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27. 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 and loss	Derivative hedging instruments	Financial liabilities measured at amortized cost	Total carrying amount
							$ million
							2010
Financial assets							
Other investments – equity shares	28	–	1,191	–	–	–	1,191
– other	28	–	1,532	–	–	–	1,532
Loans		1,141	–	–	–	–	1,141
Trade and other receivables	30	32,380	–	–	–	–	32,380
Derivative financial instruments	34	–	–	7,222	1,344	–	8,566
Cash and cash equivalents	31	13,462	5,094	–	–	–	18,556
Financial liabilities							
Trade and other payables	33	–	–	–	–	(56,499)	(56,499)
Derivative financial instruments	34	–	–	(7,254)	(279)	–	(7,533)
Accruals		–	–	–	–	(6,249)	(6,249)
Finance debt	35	–	–	–	–	(39,139)	(39,139)
		46,983	7,817	(32)	1,065	(101,887)	(46,054)

At 31 December	Note	Loans and receivables	Available-for-sale financial assets	At fair value through profit and loss	Derivative hedging instruments	Financial liabilities measured at amortized cost	Total carrying amount
							$ million
							2009
Financial assets							
Other investments	28	–	1,567	–	–	–	1,567
Loans		1,288	–	–	–	–	1,288
Trade and other receivables	30	31,016	–	–	–	–	31,016
Derivative financial instruments	34	–	–	7,960	972	–	8,932
Cash and cash equivalents	31	6,570	1,769	–	–	–	8,339
Financial liabilities							
Trade and other payables	33	–	–	–	–	(34,325)	(34,325)
Derivative financial instruments	34	–	–	(7,389)	(766)	–	(8,155)
Accruals		–	–	–	–	(6,905)	(6,905)
Finance debt	35	–	–	–	–	(34,627)	(34,627)
		38,874	3,336	571	206	(75,857)	(32,870)

The fair value of finance debt is shown in Note 35. 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 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.

27. 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. For 2010, the various value-at-risk models used in prior years were consolidated as part of a process simplification into a Monte Carlo framework. This makes 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. The results of the gas price trading are included within Exploration and Production segment results, and the gas price trading value-at-risk includes gas and power trading. The results of the oil price trading are included within Refining and Marketing segment results, and the oil price trading value-at-risk includes oil, interest rate and currency trading. Market risk exposure in respect of embedded derivatives is also not included in the value-at-risk table. Instead separate sensitivity analyses are disclosed below.

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			2010					2009
	High	**Low**	**Average**	**Year end**	High	Low	Average	Year end
Group trading	**70**	**15**	**34**	**33**	79	24	45	30
Gas price trading	**62**	**7**	**27**	**18**	62	11	28	26
Oil price trading	**39**	**10**	**19**	**25**	75	11	29	13

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 $104 million at 31 December 2010 (2009 $73 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 $1,607 million at 31 December 2010 (2009 liability of $1,331 million). Key information on the natural gas contracts is given below.

At 31 December	2010	2009
Remaining contract terms	**4 years and 5 months to 7 years and 9 months**	9 months to 8 years 9 months
Contractual/notional amount	**1,688 million therms**	2,460 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				2010				2009
	Gas price	**Oil price**	**Power price**	**Discount rate**	Gas price	Oil price	Power price	Discount rate
Favourable 10% change	**145**	**48**	**10**	**10**	175	26	23	20
Unfavourable 10% change	**(180)**	**(68)**	**(10)**	**(10)**	(215)	(43)	(19)	(20)

27. 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 2010, the foreign currency value at risk was $81 million (2009 $140 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 34.

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, Korean won and Singapore dollar and at 31 December 2010 open contracts were in place for $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 (2009 $800 million sterling, $491 million Canadian dollar, $299 million euro, $240 million Norwegian krone, $215 million Australian dollar, $51 million Korean won and $41 million Singapore dollar capital expenditures maturing within six years with over 65% of the deals maturing within two years).

For other UK, European, Canadian 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 2010, the open positions relating to cylinders consisted of receive sterling, pay US dollar, purchased call and sold put options (cylinders) for $1,340 million (2009 $1,887 million); receive euro, pay US dollar cylinders for $650 million (2009 $1,716 million); receive Australian dollar, pay US dollar cylinders for $286 million (2009 $297 million). At 31 December 2010 the open positions relating to currency forwards consisted of buy sterling, sell US dollar currency forwards for $925 million (2009 nil); buy Euro, sell US dollar currency forwards for $630 million (2009 nil); and buy Canadian dollar, sell US dollar, currency forwards for $162 million (2009 nil).

In addition, most of the group's borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2010, the total foreign currency net borrowings not swapped into US dollars amounted to $652 million (2009 $465 million). Of this total, $125 million was denominated in currencies other than the functional currency of the individual operating unit being entirely Canadian dollars (2009 $113 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 $12 million (2009 $11 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 at 31 December 2010 was 67% of total finance debt outstanding (2009 63%). The weighted average interest rate on finance debt at 31 December 2010 is 2% (2009 2%) and the weighted average maturity of fixed rate debt is five years (2009 four 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 2011, it is estimated that the group's profit before taxation for 2011 would decrease by approximately $303 million (2009 $219 million decrease in 2010). 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 2010 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 in 2010 (2009 nil and 2008 $546 million) relating to listed non-current available-for-sale investments. For further information see Note 28.

At 31 December 2010, it is estimated that an increase of 10% in quoted equity prices would result in an immediate credit to other comprehensive income of $95 million (2009 $130 million credit to other comprehensive income), whilst a decrease of 10% in quoted equity prices would result in an immediate charge to other comprehensive income of $95 million (2009 $130 million charge to other comprehensive income). BP has derivative positions that result in opposite impacts such that a 10% increase in equity prices would result in a charge to profit or loss of $70 million (2009 nil) and a 10% decrease in equity prices would result in a gain to profit or loss of $67 million (2009 nil).

27. Financial instruments and financial risk factors continued

At 31 December 2010, a single equity investment made up 80% (2009 73%) of the carrying amount of non-current available-for-sale financial assets thus the group's exposure is concentrated on changes in the share price of this equity 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.

While the global credit environment showed signs of stabilization and improvement in 2010, economic and political uncertainties continue to drive heightened awareness, discussion and co-ordination around the credit risks arising from the group's 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 or letters of credit and parent company guarantees. 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. At 31 December 2010, the maximum credit exposure was $60,643 million (2009 $49,575 million). Collateral received and recognized in the balance sheet at the year end was $313 million (2009 $549 million) and collateral held off balance sheet was $52 million (2009 $48 million). Credit exposure exists in relation to guarantees issued by group companies under which amounts outstanding at 31 December 2010 were $404 million (2009 $319 million) in respect of liabilities of jointly controlled entities and associates and $664 million (2009 $667 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.

Some mitigation of credit exposure is achieved by: netting arrangements; credit support agreements which require the counterparty to provide collateral or other credit risk mitigation; and credit insurance and other risk transfer instruments.

For the contracts comprising derivative financial instruments in an asset position at 31 December 2010, it is estimated that over 80% (2009 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 avoid concentration risks. At 31 December 2010, over 80% of the cash and cash equivalents balance was deposited with financial institutions rated A+ or higher.

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 50-60% (2009 approximately 55-60%) 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.

The group does not typically renegotiate the terms of trade receivables; however, if a renegotiation does take place, the outstanding balance is included in the analysis based on the original payment terms. There were no significant renegotiated balances outstanding at 31 December 2010 or 31 December 2009.

		$ million
Trade and other receivables at 31 December	**2010**	2009
Neither impaired nor past due	**30,181**	29,426
Impaired (net of valuation allowance)	**67**	91
Not impaired and past due in the following periods		
within 30 days	**1,358**	808
31 to 60 days	**249**	151
61 to 90 days	**101**	76
over 90 days	**424**	464
	32,380	31,016

27. Financial instruments and financial risk factors continued

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

	2010	2009
		$ million
At 1 January	**430**	391
Exchange adjustments	**(9)**	12
Charge for the year	**150**	157
Utilization	**(143)**	(130)
At 31 December	**428**	430

(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.

Following the Gulf of Mexico oil spill, the group faced significant challenges in managing liquidity risk. The group was required to make substantial cash payments in connection with the oil spill and also experienced increased requirements during the year to post letters of credit to collateralize a number of environmental liabilities totalling $624 million and post further cash collateral under trading agreements totalling $728 million. Further informaton is provided in Liquidity and capital resources on pages 63 to 67.

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. At 31 December 2010, the group had substantial amounts of undrawn borrowing facilities available, including committed facilities of $12,500 million (2009 $4,950 million), consisting of $5,250 million of standby facilities (of which $400 million is available to draw and repay by mid-September 2011, $4,550 million until mid-October 2011, and $300 million until mid-January 2013) and $7,250 million of 364-day facilities (of which $4,000 million can be drawn until late May 2011 and is repayable up to 364 days from the date of drawing, $2,000 million drawn until the end of June 2011, $750 million drawn until early July 2011, and $500 million drawn until late August 2011). These facilities are with a number of international banks and borrowings under them would be at pre-agreed rates.

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 2010, the amount drawn down against the DIP was $12,272 million (2009 $11,403 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 and A (negative outlook) assigned by Standard & Poor's, a downgrading from Aa1 (stable outlook) and AA (stable outlook), respectively assigned prior to the Gulf of Mexico oil spill.

Since the credit rating downgrading, we have issued $6.2 billion of long-term debt early in the fourth quarter 2010, and issued short-term commercial paper at competitive rates, as and when required. As an additional measure, we have increased and maintained the cash and cash equivalents held by the group to $18.6 billion at the end of 2010, compared with $8.3 billion at the end of 2009.

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.

Included within current finance debt are US Industrial Revenue/Municipal bonds where bondholders have the option to tender the bonds for repayment at interest reset dates, and the next reset date falls within 12 months of the balance sheet date. The amounts at the end of 2010 totalled $379 million, down from $2,895 million at the end of 2009. The reduction largely reflects the initial failure to re-market the bonds following the Gulf of Mexico oil spill, as well as active management by BP to withdraw or re-negotiate term-out of the bonds on reset dates to further remove the uncertainty of the liquidity risk. Also included within current finance debt at the end of 2009 was an amount of $1,622 million for loans associated with long-term gas supply contracts backed by gas pre-paid bonds with tender options at interest rate resets with BP as the liquidity provider. Following the Gulf of Mexico oil spill the bonds failed re-marketing requiring BP to acquire and hold all of the bonds, with corresponding reduction to nil in the amount reflected in finance debt at the end of 2010.

Current finance debt on the group balance sheet at 31 December 2010 includes $6,197 million (2009 nil) in respect of cash deposits received for disposals expected to complete in 2011 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.

	2010			2009		$ million
	Trade and other payables[a]	**Accruals**	**Finance debt**	Trade and other payables	Accruals	Finance debt
Within one year	**42,691**	**5,612**	**9,353**	31,413	6,202	9,790
1 to 2 years	**6,549**	**278**	**6,816**	1,059	231	6,861
2 to 3 years	**6,242**	**125**	**7,542**	1,089	106	5,359
3 to 4 years	**411**	**42**	**6,105**	566	78	5,528
4 to 5 years	**365**	**28**	**5,494**	67	49	3,151
5 to 10 years	**323**	**110**	**6,642**	85	163	5,723
Over 10 years	**25**	**54**	**724**	46	76	1,150
	56,606	**6,249**	**42,676**	34,325	6,905	37,562

[a] Trade and other payables at 31 December 2010 includes the Gulf of Mexico oil spill trust fund liability which is payable as follows: $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.

27. 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 34. 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 $6,725 million at 31 December 2010 (2009 $7,999 million) to be received on the same day as the related cash outflows.

		$ million
	2010	2009
Within one year	**986**	2,826
1 to 2 years	**1,682**	1,395
2 to 3 years	**1,358**	1,669
3 to 4 years	**1,124**	1,349
4 to 5 years	**295**	1,104
5 to 10 years	**947**	322
	6,392	8,665

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.

28. Other investments

			$ million
		2010	2009
	Current	**Non-current**	Non-current
Listed	**–**	**953**	1,296
Unlisted	**1,532**	**238**	271
	1,532	**1,191**	1,567

Other non-current investments comprise equity investments that have no fixed maturity date or coupon rate. These investments are classified as available-for-sale financial assets and as such are recorded at fair value with the gain or loss arising as a result of changes in fair value recorded directly in equity. 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 and are in level 3 of the fair value hierarchy.

At 31 December 2010, current unlisted investments relate to repurchased gas pre-paid bonds – see Note 35 for further information.

In 2010, no impairment losses were incurred relating to either unlisted investments or other listed investments. In 2009, impairment losses were incurred of $13 million relating to unlisted investments and nil relating to other listed investments.

BP has pledged listed equity investments with a carrying value of $948 million as part of a financing arrangement. As BP has retained substantially all the risks and rewards associated with the shares they continue to be reflected as an asset on the balance sheet, with a liability being reflected within finance debt. BP can 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.

29. Inventories

		$ million
	2010	2009
Crude oil	**8,969**	6,237
Natural gas	**112**	105
Refined petroleum and petrochemical products	**13,997**	12,337
	23,078	18,679
Supplies	**1,669**	1,661
	24,747	20,340
Trading inventories	**1,471**	2,265
	26,218	22,605
Cost of inventories expensed in the income statement	**216,211**	163,772

The inventory valuation at 31 December 2010 is stated net of a provision of $41 million (2009 $46 million) to write inventories down to their net realizable value. The net movement in the year in respect of inventory net realizable value provisions was $5 million credit (2009 $1,366 million credit).

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30. Trade and other receivables

				$ million
		2010		2009
	Current	**Non-current**	Current	Non-current
Financial assets				
Trade receivables	**24,255**	**–**	22,604	–
Amounts receivable from jointly controlled entities	**751**	**601**	1,317	11
Amounts receivable from associates	**448**	**220**	417	298
Other receivables	**4,763**	**1,342**	4,949	1,420
	30,217	**2,163**	29,287	1,729
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset[a]	**5,943**	**3,601**	–	–
Other receivables	**389**	**534**	244	–
	6,332	**4,135**	244	–
	36,549	**6,298**	29,531	1,729

[a] See Note 2 for further information.

Trade and other receivables are predominantly non-interest bearing. See Note 27 for further information.

Receivables with a carrying value of $18 million (2009 nil) have been pledged as security for certain of the group's liabilities.

31. Cash and cash equivalents

		$ million
	2010	2009
Cash at bank and in hand	**8,209**	3,359
Term bank deposits	**5,253**	3,211
Other cash equivalents	**5,094**	1,769
	18,556	8,339

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. Substantially all of the other cash equivalents are categorized within level 1 of the fair value hierarchy.

Cash and cash equivalents at 31 December 2010 includes $1,089 million (2009 $1,095 million) that is restricted. This relates principally to amounts required to cover initial margins on trading exchanges.

See Note 27 for further information.

32. Valuation and qualifying accounts

						$ million
		2010		2009		2008
	Doubtful debts	**Fixed assets – investments**	Doubtful debts	Fixed assets – investments	Doubtful debts	Fixed assets – investments
At 1 January	**430**	**349**	391	935	406	146
Charged to costs and expenses	**150**	**376**	157	66	191	647
Charged to other accounts[a]	**(9)**	**(3)**	12	6	(32)	143
Deductions	**(143)**	**(182)**	(130)	(658)	(174)	(1)
At 31 December	**428**	**540**	430	349	391	935

[a] Principally currency transactions.

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

33. Trade and other payables

				$ million
		2010		2009
	Current	**Non-current**	Current	Non-current
Financial liabilities				
Trade payables	**27,510**	**–**	22,886	–
Amounts payable to jointly controlled entities	**1,361**	**1,905**	304	2,419
Amounts payable to associates	**712**	**220**	692	298
Gulf of Mexico oil spill trust fund liability[a]	**5,002**	**9,899**	–	–
Other payables	**8,100**	**1,790**	7,531	195
	42,685	**13,814**	31,413	2,912
Non-financial liabilities				
Other payables	**3,644**	**471**	3,791	286
	46,329	**14,285**	35,204	3,198

[a] See Note 2 for further information.

Trade and other payables are predominantly interest free, however the Gulf of Mexico oil spill trust fund is recorded on a discounted basis. See Note 27 for further information.

34. 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 27.

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.

				$ million
		2010		2009
	Fair value asset	**Fair value liability**	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	**194**	**(280)**	318	(226)
Oil price derivatives	**1,099**	**(877)**	1,140	(1,191)
Natural gas price derivatives	**5,350**	**(3,951)**	5,636	(3,960)
Power price derivatives	**561**	**(432)**	682	(497)
Other derivatives	**–**	**(89)**	47	(47)
	7,204	**(5,629)**	7,823	(5,921)
Embedded derivative commodity price contracts	**18**	**(1,625)**	137	(1,468)
Cash flow hedges				
Currency forwards, futures and cylinders	**134**	**(124)**	182	(114)
Cross-currency interest rate swaps	**101**	**(1)**	44	(298)
	235	**(125)**	226	(412)
Fair value hedges				
Currency forwards, futures and swaps	**772**	**(80)**	490	(232)
Interest rate swaps	**337**	**(74)**	256	(122)
	1,109	**(154)**	746	(354)
	8,566	**(7,533)**	8,932	(8,155)
Of which – current	**4,356**	**(3,856)**	4,967	(4,681)
– non-current	**4,210**	**(3,677)**	3,965	(3,474)

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34. 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 27.

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
							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**

							$ million
							2009
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	162	83	33	22	16	2	318
Oil price derivatives	814	136	69	59	44	18	1,140
Natural gas price derivatives	2,958	1,059	582	354	186	497	5,636
Power price derivatives	496	139	32	12	3	–	682
Other derivatives	47	–	–	–	–	–	47
	4,477	1,417	716	447	249	517	7,823

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

							$ 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)**
Other derivatives	**–**	**(29)**	**(60)**	**–**	**–**	**–**	**(89)**
	(3,483)	**(955)**	**(628)**	**(171)**	**(115)**	**(277)**	**(5,629)**

							$ million
							2009
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(110)	(58)	(20)	(32)	(4)	(2)	(226)
Oil price derivatives	(1,083)	(67)	(29)	(11)	(1)	–	(1,191)
Natural gas price derivatives	(2,381)	(607)	(248)	(222)	(78)	(424)	(3,960)
Power price derivatives	(335)	(109)	(39)	(11)	(3)	–	(497)
Other derivatives	(47)	–	–	–	–	–	(47)
	(3,956)	(841)	(336)	(276)	(86)	(426)	(5,921)

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.

34. Derivative financial instruments continued

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

				$ million
		2010		2009
	Oil price	Natural gas price	Oil price	Natural gas price
Fair value of contracts not recognized through the income statement at 1 January	21	33	32	83
Fair value of new contracts at inception not recognized in the income statement	–	39	–	(14)
Fair value recognized in the income statement	(21)	(3)	(11)	(36)
Fair value of contracts not recognized through profit at 31 December	–	69	21	33

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
							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

							$ million
							2009
	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	163	76	23	17	10	1	290
Level 2	9,544	2,182	915	357	146	–	13,144
Level 3	264	188	162	148	128	527	1,417
	9,971	2,446	1,100	522	284	528	14,851
Less: netting by counterparty	(5,494)	(1,029)	(384)	(75)	(35)	(11)	(7,028)
	4,477	1,417	716	447	249	517	7,823
Fair value of derivative liabilities							
Level 1	(95)	(39)	(14)	(24)	–	(1)	(173)
Level 2	(9,086)	(1,681)	(597)	(234)	(47)	–	(11,645)
Level 3	(269)	(150)	(109)	(93)	(74)	(436)	(1,131)
	(9,450)	(1,870)	(720)	(351)	(121)	(437)	(12,949)
Less: netting by counterparty	5,494	1,029	384	75	35	11	7,028
	(3,956)	(841)	(336)	(276)	(86)	(426)	(5,921)
Net fair value	521	576	380	171	163	91	1,902

34. 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.

$ million

	Oil price	Natural gas price	Power price	Total
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)**
Purchases	**–**	**–**	**–**	**–**
Sales	**–**	**–**	**–**	**–**
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**

$ million

	Currency	Oil price	Natural gas price	Power price	Other	Total
Net fair value of contracts at 1 January 2009	3	149	17	–	–	169
Gains (losses) recognized in the income statement	(1)	205	91	–	(1)	294
Settlements	–	(91)	(5)	–	–	(96)
Purchases	–	–	–	1	–	1
Sales	–	–	–	(2)	1	(1)
Transfers out of level 3	(2)	(50)	(4)	–	–	(56)
Transfers into level 3	–	2	(25)	–	–	(23)
Exchange adjustments	–	–	(2)	–	–	(2)
Net fair value of contracts at 31 December 2009	–	215	72	(1)	–	286

The amount recognized in the income statement for the year relating to level 3 held-for-trading derivatives still held at 31 December 2010 was a $651 million gain (2009 $278 million gain relating to derivatives still held at 31 December 2009).

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. 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 gain of $1,428 million (2009 $3,735 million net gain and 2008 $6,721 million net gain).

Embedded derivatives

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 embedded derivatives relate to commodity prices, 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.

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

$ million 2010

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Assets	**18**	**–**	**–**	**–**	**–**	**–**	**18**
Liabilities	**(325)**	**(326)**	**(285)**	**(281)**	**(212)**	**(196)**	**(1,625)**
Net fair value	**(307)**	**(326)**	**(285)**	**(281)**	**(212)**	**(196)**	**(1,607)**

$ million 2009

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Assets	134	–	–	–	–	3	137
Liabilities	(154)	(236)	(231)	(227)	(232)	(388)	(1,468)
Net fair value	(20)	(236)	(231)	(227)	(232)	(385)	(1,331)

34. Derivative financial instruments continued

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
	2010	2009
	Commodity price	Commodity price
Net fair value of contracts at 1 January	**(1,331)**	(1,892)
Settlements	**37**	221
Gains (losses) recognized in the income statement[a]	**(350)**	535
Exchange adjustments	**37**	(195)
Net fair value of contracts at 31 December	**(1,607)**	(1,331)

[a] The amount for gains (losses) recognized in the income statement for 2009 includes a loss of $224 million arising as a result of refinements in the modelling and valuation methods used for these contracts.

The amount recognized in the income statement for the year relating to level 3 embedded derivatives still held at 31 December 2010 was a $350 million loss (2009 $347 million gain relating to embedded derivatives still held at 31 December 2009).

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

			$ million
	2010	2009	2008
Commodity price embedded derivatives	**(309)**	607	(106)
Interest rate embedded derivatives	**–**	–	(5)
Fair value (loss) gain	**(309)**	607	(111)

Cash flow hedges

At 31 December 2010, 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, as well as cross-currency interest rate swaps to fix the US dollar interest rate and US dollar redemption value, with matching critical terms on the currency leg of the swap with the underlying non-US dollar debt issuance. Note 27 outlines the management of risk aspects for currency and interest rate 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 $25 million (2009 loss of $366 million and 2008 loss of $45 million). The entire gain of $25 million is included in production and manufacturing expenses (2009 $332 million loss in production and manufacturing expense and $34 million loss in finance costs; 2008 $1 million loss in production and manufacturing expense and $44 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 loss of $53 million (2009 $136 million loss and 2008 $38 million gain).

The amounts retained in equity at 31 December 2010 are expected to mature and impact the income statement by a gain of $89 million in 2011, a loss of $23 million in 2012 and a loss of $50 million in 2013 and beyond.

Fair value hedges

At 31 December 2010, 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 2010 was $563 million (2009 $98 million loss and 2008 $2 million gain) offset by a loss on the fair value of the finance debt of $554 million (2009 $117 million gain and 2008 $20 million loss).

The interest rate and cross-currency interest rate swaps have an average maturity of four to five years, (2009 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 27 outlines the group’s approach to interest rate risk management.

Hedges of net investments in foreign operations

The group held currency swap contracts as a hedge of a long-term investment in a UK subsidiary that expired in 2009. The loss on the hedge recognized in equity in 2008 was $38 million. US dollars had been sold forward for sterling purchased and matched the underlying liability with no significant ineffectiveness reflected in the income statement.

35. Finance debt

$ million

	2010 Current	2010 Non-current	2010 Total	2009 Current	2009 Non-current	2009 Total
Borrowings	**8,312**	**30,017**	**38,329**	9,018	25,020	34,038
Net obligations under finance leases	**117**	**693**	**810**	91	498	589
	8,429	**30,710**	**39,139**	9,109	25,518	34,627
Disposal deposits	**6,197**	**–**	**6,197**	–	–	–
	14,626	**30,710**	**45,336**	9,109	25,518	34,627

Current finance debt includes the portion of long-term debt that will mature in the next 12 months, amounting to $6,976 million (2009 $3,965 million). Deposits for disposal transactions expected to complete in 2011 of $6,197 million (2009 nil) are also included. This debt will be considered extinguished on completion of the transactions.

Current finance debt also includes US Industrial Revenue/Municipal bonds of $379 million (2009 $2,895 million) with earliest contractual repayment dates within one year, and the 2009 balance included $1,622 million for loans associated with long-term gas supply contracts backed by gas pre-paid bonds. The bondholders typically have the option to tender these bonds for repayment on interest reset dates with any bonds that are tendered being remarketed. The reduction in current finance debt in 2010 attributable to such bonds largely reflects the unsuccessful remarketing of the bonds during the year. BP has repaid $2,460 million of US Industrial Revenue/Municipal bonds and at 31 December 2010 either held or had retired the bonds. All of the outstanding bonds associated with long-term gas supply contracts, amounting to $1,527 million were held by BP with the liability now recorded within other payables on the balance sheet and the bonds recorded within other current investments.

At 31 December 2010 $790 million (2009 $113 million) of finance debt was secured by the pledging of assets, and $4,780 million was secured in connection with deposits received relating to certain disposal transactions expected to complete in 2011 (2009 nil). In addition, in connection with $4,588 million (2009 nil) 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
						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**
						2009
US dollar	4	4	12,525	1	20,566	33,091
Euro	4	2	63	2	1,199	1,262
Other currencies	6	14	171	3	103	274
			12,759		21,868	34,627

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. Future minimum lease payments under finance leases are set out below.

$ million

	2010	2009
Future minimum lease payments payable within		
1 year	**153**	109
2 to 5 years	**535**	329
Thereafter	**438**	407
	1,126	845
Less finance charges	**316**	256
Net obligations	**810**	589
Of which – payable within 1 year	**117**	91
– payable within 2 to 5 years	**404**	202
– payable thereafter	**289**	296

35. 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 2010, 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, bank loans, overdrafts and US Industrial Revenue/ Municipal bonds, 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
		2010		2009
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**1,453**	**1,453**	5,144	5,144
Long-term borrowings	**37,600**	**36,876**	29,918	28,894
Net obligations under finance leases	**928**	**810**	599	589
Total finance debt	**39,981**	**39,139**	35,661	34,627

36. Capital disclosures and analysis of changes in net debt

The group defines capital as the total equity of the group. The group's approach to managing capital is set out in its financial framework which was revised during 2010, with the objective of maintaining a capital structure that allows the group to execute its strategy and is resilient to inherent volatility. The group intends to invest to grow the company and shareholder value sustainably through the business cycle, whilst providing the group with financial flexibility in the medium term as the disposal programme is completed and commitments to the Deepwater Horizon Oil Spill Trust are fulfilled.

In the light of the Gulf of Mexico oil spill and the agreement to establish the $20-billion trust fund, the BP board reviewed its dividend policy and decided that no ordinary share dividends would be paid in respect of the first three quarters of 2010. On 1 February 2011, BP announced the resumption of quarterly dividend payments, with a fourth quarter dividend of 7 cents per share. We believe this level is supported by the success of our disposal programme thus far, and by the improving business environment, but is balanced by the recognition of our continuing obligation to fund the trust until the end of 2013 and the need to retain financial flexibility. We intend to increase the dividend level over time in line with the circumstances of the company.

Going forward, the group intends to maintain a significant cash liquidity buffer and reduce the net debt ratio to within a range of 10-20%.

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 claimed, less cash and cash equivalents. Net debt and net debt ratio are non-GAAP measures. BP uses these measures to 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 2010 the net debt ratio was 21% (2009 20%).

During 2010, the company did not repurchase any of its own shares.

		$ million
At 31 December	**2010**	2009
Gross debt	**45,336**	34,627
Less: Cash and cash equivalents	**18,556**	8,339
Less: Fair value asset of hedges related to finance debt	**916**	127
Net debt	**25,864**	26,161
Equity	**95,891**	102,113
Net debt ratio	**21%**	20%

An analysis of changes in net debt is provided below.

						$ million
			2010			2009
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	**(34,500)**	**8,339**	**(26,161)**	(33,238)	8,197	(25,041)
Exchange adjustments	**194**	**(279)**	**(85)**	(60)	110	50
Net cash flow	**(3,613)**	**10,496**	**6,883**	(1,141)	32	(1,109)
Movement in finance debt relating to investing activities[b]	**(6,197)**	**–**	**(6,197)**	–	–	–
Other movements	**(304)**	**–**	**(304)**	(61)	–	(61)
At 31 December	**(44,420)**	**18,556**	**(25,864)**	(34,500)	8,339	(26,161)

[a] Including fair value of associated derivative financial instruments.
[b] See Note 35 for further information.

37. Provisions

	Decommissioning	Environmental	Spill response	Litigation and claims	Clean Water Act penalties	Other	Total
							$ million
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**

	Decommissioning	Environmental	Litigation	Other	Total
					$ million
At 1 January 2009	8,418	1,691	1,446	2,098	13,653
Exchange adjustments	398	15	22	29	464
New or increased provisions	169	588	302	1,256	2,315
Write-back of unused provisions	–	(259)	(99)	(228)	(586)
Unwinding of discount	184	32	15	16	247
Change in discount rate	324	18	(35)	8	315
Utilization	(383)	(308)	(574)	(361)	(1,626)
Deletions	(90)	(58)	(1)	(3)	(152)
At 31 December 2009	9,020	1,719	1,076	2,815	14,630
Of which – current	287	368	433	572	1,660
– non-current	8,733	1,351	643	2,243	12,970

The group makes full provision for the future cost of decommissioning oil and natural gas production facilities and related pipelines on a discounted basis on the installation of those facilities. The provision for the costs of decommissioning these 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 1.5% (2009 1.75%). 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 1.5% (2009 1.75%). 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 2010 are provisions for deferred employee compensation of $728 million (2009 $789 million) and for expected rental shortfalls on surplus properties of $45 million (2009 $246 million). These provisions are discounted using either a nominal discount rate of 3.75% (2009 4.0%) or a real discount rate of 1.5% (2009 1.75%), as appropriate.

37. Provisions continued

Provisions relating to the Gulf of Mexico oil spill

The Gulf of Mexico oil spill is described on pages 34 to 39 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 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 2010 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.

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 $427 million was included in provisions at 31 December 2010. This amount is expected to be spent evenly over the 10-year period.

As a responsible party under the 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, amongst 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. A provision of $382 million has been established for these items. 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, therefore no amounts have been provided for these items and they are disclosed as a contingent liability. See Note 44 for further information.

Spill response

The remaining provision for spill response includes the estimated future costs of both subsea operations as well as surface and shoreline work.

The subsea response provision is based on the remaining activities expected to be undertaken and has been calculated using daily rates of costs incurred to date. This includes the rig costs to complete the plugging and abandonment of the second relief well, which is in progress and is expected to complete in early March 2011, and the recovery of the subsea infrastructure used as part of the various containment systems. The majority of the vessels involved in the response have now been decontaminated. The provision includes the costs of decontaminating the remaining 25 vessels, which is expected to be complete by the end of April 2011.

The provision for surface and shoreline response is based on the daily costs currently being incurred which are underpinned by headcount, equipment and the number of vessels on hire. At the end of the year, there were approximately 360 vessels on hire and the number of personnel involved in response activities was approximately 6,200. BP and the US Coast Guard are working closely with state and local officials to clean Gulf Coast beaches before the 2011 spring and summer tourism seasons and this is the basis on which the provision at 31 December 2010 has been calculated. The provision also includes an estimate of future federal response costs and ongoing monitoring that will be required until the end of the second quarter of 2012.

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 have also been provided for.

BP believes that the history of claims received to date, and settlements made, provides 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 has been determined in accordance with IFRS and represents BP’s current best estimate of the expenditure required to settle its obligations at the balance sheet date. The measurement of this provision is subject to significant uncertainty. Actual costs could ultimately be significantly higher or lower than those recorded as the claims and settlement process progresses.

In estimating the amount of the provision, BP has determined a range of possible outcomes for Individual and Business Claims, and State and Local Claims. These determinations are based on BP’s claims payment experience, the application of insurance industry benchmark data, the use of a combination of actuarial and statistical methods and management judgements where appropriate. The methods selected are consistent with those used by the insurance industry to estimate a range of total expenditures for both reported and unreported claims. These methods have been adopted on the basis that, at this stage of development, the application of insurance industry standard techniques for the estimation of ultimate losses is an appropriate approach for the costs arising from the Deepwater Horizon oil spill.

37. Provisions continued

Through the application of this approach, BP has concluded that a reasonable range of possible outcomes for the amount of the provision as at 31 December 2010 is $6 billion to $13 billion. BP believes that the provision recorded at 31 December 2010 of $9.2 billion represents a reliable best estimate from within this range of possible outcomes. This amount is shown as payable from the trust fund under *Litigation and claims* in the table above. The provision is in addition to the $3.4 billion of claims paid in 2010. Of this total paid, $3.2 billion is included within utilization of provision in the table, 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 total utilization of provision of $4 billion under *Litigation and claims* are amounts relating to claims administration costs and legal fees. Of the total payments of $3.4 billion during the year, $3 billion was paid out of the trust fund and $0.4 billion was paid by BP.

BP's management has utilized actuarial techniques and its judgement in determining this reliable best estimate. However, it is possible that the final outcome could lie outside this range.

Many key assumptions underlie and influence both the range of possible outcomes and the reliable best estimates of total expenditures derived for both categories of claims. These 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 scope and number of claims that can be resolved successfully in the claims process, the resolution of rejected claims, the outcomes of any litigation, the effects on tourism and fisheries and other economic and environmental factors.

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 44 for further information.

Legal fees

Estimated legal fees have been provided for where we have been able to estimate reliably those which will arise in the next two years.

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 (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, the company 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. The company 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) the company'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, based on the analysis of available data by its experts, 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, the company 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.

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37. Provisions continued

Therefore, for the purposes of calculating a provision for fines and penalties under Section 311 of the Clean Water Act, the company 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 approximately 850,000 barrels captured by vessels on the surface. In utilizing this estimate, the company 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. One factor that would impact the flow rate estimate is the completion of the analysis on the blowout preventer which is now in the custody of the federal government. Similar situations exist with regard to other pieces of physical evidence critical to the flow rate analysis. 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 the company’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 2010 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.

38. 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 schemes) or defined benefit plans (final salary and other types of schemes 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 SPU. 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 are provided. These include 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 2010, contributions of $411 million (2009 $9 million and 2008 $6 million) and $694 million (2009 $795 million and 2008 $362 million) were made to the UK plans and US plans respectively. In addition, contributions of $188 million (2009 $204 million and 2008 $130 million) were made to other funded defined benefit plans. The aggregate level of contributions in 2011 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 plans are funded to a limited extent.

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 2010. 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 2010 are used to determine the pension liabilities at that date and the pension expense for 2011.

									%
Financial assumptions			UK			US			Other
	2010	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Discount rate for pension plan liabilities	**5.5**	5.8	6.3	**4.7**	5.4	6.3	**5.3**	5.8	5.7
Discount rate for other post-retirement benefit plans	**n/a**	n/a	n/a	**5.3**	5.8	6.2	**n/a**	n/a	n/a
Rate of increase in salaries	**5.4**	5.3	4.9	**4.1**	4.2	2.2	**3.8**	3.8	3.5
Rate of increase for pensions in payment	**3.5**	3.4	3.0	**–**	–	–	**1.8**	1.8	1.7
Rate of increase in deferred pensions	**3.5**	3.4	3.0	**–**	–	–	**1.3**	1.2	1.0
Inflation	**3.5**	3.4	3.0	**2.3**	2.4	0.4	**2.3**	2.3	2.0

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 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.

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38. Pensions and other post-retirement benefits continued

Our assumptions for the rate of increase in salaries are based on our inflation 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	
	2010	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Life expectancy at age 60 for a male currently aged 60	**26.1**	26.0	25.9	**24.7**	24.6	24.4	**23.3**	23.2	23.0
Life expectancy at age 60 for a male currently aged 40	**29.1**	29.0	28.9	**26.2**	26.1	25.9	**26.2**	26.1	25.9
Life expectancy at age 60 for a female currently aged 60	**28.7**	28.6	28.5	**26.3**	26.3	26.1	**27.9**	27.8	27.6
Life expectancy at age 60 for a female currently aged 40	**31.6**	31.5	31.4	**27.2**	27.2	27.0	**30.6**	30.4	30.3

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:

			%
	2010	2009	2008
First year's US healthcare cost trend rate	**7.8**	8.0	8.1
Ultimate US healthcare cost trend rate	**5.0**	5.0	5.0
Year in which ultimate trend rate is reached	**2018**	2016	2014

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:

	Policy range
Asset category	%
Total equity	45-75
Bonds/cash	17.5-50
Property/real estate	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.

38. 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. The market value of unlisted investments at 31 December 2010 was $3,348 million (2009 $2,956 million and 2008 $2,819 million). The market value of pension assets at the end of 2010 was higher than at the end of 2009 due to a rise in the market value of investments when expressed in their local currencies partially offset by a decrease in value that arises from changes in exchange rates (decreasing the reported value of investments when expressed in US dollars). Movements in the value of plan assets during the year are shown in detail in the table on page 206.

		2010		2009		2008
	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	**8.0**	**18,546**	8.0	16,945	8.0	13,704
Bonds	**5.0**	**3,866**	5.3	3,701	6.1	3,258
Property	**6.5**	**1,462**	6.5	1,269	6.5	978
Cash	**1.4**	**406**	1.1	634	2.9	299
	7.2	**24,280**	7.3	22,549	7.4	18,239
US pension plans						
Equities	**8.5**	**5,058**	8.5	4,326	8.5	3,991
Bonds	**4.5**	**1,419**	4.8	1,218	3.7	1,247
Property	**8.0**	**7**	8.0	8	8.0	8
Cash	**0.3**	**165**	0.9	271	1.9	131
	8.0	**6,649**	8.0	5,823	8.0	5,377
US other post-retirement benefit plans						
Equities	**–**	**–**	8.5	8	8.5	9
Bonds	**–**	**–**	4.8	4	3.7	4
Cash	**0.3**	**8**	–	–	–	–
	0.3	**8**	7.6	12	7.3	13
Other plans						
Equities	**8.0**	**1,182**	8.6	1,091	8.4	799
Bonds	**4.2**	**1,874**	4.4	1,651	4.2	1,481
Property	**6.3**	**83**	6.5	82	6.3	127
Cash	**2.7**	**155**	2.0	245	3.1	118
	5.4	**3,294**	5.9	3,069	5.8	2,525

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38. 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 2011 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 2011	**(343)**	**343**
Discount rate		
Effect on pension and other post-retirement benefit expense in 2011	**(76)**	**101**
Effect on pension and other post-retirement benefit obligation at 31 December 2010	**(5,370)**	**6,864**
Inflation rate		
Effect on pension and other post-retirement benefit expense in 2011	**470**	**(364)**
Effect on pension and other post-retirement benefit obligation at 31 December 2010	**5,060**	**(4,135)**
US healthcare cost trend rate		
Effect on US other post-retirement benefit expense in 2011	**31**	**(24)**
Effect on US other post-retirement benefit obligation at 31 December 2010	**401**	**(328)**

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 2011 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 2011	**41**	**4**	**4**	**9**
Effect on pension and other post-retirement benefit obligation at 31 December 2010	**581**	**73**	**72**	**187**

38. Pensions and other post-retirement benefits continued

					$ million
					2010
	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
Analysis of the amount charged to profit (loss) 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 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.
[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.

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38. 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)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	16,655	7,534	3,003	7,655	34,847
Exchange adjustments	1,896	–	–	363	2,259
Current service cost[a]	311	243	48	117	719
Past service cost	–	–	(22)	1	(21)
Interest cost	1,112	456	183	420	2,171
Curtailment	–	–	–	11	11
Settlement	–	–	–	(3)	(3)
Special termination benefits[c]	37	–	–	45	82
Contributions by plan participants	37	–	–	10	47
Benefit payments (funded plans)[d]	(977)	(1,371)	(4)	(209)	(2,561)
Benefit payments (unfunded plans)[d]	(4)	(73)	(191)	(399)	(667)
Disposals	–	–	–	(42)	(42)
Actuarial (gain) loss on obligation	2,358	730	(21)	164	3,231
Benefit obligation at 31 December[a e]	21,425	7,519	2,996	8,133	40,073
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	18,239	5,377	13	2,525	26,154
Exchange adjustments	2,054	–	–	242	2,296
Expected return on plan assets[a f]	1,426	405	1	147	1,979
Contributions by plan participants	37	–	–	10	47
Contributions by employers (funded plans)	9	795	–	204	1,008
Benefit payments (funded plans)[d]	(977)	(1,371)	(4)	(209)	(2,561)
Disposals	–	–	–	(19)	(19)
Actuarial gain on plan assets[f]	1,761	617	2	169	2,549
Fair value of plan assets at 31 December	22,549	5,823	12	3,069	31,453
Surplus (deficit) at 31 December	1,124	(1,696)	(2,984)	(5,064)	(8,620)
Represented by					
Asset recognized	1,290	–	–	100	1,390
Liability recognized	(166)	(1,696)	(2,984)	(5,164)	(10,010)
	1,124	(1,696)	(2,984)	(5,064)	(8,620)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	1,287	(1,280)	(33)	(164)	(190)
Unfunded	(163)	(416)	(2,951)	(4,900)	(8,430)
	1,124	(1,696)	(2,984)	(5,064)	(8,620)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(21,262)	(7,103)	(45)	(3,233)	(31,643)
Unfunded	(163)	(416)	(2,951)	(4,900)	(8,430)
	(21,425)	(7,519)	(2,996)	(8,133)	(40,073)

[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] The benefit payments amount shown above comprises $3,174 million benefits plus $54 million of plan expenses incurred in the administration of the benefit.
[e] The benefit obligation for other plans includes $3,880 million for the German plan, which is largely unfunded.
[f] 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.

38. Pensions and other post-retirement benefits continued

					$ million
					2008
	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	448	235	40	128	851
Past service cost	7	74	–	1	82
Settlement, curtailment and special termination benefits	30	–	–	12	42
Payments to defined contribution plans	–	170	–	25	195
Total operating charge[b]	485	479	40	166	1,170
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	2,094	632	2	194	2,922
Interest on plan liabilities	(1,239)	(444)	(198)	(450)	(2,331)
Other finance income (expense)	855	188	(196)	(256)	591
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	(6,946)	(2,895)	(8)	(404)	(10,253)
Change in assumptions underlying the present value of the plan liabilities	1,570	3	215	214	2,002
Experience gains and losses arising on the plan liabilities	(73)	(194)	18	70	(179)
Actuarial (loss) gain recognized in other comprehensive income	(5,449)	(3,086)	225	(120)	(8,430)

a The costs of managing the plan's investments are treated as being part of the investment return, the costs of administering our pensions fund 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 2010, reimbursement balances due from or to other companies in respect of pensions amounted to $483 million reimbursement assets (2009 $443 million) and $13 million reimbursement liabilities (2009 $14 million).These balances are not included as part of the pension liability, but are reflected elsewhere in the group balance sheet.

					$ million
	2010	2009	2008	2007	2006
History of surplus (deficit) and of experience gains and losses					
Benefit obligation at 31 December	**41,912**	40,073	34,847	43,100	42,433
Fair value of plan assets at 31 December	**34,231**	31,453	26,154	42,799	39,910
Deficit	**(7,681)**	(8,620)	(8,693)	(301)	(2,523)
Experience losses on plan liabilities	**(94)**	(421)	(178)	(200)	(124)
Actual return less expected return on pension plan assets	**2,037**	2,549	(10,253)	302	1,967
Actual return on plan assets	**4,261**	4,528	(7,331)	3,157	4,377
Actuarial (loss) gain recognized in other comprehensive income	**(320)**	(682)	(8,430)	1,717	2,615
Cumulative amount recognized in other comprehensive income	**(3,942)**	(3,622)	(2,940)	5,490	3,773

Estimated future benefit payments

The expected benefit payments, which reflect expected future service, as appropriate, but exclude plan expenses, up until 2020 are as follows:

					$ million
	UK pension plans	**US pension plans**	**US other post-retirement benefit plans**	**Other plans**	**Total**
2011	**994**	**805**	**207**	**612**	**2,618**
2012	**1,035**	**807**	**209**	**581**	**2,632**
2013	**1,069**	**810**	**213**	**584**	**2,676**
2014	**1,122**	**808**	**217**	**588**	**2,735**
2015	**1,167**	**788**	**221**	**576**	**2,752**
2016-2020	**6,581**	**3,636**	**1,132**	**2,815**	**14,164**

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39. Called-up share capital

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

	2010		2009		2008	
Issued	**Shares (thousand)**	**$ million**	Shares (thousand)	$ million	Shares (thousand)	$ million
8% cumulative first preference shares of £1 each	**7,233**	**12**	7,233	12	7,233	12
9% cumulative second preference shares of £1 each	**5,473**	**9**	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
At 1 January	**20,629,665**	**5,158**	20,618,458	5,155	20,863,424	5,216
Issue of new shares for employee share schemes[a]	**17,495**	**4**	11,207	3	24,791	6
Repurchase of ordinary share capital[b]	**–**	**–**	–	–	(269,757)	(67)
At 31 December	**20,647,160**	**5,162**	20,629,665	5,158	20,618,458	5,155
		5,183		5,179		5,176
Authorized						
8% cumulative first preference shares of £1 each	**7,250**	**12**	7,250	12	7,250	12
9% cumulative second preference shares of £1 each	**5,500**	**9**	5,500	9	5,500	9
Ordinary shares of 25 cents each	**36,000,000**	**9,000**	36,000,000	9,000	36,000,000	9,000

[a] Consideration received relating to the issue of new shares for employee share schemes amounted to $138 million (2009 $84 million and 2008 $180 million).
[b] Purchased for a total consideration of nil (2009 nil and 2008 $2,914 million), all of which were for cancellation. At 31 December 2010, 112,803,287 (2009 112,803,287 and 2008 150,444,408) ordinary shares bought back were awaiting cancellation. These shares have been excluded from ordinary shares in issue shown above. Transaction costs of share repurchases amounted to nil (2009 nil and 2008 $16 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

	2010		2009		2008	
	Shares (thousand)	**Nominal value $ million**	Shares (thousand)	Nominal value $ million	Shares (thousand)	Nominal value $ million
At 1 January	**1,869,777**	**467**	1,888,151	472	1,940,639	485
Shares gifted to the Employee Share Ownership Plans	**–**	**–**	(1,265)	(1)	(10,000)	(2)
Shares transferred at market price to the Employee Share Ownership Plans	**(7,125)**	**(2)**	–	–	(20,000)	(5)
Shares re-issued to employee share schemes	**(11,953)**	**(3)**	(17,109)	(4)	(22,488)	(6)
At 31 December	**1,850,699**	**462**	1,869,777	467	1,888,151	472

For each year presented, the balance at 1 January represents the maximum number of shares held in treasury during the year, representing 9.1% (2009 9.2% and 2008 9.3%) of the called-up ordinary share capital of the company.

During 2010, the movement in treasury shares represented less than 0.1% (2009 less than 0.1% and 2008 0.25%) of the ordinary share capital of the company.

On 14 January 2011, BP entered into a share swap agreement with Rosneft Oil Company that would result in BP issuing 988,694,683 new ordinary shares to Rosneft when the transaction completes, which is subject to the matters disclosed in Note 6.

40. Capital and reserves

	Share capital	Share premium account	Capital redemption reserve	Merger reserve
At 1 January 2010	**5,179**	**9,847**	**1,072**	**27,206**
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**	**–**	**–**
Transactions involving minority interests	**–**	**–**	**–**	**–**
At 31 December 2010	**5,183**	**9,987**	**1,072**	**27,206**

	Share capital	Share premium account	Capital redemption reserve	Merger reserve
At 1 January 2009	5,176	9,763	1,072	27,206
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	–	–
Changes in associates’ equity	–	–	–	–
Transactions involving minority interests	–	–	–	–
At 31 December 2009	5,179	9,847	1,072	27,206

	Share capital	Share premium account	Capital redemption reserve	Merger reserve
At 1 January 2008	5,237	9,581	1,005	27,206
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	–	–	–	–
Repurchase of ordinary share capital	(67)	–	67	–
Share-based payments[a]	6	182	–	–
Transactions involving minority interests	–	–	–	–
At 31 December 2008	5,176	9,763	1,072	27,206

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

$ million

	Own shares	Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
	(214)	(21,303)	4,811	754	22	1,584	72,655	101,613	500	102,113
	–	–	126	–	2	–	–	128	3	131
	–	–	–	–	–	–	(418)	(418)	–	(418)
	–	–	–	(291)	–	–	–	(291)	–	(291)
	–	–	–	–	(18)	–	–	(18)	–	(18)
	–	–	–	–	–	–	(3,719)	(3,719)	395	(3,324)
	–	–	126	(291)	(16)	–	(4,137)	(4,318)	398	(3,920)
	–	–	–	–	–	–	(2,627)	(2,627)	(315)	(2,942)
	88	218	–	–	–	2	(113)	339	–	339
	–	–	–	–	–	–	(20)	(20)	321	301
	(126)	(21,085)	4,937	463	6	1,586	65,758	94,987	904	95,891

	Own shares	Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
	(326)	(21,513)	2,353	63	(866)	1,295	67,080	91,303	806	92,109
	–	–	2,458	(2)	(37)	–	–	2,419	(56)	2,363
	–	–	–	–	–	–	(478)	(478)	–	(478)
	–	–	–	693	–	–	–	693	–	693
	–	–	–	–	925	–	–	925	–	925
	–	–	–	–	–	–	16,578	16,578	181	16,759
	–	–	2,458	691	888	–	16,100	20,137	125	20,262
	–	–	–	–	–	–	(10,483)	(10,483)	(416)	(10,899)
	112	210	–	–	–	289	23	721	–	721
	–	–	–	–	–	–	(43)	(43)	–	(43)
	–	–	–	–	–	–	(22)	(22)	(15)	(37)
	(214)	(21,303)	4,811	754	22	1,584	72,655	101,613	500	102,113

	Own shares	Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
	(60)	(22,112)	6,540	481	106	1,196	64,510	93,690	962	94,652
	–	–	(4,187)	–	–	–	–	(4,187)	(75)	(4,262)
	–	–	–	–	–	–	(5,828)	(5,828)	–	(5,828)
	–	–	–	(418)	–	–	–	(418)	–	(418)
	–	–	–	–	(972)	–	–	(972)	–	(972)
	–	–	–	–	–	–	21,157	21,157	509	21,666
	–	–	(4,187)	(418)	(972)	–	15,329	9,752	434	10,186
	–	–	–	–	–	–	(10,342)	(10,342)	(425)	(10,767)
	–	–	–	–	–	–	(2,414)	(2,414)	–	(2,414)
	(266)	599	–	–	–	99	(3)	617	–	617
	–	–	–	–	–	–	–	–	(165)	(165)
	(326)	(21,513)	2,353	63	(866)	1,295	67,080	91,303	806	92,109

40. 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 Plans (ESOPs) to meet the future requirements of the employee share-based payment plans.

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 affects profit or loss, 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.

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40. 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
			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

			$ million
			2008
	Pre-tax	Tax	Net of tax
Currency translation differences (including recycling)	(4,362)	100	(4,262)
Actuarial loss relating to pensions and other post-retirement benefits	(8,430)	2,602	(5,828)
Available-for-sale investments (including recycling)	(468)	50	(418)
Cash flow hedges (including recycling)	(1,166)	194	(972)
Other comprehensive income	(14,426)	2,946	(11,480)

41. Share-based payments

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

			$ million
	2010	2009	2008
Total expense recognized for equity-settled share-based payment transactions	**577**	506	524
Total (credit) expense recognized for cash-settled share-based payment transactions	**(1)**	15	(16)
Total expense recognized for share-based payment transactions	**576**	521	508
Closing balance of liability for cash-settled share-based payment transactions	**16**	32	21
Total intrinsic value for vested cash-settled share-based payments	**1**	7	2

For ease of presentation, option and share holdings 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 share-based payment plans that existed during the year are detailed below. All plans are ongoing unless otherwise stated.

Plans for executive directors

Executive Directors' Incentive Plan (EDIP) – share element

An equity-settled incentive plan for executive directors with a three-year performance period. For share plan performance periods 2008-2010 the award of shares is determined by comparing BP's total shareholder return (TSR) against the other oil majors (ExxonMobil, Shell, Total and Chevron). For the performance period 2009-2011 the award of shares is determined 50% on TSR versus a competitor group of oil majors (which in this period also included ConocoPhillips) and 50% on a balanced scorecard (BSC) of three underlying performance measures versus the same competitor group. For the period 2010-2012 the award of shares is determined one third on TSR versus a competitor group of oil majors (identical to the 2009-2011 plan group) and two thirds on a BSC of three underlying performance factors. After the performance period, the shares that vest (net of tax) are then subject to a three-year retention period. The directors' remuneration report on pages 112 to 121 includes full details of the plan.

Executive Directors' Incentive Plan (EDIP) – deferred matching share element

Following the renewal of the EDIP at the 2010 Annual General Meeting, a deferred matching share element is in place requiring a mandatory one third of directors' annual bonus to be deferred into shares for three years. The shares are matched by the company on a one-for-one basis. Vesting of both deferred and matching shares is contingent on an assessment of safety and environmental sustainability over the three-year deferral period and a director may voluntarily defer an additional one third of bonus into shares on the same terms.

Executive Directors' Incentive Plan (EDIP) – share option element

An equity-settled share option plan for executive directors that permits options to be granted at an exercise price no lower than the market price of a share on the date that the option is granted. The options are exercisable up to the seventh anniversary of the grant date and the last grants were made in 2004. From 2005 onwards the remuneration committee's policy is not to make further grants of share options to executive directors.

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 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 during the three-year period will normally preclude the conversion of units into shares, but special arrangements apply where the participant leaves for a qualifying reason.

Grants are settled in cash where participants are located in a country whose regulatory environment prohibits the holding of BP shares.

Performance unit plans

The number of units granted is made by reference to level of seniority of the 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 TSR compared against the other oil majors. In addition, free cash flow (FCF) is used as a performance measure for one of the performance plans. Plans included in this category are the Competitive Performance Plan (CPP), the Medium Term Performance Plan (MTPP) 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 long-term potential. One restricted share unit plan used in special circumstances for senior employees, 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 share immediately preceding the date of grant were granted to participants annually until 2006. There were no performance conditions and the options are exercisable between the third and tenth anniversaries of the grant date.

Savings and matching plans

BP ShareSave Plan

This is a savings-related share option plan under which employees save on a monthly basis, over a three- or five-year period, towards the purchase of shares at a fixed price determined when the option is granted. This price is usually set at a 20% discount to the market price at the time of grant. The option must be exercised within six months of maturity of the savings contract; otherwise it lapses. The plan is run in the UK and options are granted annually, usually in June. Participants leaving for a qualifying reason will have six months in which to use their savings to exercise their options on a pro-rated basis.

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41. Share-based payments continued

BP ShareMatch Plans

These are matching share plans under which BP matches employees' own contributions of shares up to a predetermined limit. The plans are run in the UK and in more than 60 other countries. The UK plan is run on a monthly basis with shares being held in trust for five years before they can be released free of any income tax and national insurance liability. In other countries the plan is run on an annual basis with shares being held in trust for three years. The plan is operated on a cash basis in those countries where there are regulatory restrictions preventing the holding of BP shares. When the employee leaves BP all shares must be removed from trust and units under the plan operated on a cash basis must be encashed.

Local plans

In some countries BP provides local scheme benefits, the rules and qualifications for which vary according to local circumstances.

Employee Share Ownership Plans (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 ESOP trusts vest unconditionally to employees, the amount paid for those shares is deducted in arriving at shareholders' equity (see Note 40). Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

At 31 December 2010 the ESOPs held 11,477,253 shares (2009 18,062,246 shares and 2008 29,051,082 shares) for potential future awards, which had a market value of $82 million (2009 $174 million and 2008 $220 million).

Share option transactions

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

	2010		2009		2008	
	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	**295,895,357**	**8.73**	326,254,599	8.70	358,094,243	8.51
Granted	**10,420,287**	**6.08**	9,679,836	6.55	8,062,899	8.96
Forfeited	**(9,499,661)**	**7.88**	(5,954,325)	8.81	(2,502,784)	8.50
Exercised	**(31,839,034)**	**7.97**	(21,293,871)	7.53	(37,277,895)	6.97
Expired	**(1,670,227)**	**8.71**	(12,790,882)	8.01	(121,864)	7.00
Outstanding at 31 December	**263,306,722**	**8.75**	295,895,357	8.73	326,254,599	8.70
Exercisable at 31 December	**242,530,635**	**8.90**	274,685,068	8.80	260,178,938	8.22

The weighted average share price at the date of exercise was $9.54 (2009 $9.10 and 2008 $10.87). For the options outstanding at 31 December 2010, the exercise price ranges and weighted average remaining contractual lives are shown below.

	Options outstanding			**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 $**
$6.09 – $7.53	**54,821,144**	**2.68**	**6.36**	**39,231,453**	**6.40**
$7.54 – $8.99	**115,187,261**	**1.71**	**8.19**	**112,551,834**	**8.17**
$9.00 – $10.45	**21,827,393**	**3.54**	**9.88**	**19,276,424**	**9.98**
$10.46 – $11.92	**71,470,924**	**4.81**	**11.14**	**71,470,924**	**11.14**
	263,306,722	**2.90**	**8.75**	**242,530,635**	**8.90**

Fair values and associated details for options and shares granted

	2010		2009		2008	
	ShareSave 3 year	**ShareSave 5 year**	ShareSave 3 year	ShareSave 5 year	ShareSave 3 year	ShareSave 5 year
Option pricing model used	**Binomial**	**Binomial**	Binomial	Binomial	Binomial	Binomial
Weighted average fair value	**$0.06**	**$0.08**	$1.07	$1.07	$1.82	$1.74
Weighted average share price	**$4.58**	**$4.58**	$7.87	$7.87	$11.26	$11.26
Weighted average exercise price	**$5.90**	**$5.90**	$6.92	$6.92	$9.70	$9.70
Expected volatility	**22%**	**23%**	32%	32%	23%	23%
Option life	**3.5 years**	**5.5 years**	3.5 years	5.5 years	3.5 years	5.5 years
Expected dividends	**8.40%**	**8.40%**	7.40%	7.40%	4.60%	4.60%
Risk free interest rate	**1.25%**	**2.00%**	3.00%	3.75%	5.00%	5.00%
Expected exercise behaviour	**100% year 4**	**100% year 6**	100% year 4	100% year 6	100% year 4	100% year 6

The group uses a valuation model to determine the fair value of options granted. The model uses the implied volatility of ordinary share price for the quarter within which the grant date of the relevant plan falls. The fair value is adjusted for the expected rates of early cancellation. Management is responsible for all inputs and assumptions in relation to the model, including the determination of expected volatility.

41. Share-based payments continued

Shares granted in 2010	CPP	EPP	EDIP-TSR	EDIP-BSC	RSP	DAB	PSP
Number of equity instruments granted (million)	**1.3**	**7.6**	**1.2**	**2.5**	**21.4**	**24.5**	**16.0**
Weighted average fair value	**$19.81**	**$9.43**	**$4.42**	**$8.94**	**$6.78**	**$9.43**	**$9.43**
Fair value measurement basis	**Monte Carlo**	**Market value**	**Monte Carlo**	**Market value**	**Market value**	**Market value**	**Market value**

Shares granted in 2009	CPP	EPP	EDIP-TSR	EDIP-BSC	RSP	DAB	PSP
Number of equity instruments granted (million)	1.4	7.6	2.1	2.1	2.4	38.9	16.5
Weighted average fair value	$9.76	$6.56	$2.74	$7.27	$8.76	$6.56	$8.32
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value	Market value	Monte Carlo

Shares granted in 2008	MTPP-TSR	MTPP-FCF	EDIP-TSR	EDIP-RET[a]	RSP	DAB	PSP
Number of equity instruments granted (million)	9.1	9.1	2.6	0.5	7.7	5.8	16.7
Weighted average fair value	$5.07	$10.34	$4.55	$11.13	$8.83	$10.34	$12.89
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value	Market value	Monte Carlo

[a] EDIP – retention element.

The group used a Monte Carlo simulation to determine the fair value of the TSR element of the 2010, 2009 and 2008 CPP, MTPP, and EDIP plans, and in 2009 and 2008 for the PSP plan. In accordance with the rules of the plans the model simulates BP's TSR and compares it against our principal strategic competitors over the three-year period of the plans. The model takes into account the historic 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.

42. Employee costs and numbers

			$ million
Employee costs	**2010**	2009	2008
Wages and salaries[a]	**9,242**	9,702	10,388
Social security costs	**789**	780	805
Share-based payments	**576**	521	508
Pension and other post-retirement benefit costs	**1,166**	1,213	579
	11,773	12,216	12,280

Number of employees at 31 December	**2010**	2009	2008
Exploration and Production	**21,100**	21,500	21,400
Refining and Marketing[b]	**52,300**	51,600	61,500
Other businesses and corporate	**6,200**	7,200	9,100
Gulf Coast Restoration Organization	**100**	–	–
	79,700	80,300	92,000
By geographical area			
US	**22,100**	22,800	29,300
Non-US[b]	**57,600**	57,500	62,700
	79,700	80,300	92,000

			2010			2009			2008
Average number of employees	**US**	**Non-US**	**Total**	US	Non-US	Total	US	Non-US	Total
Exploration and Production	**8,100**	**13,500**	**21,600**	7,900	13,800	21,700	7,800	13,800	21,600
Refining and Marketing	**12,600**	**38,300**	**50,900**	14,700	40,700	55,400	21,600	43,400	65,000
Other businesses and corporate	**1,900**	**5,000**	**6,900**	2,300	5,800	8,100	2,600	6,500	9,100
	22,600	**56,800**	**79,400**	24,900	60,300	85,200	32,000	63,700	95,700

[a] Includes termination payments of $166 million (2009 $945 million and 2008 $669 million).
[b] Includes 15,200 (2009 13,900 and 2008 21,200) service station staff.

43. Remuneration of directors and senior management

Remuneration of directors

	2010	2009	2008
			$ million
Total for all directors			
Emoluments	**15**	19	19
Gains made on the exercise of share options	**2**	2	1
Amounts awarded under incentive schemes	**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. Also included was compensation for loss of office of $3 million in 2010 (2009 nil and 2008 $1 million).

Pension contributions

During 2010 three executive directors participated in a non-contributory pension scheme 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 2010.

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 112 to 121.

Remuneration of directors and senior management

	2010	2009	2008
			$ million
Total for all senior management			
Short-term employee benefits	**25**	36	34
Post-retirement benefits	**3**	3	4
Share-based payments	**29**	20	20

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 $3 million (2009 $6 million and 2008 $3 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 41.

44. Contingent liabilities and contingent assets

Contingent liabilities relating to the Gulf of Mexico oil spill

As a consequence of the Gulf of Mexico oil spill, as described on pages 34 to 39, BP has incurred costs during the year and recognized provisions for certain future costs. Further information is provided in Note 2 and Note 37.

BP has provided for its best estimate of certain claims under the Oil Pollution Act of 1990 (OPA 90) that will be paid through the $20-billion trust fund. 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, and claims asserted in civil litigation, 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 37 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 anticipate that we will need at least a full year, and perhaps materially longer, after the initial oil impacts to gain an understanding of the natural resource damages. In addition, if 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 determined and the effects of early restoration projects are 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 or timing of the remaining Natural Resource Damages claims.

BP is named as a defendant in more than 400 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, 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. These pending lawsuits are at the very early stages of proceedings and most of the claims have been consolidated into one of two multi-district litigation proceedings. A trial of liability issues in the pending multi-district litigation is currently scheduled for February 2012. 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. See *Legal proceedings* on page 130 for further information.

Therefore no amounts have been provided for these items as of 31 December 2010. 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 37, for those relating to the Clean Water Act. It is also not possible to reliably estimate legal fees beyond two years. 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.

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 27 to 32. Any such possible obligations are therefore contingent liabilities and, at present, it is not practicable to estimate their magnitude or possible timing of payment. Furthermore, other material unanticipated obligations may arise in future in relation to the incident.

Contingent assets relating to the Gulf of Mexico oil spill

BP is the operator of the Macondo well and holds a 65% working interest, with the remaining 35% interest held by two co-owners, Anadarko Petroleum Corporation (APC) and MOEX Offshore 2007 LLC (MOEX). Under the Operating Agreement, MOEX and APC are responsible for reimbursing BP for their proportionate shares of the costs of all operations and activities conducted under the Operating Agreement. In addition, the parties are responsible for their proportionate shares of all liabilities resulting from operations or activities conducted under the Operating Agreement, except where liability results from a party’s gross negligence or wilful misconduct, in which case that party is solely responsible. BP does not believe that it has been grossly negligent nor has it engaged in wilful misconduct under the terms of the Operating Agreement or at law.

As of 31 December 2010, $6 billion had been billed to the co-owners, which BP believes to be contractually recoverable. Billings to co-owners are based upon costs incurred to date rather than amounts provided in the period. As further costs are incurred, BP believes that certain of the costs will be billable to our co-owners under the Operating Agreement.

Our co-owners have each written to BP indicating that they are withholding payment in light of the investigations surrounding, and pending determination of the root causes of, the incident. In addition, APC has publicly accused BP of having been grossly negligent and stated it has no liability for the incident, both of which claims BP refutes and intends to challenge in any legal proceedings. There are also audit rights concerning billings under the Operating Agreement which may be exercised by APC and MOEX, and which may or may not lead to an adjustment of the amount billed. BP may ultimately need to enforce its rights to collect payment from the co-owners through an arbitration proceeding as provided for in the Operating Agreement. There is a risk that amounts billed to co-owners may not ultimately be recovered should our co-owners be found not liable for these costs or be unable to pay them.

BP believes that it has a contractual right to recover the co-owners’ shares of the costs incurred, however, no recovery amounts have been recognized in the financial statements as at 31 December 2010.

44. Contingent liabilities and contingent assets continued

Other contingent liabilities

There were contingent liabilities at 31 December 2010 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 27.

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, oil fields, 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.

45. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been placed at 31 December 2010 amounted to $11,279 million (2009 $9,812 million). In addition, at 31 December 2010, the group had contracts in place for future capital expenditure relating to investments in jointly controlled entities of $437 million (2009 $622 million) and investments in associates of $80 million (2009 $170 million).

BP's share of capital commitments of jointly controlled entities amounted to $1,117 million (2009 $926 million).

46. Subsidiaries, jointly controlled entities and associates

The more important subsidiaries, jointly controlled entities and associates of the group at 31 December 2010 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 Op. Co.	100	England & Wales	Exploration and production
*BP Global Investments	100	England & Wales	Investment holding
*BP International	100	England & Wales	Integrated oil operations, investment holding, finance
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 Oil Australia	100	Australia	Integrated oil operations
BP Australia Capital Markets	100	Australia	Finance
BP Developments Australia	100	Australia	Exploration and production
BP Finance Australia	100	Australia	Finance
Azerbaijan			
Amoco Caspian Sea Petroleum	100	British Virgin Islands	Exploration and production
BP Exploration (Caspian Sea)	100	England & Wales	Exploration and production
Canada			
BP Canada Energy	100	Canada	Exploration and production
BP Canada Finance	100	Canada	Finance
Egypt			
BP Egypt Co.	100	US	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 Co.	100	US	Exploration and production, refining and marketing, pipelines and petrochemicals
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	
BP Exploration and Production	100	US	
BP Exploration (Alaska)	100	US	
BP Products North America	100	US	
BP West Coast Products	100	US	
Standard Oil Co.	100	US	
Verano Collateral Holdings	100	US	
BP Capital Markets America	100	US	Finance

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46. Subsidiaries, jointly controlled entities and associates continued

Jointly controlled entities	%	Country of incorporation or registration	Principal activities
Angola			
Angola LNG Supply Services	14	US	LNG processing and transportation
Argentina			
Pan American Energy[a b]	60	US	Exploration and production
Canada			
Sunrise Oil Sands	50	Canada	Exploration and production
China			
Shanghai SECCO Petrochemical Co.	50	China	Petrochemicals
Germany			
Ruhr Oel	50	Germany	Refining and marketing and petrochemicals
Russia			
Elvary Neftegaz Holdings BV	49	Netherlands	Exploration and appraisal
Trinidad & Tobago			
Atlantic 4 Holdings	38	US	LNG manufacture
Atlantic LNG 2/3 Company of Trinidad and Tobago	43	Trinidad & Tobago	LNG manufacture
US			
BP-Husky Refining	50	US	Refining
Watson Cogeneration[a]	51	US	Power generation
Venezuela			
Petromonagas[b]	17	Venezuela	Exploration and production

[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 2010 the group's interests in Pan American Energy and Petromonagas have been reclassified as assets held for sale. See Note 4 for further information.

Associates	%	Country of incorporation	Principal activities
Abu Dhabi			
Abu Dhabi Marine Areas	37	England & Wales	Crude oil production
Abu Dhabi Petroleum Co.	24	England & Wales	Crude oil production
Azerbaijan			
The Baku-Tbilisi-Ceyhan Pipeline Co.	30	Cayman Islands	Pipelines
South Caucasus Pipeline Co.	26	Cayman Islands	Pipelines
Russia			
TNK-BP	50	British Virgin Islands	Integrated oil operations

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47. Condensed consolidating information on certain US subsidiaries

BP p.I.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.I.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.I.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.I.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.I.c. also fully and unconditionally guarantees securities issued by BP Capital Markets p.I.c. and BP Capital Markets America Inc. These companies are 100%-owned finance subsidiaries of BP p.I.c.

Income statement

					$ 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)

47. 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

47. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million 2008
Sales and other operating revenues	6,782	–	361,143	(6,782)	361,143
Earnings from jointly controlled entities – after interest and tax	–	–	3,023	–	3,023
Earnings from associates – after interest and tax	–	–	798	–	798
Equity-accounted income of subsidiaries – after interest and tax	469	20,295	–	(20,764)	–
Interest and other revenues	514	173	1,025	(976)	736
Gains on sale of businesses and fixed assets	–	–	1,353	–	1,353
Total revenues and other income	7,765	20,468	367,342	(28,522)	367,053
Purchases	895	–	272,869	(6,782)	266,982
Production and manufacturing expenses	1,083	–	25,673	–	26,756
Production and similar taxes	2,343	–	6,610	–	8,953
Depreciation, depletion and amortization	365	–	10,620	–	10,985
Impairment and losses on sale of businesses and fixed assets	–	–	1,733	–	1,733
Exploration expense	–	–	882	–	882
Distribution and administration expenses	22	28	15,469	(107)	15,412
Fair value loss on embedded derivatives	–	–	111	–	111
Profit before interest and taxation	3,057	20,440	33,375	(21,633)	35,239
Finance costs	158	169	2,089	(869)	1,547
Net finance (income) expense relating to pensions and other post-retirement benefits	–	(822)	231	–	(591)
Profit before taxation	2,899	21,093	31,055	(20,764)	34,283
Taxation	944	(64)	11,737	–	12,617
Profit for the year	1,955	21,157	19,318	(20,764)	21,666
Attributable to					
BP shareholders	1,955	21,157	18,809	(20,764)	21,157
Minority interest	–	–	509	–	509
	1,955	21,157	19,318	(20,764)	21,666

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47. 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 2010 BP group
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	–	–	12,286	–	12,286
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	151,765	(116,716)	159,871
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	169,700	(121,021)	175,409
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	–	–	7,128	–	7,128
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

47. Condensed consolidating information on certain US subsidiaries continued

Balance sheet continued

At 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2009 BP group
Non-current assets					
Property, plant and equipment	7,366	–	100,909	–	108,275
Goodwill	–	–	8,620	–	8,620
Intangible assets	321	–	11,227	–	11,548
Investments in jointly controlled entities	–	–	15,296	–	15,296
Investments in associates	–	2	12,961	–	12,963
Other investments	–	–	1,567	–	1,567
Subsidiaries – equity-accounted basis	4,424	101,760	–	(106,184)	–
Fixed assets	12,111	101,762	150,580	(106,184)	158,269
Loans	283	1,178	5,490	(5,912)	1,039
Other receivables	–	–	1,729	–	1,729
Derivative financial instruments	–	–	3,965	–	3,965
Prepayments	–	–	1,407	–	1,407
Deferred tax assets	–	–	516	–	516
Defined benefit pension plan surpluses	–	1,071	319	–	1,390
	12,394	104,011	164,006	(112,096)	168,315
Current assets					
Loans	–	–	249	–	249
Inventories	221	–	22,384	–	22,605
Trade and other receivables	18,529	30,707	35,852	(55,557)	29,531
Derivative financial instruments	–	–	4,967	–	4,967
Prepayments	8	2	1,743	–	1,753
Current tax receivable	–	–	209	–	209
Cash and cash equivalents	(22)	28	8,333	–	8,339
	18,736	30,737	73,737	(55,557)	67,653
Total assets	31,130	134,748	237,743	(167,653)	235,968
Current liabilities					
Trade and other payables	4,662	2,374	83,725	(55,557)	35,204
Derivative financial instruments	–	–	4,681	–	4,681
Accruals	–	27	6,175	–	6,202
Finance debt	55	–	9,054	–	9,109
Current tax payable	172	–	2,292	–	2,464
Provisions	–	–	1,660	–	1,660
	4,889	2,401	107,587	(55,557)	59,320
Non-current liabilities					
Other payables	229	4,254	4,627	(5,912)	3,198
Derivative financial instruments	–	–	3,474	–	3,474
Accruals	–	74	629	–	703
Finance debt	–	–	25,518	–	25,518
Deferred tax liabilities	1,872	149	16,641	–	18,662
Provisions	1,048	–	11,922	–	12,970
Defined benefit pension plan and other post-retirement benefit plan deficits	–	–	10,010	–	10,010
	3,149	4,477	72,821	(5,912)	74,535
Total liabilities	8,038	6,878	180,408	(61,469)	133,855
Net assets	23,092	127,870	57,335	(106,184)	102,113
Equity					
BP shareholders' equity	23,092	127,870	56,835	(106,184)	101,613
Minority interest	–	–	500	–	500
Total equity	23,092	127,870	57,335	(106,184)	102,113

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47. Condensed consolidating information on certain US subsidiaries continued

Cash flow statement

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million 2010
Net cash provided by operating activities	**829**	**32,111**	**(4,584)**	**(14,740)**	**13,616**
Net cash used in 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)**
(Decrease) increase 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**

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million 2009
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

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million 2008
Net cash provided by operating activities	1,105	12,665	41,600	(17,275)	38,095
Net cash used in investing activities	(896)	–	(21,871)	–	(22,767)
Net cash used in financing activities	(209)	(12,898)	(14,677)	17,275	(10,509)
Currency translation differences relating to cash and cash equivalents	–	–	(184)	–	(184)
(Decrease) increase in cash and cash equivalents	–	(233)	4,868	–	4,635
Cash and cash equivalents at beginning of year	(10)	244	3,328	–	3,562
Cash and cash equivalents at end of year	(10)	11	8,196	–	8,197

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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. For 2009 and 2010, where relevant, information for equity-accounted entities is provided in the same level of detail as for subsidiaries. Also for 2009 and 2010, proved reserves are based on revised SEC definitions.

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 51 to 52.

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Supplementary information on oil and natural gas (unaudited) continued

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	$ million 2010 Total
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.

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Supplementary information on oil and natural gas (unaudited) continued

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
Equity-accounted entities (BP share)[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	–	–	–	142	103	–	14,486	3,192	–	17,923
Unproved properties	–	–	–	1,284	–	–	652	–	–	1,936
	–	–	–	1,426	103	–	15,138	3,192	–	19,859
Accumulated depreciation	–	–	–	–	–	–	6,300	2,674	–	8,974
Net capitalized costs	–	–	–	1,426	103	–	8,838	518	–	10,885
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	87	–	7,965
Sales between businesses	–	–	–	–	–	–	3,432	460	–	3,892
	–	–	–	–	2,268	–	9,042	547	–	11,857
Exploration expenditure	–	–	–	–	22	–	40	–	–	62
Production costs	–	–	–	–	316	–	1,602	184	–	2,102
Production taxes	–	–	–	–	911	–	3,567	–	–	4,478
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	545	–	8,414
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.

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Supplementary information on oil and natural gas (unaudited) continued

Oil and natural gas exploration and production activities continued

	Europe		North America		South America	Africa	Asia		Australasia	$ million 2009 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).

Supplementary information on oil and natural gas (unaudited) continued

Oil and natural gas exploration and production activities continued

	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
										2009
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	351	–	7,247
Sales between businesses	–	–	–	–	–	–	2,838	–	–	2,838
	–	–	–	–	1,977	–	7,757	351	–	10,085
Exploration expenditure	–	–	–	–	23	–	37	–	–	60
Production costs	–	–	–	–	354	–	1,428	159	–	1,941
Production taxes	–	–	–	–	702	–	2,597	–	–	3,299
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	431	–	6,941
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.

Supplementary information on oil and natural gas (unaudited) continued

Oil and natural gas exploration and production activities continued

$ million

2008	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
Subsidiaries[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	34,614	5,507	59,918	3,517	7,934	21,563	–	10,689	2,581	146,323
Unproved properties	626	–	5,006	165	134	2,011	–	465	1,018	9,425
	35,240	5,507	64,924	3,682	8,068	23,574	–	11,154	3,599	155,748
Accumulated depreciation	26,564	3,125	28,511	2,141	4,217	10,451	–	4,395	945	80,349
Net capitalized costs	8,676	2,382	36,413	1,541	3,851	13,123	–	6,759	2,654	75,399

The group's share of equity-accounted entities' net capitalized costs at 31 December 2008 was $13,393 million.

2008	UK	Rest of Europe	US	Rest of North America	South America	Africa	Russia	Rest of Asia	Australasia	Total
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved	–	–	1,374	2	–	–	–	136	–	1,512
Unproved	4	–	2,942	–	–	–	–	41	–	2,987
	4	–	4,316	2	–	–	–	177	–	4,499
Exploration and appraisal costs[d]	137	–	862	33	90	838	12	269	49	2,290
Development	907	695	4,914	309	768	2,966	–	859	349	11,767
Total costs	1,048	695	10,092	344	858	3,804	12	1,305	398	18,556

The group's share of equity-accounted entities' costs incurred in 2008 was $3,259 million: in Russia $1,921 million, South America $1,039 million, and Rest of Asia $299 million.

2008	UK	Rest of Europe	US	Rest of North America	South America	Africa	Russia	Rest of Asia	Australasia	Total
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	3,865	105	1,526	147	3,339	3,745	–	1,186	860	14,773
Sales between businesses	4,374	1,416	22,094	1,237	2,605	6,022	–	11,249	1,171	50,168
	8,239	1,521	23,620	1,384	5,944	9,767	–	12,435	2,031	64,941
Exploration expenditure	121	1	305	32	30	213	14	140	26	882
Production costs	1,357	150	3,002	289	429	875	18	485	62	6,667
Production taxes	503	–	2,603	2	358	–	–	5,510	110	9,086
Other costs (income)[f]	(28)	(43)	3,440	343	198	(122)	196	2,064	226	6,274
Depreciation, depletion and amortization	1,049	199	2,729	181	730	2,120	–	788	87	7,883
Impairments and losses on sale of businesses and fixed assets	–	–	308	2	4	8	–	219	–	541
	3,002	307	12,387	849	1,749	3,094	228	9,206	511	31,333
Profit (loss) before taxation[g]	5,237	1,214	11,233	535	4,195	6,673	(228)	3,229	1,520	33,608
Allocable taxes	2,280	883	3,857	205	2,218	2,672	(36)	984	513	13,576
Results of operations	2,957	331	7,376	330	1,977	4,001	(192)	2,245	1,007	20,032

The group's share of equity-accounted entities' results of operations (including the group's share of total TNK-BP results) in 2008 was a profit of $2,793 million after deducting interest of $355 million, taxation of $1,217 million and minority interest of $169 million.

2008	UK	Rest of Europe	US	Rest of North America	South America	Africa	Russia	Rest of Asia	Australasia	Total
Exploration and Production segment replacement cost profit before interest and tax										
Exploration and production activities										
Subsidiaries (as above)	5,237	1,214	11,233	535	4,195	6,673	(228)	3,229	1,520	33,608
Equity-accounted entities	(1)	–	1	40	304	(1)	2,259	191	–	2,793
Midstream activities[h i]	743	16	490	673	274	112	–	(272)	(129)	1,907
Total replacement cost profit before interest and tax	5,979	1,230	11,724	1,248	4,773	6,784	2,031	3,148	1,391	38,308

[a] These tables contain information relating to oil and natural gas exploration and production activities. 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. The group's share of equity-accounted entities' activities are excluded from the tables and included in the footnotes, with the exception of Abu Dhabi production taxes, which are included in the results of operations above.
[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 loss on embedded derivatives of $102 million. The UK region includes a $499 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 $285 million which is included in finance costs in the group income statement.
[h] Includes a $517 million write-down of our investment in Rosneft based on its quoted market price at the end of the year.
[i] Midstream activities exclude inventory holding gains and losses.

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Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves

										million barrels
Crude oil[a]										2010
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
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 a 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 801 million barrels relating to assets held for sale at 31 December 2010.
i Includes 4 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 35 million barrels of crude oil sold relating to production from assets held for sale at 31 December 2010.

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Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a]										2010
	Europe		North America		South America	Africa	Asia		Australasia	Total
	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 1,819 billion cubic feet relating to assets held for sale at 31 December 2010.
[h] Includes 12 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 141 billion cubic feet of gas (excluding gas consumed in operations) relating to production from assets held for sale at 31 December 2010.

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Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves continued

		million barrels
Bitumen[a]		**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.

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Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves continued

million barrels of oil equivalent

Total hydrocarbons[a]	Europe UK	Europe Rest of Europe	North America US[e]	North America Rest of North America	South America	Africa	Asia Russia	Asia Rest of Asia	Australasia	2010 Total
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 a 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 1,114 million barrels of oil equivalent relating to assets held for sale at 31 December 2010.
k Includes 6 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 59 million barrels of oil equivalent (excluding gas consumed in operations) relating to production from assets held for sale at 31 December 2010.

Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves continued

										million barrels
Crude oil[a]										2009
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
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 a 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.

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Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves continued

Natural gas[a]										billion cubic feet 2009
	Europe		North America		South America	Africa	Asia		Australasia	Total
	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.

Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves continued

million barrels of oil equivalent

Total hydrocarbons[a]										2009
	Europe		North America		South America	Africa	Asia		Australasia	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 a 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.

Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves continued

million barrels

Crude oil[a]										2008
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2008										
Developed	414	105	1,882	13	102	256	–	121	44	2,937
Undeveloped	123	169	1,265	1	202	350	–	372	73	2,555
	537	274	3,147	14	304	606	–	493	117	5,492
Changes attributable to										
Revisions of previous estimates	16	(11)	(212)	1	7	264	–	194	5	264
Improved recovery	39	28	182	–	8	18	–	43	3	321
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	64	–	5	173	–	–	–	242
Production[b]	(63)	(16)	(191)	(3)	(23)	(101)	–	(47)	(11)	(455)
Sales of reserves-in-place	–	–	–	–	(199)	–	–	–	–	(199)
	(8)	1	(157)	(2)	(202)	354	–	190	(3)	173
At 31 December 2008[c]										
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
Equity-accounted entities (BP share)[f]										
At 1 January 2008										
Developed	–	–	–	–	328	–	2,094	574	–	2,996
Undeveloped	–	–	–	–	243	–	1,137	205	–	1,585
	–	–	–	–	571	–	3,231	779	–	4,581
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(3)	11	217	(1)	–	224
Improved recovery	–	–	–	–	62	–	–	–	–	62
Purchases of reserves-in-place	–	–	–	–	199	–	–	–	–	199
Discoveries and extensions	–	–	–	–	13	–	26	–	–	39
Production	–	–	–	–	(34)	–	(302)	(80)	–	(416)
Sales of reserves-in-place	–	–	–	–	–	–	(1)	–	–	(1)
	–	–	–	–	237	11	(60)	(81)	–	107
At 31 December 2008[d]										
Developed	–	–	–	–	399	–	2,227	499	–	3,125
Undeveloped	–	–	–	–	409	11	944	199	–	1,563
	–	–	–	–	808	11	3,171	698	–	4,688
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2008										
Developed	414	105	1,882	13	430	256	2,094	695	44	5,933
Undeveloped	123	169	1,265	1	445	350	1,137	577	73	4,140
	537	274	3,147	14	875	606	3,231	1,272	117	10,073
At 31 December 2008										
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

[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 19 thousand barrels a day.
[c] Includes 807 million barrels of NGLs. Also includes 21 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 36 million barrels of NGLs. Also includes 216 million barrels of crude oil in respect of the 6.80% minority interest in TNK-BP.
[e] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 54 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.

Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves continued

										billion cubic feet
Natural gas[a]										2008
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2008										
Developed	2,049	63	10,670	608	3,075	990	–	1,270	1,135	19,860
Undeveloped	553	410	4,705	421	7,973	1,410	–	1,269	4,529	21,270
	2,602	473	15,375	1,029	11,048	2,400	–	2,539	5,664	41,130
Changes attributable to										
Revisions of previous estimates	23	(8)	(2,063)	51	(456)	142	–	–	361	(1,950)
Improved recovery	77	9	1,322	16	159	6	–	108	2	1,699
Purchases of reserves-in-place	–	–	183	–	–	–	–	–	–	183
Discoveries and extensions	–	–	549	125	948	82	–	37	–	1,741
Production[b]	(298)	(11)	(834)	(94)	(946)	(198)	–	(274)	(140)	(2,795)
Sales of reserves-in-place	–	–	–	–	(3)	–	–	–	–	(3)
	(198)	(10)	(843)	98	(298)	32	–	(129)	223	(1,125)
At 31 December 2008[c]										
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
Equity-accounted entities (BP share)[e]										
At 1 January 2008										
Developed	–	–	–	–	1,478	–	808	187	–	2,473
Undeveloped	–	–	–	–	831	–	353	113	–	1,297
	–	–	–	–	2,309	–	1,161	300	–	3,770
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(96)	182	1,273	(2)	–	1,357
Improved recovery	–	–	–	–	301	–	–	11	–	312
Purchases of reserves-in-place	–	–	–	–	3	–	–	–	–	3
Discoveries and extensions	–	–	–	–	192	–	–	–	–	192
Production[b]	–	–	–	–	(188)	–	(221)	(22)	–	(431)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	212	182	1,052	(13)	–	1,433
At 31 December 2008[d]										
Developed	–	–	–	–	1,498	–	1,560	176	–	3,234
Undeveloped	–	–	–	–	1,023	182	653	111	–	1,969
	–	–	–	–	2,521	182	2,213	287	–	5,203
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2008										
Developed	2,049	63	10,670	608	4,553	990	808	1,457	1,135	22,333
Undeveloped	553	410	4,705	421	8,804	1,410	353	1,382	4,529	22,567
	2,602	473	15,375	1,029	13,357	2,400	1,161	2,839	5,664	44,900
At 31 December 2008										
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

[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 193 billion cubic feet of natural gas consumed in operations, 149 billion cubic feet in subsidiaries, 44 billion cubic feet in equity-accounted entities and excludes 17 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.
[c] Includes 3,108 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 5.92% minority interest in TNK-BP.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

Supplementary information on oil and natural gas (unaudited) continued

Movements in estimated net proved reserves continued

										million barrels of oil equivalent
Total hydrocarbons[a]										2008
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2008										
Developed	767	116	3,722	118	631	427	–	340	240	6,361
Undeveloped	219	239	2,077	74	1,576	593	–	591	853	6,222
	986	355	5,799	192	2,207	1,020	–	931	1,093	12,583
Changes attributable to										
Revisions of previous estimates	20	(12)	(569)	10	(71)	289	–	194	67	(72)
Improved recovery	52	30	410	3	36	18	–	61	4	614
Purchases of reserves-in-place	–	–	32	–	–	–	–	–	–	32
Discoveries and extensions	–	–	158	22	168	187	–	7	–	542
Production[b] [f]	(115)	(18)	(334)	(20)	(186)	(135)	–	(94)	(35)	(937)
Sales of reserves-in-place	–	–	–	–	(200)	–	–	–	–	(200)
	(43)	–	(303)	15	(253)	359	–	168	36	(21)
At 31 December 2008[c]										
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
Equity-accounted entities (BP share)[g]										
At 1 January 2008										
Developed	–	–	–	–	583	–	2,233	606	–	3,422
Undeveloped	–	–	–	–	386	–	1,199	224	–	1,809
	–	–	–	–	969	–	3,432	830	–	5,231
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(20)	42	436	(1)	–	457
Improved recovery	–	–	–	–	115	–	–	2	–	117
Purchases of reserves-in-place	–	–	–	–	200	–	–	–	–	200
Discoveries and extensions	–	–	–	–	46	–	26	–	–	72
Production[b] [f]	–	–	–	–	(66)	–	(341)	(84)	–	(491)
Sales of reserves-in-place	–	–	–	–	–	–	(1)	–	–	(1)
	–	–	–	–	275	42	120	(83)	–	354
At 31 December 2008[d]										
Developed	–	–	–	–	658	–	2,495	529	–	3,682
Undeveloped	–	–	–	–	586	42	1,057	218	–	1,903
	–	–	–	–	1,244	42	3,552	747	–	5,585
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2008										
Developed	767	116	3,722	118	1,214	427	2,233	946	240	9,783
Undeveloped	219	239	2,077	74	1,962	593	1,199	815	853	8,031
	986	355	5,799	192	3,176	1,020	3,432	1,761	1,093	17,814
At 31 December 2008										
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

[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 a day.
[c] Includes 807 million barrels of NGLs. Also includes 557 million barrels of oil equivalent in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d] Includes 36 million barrels of NGLs. Also includes 239 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 54 million barrels of oil equivalent upon which a net profits royalty will be payable.
[f] Includes 33 million barrels of oil equivalent of natural gas consumed in operations, 25 million barrels of oil equivalent in subsidiaries, 8 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.

Supplementary information on oil and natural gas (unaudited) continued

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 there in, 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

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.

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Supplementary information on oil and natural gas (unaudited) continued

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

$ million, 2009

	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
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.

Supplementary information on oil and natural gas (unaudited) continued

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

										$ million
										2008
	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 2008										
Subsidiaries										
Future cash inflows[a]	36,400	13,800	165,800	6,400	26,300	40,400	–	31,400	24,200	344,700
Future production cost[b]	18,100	6,300	80,400	2,700	7,200	11,600	–	11,800	10,700	148,800
Future development cost[b]	3,300	2,900	25,600	1,300	7,200	10,900	–	7,500	3,200	61,900
Future taxation[c]	7,300	2,300	17,500	500	5,500	6,600	–	2,400	2,800	44,900
Future net cash flows	7,700	2,300	42,300	1,900	6,400	11,300	–	9,700	7,500	89,100
10% annual discount[d]	2,200	1,200	21,000	1,000	2,900	5,500	–	4,200	3,900	41,900
Standardized measure of discounted future net cash flows[e]	5,500	1,100	21,300	900	3,500	5,800	–	5,500	3,600	47,200
Equity-accounted entities (BP share)[g]										
Standardized measure of discounted future net cash flows[h]	–	–	–	–	3,600	–	4,800	900	–	9,300
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows[e]	5,500	1,100	21,300	900	7,100	5,800	4,800	6,400	3,600	56,500

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

	$ million
	2008
Sales and transfers of oil and gas produced, net of production costs	(43,600)
Development costs for the current year as estimated in previous year	9,400
Extensions, discoveries and improved recovery, less related costs	4,400
Net changes in prices and production cost	(146,800)
Revisions of previous reserves estimates	1,200
Net change in taxation	69,400
Future development costs	(7,400)
Net change in purchase and sales of reserves-in-place	(200)
Addition of 10% annual discount	14,600
Total change in the standardized measure during the year of subsidiaries[f]	(99,000)

[a] The year-end marker prices used were 2008 Brent $36.55/bbl, Henry Hub $5.63/mmBtu.
[b] Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on year-end cost levels and assume 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 $900 million at 31 December 2008.
[f] Total change in the standardized measure during the year includes the effect of exchange rate movements.
[g] 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.
[h] Minority interest in TNK-BP amounted to $300 million at 31 December 2008.

Supplementary information on oil and natural gas (unaudited) continued

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 2010, 2009 and 2008.

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
2010	**137**	**40**	**594**	**7**	**54**	**246**	**–**	**119**	**32**	**1,229**
2009	168	40	665	8	61	304	–	123	31	1,400
2008	173	43	538	9	66	277	–	128	29	1,263
Natural gas[c]										million cubic feet per day
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
2008	759	23	2,157	245	2,532	484	–	696	381	7,277
Equity-accounted entities (BP share)										
Crude oil[b]										thousand barrels per day
2010	**–**	**–**	**–**	**–**	**98**	**–**	**856**	**191**	**–**	**1,145**
2009	–	–	–	–	101	–	840	194	–	1,135
2008	–	–	–	–	92	–	826	220	–	1,138
Natural gas[c]										million cubic feet per day
2010	**–**	**–**	**–**	**–**	**399**	**–**	**640**	**30**	**–**	**1,069**
2009	–	–	–	–	392	–	601	42	–	1,035
2008	–	–	–	–	454	–	564	39	–	1,057

[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 2010. 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 2010										
Oil wells[a] – gross	**251**	**84**	**2,709**	**7**	**3,705**	**596**	**20,235**	**1,889**	**13**	**29,489**
– net	**130**	**32**	**1,121**	**3**	**2,063**	**454**	**9,081**	**424**	**2**	**13,310**
Gas wells[b] – gross	**281**	**–**	**23,041**	**366**	**498**	**106**	**63**	**639**	**68**	**25,062**
– net	**138**	**–**	**12,581**	**285**	**167**	**42**	**31**	**284**	**13**	**13,541**

[a] Includes approximately 3,989 gross (1,730 net) multiple completion wells (more than one formation producing into the same well bore).
[b] Includes approximately 2,623 gross (1,673 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.

Supplementary information on oil and natural gas (unaudited) continued

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Oil and natural gas acreage at 31 December 2010										Thousands of acres
Developed – gross	**346**	**65**	**6,920**	**198**	**1,738**	**497**	**2,282**	**2,434**	**162**	**14,642**
– net	**189**	**21**	**4,184**	**157**	**471**	**195**	**885**	**935**	**35**	**7,072**
Undeveloped[a] – gross	**1,311**	**186**	**6,970**	**7,185**	**12,434**	**21,373**	**32,137**	**18,366**	**7,330**	**107,292**
– net	**775**	**79**	**4,663**	**4,380**	**6,398**	**16,072**	**15,475**	**8,955**	**2,796**	**59,593**

[a] Undeveloped acreage includes leases and concessions.

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		
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
2008										
Exploratory										
Productive	0.8	–	2.4	–	4.4	4.3	12.5	0.5	0.6	25.5
Dry	–	0.5	0.9	0.1	0.4	2.6	23.0	0.5	0.4	28.4
Development										
Productive	6.6	0.5	379.8	28.3	112.5	18.6	10.0	45.4	4.5	606.2
Dry	0.2	–	1.1	0.9	2.9	1.5	19.5	2.1	–	28.2

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 2010. 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 2010										
Exploratory										
Gross	**1.0**	**–**	**211.0**	**3.0**	**1.0**	**3.0**	**11.0**	**3.0**	**–**	**233.0**
Net	**0.2**	**–**	**45.2**	**1.5**	**–**	**1.6**	**5.5**	**1.2**	**–**	**55.2**
Development										
Gross	**11.0**	**–**	**375.0**	**–**	**23.0**	**34.0**	**88.0**	**20.0**	**–**	**551.0**
Net	**5.5**	**–**	**140.6**	**–**	**9.5**	**10.8**	**39.7**	**6.6**	**–**	**212.7**

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 2 March 2011