
Purchases of reserves-in-place	–	38	22	–	–	–	–	41	–	101
Discoveries and extensions	36	1	207	2	4	257	–	–	–	507
Production[b f l]	(83)	(16)	(359)	(15)	(183)	(127)	–	(83)	(61)	(927)
Sales of reserves-in-place	(1)	–	(190)	(189)	–	(24)	–	–	–	(404)
	96	35	(408)	(204)	(75)	62	–	31	(81)	(544)
At 31 December 2010[c i]										
Developed	608	84	3,366	10	660	600	–	491	662	6,481
Undeveloped	574	295	1,923	–	1,192	779	–	371	462	5,596
	1,182	379	5,289	10	1,852	1,379	–	862	1,124	12,077
Equity-accounted entities (BP share)[g]										
At 1 January 2010										
Developed	–	–	–	–	623	–	2,645	377	–	3,645
Undeveloped	–	–	–	–	580	37	1,287	122	–	2,026
	–	–	–	–	1,203	37	3,932	499	–	5,671
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(20)	6	314	(19)	–	281
Improved recovery	–	–	–	–	83	–	269	2	–	354
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	179	4	–	–	–	–	183
Production[b f]	–	–	–	–	(64)[k m]	–	(354)	(73)	–	(491)
Sales of reserves-in-place	–	–	–	–	–	–	(4)	–	–	(4)
	–	–	–	179	3	6	225	(90)	–	323
At 31 December 2010[d]										
Developed	–	–	–	–	593	–	2,716	382	–	3,691
Undeveloped	–	–	–	179	613	43	1,441	27	–	2,303
	–	–	–	179	1,206[j]	43	4,157	409	–	5,994
Total subsidiaries and equity-accounted entities (BP share)[h]										
At 1 January 2010										
Developed	680	91	3,514	135	1,219	613	2,645	832	612	10,341
Undeveloped	406	253	2,183	79	1,911	741	1,287	498	593	7,951
	1,086	344	5,697	214	3,130	1,354	3,932	1,330	1,205	18,292
At 31 December 2010										
Developed	608	84	3,366	10	1,253	600	2,716	873	662	10,172
Undeveloped	574	295	1,923	179	1,805	822	1,441	398	462	7,899
	1,182	379	5,289	189	3,058	1,422	4,157	1,271	1,124	18,071

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Excludes NGLs from processing plants in which an interest is held of 29 thousand barrels of oil equivalent per day.
[c] Includes 643 million barrels of NGLs. Also includes 526 million barrels of oil equivalent in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 18 million barrels of NGLs. Also includes 278 million barrels of oil equivalent in respect of the minority interest in TNK-BP.
[e] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 78 million barrels of oil equivalent upon which a net profits royalty will be payable.
[f] Includes 35 million barrels of oil equivalent of natural gas consumed in operations, 28 million barrels of oil equivalent in subsidiaries, 7 million barrels of oil equivalent in equity-accounted entities and excludes 2 million barrels of oil equivalent of produced non-hydrocarbon components which meet regulatory requirements for sales.
[g] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[h] Includes 1,311 million barrels of oil equivalent (197 million barrels of oil equivalent for subsidiaries and 1,114 million barrels of oil equivalent for equity-accounted entities) associated with properties currently held for sale where the disposal has not yet been completed.
[i] Includes 197 million barrels of oil equivalent relating to assets held for sale at 31 December 2010. Amounts by region are: 34 million barrels of oil equivalent in US; 64 million barrels of oil equivalent in South America; and 99 million barrels of oil equivalent in Rest of Asia.
[j] Includes 222 million barrels of oil equivalent relating to assets held for sale at 31 December 2010.
[k] Includes 2 million barrels of oil equivalent sold relating to production since classification of equity-accounted entities as held for sale.
[l] Includes 38 million barrels of oil equivalent (excluding gas consumed in operations) relating to production from assets held for sale at 31 December 2010. Amounts by region are: 6 million barrels of oil equivalent in US; 11 million barrels of oil equivalent in South America; and 21 million barrels of oil equivalent in Rest of Asia.
[m] Includes 9 million barrels of oil equivalent (excluding gas consumed in operations) relating to production from assets held for sale at 31 December 2010.

Movements in estimated net proved reserves continued

million barrels

Crude oil[a]	Europe		North America		South America	Africa	Asia		Australasia	2009
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		Total
Subsidiaries										
At 1 January 2009										
Developed	410	81	1,717	11	47	464	–	195	56	2,981
Undeveloped	119	194	1,273	1	55	496	–	488	58	2,684
	529	275	2,990	12	102	960	–	683	114	5,665
Changes attributable to										
Revisions of previous estimates	7	(1)	165	2	18	(121)	–	(128)	3	(55)
Improved recovery	42	7	82	–	7	32	–	31	2	203
Purchases of reserves-in-place	1	–	–	–	–	–	–	1	–	2
Discoveries and extensions	184	–	73	–	–	114	–	–	7	378
Production[b]	(61)	(14)	(237)	(2)	(22)	(109)	–	(45)	(11)	(501)
Sales of reserves-in-place	(8)	–	–	–	–	–	–	(26)	–	(34)
	165	(8)	83	–	3	(84)	–	(167)	1	(7)
At 31 December 2009[c]										
Developed	403	83	1,862	11	49	422	–	182	58	3,070
Undeveloped	291	184	1,211	1	56	454	–	334	57	2,588
	694	267	3,073	12	105	876	–	516	115	5,658
Equity-accounted entities (BP share)[f]										
At 1 January 2009										
Developed	–	–	–	–	399	–	2,227	499	–	3,125
Undeveloped	–	–	–	–	409	11	944	199	–	1,563
	–	–	–	–	808	11	3,171	698	–	4,688
Changes attributable to										
Revisions of previous estimates	–	–	–	–	2	(2)	590	(28)	–	562
Improved recovery	–	–	–	–	50	–	8	–	–	58
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	3	–	87	–	–	90
Production	–	–	–	–	(37)	–	(307)	(71)	–	(415)
Sales of reserves-in-place	–	–	–	–	(14)	–	–	(116)	–	(130)
	–	–	–	–	4	(2)	378	(215)	–	165
At 31 December 2009[d]										
Developed	–	–	–	–	407	–	2,351	363	–	3,121
Undeveloped	–	–	–	–	405	9	1,198	120	–	1,732
	–	–	–	–	812	9	3,549	483	–	4,853
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2009										
Developed	410	81	1,717	11	446	464	2,227	694	56	6,106
Undeveloped	119	194	1,273	1	464	507	944	687	58	4,247
	529	275	2,990	12	910	971	3,171	1,381	114	10,353
At 31 December 2009										
Developed	403	83	1,862	11	456	422	2,351	545	58	6,191
Undeveloped	291	184	1,211	1	461	463	1,198	454	57	4,320
	694	267	3,073	12	917	885	3,549	999	115	10,511

[a] Crude oil includes NGLs and condensate. Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Excludes NGLs from processing plants in which an interest is held of 26 thousand barrels per day.
[c] Includes 819 million barrels of NGLs. Also includes 23 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 20 million barrels of NGLs. Also includes 243 million barrels of crude oil in respect of the 6.86% minority interest in TNK-BP.
[e] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 68 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Movements in estimated net proved reserves continued

Natural gas[a]	Europe		North America		South America	Africa	Asia		Australasia	Total
										billion cubic feet 2009
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2009										
Developed	1,822	61	9,059	659	3,316	1,050	–	1,102	1,887	18,956
Undeveloped	582	402	5,473	468	7,434	1,382	–	1,308	4,000	21,049
	2,404	463	14,532	1,127	10,750	2,432	–	2,410	5,887	40,005
Changes attributable to										
Revisions of previous estimates	(114)	(8)	549	43	322	270	–	(231)	22	853
Improved recovery	34	–	550	5	322	49	–	82	75	1,117
Purchases of reserves-in-place	159	–	–	–	–	–	–	31	–	190
Discoveries and extensions	150	–	496	94	105	59	–	–	531	1,435
Production[b]	(243)	(9)	(907)	(100)	(929)	(249)	–	(241)	(189)	(2,867)
Sales of reserves-in-place	(118)	–	(4)	–	–	–	–	(223)	–	(345)
	(132)	(17)	684	42	(180)	129	–	(582)	439	383
At 31 December 2009[c]										
Developed	1,602	49	9,583	716	3,177	1,107	–	1,579	3,219	21,032
Undeveloped	670	397	5,633	453	7,393	1,454	–	249	3,107	19,356
	2,272	446	15,216	1,169	10,570	2,561	–	1,828	6,326	40,388
Equity-accounted entities (BP share)[e]										
At 1 January 2009										
Developed	–	–	–	–	1,498	–	1,560	176	–	3,234
Undeveloped	–	–	–	–	1,023	182	653	111	–	1,969
	–	–	–	–	2,521	182	2,213	287	–	5,203
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(26)	(17)	204	(19)	–	142
Improved recovery	–	–	–	–	314	–	1	4	–	319
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	6	–	23	–	–	29
Production[b]	–	–	–	–	(165)	–	(219)	(25)	–	(409)
Sales of reserves-in-place	–	–	–	–	(388)	–	–	(154)	–	(542)
	–	–	–	–	(259)	(17)	9	(194)	–	(461)
At 31 December 2009[d]										
Developed	–	–	–	–	1,252	–	1,703	80	–	3,035
Undeveloped	–	–	–	–	1,010	165	519	13	–	1,707
	–	–	–	–	2,262	165	2,222	93	–	4,742
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2009										
Developed	1,822	61	9,059	659	4,814	1,050	1,560	1,278	1,887	22,190
Undeveloped	582	402	5,473	468	8,457	1,564	653	1,419	4,000	23,018
	2,404	463	14,532	1,127	13,271	2,614	2,213	2,697	5,887	45,208
At 31 December 2009										
Developed	1,602	49	9,583	716	4,429	1,107	1,703	1,659	3,219	24,067
Undeveloped	670	397	5,633	453	8,403	1,619	519	262	3,107	21,063
	2,272	446	15,216	1,169	12,832	2,726	2,222	1,921	6,326	45,130

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Includes 195 billion cubic feet of natural gas consumed in operations, 164 billion cubic feet in subsidiaries, 31 billion cubic feet in equity-accounted entities and excludes 16 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.
[c] Includes 3,068 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 131 billion cubic feet of natural gas in respect of the 5.79% minority interest in TNK-BP.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Movements in estimated net proved reserves continued

million barrels of oil equivalent

Total hydrocarbons[a]	Europe		North America		South America	Africa	Asia		Australasia	2009 Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2009										
Developed	724	91	3,279	126	617	645	–	385	382	6,249
Undeveloped	219	264	2,217	81	1,337	734	–	714	747	6,313
	943	355	5,496	207	1,954	1,379	–	1,099	1,129	12,562
Changes attributable to										
Revisions of previous estimates	(13)	(2)	260	9	74	(74)	–	(168)	7	93
Improved recovery	48	7	177	1	63	40	–	45	15	396
Purchases of reserves-in-place	28	–	–	–	–	–	–	6	–	34
Discoveries and extensions	210	–	158	17	18	124	–	–	98	625
Production[b f]	(102)	(16)	(393)	(20)	(182)	(152)	–	(86)	(44)	(995)
Sales of reserves-in-place	(28)	–	(1)	–	–	–	–	(65)	–	(94)
	143	(11)	201	7	(27)	(62)	–	(268)	76	59
At 31 December 2009[c]										
Developed	680	91	3,514	135	596	613	–	455	612	6,696
Undeveloped	406	253	2,183	79	1,331	704	–	376	593	5,925
	1,086	344	5,697	214	1,927	1,317	–	831	1,205	12,621
Equity-accounted entities (BP share)[g]										
At 1 January 2009										
Developed	–	–	–	–	658	–	2,495	529	–	3,682
Undeveloped	–	–	–	–	586	42	1,057	218	–	1,903
	–	–	–	–	1,244	42	3,552	747	–	5,585
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(2)	(5)	625	(32)	–	586
Improved recovery	–	–	–	–	104	–	8	1	–	113
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	4	–	92	–	–	96
Production[b f]	–	–	–	–	(66)	–	(345)	(75)	–	(486)
Sales of reserves-in-place	–	–	–	–	(81)	–	–	(142)	–	(223)
	–	–	–	–	(41)	(5)	380	(248)	–	86
At 31 December 2009[d]										
Developed	–	–	–	–	623	–	2,645	377	–	3,645
Undeveloped	–	–	–	–	580	37	1,287	122	–	2,026
	–	–	–	–	1,203	37	3,932	499	–	5,671
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2009										
Developed	724	91	3,279	126	1,275	645	2,495	914	382	9,931
Undeveloped	219	264	2,217	81	1,923	776	1,057	932	747	8,216
	943	355	5,496	207	3,198	1,421	3,552	1,846	1,129	18,147
At 31 December 2009										
Developed	680	91	3,514	135	1,219	613	2,645	832	612	10,341
Undeveloped	406	253	2,183	79	1,911	741	1,287	498	593	7,951
	1,086	344	5,697	214	3,130	1,354	3,932	1,330	1,205	18,292

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Excludes NGLs from processing plants in which an interest is held of 26 thousand barrels of oil equivalent per day.
[c] Includes 819 million barrels of NGLs. Also includes 552 million barrels of oil equivalent in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 20 million barrels of NGLs. Also includes 266 million barrels of oil equivalent in respect of the minority interest in TNK-BP.
[e] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 68 million barrels of oil equivalent upon which a net profits royalty will be payable.
[f] Includes 34 million barrels of oil equivalent of natural gas consumed in operations, 29 million barrels of oil equivalent in subsidiaries, 5 million barrels of oil equivalent in equity-accounted entities and excludes 3 million barrels of oil equivalent of produced non-hydrocarbon components which meet regulatory requirements for sales.
[g] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves

The following tables set out the standardized measure of discounted future net cash flows, and changes therein, relating to crude oil and natural gas production from the group's estimated proved reserves. This information is prepared in compliance with FASB Oil and Gas Disclosures requirements.

Future net cash flows have been prepared on the basis of certain assumptions which may or may not be realized. These include the timing of future production, the estimation of crude oil and natural gas reserves and the application of average crude oil and natural gas prices and exchange rates from the previous 12 months. Furthermore, both proved reserves estimates and production forecasts are subject to revision as further technical information becomes available and economic conditions change. BP cautions against relying on the information presented because of the highly arbitrary nature of the assumptions on which it is based and its lack of comparability with the historical cost information presented in the financial statements.

										$ million
										2011
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December 2011										
Subsidiaries										
Future cash inflows[a]	97,900	36,400	332,900	100	39,100	82,100	–	59,200	53,900	701,600
Future production cost[b]	30,500	10,900	140,700	100	10,500	16,800	–	16,000	15,600	241,100
Future development cost[b]	8,500	2,700	32,300	–	7,600	13,200	–	9,600	3,200	77,100
Future taxation[c]	37,100	15,200	57,000	–	11,400	19,800	–	8,100	9,000	157,600
Future net cash flows	21,800	7,600	102,900	–	9,600	32,300	–	25,500	26,100	225,800
10% annual discount[d]	11,200	3,100	55,500	–	4,100	12,500	–	9,800	13,500	109,700
Standardized measure of discounted future net cash flows[e]	10,600	4,500	47,400	–	5,500	19,800	–	15,700	12,600	116,100
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	–	–	–	9,100	46,700	–	188,900	34,200	–	278,900
Future production cost[b]	–	–	–	3,100	21,500	–	123,800	30,100	–	178,500
Future development cost[b]	–	–	–	1,900	5,000	–	15,600	2,400	–	24,900
Future taxation[c]	–	–	–	900	5,900	–	9,600	200	–	16,600
Future net cash flows	–	–	–	3,200	14,300	–	39,900	1,500	–	58,900
10% annual discount[d]	–	–	–	2,800	8,700	–	19,000	600	–	31,100
Standardized measure of discounted future net cash flows[g h]	–	–	–	400	5,600	–	20,900	900	–	27,800
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	10,600	4,500	47,400	400	11,100	19,800	20,900	16,600	12,600	143,900

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

			$ million
	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(30,900)	(5,700)	(36,600)
Development costs for the current year as estimated in previous year	12,800	2,900	15,700
Extensions, discoveries and improved recovery, less related costs	6,600	2,800	9,400
Net changes in prices and production cost	75,000	15,800	90,800
Revisions of previous reserves estimates	(22,000)	2,100	(19,900)
Net change in taxation	(18,200)	(1,400)	(19,600)
Future development costs	(10,800)	(2,700)	(13,500)
Net change in purchase and sales of reserves-in-place	(6,500)	(2,700)	(9,200)
Addition of 10% annual discount	10,000	1,500	11,500
Total change in the standardized measure during the year[i]	16,000	12,600	28,600

[a] The marker prices used were Brent $110.96/bbl, Henry Hub $4.12/mmBtu.
[b] Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.
[c] Taxation is computed using appropriate year-end statutory corporate income tax rates.
[d] Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.
[e] Minority interest in BP Trinidad and Tobago LLC amounted to $1,600 million.
[f] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.
[g] Minority interest in TNK-BP amounted to $1,600 million in Russia.
[h] No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.
[i] Total change in the standardized measure during the year includes the effect of exchange rate movements.

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves continued

$ million

2010

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December 2010										
Subsidiaries										
Future cash inflows[a]	73,100	25,800	264,800	200	29,300	70,800	–	52,500	42,300	558,800
Future production cost[b]	25,700	9,800	111,400	200	6,800	14,000	–	13,400	12,800	194,100
Future development cost[b]	7,400	2,500	24,300	–	6,100	14,600	–	9,900	3,100	67,900
Future taxation[c]	19,900	8,100	41,900	–	8,200	14,100	–	7,000	6,200	105,400
Future net cash flows	20,100	5,400	87,200	–	8,200	28,100	–	22,200	20,200	191,400
10% annual discount[d]	9,800	2,300	45,500	–	3,300	11,900	–	8,200	10,300	91,300
Standardized measure of discounted future net cash flows[e]	10,300	3,100	41,700	–	4,900	16,200	–	14,000	9,900	100,100
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	–	–	–	9,700	45,500	–	110,500	31,000	–	196,700
Future production cost[b]	–	–	–	4,500	19,200	–	80,900	26,500	–	131,100
Future development cost[b]	–	–	–	2,000	4,300	–	11,000	2,800	–	20,100
Future taxation[c]	–	–	–	800	7,500	–	3,900	200	–	12,400
Future net cash flows	–	–	–	2,400	14,500	–	14,700	1,500	–	33,100
10% annual discount[d]	–	–	–	2,400	8,700	–	6,100	700	–	17,900
Standardized measure of discounted future net cash flows[g h]	–	–	–	–	5,800	–	8,600	800	–	15,200
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows[j]	10,300	3,100	41,700	–	10,700	16,200	8,600	14,800	9,900	115,300

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

$ million

	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(26,600)	(4,900)	(31,500)
Development costs for the current year as estimated in previous year	10,400	2,000	12,400
Extensions, discoveries and improved recovery, less related costs	9,600	1,600	11,200
Net changes in prices and production cost	52,800	1,900	54,700
Revisions of previous reserves estimates	(9,200)	200	(9,000)
Net change in taxation	(13,400)	(300)	(13,700)
Future development costs	(4,300)	(1,400)	(5,700)
Net change in purchase and sales of reserves-in-place	(1,500)	–	(1,500)
Addition of 10% annual discount	7,500	1,500	9,000
Total change in the standardized measure during the year[i]	25,300	600	25,900

[a] The marker prices used were Brent $79.02/bbl, Henry Hub $4.37/mmBtu.
[b] Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.
[c] Taxation is computed using appropriate year-end statutory corporate income tax rates.
[d] Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.
[e] Minority interest in BP Trinidad and Tobago LLC amounted to $1,200 million.
[f] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.
[g] Minority interest in TNK-BP amounted to $600 million.
[h] No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.
[i] Total change in the standardized measure during the year includes the effect of exchange rate movements.
[j] Includes future net cash flows for assets held for sale at 31 December 2010.

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves continued

$ million

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		2009
At 31 December 2009										
Subsidiaries										
Future cash inflows[a]	50,800	17,700	204,000	4,900	26,400	58,400	–	36,100	32,500	430,800
Future production cost[b]	20,000	8,000	91,300	2,700	6,700	12,000	–	9,200	11,000	160,900
Future development cost[b]	5,000	2,500	24,900	1,000	5,600	12,200	–	6,400	3,100	60,700
Future taxation[c]	12,900	3,700	27,300	200	5,800	11,300	–	4,700	4,500	70,400
Future net cash flows	12,900	3,500	60,500	1,000	8,300	22,900	–	15,800	13,900	138,800
10% annual discount[d]	5,800	1,600	29,500	500	3,200	9,800	–	6,300	7,300	64,000
Standardized measure of discounted future net cash flows[e]	7,100	1,900	31,000	500	5,100	13,100	–	9,500	6,600	74,800
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	–	–	–	–	37,700	–	96,700	30,000	–	164,400
Future production cost[b]	–	–	–	–	17,000	–	65,200	25,200	–	107,400
Future development cost[b]	–	–	–	–	4,000	–	10,200	3,100	–	17,300
Future taxation[c]	–	–	–	–	5,200	–	4,300	100	–	9,600
Future net cash flows	–	–	–	–	11,500	–	17,000	1,600	–	30,100
10% annual discount[d]	–	–	–	–	6,800	–	7,900	800	–	15,500
Standardized measure of discounted future net cash flows[g h]	–	–	–	–	4,700	–	9,100	800	–	14,600
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	7,100	1,900	31,000	500	9,800	13,100	9,100	10,300	6,600	89,400

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

$ million

	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(18,900)	(3,400)	(22,300)
Development costs for the current year as estimated in previous year	11,700	2,100	13,800
Extensions, discoveries and improved recovery, less related costs	8,500	1,600	10,100
Net changes in prices and production cost	37,200	5,900	43,100
Revisions of previous reserves estimates	(4,300)	(200)	(4,500)
Net change in taxation	(10,600)	(1,600)	(12,200)
Future development costs	(600)	900	300
Net change in purchase and sales of reserves-in-place	(100)	(900)	(1,000)
Addition of 10% annual discount	4,700	900	5,600
Total change in the standardized measure during the year[i]	27,600	5,300	32,900

a The marker prices used were Brent $59.91/bbl, Henry Hub $3.82/mmBtu.
b Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.
c Taxation is computed using appropriate year-end statutory corporate income tax rates.
d Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.
e Minority interest in BP Trinidad and Tobago LLC amounted to $1,300 million.
f The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.
g Minority interest in TNK-BP amounted to $600 million.
h No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.
i Total change in the standardized measure during the year includes the effect of exchange rate movements.

Financial statements

Operational and statistical information

The following tables present operational and statistical information related to production, drilling, productive wells and acreage. Figures include amounts attributable to assets held for sale.

Crude oil and natural gas production

The following table shows crude oil and natural gas production for the years ended 31 December 2011, 2010 and 2009.

Production for the year[a]

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
Crude oil[b]										thousand barrels per day
2011	**113**	**32**	**453**	**2**	**39**	**190**	**–**	**138**	**25**	**992**
2010	137	40	594	7	54	246	–	119	32	1,229
2009	168	40	665	8	61	304	–	123	31	1,400
Natural gas[c]										million cubic feet per day
2011	**355**	**13**	**1,843**	**14**	**2,197**	**558**	**–**	**618**	**795**	**6,393**
2010	472	15	2,184	202	2,544	556	–	574	785	7,332
2009	618	16	2,316	263	2,492	621	–	610	514	7,450
Equity-accounted entities (BP share)										
Crude oil[b]										thousand barrels per day
2011	**–**	**–**	**–**	**–**	**90**	**–**	**865**	**210**	**–**	**1,165**
2010	–	–	–	–	98	–	856	191	–	1,145
2009	–	–	–	–	101	–	840	194	–	1,135
Natural gas[c]										million cubic feet per day
2011	**–**	**–**	**–**	**–**	**392**	**–**	**699**	**34**	**–**	**1,125**
2010	–	–	–	–	399	–	640	30	–	1,069
2009	–	–	–	–	392	–	601	42	–	1,035

[a] Production excludes royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Crude oil includes natural gas liquids and condensate.
[c] Natural gas production excludes gas consumed in operations.

Productive oil and gas wells and acreage

The following tables show the number of gross and net productive oil and natural gas wells and total gross and net developed and undeveloped oil and natural gas acreage in which the group and its equity-accounted entities had interests as at 31 December 2011. A 'gross' well or acre is one in which a whole or fractional working interest is owned, while the number of 'net' wells or acres is the sum of the whole or fractional working interests in gross wells or acres. Productive wells are producing wells and wells capable of production. Developed acreage is the acreage within the boundary of a field, on which development wells have been drilled, which could produce the reserves; while undeveloped acres are those on which wells have not been drilled or completed to a point that would permit the production of commercial quantities, whether or not such acres contain proved reserves.

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	**Rest of Europe**	**US**	**Rest of North America**			**Russia**	**Rest of Asia**		
Number of productive wells at 31 December 2011										
Oil wells[a] – gross	**197**	**73**	**2,629**	**36**	**3,764**	**566**	**20,308**	**1,750**	**13**	**29,336**
– net	**97**	**28**	**1,063**	**18**	**2,090**	**429**	**9,131**	**315**	**2**	**13,173**
Gas wells[b] – gross	**273**	**–**	**24,986**	**376**	**467**	**122**	**72**	**589**	**68**	**26,953**
– net	**137**	**–**	**12,863**	**185**	**152**	**47**	**36**	**219**	**14**	**13,653**
Oil and natural gas acreage at 31 December 2011										Thousands of acres
Developed – gross	**334**	**65**	**7,350**	**228**	**1,718**	**560**	**1,618**	**1,952**	**162**	**13,987**
– net	**182**	**21**	**4,266**	**111**	**450**	**207**	**723**	**384**	**35**	**6,379**
Undeveloped[c] – gross	**1,276**	**186**	**7,210**	**6,273**	**10,064**	**27,000**	**33,704**	**56,189**	**18,641**	**160,543**
– net	**764**	**79**	**4,798**	**4,253**	**4,571**	**17,895**	**14,712**	**17,890**	**13,452**	**78,414**

[a] Includes approximately 3,866 gross (1,702 net) multiple completion wells (more than one formation producing into the same well bore).
[b] Includes approximately 2,683 gross (1,689 net) multiple completion wells. If one of the multiple completions in a well is an oil completion, the well is classified as an oil well.
[c] Undeveloped acreage includes leases and concessions.

Operational and statistical information (continued)

Net oil and gas wells completed or abandoned

The following table shows the number of net productive and dry exploratory and development oil and natural gas wells completed or abandoned in the years indicated by the group and its equity-accounted entities. Productive wells include wells in which hydrocarbons were encountered and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well is one found to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
2011										
Exploratory										
Productive	**0.4**	**–**	**34.1**	**–**	**4.4**	**2.1**	**16.7**	**1.0**	**0.2**	**58.9**
Dry	**–**	**–**	**2.1**	**–**	**0.2**	**–**	**7.2**	**0.3**	**0.3**	**10.1**
Development										
Productive	**1.7**	**–**	**199.4**	**–**	**101.3**	**16.0**	**582.0**	**45.1**	**–**	**945.5**
Dry	**–**	**–**	**0.2**	**–**	**3.0**	**2.7**	**–**	**0.4**	**–**	**6.3**
2010										
Exploratory										
Productive	–	0.2	39.3	–	1.3	1.2	10.5	2.8	0.3	55.6
Dry	0.7	–	0.3	–	0.9	1.4	4.0	–	–	7.3
Development										
Productive	6.4	1.2	260.0	31.7	105.7	18.9	364.3	53.3	–	841.5
Dry	1.7	–	0.5	–	1.2	2.7	–	2.4	–	8.5
2009										
Exploratory										
Productive	0.1	–	47.2	–	3.0	4.5	7.0	5.3	0.6	67.7
Dry	0.2	–	4.2	–	–	1.4	4.5	6.0	0.2	16.5
Development										
Productive	9.3	1.5	403.8	17.9	135.4	20.8	293.0	45.8	1.6	929.1
Dry	–	–	3.3	–	–	0.5	4.0	0.4	0.6	8.8

Drilling and production activities in progress

The following table shows the number of exploratory and development oil and natural gas wells in the process of being drilled by the group and its equity-accounted entities as of 31 December 2011. Suspended development wells and long-term suspended exploratory wells are also included in the table.

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December 2011										
Exploratory										
Gross	**1.0**	**–**	**108.0**	**3.0**	**6.0**	**1.0**	**22.0**	**–**	**–**	**141.0**
Net	**0.1**	**–**	**30.5**	**1.5**	**2.3**	**0.2**	**10.5**	**–**	**–**	**45.1**
Development										
Gross	**6.0**	**1.0**	**748.0**	**36.0**	**16.0**	**36.0**	**209.0**	**37.0**	**–**	**1,089.0**
Net	**4.2**	**0.4**	**235.7**	**18.0**	**9.2**	**13.2**	**101.2**	**10.3**	**–**	**392.2**

Signatures

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

BP p.l.c.
(Registrant)

/s/D.J. JACKSON
D.J. Jackson
Company Secretary

Dated 6 March 2012

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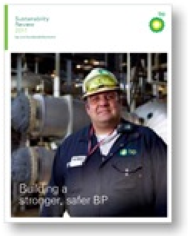
BP’s reports and publications are available to view online or download from *bp.com/annualreport*



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