ScottishPower

The power to deliver.

ScottishPower annual report & accounts 2002/03

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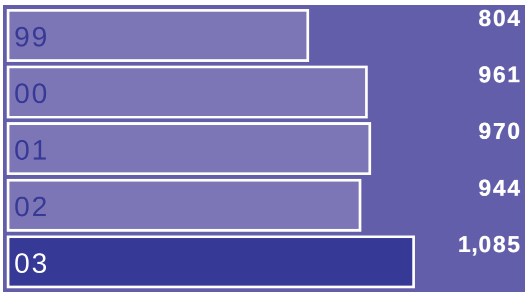
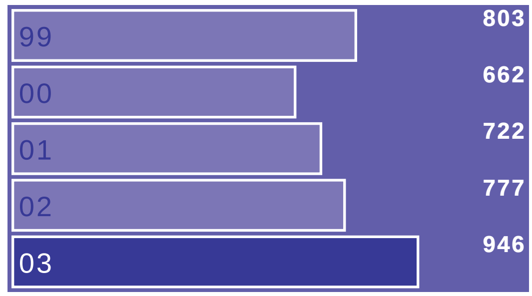
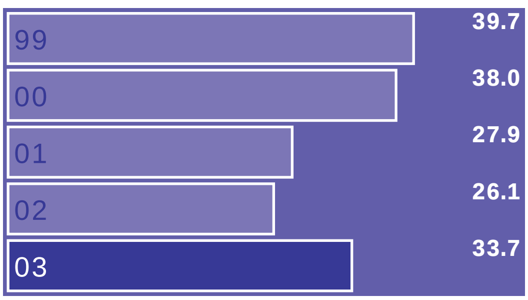
Financial Highlights



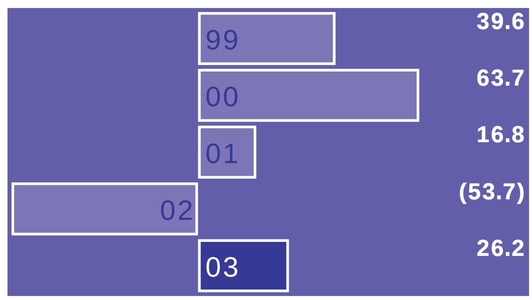
Operating profit £m
Excluding goodwill amortisation and exceptional items



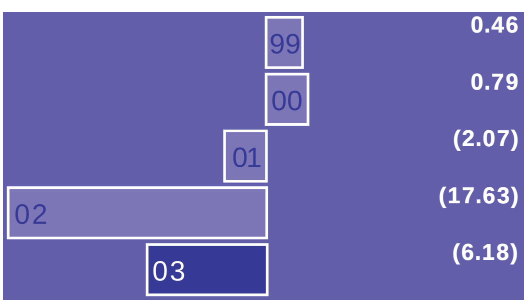
Operating profit £m



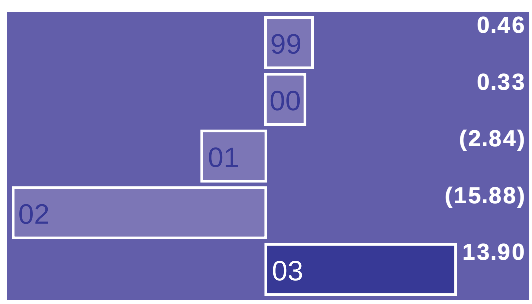
Earnings per share pence
Excluding goodwill amortisation and exceptional items



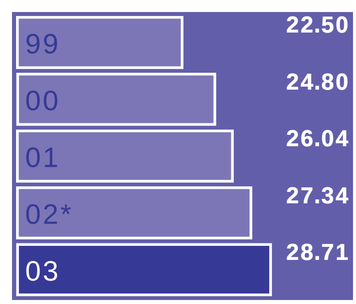
Earnings/(loss) per share pence



Total shareholder return pence
Capital appreciation plus dividend reinvestment for £1 invested on 1 April 1998
Source: Datastream



% Change in total shareholder return
Percentage change in total shareholder return index in each financial year
Source: Datastream



Dividends per share pence
*Cash dividends excluding 'dividend in specie' on demerger of Thus

	2003	2002
Turnover	**£5,274m**	£6,314m
Operating profit	**£946m**	£777m
Operating profit excluding goodwill and exceptionals	**£1,085m**	£944m
Profit/(loss) before tax	**£697m**	£(939)m
Profit before tax excluding goodwill and exceptionals	**£836m**	£567m
Earnings/(loss) per share	**26.17p**	(53.71)p
Earnings per share excluding goodwill and exceptionals	**33.71p**	26.12p
Dividends per share*	**28.71p**	27.34p

*Cash dividends excluding 'dividend in specie' on demerger of Thus

Chairman's Statement

"Today ScottishPower has an international leadership team of growing stature."

All four ScottishPower businesses produced good results during 2002/03, sustaining the recovery that began in the latter months of last year. This financial and commercial progress is especially pleasing after the challenges the energy markets have presented in both the US and the UK. Earnings per share* rose by 29% to 33.71 pence.

Our regulated businesses in the US and UK both performed well. PacifiCorp's drive to increase operational efficiency and improve customer service resulted in a substantial boost to profitability and remains on track to achieve its targeted return on equity. Our UK Infrastructure business delivered another strong performance, increasing sales and meeting demanding cost savings objectives.

In the competitive sectors, the UK Division has continued to face tough conditions but succeeded in increasing sales, maintaining profits and growing customer numbers. Our newest business, PPM, reported an operating profit of £28 million and has good opportunities to grow its successful gas storage and renewables ventures.

With profits and earnings up, debt and interest charges down, and satisfactory cash flow, ScottishPower ended the year in a sound financial position. We have announced our intention to declare three quarterly dividend payments of 4.75 pence from April 2003 and will set the fourth quarter payment to represent the balance of the dividend for the year to 31 March 2004. After March 2004, we shall aim to grow dividends in line with earnings.

The last weeks of 2001/02 saw ScottishPower refocused on energy, and these results prove clearly that this was the correct strategy. The testing period we have endured has had a positive effect on the group's culture. Today ScottishPower has an international leadership team of growing stature and a programme of development initiatives designed to raise our skills and competencies further.

We have had to sharpen existing skills and develop others that will be of lasting value. The California energy crisis that followed so soon after our merger with PacifiCorp has given us a heightened awareness of risk and better techniques for managing it. We are now applying this experience in the UK wholesale market with success. Our grasp and handling of detailed regulatory issues has improved, boding well for the next UK price review in 2005. We are developing a growing portfolio of renewable energy assets and have successfully renegotiated the Nuclear Energy Agreement with British Energy.

Against our peer groups, ScottishPower remains at or near the top of the environmental and social impact rankings, and PacifiCorp is gaining ground in the equivalent US benchmarks. Surveys among our employees, who have borne the brunt of all the change and upheaval within the businesses, show morale improving.

Pensions have been much in the news during the year and neither our US nor UK pension funds have escaped the downturn in equity markets. We have resumed contributions to our UK pension funds and will make the recovery of increased pension costs through regulatory processes one of our priorities in both the US and the UK.

Now turning to the Board, there are a number of changes to report. Nick Rose, Finance Director of Diageo, joined the Board as a non-executive director in February 2003. Ewen Macpherson will retire as a non-executive director after the AGM. We thank him for his advice and wish him well. I am grateful that Sir Peter Gregson, who had planned to retire this year, has agreed to extend his term of office for another year.

This has been an eventful but ultimately successful year during which all our employees in both the US and the UK have given strong support on a daily basis. On behalf of the Board, I want to thank them for their efforts and goodwill.

The outlook for ScottishPower remains positive, with additional improvements in performance expected from our business and good opportunities for further growth.

Charles Miller Smith

Charles Miller Smith Chairman
7 May 2003

Charles Miller Smith, Chairman

** excluding goodwill amortisation and exceptional items*

Chief Executive's Review

"This has been a year of delivery based on our consistent focus on performance."

I am pleased to report that in the past year we delivered a good set of results, with profits up substantially and earnings per share* for the year up 29%. The recovery at PacifiCorp was particularly pleasing, with operating profit** up by some 60% in the year. Our dividend for the year was 28.71 pence per share, an increase of 5%. We also delivered a total return of 13.9% for shareholders during the year. The sale of Southern Water at the beginning of the year enabled us to reduce our net debt by £2 billion, thus strengthening our balance sheet and financial ratios.

We manage regulated and competitive businesses in the UK and US to serve gas and electricity customers. We invested over £800 million in our businesses during the year, of which some £345 million (42%) was in areas of growth, such as additions to our electricity networks, new generation especially renewables, and gas storage. Investment of this sort is at the heart of our strategy to become a leading international energy company. We invest only in businesses where we can deploy proven skills and strong market knowledge.

The safety and well-being of our workforce and the public is our number one priority. Sadly the year saw two of our colleagues killed at work; one fatal accident in the UK and one in the US. Tragedies such as these reinforce my conviction that we should put nothing ahead of safety and that we all have a role and responsibility to ensure that the highest standards are maintained at all times.

During the past year we have made good progress in further enhancing the underlying quality of our business. As Business in the Community's Company of the Year 2002 we have continued to contribute significantly to the Corporate Social Responsibility agenda in both the UK and the US and are publishing our first combined Environmental and Social Impact Report in July 2003. Our robust risk management policies and procedures were recognised by the international finance magazine, Risk, with the prestigious award of Corporate Risk Manager of the Year. We have also placed great emphasis on the talent and performance management of our people: our top international cadre of 250 managers now has clear incentive based performance agreements linked directly to our strategic objectives.

Ian Russell, Chief Executive

PacifiCorp

PacifiCorp is our regulated US business, with a portfolio of over 8,000 MW of power from coal, gas, renewable and hydro resources, 15,000 miles of transmission lines and a distribution system serving 1.5 million customers in six states. PacifiCorp is a leading regional integrated utility and is a key player in western energy markets. The strategic priorities of PacifiCorp set at the beginning of 2002/03 were:

- Achieve ROE target/$1 billion EBIT by 2004/05 through:
  - General rate cases
  - Transition Plan
- Manage risk and reward balance
- Deliver excellent customer service

Operating profit for PacifiCorp increased by £233 million to £463 million for the year to 31 March 2003. Operating profit excluding goodwill amortisation for PacifiCorp for the year grew by £225 million to £597 million, as a result of regulatory rate increases and recoveries of excess power costs of £80 million, significantly lower net power costs of £257 million and continued progress in the delivery of Transition Plan benefits of £64 million in the year. These improvements were partly offset by lower transmission revenues of £19 million from reduced use of the transmission system by third parties, higher depreciation charges of £25 million, risk mitigation and project costs of £41 million, insurance, pensions, and healthcare costs of £46 million and one-off gains in the previous year and foreign exchange of £45 million.

** excluding goodwill amortisation and exceptional items*

*** excluding goodwill amortisation*

Chief Executive's Review
continued

Net capital expenditure for the year decreased by £1 million to £368 million, with £111 million invested in network growth and new generation assets, £211 million on network and generation refurbishment, and £46 million on other capital projects including information technology.

Net capital expenditure is expected to increase in 2003/04 as a result of higher generation and mining overhauls and refurbishment spend, environmental initiatives and continued investment in expanding the network. All expenditure prudently incurred is expected to earn its regulatory rate of return, and contribute to an increased rate base for PacifiCorp.

- **Achieve ROE target/$1 billion EBIT by 2004/05 through:**
  - General rate cases
  - Transition Plan

PacifiCorp remains on track towards its target of $1 billion EBIT by 2004/05 through a combination of general rate cases and benefits derived from the Transition Plan.

General rate increases of approximately $160 million per year have been awarded to PacifiCorp from 1 April 2001 to 31 March 2003, with $31 million awarded during the year ended 31 March 2003. PacifiCorp's regulatory strategy includes filing regular rate cases to increase revenues to recover increasing operational costs and capital expenditure, while realising our full allowed return on investment. In line with this plan, PacifiCorp filed a general rate case in Oregon in March 2003, for $58 million, representing a 7% rate increase, primarily as a result of increased costs related to insurance premiums, healthcare, pensions and other costs that are similarly affecting many other US companies. In California, testimony and hearings in PacifiCorp's $16 million general rate case request have been scheduled to take place through May and June of 2003. PacifiCorp also plans to file in the next few weeks for general rate cases in Wyoming and Utah.

During March 2003, PacifiCorp was denied recovery of $91 million in net excess power costs in Wyoming and is currently seeking a re-hearing of this decision. Additionally, PacifiCorp continues seeking to defer and recover approximately $16 million in net excess power costs in Washington state. An order on this case is expected by early summer 2003.

Among the legislative measures approved in PacifiCorp's service territory, Senate Bill 61 in Utah will go into effect in early summer 2003. This legislation provides an option for the Utah Public Service Commission to use a future test-year period in utility rate cases that more appropriately reflects the cost of providing service, which is necessary to reduce the period between capital investment and recovery in rates – referred to as "regulatory lag". Reducing regulatory lag should encourage needed, cost-effective investments in utility infrastructure by companies such as PacifiCorp.

The PacifiCorp Transition Plan continues to progress on track as a key driver towards increasing profitability and supporting PacifiCorp's regulatory objectives. Cumulative Transition Plan benefits total approximately $217 million, slightly ahead of this year's target of $204 million and we are now two-thirds of the way towards our goal of $300 million by 2004/05. These included new call centre technology and other process changes that helped increase employee productivity and improve customer service. In distribution, operational efficiency improvements were delivered such as Home Start, which allows overhead line crews to respond more effectively to faults. Additionally, continuing procurement cost savings and royalties from the sale of a synthetic fuel operation last year contributed to PacifiCorp's continued delivery of the Transition Plan in 2002/03.

- **Manage risk and reward balance**

PacifiCorp successfully managed power demand during the challenging summer of 2002 and winter of 2002/03 through a robust combination of existing physical resources, a weather-related hedge and peaking generation facilities. During the winter, PacifiCorp's base of coal-fired generating resources and forward gas purchase strategy minimised the risks of natural gas price volatility. PacifiCorp remains well-positioned and is fundamentally balanced for the summer of 2003.

Our long-term Integrated Resource Plan (IRP), which seeks to identify new resource requirements to implement plans to deliver safe, reliable low-cost power to customers over the next 20 years, was filed with state regulatory commissions in January 2003. The IRP is progressing with the development of the Request for Proposals (RFP) process, under which PacifiCorp will seek bids for future generation needs. RFPs will be issued for both short- and long-term electricity requirements, including renewable energy needs. The RFP process is expected to extend until spring 2004.

The IRP and the resulting RFP process have been created to identify PacifiCorp's future resource mix in a coordinated process with the six states in which PacifiCorp operates. As part of these processes, PacifiCorp is expecting to add the equivalent of approximately 4,000 MW of capacity through a combination of sources over the next decade. These include the addition of base load construction capacity or purchases (approximately 2,100 MW), peaking resources (approximately 1,200 MW) and purchased "shaped" power (approximately 700 MW). In addition, PacifiCorp also plans to implement demand side management programmes (up to 450 MW on average) and acquire renewable energy (approximately 1,400 MW). Among the steps involved in the IRP process will be an evaluation of potential future generation sources such as an additional generating unit at the Hunter station in Utah. The air quality permitting process has begun to enable PacifiCorp to develop this option. Prudently incurred costs of such investments are expected to be included in PacifiCorp's future rate base.

- **Deliver excellent customer service**

During 2002/03, PacifiCorp continued to enhance its customer service commitments, while maintaining retail rates that are among the lowest in the western US. Improvements include enhancing PacifiCorp's outage communications technology to provide customers with the ability to report outages directly, thus helping to speed repairs or pinpoint potential problem areas. PacifiCorp was recognised by TQS Research of Atlanta, Georgia, for improvements with large commercial and industrial customers. Overall customer satisfaction metrics show positive results, including improved accuracy and timeliness of customer billing. In addition, PacifiCorp successfully tested a handheld meter reading system that will improve system functionality and accuracy. The new system is expected to be implemented by the summer of 2003, with further productivity improvements to follow over the next 12 months that will enhance PacifiCorp's scheduling technology.

Based on a recent report, PacifiCorp was rated third in the US by the Department of Energy as a marketer of green energy under PacifiCorp's Blue Sky programme. In excess of 21,000 customers have signed up for Blue Sky or other renewable products. PacifiCorp's green pricing programme is one of the most progressive and successful in the US.

To improve customer service and reliability, PacifiCorp continues its infrastructure improvement projects in targeted areas, particularly along Utah's Wasatch Front where there is rapidly growing demand for electricity. The scope of this $200 million investment through 2005 includes transmission line upgrades, new distribution substations, upgrades to existing distribution substations and other system enhancements. These projects will provide additional capacity to meet future load demands throughout PacifiCorp's network, especially in high-growth areas.

Infrastructure Division

Infrastructure Division, our regulated UK wires business, is the UK's third largest distribution company and comprises the distribution and transmission networks in our Scottish service area, and the distribution network in Manweb, over 110,000 circuit km in total. The strategic priorities of the Infrastructure Division set at the beginning of 2002/03 were:

- Be at or near the regulatory efficiency frontier
  - Outperform operating cost targets
  - Achieve better than planned output from capex
- Achieve high standards of customer service
- Invest consistently to add value

For the year to 31 March 2003, the Infrastructure Division reported operating profit of £368 million, an increase of £13 million on last year. Higher regulated income of £9 million and net cost reductions of £18 million were partly offset by higher depreciation, operational rates, insurance and pension costs of £14 million.

The Infrastructure Division invested net capital expenditure of £230 million during the year, an increase of £32 million compared to the year to 31 March 2002. Of this, £141 million was invested in network refurbishment, £68 million on network expansion and £21 million on other capital projects.

Net capital expenditure in 2003/04 is expected to increase modestly, with investment concentrated on the regulatory asset base,

Chief Executive's Review
continued

delivering the regulated rate of return. In particular, further investment will be undertaken in our overhead network modernisation programme.

- **Be at or near the regulatory efficiency frontier**
  – Outperform operating cost targets
  – Achieve better than planned output from capex

In line with our strategic priorities, we expect to be at or near the regulatory efficiency frontier for the next price review period beginning in April 2005. As previously stated, targeted cash cost savings of £75 million due by March 2003 were achieved ahead of schedule by September 2002, reflecting our increased commercial focus in the division. As a result, a further target of £33 million of net cost reductions was identified for completion by 2003/04, with net cost reductions of £18 million being achieved in 2002/03 through the initiatives set out below.

We are achieving better outputs from capital expenditure by ensuring that costs are appropriately allocated to capital projects through our asset manager/service provider model and have seen procurement savings of over 10% in a number of key purchase areas such as distribution transformers, overhead lines and cables. Additionally we have conducted a benchmark review of call centre services, are making more efficient use of contractors, achieving improved staff flexibility using site start arrangements and adopting a flexible day working system.

- **Achieve high standards of customer service**

We continue to focus on delivering high standards of customer service. Our network performance as measured by Customer Interruptions and Customer Minutes Lost indicates that we are on track to be able to participate in Ofgem's Information and Incentives Programme (IIP) when the reward mechanism for outperforming the regulatory targets is put in place by 2004/05.

Our performance against Ofgem's standard for responding to customers' written correspondence has improved significantly. In addition, our performance relative to the industry as measured by Ofgem's customer satisfaction survey has ensured we are placed in the incentive reward band under the terms of the IIP. Further, a recent Government report recognised our good performance during a gale-force storm in the Mersey and North Wales area on 27 October 2002. We received specific praise for our performance in emergency preparation, telephone response and regular and realistic feedback to customers on estimated times of reconnection.

- **Invest consistently to add value**

Capital expenditure to date contributes to maintaining the value of our asset base. Progress in the Berwick and Borders Investment Programme, which represents an investment of £11 million, continues to be made with 65% of the 33kV circuits included in the programme being completed. Additionally 63% of the 11kV circuits included in the programme have been completed or are under construction. This part of the overhead line build programme has been accelerated and is on target for completion by March 2004.

Reinforcement of the transmission network will improve both the performance and resilience of our network, with high profile projects at Gretna and Chapelcross representing a £13 million investment. Benefits of these projects include the strengthening of the network to deal with the Chapelcross power station closure. These projects are being delivered on time and to budget.

The Government target of 10% of supply from renewable sources by 2010 is an opportunity for Infrastructure Division to invest in network capacity. Our transmission business has participated in a recent network study that explored the existing Scottish and Northern England networks' potential to support increased volumes of new renewable generation. The study identified three progressive steps required to upgrade our transmission network and we believe the associated investment to be valued at roughly £300 million – £400 million over 10 years dependent on renewable progress. We are currently working to develop detailed plans in relation to this opportunity. In addition, we believe our distribution networks in Scotland and Manweb are well positioned to develop network investment opportunities in support of renewable generation, should Government targets be met.

The formal price control reviews of SP Transmission, SP Distribution and SP Manweb will continue during the forthcoming year. We have been working with Ofgem and the rest of the industry to develop the framework of price controls applying to all network monopoly companies and lay the foundations for the formal distribution Price Control Reviews.

We believe a key issue for the reviews is the provision of a sufficient and stable return to allow companies to attract and retain funding from capital markets. A further issue relates to finding ways to facilitate renewable energy in line with Government targets. Both have implications for the working of the regulatory regime and for the long-term safety and integrity of the UK electricity infrastructure.

The outcome from the Price Control Review should take account of guidance from the Government on social and environmental objectives, and recognise any additional expenditure arising from such objectives. Our performance in the recent asset risk management survey demonstrated our ability to invest efficiently and effectively, and our cost and storm response performances provide us with the credibility to influence this important debate.

We should not lose sight of the fact that the industry is entering a new phase where simple cost-cutting and moderate investment leading to price cuts for customers will no longer sustain future performance, and price increases will be required. We are committed to working with Ofgem and the rest of the industry throughout the Price Control Review process to deliver a successful outcome that balances the interests of shareholders, customers and all other stakeholders.

UK Division

The UK Division is our competitive, integrated generation and supply business. The Division manages activities across the energy value chain, maximising value from a diverse energy portfolio of some 5,000 MW of coal, gas, hydro and wind powered plants through to our national customer base of over 3.6 million customers, via an energy management function that acts to balance and hedge energy needs. The strategic priorities of the UK Division set at the beginning of 2002/03 were:

- Enhance margins through our integrated operations
- Grow customer numbers and improve customer service
- Make selective investments using proven knowledge and skills

Operating profit for the UK Division increased by £18 million to £73 million for the year to 31 March 2003, mainly due to last year's results including a £19 million exceptional reorganisation charge. Operating profit, excluding goodwill amortisation and exceptional items, was £78 million for the year, £1 million lower compared to the previous year. Net energy margins have performed strongly, increasing by £15 million before higher depreciation, costs to capture and investment in energy efficiency schemes of £12 million and increased pension costs of £4 million. The impact of lower wholesale electricity prices has been mitigated by our integrated approach to managing the energy value chain whereby our own electricity production is extensively matched to our customer demand across Great Britain. The renegotiation of the Nuclear Energy Agreement (NEA) with British Energy (BE) at a market related price has delivered a benefit of approximately £25 million in the current year and provides a hedge against revenues which have been impacted by lower wholesale prices.

During the year the UK Division invested £68 million in capital projects, a £41 million reduction on the previous year. £29 million was invested in new generation and gas storage assets, £19 million in generation plant overhaul and refurbishment and £20 million on other projects including business transformation and information technology.

In 2003/04, subject to obtaining planning permission, net capital expenditure for the UK Division could increase substantially as a result of our commitment to increase our windfarm capacity. In addition, we plan to invest in gas storage development and upgrades to generation assets required to maintain our generating capacity. All investments are projected to have returns significantly in excess of the cost of capital and enhance earnings.

• Enhance margins through our integrated operations

During the year we continued to benefit from the flexibility of our plant portfolio. We have maintained what we believe is a best in class performance in the Balancing Mechanism, in particular from our flexible CCGT plant at Rye House, and our pumped storage facility at Cruachan which is being upgraded in capacity by 10%. We continue to optimise the operating regime across our plant portfolio, aiming to deliver the lowest sustainable costs and to position it to take maximum advantage of commercial opportunities.

Chief Executive's Review
continued

The renegotiation of the NEA relieved the Division of a significant cost burden during the year, but the future of the remaining restructuring contracts is still unresolved. We continue to press the Government strongly on this issue. Whilst we expect wholesale electricity prices to remain depressed for the next two years, there could be upward price pressure emerging from tightening of the capacity margin throughout Great Britain, and as environmental measures such as carbon trading and the Large Combustion Plants Directive start to take effect. We may see some price volatility before a new equilibrium is reached.

Retail sales revenues increased during the year, in part following an increase in prices to customers outside our service territories in November 2002. Prices to the majority of electricity customers in our Scottish and Manweb territories were increased effective 1 April 2003, although in both instances we have preserved our competitive dual fuel prices and provided nearly all customers affected by the April 2003 price increase with the opportunity of mitigating the increase by changing to a more economical product package.

Our business transformation programme, which is underpinned by 6 Sigma methodology, continues to deliver significant savings to the business. In the year to 31 March 2003, we have delivered revenue and cost benefits of £14 million across our business processes including sales and marketing, billing and debt. The utilisation of 6 Sigma methodology is now being extended throughout the UK Division.

- **Grow customer numbers and improve customer service**

We continue to be successful in growing our customer base. Customer numbers now stand at 3.65 million, up by approximately 150,000 in the year to 31 March 2003. As well as gaining new customers, we have successfully reduced overall churn by 4 percentage points compared with the prior year.

Customer retention and win-back continues to be an important part of our marketing activities and we have deployed TV advertising to good effect, emphasising that our dual fuel customers can benefit from a competitive price by joining ScottishPower.

In response to customer research we introduced a new bill design, to provide clearer and more concise communication of charges and have improved the level of service provided by our call centres during the year.

ScottishPower was amongst the pioneers of the industry's EnergySure accreditation scheme for sales staff, which will be governed by an external code administrator. All ScottishPower's domestic sales teams have now been accredited to this customer service and quality standard and we are now rolling out the scheme to cover all the relevant sales and marketing channels.

In addition we have introduced three new energy products during the year, including Capped Price and No Standing Charge offers, which have further enhanced the range available to customers.

- **Make selective investments using proven knowledge and skills**

The Renewables Obligation has created a market framework that allows developers to capitalise on the UK's rich resource of wind energy with eligible developments attracting Renewables Obligation Certificates (ROCs) currently worth approximately £45 for every MWh produced. With our strong track record in site identification and development, we are well placed to deliver investments with an attractive return and enhanced earnings, and to market effectively the energy produced from renewable sources.

In the year ended 31 March 2003, we have made planning applications for 279 MW of windfarm capacity and we now have in excess of 546 MW awaiting planning consent. We have also begun environmental assessments on around 300 MW of capacity at additional potential sites. Progress towards planning consent for our Whitelee 240 MW and Black Law 134 MW developments has been slowed by issues related to radar at Glasgow and Edinburgh airports respectively. A technical solution to this problem is being progressed and we are confident that the issue will be resolved. With 546 MW of windfarm capacity awaiting planning consent and the 300 MW pipeline of projects under assessment, we are making excellent progress towards alignment with the Government target of 10% of supply from renewable sources by 2010.

We are upgrading five of our smaller hydro generating stations, totalling 45 MW, to qualify for ROCs. As part of this, the upgrade to the 11 MW station at Bonnington was completed in 2002/03 with the other four stations to be upgraded over the next 15 months.

Our 60 million therm gas storage planning application at Byley in Cheshire is presently awaiting the result of a public inquiry, expected to be determined in 2003/04.

PPM

PPM is our competitive US energy company, focused on providing environmentally responsible energy products to wholesale customers. Its principal assets are thermal and renewable generation resources and gas storage assets primarily serving western US and Canadian markets. The strategic priorities of PPM set at the beginning of 2002/03 were:

- Grow its renewable/thermal energy portfolio and gas storage/hub services
- Optimise returns through the integration of assets and commercial activities

PPM reported an operating profit of £28 million for the year, compared to a loss of £5 million last year. The growth in operating profit for the year was due to the increased contribution from long-term sales contracts and gas storage activities and optimisation benefits of £53 million, partly offset by higher depreciation charges and other operating costs of £17 million to support business growth and the benefit from settlement of a £3 million contract in the prior year.

PPM's net capital expenditure for the year was £36 million, a decrease of £170 million on last year, which included investment to complete the Klamath Falls and West Valley generation projects. In the current year, the business invested £30 million in new generation and £6 million in other projects. In addition, we acquired the Katy gas storage facility for £101 million.

In 2003/04, PPM's net capital spend is expected to increase, primarily as a result of the construction of new windfarms and development opportunities including Moraine and Flying Cloud, which are expected to deliver favourable rates of return and enhance earnings.

• Grow its renewable/thermal energy portfolio and gas storage/hub services

PPM continues to grow its renewable energy business and has recently announced the development of the 44 MW Flying Cloud Wind Project in Iowa, which includes a 15 year agreement to sell power to Interstate Power & Light, a subsidiary of Alliant Energy. In addition, construction of the 51 MW Moraine Wind Project in Minnesota has commenced. The Moraine project is fully contracted with a 15 year agreement to sell power to the Northern States Power Company. This will bring PPM's total wind power under contract to more than 560 MW, and total thermal/renewable resource under PPM's ownership or control to approximately 1,350 MW.

In addition to its renewable generation portfolio, PPM has a total of 37 billion cubic feet (BCF) of gas storage capacity under ownership, up from 14 BCF the prior year. This includes the 21 BCF acquired at the Katy gas storage facility in December 2002 and a 2 BCF expansion of the Alberta Hub gas storage facility during the year. PPM has successfully integrated the Katy assets and is on target to deliver expected results. PPM intends to add to its 40% ownership in the Alberta Hub gas storage facility with the purchase of an additional ownership interest this spring.

• Optimise returns through integration of assets and commercial activities

Integration of plant operations, contract dispatch and energy management added $7 million in the year. The optimisation benefits come from displacing plant operations with low-priced power purchases, selling the displaced gas or placing it in storage, as well as using transmission and contract delivery flexibility to manage locational price differences in both gas and power.

PPM has new and expanded terms for energy supply to the Sacramento Municipal Utility District, one of PPM's largest customers. Arrangements include revisions to original long-term contracts executed in 2002/03, as well as sales of up to half the output of the 150 MW High Winds Energy Center in northern California and 100 MW of summer peaking power supply from PPM's portfolio.

In 2002/03, PPM placed 319 MW under long-term contract. In addition, PPM has effectively managed its commodity exposure, having sold its positions forward for 5-25 years. Fluctuating commodity prices have little impact on PPM's portfolio value, except where increased volatility gives PPM an opportunity to take advantage of plant options, delivery flexibility, gas storage and other tactics to maximise value.

Chief Executive's Review
continued

Regulatory and Government Policy Issues

Multi-State Process (MSP)
PacifiCorp continues work on the MSP, which is designed to resolve how prudently incurred costs are allocated among the six states in which PacifiCorp operates. A collaborative process is underway to identify possible solutions, conduct technical conferences with participants and meet with key parties to examine specific issues. PacifiCorp intends to file a final, detailed regulatory proposal with each state utility commission this summer.

RTO West
PacifiCorp and nine other utilities received initial approval of their RTO West proposal in September 2002 from the Federal Energy Regulatory Commission (FERC). Under the proposal, which the FERC called "Best in Class" among all the RTO filings in terms of the proposed design, structure and thoroughness of approach, the filing utilities will retain ownership of their transmission assets, but transfer operational control of their system to RTO West. As proposed, RTO West will help stabilise electricity transmission and guard against market manipulation in the western part of the United States and Canada, while providing a reasonable level of return for future transmission investments. The RTO West members are currently planning to file with the FERC this summer and expect a response from the FERC by the end of 2003.

Federal Energy Regulatory Commission (FERC)
The FERC continues its various investigations into western US market manipulation related to the 2000/01 energy crisis. As a regulated utility that participated in these markets primarily to meet the company's own power requirements, PacifiCorp has responded to various data requests from the FERC and other market participants. These cases involve trading practices connected with the California power crisis, as well as spot market refund cases, and complaints brought by PacifiCorp against wholesale power marketers to seek refunds for high-priced power purchased in 2001. PacifiCorp continues to press for economic recovery, while fully responding to requests for information.

British Electricity Trading and Transmission Arrangements (BETTA)
The recently announced delay by the Department of Trade and Industry to the introduction of BETTA will not have a material effect on ScottishPower in 2003/04. The financial impact of the BETTA Bill is broadly neutral for ScottishPower, but zonal charges for transmission access and losses would have a negative impact on the generation business in the UK Division. We were pleased to see that the Trade and Industry Select Committee, in its Fifth Report, recommended delay in the implementation of transmission access reform until the costs and benefits are able to be assessed on a Great Britain-wide basis. ScottishPower, together with a number of other companies, has filed for a judicial review of Ofgem's decision to implement zonal transmission losses in England and Wales.

Energy White Paper
The recently published White Paper on energy sets out to achieve a lower carbon energy system, proposing significant investment in renewable energy, energy efficiency and in networks. The UK Division is well placed to take early mover advantage on renewable generation and the Infrastructure Division should benefit from the Government's commitment to investing in networks. We are pleased that Ofgem recognises the need to plan and develop networks to facilitate the transmission of renewable energy from Scotland to centres of demand in the rest of Great Britain.

Looking ahead

During 2002/03, we reported each quarter our progress in delivering the key strategic priorities for each of our four businesses. Some of those priorities have now been achieved and further new priorities have been identified. Accordingly, looking ahead our strategic priorities are as follows:

PacifiCorp

- Achieve ROE target/$1 billion EBIT by 2004/05
- Manage energy risk and supply/demand balance
- Deliver excellent customer service
- Invest to grow the regulatory asset base, including delivery of the integrated resource plan

Infrastructure Division

- Invest consistently to add future value, including supporting renewables
- Optimise our position through the 2005 price control reviews and the introduction of BETTA
- Deliver cost-effective, high quality customer service

UK Division

- Enhance margins through our integrated operations
- Increase the value of our customer base through targeted sales growth and improved customer service
- Progress towards achieving 10% of electricity supply from renewable sources by 2010

PPM

- Continue to be a leading provider of renewable energy products
- Grow natural gas storage and hub services business
- Create additional value by optimising the returns from our capability across gas and power

Conclusion

Our consistent focus on performance last year enabled us to deliver a good set of results. We will continue to place a premium on leading operational performance, to secure further improvements in the results of our businesses. There are substantial opportunities to expand ScottishPower through incremental investments in each of our businesses, particularly in networks, generation including renewables and gas storage. With as much as 40% of our capital investment in new assets in these areas, we believe we are well positioned to continue to grow. The outlook for ScottishPower remains positive, with further improvements expected from our businesses. We also believe that our continued focus will enable us to take advantage of the opportunities to create shareholder value that will, over time, arise from the changing structure of our industry in the UK, the rest of Europe and the US.

Ian Russell Chief Executive

7 May 2003

Business Review – Description of Business

Description of business

Scottish Power plc ("ScottishPower") is an international energy business listed on both the New York and London Stock Exchanges. Through its operating subsidiaries, the company serves in excess of 5 million homes and businesses in the western US and across the UK. It provides electricity generation, transmission, distribution and supply services in both countries. The company's US activities extend to coal mining and gas storage, including a gas facility in western Canada. In Great Britain, ScottishPower also stores and supplies gas. In the year to 31 March 2003, the sales revenues of the continuing business of the group were £5.2 ($8.3) billion.

Following its creation upon privatisation in 1991, ScottishPower developed by organic growth in the British electricity, gas and telephony markets, through strategic acquisitions in the UK and by the merger with PacifiCorp in the US. During 2001/02, the group exited non-strategic businesses in the US and UK, demerged the UK telecommunications and internet business, Thus, to the company's shareholders and, in April 2002, sold the UK water and wastewater company, Southern Water, thereby concluding the process of redefining ScottishPower as an international energy business. In 2002/03, ScottishPower has focused on its strategic aim of becoming a leading international energy company.

Strategic context

ScottishPower's strategy is to become a leading international energy company, managing both regulated and competitive businesses in the US and the UK to serve electricity and gas customers. The regulated businesses provide a base for steady growth through consistent investment and proven skills in operational and regulatory management. In competitive activities in which the group has local market knowledge and skill advantages, it seeks to enhance margins through the integration of generation, energy management and customer services, again underpinned by best-in-class operational performance. The aim is to deliver steady growth in earnings per share by capitalising on the opportunities afforded by strong positions in both the US and UK markets, organising the skills and resources deployed in these different marketplaces to achieve (or, where the regulatory process permits, to better) allowed returns from regulated businesses, build sustainable value in competitive energy markets and actively manage risk, both operational and financial.

The strategy is delivered through four businesses, each clearly focused on its strategic priorities:

- PacifiCorp
- Infrastructure Division
- UK Division
- PPM Energy, Inc.

In each of the US and the UK, there is one business operating under regulation and one in competitive market conditions.

In the US, PacifiCorp operates as a regulated electricity business with significant mining subsidiaries – and the competitive energy business is PPM Energy, Inc. ("PPM"). Both are subsidiaries of PacifiCorp Holdings, Inc. ("PHI") a non-operating, US holding company, itself an indirect wholly-owned subsidiary of ScottishPower. PHI is also the parent company of PacifiCorp Group Holdings which owns the shares of subsidiaries not regulated as domestic electricity providers, including PacifiCorp Financial Services, Inc. ("PFS"), in order to facilitate the further separation of the company's non-utility operations in the US from the regulated US business, PacifiCorp.

In the UK, the regulated Infrastructure Division operates electricity transmission and distribution subsidiaries of the wholly-owned UK holding company Scottish Power UK plc ("SPUK"). Other subsidiaries operating in the now competitive UK energy markets comprise the group's competitive energy business, the UK Division, covering its British Isles generation assets, commercial and energy management activities and energy supply business units.

PacifiCorp

In November 1999, PacifiCorp and ScottishPower completed a merger under which PacifiCorp became an indirect subsidiary of ScottishPower. As a result of the merger, PacifiCorp developed and commenced its Transition Plan to implement significant organisational and operational changes arising from the strategic decision to focus on its electricity businesses in the western US.

Principal business activities

PacifiCorp is a regulated electricity company operating in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp conducts its retail electricity utility business as Pacific Power and Utah Power, and engages in electricity production and sales on a wholesale basis under the name PacifiCorp. The subsidiaries of PacifiCorp support its electricity utility operations by providing coal mining facilities and services, environmental remediation and financing.

The western US wholesale energy market had substantially lower prices and was relatively stable during 2002/03 compared with the previous year. PacifiCorp took a number of actions to maintain a balanced net energy position through the summer peak period and for the remainder of the financial year. A 120 megawatt ("MW") gas-fired peaking plant in Utah came on-line in August 2002 and, in May 2002, PacifiCorp also entered into an operating lease arrangement with PPM for the 200 MW West Valley peaking plant, also in Utah. These actions, as well as the use of other flexible physical and financial hedging instruments, assisted PacifiCorp in maintaining a balanced energy position over the financial year.

Retail electricity sales

PacifiCorp serves approximately 1.5 million retail customers in service territories aggregating about 136,000 square miles in portions of six western states. The geographical distribution of PacifiCorp's retail electricity operating revenues for the year ended 31 March 2003 was Utah, 39%; Oregon, 32%; Wyoming, 13%; Washington, 8%; Idaho, 6%; and California, 2%. The PacifiCorp service area's diverse regional economy mitigates exposure to economic swings. In the eastern portion of the service area, customer demand peaks in the summer when irrigation and cooling systems are heavily used mainly in Utah and eastern Idaho. The principal industries are mining and extracting coal, oil, natural gas, uranium and oil shale. In the western part of the service territory, mainly consisting of Oregon and southeastern Washington, customer demand peaks in the winter months due to space heating requirements and the economy generally revolves around agriculture and manufacturing, with pulp and paper, lumber and wood products, food processing and high technology being the principal industries. During 2002/03, no single retail customer accounted for more than 2% of PacifiCorp's retail electricity revenues and the 20 largest retail customers accounted for 13% of total retail electricity revenues. Trends in energy sales by class of customer are set out in Tables 3, 5 and 6 (page 31).

Retail energy sales for PacifiCorp have grown at a compound annual rate of 0.9% since 1997; however, for 2002/03, megawatt hour ("MWh") sales decreased approximately 1.2%. Adjusting for the impact of weather, the loads for both 2002/03 and 2001/02 were relatively flat, although patterns within individual states and customer classes were different. While residential and commercial loads reflected an increase of 1.2% and 3.6% respectively, as a result of increased customer numbers, the industrial class showed a 3.2% decrease as a result of a decrease in industrial customers and the effects of the economic downturn. The majority of the growth in residential customers has been in the eastern portion of PacifiCorp's service territories, whereas the western portion has remained relatively flat in terms of its growth. For the period 2004 to 2008, the underlying annual growth in retail MWh sales in PacifiCorp's franchise service territories is estimated to be in the range of 1.8% to 3.6%, dependent upon factors such as economic recovery and growth, customer numbers, weather, the potential effects on demand resulting from conservation efforts and changes in price. If prices increase in the region, demand growth over the region may slow.

Power production and fuel supply

PacifiCorp owns or has interests in generating plants with an aggregate nameplate rating of 8,410 MW and plant net capability of 7,925 MW, see Table 1 (page 30). During 2002/03, approximately 4% and 58% of PacifiCorp's energy requirements were supplied by its hydro-electric and thermal generation plants respectively. The remaining 38% was supplied by purchased power. With its present generating facilities, under average water conditions, PacifiCorp would expect that approximately 60% and 5% of its energy requirements for 2003/04 would be supplied by its thermal and hydro-electric plants, respectively, the remaining 35% being obtained through purchase arrangements. PacifiCorp will make use of existing long-term purchase contracts, and will choose appropriate cost-effective resources to meet the balance of its customer demand through short-term purchase arrangements.

At 31 March 2003, PacifiCorp had 196 million tons of recoverable coal reserves that are mined by PacifiCorp or its mining affiliates and are dedicated to nearby PacifiCorp-operated generation plants. See Table 2 (page 30). During 2002/03, these mines supplied approximately one-third of PacifiCorp's total coal requirements. Coal is also acquired through long-term and short-term contracts. Thirteen long-term coal contracts accounted for 60% of the overall 2002/03 requirements. The contract terms range from one to 20 years. The remaining 7% of PacifiCorp's coal requirement was supplied through short-term purchases. PacifiCorp has also entered into long-term, fixed-price natural gas contracts to supply its owned and leased gas-fired generation facilities. These long-term contracts meet 100% of the expected needs for natural gas at these facilities until April 2005.

To manage future generation needs and meet environmental objectives, PacifiCorp has also completed an Integrated Resource Plan ("IRP") which was filed in January 2003. This provides a framework and plan for the prudent future actions required to ensure that PacifiCorp continues to provide reliable and cost-effective electricity service to its customers. Projected growth rates and the retirement of existing resources indicate a need, subject to ongoing review, for about 4,000 additional MW of capacity between 2004 and 2014. The IRP and the resulting Request for Proposals process have been created to identify PacifiCorp's future resource mix in a coordinated process with stakeholders in the six states it serves. As part of the IRP process, PacifiCorp expects to select the optimal solution from a mix of renewable, thermal, market purchase and demand side management choices and to guide specific "build or buy" decisions made dependent on permitting, siting, emissions, cost recovery and economic conditions. Costs incurred by PacifiCorp to provide a service to its customers are expected to be included as allowable costs for ratemaking purposes. However, there can be no assurance that these costs will be fully recovered through the regulatory process.

Wholesale sales and purchased electricity

In addition to its base of thermal, renewable and hydro-electric generation assets, PacifiCorp uses a mix of long-term and short-term firm purchases and non-firm purchases to meet its load obligations and to make sales to other energy providers. PacifiCorp enters into wholesale purchase and sale transactions to provide hedges against periods of variable generation or variable retail load. Generation varies with the level of outages or transmission constraints and retail load varies with the weather, distribution system outages and the level of economic activity. During the year ended 31 March 2003, retail loads were lower than in the previous year due to milder weather and a generally weak western US economy. PacifiCorp's wholesale transactions are integral to its retail business, providing for a balanced and economically hedged position and enhancing the efficient use of its generating capacity over the long term. PacifiCorp's transmission system is available for common use consistent with open access regulatory requirements and connects with market hubs in the Pacific Northwest to provide access to what is normally low-cost hydro-electric generation and also to the southwestern US, which provides access to normally higher-cost fossil-fuel generation.

Under the requirements of the Public Utility Regulatory Policies Act of 1978, PacifiCorp purchases the output of qualifying facilities constructed and operated by entities that are not public utilities. During 2002/03, PacifiCorp purchased an average of 95 MW from qualifying facilities, compared to an average of 104 MW in 2001/02.

Proposed asset sale

In 1998, PacifiCorp announced its intention to sell its California electricity service area, including its electricity distribution assets, and has since been working to complete the sale of these properties to Nor-Cal Electric Authority ("Nor-Cal"). Various factors have

Business Review – Description of Business
continued

impeded the proposed sale. In June 2002, a validation action in the California Superior Court challenged the authority of Nor-Cal to enter into such a transaction and alleged certain conflicts of interest among Nor-Cal and its advisors. This action is ongoing and the outcome for the proposed sale remains uncertain.

Infrastructure Division

Three wholly-owned subsidiaries of SPUK – SP Transmission Limited, SP Distribution Limited and SP Manweb plc – are the "owner companies" holding the regulated assets and transmission and distribution licences and acting as an integrated business unit to concentrate divisional expertise on regulatory issues and investment strategy. A further wholly-owned subsidiary of SPUK – SP Power Systems Limited ("PowerSystems") – provides asset management expertise and conducts the day-to-day operation of the networks, implementing work programmes commissioned by and agreed with the asset-owner business. Strict commercial disciplines are applied at the asset owner-service provider interface, with PowerSystems operating as a contractor to the transmission and distribution business unit.

An integrated senior management team within the Infrastructure Division applies the benefits of growing expertise in asset ownership, financing and operational service provision to the management of the group's regulated networks businesses in both the US and the UK.

Principal business activities – transmission and distribution

ScottishPower owns and manages a substantial UK electricity distribution and transmission network which extends to over 116,000 km, with 66,800 km of underground cables and 49,900 km of overhead lines network, comprising both the distribution system to customers in its two authorised areas and, in Scotland, its high voltage transmission system (132 kiloVolt ("kV") and above, including those parts of the England-Scotland interconnector which are in its Scottish authorised area). Table 9 (page 32) shows key information with respect to the division's transmission and distribution services in 2002/03. These networks are operated under licences issued by the Gas and Electricity Markets Authority ("the Authority") and held by the transmission and distribution businesses, which are entitled to charge for the use of the systems on terms approved by the Authority under various price control formulae. The management focus of the transmission and distribution business is to outperform allowed regulatory returns from the provision of efficient, coordinated and economical networks which are open to licensed users on a non-discriminatory basis (in order to facilitate competition in generation and supply) and operated to approved standards of safety and reliability.

The income derived from the distribution business is dependent on the demand for electricity by customers in the authorised areas. Demand for electricity is affected by such factors as growth and movements in population, social trends, economic and business growth or decline, changes in the mix of energy sources used by customers, weather conditions and energy efficiency measures. Tables 10 and 11 (page 32) set out the demand in gigawatthours ("GWh") by customer type within the broadly stable levels of electricity transported over the distribution systems in the ScottishPower and Manweb home areas during the five most recent financial years.

Principal business activities – asset management

Within the PowerSystems business unit, the focus continues to be on reducing costs and improving service. Its principal business activities involve the construction and refurbishment of the UK transmission and distribution systems, their maintenance and related fault repair. PowerSystems acts as the major service provider to the ScottishPower transmission and distribution business and as the primary customer contact agent for network-related matters. PowerSystems continues to focus strongly on the efficient delivery of these services under contract. Current performance, as measured by the Office of Gas and Electricity Markets ("Ofgem") Customer Satisfaction Survey, is above average, placing ScottishPower in the "incentive" band within the Ofgem Information and Incentives Programme. PowerSystems aims to maintain this position and to continue to deliver the associated financial benefit. PowerSystems has continued to maintain a joint venture with Alfred McAlpine Utility Services Limited, called Core Utility Solutions Limited, to take advantage of the opportunities presented by the requirement for competitive provision of connections to distribution networks.

UK Division

The UK Division operates in gas and electricity markets which became fully competitive with the ending of residual price controls on residential electricity on 31 March 2002, although Ofgem continue to enforce licence conditions and regulate quality of service. The division comprises five wholly-owned subsidiaries: ScottishPower Generation Limited owns and operates the power stations and other generation assets in the British Isles and holds the group's generation licence; ScottishPower Energy Trading Limited and ScottishPower Energy Trading (Agency) Limited deal in gas and electricity at the wholesale level and in the commercial instruments and agreements which constitute the market balancing mechanisms for the competitive energy market in the UK; ScottishPower Energy Retail Limited is the gas and electricity supply company and holder of the group's supply licences, managing pricing, selling, billing and receipting for gas and electricity supply to both business and domestic customers and dealing with enquiries arising in the course of this business; and, SP Dataserve Limited is the data management and metering company, managing the data processes which underpin customer registration through to billing and settlement in the competitive energy market.

The divisional management team oversees activities across the energy value chain, maximising value from a diverse generation portfolio through to a national customer base of over 3.6 million, via an integrated commercial and energy management activity that acts to balance and hedge energy needs. Throughout 2002/03, wholesale energy prices have been low by historic standards and, in light of the emphasis on a market-based framework for energy policy set out by the

UK Government in February 2003, wholesale energy markets face the prospect of continuing structural and contractual changes. As an active market participant, the division engages fully in regulatory and contractual debate and in the consultation processes surrounding the Government's review of energy policy. In the meantime, the division aims to leverage the benefits of its flexible generation asset base and commercial operations to deliver sustained earnings through improved business processes and customer service.

Principal business activities

The group's UK Division operates ScottishPower's generating stations in the British Isles, manages the company's exposure to the wholesale electricity and gas markets and is responsible for energy supply: the sales and marketing of electricity and gas to customers throughout Great Britain, together with the associated customer registration, billing and receipting processes and handling enquiries in respect of these services.

Power plant portfolio, fuel strategy and generation sales

ScottishPower has access to some 5,000 MW of capacity, see Table 8 (page 32) comprising coal, gas, hydro-electric and wind power generation assets, giving the division a particularly flexible portfolio. Acquisition of additional thermal generation capacity is kept under continuing review but purchases will only be made at value-enhancing prices and the current market is characterised by over-capacity. In 2002/03, the windfarm business continued to expand and now has operational windfarms totalling 128 MW, planning applications for a further 546 MW and environmental assessments begun on around 300 MW of further potential sites to ensure that the company target of 10% of supply from renewables by 2010 is met.

ScottishPower's fuel purchasing strategy is based upon the objective of achieving competitive fuel prices while balancing the need for security and flexibility of supply. The major components of the fuel portfolio are coal and gas, both fuels being sourced through a combination of long-term contracts and shorter-term trading. The division has four long-term contracts with terms of greater than five years for supply from major gas fields.

Generation output was managed in order to hedge risk and optimise the position in the balancing market. Some 18 terawatthours ("TWh") were despatched, both to contribute towards the approximately 34 TWh of retail and wholesale demand provided by the division and to maintain export volumes through the interconnectors to England & Wales and to Northern Ireland.

Energy management and commercial arrangements

In addition to its own generation capacity and long-term bulk gas contracts ScottishPower has access to additional generation under contract. Through its commercial and energy management operations, the division uses medium and short-term contractual arrangements to complete its energy purchase requirements and to sell its generation output into the electricity market in Scotland and, through the interconnectors, to England & Wales and to Northern Ireland. The draft bill intended to introduce a Great Britain-wide market through the British Electricity Trading and Transmission Arrangements ("BETTA") was published in January 2003, although the new arrangements are not now expected to become effective until October 2004 at the earliest. BETTA is expected to have only a very modest impact on end-user prices and the UK Government is now in consultation on transmission losses in a Great Britain-wide market, since these could impose higher costs on all types of generation in Scotland, particularly renewables.

Through its activities in the electricity, gas and coal markets, ScottishPower's energy management business secures competitive advantage for the UK Division through hedging and optimising its position across the energy value chain, continuously evaluating and managing risk exposure. ScottishPower's Hatfield Moors gas storage site enhances the flexibility of the division's energy management position, both in meeting peak demands of supply customers and responding to the volatility of gas prices between midweek and weekends. In addition, the bulk gas contracts allow the gas to be sold out or used in the division's power stations, giving yet more flexibility. A planning application for a 60 million therm, gas storage facility was subject to a public inquiry in late 2002, with a decision anticipated later in 2003/04.

The New Electricity Trading Arrangements, introduced into England & Wales in March 2001, encourage all generators to find buyers for their output, by offering them competitive prices, and all suppliers to contract with generators to purchase sufficient electricity to meet their customers' demand. Imbalances between actual and contracted positions are settled through the balancing mechanism. The pay-as-bid and balancing process exposes market participants to the costs and consequences of their actions, and thus leads to more cost-reflective prices and more effective management of risk. Wholesale electricity prices have remained low, down by approximately 10% year-on-year, although above ScottishPower's marginal cost of generation. The UK market is characterised by over-capacity, with plant being mothballed and some companies withdrawing from the market. Low wholesale prices improve the profitability of the ScottishPower energy supply business to the extent that the group's own generation and market purchases are used to meet customer demand but short-term sales contracts with large industrial and commercial customers quickly reflect movements in the wholesale market, restricting supply margins in this sector. Under the Nuclear Energy Agreement ("NEA") of 1990, ScottishPower and Scottish & Southern were contracted, until 2005, to purchase the entire output from British Energy's nuclear plants in Scotland on the basis of a pricing formula not reflective of recent market conditions. Amendments to the NEA agreed in July 2002 were cleared by the UK and European Union authorities by November 2002 and the full effect of the revised terms has now been applied throughout 2002/03 providing a benefit of some £25 million.

Energy supply

Since September 1998, when competition was extended to residential electricity customers, the strategic focus of the ScottishPower energy supply business has been the defence of its core markets, residential and small business customers in the ScottishPower and Manweb home areas, whilst seeking profitable additional business outside these historical regional boundaries.

Business Review – Description of Business
continued

Retention of home area residential customers stands at 61% whilst targeted sales efforts, strategic marketing alliances, such as NESTMakers, the partnership with Sainsbury's and the use of e-commerce channels have helped develop a Britain-wide customer base which now stands at 3.65 million energy accounts. Customer service performance improved on the prior year and there have been further system improvements in the call centres. The business improvement programme introduced in 2001 continues to drive improvements across the retail supply business and has delivered revenue and cost benefits of £14 million in the year to 31 March 2003 in areas such as billing, debt and customer registration business processes.

Metering and data management

In the competitive energy market SP Dataserve Limited operates end-to-end process and data management in order to maximise efficiencies in the provision and control of registration and metering data. Data management covers the establishment of new customers, maintenance of existing customers and accuracy of energy settlement. To effectively manage gas and electricity customers, SP Dataserve has been improving billing performance and the management of the agents, who provide much of the data.

PPM

PPM, the group's competitive US energy business, commenced substantive operations in 2001 as PacifiCorp Power Marketing, Inc. and is growing prudently through selective expansion in renewables and gas storage services. In order to express better the range of its activities, PPM changed its name in January 2003 to PPM Energy, Inc. Its principal assets are thermal and renewable generation resources and natural gas storage facilities, including a gas storage asset in western Canada. PPM has more than 1,100 MW currently under its ownership or control and, of that, PPM has full economic interest in 861 MW, see Table 7 (page 31). PPM also has approximately 250 MW under construction. This will bring PPM's total to more than 1,350 MW upon completion of construction. In its electricity business, PPM serves a wide variety of wholesale energy customers including municipal agencies, public utility districts and investor-owned utilities. These customers are primarily located in wholesale energy markets served by the 1.8 million square mile Western Electricity Coordinating Council service territories in the western US. In addition to its active engagement in the west, PPM is currently developing wind generation projects in the mid-western US. PPM's two major gas storage facilities are in Alberta, Canada, and Texas and are each connected into substantial pipeline networks serving well-diversified customer bases under firm, long-term as well as short-term contract arrangements.

In order to meet growing customer demand for renewables, which is supported by public policy at the federal and certain state levels, PPM continues to grow its renewable energy business. In October 2002, PPM purchased the output of the 150 MW High Winds windfarm in northern California and, as it did with the Stateline Wind Energy Center along the Oregon/Washington border, has placed much of this high-quality renewable energy output under long-term contracts. PPM is also developing the 51 MW Moraine Wind Power Project in southwest Minnesota in conjunction with a long-term power sales agreement signed with the regional regulated utility, Northern States Power Company. PPM continues to grow its renewable energy business and has recently announced the development of the 44 MW Flying Cloud Wind Project in Iowa, which includes a 15 year agreement to sell power to Interstate Power & Light, a subsidiary of Alliant Energy. All of these projects will be on-line by the end of calendar year 2003.

PPM has grown its operating wind power portfolio from 263 MW in 2002 to 324 MW in 2003. With approximately another 250 MW under construction and expected to come on-line in 2003/04, this will bring PPM's total wind power under ownership or contract to more than 560 MW. In addition, PPM continues to develop wind power generation and supply arrangements and has under consideration many strategically sited windfarm opportunities. It is a western US leader in the supply of renewable energy and is committed to sustainable and clean energy development for the future, as demanded by the market.

In addition to its renewable generation portfolio, PPM has a total of 37 billion cubic feet ("BCF") of gas storage capacity under ownership, up from 14 BCF the prior year. This includes the 21 BCF acquired in December 2002 at the Katy gas storage facility in Texas and a 2 BCF expansion of the Alberta Hub gas storage facility during the year. PPM intends to add to its 40% ownership in the Alberta Hub gas storage facility with the purchase of an additional ownership interest this spring. PPM has a number of development opportunities underway to grow its gas storage business at selective locations over the next several years.

PPM creates value by securing quality assets at strategic locations and by locking in value with long-term contracts with creditworthy customers. Integration of plant operations, contract dispatch and energy management add additional value. The optimisation benefits come from displacing plant operations with low-priced power purchases, selling the displaced gas or placing it in storage, as well as using transmission and contract delivery flexibility to manage locational price differences in both gas and power. PPM aims to leverage the benefits of its flexible asset base and contracts to extract value across gas and power.

Discontinued activities

UK water and wastewater services – Southern Water

The sale of Southern Water to First Aqua Limited, a company specifically formed to undertake the acquisition, was announced on 8 March 2002 and concluded on 23 April 2002. Net cash inflows from the disposal were used primarily to reduce group net debt.

Group employees

US businesses

PHI and its subsidiaries had 6,291 employees at 31 March 2003. Of these, 6,130 were employed by PacifiCorp and its mining subsidiaries and 161 by PPM.

Approximately 59% of the employees of PacifiCorp and its mining subsidiaries are covered by union contracts, principally with the International Brotherhood of Electrical Workers, the Utility Workers Union of America and the United Mine Workers of

America. In the company's judgement, employee relations in the US businesses are satisfactory.

UK businesses

ScottishPower and its continuing UK subsidiaries had 7,534 employees, at 31 March 2003. Of these, 3,215 were employed in the Infrastructure Division and 4,319 in the UK Division. Approximately 64% of employees in the UK are union members, and 84% are covered by collective bargaining arrangements. There are a number of different collective agreements in place throughout the group, reflecting differing market conditions in which the group's businesses operate. In the company's judgement, employee relations in the UK businesses are satisfactory.

Human resources strategy

During 2002, the group reviewed its human resources strategy, assessing the mutual needs of the businesses and their employees. Following a "gap analysis" a new human resources strategy was developed and approved by the Board in July 2002. In 2003/04, plans will be developed and implemented aiming to ensure that, by 2005 and wherever they work across the group, employees share a consistent, positive experience of working for ScottishPower which encourages and supports high personal performance.

During 2002/03, health and safety arrangements were also reviewed, stimulated by an external audit of business processes. A new health and safety governance process was approved by the Executive Team in November 2002 and, following extensive discussion and communication, a new group health and safety strategy was developed for implementation in 2003/04.

Further details of group workplace policy and performance can be found in the ScottishPower Environmental and Social Impact Report and the ScottishPower Workplace Performance Report. Both will be available on the ScottishPower website.

Group environmental policy

ScottishPower recognises the need for a responsible business to embrace a wider role in society and to engage fully with shareholders, staff, communities, customers and other opinion formers. It aims to do this transparently, through an international framework, to ensure that key principles are translated into action. This framework comprises overall international visionary goals, and specific goals for the US and UK. Performance towards meeting these goals is tracked through carefully chosen Key Performance Indicators, closely related to business unit objectives. ScottishPower's strategy is to become one of the world's leading international energy companies. Hence, it must strive to achieve a balance between various needs including securing energy supply now and into the future, keeping energy affordable and minimising its impact on the environment.

Policy frameworks in the US and UK have common elements: moves to place a value on carbon dioxide ("CO_2") for trading, tightening emission controls using market instruments and supporting renewables and energy efficiency measures. In the US, President Bush's Clear Skies initiative appears to have a high Government priority, against a background of pressure to move it towards a multi-pollutant basis, including carbon. Although efforts to adopt a Renewable Portfolio Standard at the federal level have slowed, efforts continue to create viable markets for renewable generation at the state level, most notably in California. The European Union ("EU") agreed the content of an Emission Trading Directive early in December 2002 which will bring into force a mandatory emission trading regime, as soon as 2005. The UK Energy White Paper, published in February 2003, doubled the UK renewables target of 10% by 2010 to 20%, to be achieved by 2020. Energy saving and energy services received a boost, while resources were identified to support new clean-coal. In Scotland, consultations have begun on a demanding target of 40% renewables by 2020. This is being carried out at a time when operators and the UK regulator, Ofgem, are engaging in discussions which recognise the need to set network upgrades in the context of future network development for renewables and embedded generation.

The group continues to develop specific policies to respond to these regulatory challenges, aiming to grow its business sustainably in new energy markets, to invest in renewables and clean-coal technology and to ensure that customers benefit from innovations in energy efficiency. It also aims to manage existing coal-fired assets responsibly, applying appropriate abatement technologies to reduce its environmental footprint whilst supporting security of supply and affordability of power for its customers. The lines of accountability for environmental policy have been strengthened by forming the policy making Energy and Environment Committee, chaired by the Chief Executive and with direct reporting lines to ScottishPower's Executive Team.

The work of Environment Forums in the US and UK continues to provide ScottishPower with independent opinion on key environmental policies and practices. Environmental Management Systems ("EMS") in the UK, many of which are certified, are based on the ISO14001 standard. These systems continue to provide appropriate controls, and are increasingly linked to business risk management processes. In the US, PacifiCorp's coal-fired stations and one gas-fired station are all certified to ISO14001 and other parts of PacifiCorp continue to roll out EMS programmes. PacifiCorp's hydro resources business unit has completed the Lewis River Basin EMS, which has acted as the template for completion of the Rogue and Klamath EMSs and subsequent EMS development at the Umpqua and Bear River basins. PacifiCorp's power transmission and distribution business unit has embedded EMS controls at four key "hub" facilities and has strong procedures covering bird protection, oil spills and waste management, including a well established contaminant removal programme.

Research and development

ScottishPower supports research into development of the generation, transmission, distribution and supply of electricity. It also continues to contribute, on an industry-wide basis, towards the cost of research into electricity utilisation and distribution developments. In financial years 2002/03, 2001/02 and

Business Review – Description of Business continued

2000/01, expenditure on research and development in the group's businesses was £0.7 million, £3.1 million and £4.2 million, respectively.

Charitable donations

During 2002/03, donations made for charitable purposes by ScottishPower companies totalled £3.2 million. In addition, some £5.3 million of community support activity comprising community investment and commercial initiatives given in cash, through staff time and in-kind donations was undertaken by the company's US and UK operations.

Description of the company's property

US businesses

The US properties consist primarily of generating facilities, electricity transmission and distribution facilities, coal mines and a number of office facilities. Substantially all of PacifiCorp's electricity plants are subject to the lien of PacifiCorp's Mortgage and Deed of Trust.

PacifiCorp owns or has an interest in 53 hydro-electric generating plants. These have an aggregate nameplate rating of 1,067 MW and plant net capability of 1,116 MW. It also owns or has interests in 17 thermal-electricity generating plants with an aggregate nameplate rating of 7,310 MW and plant net capability of 6,777 MW. PacifiCorp also jointly owns one wind power generating plant with an aggregate nameplate rating of 33 MW and plant net capability of 33 MW. Table 1 (page 30) sets out key aspects of PacifiCorp's existing generating facilities. These generating facilities are interconnected through PacifiCorp's own transmission lines or by contract through the lines of others. Substantially all of PacifiCorp's generating facilities and reservoirs are managed on a coordinated basis to obtain maximum load carrying capability and efficiency. Portions of PacifiCorp's 72,000 miles of transmission and distribution networks are located, by franchise or permit, upon public lands, roads and streets and, by easement or licence, upon the lands of other third parties. Table 4 (page 31) sets out further information regarding the PacifiCorp networks.

PacifiCorp's coal reserves are described in Table 2 (page 30). Most are held pursuant to leases from the federal government through the Bureau of Land Management and from certain states and private parties. The leases generally have multi-year terms that may be renewed or extended and require payment of rentals and royalties. In addition, federal and state regulations require that comprehensive environmental protection and reclamation standards be met during the course of mining operations and upon completion of mining activities.

PPM has more than 1,100 MW currently under its ownership or control and, of that, PPM has full economic interest in 861 MW, see Table 7 (page 31). PPM also has approximately 250 MW under construction. This will bring PPM's total to more than 1,350 MW upon completion of construction. The majority of PPM's capacity, 300 MW contracted for a period of 25 years and 237 MW of thermal power contracted for a period of 30 years, comes from long-term agreements while 324 MW comes from outright ownership of one wind plant and two thermal plants. PPM also owns major gas storage facilities in Alberta, Canada and Texas for a total of 37 BCF of gas storage capacity under ownership, up from 14 BCF the prior year.

UK businesses

The UK properties consist of generating stations, transmission and distribution facilities and certain non-operational properties in which the company holds freehold or leasehold interests.

ScottishPower owns seven power stations in Scotland, five of which are operational and two in England. It also owns three windfarms in Northern Ireland, four in Scotland, and one in the Republic of Ireland. In addition, the company has joint venture interests in one power station in England and three windfarms, two of which are in England and one in Wales. All generation plant is owned by the group, with the exception of the non-operational Methil power station, which is held on a ground lease that expires in 2012 and the windfarms which are generally held on ground leases of at least 25 years' duration. See Table 8 (page 32) for further details of operational generation assets.

At 31 March 2003, the UK transmission facilities included approximately 4,150 circuit km of overhead lines and underground cable operated at 400 kV, 275 kV and 132 kV. In addition, the distribution facilities included over 110,000 circuit km of overhead lines and underground cable at voltages operating from 33 kV to 0.23 kV. The group holds either permanent rights or wayleaves which entitle it to run these lines and cables through private land. See Table 9 (page 32) for further details.

Business Review – Description of Legislative and Regulatory Background

As a public limited company ("plc"), Scottish Power plc is subject to the UK Companies Acts and is also registered as a holding company under the US federal Public Utility Holding Company Act of 1935, which is administered by the US federal Securities and Exchange Commission ("SEC"). Hence, Scottish Power plc, PacifiCorp and other subsidiaries are subject to regulation unless specific subsidiaries or transactions are otherwise exempt by SEC rules or orders. SPUK and its subsidiaries are exempt because SPUK is an exempt foreign utility as defined in the 1935 Act. Whereas US federal and state regulatory commissions generally have jurisdiction over mergers, acquisitions and the sale of utility assets, the UK Government, as a way to maintain control over ScottishPower and certain of its subsidiaries, required the issuance of a ScottishPower "Special Share". The Special Share only affects the corporate control transactions at the overall group holding company level and has no effect on PacifiCorp.

ScottishPower's UK operations are subject to such EU Directives as the UK Government brings into effect, specifically, the EU (energy) Liberalisation Directive and EU prohibitions on anti-competitive agreements and the abuse of a dominant position (implemented through the Competition Act 1998, which came into effect from 1 March 2000) and also to the provisions of the Utilities Act 2000 ("Utilities Act"). The Utilities Act introduced a legal framework for energy company licences based on standard, UK-wide conditions and, taken together with requirements of the Department of Trade and Industry ("DTI") and licence changes introduced by the Regulators, defines the regulatory framework within which SPUK and its subsidiaries must operate.

A summary of the more specific legislative and regulatory background to the operations of the group's businesses is set out below.

US business regulation

PacifiCorp is subject to the jurisdiction of the public utility regulatory authorities of each of the states in which it conducts retail electricity operations as to prices, services, accounting, issuance of securities and other matters. Commissioners are appointed by the individual state's governor for varying terms. PacifiCorp is a "licensee" and a "public utility" as those terms are used in the Federal Power Act ("FPA") and is, therefore, subject to regulation by the Federal Energy Regulatory Commission ("FERC") as to accounting policies and practices, certain prices and other matters.

Because PPM does not conduct retail electricity operations, it is not subject to the same state public utility commission regulation as PacifiCorp. However, certain of its wholesale activities are regulated by the FERC and the state commissions impose certain limitations on affiliate transactions. In addition, PPM's Texan and Canadian gas storage activities are subject to regulation by the Texas Railroad Commission and the Alberta Energy and Utilities Board, respectively.

Multi-State Process ("MSP")

PacifiCorp continues its active involvement in a collaborative process with stakeholders in the six states it serves to develop mutually acceptable solutions to the problems faced by PacifiCorp and the states as a result of the operations of a multi-state utility. MSP seeks to clarify roles and responsibilities, including cost allocations for future generation resources, to provide states with the ability independently to implement state energy policy objectives and to achieve a permanent consensus on each state's responsibility for the costs and entitlement to the benefits of PacifiCorp's existing assets. Between April and December 2002, PacifiCorp and key parties from the states it serves (or, in the case of California, a key monitoring contact) analysed over 50 options which were narrowed to two possibilities. A second phase of the collaborative process is under way in which the parties will further assess the two proposals with the goal of agreeing a single proposal by the summer of 2003. Any proposal resulting from the MSP would be subject to approval by the utility commissions in Utah, Oregon, Wyoming, Washington, Idaho and California, and may also require approvals from the FERC and the SEC. Additional state proceedings to approve specific contracts and tariffs would follow, probably during 2003/04.

Regional Transmission Organization ("RTO")

On 31 July 2002, the FERC issued a Notice of Proposed Rulemaking proposing a new Standard Market Design ("SMD") for wholesale electricity markets, relating to open access transmission service and standard electricity market design. The SMD proposed a number of remedies aimed at removing barriers to efficient competitive wholesale markets perceived by the FERC. PacifiCorp is one of 10 parties involved in an effort to form an RTO, named RTO West, in response to FERC Order 2000. The ten members of RTO West would be Avista Corporation, British Columbia Hydro and Power Authority, Bonneville Power Administration, Idaho Power Company, Northwestern Energy L.L.C. (formerly Montana Power Company), Nevada Power Company, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc. and Sierra Pacific Power Company. Creation of RTO West is subject to regulatory approvals from the FERC and some of the states served by these members may also assert jurisdiction over certain matters relating to the formation of RTO West. RTO West plans to operate all transmission facilities needed for bulk power transfers and to control the majority of the 60,000 miles of transmission line owned by the members. On 18 September 2002, the FERC voted that, with some modification and further development of certain details, the RTO West proposal satisfies the requirements of the FERC Order 2000. It also recognised the proposal as providing a basic framework for a SMD for the western US. On 28 April 2003, the FERC released a White Paper on its wholesale electricity SMD, proposed in July 2002, which reflected a willingness to defer to regional solutions and not adopt overly-prescriptive rules. The White Paper indicates that the FERC will refocus its forthcoming final SMD rule around the formation of RTOs and ensure that those entities have sound market rules. Additionally, the FERC affirmed that it would permit phased-in implementation and sequencing tailored to each region, and allow modifications that would benefit customers within each region. The FERC has now instituted an open-ended public comment period, specifically inviting reaction to certain aspects of the paper. It is expected that the final order will be delayed past the initial July 2003 target release date.

Business Review – Description of Legislative and Regulatory Background continued

FERC Issues

On 26 April 2001, the FERC imposed a price mitigation plan limiting prices on spot market sales in California 24 hours a day, seven days a week. On 19 June 2001, the FERC issued an order that extended the California price limits to all wholesale spot market sales in the entire 11-state western region. The 19 June 2001 order also required that all public utility sellers and buyers (the “Party” or “Parties”) in the California Independent System Operators’ (“Cal ISO”) markets participate in settlement discussions to complete the task of settling past accounts and structuring the new arrangements for California's energy future. As a result thereof, on 12 July 2001, an Administrative Law Judge (“ALJ”) issued a recommendation to the FERC based upon the settlement conference, proposing a methodology to calculate refunds for spot sales to the Cal ISO and the California Power Exchange (“CPX”) between 2 October 2000 and 20 June 2001. The FERC agreed with the ALJ-proposed methodology. On 12 December 2002, a second ALJ issued a Certification of Proposed Findings on California Refund Liability in which the ALJ preliminarily determined that $1.2 billion was still owed to suppliers by the Cal ISO and the CPX, which was calculated by offsetting a $1.8 billion refund from the $3.0 billion owed to suppliers. On 26 March 2003, the FERC staff issued a final report on price manipulation in western markets (“Staff’s Final Report”). Following issuance of the Staff’s Final Report, the FERC issued an Order on Proposed Findings on Refund Liability adopting many of the ALJ’s 12 December 2002 Proposed Findings and clarifying the method for calculating refunds for purchases made in the Cal ISO and CPX spot markets. In its order, the FERC adopted recommendations from the Staff’s Final Report, including a new proxy for gas prices, which could increase the amount of refunds, if any, owed by all Parties. The FERC expects that refunds will be distributed by the end of the summer of 2003. PacifiCorp’s level of exposure to refunds is dependent upon any final order issued by the FERC in response to the outcome of these proceedings.

The FERC has also established a second proceeding to consider the possibility of requiring refunds for wholesale spot market bilateral sales in the Pacific Northwest between 25 December 2000 and 20 June 2001. PacifiCorp's obligation to make refunds, if any, will be dependent upon any final order issued by the FERC in response to the outcome of these proceedings and cannot be determined at this time.

Relicensing of hydro-electric projects

PacifiCorp's hydro-electric portfolio consists of 53 plants with a plant net capability of 1,116 MW, about 13% of PacifiCorp's total generating capacity. The majority of the hydro-electric generating portfolio is operated under licences from the FERC, granted for periods of 30 to 50 years. There is a complex regulatory process to apply for new licences which begins five and a half years before the expiration of an existing licence and involves a number of federal and state agencies, as well as other stakeholders. Some state and federal agencies have authority to require certain terms and conditions to be included in the FERC licence. Often existing licences expire prior to the FERC’s issuing a new licence. In these cases, the FERC has historically issued annual operating licences so that the project can continue to operate while alternatives are evaluated: the FERC is expected to continue this practice.

Many of PacifiCorp's long-term operating licences have expired or will expire in the next few years, leaving the plants to operate under annual licences granted by the FERC but containing conditions requiring PacifiCorp to implement certain protection, mitigation and enhancement measures, primarily to address environmental concerns relating to fisheries, water quality, wildlife, recreation, land use, cultural resources and erosion. It is difficult to determine the economic impact of these measures, but capital expenditures and operating costs are expected to increase and in-stream flow requirements and other constraints on operations may result in lower generating output and reductions in operational flexibility. PacifiCorp has entered into settlement agreements with stakeholders in the licensing processes regarding measures to be included in the new licences for the North Umpqua, Bear River and Big Fork hydro-electric projects and has incorporated the terms of these settlement agreements into the licence applications to the FERC. PacifiCorp has also analysed the costs and benefits of relicensing the Condit, Powerdale and American Fork hydro-electric projects and as a result entered into a settlement agreement to remove or decommission these projects, rather than continuing to pursue new licences.

Most of the commitments under these settlement agreements are contingent on ultimately receiving acceptable licences from the FERC. The costs of the measures, together with the costs for hydro-electric relicensing, are expected to be included in rates and, as such, not to have a material adverse impact on the group's consolidated results or financial position.

Regulatory established returns

The regulatory commissions in the various states where PacifiCorp operates approve an appropriate level of cost recovery for debt, preferred equity and common equity which results in an allowed return on rate base costs (“ROR”), including an allowed return on equity (“ROE”) representing the return on shareholder investment. Determination of these returns, and the composition of the investment costs included in the rate base, is made by the commissions in hearings on general rate cases. Rates are then set to allow PacifiCorp the opportunity, with no guarantees, to meet its expenses, recover its investments and earn the allowed ROE for its shareholders. In recent rate cases, the Utah, Oregon and Wyoming commissions have approved RORs of 8.9%, 8.6% and 8.4% and ROEs of 11.0%, 10.8% and 10.8%, respectively. Rate cases are underway in Utah, Oregon, Wyoming and California: in each case, PacifiCorp is targeting an ROE of 11.5%. Commissions in all states served by PacifiCorp monitor PacifiCorp’s achieved ROR for appropriateness in current market conditions. PacifiCorp continues to refine its internal procedures and to work with the commissions to ensure that all prudently incurred costs are reflected in its rates and that actual rates achieve allowable ROE levels. General rate adjustments reflecting changes in the regulated cost base granted in 2002/03 have an annualised value of approximately $31 million.

Recovery of excess power costs
PacifiCorp has made progress towards recovering the deferred power costs incurred during the period of extreme volatility and unprecedented high price levels beginning in the summer of 2000 and extending through the summer of 2001. These costs are being recovered through rate orders amounting to $147.0 million in Utah, $131.0 million plus ongoing carrying charges in Oregon and $25.0 million in Idaho. A final decision on a similar request for $15.9 million in Washington is expected in early June of 2003. In Wyoming, PacifiCorp's request for deferred power cost recovery was denied (although, on 4 April 2003, PacifiCorp filed for a rehearing which is expected to move to a decision following oral arguments on 8 May 2003) and the Oregon rate order is the subject of an appeal by intervening parties which, if successful, would require some refunds. Under UK Generally Accepted Accounting Principles ("GAAP"), all PacifiCorp's net power costs are charged to the profit and loss account when incurred. There is, therefore, a time lag between the recognition of allowable excess power costs under UK GAAP compared to US GAAP, which continues to benefit future UK GAAP reported earnings.

Demand Side Management ("DSM")
PacifiCorp continues to offer its Energy Exchange programme in Utah, Oregon, Wyoming, Washington and Idaho. This programme is an optional, supplemental service which allows participating customers an opportunity voluntarily to reduce electricity usage in exchange for a payment at times and prices determined by PacifiCorp. The programme is designed to help all customers of one MW and greater to address periods of high wholesale prices and peaks in demand when they occur.

In Utah, PacifiCorp is working on several programmes, including an incentive programme to reduce summer peak loads by encouraging installation of either evaporative cooling or high efficiency (also known as unitary) air conditioning equipment, which was approved by the Utah Public Service Commission ("UPSC") on 24 March 2003. In April and May 2003, PacifiCorp filed an air conditioning load control services programme to help manage the growth of weather-driven peak loads and a refrigerator recycling programme intended to encourage customers to remove and recycle secondary refrigerators and/or to upgrade primary refrigerators to more energy efficient models. PacifiCorp has also filed for a DSM tariff in Utah. This tariff would allow PacifiCorp to recover DSM expenditures through a surcharge to customer bills. Several technical conferences have been held with interested parties and hearings have been scheduled for mid-August 2003.

On 17 March 2003, the Idaho Public Utilities Commission ("IPUC") approved an irrigation load control credit programme allowing participants to opt for billing credits in exchange for pre-scheduled load control events during the summer irrigation season of 1 June to 15 September.

Competition and deregulation
During 2002/03, PacifiCorp continued to operate its electricity distribution and retail business under state regulation. Certain industrial customers in Oregon can choose alternative electricity suppliers. However, deregulation of the retail market has not developed widely and, whilst customer demand for choice in each state may eventually lead to retail competition in some form, individual state legislatures have as yet brought forward few specific proposals for retail competition in electricity supply. In Oregon, where Senate Bill 1149 ("SB1149") required rate unbundling and the offer of alternatives, only 26 customers, representing less than 3 average MW of load, elected to take an alternative plan for calendar year 2003. PacifiCorp is recovering approximately $24 million of SB1149 implementation costs over a five-year period through retail rates.

A summary of the outcomes and the most significant further regulatory and legislative developments in the states concerned is set out below.

Utah
On 1 May 2002, the UPSC issued an order approving a stipulation agreement regarding the recovery of deferred and non-deferred net power costs in Utah. The order allows for the consolidation of a number of individual issues into an overall programme under which PacifiCorp will recover a total of $147 million of deferred power costs and commit not to file a general rate case that would take effect prior to 1 January 2004, with certain exceptions. One party has opposed the rate spread provisions of the stipulation agreement and filed a petition for review of the order. PacifiCorp intends to make a compliance filing in Utah that prepares the way for a general rate case to be filed in July 2003. The compliance filing will establish a cap of $125 million on the increase that will be defined in more detail when PacifiCorp files its revenue requirement testimony on or before 31 July 2003. As part of this filing PacifiCorp will file its ROE testimony and supporting exhibits. Hearings are expected to be held in January and February of 2004. If approved, rate changes would become effective on 1 January 2004.

Oregon
On 20 May 2002, the Oregon Public Utility Commission ("OPUC") approved a one-year $15.4 million overall rate increase effective from 1 June 2002 and intended to cover increases in power costs. Limited reconsideration of some $1.2 million of the increase was the subject of briefs filed in mid-April 2003. An order is anticipated in the summer of 2003. On 18 March 2003, PacifiCorp filed a general rate case to recover rising costs for insurance, pension funding and healthcare, among others. If approved, the increase of $57.9 million, or 7.4% in base rates, would take effect from January 2004.

Deferred accounting filings encompassing power costs that varied from the levels in Oregon rates are the subject of continuing hearings, although partial recovery of the deferred costs has continued under rate increases authorised by the OPUC for implementation in February 2001, August 2002 and January 2003. The various actions and hearings have addressed two issues: whether deferred power costs can be amortised at 3% or 6% and the total amount of deferred power costs to be recovered. A stipulation agreement recognising the 6% amortisation rate was approved by the OPUC in December 2002: appeals against OPUC rulings on the amount of the recovery have been

Business Review – Description of Legislative and Regulatory Background continued

consolidated into an action in the Oregon Court of Appeals.

Wyoming

On 6 March 2003, the Wyoming Public Service Commission granted PacifiCorp a general rate increase of $8.7 million, approximately 2.8%, but denied recovery of all deferred power costs. PacifiCorp has filed a request for a rehearing: oral arguments on 8 May 2003 are expected to lead to a decision on the rehearing in the near future. Separately, PacifiCorp anticipates filing a general rate case in Wyoming in late May 2003.

Washington

On 18 October 2002, PacifiCorp filed with the Washington Utilities & Transportation Commission to defer and recover $17.5 million of excess net power costs: the deferral and recovery request was subsequently reduced to $15.9 million based on power cost data through December 2002.

Idaho

On 7 January 2002, PacifiCorp filed with the Idaho Public Utilities Commission to recover deferred power costs: the matter was resolved in October 2002 by a $25 million package of two-year rate surcharges and the retirement of merger credits.

California

In June 2002, the California Public Utilities Commission granted an interim rate increase amounting to approximately $4.7 million, or 8.8%, annually, subject to refund pending the outcome of the general rate case submitted in December 2001. The discovery process between PacifiCorp and the Office of Ratepayer Advocates is ongoing, with evidentiary hearings scheduled for late June 2003.

Regulation of the electricity and gas industries in the UK

The UK electricity and gas industries are regulated under the provisions of the Electricity Act, the Gas Acts and the Utilities Act. The Electricity and Gas Acts provided for the privatisation and restructuring of the industries in the late 1980s and the 1990s, including the introduction of price regulation for electricity transmission and distribution and gas transportation; and of competition in electricity generation, gas storage and the supply of both gas and electricity. The Acts established the licensing of industry participants and created regulatory bodies for each of the electricity and gas industries. In 2000, the Utilities Act enabled the electricity and gas regulators to be merged as the Authority, established new independent consumer councils and provided powers for Government Ministers to give statutory guidance on social and environmental issues and to set energy efficiency targets and renewables obligations.

The Utilities Act transferred the functions of the previous electricity and gas industry regulators to the Authority and provided for the appointment of a Chairman and other members of the Authority by the Secretary of State for Trade and Industry ("Secretary of State"). The Chairman of the Authority holds office for renewable periods of five years and is the Managing Director of Ofgem which provides administrative support to the Authority. Under the Utilities Act, the principal objective of the Secretary of State and the Authority is to protect the interest of customers, wherever appropriate by promoting effective competition. In carrying out those functions, they are required to have regard to the need to secure that all reasonable demands for electricity and gas are met; the need to ensure that licence holders are able to finance their functions; the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes or residing in rural areas. The Authority exercises, concurrently with the Director General of Fair Trading, certain functions relating to monopoly situations under the Fair Trading Act 1973 and to anti-competitive conduct under the Competition Act 1980 and the Competition Act 1998. The Authority also manages UK compliance with the European Community Liberalisation Directive, which is concerned to introduce competition in generation and supply and non-discriminatory access to gas transportation and electricity transmission and distribution across the EU.

The licensing regime

The Authority is responsible for granting new licences or licence extensions for each of the following separate activities:

Electricity generation – the production of electricity at power stations, hydro-electric plants, windfarms and some industrial plants. Through its wholly-owned subsidiary, ScottishPower Generation Limited, the group is licensed to operate some 5,400 MW of UK generating capacity and, by contracting in the wholesale market, has access to capacity operated by other licensed generators.

Electricity transmission – the bulk transfer of electricity across a high voltage network of overhead lines, underground cables and associated equipment typically operating at or above 132 kV. Through its wholly-owned subsidiary, SP Transmission Limited, the group owns and is licensed to operate the transmission system in central and southern Scotland. ScottishPower's transmission system is connected to that of Scottish & Southern in the north of Scotland and is linked to the National Grid in England & Wales and to the Northern Ireland transmission system by interconnectors which enable the export and import of electricity within the UK. The Authority is currently conducting a review of BETTA and a draft bill has been published to facilitate revised arrangements in respect of the interconnector between Scotland and England; these are now expected to be in place by 2005.

Electricity distribution – the transfer of electricity from the high voltage transmission system and its delivery to customers, across a network of overhead lines and underground cables operating at voltages ranging from 33 kV to 0.23 kV. The Utilities Act required separate licensing of the 14 regional distribution businesses introduced under electricity privatisation. Each Public Electricity Distributor ("PED") licensee is required, among other duties, to develop and maintain an efficient, co-ordinated and economical system of electricity distribution and to offer terms for connection to, and use of, its distribution system on a non-discriminatory basis, in order to ensure competition in the supply and generation of electricity. Through its wholly-owned subsidiaries, SP Distribution Limited and SP Manweb plc, the group is licensed to distribute electricity within its two distribution services areas for all suppliers whose customers are within the areas. Charges for distribution are made to the various suppliers as appropriate. The Authority has granted a derogation, which will lapse only in certain limited circumstances, allowing the distribution businesses in the ScottishPower and Manweb PED licence areas to be managed and operated jointly.

Gas transportation and storage – the onshore transportation system, most of which is owned and operated by Transco, the transportation arm of National Grid Transco plc, and the rest by other gas transporters, conveys gas from the beach terminals to consumers and is interconnected with the gas transportation systems of continental Europe, Northern Ireland and the Republic of Ireland. Storage capacities are largely used to balance supply and demand over time. Major facilities are used to balance seasonal variations in demand while diurnal storage capacities provide flexibility in meeting changing gas demand on a daily basis. Competition in storage has been introduced progressively since 1998 through the auction of major storage capacity owned by Transco and the provision of new capacity by independent operators, including ScottishPower. Through its wholly-owned subsidiary, SP Gas Limited, the group is licensed as a gas transporter.

Gas shipping – gas shippers contract with gas transporters to have gas transported between the beach terminal and the point of supply. Gas shippers can also access storage facilities. The group is licensed as a gas shipper.

Supply of gas and electricity – the bulk purchase of gas and electricity by suppliers and its sale to customers, with the associated customer service activities, including customer registration, meter reading, sales and marketing, billing and revenue collection. Large industrial and commercial customers have been able to choose their energy suppliers for a number of years and the residential market was opened to competition progressively, commencing in April 1996, with residual controls on residential electricity prices ending in March 2002. Any electricity supplier wishing to supply electricity to domestic customers must obtain authorisation from the Authority and be subject to additional domestic supply obligations in its licence, including having its codes of practice (statements of intent about how the supplier will interact with customers) approved by the Authority. Broadly comparable arrangements allow British Gas Trading to supply mains gas to any connected customer in competition with licensed gas suppliers. Customers may continue to take supplies from the pre-privatisation monopoly supplier for the area or may choose an alternative licensed supplier. Once customers have changed a gas or electricity supplier, they are able to change supplier again subject to the contractual terms offered by licensed suppliers and approved by the Authority. Through its wholly owned subsidiary, ScottishPower Energy Retail Limited, the group is licensed as a gas supplier and an electricity supplier.

Modification of licences – The Authority is responsible for monitoring compliance with the conditions of licences and, where necessary, enforcing them through procedures laid down in the Electricity and Gas Acts. Under these Acts, as amended by the Utilities Act, licences consist of standard licence conditions, which apply to all classes of licences, and special conditions particular to that licence. The Authority may modify standard licence conditions collectively through making proposals to all relevant licence holders. If some licence holders object, the modification may be carried out only if the number of objectors is below a specified minority. The Authority may modify a special licence condition with the agreement of the licence holder after due notice, public consultation, and consideration of any representations or objections. In the absence of agreement for a special licence condition or if objections are above the specified minority threshold for a standard licence condition, the only means by which the Authority can secure a modification is following a modification reference to the Competition Commission and in the circumstances set out below. A modification reference requires the Competition Commission to investigate (having regard to the matters in relation to which duties are imposed on the Secretary of State and the Authority) and report on whether matters specified in the reference in pursuance of a licence operate, or may be expected to operate, against the public interest; and, if so, whether the adverse public interest effect of these factors could be remedied or prevented by modification of the conditions of the licence. If the Competition Commission so concludes, the Authority must then make such modifications to the licence as appear to it requisite for the purpose of remedying or preventing the adverse effects specified in the report, after giving due notice and consideration to any representations and objections. The Secretary of State has the power to veto any modification.

Modifications to licence conditions may also be made in consequence of a monopoly or merger reference under the Fair Trading Act 1973 or a reference under the Competition Act. ScottishPower's acquisition of Manweb in 1995 and of Southern Water in 1996 and its merger with PacifiCorp in 1999 all involved ScottishPower's giving of undertakings to the Secretary of State to agree to modifications to the licences under which the group operates in the UK. Broadly, these modifications were designed to ring-fence various UK regulated businesses, to require that the group had sufficient management and financial resources to fulfil its UK obligations and to ensure that UK regulators would continue to have access to the information needed to carry out their duties.

Term and revocation of licences – Licences under the Electricity Act, as modified by the Utilities Act, may be terminated by not less than 25 years' notice given by the Secretary of State and may be revoked in certain circumstances specified in the licence. These include the insolvency of the licensee, the licensee's failure to comply with an enforcement order made by the Authority and the licensee's failure to carry on the activities authorised by the licence.

Price controls

It is recognised that the development of competitive markets is not appropriate in some areas: the transmission and distribution of electricity and the operation of the gas transportation system. In these areas, regulatory controls are deemed necessary to protect customers in

Business Review – Description of Legislative and Regulatory Background continued

monopoly markets (by determining inflation-limited price caps) and to encourage efficiency. The group's UK transmission and distribution businesses are subject to price controls (or revenue controls in the case of the transmission business) which restrict the average amount, or total amount, charged for a bundle of services. The price caps are expressed in terms of an "RPI – X" constraint on charges, where "RPI" represents the annual percentage change in the UK's retail price index, and X may be any number determined by the Authority. The X factor is used to reflect expected efficiency gains and investment requirements. For example, where RPI is running at 3% and X is 2%, a company would be able to increase the average charge for a bundle of services by 1% per annum. The Authority from time to time reviews the price cap formulae. Through participation in, and the submission of evidence to, these price control reviews and, where necessary, through the Competition Commission modification process described above, companies have the opportunity to comment on and seek to influence the final outcome of any price control review.

Transmission price control – The revised transmission price control for ScottishPower took effect for the five years from 1 April 2000. The BETTA review, which proposes a Great Britain-wide wholesale market for electricity and revised arrangements in respect of the interconnector between Scotland and England, requires primary legislation. The draft bill published in January 2003 is expected to facilitate implementation by 2005.

Distribution price control – The maximum distribution revenue is calculated from a formula that is based on customer numbers as well as units distributed. Distribution price controls for the ScottishPower and Manweb areas, which took effect for the five years from 1 April 2000, have been subject to a review by the Authority aimed at ensuring that revenues and outputs of the business are more closely matched and meet customers' expectations. This has involved an examination of the appropriate information and incentives, and has led to a refinement of the price controls to place less emphasis on periodic reviews and more emphasis on continuous performance. Following completion of the review, in April 2002, companies' future revenues can be adjusted by up to 2% to reflect better or worse than target performance and Ofgem will seek to promote the visibility of asset risk management as a core competence in the price review process.

Environmental regulation

Throughout its operations, ScottishPower will meet, or better, relevant legislative and regulatory environmental requirements and codes of practice. ScottishPower will publish its 2002/03 Environmental and Social Impact Report in July 2003. Copies will be available on request from the Company Secretary.

US environmental regulation

Federal, state and local authorities regulate many of PacifiCorp's activities pursuant to laws designed to restore, protect and enhance the quality of the environment. These laws have increased the cost of providing electricity service and give rise to identifiable contingencies, principally in respect of Clean Air Act matters, which are subjects of discussions with the US Environmental Protection Agency ("EPA") and state regulatory authorities. PacifiCorp expects that future costs relating to these matters may be significant and consist primarily of capital expenditure. PacifiCorp expects these costs to be included in rates and, as such, not to have a material adverse impact on the group's consolidated results or financial position.

Air quality

PacifiCorp's fossil fuel-fired electricity generation plants are subject to regulation under federal, state and local requirements. Emission controls, low-sulphur coal, environmentally conscious plant operating practices and continuous emissions monitoring are all used to enable coal-burning plants to comply with emission and opacity limits, visibility and other air quality requirements. The EPA has initiated a regional haze programme intended to improve visibility at specific federally-protected areas some of which are located near PacifiCorp plants. PacifiCorp is anticipating climate change challenges with additions of renewable generation, conservation and thermal resources as outlined in the IRP. CO_2 emissions risk has been anticipated in PacifiCorp's IRP through the use of a "carbon adder". PacifiCorp also supports development of trading and other market mechanisms, as well as offset strategies, where feasible, to reduce future compliance costs to customers. The US Congress is currently considering several proposed bills that would create enforceable limits on electricity plant emission of CO_2, sulphur dioxide (SO_2), oxides of nitrogen (NOx) and mercury. It is not presently possible to determine with certainty the level of capital expenditure related to air quality and CO_2 emissions. It is believed these amounts could be significant but will be spread over a number of years. PacifiCorp also expects that the impact will be mitigated by recovery through regulatory ratemaking.

In 1999, the EPA commenced enforcement actions alleging violations of New Source Review requirements by the owners of certain coal-fired generating plants in the eastern and mid-western US. PacifiCorp is not part of those actions. However, in December 2000, the EPA notified PacifiCorp that it is investigating PacifiCorp's Carbon, Dave Johnston, Huntington and Naughton coal-fired plants and required it to provide information about their operation, maintenance, emissions, utilisation and other aspects of these plants. In early May 2003, the EPA notified PacifiCorp that it is investigating similar issues at the Bridger, Hunter and Wyodak plants. PacifiCorp is cooperating with these investigations by providing requested information to the EPA. No legal proceeding has been commenced.

Endangered species

Protection of the habitat of threatened and endangered species makes it difficult and more costly to perform some of the core activities of PacifiCorp, including the siting, construction, maintenance and operation of new and existing transmission and distribution facilities, as well as hydro, thermal and wind generation plants. In addition, endangered species issues impact the relicensing of existing hydro-electric generating projects, generally raising the price PacifiCorp must pay to purchase wholesale electricity from hydro-electric facilities owned by others and increasing the costs of operating PacifiCorp's own hydro-electric resources.

Environmental clean-ups

Under the Federal Comprehensive Environmental Response, Compensation and Liability Act and similar state statutes, entities that accidentally or intentionally disposed of, or arranged for the disposal of, hazardous materials may be liable for clean-up of the contaminated property. In addition, the current or former owners or operators of affected sites also may be liable. PacifiCorp has been identified as a potentially responsible party in connection with a number of clean-up sites because of current or past ownership or operation of the property or because PacifiCorp sent hazardous waste or other hazardous materials to the property in the past. PacifiCorp has completed several clean-up actions and is actively participating in investigations and remedial actions at other sites. The costs associated with those actions are not expected to be material to the group's consolidated results or financial position.

Mining

The federal Surface Mining and Reclamation Act of 1977 and similar state statutes establish operational, reclamation and closure standards that must be met during the operation and upon completion of mining activities. These obligations stipulate that mine property be restored consistent with specific standards and the approved reclamation plan. Significant expenditures are expected to be required as individual PacifiCorp mining operations are closed and reclamation occurs. The costs associated with reclamation are subject to the regulatory process. PacifiCorp expects to be allowed to recover these costs.

Water quality

The federal Clean Water Act and individual state clean water regulations require a permit for the discharge of wastewater, including storm water runoff from the electricity plants and coal storage areas, into surface waters. PacifiCorp believes that it has management systems in place to monitor performance, identify problems and take action to assure compliance with permit requirements.

UK environmental regulation

The group's UK businesses are subject to numerous regulatory requirements with respect to the protection of the environment, including environmental laws which regulate the construction, operation and decommissioning of power stations, pursuant to legislation implementing environmental directives adopted by the EU and protocols agreed under the auspices of international bodies such as the United Nations Economic Commission for Europe ("UNECE"). The group believes that it has taken and continues to take measures to comply with applicable laws and regulations for the protection of the environment. Applicable regulations and requirements pertaining to the environment change frequently, however, with the result that continued compliance may require material investments, or that the group's costs and results of operation are less favourable than anticipated.

Electricity generation, transmission, distribution and supply

The Electricity Act obligates the Secretary of State to take into account the effect of electricity generation, transmission, distribution and supply activities upon the physical environment in approving applications for the construction of generating facilities and the location of overhead power lines. The Electricity Act requires the group to take into account the conservation of natural features of beauty and other items of particular interest and, in terms of the Environmental Impact Assessment Regulations, to carry out an environmental assessment when it intends to construct significant overhead transmission systems or power stations of greater capacity than 50 MW. The group also prepares formal statements on the 'Preservation of Amenity and Fisheries' in line with the requirements of the Electricity Act.

The Utilities Act provided for environmental guidance to be given by the Secretary of State to the energy regulator, Ofgem, and for regulations to be drawn up which require licensed electricity suppliers to secure a certain percentage of their supplies from renewable energy sources, compliance being demonstrated by tradable 'Renewables Obligation Certificates'. The current objective is that 10% of UK energy should come from renewable sources by 2010 and a target of 20% by 2020 was included in the February 2003 Government White Paper on energy. ScottishPower continues to develop its windfarm business and expects to meet the company target of 10% generation from renewables by 2010. The Utilities Act also provided for energy efficiency targets to be set for licensed suppliers to be implemented by an 'Energy Efficiency Commitment' and the emphasis remained clearly on energy saving in the Energy White Paper.

The Environmental Protection Act of 1990 ("EPA 1990") requires that potentially polluting activities such as the operation of combustion processes (which includes power plant) requires prior authorisation. The Act also provides for the licensing of waste management and imposes certain obligations and duties on companies which produce, handle, and dispose of waste. Waste generated as a result of the group's electricity activities is managed to ensure compliance with legislation and waste minimisation is undertaken where possible.

Generation activities

The principal emissions from fossil-fuelled electricity generation are SO_2, NOx, CO_2 and particulate matter, such as dust, with the main waste being ash, namely pulverised fuel ash and furnace bottom ash. The primary focus of current environmental legislation is to reduce emissions of SO_2, NOx and particulates, the first two of which contribute to acid rain. A number of other power station emissions and discharges are subject to environmental regulation.

EPA 1990 is the primary UK statute governing the environmental regulation of power stations. In April 1991, it introduced a system of Integrated Pollution Control ("IPC") for large scale industrial processes, including power stations, now enforced with respect to emissions to atmosphere in England & Wales by the Environment Agency ("EA") and in Scotland by the Scottish Environment Protection Agency ("SEPA"). Each of ScottishPower's power stations is required to have its own IPC authorisation, issued by the EA or SEPA, regulating emissions of certain pollutants, seeking to minimise pollution of the

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environment and containing an improvement programme. Each IPC authorisation requires that a power station uses the Best Available Techniques Not Entailing Excessive Cost ("BATNEEC") to prevent the emissions described above or, to the extent this is not practicable, to minimise and render harmless any such emissions. ScottishPower's IPC authorisations do not have an expiry date, but the EA or SEPA is required to review the conditions contained within them at least once every four years and may impose new conditions to prevent or reduce emissions of pollutants, subject to the application of BATNEEC.

The EU has agreed a Directive on Integrated Pollution Prevention and Control, which introduces a system of licensing for industrial processes such as power stations. This Directive is being implemented via the Pollution Prevention and Control Regulations ("PPC Regulations") which will bring modifications to the IPC regime into effect, on a staged basis. The EU Directive will eventually require that all emission and pollution control measures are placed onto a "Best Available Techniques" basis to control impact on the environment.

The EU has adopted a framework directive on ambient air quality assessment and management and, under the auspices of UNECE, protocols regarding reductions in the emissions of SO_2 and NOx have been agreed. These are currently implemented in the EU by means of the Large Combustion Plants Directive ("LCPD"). The EU is currently finalising a "Ceilings Directive" which will implement the SO_2 and NOx targets agreed in the UNECE Gothenburg Protocol. In the UK, uncertainty remains surrounding implementation of the LCPD and the EU has now provided guidelines on outstanding issues, including whether compliance will be by emission limit values or will continue to be implemented in the UK by means of the National Air Quality Strategy published in 1997, and reviewed in 2000. The group has identified options that, given the appropriate commercial conditions, would enable it to continue the environmental improvements required by potential future limits arising from this review, without materially constraining operational and commercial flexibility. In particular, gas-reburn technology, as used at Longannet, offers greater potential to reduce emissions than other technology in use elsewhere in the UK.

Contaminated sites

While the nature of developments in environmental regulation and control cannot be predicted, the group anticipates that the direction of future changes will be towards tightening controls. In view of the age and history of many sites owned by the group, the group may incur liability in respect of sites which are found to be contaminated, together with increased costs of managing or cleaning up such sites. Site values could be affected and potential liability and clean-up costs may make disposal of potentially contaminated sites more difficult. The Contaminated Land Regulations, which implement provisions of the Environment Act 1995 ("EA1995"), require local authorities to identify sites where significant harm is being caused and to take appropriate steps. In order for harm to be demonstrated it must be shown that a source of pollution, a receptor and a pathway are present. Harm may be eliminated by clean-up or by breaking the source to receptor pathway. Clean-up is only required to 'fit for subsequent use' standards, so that environmental compliance is consistent with the intended use of the site.

Other proposals which may impose strict liability for environmental damage are also under consideration by the EU and a directive may be brought forward. ScottishPower is not currently aware of any liability which it may have under EA1995 or proposed EU directives which will have a materially adverse impact on its operations.

Employment regulation

Numerous laws and related codes of practice – international, European, UK and US – ensure that companies offer equal opportunities to all individuals, regardless of gender, race, disability and age. Similarly, both the US and the UK have extensive legislation covering health and safety at work. ScottishPower has well-defined policies in place throughout its businesses to ensure that there are equal opportunities in employment. These policies cover a range of specific issues, such as adoption, caring and development breaks, disability, disciplinary and grievance procedures, equal pay, harassment, maternity and paternity, fertility treatment, race and sex discrimination, ill health and stress.

A more extensive description of how the businesses discharge their wider responsibilities to protect the welfare, health and safety of the public and their employees, can be found in the ScottishPower Environmental and Social Impact Report and the ScottishPower Workplace Performance Report. Both will be available on the ScottishPower website. A brief overview of the two most extensively regulated aspects of employee relations follows.

Equal opportunity

US businesses

In the US, equal employment opportunities are provided without regard to race, colour, sex, religion, creed, age, sexual orientation, national origin and physical or mental disability. The group provides equal opportunity for qualified applicants and employees and maintains a programme of affirmative action, pursuant to legal requirements, in order effectively to employ minorities and women and to encourage workforce diversity. The programme also covers disabled persons and veterans. Affirmative action programmes establish specific, results-oriented procedures; determine whether effective utilisation of minorities and women is achieved; establish numerical goals for the hiring and promotion of minorities and women; incorporate equal employment principles in supervisory training; embed diversity objectives in performance reviews; and promote effective community outreach efforts for women and minority applicants.

During 2002/03, the Washington state Family Medical Leave Act Regulation was revised and both Washington and Oregon states increased their minimum wage. The Jobs for Veterans Act updates previous legislation and the new regulations will be published in December 2003. PacifiCorp reported data will comply with new regulations for 2004 reporting, and, in response, PacifiCorp will update the information it provides on the VETS-100 Report.

UK businesses
The UK businesses work with both outside organisations and an internal equality forum to consider policies for racial equality, family issues, disabled people and other key areas. ScottishPower is affiliated with a number of organisations including the Equal Opportunities Commission, Employer's Forum on Age, Employer's Forum on Disability, Commission for Racial Equality and Parents at Work. Internal human resources staffs work with these organisations to find ways to incorporate their expertise into group and business unit policies.

The Employment Act 2002 brought in requirements for flexible working, adoption, maternity and paternity leave, tribunal reform and trade union learning representatives. The UK businesses are in the process of reviewing and updating policies on these issues to ensure they meet any new requirements. They have also issued guidelines, reviewed procedures and carried out staff training to meet the requirements of the key areas of focus including equal access, data protection and working time regulations and are working to harmonise terms and conditions relating to maternity and paternity leave, working time and family policies.

Health and safety
US businesses
The US businesses have well developed annual safety and health operational plans with monthly reporting of safety performance against key performance indicators, which set accident metrics for continuing improvement year-on-year. All safety rules and policies in place across the businesses are subject to periodic review and update. Professional safety and health departments are staffed in PacifiCorp's power delivery, generation and mining businesses with an additional corporate safety department providing policy input and senior management support for both employee safety and health and for public safety. The group's US Health and Safety Committee provides executive oversight and leadership in PacifiCorp and PPM, is comprised of senior executives, and meets on a regular basis. Major initiatives are under way in PacifiCorp's power delivery, generation and mining business units and in PPM to reduce and prevent accidents.

In the US, health and safety in mining operations is regulated by the Mine Safety and Health Administration ("MSHA") electricity utility operations are regulated by the Occupational Safety and Health Administration ("OSHA") and the gas storage business is regulated by both OSHA and the Office of Pipeline Safety as these apply. PacifiCorp and PPM have safety policies and procedures in place to comply with MHSA, OSHA and the Office of Pipeline Safety regulatory requirements. Safety Management Systems similar to the criteria to qualify for OSHA's Voluntary Protection Program are also being implemented in many of the businesses.

The US businesses participate with other industry stakeholders in the regulatory process on significant OSHA and MSHA regulatory proposals affecting the utility and mining industries.

UK businesses
The UK businesses have implemented Health and Safety Executive guidance on successful health and safety management (HSG 65) and, where appropriate, have adopted the Royal Society for the Prevention of Accidents' Quality Safety Audit system to drive continuous improvement in safety performance. Occupational health provision in the UK businesses includes compliance, rehabilitation and health promotion. Monitored and audited by in-house medical staff, advice on health risk management and early intervention has contributed to a reduction in sickness absence. Managers are encouraged to deal effectively with health issues in the workplace and employees are encouraged to make lifestyle decisions that maintain and improve their health.

In the UK, the Reporting of Injuries, Diseases and Dangerous Occurrences Regulations set out the requirements for reporting of all work-related accidents. As UK regulators and enforcement authorities increasingly seek to raise the priority and importance that companies give to health and safety issues, they are likely to take action for any non-compliance.

Recent changes in UK health and safety legislation include asbestos legislation, electrical safety and quality regulations, new directives covering vibration, noise and control of substances hazardous to health. All events that have scope for damage to plant or people are investigated, the major ones being reviewed by investigating panels, normally chaired by a member of the senior management team. The results of these investigations are communicated and, where applicable, recommendations are completed. There is also increasing focus on the issue of occupational road risk, to ensure that safe driving at work and work on the road is addressed as part of mainstream health and safety management and enforcement, with publication of new Health and Safety Executive guidance in 2002. Road risk policies have been introduced within the UK generation, strategic transactions and energy management business units. Employees have been offered defensive driving training and a monthly Well Aware campaign on driving was held to raise the profile and employees' understanding of this important issue.

Business risks

Operating risk
Operating risk is the risk that assets and mechanical systems, as well as business processes and procedures, might not perform as expected, with the result that the group may be unable to meet a portion of its obligations without resorting to an unanticipated market transaction. Operating risk is primarily mitigated through a combination of sound maintenance practices, prudent and safe operational processes and insurance products, such as business interruption insurance.

Security risk
The emergence of terrorism threats, both domestic and foreign, is a risk to the entire utility industry, including ScottishPower. Potential disruptions to operations or destruction of facilities from terrorism are not readily determinable. The group has identified critical assets and developed several levels of security to meet the changed environment. A project is underway in the US to implement a security plan, starting with the most critical assets, to mitigate terrorism risks and to prepare contingency plans in case the group's facilities are targeted. Additionally,

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in the US the FERC is promulgating standards to which the group's US businesses will be subject.

In the UK, there is an established liaison with the Security Services and police, to ensure that our critical assets are protected against potential threat of terrorism.

Pension risk

As a result of the decline in the equity markets and low interest rates, the group anticipates that pension expense and cash contributions into the pension schemes will increase in the near future. The investment risk is being addressed as part of the pensions review being undertaken by both the group and its pension scheme trustees by focusing on the asset allocation of the schemes.

Regulatory risk

In the US the group is subject to the jurisdiction of federal and state regulatory authorities. The FERC establishes tariffs under which PacifiCorp provides wheeling services to the wholesale market and the retail market for states allowing retail competition, establishes both cost-based and market-based tariffs under which PacifiCorp sells power at wholesale and has licensing authority over most of PacifiCorp's hydro-electric generation facilities. The utility regulatory commissions in each state independently determine the rates PacifiCorp may charge its retail customers in that state. Each state's rate setting process is based upon that commission's acceptance of an allocated share of total PacifiCorp costs as its "responsibility". When different states adopt different methods to address this "interjurisdictional cost allocation" issue, some costs may not be incorporated into any rates in any state. Rate making is done on the basis of "normalised" costs, so if in a specific year, realised costs are higher than normal, rates will not be high enough to cover those costs. Likewise, if in a given year costs are lower than normal or revenues are higher, PacifiCorp retains the resulting higher-than-normal profit. Each commission sets rates based on a "test year" of its choosing. In states that use a historical test year, rate adjustments can follow cost increases, or decreases, by up to two years. Regulatory lag results in a delay in recovery of costs currently incurred but not in rates, and also imposes a time-value-of-money burden on PacifiCorp. Further, each commission decides what levels of expense and investment are "necessary, reasonable and prudent" in providing service. In the event that a commission decides that part of PacifiCorp's costs do not meet this standard, such costs will be "disallowed" and not recovered in rates. For these reasons, the rates authorised by the regulators may be less than the costs to PacifiCorp to provide electricity service to its customers in a given period.

Nearly all of PacifiCorp's hydro-electric projects are in some stage of the FERC relicensing under the FPA. The relicensing process is a political and public regulatory process that involves sensitive resource issues. PacifiCorp is unable to predict the requirements that may be imposed during the relicensing process, the economic impact of those requirements, whether new licences will ultimately be issued or whether PacifiCorp will be willing to meet the relicensing requirements to continue operating its hydro-electric projects.

Federal, state and local authorities regulate many of PacifiCorp's activities pursuant to laws designed to restore, protect and enhance the quality of the environment. PacifiCorp is unable to predict what material impact, if any, future changes in environmental laws and regulations may have on the group's consolidated results or financial position.

In the UK, the electricity and gas industries are regulated primarily through powers assigned, under the Utilities Act 2000, to the Authority which licenses industry participants, enforces licence conditions, regulates quality of service and sets pricing formulae for electricity transmission and distribution activities. In principle, it has wide discretion in the exercise of its obligation to act to protect the interests of customers, wherever appropriate by promoting effective competition, whilst the need to ensure that licence holders are able to finance their functions is only one of a number of other factors to which the Authority must have regard. However, the Authority operates through a process of extensive consultation and on pre-determined timetables, making its activities relatively predictable. Regulations designed to restore, protect and enhance the quality of the environment are similarly introduced through a process of intensive – and generally EU-wide – consultation with the industry and other parties. Nonetheless, there is a general tightening of environmental regulation and it must be recognised that the future impact of the costs of such requirements cannot be forecast with precision.

Political risk

In the US, PacifiCorp and PPM conduct business in conformance with a multitude of federal and state laws. The US Congress at present is considering, significant changes in energy, air quality and tax policy. Energy legislation recently passed by the US House of Representatives would make some changes in federal law affecting PacifiCorp and PPM. The proposed changes affect the hydro-electric licensing process under the FPA and extension of the renewable energy production tax credit, which would be likely to benefit PacifiCorp's efforts to develop, acquire and maintain a low-cost generation portfolio and PPM's efforts to continue developing its renewable energy portfolio. Changes to the Clean Air Act contemplated by the proposed Clear Skies Act are being monitored closely in that they may impact requirements for several emissions from fossil-fuelled generation plants.

The laws of the states in which PacifiCorp operates affect PacifiCorp's generation, transmission and distribution business. All but two of the legislatures monitored by PacifiCorp have concluded, or are close to concluding, their business for their legislative year. PacifiCorp is not aware of any new laws positively or negatively affecting PacifiCorp in any significant manner, based on a review of bills passed by the Washington and Idaho legislatures during their just completed legislative sessions. Wyoming enacted an exemption to the state sales tax for renewable energy equipment, which may make development of wind energy resources in the state more economically viable. Wyoming also passed legislation revamping the consumer advocate staff role in commission proceedings. Utah enacted legislation authorising the UPSC to use a forward-looking test year of up to 20 months in setting rates. This mechanism, if properly implemented, should enable the UPSC to set consistent rates that more accurately reflect costs during the actual rate period. California is expected to consider legislation repealing or reforming many elements of its 1996 restructuring law.

In the UK, energy policy has been set out in a Government White Paper, published in February 2003, which emphasises a continuing intention to make maximum use of market-based mechanisms whilst seeking to reduce the use of carbon, boost energy-saving and maintain efforts to mitigate the impact of fuel costs on lower-income households. There is particular emphasis on the use of renewable energy sources and developing discussion of the network enhancements likely to be required for the increased use of both renewables and embedded generation. This policy framework offers opportunities for the group and has shaped a number of current business plans. The White Paper has received broad endorsement across the UK political spectrum and appears to be largely consistent with EU policy generally. However, as the policy outlined extends well into the future, it could be subject to change and amendment by future Governments.

Litigation

ScottishPower is not aware of any material pending legal proceedings, other than ordinary routine litigation incidental to the business of the group, to which ScottishPower or any of its subsidiaries is a party, or any such proceedings known to be contemplated by any governmental authority.

Summary of Key Operating Statistics

Table 1 – Summary of PacifiCorp generating facilities

	Location	Energy source	Installation dates	Nameplate rating (MW)	Plant net capability (MW)
Hydro-electric plants					
Swift	Cougar, WA	Lewis River	1958	240.0	263.6
Merwin	Ariel, WA	Lewis River	1932-1958	135.0	144.0
Yale	Amboy, WA	Lewis River	1953	134.0	134.0
Five North Umpqua Plants	Toketee Falls, OR	N. Umpqua River	1949-1956	133.5	136.5
John C. Boyle	Keno, OR	Klamath River	1958	80.0	84.0
Copco Nos. 1 and 2 Plants	Hornbrook, CA	Klamath River	1918-1925	47.0	54.5
Clearwater Nos. 1 and 2 Plants	Toketee Falls, OR	Clearwater River	1953	41.0	41.0
Grace	Grace, ID	Bear River	1914-1923	33.0	33.0
Prospect No. 2	Prospect, OR	Rogue River	1928	32.0	34.0
Cutler	Collingston, UT	Bear River	1927	30.0	29.1
Oneida	Preston, ID	Bear River	1915-1920	30.0	28.0
Iron Gate	Hornbrook, CA	Klamath River	1962	18.0	19.5
Soda	Soda Springs, ID	Bear River	1924	14.0	14.0
Fish Creek	Toketee Falls, OR	Fish Creek	1952	11.0	12.0
33 Minor Hydro-electric Plants	Various	Various	1896-1990	88.8*	88.6*
Subtotal (53 hydro-electric plants)				1,067.3	1,115.8
Thermal electric plants					
Jim Bridger	Rock Springs, WY	Coal-Fired	1974-1979	1,541.1*	1,413.4*
Huntington	Huntington, UT	Coal-Fired	1974-1977	996.0	895.0
Dave Johnston	Glenrock, WY	Coal-Fired	1959-1972	816.8	762.0
Naughton	Kemmerer, WY	Coal-Fired	1963-1971	707.2	700.0
Hunter 1 and 2	Castle Dale, UT	Coal-Fired	1978-1980	727.9*	662.5*
Hunter 3	Castle Dale, UT	Coal-Fired	1983	495.6	460.0
Cholla Unit 4	Joseph City, AZ	Coal-Fired	1981	414.0*	380.0*
Wyodak	Gillette, WY	Coal-Fired	1978	289.7*	268.0*
Carbon	Castle Gate, UT	Coal-Fired	1954-1957	188.6	175.0
Craig 1 and 2	Craig, CO	Coal-Fired	1979-1980	172.1*	165.0*
Colstrip 3 and 4	Colstrip, MT	Coal-Fired	1984-1986	155.6*	144.0*
Hayden 1 and 2	Hayden, CO	Coal-Fired	1965-1976	81.3*	78.0*
Blundell	Milford, UT	Geothermal	1984	26.1	23.0
Gadsby	Salt Lake City, UT	Gas-Fired	1951-2002	392.6	349.0
Little Mountain	Ogden, UT	Gas-Fired	1971	16.0	14.0
Hermiston	Hermiston, OR	Gas-Fired	1996	237.0*	236.0*
James River	Camas, WA	Black Liquor	1996	52.2	52.0
Subtotal (17 thermal electric plants)				7,309.8	6,776.9
Other plants					
Foote Creek	Arlington, WY	Wind Turbines	1998	32.6*	32.6*
Subtotal (1 other plant)				32.6	32.6
Total hydro, thermal and other generating facilities (71)				8,409.7	7,925.3

Notes:

* Jointly owned plants; amount shown represents PacifiCorp's share only.

Hydro-electric project locations are stated by locality and river watershed.

Table 2 – PacifiCorp recoverable coal reserves as at 31 March 2003

Location	Plant served	Recoverable tons (in millions)	Notes
Craig, Colorado	Craig	49	(1)
Emery County, Utah	Huntington and Hunter	54	(2)
Rock Springs, Wyoming	Jim Bridger	93	(3)

Notes:

1 These coal reserves are leased and mined by Trapper Mining, Inc., a Delaware non-stock corporation operated on a cooperative basis, in which PacifiCorp has an ownership interest of approximately 20%.

2 These coal reserves are mined by PacifiCorp subsidiaries.

3 These coal reserves are leased and mined by Bridger Coal Company, a joint venture between Pacific Minerals, Inc., a subsidiary of PacifiCorp, and a subsidiary of Idaho Power Company. Pacific Minerals, Inc. has a two-thirds interest in the joint venture.

Coal reserve estimates are subject to adjustment as a result of the development of additional data, new mining technology and changes in regulation and economic factors affecting the use of such reserves.

Table 3 – PacifiCorp electricity GWh energy sales by customer class

Electricity sales, by class of customer, for the years ended 31 March 2003, 2002, 2001 and 2000 were as follows:

	2003	%	2002	%	2001	%	2000	%
Gigawatt hours sold								
– Residential	13,287	17	13,395	19	13,455	18	13,028	16
– Commercial	14,006	18	13,810	19	13,634	18	12,827	16
– Industrial	19,048	25	19,611	27	20,659	27	20,488	25
– Government, Municipal and Other	631	1	711	1	705	1	663	1
– Total Retail Sales	46,972	61	47,527	66	48,453	64	47,006	58
– Wholesale Sales and Market Trading	30,485	39	24,264	34	27,502	36	34,327	42
Total GWh Sold	77,457	100	71,791	100	75,955	100	81,333	100

Table 4 – PacifiCorp transmissionand distribution systems key information 2002/03

	Pacific Power	Utah Power	Total
Franchise area	73,647 sq miles	61,545 sq miles	135,192 sq miles
System maximum demand	3,968MW	4,581MW	8,549 MW
Transmission network (miles)			
– Overhead			14,949
Distribution network (miles)			
– Underground	5,299	8,002	13,301
– Overhead	26,260	17,505	43,765

Table 5 – Total electricity units distributed in Pacific Power service area (GWh)

Year	Residential	%	Commercial	%	Industrial	%	Other	%	Total
1998/99	7,994	32	6,908	27	10,166	40	128	1	25,196
1999/00	7,612	31	6,766	27	10,167	42	122	–	24,667
2000/01	7,768	31	7,041	28	10,164	40	130	1	25,103
2001/02	7,537	31	6,932	29	9,743	40	129	–	24,341
2002/03	7,454	31	7,081	29	9,478	40	90	–	24,103

Table 6 – Total electricity units distributed in Utah Power service area (GWh)

Year	Residential	%	Commercial	%	Industrial	%	Other	%	Total
1998/99	4,998	24	5,392	26	10,056	48	517	2	20,963
1999/00	5,416	24	6,061	27	10,321	46	541	3	22,339
2000/01	5,687	24	6,593	28	10,495	45	575	3	23,350
2001/02	5,858	25	6,878	30	9,868	43	582	2	23,186
2002/03	5,833	26	6,925	30	9,570	42	541	2	22,869

Table 7 – PPM generating facilities

	Location	Energy source	Installation date	Plant net capability MW
Thermal electric plants				
Klamath Cogeneration Plant	Klamath Falls, OR	CombinedCycle	2001	506
West Valley Generating Plant	West Valley City, UT	Natural gas-fired – single cycle	2002	200
Klamath Expansion Project	Klamath Falls, OR	Natural gas-fired – simple cycle	2002	100
Sub-total (3 thermal electric plants)				806
Renewable electric plants				
Stateline Wind Energy Center	Oregon/ Washington	Wind generation	2002	300
Klondike Wind Power Plant	Wasco, OR	Wind generation	2001	24
Subtotal (2 renewable electric plants)				324
Total all plants (Owned or controlled plants)				1,130

Summary of Key Operating Statistics
continued

Table 8 – Sources of ScottishPower owned generating capacity and output in the UK and the Republic of Ireland as at 31 March 2003

	Notes	Number of generating sets and/or installed capacity MW	Net output capacity MW	Maximum capacity available MW
Coal				
Longannet		4 x 600	2,304	
Cockenzie		4 x 300	1,152	
	1		3,456	2,880
Gas Turbine				
Rye House		1 x 715	715	715
Brighton	2	1 x 414	400	200
Knapton		1 x 42	42	42
Pumped Storage				
Cruachan		4 x 100	400	400
Conventional Hydro				
Galloway Scheme		109	106	106
Lanark Scheme		17	17	17
Windfarms				
Beinn an Tuirc		46 x 0.66	30	30
Barnesmore		25 x 0.6	15	15
Hagshaw Hill		26 x 0.6	16	16
P & L Windfarm	3	103 x 0.3	31	15
Rigged Hill		10 x 0.5	5	5
Corkey		10 x 0.5	5	5
Elliots Hill		10 x 0.5	5	5
Coal Clough	4	24 x 0.4	10	4
Carland Cross	4	15 x 0.4	6	3
Dun Law		26 x 0.66	17	17
Hare Hill		20 x 0.66	13	13
CHP		103	103	103
Total			5,392	4,591

Notes:

1 Scottish & Southern Energy is entitled to a supply of electricity from part of the capacity of ScottishPower's coal-fired generating stations at Longannet and Cockenzie.

2 Brighton power station is owned by South Coast Power Limited, with ScottishPower Generation Limited and American Electric Power, Inc. each having a 50% ownership interest.

3 The P & L Windfarm is owned by CeltPower Limited, with ScottishPower Generation Limited and Tomen Power (Europe) BV each having a 50% ownership interest.

4 The windfarms at Coal Clough and Carland Cross are owned by a joint venture between ScottishPower Generation Limited, Western Power Distribution and Renewable Energy Systems, with ScottishPower Generation Limited having a 45% ownership interest.

Table 9 – UK transmissionand distribution systems key information 2002/03

	ScottishPower	Manweb	Total
Servicearea	22,950 km^2	12,200 km^2	35,150 km^2
System maximum demand	4,324MW	3,174MW	7,498MW
Transmission network (km)			
Underground	249	–	249
Overhead	3,915	–	3,915
Distribution network (km)			
Underground	41,137	25,449	66,586
Overhead	24,460	21,537	45,997

Table 10 – Total electricity units distributed in the ScottishPower service area (GWh)

Year	Residential	%	Business	%	Total
1998/99	8,345	37	14,023	63	22,368
1999/00	8,385	38	13,996	62	22,381
2000/01	8,505	38	14,189	62	22,694
2001/02	8,698	39	13,864	61	22,562
2002/03	8,643	39	13,689	61	22,332

Table 11 – Total electricity units distributed in the Manweb service area (GWh)

Year	Residential	%	Business	%	Total
1998/99	5,037	29	12,287	71	17,324
1999/00	5,204	30	11,977	70	17,181
2000/01	5,460	32	11,826	68	17,286
2001/02	5,387	32	11,540	68	16,927
2002/03	5,512	33	11,233	67	16,745

Financial Review

"Our improved operational performance has contributed to a good set of results."

Overview of the Year to March 2003

Group turnover for the year to 31 March 2003 was £5,274 million, a reduction of £1,040 million on the previous year. From continuing operations, group turnover was lower by £276 million at £5,247 million including adverse translation movements of £205 million from the weaker US dollar. Sales were lower in PacifiCorp as a result of reduced wholesale power prices in the western US, although this was partially offset by revenue growth from our other three businesses.

PacifiCorp's turnover for the year was down by £481 million to £2,499 million mainly as a result of the lower wholesale prices experienced for most of the year and a £189 million adverse translation impact of the weaker US dollar. These reductions were offset in part by higher wholesale volumes and regulatory rate increases. Turnover for Infrastructure Division increased by £66 million for the year to £314 million. This was mainly due to increased regulated income from higher sales to third party electricity suppliers. The division also delivered non regulated revenue growth of £28 million for the year, principally due to increased new connections from its Core Utility Solutions joint venture. For the UK Division, turnover increased in the year by £26 million to £2,148 million. This was as a result of higher sales to retail customers, increased generation agency sales in Scotland and exports to Northern Ireland which have offset the impact of low wholesale electricity prices. Turnover for PPM for the year increased by £113 million to £286 million, after a £16 million adverse US dollar translation impact, as the business benefited from the first full year of its long-term power contracts and the growth of its gas storage business.

Discontinued operations' turnover in the year reduced from £791 million to £27 million compared to the prior year.

Cost of sales of £3,227 million were £1,184 million lower than last year, with £479 million of this movement due to discontinued operations. Continuing operations' cost of sales decreased by £705 million to £3,215 million primarily due to lower net power costs in PacifiCorp, offset in part by increased business activity at PPM. **Transmission and distribution costs** of £513 million were in line with the previous year, with lower discontinued operations' costs offset by increased costs for continuing operations due to higher insurance, rates and depreciation, principally in PacifiCorp and the Infrastructure Division. As a result of the demerger of Thus from the group, UK telephony and related expenses are now incurred externally, contributing to the increased costs. **Administrative expenses (including goodwill amortisation)** as shown in Table 12, were £81 million lower than the previous year, which included exceptional restructuring costs for the UK Division of £19 million. Administrative expenses, excluding goodwill amortisation and exceptional items, were £52 million lower

ScottishPower management assesses the underlying performance of its businesses by adjusting UK Generally Accepted Accounting Principles ("GAAP") statutory results to exclude items it considers to be non-recurring or non-operational in nature. In the years presented, these items are goodwill amortisation and exceptional items. Therefore, to provide more meaningful information, ScottishPower has focused its discussion of business performance on the results excluding goodwill amortisation and exceptional items. In accordance with recent guidance from the UK Auditing Practices Board, the UK Listing Authority, and the US Securities and Exchange Commission, where non-GAAP figures are discussed comparable UK GAAP figures have also been discussed and reconciled to the non-GAAP figures. The full statutory results are presented in the "Profit and Loss Account" and in Note 1 "Segmental information" on pages 74 to 76 and on page 78 respectively.

David Nish, Finance Director

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Table 12 – Administrative expenses (£m)	2002/03	2001/02
Administrative expenses	614.5	695.1
Goodwill amortisation	(139.0)	(149.0)
Exceptional items	–	(18.5)
Administrative expenses excluding goodwill & exceptionals	475.5	527.6

than last year, with discontinued operations accounting for £139 million of this movement. Continuing operations' administrative expenses, excluding goodwill amortisation and exceptional items, were £474 million, an increase of £87 million compared to last year. This increase was attributable to higher pension and other employee related costs throughout the group; higher depreciation charges and one-off gains in the previous year in PacifiCorp and increased energy efficiency and customer capture costs in the UK Division. **Depreciation** for continuing operations increased by £33 million to £442 million reflecting the level of capital investment made in the previous year. Depreciation for discontinued operations reduced by £140 million to £6 million for the year.

As shown in Table 13, **group operating profit** increased by £169 million to £946 million for the year to 31 March 2003. Group operating profit from continuing operations was £932 million, £297 million higher than the previous year. Excluding goodwill amortisation and exceptional items, group operating profit from continuing operations increased by £270 million to £1,071 million. Our US operations delivered the majority of the increase. PacifiCorp contributed operating profit excluding goodwill amortisation of £597 million for the year, an increase of £225 million on the previous year. This was mainly due to lower net power costs, rate increases, regulatory recoveries of excess power costs and Transition Plan benefits. The Infrastructure Division's operating profit of £368 million for the year represented an increase of £13 million mainly due to higher regulated revenues and net cost savings. The UK Division's operating profit, excluding goodwill amortisation and exceptional items, of £78 million was consistent with the prior year with the impact of low wholesale prices mitigated by our integrated approach to managing the energy value chain and the benefit from the settlement of the Nuclear Energy Agreement ("NEA") with British Energy ("BE"). PPM reported operating profit of £28 million for the year compared to a loss of £5 million in the previous year, with the full year benefit of assets and contracts acquired in the prior year and the continued progress made during the year in growing its portfolio of assets.

Operating profit from discontinued operations fell by £127 million to £14 million for the year, compared to the prior year.

Goodwill amortisation of £139 million for the year was £10 million lower than for the previous year. This was due to the demerger of Thus in March 2002 and movements in US dollar exchange rates reducing the goodwill charge for PacifiCorp. Operating profit for the year to 31 March 2002 included an exceptional reorganisation charge of £19 million. This arose as a result of restructuring in the UK Division and included severance and related costs. There were no exceptional operating items in the year to 31 March 2003.

The **net interest** charge of £254 million for the year was £156 million lower than the charge for the previous year which included exceptional interest charges of £31 million, resulting from the restructuring of the debt portfolio in advance of the disposal of Southern Water. Excluding exceptional interest, the charge was £125 million lower primarily attributable to substantially lower net debt following the sale of Southern Water and our US dollar hedging strategy.

Profit before tax for the year as shown in Table 14, of £697 million increased by £1,636 million on last year's loss before tax of £939 million. This was primarily due to the exceptional items charged to the profit and loss account in the prior financial year, relating to the disposal of Southern Water and Appliance Retailing. Excluding goodwill amortisation and exceptional items, group profit before tax for the year to 31 March 2003 increased by £269 million (47%) to £836 million, whilst continuing operations' profit before tax, increased by £364 million (79%) to £825 million as a result of improved group operating profit and lower interest charges.

The **tax charge** for the year increased from £83 million to £209 million on profit before tax of £697 million compared to a loss before tax of £939 million in the previous year. The tax charge represented an effective rate of tax (on profits excluding goodwill amortisation and exceptional items) of 25%. This represents an increase from the prior year rate of 21.5%, reflecting a higher proportion of group profits being derived from our US operations, taxed at a rate higher than in the UK. The effective tax rate is calculated by dividing tax, excluding exceptional tax credits, shown in Table 23, by profit before tax, excluding goodwill and exceptional items, shown in Table 14, expressed as a percentage. The effective tax rate calculated on a basis including goodwill amortisation and exceptional items was 30% compared to (9)% in the previous year as a significant proportion of the exceptional items in the prior year were non-taxable.

There were no **exceptional items** in the year. Exceptional items in the previous financial year, including interest and tax, were £1,318

Table 13 – Group operating profit (£m)	Continuing operations		Total operations	
	2002/03	2001/02	2002/03	2001/02
Operating profit	931.9	635.4	945.9	776.6
Goodwill amortisation	139.0	146.6	139.0	149.0
Exceptional items	–	18.5	–	18.5
Operating profit excluding goodwill & exceptionals	1,070.9	800.5	1,084.9	944.1

Table 14 – Profit/(loss) before tax (£m)	Continuing operations		Total operations	
	2002/03	2001/02	2002/03	2001/02
Profit/(loss) before tax	685.8	276.5	696.8	(938.8)
Goodwill amortisation	139.0	146.6	139.0	149.0
Exceptional items before tax	–	37.3	–	1,356.9
Profit before tax excluding goodwill & exceptionals	824.8	460.4	835.8	567.1

million. Included within this total were exceptional charges of £1,308 million related to the disposal of Southern Water, including the write back of goodwill previously taken to reserves, and the disposal of and withdrawal from Appliance Retailing. The other exceptional items in the previous financial year were reorganisation costs of £19 million, interest of £31 million and a tax credit on exceptional items of £39 million.

Net debt reduced in the year by £1,887 million to £4,321 million. Operating cash flow for the year was £1,413 million, an increase of £165 million. This was mainly as a result of improved operational performance in PacifiCorp. Group net capital expenditure in the year was £717 million, a decrease of £512 million, of which £180 million related to continuing operations and £332 million related to discontinued operations. Net inflows from acquisitions and disposals of £1,899 million, including net debt disposed of, mainly represented proceeds from the sale of Southern Water partially offset by PPM's £101 million acquisition of the Katy gas storage facility from Aquila, Inc. Net debt also benefited from the weaker dollar which reduced the sterling value of dollar debt by £290 million. Gearing (net debt/shareholders' funds) decreased to 93% from 131% at 31 March 2002 and net debt/EBITDA excluding exceptionals (earnings before interest, tax, depreciation, goodwill amortisation, deferred income released to the profit and loss account and exceptional items), improved from 4.1 times last year to 2.8 times. EBITDA is a measure of performance often used in bank facilities. EBITDA is shown in Table 15.

Group earnings per share as shown in Table 16 improved from a loss of 53.71 pence for the year to 31 March 2002 to earnings of 26.17 pence for the year to 31 March 2003, an increase of 79.88 pence. Excluding goodwill amortisation and exceptional items, group earnings per share for the year were 33.71 pence, an increase of 7.59 pence (29%).

The full year **dividends** of 28.708 pence per share, were consistent with our stated aim of a 5% annual increase in dividends to 31 March 2003. As stated at the time of announcing the proposed disposal of Southern Water, with effect from the financial year commencing 1 April 2003,

Table 15 – EBITDA excluding exceptionals (£m)

	2002/03	2001/02
Profit/(loss) before interest & tax	**951.1**	(528.6)
Depreciation & goodwill amortisation	**586.2**	717.0
Deferred income released to the profit and loss account	**(18.6)**	(17.8)
Earnings before interest, tax, depreciation, amortisation (EBITDA)	**1,518.7**	170.6
Exceptional items excluding interest & tax	**–**	1,326.1
EBITDA excluding exceptionals	**1,518.7**	1,496.7

Table 16 – Group earnings/(loss) per share (pence)

	Continuing operations		Total operations	
	2002/03	2001/02	**2002/03**	2001/02
Earnings/(loss) per share (EPS)	**25.76**	11.65	**26.17**	(53.71)
EPS impact of goodwill amortisation	**7.54**	7.98	**7.54**	8.11
EPS impact of exceptional items	**–**	1.41	**–**	71.72
EPS excluding goodwill & exceptionals	**33.30**	21.04	**33.71**	26.12

ScottishPower intends to target dividend cover, based on full year earnings excluding goodwill amortisation and exceptional items, in the range 1.5 – 2.0 times and ideally towards the middle of that range. ScottishPower will aim to grow dividends broadly in line with earnings thereafter.

To implement this policy, in the absence of unforeseen circumstances, ScottishPower intends to pay an identical dividend for each of the first three quarters of each year, with the dividend for the fourth quarter representing the balance of the total dividend for each year. In respect of each of the quarters ending 30 June 2003, 30 September 2003 and 31 December 2003, ScottishPower aims to declare a dividend of 4.75 pence per share.

Pensions

As required by the transitional arrangements of Financial Reporting Standard ("FRS") 17, we have disclosed, at 31 March 2003, a deficit of £231 million net of deferred tax for our UK defined benefit pension schemes and a deficit of £214 million ($338 million) net of deferred tax for our US schemes. With the obligation to fund other post-retirement benefits in the US, we have also reported a deficit under FRS 17 at 31 March 2003 of £122 million ($193 million), net of deferred tax. As an indication of the volatility of these valuations, the movement in asset market values in April 2003 would have reduced the deficit for the UK schemes by 40%, and the US schemes by 5%.

The charge in the year for these pension schemes has increased from £7 million to £16 million in the UK, and from £8 million ($11 million) to £26 million ($41 million) in the US. Contribution payments to the UK schemes have recommenced. Achieving regulatory recovery of these costs is a priority and we have a focus on ensuring inclusion of any increased expense in US rate cases and the regulatory Price Control Reviews in the UK.

Business Reviews

PacifiCorp

The key financial information is shown in Table 17.

PacifiCorp turnover was £2,499 million in the year, a reduction of £481 million on the prior year mainly due to lower wholesale electricity prices experienced for most of the year. Excluding the effect of foreign exchange, wholesale revenues were £409 million lower than last year. There was a 63% decrease in average short-term and spot market wholesale prices in the year ($83/MWh to $31/MWh) and lower long-term volumes. This was partially offset by higher short-term and spot volumes and long-term prices. Factors contributing to the lower market price included new generation brought on-line in the western US, the continuing effect of the Federal Energy Regulatory Commission ("FERC") market mitigation, and milder weather and economic conditions affecting demand growth. Residential and commercial revenues increased by £9 million (1.4%) and £10 million (2.1%) respectively, mainly as a result of higher prices and growth in customer numbers, offset by lower average customer usage due to milder weather. Industrial revenues were down by £4 million (0.8%) in the year as the impact of lower volumes, due to a weaker economy, more

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Table 17 – PacifiCorp (£m)	2002/03	2001/02
External turnover	**2,499.4**	2,980.7
Operating profit	**462.8**	229.9
Goodwill amortisation	**133.9**	141.7
Operating profit excluding goodwill	**596.7**	371.6

Table 18 – Infrastructure Division (£m)	2002/03	2001/02
External turnover	**314.0**	247.6
Operating profit	**367.8**	354.9

than offset higher prices and increased irrigation revenues. Other revenue growth, primarily as a result of excess power cost recoveries in Utah and Oregon, were more than offset by lower wheeling revenues and unfavourable foreign exchange movements.

Operating profit for PacifiCorp increased by £233 million to £463 million for the year to 31 March 2003. Operating profit excluding goodwill amortisation for PacifiCorp for the year grew by £225 million to £597 million, as a result of regulatory rate increases and recoveries of excess power costs of £80 million, significantly lower net power costs of £257 million and continued progress in the delivery of Transition Plan benefits of £64 million in the year. These improvements were partly offset by lower transmission revenues of £19 million from reduced use of the transmission system by third parties, higher depreciation charges of £25 million, risk mitigation and project costs of £41 million, insurance, pensions and healthcare costs of £46 million, and one-off gains in the previous year and foreign exchange of £45 million.

Infrastructure Division

The key financial information is shown in Table 18.

External turnover within the Infrastructure Division increased by £66 million for the year to £314 million. Infrastructure Division's sales are mainly internal to our UK Division however, the impact of competition on our home markets has resulted in an increase in regulated income from third party electricity suppliers of £38 million. Other revenue growth of £28 million has also been delivered from external non regulated sales, principally due to increased new connections from its Core Utility Solutions joint venture.

Infrastructure Division reported operating profit of £368 million for the year, an increase of £13 million on last year. Higher regulated income of £9 million and net cost reductions of £18 million were partly offset by higher depreciation, operational rates, insurance and pension costs of £14 million.

UK Division

The key financial information is shown in Table 19.

UK Division turnover increased by £26 million to £2,148 million for the year. Although wholesale market prices were down in the year, agency turnover increased by £17 million due to volume growth from 4,656 GWh to 6,262 GWh (34%) and exports to Northern Ireland increased by £19 million, following the first full year of trading. Total sales in England & Wales, including exports, decreased by £13 million due to adverse prices, partly offset by favourable volumes which increased by 1,461 GWh to 11,840 GWh. Wholesale gas volumes increased in the year by 1.4 billion therms, however, lower prices resulted in sales revenues dropping by £10 million on last year. Retail supply turnover grew by £11 million with higher retail gas sales of £52 million and increased turnover from out-of-area customer gains of £53 million, partially offset by loss of market share and lower sales prices in our home areas which reduced turnover by £94 million. Other revenues increased by £2 million in the year. Customer numbers have increased to 3.65 million in the year. Retention of home area residential customers stands at 61%.

Operating profit for the UK Division increased by £18 million to £73 million for the year to 31 March 2003, mainly due to last year's results including a £19 million exceptional reorganisation charge. Operating profit, excluding goodwill amortisation and exceptional items, was £78 million for the year, £1 million lower compared to the previous year. Net energy margins have performed strongly, increasing by £15 million before higher depreciation, costs to capture and investment in energy efficiency schemes of £12 million and increased pension costs of £4 million. The impact of lower wholesale electricity prices has been mitigated by our integrated approach to managing the energy value chain whereby our own electricity production is extensively matched to our customer demand across Great Britain. The renegotiation of the NEA with BE at a market related price has delivered a benefit of approximately £25 million in the current year and provides a hedge against revenues which have been impacted by lower wholesale prices.

PPM

The key financial information is shown in Table 20.

Turnover for PPM for the year increased by £113 million to £286 million, after a £16 million adverse US dollar translation impact, as the business benefited from the first full year of its Klamath and Stateline long-term power contracts and growth of its gas storage business, including the Katy gas storage facility acquired in December 2002.

PPM reported an operating profit of £28 million for the year, compared to a loss of £5 million last year. The growth in operating profit for the year was due to the increased contribution from long-term sales contracts and gas storage activities and optimisation benefits of £53 million, partly offset by higher depreciation charges and other operating costs of £17 million to support business growth and the benefit from settlement of a £3 million contract in the prior year.

Table 19 – UK Division (£m)	2002/03	2001/02
External turnover	**2,147.8**	2,121.4
Operating profit	**73.0**	55.3
Goodwill amortisation	**4.9**	4.9
Exceptional items	**–**	18.5
Operating profit excluding goodwill & exceptionals	**77.9**	78.7

Table 20 – PPM (£m)	2002/03	2001/02
External turnover	**285.9**	173.1
Operating profit/(loss)	**28.3**	(4.7)
Goodwill amortisation	**0.2**	–
Operating profit/(loss) excluding goodwill	**28.5**	(4.7)

Table 21 – Interest (£m)	2002/03	2001/02
Interest	**254.3**	410.2
Exceptional interest	**–**	(30.8)
Interest excluding exceptional interest	**254.3**	379.4
Foreign exchange (loss)/gain	**(0.5)**	6.9
Interest excluding exceptional interest & foreign exchange (loss)/gain	**253.8**	386.3

Discontinued Operations

Discontinued operations consisted of Southern Water, Appliance Retailing and Thus for the year to 31 March 2002 and Southern Water for the year to 31 March 2003. The disposal of Southern Water was completed on 23 April 2002 and turnover and operating profit generated in the period prior to disposal were £27 million and £14 million respectively. The disposal of and withdrawal from Appliance Retailing was completed by 31 March 2002 and the Thus demerger was completed in March 2002.

In the year, discontinued operations' turnover decreased from £791 million to £27 million, compared to the prior year. Of this reduction, £403 million was due to Southern Water, £229 million to Thus and £132 million to Appliance Retailing.

Discontinued operations' operating profit for the year reduced by £127 million to £14 million, with Southern Water profits decreasing by £202 million, partly offset by reduced losses in Thus and Appliance Retailing of £66 million and £9 million respectively.

Interest, Tax, Earnings and Dividends

Interest

The net interest charge for the year as shown in Table 21 of £254 million was £156 million lower than the charge for the previous year which included exceptional interest of £31 million. The exceptional interest principally related to the restructuring of the group debt portfolio prior to the sale of Southern Water. Excluding exceptional interest, the charge was £125 million lower. This was attributable to substantially lower net debt following the sale of Southern Water, together with lower US interest rates, a change in the fixed/variable debt profile and favourable exchange benefits from the weaker US dollar. The lower interest charge also included a benefit of £46 million associated with our dollar hedging strategy. Underlying UK interest, excluding the benefit of our dollar hedging strategy, was £104 million, a reduction of £110 million on last year. The interest charge for the US increased by £24 million to £196 million, principally as a result of higher underlying debt. Pre-exceptional interest, adjusted for foreign exchange gains and losses, as shown in Table 21, is covered by profit on ordinary activities, before interest, excluding goodwill amortisation and exceptional items shown in Table 22, 4.3 times for the year to 31 March 2003, improved from 2.5 times for the previous year. Interest is covered by profit on ordinary activities 3.7 times, up from (1.3) times in the previous year.

Tax

The tax charge as shown in Table 23 of £209 million is £126 million higher than the charge for the prior year. The main reasons for the increase are the tax credit on exceptional items of £39 million included in the prior year charge, higher pre-tax profits in the current financial year due to improved operational performance and a higher effective rate of tax. The effective tax rate increased to 25%, from the prior year rate of 21.5% on profits excluding goodwill amortisation and exceptional items. The increase was due to a greater proportion of group profits being derived from our US operations, which are subject to a higher rate of tax. The effective tax rate benefits from prior period tax planning, following agreement with the tax authorities on treatment of specific items and the financial structure of the group. The tax charge was £209 million on profit before tax of £697 million, compared to a tax charge of £83 million on a loss before tax of £939 million in the previous year. Going forward, the effective tax rate is expected to increase in the financial year to 31 March 2004 due to an increased proportion of US profits and lower benefits from prior period tax planning.

Earnings and Dividends

Key group earnings/(loss) per share and profit/(loss) after tax information is shown in Table 16 and Table 24 respectively.

Profit after tax increased by £1,510 million to £488 million. This increase was due to exceptional items in the prior year of £1,318 million, improved operational performance in our continuing operations in the current financial year and lower interest charges, partly offset by the profit reduction from our discontinued operations. Excluding exceptional items and goodwill amortisation, profit after tax increased by £182 million to £627 million with profit after tax for continuing operations, improving by £226 million to £619 million. With a weighted average 1,844 million shares in issue during the year, earnings per share improved from a loss of 53.71 pence for the year to 31 March 2002 to earnings of 26.17 pence in the year

Table 22 – Profit/(loss) before interest (£m)	2002/03	2001/02
Profit/(loss) before interest	**951.1**	(528.6)
Goodwill amortisation	**139.0**	149.0
Exceptional items (excluding interest & tax)	**–**	1,326.1
Profit before interest excluding goodwill & exceptionals	**1,090.1**	946.5

Table 23 – Tax (£m)	2002/03	2001/02
Tax	**209.0**	83.2
Exceptional tax credit	**–**	38.8
Tax excluding exceptional tax credit	**209.0**	122.0

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to 31 March 2003, due to the reasons mentioned above. Excluding goodwill amortisation and exceptional items, group earnings per share for the year were 33.71 pence, an increase of 7.59 pence and 33.30 pence for continuing operations, an increase of 12.26 pence.

Total cash dividends per share for the year of 28.708 pence were consistent with our stated aim of a 5% annual increase in dividends to 31 March 2003. Dividends in the prior year included a 'dividend in specie' of £437 million arising on the demerger of Thus on 19 March 2002.

Group **net assets** reduced by 2% in the year, from £4,818 million to £4,712 million with our balance sheet hedging strategy significantly mitigating the adverse impact of the weaker US dollar. The impact on net assets of the Southern Water disposal in April 2002 was offset by lower net debt following receipt of the sale proceeds.

Fixed assets of £11,600 million were £2,977 million lower than the previous year, mainly due to the disposal of Southern Water. Intangible assets, which represent goodwill arising on acquisition, reduced by £378 million, comprising £139 million amortised to the profit and loss account and £252 million of exchange movements on the translation of PacifiCorp goodwill, offset by an increase of £12 million arising on the acquisition of the Katy gas storage facility. Tangible assets reduced by £2,624 million mainly due to the disposal of Southern Water's fixed assets of £2,475 million. Other movements were due to gross capital expenditure of £787 million and the acquisition of the Katy gas storage facility, offset by depreciation charged to the profit and loss account of £447 million and exchange movements on the translation of US balances. Investments increased by £25 million mainly due to the purchase of our own shares, which are held in trust for employee related share schemes.

Current assets, excluding short-term bank and other deposits, increased by £333 million from 31 March 2002. Increases to debtors were principally due to valuations of forward contracts associated with our balance sheet hedging strategy and growth of our PPM business, partly offset by a reduction as a result of the disposal of Southern Water and exchange movements. **Creditors** due within one year, excluding loans and other borrowings, were £166 million lower than at 31 March 2002. The disposal of Southern Water, prior period US tax settlements, lower regulatory liabilities as a consequence of the Utah settlement on excess power costs and exchange movements were the main reasons for the reduction.

Provisions for liabilities and charges were £492 million lower in the year with deferred tax £389 million lower, principally due to the sale of Southern Water. Other provisions are also lower due to utilisation during the year, together with the effect of foreign exchange. **Deferred income**, which principally represents grants and customer contributions in our US and UK regulated businesses, increased by £8 million.

Total Recognised Gains and Losses

The Statement of Total Recognised Gains and Losses combines the profit or loss for the year together with other gains and losses taken directly to reserves as required under UK GAAP. Total recognised gains for the year to 31 March 2003 were £424 million, compared to losses for the prior year of £1,006 million, which included £1,318 million of net exceptional charges (after interest and tax). Excluding the net exceptional charges, total recognised gains increased by £112 million compared to last year, as a result of £152 million growth in profit for the financial year, offset by the net impact of foreign exchange movements and hedging of the group's results and net assets. The weaker dollar exchange rates during the year resulted in unfavourable exchange movements of £387 million, which were largely mitigated by the benefits of £358 million, less tax of £29 million, arising from our strategy to hedge foreign currency net assets.

Table 24 – Profit/(loss) after tax (£m)

	Continuing operations		Total operations	
	2002/03	2001/02	**2002/03**	2001/02
Profit/(loss) after tax	**480.2**	220.9	**487.8**	(1,022.0)
Goodwill amortisation	**139.0**	146.6	**139.0**	149.0
Exceptional items including interest & tax	**–**	26.0	**–**	1,318.1
Profit after tax excluding goodwill & exceptionals	**619.2**	393.5	**626.8**	445.1

Capital Expenditure, Cash Flow and Net Debt

Capital Expenditure

In the year to 31 March 2003, the group invested £818 million in its asset base, with 42% invested for growth. Of this, £717 million related to net capital expenditure, a decrease of £512 million, of which £180 million related to continuing operations and £332 million related to discontinued operations. In addition, £101 million was invested on the acquisition of the Katy gas storage facility.

PacifiCorp

Capital expenditure in PacifiCorp decreased by £1 million to £368 million, with £111 million invested in network growth and new generation assets, including the gas fired peaking plant at Gadsby. A further £211 million was invested in network and generation refurbishment, and £46 million on other projects, including information technology. Net capital expenditure is expected to increase in 2003/04 as a result of upgrades to transmission and distribution networks to improve system reliability, increased generation overhauls and higher mining expenditure. All expenditure prudently incurred is expected to earn its regulatory rate of return, and contribute to an increased rate base for PacifiCorp.

Infrastructure Division

The Infrastructure Division invested net capital expenditure of £230 million during the year, an increase of £32 million compared to the year to 31 March 2002. Of this, £141 million was invested in network refurbishment, £68 million on network expansion and £21 million on other capital projects. Net capital expenditure in 2003/04 is expected to increase modestly, with investment concentrated on the regulatory asset base, delivering the regulated rate of return. In particular, further investment will be undertaken in our overhead network modernisation programme.

UK Division

During the year the UK Division invested £68 million in capital projects, a £41 million reduction on the previous year. Of this, £10 million was invested in windfarms, and £19 million expanding our gas storage assets and completing the Daldowie Private Finance Initiative project, which manufactures waste derived fuel. A further £19 million was invested in generation plant overhaul and refurbishment and £20 million on other projects including business transformation and information technology. In 2003/04, subject to obtaining planning permission, net capital expenditure for the UK Division could rise substantially as a result of our commitment to increase our windfarm capacity. In addition, we plan to invest in gas storage development and upgrades to generation assets required to maintain our generating capacity. All investments are projected to have returns significantly in excess of the cost of capital and enhance earnings.

PPM

PPM's net capital expenditure for the year was £36 million, a decrease of £170 million on last year, which included investment to complete the Klamath Falls and West Valley generation projects. In the year to 31 March 2003, the division invested £10 million completing its thermal generation assets and £20 million on wind power, including the purchase of the operational Klondike windfarm in eastern Oregon and commencement of construction of the Moraine windfarm in Minnesota. PPM also invested £6 million in gas storage assets and in information technology projects. In addition, PPM acquired the Katy gas storage facility for £101 million in December 2002. In 2003/04 PPM's net capital spend is expected to increase, primarily as a result of the construction of new windfarms and development opportunities including Moraine and Flying Cloud, which are expected to deliver favourable rates of return and enhance earnings.

Discontinued Operations

During the year, Southern Water incurred net capital expenditure of £15 million, prior to its sale in April 2002.

Cash Flow and Net Debt

Net cash inflow from operating activities of £1,413 million was £165 million higher than the prior year, with improved operational performance in PacifiCorp offsetting the reduction in operating cash flows from discontinued operations. Capital expenditure and financial investment outflows reduced by £443 million, reflecting the reduction in capital expenditure due to our discontinued operations and lower PPM capital spend. Interest, tax and dividend payments in the year amounted to £1,012 million, £52 million higher than the prior year. Net receipts from acquisitions and disposals of £1,899 million including net debt disposed of, mainly represented the proceeds from the sale of Southern Water, partially offset by PPM's £101 million acquisition of the Katy gas storage facility from Aquila, Inc. As a result, net debt at 31 March 2003 was £4,321 million, £1,887 million lower than at 31 March 2002, with the benefit of a weaker dollar also reducing the sterling value of dollar debt.

Overview of the Year to March 2002

Group turnover for the year to 31 March 2002 decreased by £35 million to £6,314 million, compared to the year to 31 March 2001. Continuing operations' turnover increased by £113 million to £5,523 million, with PacifiCorp contributing revenues of £2,981 million, a fall of £126 million on 2000/01 due to significant reductions in wholesale market prices, partly offset by rate increases and foreign exchange benefits. Infrastructure Division turnover was £248 million, an increase of £24 million on 2000/01 due to higher regulatory sales volumes and prices. Turnover in the UK Division rose by £58 million to £2,121 million as a result of higher gas retail and wholesale revenues and increased output from new generating plant, partially offset by lower electricity retail sales due to lower volumes and prices. PPM turnover increased by £157 million to £173 million primarily due to new gas revenues.

Turnover for discontinued operations fell by £148 million to £791 million following our exit from Appliance Retailing, which resulted in lower group revenues year-on-year of £185 million, offset in part by year-on-year revenue growth from Southern Water of £7 million and from Thus of £30 million.

Cost of sales for 2001/02 fell by £59 million to £4,411 million compared to 2000/01, which included £62 million of exceptional reorganisation costs incurred by PacifiCorp. Cost of sales, excluding exceptional items, were £3 million higher than 2000/01 at £4,411 million, with continuing operations' costs increasing by £83 million to £3,920 million. PacifiCorp's cost of sales excluding exceptional items, were less than the year to 31 March 2001 as lower purchase volumes and prices were partly offset by foreign exchange movements. Costs within the UK Division increased mainly due to gas purchase costs for Rye House power station, which was acquired in March 2001. The growth of PPM also contributed to higher costs. Cost of sales for discontinued operations fell by £80 million to £491 million, mainly due to our exit from Appliance Retailing. **Transmission and distribution costs** of £513 million were £54 million lower than the year to 31 March 2001, which included £45 million of exceptional reorganisation costs incurred by PacifiCorp. Pre-exceptional transmission and distribution costs fell by £9 million as a result of lower net operating costs in the Infrastructure Division. **Administrative expenses (including goodwill amortisation)** increased by £53 million to £695 million, with £26 million of this increase attributable to higher exceptional items and higher goodwill amortisation in 2001/02. Administrative expenses, excluding goodwill amortisation and exceptional items, increased by £27 million, with increased depreciation charges in both the UK and US and foreign exchange movements partly offset, by lower discontinued operations' costs, due to our exit from Appliance Retailing. **Depreciation** for continuing operations increased by £46 million to £409 million, reflecting investment in new generation in the US and the acquisition of Rye House in the UK. Depreciation for discontinued operations increased from £118 million to £146 million.

Table 25 – Group operating costs (£m)

	Cost of sales		Transmission and distribution costs		Administrative expenses	
	2001/02	2000/01	**2001/02**	2000/01	**2001/02**	2000/01
Operating costs	**4,410.8**	4,469.5	**512.6**	566.7	**695.1**	641.6
Goodwill amortisation	**–**	–	**–**	–	**(149.0)**	(127.6)
Exceptional items	**–**	(62.1)	**–**	(45.1)	**(18.5)**	(13.5)
Operating costs excluding goodwill & exceptionals	**4,410.8**	4,407.4	**512.6**	521.6	**527.6**	500.5

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Table 25 provides key financial information on group operating costs.

Group operating profit for the year to 31 March 2002 as shown in Table 26 improved by £55 million to £777 million as a result of exceptional Transition Plan costs incurred in the year to 31 March 2001, partly offset by increased goodwill amortisation charges and lower operational profits in the year to 31 March 2002. Excluding goodwill amortisation and exceptional items, group operating profit reduced by £26 million to £944 million, with operating profit from continuing operations falling by £15 million to £801 million. The challenging conditions experienced in the UK energy market and the price premium borne under the NEA resulted in a fall of £44 million in the UK Division's profit excluding goodwill amortisation and exceptional items. However, this was substantially offset by the benefits derived from Infrastructure Division's operating cost saving programme, where operating profit increased by £14 million, and by the recovery in PacifiCorp's operating performance in the US. PacifiCorp reported a year-on-year profit improvement of £25 million, excluding goodwill amortisation and exceptional items, after incurring some $300 million of additional excess net power costs early in 2001/02, as a result of the unprecedented fall in wholesale price levels in the western US market. Operating profit for PPM reduced by £9 million to a loss of £5 million as a result of new costs associated with the start-up of the business.

Operating profit for our discontinued operations decreased by £11 million to £141 million, as a result of a £5 million fall in Southern Water's profit and a £6 million increase in Thus' losses for the period to 19 March 2002, the date of the demerger.

Exceptional items of £1,326 million (before interest and tax) were recognised in the year to 31 March 2002. These exceptional items related to the disposal of Southern Water, UK reorganisation costs, and a charge of £120 million associated with our disposal of and withdrawal from Appliance Retailing. An exceptional charge of £121 million was incurred in 2000/01 in respect of the costs of implementing the PacifiCorp Transition Plan.

Table 26 – Group operating profit (£m)

	Continuing operations		Total operations	
	2001/02	2000/01	**2001/02**	2000/01
Operating profit	**635.4**	569.4	**776.6**	721.9
Goodwill amortisation	**146.6**	125.2	**149.0**	127.6
Exceptional items	**18.5**	120.7	**18.5**	120.7
Operating profit excluding goodwill & exceptionals	**800.5**	815.3	**944.1**	970.2

Table 27 – PacifiCorp (£m)

	2001/02	2000/01
External turnover	**2,980.7**	3,106.2
Operating profit	**229.9**	101.3
Goodwill amortisation	**141.7**	124.8
Exceptional items	**–**	120.7
Operating profit excluding goodwill & exceptionals	**371.6**	346.8

Business Reviews

PacifiCorp

The key financial information is shown in Table 27.

Turnover in PacifiCorp for 2001/02 fell by £126 million to £2,981 million compared to 2000/01. Excluding the effect of foreign exchange, residential and commercial revenues increased by £35 million or 6% and £26 million or 5% respectively, mainly as a result of price increases and customer growth partly offset by lower volumes due to weather and the impact of demand side management programmes. Industrial revenues were down by £18 million as a result of a 5% decrease in volumes due to lower irrigation usage and the impact of US economic conditions. A 22% decrease in average short-term firm and spot market wholesale prices ($107/MWh to $83/MWh) and lower long-term volumes significantly impacted wholesale revenues in the year. Partially offsetting this was an increase in short-term firm and spot volumes, leaving turnover from wholesale activities down by £275 million or 19% on the year ended 31 March 2001. Other revenue growth mainly came from increased wheeling revenues and favourable foreign exchange movements.

For the year to 31 March 2002, PacifiCorp's operating profit increased by £129 million to £230 million, despite the impact of additional excess power costs of $300 million incurred in the first six months. Excluding goodwill amortisation and exceptional items, PacifiCorp's operating profit increased by £25 million to £372 million. Increases in regulatory rates charged to customers and other revenues of £72 million and continued Transition Plan savings of £24 million, were offset by higher depreciation on regulated assets of £25 million, costs of strategic and risk initiatives of £45 million and other movements of £1 million including higher net power costs and foreign exchange movements.

Infrastructure Division

The key financial information is shown in Table 28.

The Infrastructure Division reported external turnover of £248 million for 2001/02, an increase of £24 million compared to 2000/01, due to higher regulated income. Although the Infrastructure Division's sales were still mainly internal to the UK Division, customer retention in our home markets had declined due to competition and, as a result, external sales increased as distribution and transmission use of system charges were recovered from third party suppliers.

In the year to 31 March 2002, operating profit for the Infrastructure Division improved by £14 million to £355 million, as it continued to deliver financial upsides from its restructuring programme, with operating cost reductions of £39 million achieved during the year. These savings helped offset the impact of regulatory price reductions experienced in the first half of 2001/02 and a gain on business disposals reported within the 2000/01 results of £18 million.

Table 28 – Infrastructure Division (£m)

	2001/02	2000/01
External turnover	**247.6**	223.7
Operating profit	**354.9**	341.3

Table 29 – UK Division (£m)

	2001/02	2000/01
External turnover	**2,121.4**	2,063.8
Operating profit	**55.3**	122.3
Goodwill amortisation	**4.9**	0.4
Exceptional items	**18.5**	–
Operating profit excluding goodwill & exceptionals	**78.7**	122.7

Table 30 – PPM (£m)

	2001/02	2000/01
External turnover	**173.1**	16.1
Operating (loss)/profit	**(4.7)**	4.5

UK Division

The key financial information is shown in Table 29.

Turnover for the UK Division grew by £58 million to £2,121 million for the year to 31 March 2002. Turnover was £106 million higher due to sales from Rye House power station. As a result of the decrease in wholesale market prices, agency turnover fell by £7 million despite volume growth from 3,874 GWh to 4,656 GWh and export sales in England & Wales reduced by £16 million, with volumes 22 GWh lower at 4,539 GWh. Sales from exports via the Northern Ireland Interconnector of 356 GWh improved turnover by £8 million in the year. Turnover also increased due to higher wholesale gas sales. Supply turnover was down by £60 million on the year to 31 March 2001, with higher retail gas sales of £48 million and increased turnover from out-of-area customer gains of £54 million, offset by loss of market share and lower prices in our home areas which reduced turnover by £162 million.

Operating profit in the UK Division fell by £67 million to £55 million, with £23 million of this decline attributable to increased goodwill amortisation of £4 million and exceptional costs of £19 million incurred during 2001/02 following restructuring within the division. Operating profit excluding goodwill amortisation and exceptional items decreased by £44 million to £79 million, primarily due to the impact of falling wholesale market prices and the burden of the NEA. As a result of these market pressures, generation margins were £63 million lower than in 2000/01. Partially offsetting this was an improvement in electricity and gas retail margins of £29 million after the increased cost of acquiring new customers. The results for the year ended 31 March 2002 also included the New Electricity Trading Arrangements ("NETA") system error of £10 million.

PPM

The key financial information is shown in Table 30.

PPM's turnover increased by £157 million to £173 million for the year to 31 March 2002 due to new revenues from the start-up operations of the Klamath and Stateline plants.

PPM reported an operating loss of £5 million in year to 31 March 2002, compared with a profit of £4 million in the year to 31 March 2001 as a result of increased costs associated with the start-up of the business.

Discontinued Operations

The key financial information is shown in Table 31.

Southern Water

For the year to 31 March 2002, turnover from Southern Water increased by £7 million to £430 million, as a result of regulatory price increases and customer growth, partly offset by the move to measured supply and surface water rebates. Southern Water's operating profit of £216 million fell by £5 million compared to the prior year, as a result of new capital obligation costs and increased depreciation charges, offset in part by cost savings. The sale of Southern Water was announced in March 2002 and was completed in April 2002.

Appliance Retailing

The decision to withdraw from Appliance Retailing was announced in June 2001 and resulted in an exceptional charge of £120 million being recognised in 2001/02. The disposal of part of the business to Powerhouse Retail was finalised in October 2001 and the closure of the remaining operations was completed by the end of 2001/02. Appliance Retailing reported turnover of £132 million, down £185 million on 2000/01, and an operating loss of £9 million, consistent with the year to 31 March 2001.

Thus

The demerger of Thus was completed on 19 March 2002. The financial results of the group included the results of Thus up to this date. Turnover for Thus to 19 March 2002 was £30 million higher than the prior year at £229 million mainly due to increased data and telecoms revenues. Thus incurred an operating loss of £66 million, an increase of £6 million on the year to 31 March 2001.

Interest, Tax, Earnings and Dividends

Interest

The net interest charge for the year to 31 March 2002, as shown in Table 32, increased by £77 million to £410 million and included an exceptional charge of £31 million, principally related to the restructuring of the group debt portfolio as a consequence of the decision to sell Southern Water. Excluding exceptional charges, net interest was £379 million, an increase of £46 million on 2000/01, primarily as a result of higher levels of debt in both the UK and US. The UK interest charge, excluding exceptional interest, rose by £30 million to £214 million and the charge for the US increased by £32 million to £172 million. Also included within

Table 31 – Southern Water, Appliance Retailing and Thus (£m)

	Southern Water		Appliance Retailing		Thus	
	2001/02	2000/01	2001/02	2000/01	2001/02	2000/01
External turnover	**429.9**	422.4	**132.3**	317.7	**229.1**	199.4
Operating profit/(loss)	**216.3**	221.6	**(9.0)**	(8.7)	**(66.1)**	(60.4)

Table 32 – Interest (£m)

	2001/02	2000/01
Interest	**410.2**	332.9
Exceptional interest	**(30.8)**	–
Interest excluding exceptional interest	**379.4**	332.9

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interest was a £7 million benefit due to foreign exchange hedging.

Tax

The tax charge as shown in Table 33 for the year to 31 March 2002 was £83 million, £12 million lower than in 2000/01. Excluding the exceptional tax credit of £39 million, the tax charge was £122 million, £19 million lower than in 2000/01. The exceptional tax credit in 2001/02 related to the exceptional charges incurred during the year following the disposal of and withdrawal from our Appliance Retailing business and restructuring of the debt portfolio following the decision to sell Southern Water. The group's effective tax rate benefited from the release of provisions made in prior years following agreement with the tax authorities on the treatment of specific items. Although corporate tax rates were higher in the US than in the UK, the financial structure of the group resulted in a reduction in the amount of overseas tax payable. The tax charge was £83 million on a loss before tax of £939 million, compared to a tax charge of £95 million on profit before tax of £380 million in 2000/01.

Earnings and Dividends

Key (loss)/profit after tax and group (loss)/earnings per share information is shown in Table 34 and Table 35 respectively.

The loss after tax for the year to 31 March 2002 amounted to £1,022 million, compared to a profit of £285 million for 2000/01, with the fall in profits mainly due to higher exceptional charges associated with the sale of Southern Water including a £738 million write back of goodwill. A pre-tax exceptional charge of £121 million was included in the 2000/01 year's results in respect of PacifiCorp Transition Plan implementation costs. Excluding the impact of goodwill amortisation and exceptional items, profit after tax decreased by £42 million to £445 million primarily as a result of lower UK Division operating profit and increased interest charges. With a weighted average 1,838 million shares in issue during 2001/02, the loss per share was 53.71 pence compared to earnings per share of 16.80 pence in the year to 31 March 2001. Excluding goodwill amortisation and exceptional items, earnings per share were 26.12 pence for the year compared to 27.86 pence in the year to 31 March 2001.

Table 33 – Tax (£m)	**2001/02**	2000/01
Tax	**83.2**	95.2
Exceptional tax credit	**38.8**	45.9
Tax excluding exceptional tax credit	**122.0**	141.1

The total cash dividends per share of 27.34 pence were 5% higher than the 2000/01 dividends of 26.04 pence. The increase was consistent with our stated aim of growing dividends by 5% per annum, for each of the three financial years to 31 March 2003. Dividends for the year also included a 'dividend in specie' of £437 million arising on the demerger of Thus on 19 March 2002.

Total Recognised Gains and Losses

The statement of total recognised gains and losses combines the profit or loss for the year together with other gains and losses taken directly to reserves. Total recognised losses for 2001/02 were £1,006 million, compared to gains for 2000/01 of £801 million. The fall in recognised gains of £1,807 million was primarily due to the net exceptional charges (after interest and tax) of £1,318 million in the year to 31 March 2002 and the strengthening in dollar exchange rates from $1.60/£ at 31 March 2000 to $1.42/£ at 31 March 2001, which resulted in exchange movements of £493 million being recognised in the year to 31 March 2001.

Treasury

The treasury focus during the year continued to be to minimise interest payments and manage risk. The group continues to ensure that borrowings are financed from a variety of competitive sources and that committed facilities are available both to cover uncommitted borrowings and to meet the financing needs of the group in the future. Cash requirements are subject to seasonal variations. A further focus was to maximise the return on investment of the proceeds from the sale of Southern Water while avoiding excessive credit risk.

Since the merger with PacifiCorp the group's external borrowings have been sourced in two separate pools. In the UK, Scottish Power UK plc ("SPUK") continues to be the finance vehicle for the majority of the UK activities. In the US, predominantly all of the debt is issued by PacifiCorp, the regulated utility, and is entirely denominated in US dollars.

In both cases regulatory constraints apply to financing activities. Scottish Power plc ("SP plc") is not permitted to borrow from its subsidiaries with the exception of certain intermediate holding companies in the US ownership chain and is currently financed by way of dividends and external debt. During the year SP plc's two £50 million bilateral 364 day committed facilities were renewed. Both were undrawn at the year-end. PacifiCorp's principal debt limitations are a 60% debt to defined capitalisation test and an interest coverage covenant (EBITDA/interest) of 2 times contained in its principal credit agreements. PacifiCorp has been in compliance with these covenants throughout the year to 31 March 2003. In addition, under the Public Utility Holding Company Act of 1935 there are restrictions on the ability of group companies to lend or borrow from one another.

Table 34 – (Loss)/profit after tax (£m)	**2001/02**	2000/01
(Loss)/profit after tax	**(1,022.0)**	284.5
Goodwill amortisation	**149.0**	127.6
Exceptional items including interest & tax	**1,318.1**	74.8
Profit after tax excluding goodwill & exceptionals	**445.1**	486.9

Table 35 – Group (loss)/earnings per share (pence)	**2001/02**	2000/01
(Loss)/earnings per share (EPS)	**(53.71)**	16.80
EPS impact of goodwill amortisation	**8.11**	6.97
EPS impact of exceptional items	**71.72**	4.09
EPS excluding goodwill & exceptionals	**26.12**	27.86

In the UK, financing activities have been heavily influenced by the disposal of Southern Water. No new long-term financing was put in place during the year and all short-term debt was repaid following receipt of the sale proceeds.

There have been no new issues under ScottishPower's Euro-Medium Term Note Programme, established in November 1997. Cumulative issues outstanding under the programme now total some $2,700 million against a programme limit of $7,000 million. SP plc and SPUK are the issuers under the programme; no issues have been made since SP plc was added as an issuer as part of the annual update in 2001.

Total borrowings from the European Investment Bank ("EIB") amount to £199 million, following the repayment of £129 million as a result of the sale of Southern Water as agreed under the terms of the sale and purchase agreement with First Aqua Limited.

During the year SPUK has not added to its index-linked liabilities. The current total of £275 million has been created through a combination of issues of direct index-linked debt and through swapping fixed rate debt into index-linked. This represents around 12% of the UK debt portfolio in recognition of the fact that a large percentage of UK revenues are linked to inflation.

SPUK cancelled its £1,000 million revolving credit facility following receipt of the proceeds of the sale of Southern Water in April 2002. No facility has been required through the rest of the year, as liquidity has been provided by the funds received from the sale. It is possible that SP plc will wish to raise new bank finance during the financial year to 31 March 2004. Borrowings under this facility would be used for general corporate purposes.

The UK distribution, transmission and generation subsidiaries have provided upstream guarantees to support the majority of SPUK's debt that existed at 1 October 2001, following their incorporation to comply with the Utilities Act 2000. As at 31 March 2003 the total amount of debt guaranteed by the three companies amounted to £2,210 million. New debt issued by SPUK after 1 October 2001 is not permitted to benefit from the guarantee of SPUK's subsidiaries, SP Distribution Limited and SP Transmission Limited.

During the year to 31 March 2003, PacifiCorp issued no new long-term debt. Scheduled repayments of $144.6 million were made during the year. PacifiCorp has an effective shelf registration statement for up to $1.1 billion of long-term debt of which $800 million has been authorised to be issued by the applicable regulatory commissions, subject to certain conditions. Any such issuance would be subject to market conditions. PacifiCorp has debt maturities out as far as 2037.

In June 2002 PacifiCorp extended its expiring bank facilities and now has two facilities: a $300 million three year facility maturing in June 2005 and a $500 million 364 day facility maturing in June 2003. Negotiations are currently underway to replace the $500 million facility. These two bank facilities are provided by a group of core bank relationships that is regarded as common to both SPUK and PacifiCorp.

The group continues to manage its interest rate exposure by maintaining a percentage of its debt at fixed rates of interest. This is done either directly by means of fixed rate debt issues or by use of interest and cross-currency swaps to convert variable rate debt into fixed rate debt and fixed/variable non-functional currency denominated debt into fixed rate functional currency debt. The use of derivative financial instruments relates directly to underlying existing and anticipated indebtedness. The group treasury operates strictly within policies set out by the Board and is subject to regular examination by internal audit. The group's policy is to maintain at least 50% of its anticipated year-end debt at fixed interest rates.

In recognition of the long life of the group's assets and anticipated indebtedness and to create financial efficiencies, the group has entered into borrowing agreements for periods out to 2039. In addition, SPUK entered into derivative contracts to a notional value of £100 million, which may result in fixed interest rates of 4.25% for periods out to 2030 on this notional amount. At 31 March 2003, the interest rate on some 71% (UK 60%, US 80%) of debt was fixed.

The weighted average period to maturity of year-end fixed debt and swaps was 12 years (UK 11 years, US 13 years).

During 2002/03, the group maintained its policy of hedging a substantial part of the foreign currency value of its US business. Notional US$ debt has been created by the use of cross-currency interest rate swaps, cross-currency basis swaps and foreign currency forward contracts. The current amount of these hedges is $5,000 million representing approximately 84% of the group's US net assets.

Both SPUK and PacifiCorp have credit ratings published by Standard & Poor's Ratings Group, Moody's Investors Service and The Fitch Group. SPUK's long-term ratings for guaranteed debt, pre 1 October 2001, are now A-, A2 and A from the three agencies respectively. SPUK's long-term ratings for unguaranteed debt are A-, A3 and A from the three agencies respectively. PacifiCorp's senior secured debt is rated A, A3 and A, and its unsecured debt is rated BBB+, Baa1 and A-. Short-term ratings of A-2, P-2 and F-1 apply to both companies. PacifiCorp Group Holdings, a subsidiary of PacifiCorp Holdings Inc., has slightly lower ratings although they remain investment grade. Ratings from Standard & Poor's and Moody's are on negative outlook. These security ratings are not recommendations to buy, sell or hold securities. The ratings are subject to change or withdrawal at any time by the respective credit rating agencies. Each credit rating should be evaluated independently of any other rating.

Any adverse change to credit ratings of group companies could negatively impact on their ability to access capital markets and on the rates of interest that they would be charged for such access. The EIB debt within SP Transmission Limited and SP Distribution Limited contains credit downgrade language, which does not constitute default, but means that, should the ratings of SP Transmission Limited or SP Distribution Limited fall, the EIB will be entitled to ask for additional security in the form of a guarantee acceptable to the EIB. PacifiCorp has no rating downgrade triggers within its debt instruments, although interest rates on loans under their bank facilities and commitment fees on the facilities would increase with a ratings downgrade. The EIB

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debt within SP Manweb plc contains financial covenants relating to interest cover and gearing of SP Manweb plc. Following the cancellation of SPUK's £1,000 million revolving credit facility there are no other financial covenants within the UK businesses' debt.

The proceeds of the sale of Southern Water were partially utilised to repay SPUK's short-term borrowings and to redeem the EIB debt of Southern Water as agreed under the sale and purchase agreement with First Aqua Limited. The remaining cash received has been utilised on an ongoing basis to fund the existing business and to repay debt as it matures. The investment of surplus cash is undertaken to maximise the return within Board approved policies which govern the ratings criteria, maximum investment and the maturity with any one counterparty. Counterparties are required to have a short-term rating of at least A-1, P-1 or F-1 from the three major rating agencies.

Quantitative and Qualitative Disclosures about Market Risk

Market Rate Sensitive Instruments and Risk Management

The following discussion about the group's risk management activities includes "forward-looking" statements that involve risk and uncertainties. Actual results could differ materially from those projected in the forward-looking statements.

The Tables in Note 20 to the Accounts (pages 93 to 98) summarise the financial instruments, including derivative instruments and derivative commodity instruments, held by the group at 31 March 2003, which are sensitive to changes in interest rates, foreign exchange rates and commodity prices. The group uses interest rate swaps, forward foreign exchange contracts and other financially settled derivative instruments to manage the primary market exposures associated with the underlying assets, liabilities and committed transactions. Financially settled "weather" derivatives are used to manage risk created by adverse weather circumstances affecting commodity demand and operations. The group also uses commodity derivatives (that can be settled financially or by delivery of the physical commodity) to further manage its commodity price and volumetric risks. These instruments are employed to reduce risk by creating offsetting financial exposures or by directly hedging such commodity exposures.

Such physically or financially settled instruments (as above) held by the group match offsetting physical transactions and are not held for financial trading purposes in the vast majority of instances. Similarly, such weather derivatives are not held for financial trading purposes. Subject to risk management controls, businesses may enter into financial transactions that are designed to reduce earnings volatility and improve the return on assets and are structured around the physical assets of the group. ScottishPower Energy Trading (Agency) Limited is authorised by the UK Financial Services Authority to undertake investment activity in the energy markets as an Energy Market Participant.

Risk Management

Overview

The main financial risks faced by the group are interest rate risk, inflation risk, insurance risk, foreign exchange risk, liquidity risk, credit risk, energy price risk and energy volumetric risk (created by varying demand due to weather and economic circumstances and varying supply due to forced outages or other physical supply and logistics limitations). The Board has reviewed and agreed policies for managing each of these risks as summarised below. In order to mitigate the financial risks identified, the Board has endorsed the use of derivative financial instruments including swaps, both interest rate and cross-currency, swaptions, options, forward-rate agreements, financial and commodity forward contracts, commodity futures, commodity options and weather derivatives.

Energy Risk Management

Energy risk is governed globally by the Group Energy Risk Committee ("GERC"), chaired by the Finance Director with membership from the divisions and Independent Risk Management. The GERC defines, and the ScottishPower Board approves, the group risk management policies and limits as well as the UK and the US risk policies and limits. These policies and limits, as well as the GERC approved procedures, are designed to create consistent risk measurement, monitoring and management standards throughout the group. The monitoring and management of the level of exposure covered is handled by the businesses, with full oversight by a corporate risk management function, reporting to the Finance Director independent of the businesses. The businesses with commodity exposure are authorised to manage this exposure using approved products, policies and limits. These businesses report monthly to a local risk committee, as well as the GERC.

Market exposures are quantified and controlled using a number of different risk measures. These include Value-at-Risk ("VaR") methods for earnings volatility control. VaR is a statistically based measure of the potential financial loss on a price exposure position over a defined period to a given level of confidence. VaR computations for the group's energy commodity portfolios are based on a historical simulation technique. This technique utilises historical price changes over a specified period to simulate potential forward price curves in the energy markets to estimate the potential unfavourable impact of price changes in the portfolio positions scheduled to settle within the following 24 months. The quantification of market risk using VaR provides a consistent measure of risk across the group's continually changing portfolio. VaR represents an estimate of reasonably possible changes in fair value that would be measured on its portfolio assuming hypothetical movements in future market rates and is not necessarily indicative of actual results that may occur. Changes in markets inconsistent with historical trends or assumptions used, could cause actual results to exceed predicted limits.

The group's VaR computations for its energy commodity portfolio utilise several key assumptions, including a 99% confidence level for the resultant price changes and a holding period of five days. The calculation includes short-term derivative commodity instruments held for trading and balancing purposes, the expected resource and demand obligations from the group's long-term contracts, the expected generation levels from the group's generation assets and the expected retail and wholesale load levels. Optionality embedded within the group's long-term contracts, generation assets and other derivative instruments with option characteristics within the energy portfolio are treated in the historical simulation of VaR as static expected or delta positions through the simulation process. Expected positions and option deltas are recalculated on a daily basis to determine the portfolio position changes due to changes in market prices.

Commodity price exposure is defined as the possibility that a change in the price of the commodity will alter the proceeds of sales or the costs of purchases. Commodity volume risk is defined as the possibility that a change in the supply of or demand for the commodity will create an unexpected imbalance and change the requirements for the commodity. Additional risk measures are applied to quantify risks beyond the confidence intervals defined in the VaR methodology and determine volumetric risks in physical positions.

Credit Risk Management

The role of the group's credit function is to set consistent standards for assessing and quantifying (scoring) the credit risk induced by contractual obligations of wholesale trading partners and industrial and commercial clients. A group credit committee provides an umbrella oversight to ensure a consistent approach to counterparty rating and limit management is adopted across the group and oversees the allocation of limits to those entities that overlap both the US and the UK markets. This group credit committee ensures that each individual business is subject to concentration rules that prevent misallocation of credit risk amongst counterparties. The UK and the US credit committees provide local expertise to understanding the credit environment in each geographic location. All decisions are supported by rigorous measurement and reporting of credit exposures and the use of credit rating models. Credit approvals are subject to regular and/or event driven reviews. Despite mitigation efforts, defaults by counterparties occur from time to time.

Treasury Management

The group treasury function is authorised to conduct the day-to-day treasury activities of the group within policies set out by the Board. The group treasury function reports regularly to the Board, through the monthly group performance and risk report and is subject to internal audit.

Interest Rate Risk Management

The group continues to access funding opportunities in the major global markets in a range of currencies at both fixed and floating rates of interest, using derivatives where appropriate, to convert the obligations and payments into fixed or floating rate functional currency.

The exposure to fluctuating interest rates is managed by either issuing fixed or floating rate debt or using a spectrum of financial instruments to create the desired fixed/floating mix. The group's policy is to maintain at least 50% of its anticipated year-end debt at fixed interest rates. At 31 March 2003, 71% (2002 66%) of the group's debt was either issued as fixed or converted to fixed rates using interest rates swaps.

All treasury transactions are undertaken to manage the risks arising from underlying activities and no speculative trading is undertaken. The counterparties to these instruments generally consist of financial institutions and other bodies with good credit ratings, that is "AA" rated by at least one of Standard & Poor's, Moody's or Fitch. Although the group is potentially exposed to credit risk in the event of non-performance by counterparties, such credit risk is controlled through credit rating reviews of the counterparties and by limiting the total amount of exposure to any one party to levels agreed by the Board. The group does not believe that it is over exposed to any material concentration of credit risk.

Inflation Risk Management

In recognition of the fact that a large percentage of UK revenues are linked to inflation, SPUK maintains part of its debt portfolio in index-linked liabilities. This is done either through issues of debt or through swapping fixed rate debt into index-linked. Currently index-linked liabilities total £275 million, which represents around 12% of the UK debt portfolio.

Insurance Risk Management

Where cost effective, the group maintains a wide-ranging insurance programme providing financial protection, predominately against catastrophic risks. In March 2002 the group experienced increases in the cost of insurance and a loss of limited aspects of coverage as a result of changes in the global insurance market. There continues to be upward pressure on insurance costs and a comprehensive review of our insurance strategy during the last twelve months has helped to mitigate this pressure but some classes of insurance continue to increase significantly in cost. These increases do not, however, have a material impact on the overall business performance.

Foreign Exchange Risk Management

Translation Risk

The group has currently hedged $5,000 million, representing approximately 84% of its US net assets, as a strategic hedge of the investment. Liabilities have been created, for periods out to 2011, by means of cross-currency interest rate and basis swaps and by means of forward foreign exchange contracts. The resulting interest flow in US dollars acts as a natural partial hedge to the translation of US profits but these profits are further hedged, up to four years into the future, by means of forward sales of US dollars. All foreign currency derivative contracts are subject to the same controls as interest rate derivatives referred to above.

Transaction Risk

Transactions denominated in a foreign currency are not numerous in the group. Where they arise as a result of imports of capital or other goods denominated in foreign currencies the exposure is hedged as soon as it arises.

Liquidity Risk Management

The group's policy is to arrange that debt maturities are spread over a wide range of dates, thereby ensuring that the group is not subject to excessive refinancing risk in any one year. The group had undrawn committed revolving credit facilities totalling £606 million, as at 31 March 2003, which provide backstop liquidity should the need arise. The majority of these facilities are at PacifiCorp. Liquidity in the UK is currently supported by the remaining cash held from the proceeds of the Southern Water sale.

Energy Price Risk Management

UK Division

NETA was introduced in England & Wales on 27 March 2001, replacing the previous 'Pool' mechanism for the sale and purchase of wholesale power in England & Wales. NETA provides for a bilateral wholesale market, with suppliers, traders and

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generators trading firm physical forward contracts for bulk electricity supply. In addition to trading to directly manage our market price exposure in the England & Wales market, the UK Division also manages its price exposure arising from sales within the Scottish market by trading forward contracts.

The balancing mechanism, operated from 1 hour ahead of real-time (gate closure) up to real-time by the National Grid Company, is used to manage the grid system on a second-by-second basis. Market participants can participate actively in this market through the submission of bids and offers to vary their output as a generator or demand as a customer. The mechanism also provides for calculation and settlement of imbalance charges arising from the differences between parties' contract positions and their actual physical energy flows.

The UK Division has procedures in place to minimise exposure to uncertain balancing mechanism prices, that is, the possibility that the UK Division will face high charges for shortfalls in physical energy or receive low revenues for surplus physical energy. These procedures involve the UK Division entering into bilateral contracts for the sale and purchase of energy across a range of time periods to minimise exposure to the balancing mechanism. In addition, our portfolio of flexible generating assets in England and Scotland can be used up to gate closure to minimise further this exposure and also to attract premium income from providing flexible power to the balancing mechanism.

The UK Division has also entered into longer-term (in excess of one year) arrangements to protect against longer-term volatility of power prices. The time periods covered by these longer-term arrangements are reviewed on a continuous basis to provide the desired level of price stability.

The UK Division also has procedures in place to minimise exposure to gas price variations. In a similar manner to our power price exposure management strategy, gas price risk is managed through a combination of longer-term contracts and shorter-term trading contracts with flexible delivery profiles, certain derivative financial instruments and through the use of flexibility within our portfolio of power generating and gas storage assets.

The UK Division mitigates its exposure to coal price risk through the use of a combination of financial and physical contracts.

Cover against volatile spot prices is built up on a rolling basis through the year and, at 31 March 2003, a significant proportion of the UK Division's exposure to power, gas and coal price variations for the following financial year have been mitigated.

The UK Division measures the market risk in its energy portfolio daily utilising ScottishPower's VaR approach (described above), as well as other measurements of net position, and monitors its portfolio exposure to market risk in comparison to established thresholds. The UK Division also measures its open positions at price risk in terms of volumes at each delivery location for each forward time period.

As at 31 March 2003, the UK Division's estimated potential five-day unfavourable impact on fair value of the energy commodity portfolio over the next 24 months was £11.8 million, as measured by the VaR computations described above, compared to £16.2 million as at 31 March 2002. The average daily VaR (five-day holding) for the year ended 31 March 2003 was £11.3 million. The maximum and minimum VaR measured during the year ended 31 March 2003 were £16.7 million and £7.7 million, respectively. Changes in markets inconsistent with historical trends or assumptions used could cause actual results to exceed predicted limits. Market risks associated with derivative commodity instruments held for purposes other than hedging and balancing the UK Division's energy commodity portfolio were not material as of 31 March 2003.

PacifiCorp

PacifiCorp's market risk to commodity price change is primarily related to its fuel and electricity purchases and sales arising principally from its electricity supply obligation in the US. As in the UK this risk to price change is subject to fluctuations in weather, economic growth and generation resource availability which impacts supply and demand. Risk limits are established to govern energy purchases and sales. Price risk is managed principally through the operation of its generation and transmission system in the western US and through its wholesale energy purchase and sales activities. Physically settled contracts are used to hedge PacifiCorp's excess or shortage of net electricity for future months.

While PacifiCorp plans for resources to meet its current and expected retail and wholesale load obligations, resource availability, price volatility and volumetric volatility around both load and resources may materially impact the power costs to PacifiCorp and profits from surplus power sales in the future. Prices paid by PacifiCorp to provide certain load balancing resources to supply its load may exceed the amounts it receives through retail rates and wholesale prices. Prices received by PacifiCorp to dispose of resources made excess by changes in retail and wholesale load obligations may fall short of the amounts PacifiCorp has paid for such resources. In the 2000/01 power crisis, regulatory approval of deferred accounting treatment under US GAAP for these excess costs mitigated a portion of this price risk to the extent that recovery mechanisms were implemented. Recovery of amounts allowed by the commissions are scheduled to continue through 2003/04 and for some years beyond. However, such deferred accounting treatment was granted in the extraordinary circumstance of the power crisis and subsequent use of this mechanism is not automatic and is not guaranteed for future use.

PacifiCorp continues to actively manage commodity price volatility and reduce exposure. These steps included adding to its generation portfolio and entering into transactions that help to shape PacifiCorp's system resource portfolio, including physical hedging products and financially settled weather (temperature-related) derivative instruments that reduce volume and price risk on days with weather extremes. In addition, hydrogeneration hedges have been put in place for the next three years to limit volume and price risks associated with Pacific Northwest hydrogeneration availability.

PacifiCorp measures the market risk in its natural gas and electricity portfolio daily utilising ScottishPower's VaR approach (described above), as well as other measurements of net position, and monitors its portfolio exposure to market risk in comparison to established thresholds. PacifiCorp also measures its open positions at price risk in terms of volumes at each delivery location for each forward time period.

At 31 March 2003, PacifiCorp's estimated potential five-day unfavourable impact on fair value of the natural gas and electricity commodity portfolio over the next 24 months was £11.0 million, as measured by the VaR computations described above, compared to £11.4 million at 31 March 2002. The average daily VaR (five-day holding) for the year ended 31 March 2003 was £12.4 million. The maximum and minimum VaR measured during the year ended 31 March 2003 were £22.3 million and £6.1 million, respectively. Changes in markets inconsistent with historical trends or assumptions used could cause actual results to exceed predicted limits. Market risks associated with derivative commodity instruments held for purposes other than hedging and balancing PacifiCorp's energy commodity portfolio were not material at 31 March 2003.

PPM

PPM Energy, Inc. ("PPM") is ScottishPower's competitive US energy company, which is primarily focused on providing environmentally responsible energy products to wholesale customers. The strategic priorities of PPM are to grow its renewable/thermal energy portfolio and gas storage/hub services business and optimise returns through the integration of assets, trading and commercial activities. PPM's strategy is to match the output of PPM assets and long-term sales obligations. Imbalances between asset positions and long-term sales are managed via wholesale energy purchases and sales activities.

PPM owns the output from several wind generation facilities located throughout the US. Associated with the wind energy production are Renewable Energy Certificates ("RECs") that represent the environmental attributes of the renewable energy. Consistent with its overall portfolio strategy, PPM balances its wind asset position with long-term forward sales and some spot sales of both energy and renewable attributes. Wind generation resource availability and variability is subject to price changes for that portion of the output that is not committed to long-term fixed price bilateral contracts. Imbalances in the REC portfolio are subject to price changes in the REC market.

PPM owns or manages over 800 MW of thermal capacity on its own behalf and on the behalf of third parties. Substantially all of this capacity is committed to long-term contracts, with the imbalance being subject to generation resource availability and the relationship of fuel costs to electricity prices (or "spark spread"). PPM manages short-term and daily imbalance through real-time markets. PPM's risk in this business is principally if counterparties fail to perform in accordance with contracts and if PPM's generation assets fail to perform at reasonable levels.

Finally, PPM also owns natural gas storage facilities in Canada and Texas. PPM's strategy is to develop a natural gas storage/hub services business that will own and operate facilities across North America. The business model employed by PPM is designed to minimise commodity risk and provide a service for a fee for both long-term and short-term hub services. Hub services is a generic term used to describe various fee-based transactions carried out by the storage operator such as parking and loaning of gas. As a result, the hub services business is subject to the risks associated with the operations and marketing of the storage facilities and services.

Subject to market risk limitations delegated by ScottishPower and oversight by the corporate risk management group, PPM will occasionally maintain or create open positions in response to (or in anticipation of) long-term origination or development transactions creating exposure to market price movements. Therefore, PPM actively participates in the wholesale power and gas markets to manage its open positions. In addition, PPM engages in point-of-view energy management activities in accordance with strict limits approved by the business unit risk committee (chaired by the group risk management function). Control and performance metrics for such activities are tracked daily.

PPM measures the market risk in its natural gas and electricity portfolio daily utilising ScottishPower's VaR approach (described above), as well as other measurements of net position, and monitors its portfolio exposure to market risk in comparison to established thresholds. PPM also measures its open positions at price risk in terms of volumes at each delivery location for each forward time period.

At 31 March 2003, PPM's estimated potential five-day unfavourable impact on fair value of the energy commodity portfolio over the next 24 months was £2.4 million, as measured by the VaR computations described above, compared to £5.3 million at 31 March 2002. The average daily VaR (five-day holding) for the year ended 31 March 2003 was £2.4 million. The maximum and minimum VaR measured during the year ended 31 March 2003 were £6.2 million and £0.9 million, respectively. Changes in markets inconsistent with historical trends or assumptions used could cause actual results to exceed predicted limits. Market risks associated with derivative commodity instruments held for purposes other than hedging and balancing PPM's energy commodity portfolio were not material at 31 March 2003.

Contractual Obligations and Commercial Commitments

The group enters into various financial obligations and commitments in the normal course of business. Contractual financial obligations are considered to comprise known future cash payments that the group is required to make under contractual arrangements in place at 31 March 2003. Commercial commitments are defined as those obligations of the group which only become payable if certain pre-defined events occur.

Table 36 details the group's contractual obligations at 31 March 2003.

The 'Loans and other borrowings' figures in Table 36 are stated at book value at 31 March 2003.

The group has commercial commitments in respect of surety bonds in the US. At 31 March 2003 the total amount that may be payable by the group in respect of these commitments is estimated to be £32.7 million, of which £18.8 million would be payable within one year, £13.3 million

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Table 36 – Contractual obligations at 31 March 2003 (£m)

	Within 1 year	Between 1 and 3 years	Between 3 and 5 years	After 5 years	Total
Loans and other borrowings (including overdrafts)	208.4	525.0	347.2	3,887.5	**4,968.1**
Finance leases	0.1	0.2	0.6	16.6	**17.5**
Operating leases	10.9	16.0	5.8	17.8	**50.5**
Power purchase commitments	1,292.8	1,701.4	1,154.2	3,330.5	**7,478.9**
Capital commitments	99.3	5.2	2.8	20.1	**127.4**
Other firm commitments	53.1	95.9	88.7	29.4	**267.1**
Total contractual obligations at 31 March 2003	1,664.6	2,343.7	1,599.3	7,301.9	**12,909.5**

between one and three years, £0.4 million between three and five years and £0.2 million after five years.

The actual net capital expenditure incurred by the group for the year ended 31 March 2003 was £717 million. The group's estimated net capital expenditure, which is subject to continuing review and revision, for the year ended 31 March 2004 is within the range of £800 million – £900 million.

Fair Value of Derivative Contracts

Table 37 details the changes in the fair value of the group's energy related and treasury derivative contracts which are subject to the requirements of Statement of Financial Accounting Standard ("FAS") No. 133 'Accounting for Derivative Instruments and Hedging Activities'. FAS 133 requires, for the purposes of US GAAP, all derivatives, as defined by the standard, to be marked to market value, except for those which qualify for specific exemption under the standard or associated guidance, for example those defined as normal purchases and normal sales. The derivatives which are marked to market value in accordance with FAS 133 include only certain of the group's commercial contractual arrangements as many of these arrangements fall outside the scope of FAS 133. In addition, the effect of changes in the fair value of certain long-term contracts entered into to hedge PacifiCorp's future retail energy resource requirements, which are being marked to market value in accordance with FAS 133, are subject to regulation in the US and are therefore deferred as regulatory assets or liabilities pursuant to FAS 71 'Accounting for the Effects of Certain Types of Regulation'. The FAS 133 liability relating to PacifiCorp of £319.9 million, as set out in Table 37, is offset under US GAAP by a US regulatory net asset of £320.6 million.

The forward market price curve is derived using daily market quotes from independent energy brokers and reporting services, as well as direct information received from third party offers and actual transactions entered into by the group. For certain contracts extending past 2006, the forward prices are derived using a fundamentals model (cost-to-build approach) that is updated as warranted, at least quarterly, to reflect changes in the market. Short-term energy contracts, without explicit or embedded optionality, are valued based upon the relevant portion of the forward market price curve or quoted market prices. Energy contracts with explicit or embedded optionality and long-term energy contracts are valued by separating each contract into its component physical and financial forward, swap and option legs. Forward and swap legs are valued against the appropriate market curve. The optionality is valued using a modified Black-Scholes model or a stochastic simulation (Monte Carlo) approach. Each option component is modelled and valued separately using the appropriate forward market price curve. Interest rate swaps and forward-rate agreements are valued by calculating the present value of future cash flows estimated using forward market curves. Interest rate swaptions are valued using the market yield curve and implied volatilities at the period end. Cross-currency swaps are valued by adding the present values of the two legs of each swap: present values are calculated by discounting the future cash flows, estimated using the appropriate forward market curve for that currency, at the appropriate market discount rates. Forward foreign exchange contracts are valued using market forward exchange rates at the period-end.

Table 37 – Fair value of energy related and treasury derivative contracts (£m)

	PacifiCorp	PPM	UK Division	Treasury	Total
Fair value of contracts outstanding at 1 April 2002	(355.3)	(52.7)	62.5	31.3	(314.2)
Cumulative effect of accounting change	(2.1)	230.7	-	-	228.6
Contracts realised or otherwise settled during the year	70.1	(19.3)	4.3	(85.4)	(30.3)
Changes in fair values attributable to changes in valuation techniques and assumptions	124.8	-	(7.2)	-	117.6
Other changes in fair value	(192.8)	27.3	(19.0)	427.9	243.4
Foreign exchange movement	35.4	(12.4)	-	-	23.0
Fair value of contracts outstanding at 31 March 2003	(319.9)	173.6	40.6	373.8	**268.1**

	Within 1 year	Between 1 and 3 years	Between 3 and 5 years	After 5 years	Total
Prices actively quoted	14.3	57.0	35.5	13.2	**120.0**
Prices based on models and other valuation methods	93.4	76.6	59.0	(80.9)	**148.1**
Total	107.7	133.6	94.5	(67.7)	**268.1**

In Table 37, the cumulative effect of accounting change represents the cumulative effect on US GAAP earnings of adopting revised FAS 133 guidance effective from 1 April 2002 issued by the Derivatives Implementation Group ("DIG") under Revised Issue C15 'Normal Purchases and Normal Sales Exception for Certain Option-Type Contracts in Electricity' and Issue C16 'Applying the Normal Purchases and Normal Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract'. This new guidance had the effect of including an increased number of the group's contracts within the scope of FAS 133.

Changes in fair values attributable to changes in valuation techniques and assumptions reflect changes in the fair value of mark-to-market values as a result of applying refinements in valuation modelling techniques.

Other changes in fair value reflect changes in underlying economic fundamentals which impact on the value of the derivative including commodity price risk, which is influenced by contract size, term, location and unique or specific contract terms; movements in foreign exchange rates which impact the value of cross-currency swaps and movements in interest rates which impact on the value of interest rate swaps, forward-rate agreements and cross-currency swaps.

Pension Arrangements

As required by the transitional arrangements for FRS 17, we have disclosed, at 31 March 2003, a deficit of £231 million net of deferred tax for our UK defined benefit pension schemes and a deficit of £214 million ($338 million) net of deferred tax for our US schemes. With the obligation to fund other post-retirement benefits in the US, we have also reported a deficit under FRS 17 at 31 March 2003 of £122 million ($193 million), net of deferred tax. As an indication of the volatility of these valuations, the movement in asset market values in April 2003 would have reduced the deficit for the UK schemes by 40%, and the US schemes by 5%.

FRS 17 prescribes detailed rules for the calculation of scheme assets and liabilities and indicates the net accounting surplus or deficit that would exist on an ongoing basis using market conditions at the balance sheet date. As noted above, fluctuations in investment conditions can result in significant volatility in funding levels.

Pension schemes are however, managed over the long-term. Investment and liability decisions are based on underlying actuarial and economic circumstance with the intention of making sure that the schemes have sufficient assets to meet liabilities as they fall due, rather than meeting accounting requirements.The company and the trustees of the group's schemes are currently reviewing the investment strategy on the asset/liability matching of the group's schemes.

The charge in the year for these pension schemes has increased from £7 million to £16 million in the UK, and from £8 million ($11 million) to £26 million ($41 million) in the US. Contribution payments to the UK schemes have recommenced. Achieving regulatory recovery of these costs is a priority and we have a focus on ensuring inclusion of any increased expense in US rate cases and the regulatory Price Control Reviews in the UK.

Creditor Payment Policy and Practice

In the UK, the group's current policy and practice concerning the payment of its trade creditors is to follow the Better Payment Practice Code to which it is a signatory. Copies of the Code may be obtained from the Department of Trade and Industry or from the website www.payontime.co.uk.

The group's policy and practice is to settle terms of payment when agreeing the terms of the transaction, to include the terms in contracts and to pay in accordance with its contractual and legal obligations. The group's creditor days at 31 March 2003 for its UK businesses and US business were 22 days and 40 days, respectively.

Going Concern

The directors confirm that the company remains a going concern on the basis of its future cash flow forecasts and has sufficient working capital for present requirements.

Dividend Policy

As stated at the time of announcing the proposed disposal of Southern Water, with effect from the financial year commencing 1 April 2003, ScottishPower intends to target dividend cover, based on full year earnings excluding goodwill amortisation and exceptional items, in the range 1.5 – 2.0 times and ideally towards the middle of that range. ScottishPower will aim to grow dividends broadly in line with earnings thereafter.

To implement this policy, in the absence of unforeseen circumstances, ScottishPower intends to pay an identical dividend for each of the first three quarters of each year, with the dividend for the fourth quarter representing the balance of the total dividend for each year. In respect of each of the quarters ending 30 June 2003, 30 September 2003 and 31 December 2003, ScottishPower aims to declare a dividend of 4.75 pence per share.

Accounting Developments

The UK Accounting Standards Board ("ASB") did not issue any new standards during the year ended 31 March 2003. FRS 17 'Retirement benefits', issued in November 2000, requires certain disclosures relating to pensions and other post-retirement benefits which have been included in this year's Accounts. In November 2002, the ASB issued an amendment standard to defer the mandatory application of the measurement rules within FRS 17 until 2005/06. Had the measurement rules within FRS 17 been applied during the financial year 2002/03, the group's operating profit would have increased by £5 million, finance costs would have reduced by £31 million and profit before tax would have increased by £36 million. Net assets and reserves at 31 March 2003 would have been reduced by £479 million.

In January 2003, the ASB issued a non-mandatory Statement on the Operating and Financial Review. The group has complied with the principles set out in this statement as a matter of best practice.

The ASB issued a number of exposure drafts during the past year. Most of those exposure drafts have been issued simultaneously with exposure drafts issued by the International Accounting Standards Board ("IASB") on the same topics. This is in line with the ASB's objective to highlight new international proposals for UK companies and to facilitate a smooth convergence of UK and international standards. In June 2002, the European Union ("EU") adopted its Regulation which requires that the group accounts of listed companies in the EU should, from 2005/06, be drawn up on the basis of adopted International Accounting Standards ("IAS"). IAS continue to evolve and, at present, it is not possible to determine precisely what impact the new accounting regime will have on the group's reported results. However, it is likely that the proposals would, if implemented, have a material effect on how UK companies report their financial results. In particular, a greater degree of volatility in reported profits is likely

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to be one consequence of the proposed rules, especially in relation to accounting for financial instruments, many of which are likely to be marked to market value at each balance sheet date, irrespective of the fact that they may be held for commercial risk mitigation purposes or to achieve a balanced energy position. The IASB's project on reporting financial performance is in its early stages of development but has the potential to alter radically the way in which UK listed companies present their financial results. The group continues to monitor the output of the relevant accounting regulatory bodies in the UK, the US and internationally.

The Urgent Issues Task Force committee of the ASB issued a number of accounting pronouncements during the year. These pronouncements had no material impact on the group's results and financial position.

The group's results are also presented in accordance with US GAAP. The group's results under US GAAP have been impacted materially by the implementation of revised guidance relating to FAS 133. This guidance, issued by the DIG, comprised Revised Issue C15 'Normal Purchase and Normal Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity' and Issue C16 'Applying the Normal Purchases and Normal Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract'. The cumulative adjustment to profit under US GAAP on adoption of this guidance was an increase to profit of £141.1 million, net of tax. On 1 April 2002 the group also implemented FAS 142 'Goodwill and Other Intangible Assets'. This standard prohibits the amortisation of goodwill and requires that goodwill be tested annually for impairment and in interim periods if certain events occur which indicate that the carrying value of the goodwill may be impaired. The group performed its annual goodwill impairment review as of 1 October 2002 and determined that goodwill recognised under US GAAP is not impaired. During the year the group implemented the Financial Accounting Standards Board ("FASB") Interpretation 45 ("FIN 45") 'Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others: an Interpretation of FASB Statements No. 5, 57 and 107 and rescission of FASB Interpretation No. 34'. The adoption of FIN 45 did not have a material effect on the group's results or financial position under US GAAP. The group's guarantees, as defined in FIN 45, are disclosed in Note 35 to the Accounts. FAS 146 'Accounting for Costs Associated with Exit or Disposal Activities' applies to exit or disposal activities initiated after 31 December 2002 and did not have a material effect on the group's results or financial position under US GAAP. The FASB issued FAS 148 'Accounting for Stock-Based Compensation – Transition and Disclosure' which provides alternative methods of transition for a change to the fair value based method of accounting for stock-based employee compensation. The group has adopted the disclosure requirements of this standard and these are set out in Note 35 to the Accounts. In June 2002, the Emerging Issues Task Force ("EITF") of the FASB reached a partial consensus on Issue No. 02-3 'Accounting for Contracts Involved in Energy Trading and Risk Management Activities'. The partial consensus requires all mark-to-market gains and losses arising from energy trading activities (whether realised or unrealised) accounted for under EITF Issue No. 98-10 'Accounting for Contracts Involved in Energy Trading and Risk Management Activities' be presented on a net basis in the income statement and that the gross transaction volume be disclosed for those energy trading contracts that are physically settled. EITF Issue No. 02-3 did not have a material effect on the group's results or financial position under US GAAP. The group adopted FAS 143 'Accounting for Asset Retirement Obligations' on 1 April 2003. The group estimates that the cumulative post-tax effect of adopting FAS 143 will increase net income under US GAAP by £1.7 million, which will be recorded primarily as a US net regulatory liability if PacifiCorp receives regulatory approval. The group adopted FAS 145 'Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections' on 1 April 2003. The adoption of this standard had no impact on the group's results and financial position under US GAAP. FAS 149 'Amendment of Statement 133 on Derivative Instruments and Hedging Activities' amends and clarifies financial reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities and is effective for contracts entered into or modified after 30 June 2003. The group is currently evaluating the effect that FAS 149 will have on its results and financial position under US GAAP. In January 2003 the FASB issued FIN 46 'Consolidation of Variable Interest Entities' which requires existing unconsolidated variable interest entities to be consolidated by their primary beneficiaries in certain circumstances. FIN 46 applies immediately to variable interest entities created after 31 January 2003 and applies to accounting periods beginning after 15 June 2003 in respect of variable interest entities created before 1 February 2003. The adoption of this interpretation is not expected to have a material impact on the group's results and financial position under US GAAP.

Critical Accounting Policies – UK GAAP

The group Accounts are prepared in accordance with UK GAAP. This requires the directors to adopt those accounting policies which are most appropriate for the purpose of the Accounts giving a true and fair view. The group's material accounting policies are set out in full on pages 70 to 73. In preparing the Accounts in conformity with UK GAAP, the directors are required to make estimates and assumptions that impact on the reported amounts of revenues, expenses, assets and liabilities. Actual results may differ from these estimates. Certain of the group's accounting policies have been identified as critical accounting policies by considering which policies involve particularly complex or subjective decisions or assessments and these are discussed below. The discussion below should be read in conjunction with the full statement of Accounting Policies. The critical accounting policies have been discussed with the group's senior management and the Audit Committee.

UK GAAP – Turnover

Income from the sale of energy includes an estimate of the number and value of units supplied to customers between the most recent measurement and the year-end. This is estimated based on the energy delivered each month compared to the amounts billed to customers. Estimates of unbilled units and debt are reviewed regularly to ensure that income is recognised only where there is sufficient reliability of the estimates.

UK GAAP – Provision for Doubtful Debts
The group estimates its provision for doubtful debts relating to trade debtors by a combination of two methods. Firstly, specific amounts are evaluated where information is available that a customer may be unable to meet its financial obligations. In these circumstances, assessment is made based on available information to record a specific provision against the amount receivable from that customer to adjust the carrying value of the debtor to the amount expected to be collected. In addition, a provision for doubtful debts within the portfolio of other debtors is made using historical experience and ageing analysis to estimate the provision required to reduce the carrying value of trade debtors to their estimated recoverable amounts. This process involves the use of assumptions and estimates which may differ from actual experience. Management of debt recovery is a key priority for the group and the estimates of provisions for doubtful debts are reviewed regularly.

UK GAAP – Depreciation, Amortisation and Impairment
Tangible fixed assets, other than land, are generally depreciated on the straight line method over their estimated operational lives. Operational lives are estimated based on a number of factors including the expected usage of the asset, expected physical deterioration and technological obsolescence. Goodwill on acquisitions prior to 31 March 1998 was written off to reserves. Goodwill on subsequent acquisitions is amortised on a straight line basis over its estimated useful economic life. The estimated useful economic life of the goodwill on acquisition of PacifiCorp is 20 years. This is based on an assessment of the long-term nature of PacifiCorp's electricity business and the potential impact of change to the regulatory regime for utility companies in the US. In certain circumstances, accounting standards require tangible fixed assets and goodwill to be reviewed for impairment. When a review for impairment is conducted, the recoverable amount is assessed by reference to the net present value of the expected future cash flows of the relevant Income Generating Unit ("IGU"), or disposal value if higher. The discount rate applied is based on the group's weighted average cost of capital with appropriate adjustments for the risks associated with the IGU. Estimates of cash flows are consistent with management's plans and forecasts. Estimation of future cash flows involves a significant degree of judgement.

UK GAAP – US Regulatory Assets
US regulatory assets are only recognised where they comprise rights or other benefits which have arisen as a result of past transactions or events which have created an obligation to transfer economic benefits to a third party. The interpretation of these principles requires assessment of regulatory events to determine when an asset should be recognised. The application of this policy has generally led to US regulatory assets only being recognised when reflected in customers' bills.

UK GAAP – Environmental Provisions
Provision is made for liabilities relating to environmental obligations when the related environmental disturbance occurs, based on the net present value of estimated future costs. Estimates of environmental liabilities are principally based on reports prepared by external consultants. The ultimate cost of environmental disturbance is uncertain and there may be variances from these cost estimates, which could affect future results. At 31 March 2003, the group had provided £85.2 million for environmental obligations.

UK GAAP – Decommissioning and Mine Reclamation Provisions
Provision is made for the decommissioning of major capital assets where the costs are incurred at the end of the lives of the assets. Similarly, closure and reclamation costs are a normal consequence of mining with the majority of the expenditure incurred at the end of the life of the mine. Although the ultimate cost to be incurred is uncertain, estimates have been made of the respective costs based on local conditions and requirements. At 31 March 2003, the group had provided £83.3 million for decommissioning costs and £72.3 million for mine reclamation costs.

UK GAAP – Tax
The group's tax charge is based on the profits for the year and tax rates in force. Estimation of the tax charge requires an assessment to be made of the potential tax treatment of certain items which will only be resolved once finally agreed with the relevant tax authorities. In particular, the tax returns of the group's US businesses are examined by the Internal Revenue Service and state agencies on a several year lag. Assessment of the likely outcome of the examinations is based upon historical experience and the current status of examination issues.

UK GAAP – Pensions and Other Post-Retirement Benefits
The group operates a number of defined benefit schemes for its employees. In addition, other post-retirement benefits are provided to employees within the group's US businesses. The group accounts for these arrangements under UK GAAP in accordance with Statement of Standard Accounting Practice ("SSAP") No. 24 'Accounting for pension costs'. The impact on the group's Accounts had the measurement rules of FRS 17 'Retirement benefits' been implemented is summarised in 'Accounting Developments' on page 49.

The expense and balance sheet items relating to the group's accounting for pension schemes under SSAP 24 are based on actuarial valuations. Inherent in these valuations are key assumptions, including discount rates, earnings increases and pension increases in payment. These actuarial assumptions are reviewed periodically and modified as appropriate. The effect of modifications is generally amortised over future periods. The assumptions adopted are based on prior experience, market conditions and the advice of plan actuaries.

Where, as in 2002/03, there are significant market changes in the interim period between formal actuarial valuations, the effect of such changes is recognised in calculating pension costs. Where, as in 2001/02, the impact of amortisation of pension surpluses would imply a negative pension charge in respect of a scheme, the costs relating to that scheme is set to a minimum of £nil.

The group chooses a discount rate for each scheme which reflects yields on high-quality fixed-income investments, which may be increased for SSAP 24 purposes to allow for higher returns expected over the longer-term from the schemes' equity holdings. The pension liability and future pension expense both increase as the discount rate is reduced.

If the SSAP 24 expense for the year ended 31 March 2003 had been based on a discount rate 0.5% p.a. higher or lower than those actually used, the expense would have

Financial Review
continued

reduced or increased, respectively, by £10.6 million in respect of the group's UK pension schemes and £4.4 million in respect of the group's US pension schemes.

The discount rates used for the purposes of UK GAAP for the group's principal pension schemes are set out in Table 38.

Table 38 – Discount rates

Pension fund	Discount rate-UK GAAP	Discount rate-US GAAP
ScottishPower	6.0%	5.4%
Manweb	6.8%*	5.4%
PacifiCorp	7.5%	6.75%

* 4.8% post-retiral

UK GAAP – Derivative Financial Instruments

The group uses derivative instruments in the normal course of business to offset fluctuations in earnings, cash flows and equity associated with movements in exchange rates, interest rates and commodity prices. Derivative financial instruments entered into for hedging purposes are recognised in the group's Accounts when the hedged item is recognised. Certain derivatives may therefore be included at cost in the group's balance sheet. This amount may be significantly different from the market value of the derivative. In limited circumstances the group holds derivative financial instruments for trading purposes. These derivatives are marked to market and unrealised gains and losses are recognised in the group's profit and loss account. The net unrealised gains on financial assets and liabilities held for trading at 31 March 2003 was £0.4 million.

Critical Accounting Policies – US GAAP

In addition to preparing the group Accounts in accordance with UK GAAP, the directors are also required to prepare a reconciliation of the group's profit or loss and shareholders' funds between UK GAAP and US GAAP. The adjustments required to reconcile the group's profit or loss and shareholders' funds from UK GAAP to US GAAP are explained in Note 35 to the Accounts. Certain of the group's US GAAP accounting policies have been identified as critical US GAAP accounting policies and these are discussed below. The discussion below should be read in conjunction with the full discussion of the differences between the group's UK and US GAAP accounting policies set out in Note 35.

US GAAP – US Regulatory Assets

The group prepares its US GAAP financial information in accordance with FAS 71 'Accounting for the Effects of Certain Types of Regulation' in respect of its regulated US business, PacifiCorp.

In order to apply FAS 71, certain conditions must be satisfied, including the following: an independent regulator must set rates; the regulator must set the rates to cover the specific costs of delivering service; and the service territory must lack competitive pressures to reduce rates below the rates set by the regulator. FAS 71 requires the group to reflect the impact of regulatory decisions and requires that certain costs be deferred on the balance sheet under US GAAP until matching revenue can be recognised. FAS 71 provides that regulatory assets may be capitalised, under US GAAP, if it is probable that future revenues, in an amount at least equal to the capitalised costs, will result from the inclusion of that cost in allowable costs for rate-making purposes. In addition the rate actions should permit recovery of the specific previously incurred costs rate rather than to provide for expected levels of similar future costs. An entity applying FAS 71 does not need absolute assurance prior to capitalising a cost, only reasonable assurance. Based on the group's US regulatory net asset balance under US GAAP at 31 March 2003, if the group stopped applying FAS 71 to its remaining regulated US operations, it would have recorded an extraordinary loss after tax, of £580.8 million under US GAAP. PacifiCorp intends to seek recovery of all of its prudent costs, including stranded costs, in the event of deregulation. However, due to the current lack of definitive legislation, it is not possible to predict whether PacifiCorp will be successful.

Because of potential regulatory and/or legislative actions in the various states in which PacifiCorp operates, the group may have regulatory asset write offs and charges for impairment of regulatory assets, under US GAAP, in future periods. Such impairment reviews would involve estimates of future cash flows including estimated future prices, cash costs of operations, sales and load growth forecasts and the nature of any legislative or regulatory cost recovery mechanism.

US GAAP – Derivative Financial Instruments

The group accounts for its derivative financial instruments under US GAAP in compliance with FAS 133. Certain of the group's derivatives are treated as normal purchases and normal sales and are therefore excluded from the requirements of FAS 133. Derivatives falling within the scope of FAS 133 are required to be recorded in the balance sheet under US GAAP at fair value. Changes in the fair values of derivatives that are not designated as hedges are adjusted through earnings under US GAAP with the exception of long-term energy contracts that were in existence on 1 April 2001 and are included in PacifiCorp's rate-making base. For these long-term energy contracts PacifiCorp received regulatory accounting orders to adjust the fair value through regulatory assets or liabilities, reversing recorded amounts as the contracts settle. For derivatives designated as effective cash flow hedges, the changes in fair values are recognised under US GAAP in accumulated other comprehensive income until the hedged items are recognised in earnings. For derivatives designated as effective fair value hedges, the changes in fair values are recognised under US GAAP in the income statement, offset to the extent that they are effective, by fair value movements on the designated risk of the item being hedged. The group's future results under US GAAP could be impacted by changes in market conditions to the extent that changes in contract values are not offset by regulatory or hedge accounting.

US GAAP – Pensions and Other Post-Retirement Benefits

The group accounts for its pension schemes under US GAAP in accordance with FAS 87 'Employers' Accounting for Pensions'. Under FAS 87, the group's pension schemes generally had assets with a fair value at 31 March 2003 that was less than the accumulated benefit obligation under the schemes at the same date, primarily due to declines in equity markets. As a result, at 31 March 2003 the group recognised a

Table 39 – Impact of UK GAAP exceptional items and goodwill amortisation on US GAAP EPS

	2002/03	**2002/03 Effect on US GAAP EPS**	2001/02	2001/02 Effect on US GAAP EPS
	£m	**(pence)**	£m	(pence)
UK GAAP exceptional items				
UK GAAP – continuing operations	**–**	**–**	(26.0)	(1.41)
UK GAAP – discontinued operations	**–**	**–**	(1,292.1)	(70.31)
UK/US GAAP adjustment for UK GAAP exceptional items	**–**	**–**	279.1	15.19
Effect on US GAAP of UK GAAP exceptional items	**–**	**–**	(1,039.0)	(56.53)
Goodwill amortisation				
UK GAAP	**(139.0)**	**(7.54)**	(149.0)	(8.10)
UK/US GAAP adjustment for goodwill amortisation	**139.0**	**7.54**	(23.5)	(1.28)
Effect on US GAAP of goodwill amortisation	**–**	**–**	(172.5)	(9.38)

minimum pension liability under US GAAP of £717.4 million, of which £569.0 million was charged to accumulated other comprehensive income and £148.4 million was recognised as a US regulatory asset. If a discount rate had been used for accumulated benefit obligation purposes which was 0.5% p.a. higher than that actually used, the impact would have been to reduce the minimum pension liability by £375.7 million for the UK schemes and £24.1 million for the US schemes. The discount rates used for the purposes of US GAAP for the group's principal pension schemes are set out in Table 38.

Off Balance Sheet Arrangements

The group has not entered into any transactions or arrangements which have given rise to off balance sheet obligations other than in respect of the following. The group has entered into various operating leases. In accordance with UK GAAP, future payments under these leases, amounting to £50.5 million at 31 March 2003, are not recognised as liabilities in the group's balance sheet. The group has entered into various energy-related and treasury derivative contracts, primarily for hedging purposes. In accordance with UK GAAP, the value of derivatives held for hedging purposes are only recognised when the hedged item is recognised. This contrasts with US GAAP which requires that derivatives, as defined in the relevant US accounting standards, are reflected as assets or liabilities at their market values at the balance sheet date. An analysis of the group's derivatives, as defined under US GAAP, is set out in 'Fair Value of Derivative Contracts' above. As discussed in 'Accounting Developments' above, FIN 45 requires recognition and disclosure of certain guarantees. To the extent they are not required to be recognised, guarantees are regarded as off balance sheet arrangements under US GAAP. Full details of the guarantees required to be disclosed under FIN 45, principally relating to disposal of certain of the group's former operations, are set out in Note 35 to the Accounts. The directors believe that it is extremely unlikely that these guarantees will give rise to a material financial exposure for the group.

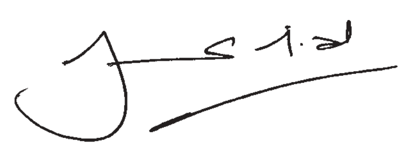
UK GAAP to US GAAP Reconciliation

The consolidated Accounts of the group are prepared in accordance with UK GAAP which differ in significant respects from US GAAP. Reconciliations of profit/(loss) and equity shareholders' funds between UK GAAP and US GAAP are set out in Note 35 to the Accounts. Under US GAAP, the profit for the year ended 31 March 2003 was £648 million, before crediting a cumulative adjustment for the effect of implementing DIG guidance Revised C15 and C16, net of tax, of £141 million, compared to a loss of £825 million in the previous year after charging an extraordinary item, net of tax, of £8 million and before charging a cumulative adjustment for the effect of implementing FAS 133, net of tax, of £62 million. Earnings per share under US GAAP, before the cumulative adjustment for Revised C15 and C16, were 35.16 pence per share compared to a loss, before the cumulative adjustment for FAS 133, of 44.91 pence per share in 2001/02. Earnings per share under US GAAP were 42.81 pence per share compared to a loss per share for the year ended 31 March 2002 of 48.26 pence. In accordance with US GAAP, earnings/(loss) per share are stated based on US GAAP earnings, without adjustments for the impact of the UK GAAP exceptional items and goodwill amortisation, as such additional measures of underlying performance are not permitted under US GAAP. The inclusion of UK GAAP exceptional items in the determination of earnings per share in accordance with US GAAP decreased earnings by £1,039 million or 56.53 pence per share in 2001/02. The inclusion of goodwill amortisation decreased earnings by £173 million or 9.38 pence per share in 2001/02. This additional information has been provided to aid investors' comparison between the results reported under US and UK GAAP. Equity shareholders' funds under US GAAP amounted to £5,480 million at 31 March 2003 compared to £5,850 million at 31 March 2002.

Table 39 details the impact of UK GAAP exceptional items and goodwill amortisation on the reported results under US GAAP for 2002/03 and 2001/02.

Summary

We have delivered a good set of financial results with earnings per share increased from a loss of 53.71 pence last year to earnings of 26.17 pence. Excluding goodwill amortisation and exceptional items, earnings per share were up 29% on last year to 33.71 pence. Our increased profit before tax reflects improved business operational performance and lower interest charges due to our lower net debt position, which has also contributed to a stronger balance sheet.



David Nish Finance Director

7 May 2003

Board of Directors & Executive Team

Executive Directors

Ian Russell (50) is Chief Executive, having been appointed to this position in April 2001. He joined ScottishPower as Finance Director in April 1994 and became Deputy Chief Executive in November 1998. He is a member of the Institute of Chartered Accountants of Scotland, having trained with Thomson McLintock, and has held senior finance positions with Tomkins plc and HSBC.

Charles Berry (51) is Executive Director UK, responsible in this capacity for the UK energy businesses of Generation, Energy Management and Supply. He joined ScottishPower in November 1991 and was appointed to the Board in April 1999. He is a member of the Board of the Energy Saving Trust. Prior to joining ScottishPower, he was Group Development Director of Norwest Holst, a subsidiary of Compagnie Générale des Eaux, and prior to that held management positions within subsidiaries of Pilkington plc. He holds a BSc (First Class Hons) in Electrical Engineering from the University of Glasgow and a Masters Degree in Management from the Massachusetts Institute of Technology.

David Nish (43) is Finance Director, having joined ScottishPower in September 1997 as Deputy Finance Director and then being appointed to the Board as Finance Director in December 1999. In this capacity, he also has responsibility at Board level for performance management and information technology. He is a member of the Institute of Chartered Accountants of Scotland and its Qualifications Board, a member of the Scottish Council of the CBI and a non-executive director of The Royal Scottish National Orchestra. Prior to joining ScottishPower, he was a partner with Price Waterhouse. He has a BAcc from the University of Glasgow.

Chairman

Charles Miller Smith (63) joined the Board as Deputy Chairman in August 1999 and was appointed Chairman in April 2000. Following a career with Unilever for some 30 years, during the last five of which he was Director of Finance and latterly of the Food Executive, he was appointed Chief Executive of ICI in 1995 and then served as Chairman from 1999 to 2001. He is an international adviser to Goldman Sachs, a member of the Board of the Indian company, ICICI One Source plc, and a member of the Ministry of Defence Management Board. He is currently serving on the committee chaired by Professor Laura Tyson of London Business School which is considering, in the light of the recommendations of the Higgs Review, ways of broadening the pool of non-executive directors. He is also a Governor of the Henley Management College.

Non-Executive Directors

Euan Baird (65) joined the Board in January 2001. He served as Chairman and Chief Executive Officer of Schlumberger Limited from 1986 to February 2003. He is now non-executive Chairman of Rolls-Royce plc and a non-executive director of Société Générale and Areva. He is a trustee of Tocqueville Alexis Trust and Carnegie Institution of Washington, and a member of the Comité National de la Science in France and the Prime Minister's Council of Science and Technology in the UK. His current term of office will expire at the AGM in 2004.

Mair Barnes (58) joined the Board in April 1998. She is a non-executive director of GWR Group plc, Patientline plc and the South African company, Woolworths Holdings Limited. She is a member of the Department of Trade and Industry's Strategy Board and Services Group Board. She was previously Managing Director of Woolworths plc in the UK until 1994, and subsequently became Chairman of Vantios plc until 1998. She was also formerly a non-executive director of Abbey National plc, Littlewoods plc and George Wimpey plc. Her current term of office will expire at the AGM in 2004.

Philip Carroll (65) joined the Board in January 2002. He was formerly Chairman and Chief Executive Officer of Fluor Corporation, a California-based international engineering, construction and services company, until his retirement in February 2002. Previously, he was with Shell Oil for over 35 years, serving as President and Chief Executive Officer from 1993 to 1998. He is an honorary life member of the Board of the American Petroleum Institute and holds various posts with the James A Baker III Institute for Public Policy of Rice University and the University of Houston. His current term of office will expire at the AGM in 2005.

Sir Peter Gregson GCB (66) joined the Board in December 1996 and is the company's senior independent non-executive director and Chairman of the Remuneration Committee. He was formerly a career civil servant, having served latterly as Permanent Secretary of the Department of Energy from 1985 to 1989 and Permanent Secretary of the Department of Trade and Industry until his retirement in June 1996. He was previously Deputy Chairman of the Board of Companions of the Chartered Institute of Management and a non-executive director of Woolwich plc. His current term of office has been extended by up to one year, such that it will expire not later than the AGM in 2004.

Nolan Karras (58) joined the Board in November 1999. He continues as a non-executive director of PacifiCorp, having previously (until the merger in November 1999) served as Chairman of the PacifiCorp Personnel Committee. He is President of The Karras Company, Inc., and a Registered Principal for Raymond James Financial Services. He is Chief Executive Officer of Western Hay Company, Inc., and a non-executive director of Beneficial Life Insurance Company. He is Chairman of the Utah State Higher Education Board of Regents and a member of the board of Ogden-Weber Applied Technology College. He also served as a member of the Utah House of Representatives from 1981 to 1990, and as Speaker of the Utah House of Representatives from 1989 to 1990. His current term of office will expire at the AGM in 2006.

Ewen Macpherson (61) joined the Board in September 1996 and is Chairman of the Audit Committee. He had a long career with 3i Group plc, leading to his appointment as Chief Executive from 1992 until his retirement in 1997. He is Chairman of Merrill Lynch New Energy Technology plc and a non-executive director of Foreign & Colonial Investment Trust plc and Pantheon International Participations plc. He is also Chairman of the Trustees of GlaxoSmithKline Pension Fund. Previous appointments include non-executive directorships of M&G Group plc, Booker plc and The Law Debenture Corporation plc. He will retire from the Board after the AGM in 2003.

Nick Rose (45) joined the Board in February 2003; he is the Audit Committee's "financial expert" and will succeed Ewen Macpherson as Chairman of the Committee later in the year. He is Finance Director of Diageo plc, having been appointed to this position in July 1999. Previously he held senior finance positions with GrandMet and was latterly Finance Director of International Distillers & Vintners in 1996 and then of United Distillers & Vintners in 1997. He is also a director of Moët Hennessy. His current term of office, subject to his election in 2003, will expire at the AGM in 2006.

Executive Team

The Executive Team is constituted as a committee of the Board and includes not only the Executive Directors of the Board but also the following key Executives and Officers from the group:

Julian Brown (53) was appointed Group Director, Strategy in April 1997, having joined ScottishPower in 1993. He began his commercial career with Exxon Chemical in Australia and subsequently spent seven years with management consultants McKinsey and Company. He holds a BSc from the Australian National University and a PhD in Chemistry from University College London. With effect from 1 April 2003, he left the Executive Team to assume a new position within the group.

Dominic Fry (43) joined ScottishPower in September 2000 as Group Director, Corporate Communications. He is responsible for investor and media relations, communications with employees, corporate social responsibility and management of the group's overall reputation. He has held appointments as Communications Director with J Sainsbury plc and Eurotunnel plc. He chairs the Trading Board of the Glasgow Science Centre and is a communications adviser to the Royal Shakespeare Company and Business in the Community. He was educated at the Université Paul Valéry III in Montpellier and the University of North Carolina.

Terry Hudgens (48) was appointed Chief Executive Officer of ScottishPower's competitive US energy business, PPM, in May 2001 and joined the Executive Team in December 2001. He joined PacifiCorp as Senior Vice President of Power Supply in April 2000, having previously spent 25 years with Texaco, Inc. He was formerly President of Texaco Natural Gas and served as Texaco's senior representative and elected officer in the Natural Gas Supply Association. He has a bachelor's degree in civil engineering from the University of Houston.

Judi Johansen (44) was appointed President and Chief Executive Officer of PacifiCorp in June 2001 and joined the Executive Team in December 2001. She is responsible for all of PacifiCorp's operations. She joined PacifiCorp as Executive Vice President of Regulation and External Affairs in December 2000, having held senior positions with the Bonneville Power Administration and Washington Water Power. She is involved in several civic and professional activities. She has a bachelor's degree in political science from Colorado State University and a law degree from Northwestern School of Law at Lewis & Clark College in Portland, Oregon.

Ronnie Mercer (59) was appointed Group Director, Infrastructure in April 2001 and is responsible in this role for the UK wires business. He is a member of the Board of the Electricity Association. He joined the ScottishPower Generation Business in 1994 and was appointed Generation Director in 1996 and then Managing Director of Southern Water in 1998. Previous career positions include Scottish Director and Managing Director roles in British Steel. He was educated at Paisley College of Technology.

Andrew Mitchell (51) was appointed Group Company Secretary in July 1993 and is responsible in this role for corporate governance and reporting, shareholder services, compliance and group security. He also serves as Chairman of the trustees of the group's UK pension schemes and as the company's e7 representative. Prior to joining ScottishPower, he held a number of company secretarial appointments, latterly as Company Secretary of The Laird Group plc and then Stakis plc, now part of the Hilton Group. He is a graduate in law from the University of Edinburgh (LLB Hons) and the London School of Economics (LLM) and is a member of the Institute of Chartered Secretaries and Administrators.

Michael Pittman (50) was appointed Group Director, Human Resources in November 2001. He has groupwide responsibility for human resources, leading the focus on talent management, one of the group's main strategic thrusts. He joined PacifiCorp in December 1979 and was appointed to the PacifiCorp Board in May 2000. He chairs the PacifiCorp Foundation for Learning Board and is involved in numerous civic activities. He has held several positions within PacifiCorp, including safety and health, risk management and operations. He holds an advanced degree in environmental health from the University of Washington.

James Stanley (48) was appointed Group Director, Commercial and Legal in March 1996. He is responsible in this role for the provision of all legal, commercial and associated services throughout the group and particularly the negotiation, structuring and delivery of M&A projects such as the sale of Southern Water plc. In his early career he specialised in commercial litigation in private practice. In 1986 he moved to the Trafalgar House Group and subsequently became both Commercial Director of John Brown plc and General Counsel to the Global Engineering Division of the Group. He is a graduate in law from Nottingham University and the College of Law in Chester where he qualified as a solicitor in 1980.

Board of Directors & Executive Team
continued

Members of the Audit Committee
Ewen Macpherson, Chairman
Philip Carroll
Sir Peter Gregson
Nolan Karras
Nick Rose

Members of the Nomination Committee
Charles Miller Smith, Chairman
Mair Barnes
Sir Peter Gregson
Nolan Karras
Ian Russell

Members of the Remuneration Committee
Sir Peter Gregson, Chairman
Euan Baird
Mair Barnes
Nolan Karras
Ewen Macpherson

Board & Executive Team changes

Allan Leighton resigned from the Board on 12 June 2002. Nick Rose was appointed to the Board on 19 February 2003; in accordance with the Articles of Association, he will retire from office at the Annual General Meeting and, being eligible, offers himself for election. In addition, Charles Miller Smith, David Nish and Ewen Macpherson retire by rotation at the Annual General Meeting. Charles Miller Smith and David Nish, being eligible, offer themselves for re-election. Ewen Macpherson will retire from the Board and accordingly does not seek re-election. David Nish has a service contract terminable by either party upon one year's notice.

Julian Brown served as a member of the Executive Team throughout the year but assumed a new position within the group with effect from 1 April 2003.

For US reporting purposes the members of the Executive Team are regarded as officers of the company.

Corporate Governance

Corporate governance statement

The company is committed to the highest standards of corporate governance. This statement, together with the Remuneration Report of the Directors, set out on pages 61 to 68, describes the extent to which, in respect of the financial year ended 31 March 2003, the company has been in compliance with the principles of good governance set out in Section 1 of the Combined Code (as appended to the Listing Rules of the UK Listing Authority) in the UK and with the Sarbanes-Oxley Act 2002 and associated rules (to the extent they apply to the company) in the US.

The company acknowledges the consideration of the role and effectiveness of non-executive directors contained in the Higgs Report and the guidance for audit committees contained in the Smith Report. Arising from the Higgs Report, the company will review its corporate governance policies and practices, in due course, in the light of any revisions made to the Combined Code.

Board of directors

There is a well-established division of authority and responsibility at the most senior level within the company through the separation of the roles of Chairman and Chief Executive.

In addition to the Chairman, there are currently three executive and seven non-executive directors on the Board. All the non-executive directors are considered by the Board to be independent and Sir Peter Gregson is the senior independent director.

The company has made provision for the non-executive directors to meet annually without the presence of the Chairman and the Chief Executive; this practice has been established for a number of years.

The non-executive directors are from a wide range of backgrounds, and all directors have the benefit of induction and training tailored to individual requirements following their appointment to the Board. Their experience allows them to exercise independent judgement on the Board and their views carry significant weight in Board decisions. They contribute to the company's strategy and policy formulation, in addition to monitoring its performance and its executive management.

The non-executive directors are appointed for a specified term of three years; reappointment is not automatic, and each non-executive director's position is subject to review prior to his or her expiry from office. It is company policy that non-executive directors serve no more than two three-year terms unless there are exceptional circumstances. In the case of Sir Peter Gregson, it was felt appropriate in the interests of orderly succession planning to extend his term of office by up to one year. Directors are elected at the first annual general meeting following their appointment and thereafter are re-elected at least every three years.

Board meetings are held on a regular basis, twelve times a year, and otherwise as required. Of the normal twelve meetings, six are held at company locations in the UK and US and the remaining six are conducted by telephone conference. The Board has a schedule of matters concerning key aspects of the company's activities which are reserved to it for decision. The Board exercises full control over strategy, investment and capital expenditure. In addition, individual executive directors have specific responsibilities for such matters as health, safety, environment and regulation. The decisions reserved to the Board include any changes to the company's constitution or share capital or to the group structure; the adoption of business plans and budgets; the approval of capital expenditure over certain limits; and the adoption or variation of major policies.

All directors have access to the Company Secretary, who is responsible for ensuring that all Board procedures are observed and, through the Chairman, is responsible for all corporate governance matters. Any director wishing to do so, in furtherance of his or her duties, may take independent professional advice at the company's expense.

During the year, the Institute of Chartered Secretaries and Administrators conducted an independent evaluation of the performance of the Board. The evaluation looked at the operation of the Board, including its corporate governance and decision-making framework and the operation and content of its meetings. The evaluation process, on the basis of private interviews with each of the directors, was considered to have been a thorough process; and its outcome, including specific recommendations, was regarded as very positive.

Table 40 shows the number of, and individual attendance at, meetings of the Board, as well as of the Nomination, Remuneration and Audit Committees during the year.

Board committees

The Board has three principal standing committees: namely, the Nomination, Remuneration and Audit Committees, together with certain other committees. The current membership of each of the principal committees is shown on page 56. In addition, authority (as described below) is delegated to the Executive Team. Details are as follows:

Nomination Committee

The Nomination Committee is chaired by the Chairman of the Board with, as members of the Committee, the Chief Executive and three independent non-executive directors. It has a remit to consider and make recommendations to the Board on all new appointments of directors, having regard to the overall balance and composition of the Board; to consider and approve the remit and responsibilities of the executive directors; and to review and advise upon issues of succession planning and organisational development.

Remuneration Committee

The Remuneration Committee is chaired by Sir Peter Gregson and all members of the Committee are independent non-executive directors. It has a remit to consider and make recommendations on Board remuneration policy and, on behalf of the Board, to determine specific remuneration packages for each of the executive directors. In discharging its remit, the Committee has regard to the provisions of the Combined Code and has as an objective the aim of providing packages to attract, retain and motivate executive directors of the quality required; to judge the company's position in matters of remuneration policy and practice relative to other companies; and to take into account wider issues of pay-setting. It also has responsibility for the company's bonus and incentive schemes. The Remuneration Report of the Directors for 2002/03 is set out on pages 61 to 68.

Corporate Governance
continued

Audit Committee

The Audit Committee is chaired by Ewen Macpherson and all members of the Committee are independent non-executive directors. Nick Rose has been identified as the Committee's "financial expert" and, following Ewen Macpherson's retirement, will become chairman of the Committee.

The Committee has written terms of reference. Its principal role is to review:

• the effectiveness of the system of internal control and consider reports from both internal and external auditors on key risks facing the group and controls over these risks

• the company's quarterly financial statements, including accounting policies, compliance with legal and regulatory requirements, judgmental issues and the findings of the external auditors

• the activities and effectiveness of the internal audit function

• the relationship with the external auditors, including the engagement of auditors, the audit scope and approach, fees and performance and provision of non-audit services by the external auditors

• compliance with legal and regulatory requirements

• litigation and claims affecting the group.

Meetings of the Committee are normally attended by the Chief Executive, Finance Director, Director of Internal Audit, Company Secretary and representatives of the external auditors. However the Committee also meets in private session, at least once annually, and otherwise as required, with the external auditors, external counsel the Director of Internal Audit and senior management.

Other Committees

During the year, the company established a Group Finance Committee and a Treasury Committee. The Group Finance Committee, comprising both executive and non-executive directors, was created to review the structure, financing, tax and treasury affairs of the group and make recommendations on these matters to the Board. The Treasury Committee was established to implement finance and treasury operations within limits set by the Board, including such matters as authorities for the operation of bank accounts and the approval of bond and note issues, loan facilities and guarantees.

Executive Team

The Executive Team comprises the Chief Executive and other executive directors, together with the Chief Executive Officer, PacifiCorp; Chief Executive Officer, PPM; Group Director, Infrastructure; Group Director, Commercial and Legal; Group Director, Corporate Communications; Group Director, Human Resources; Group Director, Strategy; and the Group Company Secretary. Operational control and implementation of group strategy and policy are responsibilities delegated by the Board to the Chief Executive who is supported by the Executive Team (and by divisional and business boards) in the discharge of these functions. Major issues and decisions are reported to the Board.

Relations with shareholders

The company's Investor Relations department communicates with its institutional investors through analysts' briefings and extensive investor roadshows in the UK, US and Europe. Transparency is further promoted by timely stock exchange announcements, formal meetings with management and site visits. Broader communication with shareholders takes place via the Annual General Meeting, the Annual Report & Accounts, and the company website to which all material stock exchange announcements are posted. All Board members attend the AGM and they are available to answer shareholder questions.

The company website, www.scottishpower.com, provides current information on share prices, financial results and analysts' presentations. Information regarding the AGM, results and other events are typically made available to shareholders by webcast.

Internal control

The directors of ScottishPower have overall responsibility for the system of internal controls and for reviewing the effectiveness of the system. The system of internal control is designed to manage rather than eliminate the risk of failure to achieve

Table 40 – Board and Committee attendance during the year ended 31 March 2003

	Charles Miller Smith (N*, A[1])	Euan Baird (R)	Mair Barnes (N, R)	Philip Carroll (A)	Sir Peter Gregson (N, R*, A)	Nolan Karras (N, R, A[2])	Ewen Macpherson (R, A*)	Nick Rose[3] (A)	Ian Russell (N)	Charles Berry	David Nish
Board (12 meetings)	12	8	11	11	11	12	12	1	12	12	10
Nomination Committee (5 meetings)	5		4		5	5			5		
Remuneration Committee (4 meetings)		4	3		4	4	4				
Audit Committee (7 meetings)	7			7	7	2	7	1			

N – Nomination Committee
R – Remuneration Committee
A – Audit Committee

* Committee Chairman

[1] Resigned from the Audit Committee in April 2003
[2] Appointed to the Audit Committee in January 2003
[3] Appointed February 2003

business objectives. In pursuing these objectives, internal control can only provide reasonable and not absolute assurance against material misstatement or loss.

The Executive Team is responsible for implementing the risk management strategy; ensuring that an appropriate risk management framework is operating effectively across the company; embedding a risk culture throughout the group; and providing the Board and the Audit Committee with a consolidated view of the risk profile of the company, identifying any major exposures and mitigating actions.

The risk management framework and internal control system across the group, which is subject to continuous development, provides the basis on which the company has complied with the Combined Code provisions on internal control.

Control environment

The company is committed to ensuring that a proper control environment is maintained. There is a commitment to competence and integrity and to the communication of ethical values and control consciousness to managers and employees. Employees are required to adhere to the company's Code of Conduct and Disciplinary Rules. Furthermore, in compliance with the Sarbanes-Oxley Act 2002, the company has adopted a Code of Ethics for the Chief Executive, Finance Director and principal accounting officers. Human resources policies underpin that commitment by a focus on enhancing job skills and promoting high standards of probity among staff. In addition, the appropriate organisational structure has been developed within which to control the businesses and to delegate authority and accountability, having regard to acceptable levels of risk.

The company has developed a fraud policy and implemented procedures to ensure that all incidences of fraud are appropriately investigated and reported.

A Disclosure Committee has been established to ensure effective disclosure controls are operating around the production of key published financial statements and to provide assurance to the Chief Executive and Finance Director that they may sign their formal certification to the Securities and Exchange Commission ("SEC") in accordance with Section 302 of the Sarbanes-Oxley Act 2002.

Identification and evaluation of risks and control objectives

The company's strategy is to follow an appropriate risk policy, which effectively manages exposures related to the achievement of business objectives.

Each business identifies and assesses the key business risks associated with the achievement of its strategic objectives. Any key actions needed to further enhance the control environment are identified along with the person responsible for the management of the specific risk. Each month a detailed review of the key risks, controls and action plans within each of the businesses takes place and a Risk Report is produced for review and challenge by the board of each business. This monthly Risk Report is a standing item on the agenda of the business boards which operate throughout the group. This is a key tool in ensuring the active management of risk across the organisation.

Business controls managers have been appointed within each of the businesses to help ensure that the risk management and internal control system is consistently adopted, updated and embedded into the business processes.

The corporate centre also considers those risks to the group's strategic objectives that may not be identified and managed at a business level.

The Board and Executive Team on a monthly basis receive the group-wide Risk Report together with supporting documentation for review. This report highlights the most significant risks across the group and the actions being taken to mitigate them, and also identifies the individuals responsible for the management of these risks. The information being supplied to the Board and Executive Team is continually being developed to include quantitative measures such as sensitivity analyses and Value-at-Risk calculations for issues reported on in the Group Energy Risk Report.

The use of a well-defined risk management methodology across all businesses allows a consistent and coordinated approach to risk reporting for review by the Board, which also receives regular reports on these matters from the Audit Committee, to enable the directors to review the effectiveness of the system of internal control on a regular basis.

A key element and requirement of the risk evaluation process is that a written certificate is provided quarterly by all members of the Executive Team, confirming that they have reviewed the effectiveness during the year of the system of internal control under their responsibility.

Energy management

A Group Energy Risk Committee ("GERC") has been established to assist the Executive Team in ensuring that there is an appropriate risk and control governance framework in place over energy activities. The GERC meets monthly and the key responsibility of this group is to make suitable recommendations to the Executive Team on energy-related risk management issues. In addition, the Group Energy Risk Director, with other members of the GERC, continues to enhance business processes and systems to ensure that all risks pertaining to operating the trading and energy businesses are understood, quantified, managed and reported on a consistent basis across the group.

The GERC also provides advice and guidance to the businesses on interpretation and execution of the Group Energy Risk Policy.

Monitoring and corrective action

The Executive Team reviews monthly the key risks facing the group and the controls and monitoring procedures for these. Operation of the group's control and monitoring procedures is reviewed and tested by the group's internal audit function under the supervision of the Director of Internal Audit, reporting to the Finance Director and with access to the Chairman of the Audit Committee. Internal audit reports and recommendations on the group's procedures are reviewed regularly by the Audit Committee. As part of their external audit responsibilities, the external auditors also provide reports to the Audit Committee on the operation of the group's internal financial control procedures. The Audit

Corporate Governance
continued

Committee also receives regular reports on the continued development, implementation and evaluation of the risk management and internal control system.

Auditor independence
The Audit Committee and the firm of external auditors have safeguards to avoid the possibility that the auditors' objectivity and independence could be compromised. These safeguards include the implementation of a policy on the use of the external auditor for non-audit-related services. This policy has been revised during the year to reflect the provisions of the Sarbanes-Oxley Act 2002 and subsequent SEC rules.

Where it is deemed that the work to be undertaken is of a nature that is generally considered reasonable to be completed by the external auditors for sound commercial and practical reasons, including confidentiality, the conduct of such work will be permissible provided that it has been pre-approved by the Audit Committee. Examples of pre-approved services include the completion of regulatory audits, provision of taxation and regulatory advice, reporting to the SEC and the UK Listing Authority and the completion of certain financial due diligence work. All these services are also subject to a pre-defined fee limit. Any work performed in excess of this limit must be approved by the Finance Director and the Chairman of the Audit Committee. Details of audit and non-audit fees paid to the external auditors are contained in Note 2 to the Group Profit and Loss Account on page 79.

Evaluation of disclosure controls and procedures (Sarbanes-Oxley Act 2002)
The Chief Executive and the Finance Director have evaluated the effectiveness of the group's disclosure controls and procedures within 90 days of the date of this document. Based on this evaluation, the Chief Executive and Finance Director concluded that the disclosure controls and procedures are effective in all material respects to ensure that material information relating to the group would be made known to them by others within the group.

There have been no significant changes to the group's internal controls or in other factors that could materially affect these controls after the date of their evaluation.

Social, environmental and ethical risks and opportunities
Information regarding the social, environmental and ethical policies and practices of the company can be found in the separate Environmental and Social Impact Report.

Political donations and expenditure
ScottishPower is a politically neutral organisation but is required to comply with the Political Parties, Elections and Referendums Act 2000. This legislation defines political "donations" and "expenditure" in wider terms than would be commonly understood by these phrases. The definitions include expenditure which the Board believes it is in the interests of the company to incur. The Act also requires companies to obtain prior shareholder approval of this expenditure; at the Annual General Meeting in 2002, the company obtained authorisation up to a maximum amount of £100,000.

During the financial year ended 31 March 2003, the company paid a total of £9,500 for activities which may be regarded as falling within the terms of the Act. These activities comprised the sponsorship of briefings, receptions and fringe meetings at party conferences. These occasions present an important opportunity for the company to represent its views on a non-partisan basis to politicians from across the political spectrum. The payments do not indicate support, and are not intended to influence support, for any particular political party.

It should be noted that these activities do not contravene the restrictions on political contributions under the US Public Utility Holding Company Act of 1935, to which the company is subject.

Remuneration Report of the Directors

Introduction

The following statement sets out how, for the financial year ending 31 March 2003, the company has adopted the remuneration principles set out in Part B of the Combined Code and has taken account of the Directors' Remuneration Report Regulations 2002 which came into effect on 1 August 2002.

Consideration of remuneration matters by the directors

The ScottishPower Board is responsible for determining the remuneration policy for the ScottishPower group. The Remuneration Committee, with delegated authority from the Board, determines the detail of remuneration arrangements for the Executive Team, including the executive directors, and reviews proposals in respect of other senior executives. The relationship between the Board and the Committee is based on formal Terms of Reference, which are regularly reviewed to ensure that they reflect best practice.

The Remuneration Committee consists solely of independent non-executive directors. Its members are Sir Peter Gregson (Chairman), Euan Baird, Mair Barnes, Nolan Karras and Ewen Macpherson. These members have no personal financial interest, other than as shareholders, in the matters considered by the Committee. Details of the payments made to all non-executive directors are set out in Table 41 (page 65).

The Chairman of the company, Charles Miller Smith, and the Chief Executive, Ian Russell, are invited to attend meetings and may provide guidance on the impact of remuneration policy and advise, as appropriate, on the performance of senior executives. They are not present during any discussion of their own remuneration. The Terms of Reference contain conflict of interest provisions to ensure that no directors are involved in any decision relating to their own remuneration.

The Committee is able to draw on advice from independent remuneration consultants and internal expertise. During the year, the Committee appointed Towers, Perrin, Forster & Crosby, Inc., ("Towers Perrin") as remuneration consultant and independent adviser following a competitive tendering process. Towers Perrin also provides remuneration and other human resources consultancy services directly to some ScottishPower companies within parameters established by the Committee. Company executives whom the Committee may consult include the Group Company Secretary, Andrew Mitchell (who acts as Secretary to the Committee), the Group Director, Human Resources, Michael Pittman, the Director Group Talent Management and Reward, Sandy Begbie, and the Head of Group Reward, Nigel Johnson. The Terms of Reference empower the Committee to avail itself of external legal and professional advice at the expense of the company.

During the year, the Board accepted all of the recommendations from the Committee without significant amendment.

Statement of remuneration policy

Philosophy and policy

ScottishPower seeks to ensure that remuneration and incentive schemes are in line with best practice, provide a strong link to individual and company performance and promote a community of interest between employees and shareholders.

Rewards for executives and directors are designed to attract and retain individuals of high quality, who have the requisite skills and are incentivised to achieve levels of performance which exceed that of competitor companies. As such, remuneration packages must be market-competitive and capable of rewarding exceptional performance. All senior management remuneration packages are set according to a mid-market position, with packages above the mid-market level provided only where supported by demonstrably superior personal performance. Remuneration packages will be developed to reflect the prevailing market practice in each business environment.

Annual bonus arrangements have been structured so that stretching targets are based on corporate, business unit and individual performance.

The company operates a Personal Shareholding Policy, requiring executives and senior managers to build-up and retain a shareholding in the company in proportion to their annual salaries. These proportions are three times base salary for the Chief Executive and two times base salary for other executive directors. The Committee considers this policy to be in line with evolving best practice and in the interests of shareholders.

In setting remuneration levels, the Committee commissions an independent evaluation of the roles of the Executive Team, and also of the next levels of management within the company. The Committee takes independent advice from Towers Perrin on market-level remuneration, based on comparisons with utility and other companies of similar size and complexity with which the company competes for executive talent.

The Committee recognises the importance of linking rewards to business and personal performance and believes that the arrangements detailed below provide an appropriate focus on performance and balance between short- and long-term incentives. At target level, base salary is expected to deliver around 45% of total reward excluding benefits and pension. The annual bonus plan and long-term incentive arrangements are expected to provide 55% of total reward for the achievement of stretching target level business and personal performance objectives. Higher proportions of performance based reward are available for the delivery of exceptional personal and business performance resulting in enhanced shareholder value.

The Committee constantly monitors market practice in order to remain competitive and to reflect good corporate governance practice. At this time, no substantial changes to the company's policies with regard to directors' remuneration are envisaged over the next year. However, the Committee may develop policy and, should it determine any changes to be appropriate, will report such changes to shareholders through established channels of consultation and reporting. For example, the Committee and the Board will consider carefully the recommendations of the Higgs Report and may amend policy accordingly.

Remuneration Report of the Directors
continued

Elements of the remuneration package

Base salaries

The Committee sets base salaries for the Executive Team by reference to individual performance through a formal appraisal system applied to all management employees, and to external market data, reflecting similar roles in comparable companies. Account is also taken of salary increases and employment conditions across the company.

Annual performance-related bonus

Executive directors and senior management participate in the company's performance-related annual bonus plans. Any payments to UK executives under the schemes are non-pensionable and are determined by the Committee following assessment against predetermined targets.

The 2002/03 plan for executive directors provided a maximum bonus opportunity of 75% of salary. For the Chief Executive, half is determined by the company's financial performance, with the balance linked to the achievement of key strategic objectives, both short-term and long-term. For the Finance Director and the Executive Director UK, one-third is determined by the company's financial performance, one-third is based on the performance of the relevant function/ division and one-third on the achievement of key strategic objectives, both short-term and long-term. Objectives are set annually by the Board and performance against these is reviewed on a six-monthly basis. The Committee has approved the bonus plan for 2003/04 and no significant changes have been made.

Exceptionally, in 2002/03 an interim payment of up to 20% of salary was made to executive directors at the half year in recognition of the substantial improvement in the company's performance during the first two quarters. This interim payment was outside of normal policy and it is not anticipated that this practice will be repeated. The aggregate of the interim and final payments was kept within the normal maximum of 75% of salary.

Executive share plans

The company operates a performance share plan, known as the Long Term Incentive Plan ("LTIP"), and an Executive Share Option Plan 2001 ("ExSOP") for executive directors and other senior managers.

Under the LTIP, awards to acquire shares in ScottishPower at nil or nominal cost are made to the participants up to a maximum value equal to 75% of base salary. The award will vest only if the Committee is satisfied that there has been an underlying improvement in the performance of the company and, to this end, certain gateway performance targets are measured and the Committee reviews performance against these measures when determining if awards vest. The measures relate to the key financial performance indicators of the company and customer service standards, including those published by Ofgem, Energywatch and the US Public Utility Commissions. These measures provide a mechanism to safeguard stakeholder interests and provide an overview of the financial and operational success of the business.

The number of shares which actually vest is dependent upon the company's comparative Total Shareholder Return ("TSR") performance, over a three-year performance period. TSR measures ScottishPower's comparative performance against key competitors and only provides rewards if ScottishPower exceeds the median performance of appropriate comparators. The Committee chose TSR as the performance measure for the LTIP as it believes that it provides a clear link to the creation of shareholder value.

LTIP awards were granted to 48 directors and senior executives during the year (Award 7). TSR performance is measured against an international comparator group of 39 major energy companies, as identified below.

AES Corp; American Electric Power Inc; Calpine Corp; Centrica; Chubu Electric Power Co Inc; CLP Holdings Limited; Constellation Energy Group Inc; Dominion Resources Inc; Duke Energy Corp; Dynegy Inc; Edison SpA; Edison International; El Paso Corp; Electricidade de Portugal SA; Electrabel SA; Endesa SA; Ente Nazionale per l'Energia Elettrica SpA (Enel); Entergy Corp; Exelon; FirstEnergy Corp; FPL Group Inc; Gas Natural SDG SA; Iberdrola SA; Kansai Electric Power Co Inc; Lattice Group plc; National Grid Group plc; PPL Corp; Progress Energy Inc; Public Service Enterprise Group Inc; Reliant Energy Inc; RWE AG; Scottish & Southern Energy plc; Southern Company Inc; Tenaga Nasional Bhd; The Tokyo Electric Power Co Inc; TXU; Union Fenosa; Williams Companies Inc; Xcel Energy Inc.

No shares vest unless the company's TSR performance is at least equal to the median performance of the comparator group, at which point 40% of the initial award vests. 100% of the shares vest if the company's performance is equal to or exceeds the top quartile. The number of shares that vest for performance between these two points is determined on a straight-line basis.

For LTIP awards which had the potential to vest during the year, performance was measured against that of the FTSE 100 index and an index of the Electricity and Water sectors of the FTSE All Share Index. As the performance criteria were not achieved, Award 4 of the LTIP (May 1999 – May 2002) lapsed with no vesting of shares.

The Committee has approved the operation of the LTIP for 2003/04 and no significant changes have been implemented.

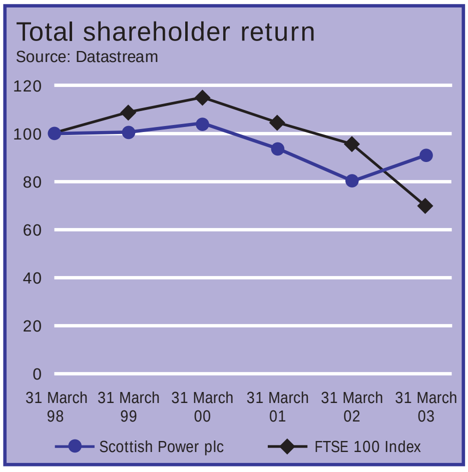
Options were granted at market value to 285 directors and other executives across the company during the year. Options granted to UK executives under the ExSOP are subject to the performance criterion that the average annual percentage increase in the company's earnings per share* ("EPS") be at least 3% (adjusted for any increase in the Retail Price Index). The Committee believes that EPS* is an appropriate measure for the purposes of testing the ExSOP because it is based on the underlying financial performance of the company. This criterion is assessed at the end of the third financial year, the first year being the financial year starting immediately before the date of grant. If not satisfied on the third anniversary, the criterion may be retested, from the same base, on the fourth and fifth anniversaries of grant. Unvested options lapse at the fifth anniversary.

The Committee has approved the operation of the ExSOP for 2003/04 and no changes have been implemented.

** excluding goodwill amortisation and exceptional items*

Performance graph

The new Directors' Remuneration Report Regulations require that a graph be presented showing the company's TSR performance against the TSR performance of a broad equity market index over a five-year period. The FTSE 100 has been chosen because it is the principal index in which the company's shares are quoted. The graph below presents the comparative TSR performance of the company during the period 1 April 1998 – 31 March 2003. The graph shows that ScottishPower has outperformed the index over this period.



This graph looks at the value, by 31 March 2003, of £100 invested in ScottishPower on 31 March 1998 compared with that of £100 invested in the FTSE 100 Index. The other points plotted are the values at intervening financial year-ends.

All-employee share plans

To facilitate high levels of share ownership by employees, the company operates a savings-related share option plan, which is open to executive directors and all UK employees. Under this plan, options are granted over ScottishPower shares at a discount of 20% from the prevailing market price at the time of grant to eligible employees who commit to save up to £250 per month over a period of three or five years.

The company also operates an Employee Share Ownership Plan ("ESOP") and was amongst the first to introduce these arrangements for executive directors and all UK employees. The ESOP enables employees to purchase shares in the company from pre-tax income up to the limits specified in the legislation. The value of these shares is at risk as they are not normally released until the legislation allows. The company matches these shares at no cost to the employee on a one-for-one ratio. The legislation also enables the company to award free shares to employees.

The savings-related share option plan and the ESOP are all employee Inland Revenue approved plans and as such are not subject to performance conditions.

Pension

The executive directors, and other UK-based senior managers of the company, are provided with pension benefits through the company's main pension scheme, and through an executive top-up pension plan which provides a maximum pension of two-thirds of final salary on retirement at age 63, reduced where service to age 63 is less than 20 years. Pensionable salary is normally base salary in the 12 months prior to leaving the company although there are prescribed mechanisms for calculating pensionable salary by averaging base salary over a period of up to three out of the last 10 years' service. The employee contributes 5% of salary to the scheme. Life assurance provision of four times pensionable salary and a widow's pension of half the executive's pension on death are provided.

Individuals who joined the company (in the UK) on or after 1 June 1989 are subject to the Inland Revenue 'earnings cap', introduced by the Finance Act 1989. Entitlement to pension benefits above the cap cannot be provided through the company's approved pension scheme, and therefore arrangements on an unapproved basis have been made to provide total benefits for executives affected by the legislation as though there was no cap. The total liability in respect of executives and senior employees arising in relation to unapproved benefits accrued for service for the year to 31 March 2003 was £208,700. The Trustee body of the Executive Top Up Plan is chaired by the Company Secretary.

The Committee has reported the pension expense in accordance with the requirements of the UK Listing Authority and Directors' Remuneration Report Regulations. Pension costs detailed in the Accounts are calculated as the cost of providing benefits accrued in the 2002/03 year, in accordance with appropriate accounting standards.

Benefits

Executive directors are eligible for a range of benefits on which they are assessed for tax. These include the provision of a company car, fuel, private medical provision and permanent health insurance. The provision and level of benefits is reviewed regularly to ensure that practice is in line with the market.

Service contracts

ScottishPower has reviewed its policy on service contracts and, in accordance with the best practice recommendation of the Combined Code, has resolved that new appointees to the Board be offered rolling contracts with notice periods of one year. The Committee recognises however that exceptional circumstances may arise and that it may be necessary, in the case of appointments from outside the company, to offer a longer initial notice period. In such cases the intent would be subsequently to reduce this period to one year following an agreed initial period.

The Committee's policy on early termination is to emphasise the duty to mitigate to the fullest extent practicable. Senior managers within the company have notice periods ranging from six months to one year.

Executive directors, Charles Berry and David Nish, were appointed to the Board on or

Remuneration Report of the Directors
continued

after 1 April 1999; these appointments have rolling service contracts terminable on one year's notice from both parties. Charles Berry has a service contract dated 30 July 1999 (and subsequently varied) and David Nish has a service contract dated 13 December 1999 (and subsequently varied). Both contracts include a clause enabling the company, at its sole discretion, to make a payment in lieu of notice equal to the value of the salary and contractual benefits the executive director would have received during the notice period.

The Chief Executive, Ian Russell, has a service contract dated 30 July 1999 terminable by the executive on one year's notice and by the company on two years' notice. The Chief Executive has chosen to reduce the notice period from the company to one year. The contract includes a clause enabling the company, at its sole discretion, to make a payment in lieu of notice equal to the value of the salary and contractual benefits the Chief Executive would have received during the notice period. The company would however pursue mitigation to minimise, as far as possible, costs to the company on termination.

The Chairman, Charles Miller Smith, is a non-executive director and he does not have a service contract with the company.

External non-executive appointments

The company encourages its directors to become non-executive directors of other companies, provided that these appointments are not with competing companies, are not likely to lead to any conflicts of interest, and do not require extensive commitments of time which would prejudice their roles within the company. This serves to add to their personal and professional experience and knowledge, to the benefit of the company. Any fees derived from such appointments may be retained by the executives.

Remuneration policy for non-executive directors

The remuneration of non-executive directors is determined by the Board and, during the year consisted of a base fee of £24,000 p.a., a committee membership fee of £3,500 p.a., a fee of £7,500 p.a. for chairing the Audit Committee and the Remuneration Committee, and an international travel fee of £1,000 for attending a tranche of meetings that involve a Transatlantic journey. In line with best practice, the independent non-executive directors do not have service contracts, are not members of the company's pension schemes and do not participate in any bonus, share option or other profit or long term incentive plan. Full details of the remuneration of the non-executive directors are contained in Table 41.

Compensation of directors and officers

For US reporting purposes, it is necessary to provide information on compensation and interests for directors and officers. The aggregate amount of compensation paid by the group to all directors and officers of the company, as a group, was £5,407,075.

During 2002/03 the aggregate amount set aside or accrued by the group to provide pension, retirement or similar benefits for directors and officers of the company pursuant to any existing plan provided or contributed to by the group was £1,016,900.

Interest of management in certain transactions

There have been no material transactions during the group's three most recent financial years, nor are there presently proposed to be any material transactions to which the company or any of its subsidiaries was or is a party and in which any director or officer, or 10% shareholder, or any relative or spouse thereof or any relative of such a spouse, who had the same home as such person or who is a director or officer of any subsidiary of the company has or is to have a direct or indirect material interest.

During the group's three most recent financial years there has been no, and at present there is no, outstanding indebtedness to the company or any of its subsidiaries owed or owing by any director or officer of the group or any associate thereof.

Directors' interests

Other than as disclosed, none of the directors had a material interest in any contract of significance with the company and its subsidiaries during or at the end of the financial year. The directors' interests, all beneficial, in the ordinary shares of the company, including interests in options under the company's ExSOP and Sharesave Scheme and awards under the LTIP, are shown on pages 67 to 68.

Directors' and officers' liability insurance

The company maintains liability insurance for the directors and officers of the company and its subsidiaries.

Directors' emoluments and interests

Total emoluments

Table 41 provides a breakdown of the total emoluments of the Chairman and all the directors in office during the year ended 31 March 2003.

Directors' pension benefits

Details of pension benefits earned by the executive directors during the year are shown in Table 42.

The following tables provide details of the remuneration, pensions and share interests of the directors and the information is audited.

Table 41 – Directors' emoluments 2002/03

Total emoluments	Basic salary £000's 2003	Basic salary £000's 2002	Bonuses £000's 2003	Bonuses £000's 2002	Benefits in kind £000's 2003	Benefits in kind £000's 2002	Total £000's 2003	Total £000's 2002
Chairman and executive directors								
Charles Miller Smith (Non-Executive Chairman)	**235.0**	235.0	**–**	–	**14.0**	13.8	**249.0**	248.8
Sir Ian Robinson (retired 4 May 2001)	**–**	93.3	**–**	–	**–**	2.9	**–**	96.2
Ian Russell (appointed Chief Executive 17 April 2001)	**550.0**	542.9	**412.5**	–	**32.8**	27.6	**995.3**	570.5
Charles Berry	**300.0**	280.0	**225.0**	–	**25.8**	19.2	**550.8**	299.2
David Nish	**350.0**	325.0	**262.5**	–	**31.2**	23.9	**643.7**	348.9
Alan Richardson (retired 31 December 2001) *	**–**	225.0	**–**	–	**–**	0.8	**–**	225.8
Ken Vowles (retired 31 March 2002)	**–**	300.0	**–**	–	**–**	16.0	**–**	316.0
Total	**1,435.0**	2,001.2	**900.0**	–	**103.8**	104.2	**2,438.8**	2,105.4

	Fees £000's 2003	Fees £000's 2002	Bonuses £000's 2003	Bonuses £000's 2002	Benefits in kind £000's 2003	Benefits in kind £000's 2002	Total £000's 2003	Total £000's 2002
Non-executive directors (fees and expenses)								
Euan Baird	**29.5**	28.5	**–**	–	**0.3**	0.7	**29.8**	29.2
Mair Barnes	**33.0**	32.0	**–**	–	**0.3**	1.0	**33.3**	33.0
Philip Carroll (appointed 15 January 2002)	**31.5**	4.4	**–**	–	**5.0**	0.6	**36.5**	5.0
Sir Peter Gregson	**44.0**	40.5	**–**	–	**1.2**	2.8	**45.2**	43.3
Nolan Karras**	**35.9**	32.8	**–**	–	**14.8**	19.7	**50.7**	52.5
Allan Leighton (resigned 12 June 2002)	**5.5**	27.5	**–**	–	**–**	0.1	**5.5**	27.6
Ewen Macpherson	**40.5**	39.5	**–**	–	**–**	4.0	**40.5**	43.5
Keith McKennon (retired 27 July 2001)	**–**	21.3	**–**	–	**–**	17.4	**–**	38.7
Robert Miller (resigned 8 June 2001)	**–**	6.1	**–**	–	**–**	2.2	**–**	8.3
John Parnaby (retired 27 July 2001)	**–**	12.8	**–**	–	**–**	3.9	**–**	16.7
Nick Rose (appointed 19 February 2003)	**3.7**	–	**–**	–	**–**	–	**3.7**	–
Total	**223.6**	245.4	**–**	–	**21.6**	52.4	**245.2**	297.8

Other emoluments

* Alan Richardson received an additional £381,220 during the financial year ended 31 March 2002 in respect of housing, foreign service allowance and other essential costs associated with his assignment as Executive Director, US, based in Portland, Oregon. These costs include relocation and repatriation to the UK.

** Nolan Karras received emoluments in the US of £16,807 (2002 £22,613) in respect of services to the PacifiCorp and Utah advisory boards in the form of cash and shares.

(i) The emoluments of the highest paid director (Ian Russell) excluding pension contributions were £995,280 (2002 £570,531). In addition, gains on exercise of share options during the year by Ian Russell amounted to £nil (2002 £138,628). Details of other share related incentives are contained in Table 44.

(ii) Ian Russell has an entitlement under the unapproved pension benefits described further in Table 42.

(iii) Sir Ian Robinson retired from the Board on 4 May 2001 and as an employee on 31 May 2001. Alan Richardson retired from the Board and as an employee on 31 December 2001. Ken Vowles retired from the Board and as an employee on 31 March 2002.

(iv) In addition to the above, payments were made during the financial year ended 31 March 2002 to Sir Ian Robinson, £385,000; Alan Richardson, £372,099; and Ken Vowles, £405,649, in accordance with the terms of their respective contracts.

Remuneration Report of the Directors
continued

Table 42 – Defined benefits pension scheme 2002/03

	Transferred -in benefits £ p.a.	Additional pension earned in year (net of inflation) £ p.a.	Accrued pension at end of year £ p.a.	(A) Transfer value of increases after inflation (net of director's contribution) £	Value of accrued pension at start of year £	Value of accrued pension at end of year £	(B) Total change in value during the year (net of director's contributions) £
Ian Russell	15,094	11,947	160,286	142,710	1,493,751	1,915,459	416,818
Charles Berry	–	12,031	97,175	144,625	880,682	1,197,029	311,487
David Nish	37,333	10,851	79,932	100,339	536,162	804,254	263,232

(i) The accrued entitlement of the highest paid director (Ian Russell) was £160,286 (2002 £144,159). During the year, retirement benefits were accrued under the defined benefits pension scheme in respect of three directors (2002 five directors).

(ii) The transfer value of the increases after inflation (A) represents the current capital sum which would be required, using demographic and financial assumptions, to produce an equivalent increase in accrued pension and ancillary benefits, excluding the statutory inflationary increase, and after deduction of members' contributions. Although the transfer value represents a liability to the Pension Scheme in respect of approved benefits and to the company in respect of unapproved benefits, it is not a single sum paid or due to be paid to the individual director and cannot therefore meaningfully be added to the annual remuneration. Instead, this value would not be payable until the director's retirement date, and thereafter would be spread over the remainder of his lifetime (and also covering the cost of dependants' benefits after his death).

(iii) The total change in value (B) in the last column of the table above reflects the following elements:

1. Changes to the economic and demographic assumptions underlying the transfer value basis over the year.

2. Increases in pensionable salary received by directors during the year.

3. The directors have completed another year of pensionable service during the year.

4. The directors are a year closer to drawing their pensions at the end of the year.

During the year the transfer value basis for approved benefits altered. The transfer value for approved benefits at the start of the year was calculated broadly in line with the statutory Minimum Funding Requirement ("MFR") basis. However, by the end of the year the MFR transfer value basis for approved benefits no longer met the actuarial profession's guidance for certifying transfer values. Based on current market conditions, the end of year transfer value basis provides for higher transfer values than the basis at the start of the year (all other things being equal).

The change in the amount of the transfer values over the year includes the effect of fluctuations in factors that are beyond the control of the company and its directors, such as stock market movements and long-term interest rates.

(iv) The accrued pension shown is that which would be paid annually on retirement based upon service to the end of the year. Members of the company's schemes have the option of paying additional voluntary contributions; neither the contributions nor the resulting benefits are included in the above table.

(v) Directors who joined the pension scheme on or after 1 June 1989 are subject to the earnings cap, introduced in the Finance Act 1989. Pension entitlements which cannot be provided through the company's approved schemes due to the earnings cap are provided through unapproved pension arrangements, details of which are included in the Remuneration Report. The pension benefits disclosed above include approved and unapproved pension arrangements.

(vi) The increase in accrued pension during the year excludes the increase due to RPI inflation as measured at December 2002 (2.9%).

(vii) The value of directors' entitlements has been calculated on the basis of actuarial advice in accordance with Actuarial Guidance note GN11, in two parts: the approved element being based upon the normal cash equivalent transfer value assumptions less directors' contributions; the unapproved element being calculated in line with FRS 17 assumptions.

(viii) Transferred-in benefits represent pension rights accrued in respect of previous employments.

(ix) The total liabilities, calculated on a FRS 17 basis, for the 9 executives and senior employees arising in relation to unapproved benefits for service for the year to 31 March 2003 was £208,700 (2002 £690,000). All benefits for the above are provided on a defined benefit basis.

Table 43 – Directors' interests in ScottishPower shares

	Ordinary shares		Share options (Executive)		Share options (Sharesave)		Long Term Incentive Plan			
	31.3.03	1.4.02 (or date of appointment if later)	31.3.03	1.4.02 (or date of appointment if later)	31.3.03	1.4.02 (or date of appointment if later)	31.3.03 **Vested	31.3.03 *Potential	1.4.02 (or date of appointment if later) **Vested	1.4.02 (or date of appointment if later) *Potential
Charles Miller Smith	11,000	11,000	–	–	–	–	–	–	–	–
Euan Baird	110,770	100,000	–	–	–	–	–	–	–	–
Mair Barnes	1,400	1,400	–	–	–	–	–	–	–	–
Philip Carroll	4,000	–	–	–	–	–	–	–	–	–
Sir Peter Gregson	1,186	1,093	–	–	–	–	–	–	–	–
Nolan Karras	36,346	31,286	–	–	–	–	–	–	–	–
Ewen Macpherson	5,000	5,000	–	–	–	–	–	–	–	–
Nick Rose (appointed 19 February 2003)	–	–	–	–	–	–	–	–	–	–
Ian Russell	•87,741	86,817	498,678	227,743	4,371	4,371	12,682	238,675	12,682	175,063
Charles Berry	•22,553	18,958	255,443	107,660	2,941	903	–	124,328	4,433	87,904
David Nish	•12,742	7,294	296,636	124,223	2,509	2,509	–	137,954	4,191	85,030

None of the directors has an interest in ordinary shares which is greater than 1% of the issued share capital of the company.

* These shares represent, in each case, the maximum number of shares which the directors may receive, dependent on the satisfaction of performance criteria as approved by shareholders in connection with the Long Term Incentive Plan.

** These shares represent the number of shares the directors are entitled to receive when the LTIP award is exercisable after the fourth anniversary of grant calculated according to the performance criteria measured over the three-year performance period.

• These shares include the number of shares which the directors hold in the Employee Share Ownership Plan, shown below.

	Free shares	Partnership shares	Matching shares	Dividend shares	Total
Ian Russell	50	799	799	135	1,783
Charles Berry	50	799	799	135	1,783
David Nish	50	799	799	135	1,783

Between 31 March 2003 and 7 May 2003, Ian Russell, Charles Berry and David Nish each acquired 32 Partnership shares and 32 Matching shares as part of the regular monthly transactions of the Employee Share Ownership Plan; and Nolan Karras acquired 20 ScottishPower ADSs (80 Ordinary shares) as part of the PacifiCorp Compensation Reduction Plan. Otherwise, there have been no changes to the directors' interests between 31 March 2003 and 7 May 2003.

Table 44 – Directors' interests in performance and other share plans at 31 March 2003

	1 April 2002	Granted	Exercised	Lapsed#	31 March 2003	Option exercise price (pence)	Date exercised	Market price at date of exercise (pence)	Date from which exercisable	Expiry date
Long Term Incentive Plan										
Ian Russell	12,682	–	–	–	12,682	nil			7 May 02	6 May 05
	37,988	–	–	37,988	–	nil			10 May 03	9 May 06
	45,000	–	–	–	45,000	nil			5 May 04	4 May 07
	92,075	–	–	–	92,075	nil			4 May 04	3 May 08
	–	101,600	–	–	101,600	nil			2 May 05	1 May 09
	187,745	**101,600**	**–**	**37,988**	**251,357**					
Charles Berry	4,433	–	4,433	–	–	nil	17 May 02	389.375	7 May 02	6 May 05
	18,994	–	–	18,994	–	nil			10 May 03	9 May 06
	25,384	–	–	–	25,384	nil			5 May 04	4 May 07
	43,526	–	–	–	43,526	nil			4 May 04	3 May 08
	–	55,418	–	–	55,418	nil			2 May 05	1 May 09
	92,337	**55,418**	**4,433**	**18,994**	**124,328**					
David Nish	4,191	–	4,191	–	–	nil	17 May 02	389.375	7 May 02	6 May 05
	11,731	–	–	11,731	–	nil			10 May 03	9 May 06
	23,076	–	–	–	23,076	nil			5 May 04	4 May 07
	50,223	–	–	–	50,223	nil			4 May 04	3 May 08
	–	64,655	–	–	64,655	nil			2 May 05	1 May 09
	89,221	**64,655**	**4,191**	**11,731**	**137,954**					

During the year, the performance period for the awards granted under the Long Term Incentive Plan in 1999 ended and, on the basis of the company's total shareholder return, none of the awards vested.

Awards granted during the year were granted for no consideration. The market value of a ScottishPower share at the date of grant was 406.00 pence.

Footnote
Awards granted to directors under the Long Term Incentive Plan on 10 May 2003 were as follows: Ian Russell 129,568; Charles Berry 62,790; and David Nish 82,724.

Remuneration Report of the Directors
continued

Table 44 – Directors' interests in performance and other share plans at 31 March 2003 continued

	1 April 2002	Granted	Exercised	Lapsed	31 March 2003	Option exercise price (pence)	Date exercised	Market price at date of exercise (pence)	Date from which exercisable	Expiry date
Executive Share Option Plan 2001										
Ian Russell	227,743	–	–	–	227,743	483.0			21 Aug 04	21 Aug 11
	–	270,935	–	–	270,935	406.0			2 May 05	2 May 12
	227,743	**270,935**	**–**	**–**	**498,678**					
Charles Berry	107,660	–	–	–	107,660	483.0			21 Aug 04	21 Aug 11
	–	147,783	–	–	147,783	406.0			2 May 05	2 May 12
	107,660	**147,783**	**–**	**–**	**255,443**					
David Nish	124,223	–	–	–	124,223	483.0			21 Aug 04	21 Aug 11
	–	172,413	–	–	172,413	406.0			2 May 05	2 May 12
	124,223	**172,413**	**–**	**–**	**296,636**					
Sharesave Scheme										
Ian Russell	4,371	–	–	–	4,371	386.0			1 Sep 06	28 Feb 07
	4,371	**–**	**–**	**–**	**4,371**					
Charles Berry	903	–	–	903	–	429.0*			1 Sep 02	28 Feb 03
	–	2,941	–	–	2,941	323.0*			1 Sep 05	28 Feb 06
	903	**2,941**	**–**	**903**	**2,941**					
David Nish	2,509	–	–	–	2,509	386.0*			1 Sep 04	28 Feb 05
	2,509	**–**	**–**	**–**	**2,509**					

*Denotes options granted under a three-year scheme.

(i) The market price of the shares at 31 March 2003 was 376.00 pence and the range during 2002/03 was 298.75 pence to 416.00 pence.

(ii) The Long Term Incentive Plan makes annual awards to acquire shares in ScottishPower at nil or nominal cost to the plan participants up to a maximum value equal to 75% of base salary. The award will vest only if the Remuneration Committee is satisfied that certain performance measures related to the sustained underlying financial performance of the company and improvements in certain Customer Service Standards published by Ofgem, Energywatch and the US Public Utility Commissions are achieved over a period of three financial years commencing with the financial year preceding the date an award is made. Assuming that such targets have been achieved, the number of shares that can be acquired will be dependent upon how the company ranks in terms of its total shareholder return performance over a three-year period, in comparison to the constituent companies of the FTSE 100 index and the Electricity and Water sectors and a group of international energy companies. A percentage of each half of the award will vest depending upon the company's ranking within each of the comparator groups. The plan participant may acquire the shares in respect of the percentage of the award which has vested at any time after the third or fourth year, as appropriate, up to the seventh year after the grant of the award. No dividends accrue to participants prior to vesting.

(iii) The company grants options annually under the Executive Share Option Plan 2001 to relevant executives and senior managers. These options are subject to the performance criterion that the percentage increase in the company's annualised earnings per share be at least 3% (adjusted for any increase in the Retail Price Index). This criterion is assessed at the end of the third financial year, the first year being the financial year starting immediately before the date of grant. If the criterion is not satisfied over this period it is tested again at the end of the fourth financial year. If the criterion is not satisfied over this period, it is tested again at the end of the fifth financial year. If the criterion is not satisfied over this period, then the options lapse.

(iv) The option price for Sharesave options is calculated by reference to the middle-market quotation on the day immediately preceding the date of invitation and discounted by 20% in accordance with the Inland Revenue rules for such schemes.

(v) The number of options granted to a director under the Sharesave Scheme is calculated by reference to the total amount which the director agrees to save for a period of three or five years under an Inland Revenue approved savings contract, subject to a current maximum.

(vi) Total gains made on exercise of directors' share options and awards during the year were £33,580 (2002 £295,205).

(vii) Awards and options granted during the year under the Long Term Incentive Plan and Executive Share Option Plan 2001 were granted for no consideration.

Footnote

Options granted to directors under the Executive Share Option Plan 2001 on 10 May 2003 were as follows: Ian Russell 345,514; Charles Berry 167,441; and David Nish 220,598.

Approved by the Board and signed on its behalf by

P. L. Gregson

Sir Peter Gregson
Chairman of the Remuneration Committee
7 May 2003

Directors' responsibility for the Accounts

The directors are required by law to prepare Accounts for each financial year and to present them annually to the company's members at the Annual General Meeting. The Accounts, of which the form and content are prescribed by the Companies Act 1985 and applicable accounting standards, must give a true and fair view of the state of affairs of the company and of the group as at the end of the financial year, and of the group's profit or loss for the period.

The directors confirm that suitable Accounting Policies have been used and applied consistently, and that reasonable and prudent judgements and estimates have been made in the preparation of the Accounts for the year ended 31 March 2003. The directors also confirm that applicable accounting standards have been followed and that the Accounts have been prepared on the going concern basis.

The directors are responsible for maintaining proper accounting records and sufficient internal controls to safeguard the assets of the company and of the group and to prevent and detect fraud or any other irregularities.

Auditors

Following the conversion of the company's auditors PricewaterhouseCoopers to a Limited Liability Partnership (LLP) from 1 January 2003, PricewaterhouseCoopers resigned on 21 March 2003 and the directors appointed its successors, PricewaterhouseCoopers LLP, as auditors. A resolution to re-appoint PricewaterhouseCoopers LLP as auditors to the company will be proposed at the Annual General Meeting.

Report of the directors

The Report of the Directors comprising the statements and reports has been approved by the Board and signed on its behalf by

Andrew Mitchell
Secretary
7 May 2003

Cautionary statement for purposes of the "Safe Harbor" provisions of the Private Securities Litigation Reform Act of 1995

Some statements made in this Annual Report & Accounts are forward-looking statements within the meaning of the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. All statements with respect to us, our corporate plans, future financial condition, future results of operations, future business plans, strategies, objectives and beliefs and other statements that are not historical facts are forward looking. Statements containing the words "may", "will", "expect", "anticipate", "intend", "estimate", "continue", "plan", "project", "target", "on track to", "strategy", "aim", "seek", "will meet" or other similar words are also forward looking. These statements are based on our management's assumptions and beliefs in light of the information available to us. These assumptions involve risks and uncertainties which may cause the actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements.

ScottishPower wishes to caution readers, and others to whom forward-looking statements are addressed, that any such forward-looking statements are not guarantees of future performance and that actual results may differ materially from estimates in the forward-looking statements. ScottishPower undertakes no obligation to revise these forward-looking statements to reflect events or circumstances after the date hereof. Important factors that may cause results to differ from expectations include, for example:

– any regulatory changes (including changes in environmental regulations) that may increase the operating costs of the group, may require the group to make unforeseen capital expenditures or may prevent the regulated business of the group from achieving acceptable returns;

– future levels of industry generation and supply, demand and pricing, political stability, competition and economic growth in the relevant areas in which the group has operations;

– the availability of acceptable fuel at favorable prices;

– the availability of operational capacity of plants;

– the success of reorganizational and cost-saving efforts; and

– development and use of technology, the actions of competitors, natural disasters and other changes to business conditions.

Accounts 2002/03

Accounting Policies and Definitions

Definitions

Business segment definitions
ScottishPower defines business segments for management reporting purposes based on a combination of factors, principally differences in products and services and the regulatory environment in which the businesses operate.

Business segments have been included under either 'continuing operations' or 'discontinued operations' as appropriate.

The business segments of the group are defined as follows:

Continuing operations

United Kingdom

UK Division – Integrated Generation and Supply
The generation of electricity from the group's own power stations, the purchase of external supplies of coal and gas for the generation of electricity, the purchase of external supplies of electricity and gas for sale to customers, together with related billing and collection activities, gas storage, sale of gas to industrial and domestic customers and the sale of electricity to electricity suppliers, in Scotland and England & Wales and full participation in the New Electricity Trading Arrangements ("NETA") in England & Wales.

Infrastructure Division – Power Systems
The transmission and distribution businesses in Scotland and the distribution business of Manweb operating in Merseyside and North Wales and, specifically, the transportation of units of electricity from the power stations through the transmission and distribution networks to customers in Scotland and to customers in Northern Ireland and England & Wales through the Interconnectors.

United States

US Division – PacifiCorp
A vertically integrated electric utility that includes the generation, transmission and distribution and sale of electricity to retail, industrial and commercial customers in portions of six western states; Utah, Oregon, Wyoming, Washington, Idaho and California. The operations also include wholesale sales and power purchase transactions with various entities. The state regulatory commissions and Federal Energy Regulatory Commission ("FERC") regulate the retail and wholesale operations. The subsidiaries of PacifiCorp support its electric utility operations by providing coal mining facilities and services, environmental remediation and financing.

US Division – PPM
The competitive energy development, origination and marketing business serving wholesale customers in North American markets. Electricity products and services are provided from gas generation and renewable wind generation resources located in the western and mid-western US. Natural gas storage and hub services are provided from gas storage facilities located in Alberta, Canada and in Texas.

Discontinued operations

United Kingdom

Southern Water
The provision of water and wastewater services in the south-east of England, together with related billing and collection activities. The disposal of the Southern Water business was completed on 23 April 2002.

Thus
The provision of telecommunications services, internet access and information services to national corporates, small and medium-sized enterprises and residential customers. Thus Group plc ("Thus") was demerged from ScottishPower on 19 March 2002.

Appliance Retailing
The retailing and servicing of domestic electrical goods and home entertainment appliances. The business was disposed of and withdrawn from during the year ended 31 March 2002.

Revenue cost definitions

Cost of sales
The cost of sales for the group, excluding Southern Water, reflect the direct costs of the generation and purchase of electricity, the purchase and transportation of natural gas, appliance retailing and telecommunications services. For Southern Water, cost of sales represented the cost of extracting water from underground and raw water surface reservoirs and of its treatment and supply to customers and the collection of wastewater and its treatment and disposal.

Transmission and distribution costs
The cost of transmitting units of electricity from the power stations through the transmission and distribution networks to customers. It includes the costs of metering, billing and debt collection. This heading is considered more appropriate to the electricity industry than the standard Companies Act heading of distribution costs.

Administrative expenses
The indirect costs of businesses, the costs of corporate services, property rates and goodwill amortisation.

Other definitions

Company or ScottishPower
Scottish Power plc.

Group
Scottish Power plc and its consolidated subsidiaries.

Associated undertakings
Entities in which the group holds a long-term participating interest and exercises significant influence.

Joint ventures
Entities in which the group holds a long-term interest and shares control with another company external to the group.

Subsidiary undertakings
Entities in which the group holds a long-term controlling interest.

Accounting Policies

Basis of accounting

The Accounts have been prepared under the historical cost convention, modified to include the revaluation of certain tangible fixed assets, and in accordance with applicable accounting standards in the UK and, subject to the treatment, prior to the disposal of Southern Water, of water infrastructure grants and contributions described under "Grants and contributions" below, comply with the requirements of the Companies Act 1985.

Basis of consolidation

The group Accounts include the Accounts of the company and its subsidiary undertakings together with the group's share of results and net assets of associated undertakings and joint ventures.

For commercial reasons certain subsidiaries have a different year end. The consolidation includes the Accounts of these subsidiaries as adjusted for material transactions in the period between the year ends and 31 March.

Use of estimates

The preparation of Accounts in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Accounts and the reported amounts of revenues and expenses during the reporting period. Actual results can differ from those estimates.

Turnover

Turnover comprises the sales value of energy, goods and other services supplied to customers during the year and excludes Value Added Tax and intra-group sales. Turnover from the sale of energy is the value of units supplied during the year and includes an estimate of the value of units supplied to customers between the date of their last meter reading and the year end, based on external data supplied by the electricity and gas market settlement processes. Prior to the disposal of Southern Water in April 2002, turnover also included the sales value of water and wastewater services.

Interest

Interest on the funding attributable to major capital projects is capitalised gross of tax relief during the period of construction and written off as part of the total cost over the operational life of the asset. All other interest payable and receivable is reflected in the profit and loss account as it arises.

Financial instruments

Debt instruments

All borrowings are stated at the fair value of consideration received after deduction of issue costs. The issue costs and interest payable on bonds are charged to the profit and loss account at a constant rate over the life of the bond. Premiums and discounts arising on the early repayment of borrowings are recognised in the profit and loss account as incurred and received.

Interest rate swaps/Forward rate agreements

These are used to manage debt interest rate exposures. Amounts payable or receivable in respect of these agreements are recognised as adjustments to interest expense over the period of the contracts. The cash flows from, and gains and losses arising on terminations of, these contracts are recognised as returns on investments and servicing of finance. Where associated debt is not retired in conjunction with the termination of an interest swap, gains and losses are deferred and are amortised to interest expense over the remaining life of the associated debt to the extent that such debt remains outstanding.

Interest rate caps/Swaptions/Options

Premiums received and payable on these contracts are amortised over the period of the contracts and are disclosed as interest income and expense. The accounting for interest rate caps and swaptions is otherwise in accordance with interest rate swaps detailed above.

Cross currency interest rate swaps

These are used both to hedge foreign exchange and interest rate exposures arising on foreign currency debt and to hedge overseas net investment. Where used to hedge debt issues, the debt is recorded at the hedge contracted rate and accounting is otherwise in accordance with interest rate swaps detailed above. Where used to hedge overseas net investment, spot gains or losses are recorded in the statement of total recognised gains and losses, with interest recorded in the profit and loss account.

Forward contracts

The group enters into forward contracts for the purchase and/or sale of foreign currencies in order to manage its exposure to fluctuations in currency rates and to hedge overseas net investment. The cash flows from forward purchase contracts are classified in a manner consistent with the underlying nature of the hedged transaction. Hence, unrealised gains and losses on contracts hedging forecast transactions are not accounted for until the maturity of the contract. Foreign currency debtors and creditors that are hedged with forward contracts are translated at the contracted rate at the balance sheet date. Spot gains or losses on hedges of the overseas net investment are recorded in the statement of total recognised gains and losses with the interest rate differential reflected in the profit and loss account. Where a currency forward contract no longer represents a hedge because either the underlying asset or liability has been derecognised, or the effectiveness of the hedge has been undermined, it is restated at fair value and any change in value is taken directly to the profit and loss account and reported within exchange losses.

Hydro-electric and temperature hedges

These instruments are used to hedge fluctuations in weather and temperature in the US. On a periodic basis, the group estimates and records a gain or loss in the profit and loss account corresponding to the total expected future cash flows from these contracts.

Commodity contracts

Where there is no physical delivery associated with commodity contracts, they are recorded at fair value on the balance sheet and movements reflected through the profit and loss account. Gas future contracts are undertaken for hedging and proprietary trading purposes. Where the instrument is a hedge, the daily margin calls are initially reflected on the balance sheet and subsequently reflected through the profit and loss account to match the recognition of the hedged item. Where the instrument is for proprietary trading the margin calls are reflected through the profit and loss account.

Accounting Policies and Definitions

Taxation
In accordance with Financial Reporting Standard 19 'Deferred tax', full provision is made for deferred tax on a non-discounted basis.

Goodwill
Purchased goodwill represents the excess of the fair value of the purchase consideration over the fair value of the net assets acquired. Goodwill arising from acquisitions prior to 31 March 1998 was written off against reserves.
On disposal of trading entities, the goodwill previously included in reserves is charged to the profit and loss account matched by an equal credit to reserves.
Goodwill arising on acquisitions since 1 April 1998 has been capitalised and amortised through the profit and loss account over its estimated useful economic life. Goodwill arising on overseas acquisitions is regarded as a currency asset and is retranslated at the end of each period at the closing rate of exchange.

Tangible fixed assets
Accounting for non-water infrastructure assets
Tangible fixed assets are stated at cost or valuation and are generally depreciated on the straight line method over their estimated operational lives. Tangible fixed assets include capitalised employee, interest and other costs which are directly attributable to construction of fixed assets.

Land is not depreciated except in the case of mines (see below). The main depreciation periods used by the group are as set out below.

	Years
Coal, oil-fired, gas and other generating stations	22-45
Hydro plant and machinery	20-100
Other buildings	40
Transmission and distribution plant	20-75
Towers, lines and underground cables	40-60
Vehicles, computer software costs, miscellaneous equipment and fittings	3-40

The carrying values of tangible fixed assets are reviewed for impairment in periods if events or changes in circumstances indicate the carrying value may not be recoverable. For those assets with estimated remaining useful economic lives of more than 50 years, impairment reviews are undertaken annually. Impairment losses are recognised in the period in which they are identified.

Mine reclamation and closure costs
Provision is made for mine reclamation and closure costs when an obligation arises out of events prior to the year end. The amount recognised is the present value of the estimated future expenditure determined in accordance with local conditions and requirements. A corresponding tangible fixed asset is also created of an amount equal to the provision. This asset, together with the cost of the mine, is subsequently depreciated on a unit of production basis. The unwinding of the discount is included within net interest and similar charges.

Decommissioning costs
Provision is made for the estimated decommissioning costs at the end of the producing lives of the group's power stations on a discounted basis. Capitalised decommissioning costs are depreciated over the useful lives of the related assets. The unwinding of the discount is included within net interest and similar charges.

Infrastructure accounting
Water infrastructure assets, being mains and sewers, reservoirs, dams, sludge pipelines and sea outfalls comprised a network of systems. Expenditure on water infrastructure assets relating to increases in capacity or enhancement of the network and on maintaining the operating capability of the network in accordance with defined standards of service was treated as an addition to fixed assets.

The depreciation charge for water infrastructure assets was the estimated level of annualised expenditure required to maintain the operating capability of the network and was based on the asset management plan agreed with the water industry regulator as part of the price regulation process.

The asset management plan was developed from historical experience combined with a rolling programme of reviews of the condition of the infrastructure assets.

Leased assets
As lessee
Assets leased under finance leases are capitalised and depreciated over the shorter of the lease periods and the estimated operational lives of the assets. The interest element of the finance lease repayments is charged to the profit and loss account in proportion to the balance of the capital repayments outstanding. Rentals payable under operating leases are charged to the profit and loss account on a straight line basis.

As lessor
Rentals receivable under finance leases are allocated to accounting periods to give a constant periodic rate of return on the net cash investment in the lease in each period. The amounts due from lessees under finance leases are recorded in the balance sheet as a debtor at the amount of the net investment in the lease after making provisions for bad and doubtful rentals receivable.

Investments
Investments in subsidiary and associated undertakings and joint ventures are stated in the balance sheet of the parent company at cost, or nominal value of shares issued as consideration where applicable, less provision for any impairment in value. The group profit and loss account includes the group's share of the operating profits less losses, net interest charge and taxation of associated undertakings and joint ventures. The group balance sheet includes the investment in associated undertakings and joint ventures at the group's share of their net assets. Other fixed asset investments are carried at cost less provision for impairment in value.

Own shares held under trust
The amount recorded in the balance sheet for shares in the company purchased for employee sharesave schemes represents the amounts receivable from option holders on exercise of the options.

The group has taken advantage of the exemption within Urgent Issues Task Force ("UITF") Abstract 17 not to apply the requirements therein to Inland Revenue approved savings-related share option schemes and equivalent overseas schemes.

Long Term Incentive Plan ("LTIP")
Shares in the company purchased for the LTIP are held under trust and are recorded within investments in the balance sheet at cost. The cost of awards made by the trust under the LTIP, being the difference between the fair value of the shares and the option price at the date of grant, is taken to the profit and loss account on a straight line basis over the period in which performance is measured.

Stocks
Stocks are valued at the lower of average cost and net realisable value.

US regulatory assets
Statement of Financial Accounting Standard ("FAS") 71 'Accounting for the Effects of Certain Types of Regulation' establishes US GAAP for utilities in the US whose regulators have the power to approve and/or regulate rates that may be charged to customers. FAS 71 provides that regulatory assets may be capitalised if it is probable that future revenue in an amount at least equal to the capitalised costs will result from the inclusion of that cost in allowable costs for ratemaking purposes. Due to the different regulatory environment, no equivalent GAAP applies in the UK.

Under UK GAAP, the group's policy is to recognise regulatory assets established in accordance with FAS 71 only where they comprise rights or other access to future economic benefits which have arisen as a result of past transactions or events which have created an obligation to transfer economic benefits to a third party. Measurement of the past transaction or event and hence the regulatory asset, is determined in accordance with UK GAAP.

Grants and contributions
Capital grants and customer contributions in respect of additions to non-water infrastructure fixed assets are treated as deferred income and released to the profit and loss account over the estimated operational lives of the related assets. Prior to the disposal of Southern Water in April 2002, grants and contributions receivable relating to water infrastructure assets were deducted from the cost or valuation of those assets. While this treatment was in accordance with SSAP 4, it was not in accordance with the Companies Act 1985. The Act requires capital grants and contributions to be shown as deferred income rather than offset against the cost or valuation of tangible fixed assets.

This departure from the requirements of the Act was, in the opinion of the directors, necessary for the Accounts to give a true and fair view as, while provision was made for depreciation of water infrastructure assets, these assets did not have determinable finite lives and therefore no basis existed on which to recognise grants and contributions as deferred income. The effect of this treatment on the value of tangible fixed assets is disclosed in Note 16.

Pensions
The group provides pension benefits through both defined benefit and defined contribution arrangements. The regular cost of providing pensions and related benefits and any variations from regular cost arising from the actuarial valuations for defined benefit schemes are charged to the profit and loss account over the expected remaining service lives of current employees following consultations with the actuary. Any difference between the charge to the profit and loss account and the actual contributions paid to the pension schemes is included as an asset or liability in the balance sheet. Payments to defined contribution schemes are charged against profits as incurred.

Post-retirement benefits other than pensions
Certain additional post-retirement benefits, principally healthcare benefits, are provided to eligible retirees within the group's US businesses. The estimated cost of providing such benefits is charged against profits on a systematic basis over the employees' working lives within the group.

Environmental liabilities
Provision for environmental liabilities is made when expenditure on remedial work is probable and the group is obliged, either legally or constructively through its environmental policies, to undertake such work. Where the amount is expected to be incurred over the long-term, the amount recognised is the present value of the estimated future expenditure and the unwinding of the discount is included within net interest and similar charges.

Foreign currencies

Group
The results and cash flows of overseas subsidiaries are translated to sterling at the average rate of exchange for each quarter of the financial year. The net assets of such subsidiaries and the goodwill arising on their acquisition are translated to sterling at the closing rates of exchange ruling at the balance sheet date. Exchange differences which relate to the translation of overseas subsidiaries and of matching foreign currency borrowings and derivatives are taken directly to group reserves and are shown in the statement of total recognised gains and losses.

Company
Transactions in foreign currencies are recorded at the rate ruling at the date of the transaction. At the year end, monetary assets and liabilities denominated in foreign currencies are translated at the rate of exchange ruling at the balance sheet date or, where applicable, at the hedged contracted rate. Any gain or loss arising on the restatement of such balances is taken to the profit and loss account.

Overseas net investments that are partially hedged with foreign currency borrowings and derivatives are viewed as a foreign currency asset to the extent that they are matched with these instruments. Exchange differences arising on re-translation of the investment and the borrowings and derivatives are taken directly to reserves. The remaining unhedged element of the investment is recorded at historical cost at the exchange rate ruling at the date of acquisition without further re-translation.

Exchange rates
The exchange rates applied in the preparation of the Accounts were as follows:

	Year ended 31 March		
	2003	2002	2001
Average rate for quarters ending:			
30 June	**$1.46/£**	$1.42/£	$1.53/£
30 September	**$1.55/£**	$1.44/£	$1.48/£
31 December	**$1.57/£**	$1.44/£	$1.45/£
31 March	**$1.60/£**	$1.43/£	$1.46/£
Closing rate as at 31 March	**$1.58/£**	$1.42/£	$1.42/£

A glossary of terms used in the Accounts and their US equivalents is set out on page 133.

Group Profit and Loss Account
for the year ended 31 March 2003

	Notes	Year ended 31 March 2003 Continuing operations 2003 £m	Discontinued operations 2003 £m	Total 2003 £m
Turnover: group and share of joint ventures and associates		5,273.1	26.7	5,299.8
Less: share of turnover in joint ventures		(25.2)	–	(25.2)
Less: share of turnover in associates		(0.8)	–	(0.8)
Group turnover	1	5,247.1	26.7	5,273.8
Cost of sales		(3,215.4)	(11.4)	(3,226.8)
Gross profit		2,031.7	15.3	2,047.0
Transmission and distribution costs		(512.6)	–	(512.6)
Administrative expenses (including goodwill amortisation)		(613.2)	(1.3)	(614.5)
Other operating income		26.0	–	26.0
Operating profit before goodwill amortisation		1,070.9	14.0	1,084.9
Goodwill amortisation		(139.0)	–	(139.0)
Operating profit	1, 2	931.9	14.0	945.9
Share of operating profit in joint ventures		4.8	–	4.8
Share of operating profit in associates		0.4	–	0.4
Profit on ordinary activities before interest		937.1	14.0	951.1
Net interest and similar charges				
– Group		(245.9)	(3.0)	(248.9)
– Joint ventures		(5.4)	–	(5.4)
	5	(251.3)	(3.0)	(254.3)
Profit on ordinary activities before goodwill amortisation and taxation		824.8	11.0	835.8
Goodwill amortisation		(139.0)	–	(139.0)
Profit on ordinary activities before taxation		685.8	11.0	696.8
Taxation				
– Group		(205.8)	(3.4)	(209.2)
– Joint ventures		0.3	–	0.3
– Associates		(0.1)	–	(0.1)
	6	(205.6)	(3.4)	(209.0)
Profit after taxation		480.2	7.6	487.8
Minority interests	27	(5.2)	–	(5.2)
Profit for the financial year		475.0	7.6	482.6
Dividends	8	(529.5)	–	(529.5)
Loss retained	26	(54.5)	7.6	(46.9)
Earnings per ordinary share	7	25.76p	0.41p	26.17p
Adjusting item – goodwill amortisation		7.54p	–	7.54p
Earnings per ordinary share before goodwill amortisation	7	33.30p	0.41p	33.71p
Diluted earnings per ordinary share	7			26.11p
Adjusting item – goodwill amortisation				7.52p
Diluted earnings per ordinary share before goodwill amortisation	7			33.63p
Dividends per ordinary share	8			28.708p

The Accounting Policies and Definitions on pages 70 to 73, together with the Notes on pages 78 to 83, 85 to 87, 89 to 126 and 128 to 130 form part of these Accounts.

Group Profit and Loss Account
for the year ended 31 March 2002

		Year ended 31 March 2002						
	Notes	Continuing operations 2002 £m	Exceptional items -continuing operations (Note 4) 2002 £m	Total continuing operations 2002 £m	Discontinued operations 2002 £m	Exceptional items -discontinued operations (Note 4) 2002 £m	Total discontinued operations 2002 £m	Total 2002 £m
Turnover: group and share of joint ventures and associates		5,545.9	–	5,545.9	791.3	–	791.3	6,337.2
Less: share of turnover in joint ventures		(22.6)	–	(22.6)	–	–	–	(22.6)
Less: share of turnover in associates		(0.5)	–	(0.5)	–	–	–	(0.5)
Group turnover	1	5,522.8	–	5,522.8	791.3	–	791.3	6,314.1
Cost of sales		(3,920.0)	–	(3,920.0)	(490.8)	–	(490.8)	(4,410.8)
Gross profit		1,602.8	–	1,602.8	300.5	–	300.5	1,903.3
Transmission and distribution costs		(479.3)	–	(479.3)	(33.3)	–	(33.3)	(512.6)
Administrative expenses (including goodwill amortisation)		(533.8)	(18.5)	(552.3)	(142.8)	–	(142.8)	(695.1)
Other operating income		64.2	–	64.2	3.6	–	3.6	67.8
Utilisation of Appliance Retailing disposal provision		–	–	–	13.2	–	13.2	13.2
Operating profit before goodwill amortisation		800.5	(18.5)	782.0	143.6	–	143.6	925.6
Goodwill amortisation		(146.6)	–	(146.6)	(2.4)	–	(2.4)	(149.0)
Operating profit	1, 2	653.9	(18.5)	635.4	141.2	–	141.2	776.6
Share of operating profit in joint ventures		2.2	–	2.2	–	–	–	2.2
Share of operating profit in associates		0.2	–	0.2	–	–	–	0.2
		656.3	(18.5)	637.8	141.2	–	141.2	779.0
Loss on disposal of and withdrawal from Appliance Retailing before goodwill write back	4	–	–	–	–	(105.0)	(105.0)	(105.0)
Goodwill write back	4	–	–	–	–	(15.1)	(15.1)	(15.1)
Loss on disposal of and withdrawal from Appliance Retailing	4	–	–	–	–	(120.1)	(120.1)	(120.1)
Provision for loss on disposal of Southern Water before goodwill write back	4	–	–	–	–	(449.3)	(449.3)	(449.3)
Goodwill write back	4	–	–	–	–	(738.2)	(738.2)	(738.2)
Provision for loss on disposal of Southern Water	4	–	–	–	–	(1,187.5)	(1,187.5)	(1,187.5)
Profit / (loss) on ordinary activities before interest		656.3	(18.5)	637.8	141.2	(1,307.6)	(1,166.4)	(528.6)
Net interest and similar charges								
– Group before exceptional interest and similar charges		(336.3)	–	(336.3)	(36.9)	–	(36.9)	(373.2)
– Exceptional interest and similar charges	4	–	(18.8)	(18.8)	–	(12.0)	(12.0)	(30.8)
– Joint ventures		(6.2)	–	(6.2)	–	–	–	(6.2)
	5	(342.5)	(18.8)	(361.3)	(36.9)	(12.0)	(48.9)	(410.2)
Profit / (loss) on ordinary activities before goodwill amortisation and taxation		460.4	(37.3)	423.1	106.7	(1,319.6)	(1,212.9)	(789.8)
Goodwill amortisation		(146.6)	–	(146.6)	(2.4)	–	(2.4)	(149.0)
Profit / (loss) on ordinary activities before taxation		313.8	(37.3)	276.5	104.3	(1,319.6)	(1,215.3)	(938.8)
Taxation								
– Group before tax on exceptional items		(68.0)	–	(68.0)	(55.1)	–	(55.1)	(123.1)
– Tax on exceptional items	4	–	11.3	11.3	–	27.5	27.5	38.8
– Joint ventures		1.1	–	1.1	–	–	–	1.1
	6	(66.9)	11.3	(55.6)	(55.1)	27.5	(27.6)	(83.2)
Profit / (loss) after taxation		246.9	(26.0)	220.9	49.2	(1,292.1)	(1,242.9)	(1,022.0)
Minority interests	27	(6.9)	–	(6.9)	41.8	–	41.8	34.9
Profit / (loss) for the financial year		240.0	(26.0)	214.0	91.0	(1,292.1)	(1,201.1)	(987.1)
Dividends								
– Cash	8	(503.5)	–	(503.5)	–	–	–	(503.5)
– Dividend in specie on demerger of Thus	8	–	–	–	(436.6)	–	(436.6)	(436.6)
		(503.5)	–	(503.5)	(436.6)	–	(436.6)	(940.1)
Loss retained	26	(263.5)	(26.0)	(289.5)	(345.6)	(1,292.1)	(1,637.7)	(1,927.2)
Earnings / (loss) per ordinary share	7	13.06p	(1.41)p	11.65p	4.95p	(70.31)p	(65.36)p	(53.71)p
Adjusting items – exceptional items		–	1.41p	1.41p	–	70.31p	70.31p	71.72p
– goodwill amortisation		7.98p	–	7.98p	0.13p	–	0.13p	8.11p
Earnings per ordinary share before exceptional items and goodwill amortisation	7	21.04p	–	21.04p	5.08p	–	5.08p	26.12p
Diluted loss per ordinary share	7							(53.64)p
Adjusting items – exceptional items								71.63p
– goodwill amortisation								8.10p
Diluted earnings per ordinary share before exceptional items and goodwill amortisation	7							26.09p
Cash dividends per ordinary share	8							27.34p

The Accounting Policies and Definitions on pages 70 to 73, together with the Notes on pages 78 to 83, 85 to 87, 89 to 126 and 128 to 130 form part of these Accounts.

Group Profit and Loss Account
for the year ended 31 March 2001

	Notes	Continuing operations 2001 £m	Exceptional item -continuing operations (Note 4) 2001 £m	Total continuing operations 2001 £m	Total discontinued operations 2001 £m	Total 2001 £m
		Year ended 31 March 2001				
Turnover: group and share of joint ventures and associates		5,421.9	–	5,421.9	939.5	6,361.4
Less: share of turnover in joint ventures		(11.7)	–	(11.7)	–	(11.7)
Less: share of turnover in associates		(0.4)	–	(0.4)	–	(0.4)
Group turnover	1	5,409.8	–	5,409.8	939.5	6,349.3
Cost of sales		(3,837.0)	(62.1)	(3,899.1)	(570.4)	(4,469.5)
Gross profit		1,572.8	(62.1)	1,510.7	369.1	1,879.8
Transmission and distribution costs		(483.2)	(45.1)	(528.3)	(38.4)	(566.7)
Administrative expenses (including goodwill amortisation)		(446.1)	(13.5)	(459.6)	(182.0)	(641.6)
Other operating income		46.6	–	46.6	3.8	50.4
Operating profit before goodwill amortisation		815.3	(120.7)	694.6	154.9	849.5
Goodwill amortisation		(125.2)	–	(125.2)	(2.4)	(127.6)
Operating profit	1, 2	690.1	(120.7)	569.4	152.5	721.9
Share of operating loss in joint ventures		(9.4)	–	(9.4)	–	(9.4)
Share of operating profit in associates		0.1	–	0.1	–	0.1
Profit on ordinary activities before interest		680.8	(120.7)	560.1	152.5	712.6
Net interest and similar charges						
– Group		(293.7)	–	(293.7)	(36.3)	(330.0)
– Joint ventures		(2.9)	–	(2.9)	–	(2.9)
	5	(296.6)	–	(296.6)	(36.3)	(332.9)
Profit on ordinary activities before goodwill amortisation and taxation		509.4	(120.7)	388.7	118.6	507.3
Goodwill amortisation		(125.2)	–	(125.2)	(2.4)	(127.6)
Profit on ordinary activities before taxation		384.2	(120.7)	263.5	116.2	379.7
Taxation						
– Group before tax on exceptional item		(145.9)	–	(145.9)	6.7	(139.2)
– Tax on exceptional item	4	–	45.9	45.9	–	45.9
– Joint ventures		(1.9)	–	(1.9)	–	(1.9)
	6	(147.8)	45.9	(101.9)	6.7	(95.2)
Profit after taxation		236.4	(74.8)	161.6	122.9	284.5
Minority interests		(10.4)	–	(10.4)	33.4	23.0
Profit for the financial year		226.0	(74.8)	151.2	156.3	307.5
Dividends	8	(477.3)	–	(477.3)	–	(477.3)
Loss retained	26	(251.3)	(74.8)	(326.1)	156.3	(169.8)
Earnings per ordinary share	7	12.35p	(4.09)p	8.26p	8.54p	16.80p
Adjusting items – exceptional item		–	4.09p	4.09p	–	4.09p
– goodwill amortisation		6.84p	–	6.84p	0.13p	6.97p
Earnings per ordinary share before exceptional item and goodwill amortisation	7	19.19p	–	19.19p	8.67p	27.86p
Diluted earnings per ordinary share	7					16.74p
Adjusting items – exceptional item						4.07p
– goodwill amortisation						6.94p
Diluted earnings per ordinary share before exceptional item and goodwill amortisation	7					27.75p
Dividends per ordinary share	8					26.04p

The Accounting Policies and Definitions on pages 70 to 73, together with the Notes on pages 78 to 83, 85 to 87, 89 to 126 and 128 to 130 form part of these Accounts.

Statement of Total Recognised Gains and Losses

for the year ended 31 March 2003

	Note	**2003 £m**	2002 £m	2001 £m
Profit / (loss) for the financial year		**482.6**	(987.1)	307.5
Exchange movement on translation of overseas results and net assets	26	**(387.0)**	(4.2)	493.1
Translation differences on foreign currency hedging	26	**357.6**	(19.5)	–
Tax on translation differences on foreign currency hedging	26	**(28.8)**	–	–
Unrealised gains on fixed asset disposals	26	**–**	4.9	–
Total recognised gains and losses for the financial year		**424.4**	(1,005.9)	800.6

Note of Historical Cost Profits and Losses

for the year ended 31 March 2003

	Note	**2003 £m**	2002 £m	2001 £m
Profit / (loss) on ordinary activities before taxation		**696.8**	(938.8)	379.7
Differences between historical cost depreciation charge and actual depreciation charge for the year calculated on the revalued amount of fixed assets	26	**2.0**	3.4	3.4
Fixed asset revaluation gains realised on disposal	26	–	168.2	–
Historical cost profit / (loss) on ordinary activities before taxation		**698.8**	(767.2)	383.1
Historical cost loss retained for the financial year after taxation, minority interest and dividends		**(44.9)**	(1,755.6)	(166.4)

Reconciliation of Movements in Shareholders' Funds

for the year ended 31 March 2003

	2003 £m	2002 £m	2001 £m
Profit / (loss) for the financial year	**482.6**	(987.1)	307.5
Dividends			
– Cash	**(529.5)**	(503.5)	(477.3)
– Dividend in specie on demerger of Thus	**–**	(436.6)	–
Loss retained	**(46.9)**	(1,927.2)	(169.8)
Exchange movement on translation of overseas results and net assets	**(387.0)**	(4.2)	493.1
Translation differences on foreign currency hedging	**357.6**	(19.5)	–
Tax on translation differences on foreign currency hedging	**(28.8)**	–	–
Unrealised gains on fixed asset disposals	**–**	4.9	–
Share capital issued	**12.0**	16.2	6.6
Goodwill realised on disposals	**–**	753.3	–
Goodwill realised on demerger of Thus	**–**	14.7	–
Net movement in shareholders' funds	**(93.1)**	(1,161.8)	329.9
Opening shareholders' funds	**4,731.4**	5,893.2	5,563.3
Closing shareholders' funds	**4,638.3**	4,731.4	5,893.2

The Accounting Policies and Definitions on pages 70 to 73, together with the Notes on pages 78 to 83, 85 to 87, 89 to 126 and 128 to 130 form part of these Accounts.

Notes to the Group Profit and Loss Account
for the year ended 31 March 2003

1 Segmental information

(a) Turnover by segment

	Notes	Total turnover 2003 £m	Total turnover 2002 £m	Total turnover 2001 £m	Inter-segment turnover 2003 £m	Inter-segment turnover 2002 £m	Inter-segment turnover 2001 £m	External turnover 2003 £m	External turnover 2002 £m	External turnover 2001 £m
United Kingdom – continuing operations										
UK Division – Integrated Generation and Supply		**2,180.8**	2,160.7	2,099.1	**(33.0)**	(39.3)	(35.3)	**2,147.8**	2,121.4	2,063.8
Infrastructure Division – Power Systems		**667.3**	646.6	666.3	**(353.3)**	(399.0)	(442.6)	**314.0**	247.6	223.7
United Kingdom total – continuing operations								**2,461.8**	2,369.0	2,287.5
United States – continuing operations										
US Division										
PacifiCorp	(i)	**2,502.2**	2,980.7	3,106.2	**(2.8)**	–	–	**2,499.4**	2,980.7	3,106.2
PPM	(i), (ii)	**293.6**	173.1	16.1	**(7.7)**	–	–	**285.9**	173.1	16.1
United States total – continuing operations								**2,785.3**	3,153.8	3,122.3
Total continuing operations								**5,247.1**	5,522.8	5,409.8
United Kingdom – discontinued operations										
Southern Water		**26.7**	430.6	422.9	**–**	(0.7)	(0.5)	**26.7**	429.9	422.4
Thus		**–**	257.8	233.8	**–**	(28.7)	(34.4)	**–**	229.1	199.4
Appliance Retailing		**–**	133.9	325.4	**–**	(1.6)	(7.7)	**–**	132.3	317.7
United Kingdom total – discontinued operations								**26.7**	791.3	939.5
Total	(iii)							**5,273.8**	6,314.1	6,349.3

(b) Operating profit/(loss) by segment

	Notes	**Before goodwill amortisation 2003 £m**	**Goodwill amortisation 2003 £m**	**2003 £m**	Before goodwill amortisation and exceptional item 2002 £m	Goodwill amortisation 2002 £m	Exceptional item 2002 £m	2002 £m	Before goodwill amortisation and exceptional item 2001 £m	Goodwill amortisation 2001 £m	Exceptional item 2001 £m	2001 £m
United Kingdom – continuing operations												
UK Division – Integrated Generation and Supply		**77.9**	**(4.9)**	**73.0**	78.7	(4.9)	(18.5)	55.3	122.7	(0.4)	–	122.3
Infrastructure Division – Power Systems		**367.8**	**–**	**367.8**	354.9	–	–	354.9	341.3	–	–	341.3
United Kingdom total – continuing operations		**445.7**	**(4.9)**	**440.8**	433.6	(4.9)	(18.5)	410.2	464.0	(0.4)	–	463.6
United States – continuing operations												
US Division												
PacifiCorp	(i)	**596.7**	**(133.9)**	**462.8**	371.6	(141.7)	–	229.9	346.8	(124.8)	(120.7)	101.3
PPM	(i), (ii)	**28.5**	**(0.2)**	**28.3**	(4.7)	–	–	(4.7)	4.5	–	–	4.5
United States total – continuing operations		**625.2**	**(134.1)**	**491.1**	366.9	(141.7)	–	225.2	351.3	(124.8)	(120.7)	105.8
Total continuing operations		**1,070.9**	**(139.0)**	**931.9**	800.5	(146.6)	(18.5)	635.4	815.3	(125.2)	(120.7)	569.4
United Kingdom – discontinued operations												
Southern Water		**14.0**	**–**	**14.0**	216.3	–	–	216.3	221.6	–	–	221.6
Thus		**–**	**–**	**–**	(63.7)	(2.4)	–	(66.1)	(58.0)	(2.4)	–	(60.4)
Appliance Retailing		**–**	**–**	**–**	(9.0)	–	–	(9.0)	(8.7)	–	–	(8.7)
United Kingdom total – discontinued operations		**14.0**	**–**	**14.0**	143.6	(2.4)	–	141.2	154.9	(2.4)	–	152.5
Total		**1,084.9**	**(139.0)**	**945.9**	944.1	(149.0)	(18.5)	776.6	970.2	(127.6)	(120.7)	721.9

(c) Depreciation and impairment by segment

	Note	**Depreciation 2003 £m**	Depreciation 2002 £m	Impairment 2002 £m	Total 2002 £m	Depreciation 2001 £m
United Kingdom – continuing operations						
UK Division – Integrated Generation and Supply		**87.3**	72.9	13.0	85.9	51.6
Infrastructure Division – Power Systems		**112.4**	108.3	–	108.3	107.6
United Kingdom total – continuing operations		**199.7**	181.2	13.0	194.2	159.2
United States – continuing operations						
US Division						
PacifiCorp	(i)	**233.9**	225.4	–	225.4	203.5
PPM	(i)	**8.0**	2.4	–	2.4	0.1
United States total – continuing operations		**241.9**	227.8	–	227.8	203.6
Total continuing operations		**441.6**	409.0	13.0	422.0	362.8
United Kingdom – discontinued operations						
Southern Water		**5.6**	77.6	–	77.6	71.2
Thus		**–**	65.2	–	65.2	36.5
Appliance Retailing		**–**	3.2	–	3.2	9.8
United Kingdom total – discontinued operations		**5.6**	146.0	–	146.0	117.5
Total depreciation and impairment charged to operating profit		**447.2**	555.0	13.0	568.0	480.3
Impairment within loss on disposal of and withdrawal from Appliance Retailing		**–**	–	32.2	32.2	–
Impairment within provision for loss on disposal of Southern Water		**–**	–	449.3	449.3	–
Total depreciation and impairment		**447.2**	555.0	494.5	1,049.5	480.3

1 Segmental information continued

(i) The former 'PacifiCorp' segment has been separated into two reporting segments, PacifiCorp, the US regulated business and PPM, the competitive US energy business, which commenced substantive operations during 2001.

(ii) PPM completed the acquisition of the Katy gas storage facility and certain other trade and assets from Aquila, Inc. in December 2002. The post acquisition results of the acquired business are included within the PPM segment and amounted to turnover of £3.2 million, operating profit, before goodwill amortisation, of £1.0 million and operating profit, after goodwill amortisation, of £0.8 million.

(iii) In the segmental analysis turnover is shown by geographical origin. Turnover analysed by geographical destination is not materially different.

2 Operating profit

Operating profit is stated after charging/(crediting):	Note	**2003 £m**	2002 £m	2001 £m
Depreciation and impairment of tangible fixed assets		**447.2**	568.0	480.3
Amortisation of goodwill		**139.0**	149.0	127.6
Release of customer contributions/grants		**(18.6)**	(17.8)	(15.1)
Research and development		**0.7**	3.1	4.2
Hire of plant and equipment – operating leases		**0.1**	0.1	0.3
Hire of other assets – operating leases		**14.6**	55.6	54.6
Auditors' remuneration for audit of				
– group		**1.5**	1.5	1.5
– company		**–**	–	–
Non-audit fees paid to auditors:				
Regulatory advice		**–**	0.3	1.3
Taxation, compliance and advice		**4.8**	5.2	3.1
Due diligence, UK Listing Authority and SEC reporting		**0.3**	3.4	0.8
Other audit and assurance services		**1.0**	0.8	0.8
Advice on systems and consultancy services	(i)	**0.3**	6.9	5.4
Total UK and US non-audit fees paid to auditors		**6.4**	16.6	11.4

(i) Fees for the year ended 31 March 2003 include an amount of £0.3 million which was paid to PricewaterhouseCoopers Consulting in the period prior to its disposal by PricewaterhouseCoopers on 2 October 2002.

(ii) The Audit Committee and the firm of external auditors have safeguards to avoid the possibility that the auditors' objectivity and independence could be compromised. These safeguards include the implementation of a policy on the use of the external auditor for non-audit-related services. This policy has been revised during the year to incorporate the provisions of the Sarbanes-Oxley Act 2002 and subsequent Securities and Exchange Commission ("SEC") rules.

Where it is deemed that the work to be undertaken is of a nature that is generally considered reasonable to be completed by the auditor of the group for sound commercial and practical reasons, including confidentiality, the conduct of such work will be permissible provided that it has been pre-approved by the Audit Committee. Examples of pre-approved services include the completion of regulatory audits, provision of taxation and regulatory advice, reporting to the SEC and the UK Listing Authority and the completion of certain financial due diligence work. All these services are also subject to a pre-defined fee limit. Any work performed in excess of this limit must be approved by the Finance Director and the Chairman of the Audit Committee.

Fees and expenses invoiced by the auditors for non-audit services include £2.3 million (2002 £10.4 million, 2001 £7.5 million) payable in the UK.

For the year ended 31 March 2003, all of the above non-audit fees were charged to operating profit.

For the year ended 31 March 2002, £15.1 million of the above non-audit fees were charged to operating profit, £0.6 million were charged to exceptional loss on disposal of and withdrawal from Appliance Retailing and £0.9 million were charged to exceptional provision for loss on disposal of Southern Water.

For the year ended 31 March 2001, £10.7 million of the above non-audit fees were charged to operating profit and £0.7 million were included within the costs of sale of the businesses held for disposal.

Operating profit for the years ended 31 March 2003, 31 March 2002 and 31 March 2001 is also stated after charging/(crediting) £27.8 million, £(4.2) million and £(4.3) million respectively in relation to finance leases in the US, which are financed by non-recourse borrowings and qualify for linked presentation under FRS 5. Net earnings comprise gross loss/(earnings), after provision against the carrying value of the group's residual interests, of £3.2 million, £(32.3) million and £(33.8) million less finance costs of £24.6 million, £28.1 million and £29.5 million respectively.

Notes to the Group Profit and Loss Account
for the year ended 31 March 2003 – continued

3 Employee information

(a) Employee costs	Note	2003 £m	2002 £m	2001 £m
Wages and salaries		**553.1**	695.6	676.8
Social security costs		**36.7**	46.9	50.3
Pension costs	(i)	**68.0**	43.9	28.4
Total employee costs		**657.8**	786.4	755.5
Less: charged as capital expenditure		**(155.2)**	(191.3)	(151.2)
Charged to the profit and loss account		**502.6**	595.1	604.3

(i) Pension costs above comprise pension costs, company contributions to the PacifiCorp 401(k) plan and costs of other post-retirement and other post-employment benefits. The cost of the group's pension arrangements for the year ended 31 March 2003 was £41.8 million (2002 £21.4 million, 2001 £23.0 million).

(b) Employee numbers
The year end and average numbers of employees (full-time and part-time) employed by the group, including executive directors, were:

		At 31 March			Annual average		
	Note	2003	2002	2001	2003	2002	2001
United Kingdom – continuing operations							
UK Division – Integrated Generation and Supply		**4,319**	4,582	4,278	**4,362**	4,589	4,178
Infrastructure Division – Power Systems		**3,215**	3,084	3,265	**3,238**	3,174	3,332
United Kingdom total – continuing operations		**7,534**	7,666	7,543	**7,600**	7,763	7,510
United States – continuing operations							
US Division							
PacifiCorp		**6,130**	6,289	6,626	**6,175**	6,436	7,027
PPM		**161**	98	42	**128**	76	26
United States total – continuing operations		**6,291**	6,387	6,668	**6,303**	6,512	7,053
Total continuing operations		**13,825**	14,053	14,211	**13,903**	14,275	14,563
United Kingdom – discontinued operations							
Southern Water		**–**	2,109	2,138	**2,024**	2,125	2,160
Thus		**–**	–	2,686	**–**	2,392	2,696
Appliance Retailing		**–**	–	2,946	**–**	2,391	2,988
United Kingdom total – discontinued operations	(i)	**–**	2,109	7,770	**2,024**	6,908	7,844
Total		**13,825**	16,162	21,981	**15,927**	21,183	22,407

The year end and average numbers of full-time equivalent staff employed by the group, including executive directors, were:

		At 31 March			Annual average		
	Note	2003	2002	2001	2003	2002	2001
United Kingdom							
– continuing operations		**7,163**	7,353	7,184	**7,240**	7,391	7,125
– discontinued operations	(i)	**–**	2,056	7,025	**1,982**	6,314	7,049
United States		**6,265**	6,349	6,612	**6,268**	6,474	6,993
Total		**13,428**	15,758	20,821	**15,490**	20,179	21,167

(i) The annual average for 2003 for Southern Water is calculated for the period prior to disposal on 23 April 2002. The annual average for 2002 for discontinued operations is calculated for the period prior to disposal or demerger. This represents the period to 8 October 2001 for Appliance Retailing and the period to 19 March 2002 for Thus.

(c) Directors' remuneration
Details, for each director, of remuneration, pension entitlements and interests in share options are set out on pages 65 to 68. This information forms part of the Accounts.

4 Exceptional items

	Notes	**2003 Continuing operations and Total £m**	2002 Continuing operations £m	2002 Discontinued operations £m	2002 Total £m	2001 Continuing operations and Total £m
(a) Recognised in arriving at operating profit						
Reorganisation costs	(i), (v)	**–**	(18.5)	–	(18.5)	(120.7)
Total recognised in arriving at operating profit		**–**	(18.5)	–	(18.5)	(120.7)
(b) Recognised after operating profit						
Loss on disposal of and withdrawal from Appliance Retailing	(ii)	**–**	–	(120.1)	(120.1)	–
Provision for loss on disposal of Southern Water before goodwill write back	(iii)	**–**	–	(449.3)	(449.3)	–
Goodwill write back relating to Southern Water	(iii)	**–**	–	(738.2)	(738.2)	–
Total recognised after operating profit		**–**	–	(1,307.6)	(1,307.6)	–
Total exceptional items before interest and taxation		**–**	(18.5)	(1,307.6)	(1,326.1)	(120.7)
Restructuring of debt portfolio	(iv)	**–**	(18.8)	(12.0)	(30.8)	–
Tax on exceptional items		**–**	11.3	27.5	38.8	45.9
Total exceptional items (net of tax)		**–**	(26.0)	(1,292.1)	(1,318.1)	(74.8)

Year ended 31 March 2003
There were no exceptional items during the year ended 31 March 2003.

Year ended 31 March 2002
(i) An exceptional charge of £18.5 million was incurred relating to reorganisation costs for the UK Division – Integrated Generation and Supply and primarily represented severance and related costs.

(ii) An exceptional charge of £120.1 million related to the loss on disposal of and withdrawal from the group's Appliance Retailing operations. This charge included £15.1 million of goodwill previously written off to reserves. The pre-goodwill loss of £105.0 million comprised asset impairments of £54.2 million (including a provision for impairment of tangible fixed assets of £32.2 million) and provisions for trading losses and closure costs of £50.8 million. The loss on disposal of and withdrawal from Appliance Retailing was stated before a tax credit of £21.0 million.

(iii) On 23 April 2002, the group completed the sale of Aspen 4 Limited (the holding company of Southern Water plc) to First Aqua Limited for a total consideration, before expenses, of £2.05 billion including repayment and acquisition of intra-group non-trading indebtedness and assumption by First Aqua Limited of Southern Water's non-trading debt due to third parties. An exceptional charge of £1,187.5 million related to the provision for the loss on disposal of the group's Southern Water business. This charge included £738.2 million of goodwill previously written off to reserves and was stated before a tax credit of £2.9 million.

(iv) Exceptional finance costs of £12.0 million, comprising hedging and debt redemption costs associated with the proposed refinancing of Southern Water, have been included within the results of Discontinued operations. Exceptional finance costs of £18.8 million, relating to the restructuring of the group's debt portfolio in anticipation of the disposal of Southern Water, have been included within the results of Continuing operations.

Year ended 31 March 2001

(v) The charge of £120.7 million related to the cost of the Transition Plan for PacifiCorp announced on 4 May 2000 and primarily represented severance and related costs for approximately 1,600 employees.

5 Net interest and similar charges

Analysis of net interest and similar charges	Notes	**2003 £m**	2002 £m	2001 £m
Interest on bank loans and overdrafts		**18.6**	32.8	38.1
Interest on other borrowings		**331.0**	379.5	333.7
Finance leases		**2.1**	2.3	2.2
Total interest payable		**351.7**	414.6	374.0
Interest receivable		**(107.1)**	(15.0)	(33.7)
Capitalised interest	(i)	**(17.3)**	(36.1)	(32.2)
Net interest charge		**227.3**	363.5	308.1
Unwinding of discount on provisions		**26.5**	22.8	16.0
Foreign exchange loss/(gain)		**0.5**	(6.9)	8.8
Net interest and similar charges before exceptional items		**254.3**	379.4	332.9
Exceptional interest on bank loans and overdrafts		**–**	12.0	–
Exceptional interest on other borrowings		**–**	18.8	–
Exceptional interest and similar charges	4(iv)	**–**	30.8	–
Net interest and similar charges after exceptional items		**254.3**	410.2	332.9
Interest cover (times)	(ii)	**4.3**	2.5	3.0

(i) The tax relief on the capitalised interest was £4.4 million (2002 £10.5 million; 2001 £9.1 million).

(ii) Interest cover is calculated by dividing profit on ordinary activities before interest (before exceptional items and goodwill amortisation) by the sum of the net interest charge (before exceptional interest and similar charges) and the unwinding of discount on provisions.

Notes to the Group Profit and Loss Account

for the year ended 31 March 2003 – continued

6 Tax on profit/(loss) on ordinary activities

	2003 £m	Before exceptional items 2002 £m	Exceptional items 2002 £m	2002 £m	Before exceptional item 2001 £m	Exceptional item 2001 £m	2001 £m
Current tax:							
UK Corporation tax	**124.4**	82.6	(32.5)	50.1	175.3	–	175.3
Foreign tax	**78.9**	17.3	–	17.3	5.7	(8.7)	(3.0)
Double taxation relief	**–**	–	–	–	(61.2)	–	(61.2)
	203.3	99.9	(32.5)	67.4	119.8	(8.7)	111.1
Adjustments to UK Corporation tax in respect of prior years	**(44.9)**	(54.4)	–	(54.4)	(29.7)	–	(29.7)
Total current tax for year	**158.4**	45.5	(32.5)	13.0	90.1	(8.7)	81.4
Deferred tax:							
Origination and reversal of timing differences	**50.6**	76.5	(6.3)	70.2	86.0	(37.2)	48.8
Adjustments in respect of prior years	**–**	–	–	–	(35.0)	–	(35.0)
Total deferred tax for year	**50.6**	76.5	(6.3)	70.2	51.0	(37.2)	13.8
Total tax on profit/(loss) on ordinary activities	**209.0**	122.0	(38.8)	83.2	141.1	(45.9)	95.2
Effective rate of tax before goodwill amortisation	**25.0%**	21.5%			22.5%		

The current tax charge on profit/(loss) on ordinary activities for the year varied from the standard rate of UK Corporation tax as follows:

	2003 £m	2002 £m	2001 £m
Corporation tax at 30%	**209.0**	(281.6)	113.9
Losses and other permanent differences	**3.9**	28.1	6.2
Effect of tax rate applied to overseas earnings	**(0.7)**	(21.8)	11.2
Permanent differences on exceptional items	**–**	368.2	(9.7)
Goodwill amortisation	**41.7**	44.7	38.3
Adjustments in respect of prior years	**(44.9)**	(54.4)	(64.7)
Tax charge (current and deferred)	**209.0**	83.2	95.2
Origination and reversal of timing differences – deferred tax charge	**(50.6)**	(70.2)	(13.8)
Current tax charge for year	**158.4**	13.0	81.4

7 Earnings/(loss) per ordinary share

(a) Earnings/(loss) per ordinary share have been calculated for all years by dividing the profit/(loss) for the financial year by the weighted average number of ordinary shares in issue during the financial year, based on the following information:

	2003	2002	2001
Profit/(loss) for the financial year (£ million)	**482.6**	(987.1)	307.5
Basic weighted average share capital (number of shares, million)	**1,843.9**	1,837.8	1,830.3
Diluted weighted average share capital (number of shares, million)	**1,848.4**	1,840.1	1,837.4

The difference between the basic and the diluted weighted average share capital is wholly attributable to outstanding share options and shares held in trust for the group's Employee Share Ownership Plan. These share options are dilutive by reference to continuing operations and accordingly a diluted earnings/(loss) per share has been calculated which has the impact of reducing the net earnings/(loss) per ordinary share.

(b) The calculation of earnings/(loss) per ordinary share, on a basis which excludes exceptional items and goodwill amortisation, is based on the following adjusted earnings:

	Continuing operations 2003 £m	Discontinued operations 2003 £m	Total 2003 £m	Continuing operations 2002 £m	Discontinued operations 2002 £m	Total 2002 £m	Continuing operations 2001 £m	Discontinued operations 2001 £m	Total 2001 £m
Profit/(loss) for the financial year	**475.0**	**7.6**	**482.6**	214.0	(1,201.1)	(987.1)	151.2	156.3	307.5
Adjusting items – exceptional items									
(net of attributable taxation)	**–**	**–**	**–**	26.0	1,292.1	1,318.1	74.8	–	74.8
– goodwill amortisation	**139.0**	**–**	**139.0**	146.6	2.4	149.0	125.2	2.4	127.6
Adjusted earnings	**614.0**	**7.6**	**621.6**	386.6	93.4	480.0	351.2	158.7	509.9

The group's net interest and similar charges have been allocated between continuing and discontinued operations on the basis of external and internal borrowings of the respective operations. The group's tax charge has been allocated between continuing and discontinued operations based on the profit/(loss) before tax of the respective operations.

ScottishPower management assess the performance of the group by adjusting earnings per share, calculated in accordance with FRS 14, to exclude items they consider to be non-recurring or non-operational in nature. Management believes that the exclusion of such items provides a better comparison of business performance. Consequently, an adjusted earnings per share figure is presented for all years.

8 Dividends

(a) Cash dividends

	2003 pence per ordinary share	2002 pence per ordinary share	2001 pence per ordinary share	**2003 £m**	2002 £m	2001 £m
First interim dividend paid	**7.177**	6.835	6.510	**132.5**	125.4	119.1
Second interim dividend paid	**7.177**	6.835	6.510	**132.7**	125.9	119.3
Third interim dividend paid	**7.177**	6.835	6.510	**132.1**	126.1	119.5
Final dividend	**7.177**	6.835	6.510	**132.2**	126.1	119.4
Total cash dividends	**28.708**	27.340	26.040	**529.5**	503.5	477.3

(b) Dividend in specie on demerger of Thus

	Note	**2003 £m**	2002 £m	2001 £m
Demerger dividend	34	**–**	436.6	–

The demerger of Thus was recorded in the group Accounts at the book value of the net assets which were deconsolidated of £421.9 million, together with £14.7 million of related goodwill which had previously been written off to reserves, giving a dividend in specie of £436.6 million.

The demerger of Thus was recorded in the individual company Accounts of Scottish Power plc at the book value of the cost of investment in the ordinary and preference shares of Thus, giving a dividend in specie of £396.3 million.

Group Cash Flow Statement

for the year ended 31 March 2003

	Notes	**2003 £m**	2002 £m	2001 £m
Cash inflow from operating activities	10	**1,412.9**	1,248.4	1,411.6
Dividends received from joint ventures		**0.9**	0.3	2.1
Returns on investments and servicing of finance	9	**(297.0)**	(377.8)	(373.5)
Taxation		**(191.3)**	(85.0)	(152.6)
Free cash flow		**925.5**	785.9	887.6
Capital expenditure and financial investment	9	**(704.9)**	(1,148.3)	(1,081.4)
Cash flow before acquisitions and disposals		**220.6**	(362.4)	(193.8)
Acquisitions and disposals	9	**1,799.0**	150.0	482.9
Equity dividends paid		**(523.4)**	(496.8)	(471.3)
Cash inflow/(outflow) before use of liquid resources and financing		**1,496.2**	(709.2)	(182.2)
Management of liquid resources	9,13	**(161.1)**	(38.7)	(11.9)
Financing				
– Issue of ordinary share capital	9	**12.0**	16.2	6.6
– Redemption of preferred stock of PacifiCorp	9	**(5.1)**	(69.5)	–
– (Decrease)/increase in debt	9,13	**(1,191.4)**	982.4	189.5
		(1,184.5)	929.1	196.1
Increase in cash in year	13	**150.6**	181.2	2.0

Free cash flow represents cash flow from operating activities after adjusting for dividends received from joint ventures, returns on investments and servicing of finance and taxation.

Reconciliation of Net Cash Flow to Movement in Net Debt

for the year ended 31 March 2003

	Note	**2003 £m**	2002 £m	2001 £m
Increase in cash in year		**150.6**	181.2	2.0
Cash outflow/(inflow) from decrease/(increase) in debt		**1,191.4**	(982.4)	(189.5)
Cash outflow from movement in liquid resources		**161.1**	38.7	11.9
Change in net debt resulting from cash flows		**1,503.1**	(762.5)	(175.6)
Net debt/(funds) disposed		**100.0**	(46.9)	–
Foreign exchange movement		**289.9**	(6.3)	(264.7)
Other non-cash movements		**(5.6)**	(107.6)	(3.3)
Movement in net debt in year		**1,887.4**	(923.3)	(443.6)
Net debt at end of previous year		**(6,208.4)**	(5,285.1)	(4,841.5)
Net debt at end of year	13	**(4,321.0)**	(6,208.4)	(5,285.1)

The Accounting Policies and Definitions on pages 70 to 73, together with the Notes on pages 78 to 83, 85 to 87, 89 to 126 and 128 to 130 form part of these Accounts.

Notes to the Group Cash Flow Statement
for the year ended 31 March 2003

9 Analysis of cash flows

	Note	2003 £m	2002 £m	2001 £m
(a) Returns on investments and servicing of finance				
Interest received		**112.0**	33.1	32.7
Interest paid		**(404.2)**	(402.8)	(395.8)
Dividends paid to minority interests		**(4.8)**	(8.1)	(10.4)
Net cash outflow for returns on investments and servicing of finance		**(297.0)**	(377.8)	(373.5)
(b) Capital expenditure and financial investment				
Purchase of tangible fixed assets		**(735.9)**	(1,244.7)	(1,143.6)
Deferred income received		**69.5**	76.9	97.3
Sale of tangible fixed assets		**10.4**	17.7	26.4
(Purchase)/sale of fixed asset investments		**(48.9)**	1.8	(61.5)
Net cash outflow for capital expenditure and financial investment		**(704.9)**	(1,148.3)	(1,081.4)
(c) Acquisitions and disposals				
Purchase of businesses and subsidiary undertakings	12	**(101.3)**	–	(230.2)
Sale of businesses and subsidiary undertakings	12	**1,900.3**	150.0	713.1
Net cash inflow from acquisitions and disposals		**1,799.0**	150.0	482.9
(d) Management of liquid resources*				
Cash outflow in relation to short-term deposits and other short-term investments		**(161.1)**	(38.7)	(11.9)
Net cash outflow for management of liquid resources		**(161.1)**	(38.7)	(11.9)
(e) Financing				
Issue of ordinary share capital		**12.0**	16.2	6.6
Redemption of preferred stock of PacifiCorp		**(5.1)**	(69.5)	–
		6.9	(53.3)	6.6
Debt due within one year:				
– net (repayment)/drawdown of uncommitted facilities		**(203.6)**	120.8	6.6
– (repayment)/drawdown of committed bank loan		**(100.0)**	100.0	–
– net commercial paper (redeemed)/issued		**(288.9)**	(52.8)	6.1
– medium-term notes/private placements		**(86.4)**	79.9	(58.9)
– (redemption)/issue of loan notes		**(2.2)**	(0.1)	0.4
– European Investment Bank loans		**(129.2)**	114.8	(4.6)
– mortgages		**(5.9)**	72.6	(96.4)
– non-recourse notes		**–**	–	(147.2)
– 5.875% euro-US dollar bond 2003		**(183.5)**	183.5	–
– other		**18.3**	(1.3)	0.5
Debt due after one year:				
– net repayment of uncommitted facilities		**–**	(3.8)	–
– medium-term notes/private placements		**(127.3)**	7.5	594.2
– European Investment Bank loans		**–**	(129.2)	42.8
– 5.875% euro-US Dollar bond 2003		**–**	(183.3)	–
– variable coupon Australian dollar bond issue		**–**	233.8	–
– mortgages		**(83.0)**	449.5	(25.8)
– secured pollution control revenue bonds		**–**	2.8	0.2
– unsecured pollution control revenue bonds		**2.1**	(2.9)	1.9
– junior debentures		**–**	–	(117.0)
– non-recourse notes		**–**	–	(21.2)
– preferred securities		**0.3**	–	–
– other		**(2.1)**	(9.7)	8.0
Finance leases:				
– finance leases		**–**	0.3	(0.1)
(Decrease)/increase in debt		**(1,191.4)**	982.4	189.5
Net cash (outflow)/inflow from financing		**(1,184.5)**	929.1	196.1

*Liquid resources include term deposits of less than one year, commercial paper and other short-term investments.

Notes to the Group Cash Flow Statement

for the year ended 31 March 2003 – continued

10 Reconciliation of operating profit to net cash inflow from operating activities

	2003 £m	2002 £m	2001 £m
Operating profit	**945.9**	776.6	721.9
Depreciation and amortisation	**586.2**	717.0	607.9
Loss/(profit) on sale of tangible fixed assets and disposal of businesses	**2.7**	(7.7)	(19.9)
Release of deferred income	**(18.6)**	(17.8)	(15.1)
Movements in provisions for liabilities and charges	**(73.1)**	(93.6)	57.5
(Increase)/decrease in stocks	**(1.9)**	10.4	(13.3)
(Increase)/decrease in debtors	**(169.4)**	58.4	(137.2)
Increase/(decrease) in creditors	**141.1**	(194.9)	209.8
Net cash inflow from operating activities	**1,412.9**	1,248.4	1,411.6

11 Effect of acquisitions and disposals on cash flows

	Acquisition 2003 £m	Disposal 2003 £m	Disposals 2002 £m
Cash inflow/(outflow) from operating activities	**1.0**	**16.0**	(39.5)
Returns on investments and servicing of finance	**–**	**(6.6)**	0.7
Capital expenditure and financial investment	**(1.4)**	**(9.2)**	(93.2)
Acquisitions and disposals	**–**	**–**	3.3
Management of liquid resources	**–**	**–**	4.0
Financing	**–**	**4.5**	–
(Decrease)/increase in cash	**(0.4)**	**4.7**	(124.7)

The analysis of cash flows of the acquisition in 2003 relates to the post-acquisition cash flows of the Katy gas storage facility. The effect of the disposal on cash flows in 2003 relates to the disposal of Southern Water.

The effect of disposals on cash flows in 2002 principally related to the group's demerger of Thus and the disposal of and withdrawal from Appliance Retailing. The cash flows relating to acquisitions during 2002 were not material.

The effect of acquisitions and disposals on cash flows during 2001 was not material.

12 Analysis of cash flows in respect of acquisitions and disposals

	Acquisition 2003 £m	Disposals 2003 £m	Disposals 2002 £m	Acquisitions 2001 £m	Disposals 2001 £m
Cash consideration including expenses	**(101.3)**	**1,139.4**	13.9	(227.7)	716.5
Cash settlement of inter-company loan	**–**	**756.4**	–	–	–
Bank overdraft disposed/(cash at bank disposed)	**–**	**6.2**	(9.2)	–	–
Deferred consideration in respect of prior year disposals/(acquisitions)	**–**	**10.5**	152.1	(2.5)	–
Expenses paid in respect of prior year disposals	**–**	**(12.2)**	(6.8)	–	(3.4)
	(101.3)	**1,900.3**	150.0	(230.2)	713.1

In 2003, the cash flows in respect of the acquisition represent the purchase of the Katy gas storage facility. The cash flows in respect of disposals principally represent the proceeds from the sale of Southern Water.

In 2002, the cash flows in respect of disposals principally represent the collection of a note receivable on the discontinued operations of PacifiCorp's mining and resource development business, NERCO, which was sold in 1993 and the disposal of PacifiCorp's synthetic fuel operations.

In 2001, cash flows in respect of acquisitions principally represent the purchase of Rye House power station. The cash flows in respect of disposals mainly comprise proceeds from the sale of Centralia and Powercor.

13 Analysis of net debt

2001/02	At 1 April 2001 £m	Cash flow £m	Disposal (excl. cash & overdrafts) £m	Exchange £m	Other non-cash changes £m	At 31 March 2002 £m
Cash at bank	139.7	163.4	–	(0.3)	–	302.8
Overdrafts	(52.5)	17.8	–	0.1	–	(34.6)
		181.2				
Debt due after 1 year	(4,868.3)	(364.7)	–	(3.7)	(106.3)	(5,343.0)
Debt due within 1 year	(575.4)	(617.4)	4.4	(2.5)	(1.3)	(1,192.2)
Finance leases	(19.1)	(0.3)	–	–	–	(19.4)
		(982.4)				
Other deposits	90.5	38.7	(51.3)	0.1	–	78.0
Total	(5,285.1)	(762.5)	(46.9)	(6.3)	(107.6)	(6,208.4)

'Other non-cash changes' to net debt represents amortisation of finance costs of £1.5 million, finance costs of £5.6 million representing the effects of the Retail Price Index ("RPI") on bonds carrying an RPI coupon and the recognition of the share of debt in joint arrangements of £100.5 million.

2002/03	At 1 April 2002 £m	Cash flow £m	Disposal (excl. cash & overdrafts) £m	Exchange £m	Other non-cash changes £m	**At 31 March 2003 £m**
Cash at bank	302.8	139.5	–	(12.2)	–	**430.1**
Overdrafts	(34.6)	11.1	–	2.4	–	**(21.1)**
		150.6				
Debt due after 1 year	(5,343.0)	210.0	100.0	278.9	(5.5)	**(4,759.6)**
Debt due within 1 year	(1,192.2)	981.4	–	23.5	(0.1)	**(187.4)**
Finance leases	(19.4)	–	–	1.9	–	**(17.5)**
		1,191.4				
Other deposits	78.0	161.1	–	(4.6)	–	**234.5**
Total	(6,208.4)	1,503.1	100.0	289.9	(5.6)	**(4,321.0)**

'Other non-cash changes' to net debt represents amortisation of finance costs of £1.6 million and finance costs of £4.0 million representing the effects of the RPI on bonds carrying an RPI coupon.

Group Balance Sheet
as at 31 March 2003

	Notes	**2003 £m**	2002 £m
Fixed assets			
Intangible assets	15	**2,280.6**	2,658.9
Tangible assets	16	**9,028.7**	11,652.3
Investments			
– Investments in joint ventures:			
Share of gross assets		**111.9**	119.3
Share of gross liabilities		**(111.8)**	(119.2)
		0.1	0.1
– Loans to joint ventures		**40.2**	36.8
		40.3	36.9
– Investments in associates		**2.8**	5.2
– Other investments		**247.3**	223.5
	17	**290.4**	265.6
		11,599.7	14,576.8
Current assets			
Stocks	18	**154.6**	167.0
Debtors			
– Gross debtors		**1,684.5**	1,448.2
– Less non-recourse financing		**(148.2)**	(257.4)
	19	**1,536.3**	1,190.8
Short-term bank and other deposits		**664.6**	380.8
		2,355.5	1,738.6
Creditors: amounts falling due within one year			
Loans and other borrowings	20	**(208.5)**	(1,226.8)
Other creditors	21	**(1,785.7)**	(1,951.9)
		(1,994.2)	(3,178.7)
Net current assets/(liabilities)		**361.3**	(1,440.1)
Total assets less current liabilities		**11,961.0**	13,136.7
Creditors: amounts falling due after more than one year			
Loans and other borrowings	20	**(4,777.1)**	(5,362.4)
Provisions for liabilities and charges			
– Deferred tax	23	**(1,301.9)**	(1,691.2)
– Other provisions	22	**(610.9)**	(713.8)
		(1,912.8)	(2,405.0)
Deferred income	24	**(558.9)**	(551.2)
Net assets	14	**4,712.2**	4,818.1
Called up share capital	25, 26	**928.0**	926.3
Share premium	26	**2,264.4**	2,254.1
Revaluation reserve	26	**43.5**	45.5
Capital redemption reserve	26	**18.3**	18.3
Merger reserve	26	**406.4**	406.4
Profit and loss account	26	**977.7**	1,080.8
Equity shareholders' funds	26	**4,638.3**	4,731.4
Minority interests (including non-equity)	27	**73.9**	86.7
Capital employed		**4,712.2**	4,818.1
Net asset value per ordinary share	14	**249.2p**	254.8p

Approved by the Board on 7 May 2003 and signed on its behalf by

Charles Miller Smith

Charles Miller Smith
Chairman

David Nish
Finance Director

The Accounting Policies and Definitions on pages 70 to 73, together with the Notes on pages 78 to 83, 85 to 87, 89 to 126 and 128 to 130 form part of these Accounts.

Notes to the Group Balance Sheet
as at 31 March 2003

14 Segmental information

(a) Net assets by segment	Notes	2003 £m	2002 £m
United Kingdom – continuing operations			
UK Division – Integrated Generation and Supply		**908.4**	873.4
Infrastructure Division – Power Systems		**2,175.4**	2,070.7
United Kingdom total – continuing operations		**3,083.8**	2,944.1
United States – continuing operations			
US Division			
PacifiCorp	(i)	**6,787.2**	7,521.9
PPM	(i)	**375.8**	254.1
United States total – continuing operations		**7,163.0**	7,776.0
Total continuing operations		**10,246.8**	10,720.1
United Kingdom – discontinued operations			
Southern Water		**–**	2,347.6
United Kingdom total – discontinued operations		**–**	2,347.6
Unallocated net liabilities			
Net debt		**(4,321.0)**	(6,208.4)
Deferred tax		**(1,301.9)**	(1,691.2)
Corporate tax		**(251.1)**	(293.3)
Proposed dividend		**(132.2)**	(126.1)
Fixed asset investments		**290.4**	265.6
Other	(ii)	**181.2**	(196.2)
Total unallocated net liabilities		**(5,534.6)**	(8,249.6)
Total		**4,712.2**	4,818.1

Net asset value per ordinary share has been calculated based on the following net assets and the number of shares in issue at the end of the respective financial years (after adjusting for the effect of shares held in trust for the group's Sharesave Schemes and Employee Share Ownership Plan):

	31 March 2003	31 March 2002
Net assets (as adjusted) (£ million)	**4,600.1**	4,692.5
Number of ordinary shares in issue at year end (as adjusted) (number of shares, million)	**1,845.6**	1,841.9

(b) Capital expenditure by segment	Notes	2003 £m	2002 £m
United Kingdom – continuing operations			
UK Division – Integrated Generation and Supply	(iii)	**73.2**	109.2
Infrastructure Division – Power Systems	(iii)	**273.1**	240.1
United Kingdom total – continuing operations		**346.3**	349.3
United States – continuing operations			
US Division			
PacifiCorp	(i),(iii)	**388.4**	393.2
PPM	(i)	**36.1**	206.2
United States total – continuing operations		**424.5**	599.4
Total continuing operations		**770.8**	948.7
United Kingdom – discontinued operations			
Southern Water	(iii)	**15.8**	279.5
Thus		**–**	78.0
Appliance Retailing		**–**	0.1
Total discontinued operations		**15.8**	357.6
Total		**786.6**	1,306.3

(c) Total assets by segment	Notes	2003 £m	2002 £m
United Kingdom – continuing operations			
UK Division – Integrated Generation and Supply		**1,601.4**	1,563.6
Infrastructure Division – Power Systems		**2,808.7**	2,657.6
United Kingdom total – continuing operations		**4,410.1**	4,221.2
United States – continuing operations			
US Division			
PacifiCorp	(i)	**7,709.2**	8,600.3
PPM	(i)	**542.8**	278.6
United States total – continuing operations		**8,252.0**	8,878.9
Total continuing operations		**12,662.1**	13,100.1
United Kingdom – discontinued operations			
Southern Water		**–**	2,568.9
Total discontinued operations		**–**	2,568.9
Unallocated total assets	(iv)	**1,293.1**	646.4
Total		**13,955.2**	16,315.4

Notes to the Group Balance Sheet
as at 31 March 2003 – continued

14 Segmental information continued

(i) The former 'PacifiCorp' segment has been separated into two reporting segments, PacifiCorp, the US regulated business and PPM, the competitive US energy business, which commenced substantive operations during 2001.

(ii) Other unallocated net liabilities principally includes interest and amounts relating to gains arising on retranslation of forward contracts and cross currency interest rate swaps used to hedge net overseas investments.

(iii) Capital expenditure by business segment is stated gross of capital grants and customer contributions. Capital expenditure net of contributions amounted to £717.1 million (2002 £1,229.4 million). Capital grants and customer contributions receivable during the year of £69.5 million (2002 £76.9 million) comprised UK Division – Integrated Generation and Supply £5.4 million (2002 £0.2 million), Infrastructure Division – Power Systems £43.2 million (2002 £42.5 million), PacifiCorp £20.0 million (2002 £22.1 million) and Southern Water £0.9 million (2002 £12.1 million).

(iv) Unallocated total assets includes investments, interest receivable, bank deposits and amounts relating to gains arising on retranslation of forward contracts and cross currency interest rate swaps used to hedge net overseas investments.

15 Intangible fixed assets

Year ended 31 March 2002	Note	Goodwill £m
Cost:		
At 1 April 2001		3,017.9
Thus open offer	34	34.4
Demerger of Thus	34	(70.4)
Exchange		(4.1)
At 31 March 2002		2,977.8
Amortisation:		
At 1 April 2001		177.1
Amortisation for the year		149.0
Demerger of Thus	34	(7.8)
Exchange		0.6
At 31 March 2002		318.9
Net book value:		
At 31 March 2002		2,658.9
At 31 March 2001		2,840.8

Year ended 31 March 2003	Note	Goodwill £m
Cost:		
At 1 April 2002		2,977.8
Acquisition	32	12.4
Exchange		(286.0)
At 31 March 2003		**2,704.2**
Amortisation:		
At 1 April 2002		318.9
Amortisation for the year		139.0
Exchange		(34.3)
At 31 March 2003		**423.6**
Net book value:		
At 31 March 2003		**2,280.6**
At 31 March 2002		2,658.9

Goodwill capitalised is being amortised over its estimated useful economic life of 20 years. Goodwill capitalised relating to Thus was being amortised over its estimated useful economic life of 15 years.

16 Tangible fixed assets

Year ended 31 March 2002	Notes	Land and buildings £m	Water infrastructure assets £m	Plant and machinery £m	Vehicles and equipment £m	Total £m
Cost or valuation:						
At 1 April 2001		1,385.2	1,174.9	10,053.5	1,480.3	14,093.9
Additions		88.5	76.7	986.5	154.6	1,306.3
Impairment	(i), (ix)	(6.9)	(306.3)	(136.1)	–	(449.3)
Valuation adjustment	(ii)	–	(109.1)	(207.3)	–	(316.4)
Grants and contributions		–	(9.2)	–	–	(9.2)
Disposals		(13.7)	(0.6)	(57.3)	(94.9)	(166.5)
Demerger of Thus	34	(11.9)	–	(466.2)	(136.8)	(614.9)
Exchange		(0.3)	–	(3.7)	(0.5)	(4.5)
At 31 March 2002		1,440.9	826.4	10,169.4	1,402.7	13,839.4
Depreciation:						
At 1 April 2001		265.6	88.4	1,401.9	417.2	2,173.1
Reclassification		(42.6)	–	42.6	–	–
Charge for the year		32.8	21.2	323.1	177.9	555.0
Impairment	(ix)	1.6	–	12.2	31.4	45.2
Valuation adjustment	(ii)	–	(109.1)	(207.3)	–	(316.4)
Disposals		(13.3)	(0.5)	(29.9)	(80.9)	(124.6)
Demerger of Thus	34	(3.1)	–	(78.9)	(64.1)	(146.1)
Exchange		–	–	0.6	0.3	0.9
At 31 March 2002		241.0	–	1,464.3	481.8	2,187.1
Net book value:						
At 31 March 2002		1,199.9	826.4	8,705.1	920.9	11,652.3
At 31 March 2001		1,119.6	1,086.5	8,651.6	1,063.1	11,920.8
Year ended 31 March 2003						
Cost or valuation:						
At 1 April 2002		1,440.9	826.4	10,169.4	1,402.7	13,839.4
Additions		24.1	0.1	651.8	110.6	786.6
Acquisition	32	7.1	–	81.2	–	88.3
Grants and contributions		–	(0.8)	–	–	(0.8)
Disposals		(7.3)	(0.3)	(45.8)	(52.9)	(106.3)
Valuation adjustment	(ii)	–	–	149.8	–	149.8
Disposal of Southern Water	33	(811.1)	(825.4)	(714.3)	(235.1)	(2,585.9)
Exchange		(21.0)	–	(541.3)	(58.8)	(621.1)
At 31 March 2003		**632.7**	**–**	**9,750.8**	**1,166.5**	**11,550.0**
Depreciation:						
At 1 April 2002		241.0	–	1,464.3	481.8	2,187.1
Reclassification		–	–	3.2	(3.2)	–
Charge for the year		13.9	1.5	287.9	143.9	447.2
Disposals		(0.8)	(0.3)	(40.8)	(51.1)	(93.0)
Valuation adjustment	(ii)	–	–	149.8	–	149.8
Disposal of Southern Water	33	(75.0)	(1.2)	(2.0)	(33.0)	(111.2)
Exchange		(1.8)	–	(43.0)	(13.8)	(58.6)
At 31 March 2003		**177.3**	**–**	**1,819.4**	**524.6**	**2,521.3**
Net book value:						
At 31 March 2003		**455.4**	**–**	**7,931.4**	**641.9**	**9,028.7**
At 31 March 2002		1,199.9	826.4	8,705.1	920.9	11,652.3

Historical cost analysis	2003 £m	2002 £m
Cost	**11,496.0**	13,785.4
Depreciation based on cost	**(2,510.8)**	(2,178.6)
Net book value based on cost	**8,985.2**	11,606.8

Included in the cost or valuation of tangible fixed assets above are:	Notes	2003 £m	2002 £m
Assets in the course of construction		**556.1**	1,181.1
Other assets not subject to depreciation	(v)	**114.3**	158.1
Grants and contributions in respect of water infrastructure assets		**–**	(42.2)
Capitalised interest	(iv)	**40.4**	130.6

(i) The impairment of assets of £449.3 million in 2001/02 represented the provision for loss on disposal of Southern Water. The total impairment of group assets is detailed in Note 1(c).

(ii) The valuation adjustment in 2002/03 represents an adjustment to the cost and accumulated depreciation of the tangible fixed assets of Southern Water on disposal. The valuation adjustment in 2001/02 represented elimination of the accumulated depreciation on the tangible fixed assets of Southern Water which were impaired.

(iii) The Manweb distribution and Southern Water operational assets were revalued by the directors on 30 September 1997 on a market value basis. The valuation of the Manweb distribution assets has not been and will not be updated, as permitted under the transitional provisions of FRS 15 'Tangible fixed assets'. The net book value of tangible fixed assets included at valuation at 31 March 2003 relates to Manweb distribution assets and was £580.8 million (2002 £599.6 million).

(iv) Interest on the funding attributable to major capital projects was capitalised during the year at a rate of 5% (2002 7%) in the UK and 7% (2002 4%) in the US.

(v) Other assets not subject to depreciation are land. Land and buildings held by the group are predominantly freehold.

(vi) The historical cost of fully depreciated tangible fixed assets still in use was £298.0 million (2002 £272.6 million).

(vii) Capitalised computer software costs developed for internal use include employee, interest and other external direct costs of materials and services which are directly attributable to the development of computer software. Cumulative computer software costs capitalised are £525.8 million (2002 £490.7 million, 2001 £455.5 million). The depreciation charge was £79.6 million (2002 £73.4 million, 2001 £52.5 million).

(viii) The net book value of land and buildings under finance leases at 31 March 2003 was £17.5 million (2002 £22.3 million). The charge for depreciation against these assets during the year was £0.1 million (2002 £2.1 million).

(ix) Assets which were impaired in 2001/02 were valued on the basis of their estimated recoverable amounts. The impairment charge for the year ended 31 March 2002 of £494.5 million was charged to the profit and loss account as follows: cost of sales £13.0 million, loss on disposal of and withdrawal from Appliance Retailing £32.2 million and provision for loss on disposal of Southern Water £449.3 million.

Notes to the Group Balance Sheet
as at 31 March 2003 – continued

17 Fixed asset investments

	Notes	Joint ventures Shares £m	Joint ventures Loans £m	Associated undertakings Shares £m	Own shares held under trust £m	Other investments £m	Total £m
Cost or valuation:							
At 1 April 2001		18.8	25.0	5.0	65.4	182.1	296.3
Additions		–	16.1	–	25.6	2.3	44.0
Share of retained (loss)/profit		(2.4)	(0.5)	0.2	–	–	(2.7)
Disposals and other		(16.3)	(3.8)	–	(19.8)	(7.7)	(47.6)
Demerger of Thus	34	–	–	–	–	(24.2)	(24.2)
Exchange		–	–	–	–	(0.2)	(0.2)
At 31 March 2002		0.1	36.8	5.2	71.2	152.3	265.6
Additions		–	6.8	–	36.2	19.4	62.4
Share of retained (loss)/profit		–	(0.3)	0.3	–	–	–
Disposals and other		–	(3.1)	(0.8)	(10.3)	(5.3)	(19.5)
Disposal of Southern Water	33	–	–	(1.9)	–	–	(1.9)
Exchange		–	–	–	–	(16.2)	(16.2)
At 31 March 2003		**0.1**	**40.2**	**2.8**	**97.1**	**150.2**	**290.4**

The principal subsidiary undertakings, joint ventures and associated undertakings are listed on page 130.

Details of listed investments, including own shares held under trust, are given below:

	£m
Balance Sheet value at 31 March 2003	154.6
Market value at 31 March 2003	133.2

(a) Shares in the company held under trust during the year are as follows:

2001/02	Notes	Dividends waived	Shares held at 1 April 2001 (000s)	Shares acquired during year (000s)	Shares transferred during year (000s)	Shares held at 31 March 2002 (000s)	Nominal value at 31 March 2002 £m	Market value at 31 March 2002 £m
Long Term Incentive Plan	(i)	no	2,712	1,355	(379)	3,688	1.8	13.3
ScottishPower Sharesave Schemes	(ii)	yes	15,240	–	(6,917)	8,323	4.2	29.9
Executive Share Option Plan 2001	(iii)	yes	–	2,360	–	2,360	1.2	8.5
PacifiCorp Stock Incentive Plan	(iv)	no	114	122	(76)	160	0.1	0.6
Employee Share Ownership Plan	(v)	no	747	1,659	(224)	2,182	1.1	7.8
			18,813	5,496	(7,596)	16,713	8.4	60.1

2002/03	Notes	Dividends waived	Shares held at 1 April 2002 (000s)	Shares acquired during year (000s)	Shares transferred during year (000s)	**Shares held at 31 March 2003 (000s)**	**Nominal value at 31 March 2003 £m**	**Market value at 31 March 2003 £m**
Long Term Incentive Plan	(i)	no	3,688	–	(218)	**3,470**	**1.7**	**13.0**
ScottishPower Sharesave Schemes	(ii)	yes	8,323	–	(2,064)	**6,259**	**3.1**	**23.5**
Executive Share Option Plan 2001	(iii)	yes	2,360	7,387	–	**9,747**	**4.9**	**36.6**
PacifiCorp Stock Incentive Plan	(iv)	no	160	–	(54)	**106**	**0.1**	**0.4**
Employee Share Ownership Plan	(v)	no	2,182	1,574	(755)	**3,001**	**1.5**	**11.3**
			16,713	8,961	(3,091)	**22,583**	**11.3**	**84.8**

(i) Shares of the company are held under trust as part of the Long Term Incentive Plan for executive directors and other senior managers (see Remuneration Report of the Directors on pages 61 to 68 for details of the Plan).

(ii) Shares of the company are held in two Qualifying Employee Share Ownership Trusts as part of the Scottish Power UK plc Sharesave Scheme and the Scottish Power plc Sharesave Scheme. Holders of options granted under the schemes will be awarded shares by the Trusts upon the exercise of the options. Details of options granted under these schemes are disclosed in Note 25.

(iii) Shares of the company are held under trust as part of the Executive Share Option Plan 2001 for executive directors and other senior managers (see Remuneration Report of the Directors on pages 61 to 68 for details of the plan).

(iv) Options granted under the PacifiCorp Stock Incentive Plan are for ScottishPower ADSs; for the purposes of the table above, ADSs have been converted to ScottishPower ordinary shares as follows: one ScottishPower ADS equals four ScottishPower ordinary shares.

(v) Shares of the company are held in the Employee Share Ownership Plan Trust on behalf of employees of the ScottishPower group. Shares appropriated under the Free Element and the Matching Element are subject to forfeiture for a period of three years from the date of appropriation. Shares appropriated under the Partnership Element of the Employee Share Ownership Plan are not subject to forfeiture.

18 Stocks

	2003 £m	2002 £m
Raw materials and consumables	**91.7**	95.7
Fuel stocks	**50.3**	48.4
Work in progress	**12.6**	21.7
Finished goods and goods for resale	**–**	1.2
	154.6	167.0

19 Debtors

	Notes	2003 £m	2002 £m
(a) Amounts falling due within one year:			
Trade debtors	(i)	**424.8**	470.9
Amounts receivable under finance leases – US	(ii), (iii)	**29.4**	124.1
Less non-recourse financing		**(20.9)**	(92.9)
		8.5	31.2
Amounts receivable under finance leases – UK	(iii)	**0.1**	0.1
Prepayments and accrued income		**393.3**	395.2
Other debtors	(iv)	**530.1**	114.7
		1,356.8	1,012.1
(b) Amounts falling due after more than one year:			
Amounts receivable under finance leases – US	(ii), (iii)	**233.0**	318.0
Less non-recourse financing		**(127.3)**	(164.5)
		105.7	153.5
Amounts receivable under finance leases – UK	(iii)	**4.1**	4.2
Other debtors		**69.7**	21.0
		1,536.3	1,190.8

(i) Trade debtors are stated net of provisions for doubtful debts of £76.7 million (2002 £101.1 million).

(ii) The group's finance lease assets in the US which are financed by non-recourse borrowing qualify for linked presentation under FRS 5. The provider of the finance has agreed in writing in the finance documentation that it will seek repayment of the finance, as to both principal and interest, only to the extent that sufficient funds are generated by the specific assets it has financed and that it will not seek recourse in any other form. The directors confirm that the group has no obligation to support any losses arising under these leases nor is there any intention to do so.

(iii) Amounts receivable under finance leases falling due after more than one year at 31 March 2003 of £237.1 million (2002 £322.2 million) are due as follows: within 1-2 years, £32.3 million (2002 £28.7 million); within 2-3 years, £25.8 million (2002 £36.8 million); within 3-4 years, £33.2 million (2002 £28.6 million); within 4-5 years, £27.7 million (2002 £38.3 million) and after 5 years, £118.1 million (2002 £189.8 million). Amounts received under finance leases during the year were £51.6 million (2002 £58.8 million).

(iv) Included within Other debtors falling due within one year is an amount of £297.1 million (2002 £nil) relating to the value of net investment swaps as disclosed in Note 20(b).

20 Loans and other borrowings

Details of the group's objectives, policies and strategy with regard to financial instruments and risk management are contained within the Financial Review on pages 33 to 53. The analyses of financial instruments in this Note, other than currency disclosures, do not include short-term debtors and creditors as permitted by FRS 13.

(a) Analysis by instrument	Notes	Weighted average interest rate 2003	Weighted average interest rate 2002	2003 £m	2002 £m
Unsecured debt of UK businesses					
Bank overdraft		**–**	–	**2.7**	11.0
Committed bank loans		**4.2%**	5.0%	**–**	100.0
Uncommitted bank loans		**4.4%**	5.0%	**9.3**	212.9
Commercial paper	(i)	**4.3%**	5.0%	**–**	195.0
Medium-term notes/private placements	(ii)	**5.0%**	5.6%	**1,035.7**	1,245.1
Loan notes	(iii)	**4.1%**	4.9%	**3.6**	5.9
European Investment Bank loans	(iv)	**5.9%**	6.8%	**199.2**	328.4
5.875% euro-US dollar bond 2003		**7.0%**	7.0%	**–**	183.5
Variable coupon bond 2008		**6.9%**	6.9%	**–**	99.8
Variable rate Australian dollar bond 2011		**4.7%**	5.7%	**234.2**	233.8
5.250% deutschmark bond 2008		**6.8%**	6.8%	**245.8**	245.7
6.625% euro-sterling bond 2010		**6.7%**	6.7%	**198.4**	198.2
8.375% euro-sterling bond 2017		**8.5%**	8.4%	**197.7**	197.5
6.750% euro-sterling bond 2023		**6.8%**	6.8%	**247.2**	247.1
Unsecured debt of US businesses					
Bank overdraft		**–**	–	**18.4**	23.6
Commercial paper	(i)	**1.4%**	2.2%	**15.8**	124.0
Preferred securities	(v)	**8.6%**	8.6%	**208.9**	231.9
Pollution control revenue bonds	(vi)	**2.0%**	2.1%	**284.9**	316.4
Finance leases	(vii)	**11.9%**	11.9%	**17.5**	19.4
Other borrowings		**1.0%**	–	**18.1**	–
Unsecured debt				**2,937.4**	4,219.2
Secured debt of US businesses					
First mortgage and collateral bonds	(viii)	**7.5%**	7.5%	**1,726.0**	2,011.1
Pollution control revenue bonds	(vi)	**2.4%**	2.6%	**179.2**	198.9
Other secured borrowings	(ix)	**6.5%**	6.6%	**143.0**	160.0
Secured debt				**2,048.2**	2,370.0
				4,985.6	6,589.2

Notes to the Group Balance Sheet

as at 31 March 2003 – continued

20 Loans and other borrowings continued

(i) Commercial paper

Scottish Power UK plc has an established US$2.0 billion (2002 US$2.0 billion) euro-commercial paper programme. Paper is issued in a range of currencies and swapped back into sterling. PacifiCorp has a US$1.5 billion (2002 US$1.5 billion) domestic commercial paper programme. Amounts borrowed under the commercial paper programmes are repayable in less than one year.

(ii) Medium-term notes/private placements

Scottish Power plc and Scottish Power UK plc have an established joint US$7.0 billion (2002 US$7.0 billion) euro-medium-term note programme. Scottish Power plc has as yet not issued under the programme. Paper is issued in a range of currencies and swapped back into sterling. As at 31 March 2003, maturities range from 1 to 37 years.

(iii) Loan notes

All loan notes are redeemable at the holders' discretion. The ultimate maturity date for currently outstanding loan notes is 2006.

(iv) European Investment Bank ("EIB") loans

These loans incorporate agreements with various interest rates and maturity dates. The maturity dates of these arrangements range from 2009 to 2011. Following the sale of Aspen 4 Limited (the holding company of Southern Water plc) in April 2002, the EIB loans relating to Southern Water were repaid.

(v) Preferred securities

Wholly-owned subsidiary trusts of PacifiCorp ("the Trusts") have issued redeemable preferred securities representing preferred undivided beneficial interests in the assets of the Trusts. The sole assets of the Trusts are junior subordinated deferrable interest debentures of PacifiCorp that bear interest at the same rates as the preferred securities to which they relate, and certain rights under related guarantees by PacifiCorp.

(vi) Pollution control revenue bonds

Bonds issued by qualified tax exempt entities to finance, or refinance, the cost of certain pollution control, solid waste disposal and sewage facilities. PacifiCorp has entered into agreements with the issuers pursuant to which PacifiCorp received the proceeds of the issuance and agreed to make payments sufficient to pay principal of, interest on, and certain additional expenses. The interest on the bonds is not subject to federal income taxation for most bondholders. In some cases, PacifiCorp has issued first mortgage and collateral bonds as collateral for repayment.

(vii) Finance leases

These are facility leases that are accounted for as capital leases, maturity dates range from 2014 to 2022.

(viii) First mortgage and collateral bonds

First mortgage and collateral bonds of PacifiCorp may be issued in amounts limited by its Electric operation's property, earnings and other provisions of the mortgage indenture. Approximately US$12.0 billion of the eligible assets (based on original costs) of PacifiCorp is subject to the lien of the mortgage.

(ix) Other secured borrowings

Included within other secured borrowings is ScottishPower's share of debt in a joint arrangement for the Klamath co-generation plant. The borrowings are the subject of a guarantee, for US$60.0 million, provided by NA General Partnership in respect of second lien revenue bonds.

	At 31 March 2003		At 31 March 2002	
(b) Fair value of financial instruments	**Book amount £m**	**Fair value £m**	Book amount £m	Fair value £m
Short-term debt and current portion of long-term debt	**209.2**	**209.2**	1,263.1	1,263.1
Long-term debt	**4,807.2**	**5,384.3**	5,356.0	5,555.2
Cross currency interest rate swaps	**(30.8)**	**(50.0)**	(29.9)	(26.0)
Total debt	**4,985.6**	**5,543.5**	6,589.2	6,792.3
Interest rate swaps	**–**	**(22.6)**	–	22.6
Interest rate swaptions	**4.0**	**2.6**	4.0	1.4
Forward rate agreements	**–**	**8.4**	–	–
Forward contracts	**–**	**(46.7)**	16.8	10.8
Net investment forward contracts	**(9.5)**	**(9.9)**	–	–
Net investment swaps	**(297.1)**	**(255.8)**	–	–
Energy hedge contracts	**–**	**35.0**	(0.3)	60.3
Energy trading contracts	**(0.4)**	**(0.4)**	(1.0)	(1.0)
Total financial instruments	**4,682.6**	**5,254.1**	6,608.7	6,886.4

The assumptions used to estimate fair values of financial instruments are summarised below:

(i) For short-term borrowings (uncommitted borrowing, commercial paper and short-term borrowings under the committed facilities), the book value approximates to fair value because of their short maturities.

(ii) The fair values of all quoted euro bonds are based on their closing clean market price converted at the spot rate of exchange as appropriate.

(iii) The fair values of the EIB loans have been calculated by discounting their future cash flows at market rates adjusted to reflect the redemption adjustments allowed under each agreement.

(iv) The fair values of unquoted debt have been calculated by discounting the estimated cash flows for each instrument at the appropriate market discount rate in the currency of issue in effect at the balance sheet date.

(v) The fair values of the sterling interest rate swaps, sterling forward rate agreements and sterling interest rate caps have been estimated by calculating the present value of estimated cash flows.

(vi) The fair values of the sterling interest rate swaptions are estimated using the sterling yield curve and implied volatilities as at 31 March.

(vii) The fair values of the cross currency interest rate swaps have been estimated by adding the present values of the two sides of each swap. The present value of each side of the swap is calculated by discounting the estimated future cash flows for that side, using the appropriate market discount rates for that currency in effect at the balance sheet date.

(viii) The fair values of the forward contracts and tax equalisation swaps are estimated using market forward exchange rates on 31 March.

(ix) The fair values of gas futures are the margin calls under those contracts.

(x) The fair values of weather derivatives have been estimated assuming for water related derivatives a normal water year in several water basins, and for temperature related derivatives a normal daily high temperature of certain cities in the US.

20 Loans and other borrowings continued

(c) Maturity analysis	2003 £m	2002 £m
Repayments fall due as follows:		
Within one year, or on demand	**208.5**	1,226.8
After more than one year	**4,777.1**	5,362.4
	4,985.6	6,589.2
Repayments due after more than one year are analysed as follows:		
Between one and two years	**223.0**	198.9
Between two and three years	**302.2**	238.6
Between three and four years	**246.2**	340.4
Between four and five years	**101.6**	259.5
More than five years	**3,904.1**	4,325.0
	4,777.1	5,362.4

Included in the within one year, or on demand figure above is £0.1 million, in the between two and five years figures is £0.8 million and in the more than five years figure is £16.6 million relating to finance leases (2002 £nil, £0.6 million and £18.8 million respectively).

Liabilities:	2004 £m	2005 £m	2006 £m	2007 £m	2008 £m	Thereafter £m	Total £m	Fair Value* £m
Fixed rate (GBP)	25.0	50.0	–	100.0	25.0	1,109.9	**1,309.9**	**1,486.9**
Average interest rate (GBP)	6.1%	6.6%	–	6.5%	6.7%	6.6%	6.6%	
Fixed rate (USD) – UK group	–	–	–	–	–	51.4	**51.4**	**73.6**
Average interest rate (USD) – UK group	–	–	–	–	–	4.6%	4.6%	
Fixed rate (USD) – US group	88.6	153.4	169.9	132.0	76.6	1,475.7	**2,096.2**	**2,449.5**
Average interest rate (USD) – US group	7.3%	7.3%	7.4%	7.6%	7.7%	7.7%	7.6%	
Fixed rate (CHF)	4.1	–	–	–	–	–	**4.1**	**4.1**
Average interest rate (CHF)	2.5%	–	–	–	–	–	2.5%	
Fixed rate (CZK)	–	–	34.2	–	–	–	**34.2**	**47.5**
Average interest rate (CZK)	–	–	6.9%	–	–	–	6.9%	
Fixed rate (EUR)	7.0	14.6	–	–	–	282.6	**304.2**	**332.2**
Average interest rate (EUR)	4.9%	4.8%	–	–	–	5.2%	5.2%	
Index-linked (GBP)	–	–	–	–	–	184.1	**184.1**	**194.6**
Average interest rate (GBP)	–	–	–	–	–	3.49 x RPI	3.49 x RPI	
Variable rate (GBP)	31.6	5.0	–	–	–	87.0	**123.6**	**127.0**
Average interest rate (GBP)	3m LIBOR	3m LIBOR	–	–	–	4m LIBOR	4m LIBOR	
Variable rate (USD) – UK group	–	–	66.3	–	–	21.2	**87.5**	**84.9**
Average interest rate (USD) – UK group	–	–	3m LIBOR	–	–	3m LIBOR	3m LIBOR	
Variable rate (USD) – US group	52.2	–	9.9	14.2	–	389.8	**466.1**	**446.6**
Average interest rate (USD) – US group	1m LIBOR	–	BMA	BMA	–	BMA	BMA	
Variable rate (USD) – US group	–	–	–	–	–	49.5	**49.5**	**49.5**
Average interest rate (USD) – US group	–	–	–	–	–	MCBY	MCBY	
Variable rate (AUD)	–	–	–	–	–	234.2	**234.2**	**257.1**
Average interest rate (AUD)	–	–	–	–	–	3m BBSW	3m BBSW	
Variable rate (EUR)	–	–	–	–	–	18.7	**18.7**	**21.0**
Average interest rate (EUR)	–	–	–	–	–	5m LIBOR	5m LIBOR	
Variable rate (JPY)	–	–	21.9	–	–	–	**21.9**	**19.0**
Average interest rate (JPY)	–	–	6m LIBOR	–	–	–	6m LIBOR	
							4,985.6	**5,593.5**

The disclosures represent the interest profile and currency profile of financial liabilities before the impact of derivative hedging instruments.

The average variable rates above, LIBOR, exclude margins. LIBOR is the London Inter Bank Offer Rate.
GBP – Pounds Sterling, USD – American Dollars, CHF – Swiss Francs, CZK – Czech Koruna, EUR – Euros, JPY – Japanese Yen, AUD – Australian Dollars. BMA is a weekly high grade market index comprised of 7-day tax exempt variable rate demand notes produced by municipal market data. MCBY is the Moody's Corporate Bond Yield. It is derived from the pricing data of 100 corporate bonds in the US market, each with current outstandings of over $100 million and maturities of 30 years. BBSW is the Australian Bank Bill Rate.

Reference to 'm' in 'm LIBOR' and 'm BBSW' represents months.

* Fair value represents the fair value of the total debt excluding the fair value of related cross currency interest rate swaps, details of which are set out in Note 20(g).

Notes to the Group Balance Sheet
as at 31 March 2003 – continued

20 Loans and other borrowings continued

(d) Interest rate analysis	At 31 March 2003 UK £m	At 31 March 2003 US £m	At 31 March 2003 Total £m	At 31 March 2002 UK £m	At 31 March 2002 US £m	At 31 March 2002 Total £m
Fixed rate borrowings	**1,427.0**	**2,096.2**	**3,523.2**	1,920.2	2,446.2	4,366.4
Floating rate borrowings	**946.8**	**515.6**	**1,462.4**	1,583.7	639.1	2,222.8
	2,373.8	**2,611.8**	**4,985.6**	3,503.9	3,085.3	6,589.2

	Weighted average interest rate at which borrowings are fixed				Weighted average period for which interest rate is fixed			
	At 31 March 2003		At 31 March 2002		At 31 March 2003		At 31 March 2002	
	UK %	US %	UK %	US %	UK Years	US Years	UK Years	US Years
Fixed rate borrowings	**6.7**	**7.6**	6.9	7.6	**11**	**13**	10	13

All amounts in the analysis above take into account the effect of interest rate swaps and currency swaps. Floating rate borrowings bear interest at rates based on LIBOR, certificate of deposit rates, interbank borrowing rates, prime rates or other short-term market rates. The average interest rates on short-term borrowings as at 31 March 2003 were as follows: UK operations 3.6%, US operations 1.4% (2002 4.3% and 2.2% respectively).

Based on the floating rate net debt of £1,462.4 million at 31 March 2003 (2002 £2,222.8 million), a 100 basis point change in interest rates would result in a £14.6 million change in profit/(loss) before tax for the year (2002 £22.2 million change).

(e) Financial assets	At 31 March 2003 UK £m	At 31 March 2003 US £m	At 31 March 2003 Total £m	At 31 March 2002 UK £m	At 31 March 2002 US £m	At 31 March 2002 Total £m
Fixed rate financial assets	**8.3**	**114.2**	**122.5**	7.4	184.7	192.1
Floating rate financial assets	**542.7**	**157.9**	**700.6**	219.0	196.8	415.8
	551.0	**272.1**	**823.1**	226.4	381.5	607.9

Included within US fixed rate financial assets at 31 March 2003 are amounts receivable under finance leases of £262.4 million (2002 £442.1 million) less non-recourse finance of £148.2 million (2002 £257.4 million). The floating rate financial assets of the group's UK and US operations are principally cash deposits of which £2.2 million in the UK and £nil in the US (2002 £2.1 million and £24.5 million respectively) are subject to either a legal assignment or a charge in favour of a third party.

	Weighted average interest rate at which financial assets are fixed				Weighted average period for which interest is fixed			
	At 31 March 2003		At 31 March 2002		At 31 March 2003		At 31 March 2002	
	UK %	US %	UK %	US %	UK Years	US Years	UK Years	US Years
Fixed rate financial assets	**8.2**	**10.0**	8.4	9.4	**5**	**9**	7	9

All amounts in the analysis above take into account the effect of interest rate swaps and currency swaps. Floating rate investments pay interest at rates based on LIBOR, certificate of deposit rates, prime rates or other short-term market rates. The average interest rates on short-term financial assets as at 31 March 2003 were as follows: UK operations 3.6%, US operations 1.2% (2002 3.7% and 2.0% respectively).

The fair values of the financial assets are not materially different from their book values.

The group also has certain equity investments which have been excluded from the disclosures above because they have no maturity date. As at 31 March 2003, the book value of these investments was £68.9 million (2002 £78.5 million) and the fair value was £59.8 million (2002 £71.1 million).

(f) Borrowing facilities

The group has the following undrawn committed borrowing facilities at 31 March 2003 in respect of which all conditions precedent have been met. Of the facilities shown £100.0 million (2002 £1,000.0 million) relates to operations in the UK. The remaining £506.1 million (2002 £618.0 million) relates to operations in the US. Scottish Power UK plc's £1,000.0 million facility was cancelled following completion of the sale of Southern Water in April 2002. Both facilities are floating rate facilities.

	At 31 March 2003 £m	At 31 March 2002 £m
Expiring within one year	**416.3**	618.0
Expiring between two and five years	**189.8**	1,000.0

Commitment fees on the above facilities were as follows: Scottish Power UK group £0.2 million (2002 £4.1 million); PacifiCorp £0.9 million (2002 £0.6 million).

20 Loans and other borrowings continued

(g) Maturity analysis of derivatives	2004 £m	2005 £m	2006 £m	2007 £m	2008 £m	Thereafter £m	**Total £m**	**Fair Value* £m**
Interest rate swaps								
Variable to fixed (GBP)	275.0	–	–	50.0	–	50.0	**375.0**	**19.5**
Average pay rate	5.5%	–	–	5.5%	–	6.3%	5.6%	
Average receive rate	5m LIBOR	–	–	3m LIBOR	–	3m LIBOR	5m LIBOR	
Fixed to index-linked (GBP)	–	–	–	–	–	100.0	**100.0**	**11.3**
Average pay rate	–	–	–	–	–	3.35 x RPI	3.35 x RPI	
Average receive rate	–	–	–	–	–	6.2%	6.2%	
Fixed to variable (GBP)	50.0	150.0	50.0	220.0	169.9	992.1	**1,632.0**	**(98.4)**
Average pay rate	6m LIBOR	6m LIBOR	6m LIBOR	6m LIBOR	6m LIBOR	6m LIBOR	6m LIBOR	
Average receive rate	5.0%	5.7%	5.3%	5.9%	5.6%	6.4%	6.1%	
Variable to variable (GBP)	–	5.0	–	–	–	30.0	**35.0**	**(0.7)**
Average pay rate	–	6m LIBOR	–	–	–	6m LIBOR	6m LIBOR	
Average receive rate	–	3m LIBOR	–	–	–	12m LIBOR	11m LIBOR	
Variable to fixed (USD)	–	–	316.3	158.2	158.2	948.9	**1,581.6**	**45.7**
Average pay rate	–	–	3.3%	3.7%	4.0%	4.1%	3.92%	
Average receive rate	–	–	6m LIBOR	6m LIBOR	6m LIBOR	6m LIBOR	6m LIBOR	
Swaptions								
Notional amount (GBP)	–	–	–	–	–	100.0	**100.0**	**2.6**
Average pay rate	–	–	–	–	–	4.3%	4.3%	
Average receive rate	–	–	–	–	–	6m LIBOR	6m LIBOR	
Forward rate agreements								
Notional amount (GBP)	703.8	–	–	–	–	–	**703.8**	**(5.5)**
Average pay rate	6m LIBOR	–	–	–	–	–	6m LIBOR	
Average receive rate	5.4%	–	–	–	–	–	5.4%	
Notional amount (USD)	1,107.1	–	–	–	–	–	**1,107.1**	**13.9**
Average pay rate	3.8%	–	–	–	–	–	3.8%	
Average receive rate	6m LIBOR	–	–	–	–	–	6m LIBOR	
Cross currency swaps								
Receive fixed USD pay variable GBP	–	–	–	–	–	51.4	**51.4**	**(22.0)**
Average pay rate (GBP)	–	–	–	–	–	6m LIBOR	6m LIBOR	
Average receive rate (USD)	–	–	–	–	–	4.6%	4.6%	
Receive variable USD pay fixed GBP	–	–	33.1	–	–	21.2	**54.3**	**3.6**
Average pay rate (GBP)	–	–	6.7%	–	–	4.9%	6.0%	
Average receive rate (USD)	–	–	3m LIBOR	–	–	3m LIBOR	3m LIBOR	
Receive variable USD pay variable GBP	–	–	33.3	–	–	–	**33.3**	**1.9**
Average pay rate (GBP)	–	–	6m LIBOR	–	–	–	6m LIBOR	
Average receive rate (USD)	–	–	3m LIBOR	–	–	–	3m LIBOR	
Receive variable AUD pay variable GBP	–	–	–	–	–	237.8	**237.8**	**(11.7)**
Average pay rate (GBP)	–	–	–	–	–	6m LIBOR	6m LIBOR	
Average receive rate (AUD)	–	–	–	–	–	3m BBSW	3m BBSW	
Receive fixed CHF pay variable GBP	4.1	–	–	–	–	–	**4.1**	**(0.6)**
Average pay rate (GBP)	3m LIBOR	–	–	–	–	–	3m LIBOR	
Average receive rate (CHF)	2.7%	–	–	–	–	–	2.7%	
Receive fixed CZK pay variable GBP	–	–	34.3	–	–	–	**34.3**	**(13.1)**
Average pay rate (GBP)	–	–	6m LIBOR	–	–	–	6m LIBOR	
Average receive rate (CZK)	–	–	3.5%	–	–	–	3.5%	
Receive fixed EUR pay fixed GBP	–	–	–	–	–	246.6	**246.6**	**(2.6)**
Average pay rate (GBP)	–	–	–	–	–	6.7%	6.7%	
Average receive rate (EUR)	–	–	–	–	–	5.3%	5.3%	
Receive fixed EUR pay variable GBP	7.0	14.6	–	–	–	36.8	**58.4**	**(6.3)**
Average pay rate (GBP)	6m LIBOR	6m LIBOR	–	–	–	6m LIBOR	6m LIBOR	
Average receive rate (EUR)	4.9%	4.8%	–	–	–	5.0%	5.0%	
Receive variable EUR pay variable GBP	–	–	–	–	–	18.7	**18.7**	**(2.2)**
Average pay rate (GBP)	–	–	–	–	–	6m LIBOR	6m LIBOR	
Average receive rate (EUR)	–	–	–	–	–	5m LIBOR	5m LIBOR	
Receive fixed JPY pay variable GBP	–	–	21.9	–	–	–	**21.9**	**3.0**
Average pay rate (GBP)	–	–	6m LIBOR	–	–	–	6m LIBOR	
Average receive rate (JPY)	–	–	6m LIBOR	–	–	–	6m LIBOR	
Receive fixed GBP pay fixed USD	–	503.8	–	–	–	–	**503.8**	**(30.6)**
Average pay rate (USD)	–	3.6%	–	–	–	–	3.6%	
Average receive rate (GBP)	–	5.1%	–	–	–	–	5.1%	
Receive fixed GBP pay variable USD	–	–	–	35.0	–	–	**35.0**	**(5.0)**
Average pay rate (USD)	–	–	–	5.3%	–	–	5.3%	
Average receive rate (GBP)	–	–	–	6m LIBOR	–	–	6m LIBOR	
Receive variable GBP pay fixed USD	352.2	413.4	343.7	–	–	–	**1,109.3**	**1.1**
Average pay rate (USD)	3.7%	3.5%	3.7%	–	–	–	3.6%	
Average receive rate (GBP)	6m LIBOR	6m LIBOR	6m LIBOR	–	–	–	6m LIBOR	
Receive variable GBP pay variable USD	–	105.3	317.0	105.7	351.1	1,913.2	**2,792.3**	**(221.3)**
Average pay rate (USD)	–	6m LIBOR	6m LIBOR	6m LIBOR	6m LIBOR	6m LIBOR	6m LIBOR	
Average receive rate (GBP)	–	6m LIBOR	6m LIBOR	6m LIBOR	6m LIBOR	6m LIBOR	6m LIBOR	
Forward contracts								
Buy GBP, sell USD	1,856.5	204.1	113.5	128.7	–	–	**2,302.8**	**(49.9)**
Buy USD, sell GBP	1,173.0	–	–	–	–	–	**1,173.0**	**(6.7)**
							14,311.5	**(374.0)**

The abbreviations contained in the table are defined in Note 20(c). The above table includes derivatives relating to the partial hedging of the net assets of the US business and the implementation of the change in policy regarding the interest rate mix of the group's debt.

* Derivatives which have a positive fair value are shown in the table above as bracketed, while derivatives with a negative fair value are shown without brackets to follow the convention in Note 20(b) that financial liabilities are shown without brackets.

Notes to the Group Balance Sheet
as at 31 March 2003 – continued

20 Loans and other borrowings continued

(h) Hedges
Gains and losses on instruments used for hedging are not recognised until the exposure that is being hedged is itself recognised. Unrecognised gains and losses on instruments used for hedging, and the movements therein, are as follows:

	Note	Gains £m	Losses £m	Total net gains/losses £m
Unrecognised gains and (losses) on hedges at 1 April 2001		108.7	(178.6)	(69.9)
Transfer from gains to losses	(i)	(0.2)	0.2	–
Transfer from losses to gains	(i)	(0.1)	0.1	–
(Gains) and losses arising in previous years that were recognised in 2001/02		3.3	8.2	11.5
Gains and (losses) arising before 1 April 2001 that were not recognised in 2001/02		111.7	(170.1)	(58.4)
Gains and (losses) arising in 2001/02 that were not recognised in 2001/02		(47.6)	27.5	(20.1)
Unrecognised gains and (losses) on hedges at 31 March 2002		64.1	(142.6)	(78.5)
Gains and (losses) expected to be recognised in 2002/03		14.4	(17.7)	(3.3)
Gains and (losses) expected to be recognised in 2003/04 or later		49.7	(124.9)	(75.2)

(i) Figures in the table above are calculated by reference to the 31 March 2002 fair value of the derivative concerned.

	Note	Gains £m	Losses £m	Total net gains/losses £m
Unrecognised gains and (losses) on hedges at 1 April 2002		64.1	(142.6)	(78.5)
Transfer from gains to losses	(ii)	(6.7)	6.7	–
Transfer from losses to gains	(ii)	(49.4)	49.4	–
(Gains) and losses arising in previous years that were recognised in 2002/03		(23.2)	4.1	(19.1)
Gains and (losses) arising before 1 April 2002 that were not recognised in 2002/03		(15.2)	(82.4)	(97.6)
Gains and (losses) arising in 2002/03 that were not recognised in 2002/03		196.6	(52.8)	143.8
Unrecognised gains and (losses) on hedges at 31 March 2003		181.4	(135.2)	46.2
Gains and (losses) expected to be recognised in 2003/04		33.1	(48.1)	(15.0)
Gains and (losses) expected to be recognised in 2004/05 or later		148.3	(87.1)	61.2

(ii) Figures in the table above are calculated by reference to the 31 March 2003 fair value of the derivative concerned.

The analysis above excludes any gains and losses in respect of the net investment swaps and net investment forward contracts as gains and losses arising on these contracts are recorded in the statement of total recognised gains and losses.

(i) Fair value of financial assets and liabilities held for trading	2003 £m	2002 £m
Net realised and unrealised gains included in profit and loss account	**2.9**	4.5
Fair value of financial assets held for trading at 31 March	**11.0**	3.7
Fair value of financial liabilities held for trading at 31 March	**(10.6)**	(2.7)

In the UK and US a limited amount of proprietary trading within the limits and guidelines of the risk management framework is undertaken.

The transactions included in the table above consist of forward purchase and sale contracts of electricity and forward purchase and sale contracts of gas and gas futures contracts.

(j) Currency exposures
As explained in the Financial Review on pages 33 to 53 the group uses forward contracts and cross currency interest rate swaps to mitigate the currency exposures arising from its net investment overseas. Gains and losses arising on net investment overseas and the forward contracts and cross currency interest rate swaps used to hedge the currency exposures, are recognised in the statement of total recognised gains and losses.

The group did not hold material net monetary assets or liabilities in currencies other than functional currency at 31 March 2003 and 31 March 2002.

21 Other creditors

	2003 £m	2002 £m
Amounts falling due within one year:		
Trade creditors	**135.9**	172.0
Corporate tax	**251.1**	293.3
Other taxes and social security	**62.6**	56.9
Payments received on account	**43.2**	29.3
Capital creditors and accruals	**73.0**	135.4
Other creditors	**396.5**	395.6
Accrued expenses	**691.2**	743.3
Proposed dividend	**132.2**	126.1
	1,785.7	1,951.9

22 Provisions for liabilities and charges – Other provisions

2000/01	At 1 April 2000 £m	Acquisition/ revision to provisional fair values £m	Disposal £m	New provisions £m	Unwinding of discount £m	Utilised during year £m	Exchange £m	At 31 March 2001 £m
Reorganisation and restructuring	44.0	–	–	54.7	–	(17.8)	4.2	85.1
Environmental and health	84.0	–	–	3.7	2.3	(2.4)	9.2	96.8
Decommissioning costs	91.5	(15.2)	(6.7)	–	3.9	(0.8)	9.4	82.1
Onerous contracts	79.0	171.5	–	–	6.3	(12.7)	–	244.1
Pensions, post-retirement and post-employment benefits	97.6	–	–	98.6	–	(47.6)	16.3	164.9
Mine reclamation costs	104.8	–	(17.3)	–	3.5	(11.8)	11.1	90.3
Other	20.5	–	–	6.9	–	(13.3)	1.3	15.4
	521.4	156.3	(24.0)	163.9	16.0	(106.4)	51.5	778.7

2001/02	At 1 April 2001 £m	Demerger of Thus (Note 34) £m	New provisions £m	Unwinding of discount £m	Utilised during year £m	Exchange £m	At 31 March 2002 £m
Reorganisation and restructuring	85.1	–	18.5	–	(40.8)	(0.2)	62.6
Environmental and health	96.8	–	0.1	5.7	(4.4)	–	98.2
Decommissioning costs	82.1	–	–	4.8	(0.3)	–	86.6
Onerous contracts	244.1	–	–	8.5	(67.3)	–	185.3
Pensions, post-retirement and post-employment benefits	164.9	–	17.3	–	(19.3)	(0.2)	162.7
Mine reclamation costs	90.3	–	–	3.8	(9.1)	(0.1)	84.9
Disposal of and withdrawal from Appliance Retailing	–	–	50.8	–	(43.5)	–	7.3
Other	15.4	(0.9)	22.6	–	(10.9)	–	26.2
	778.7	(0.9)	109.3	22.8	(195.6)	(0.5)	713.8

2002/03	Notes	At 1 April 2002 £m	Disposal of Southern Water (Note 33) £m	New provisions £m	Unwinding of discount £m	Utilised during year £m	Exchange £m	**At 31 March 2003 £m**
Reorganisation and restructuring	(a)	62.6	(2.5)	4.7	–	(32.3)	(3.0)	**29.5**
Environmental and health	(b)	98.2	(3.1)	–	9.5	(10.9)	(8.5)	**85.2**
Decommissioning costs	(c)	86.6	–	0.5	4.8	(0.6)	(8.0)	**83.3**
Onerous contracts	(d)	185.3	–	–	8.4	(32.4)	–	**161.3**
Pensions, post-retirement and post-employment benefits	(e)	162.7	–	52.0	–	(47.4)	(17.0)	**150.3**
Mine reclamation costs	(f)	84.9	–	–	3.8	(8.1)	(8.3)	**72.3**
Disposal of and withdrawal from Appliance Retailing	(g)	7.3	–	–	–	(2.1)	–	**5.2**
Other	(h)	26.2	–	11.9	–	(13.4)	(0.9)	**23.8**
		713.8	(5.6)	69.1	26.5	(147.2)	(45.7)	**610.9**

(a) The provisions for reorganisation and restructuring principally comprise certain costs relating to the PacifiCorp Transition Plan announced in May 2000 and reorganisation provisions established in 2001/02 for the UK Division – Integrated Generation and Supply. The provisions are principally in respect of severance costs, most of which are expected to be incurred in the period up to March 2004. The PacifiCorp Transition Plan, upon completion, will result in a reduction in employee numbers of approximately 1,600 from the 1998 levels. At 31 March 2003, PacifiCorp had reduced its employees by approximately 1,050 under this Plan. The reorganisation provisions established in 2001/02 for the UK Division – Integrated Generation and Supply will result in a reduction in employee numbers of approximately 500 from 2002/03 onwards. At 31 March 2003, the UK Division – Integrated Generation and Supply had reduced its employees by 359.

(b) The environmental and health provisions principally comprise the costs of notified environmental remediation work and constructive obligations in respect of potential environmental remediation costs identified by an external due diligence review in the US. These costs are expected to be incurred in the period up to March 2010. Included within the ‘Unwinding of discount’ of £9.5 million for 2002/03 is £3.9 million relating to a change in the discount rate.

(c) The provision for decommissioning costs is the discounted future estimated costs of decommissioning the group’s power plants, principally in the US, but also in the UK. The decommissioning of these plants is expected to occur over the period between 2004 and 2047.

(d) The provision for onerous contracts comprises the costs of contracted energy purchases. The costs provided are expected to be incurred in the period up to 31 March 2009 as follows: less than 1 year £41.4 million, between 1 and 2 years £37.3 million, between 2 and 5 years £75.7 million and the remainder after 5 years £6.9 million.

(e) Details of the group’s pensions, post-retirement and post-employment benefits are disclosed in Notes 28 and 35.

(f) The provision for mine reclamation costs comprises the discounted future estimated costs of reclaiming the group’s mines in the US. The costs are expected to be incurred in the period up to 2031.

(g) The Appliance Retailing provision comprises closure costs, principally property lease termination premia, expected to be incurred in the period up to 2004.

(h) The Other category comprises various provisions which are not individually sufficiently material to warrant separate disclosure.

Notes to the Group Balance Sheet
as at 31 March 2003 – continued

23 Provisions for liabilities and charges – Deferred tax

Deferred tax provided in the Accounts is as follows:

	Provided 2003 £m	Provided 2002 £m
Accelerated capital allowances	**1,539.9**	1,978.5
Other timing differences	**(238.0)**	(287.3)
	1,301.9	1,691.2

	Note	£m
Deferred tax provided at 1 April 2000		1,612.1
Charge to profit and loss account		13.8
Movements arising from revisions to fair values		(98.5)
Exchange		97.9
Deferred tax provided at 1 April 2001		1,625.3
Charge to profit and loss account		70.2
Other movements		(4.3)
Deferred tax provided at 1 April 2002		1,691.2
Charge to profit and loss account		50.6
Disposal of Southern Water	33	(361.0)
Exchange		(80.5)
Other movements		1.6
Deferred tax provided at 31 March 2003		**1,301.9**

24 Deferred income

	At 1 April 2001 £m	Receivable during year £m	Released to profit and loss account £m	Disposal £m	Exchange £m	At 31 March 2002 £m
Grants and customer contributions	501.5	67.7	(17.8)	(0.1)	(0.1)	551.2

	At 1 April 2002 £m	Receivable during year £m	Released to profit and loss account £m	Disposal of Southern Water (Note 33) £m	Exchange £m	At 31 March 2003 £m
Grants and customer contributions	551.2	68.7	(18.6)	(37.4)	(5.0)	**558.9**

Deferred income excludes grants and contributions received, prior to the disposal of Southern Water in April 2002, in respect of water infrastructure assets.

25 Share capital

	Note	2003 £m	2002 £m
Authorised:			
3,000,000,000 (2002 3,000,000,000) ordinary shares of 50p each		**1,500.0**	1,500.0
One Special Share of £1	(a)	**–**	–
		1,500.0	1,500.0
Allotted, called up and fully paid:			
1,855,932,802 (2002 1,852,646,984) ordinary shares of 50p each		**928.0**	926.3
One Special Share of £1	(a)	**–**	–
		928.0	926.3

25 Share capital continued

(a) Special Share

The 'Special Share', which can be held only by one of the Secretaries of State or any other person acting on behalf of HM Government, does not carry rights to vote at the general or separate meetings but entitles the holder to attend and speak at such meetings. Written consent of the Special Shareholder is required before certain provisions of the company's Articles of Association or certain rights attaching to the Special Share are varied. This share shall confer no rights to participate in the capital or profits of the company, except that in a winding up the Special Shareholder shall be entitled to repayment in priority to the other shareholders. The Special Share is redeemable at par at any time by the Special Shareholder after consultation with the company.

(b) Employee share schemes

The group has six types of share based plans for employees. Options have been granted and awards made to eligible employees to subscribe for ordinary shares or ADSs in Scottish Power plc in accordance with the rules of each plan.

The ScottishPower Sharesave Schemes are savings related and under normal circumstances share options are exercisable on completion of a three or five year save-as-you-earn contract as appropriate.

The PacifiCorp Stock Incentive Plan relates to options over ScottishPower ADSs which vest over two or three years, as appropriate.

The Executive Share Option Scheme applied to executive directors and certain senior managers. However, this Scheme was replaced with the Long Term Incentive Plan and, although it will not affect options already granted, this plan supersedes the Executive Share Option Scheme.

Awards granted under the Long Term Incentive Plan will vest only if the Remuneration Committee is satisfied that certain performance measures related to the sustained underlying financial performance of the group and improvements in customer service standards are achieved over a period of three financial years commencing with the financial year preceding the date an award is made.

Options granted under the Executive Share Option Plan 2001 ("ExSOP") to executive directors and certain senior managers are subject to the performance criterion that the percentage increase in the company's annualised earnings per share, excluding goodwill amortisation and exceptional items, be at least 3% (adjusted for any increase in the RPI).

The Employee Share Ownership Plan ("ESOP") allows eligible employees to make contributions from pre-tax salary to buy shares in ScottishPower which are held in trust (Partnership Shares). These shares are matched by the company (Matching Shares) and are also held in trust. At the launch of the ESOP, Free Shares were offered to employees.

The K Plus Plan consists of the K Plus Employee Savings Plan and the K Plus Employee Stock Ownership Plan. The K Plan Employee Savings Plan is a 401(k) based qualified retirement plan designed to provide income during employees' retirement. The K Plus Employee Stock Ownership Plan provides for matching contributions by PacifiCorp based on employees' contributions, plus additional discretionary employer contributions made to all eligible employees.

(i) Summary of movements in share options in ScottishPower shares

	ScottishPower Sharesave Schemes (number of shares 000s)	Weighted average exercise price (pence)	Southern Water Sharesave Scheme (number of shares 000s)	Weighted average exercise price (pence)	Executive Share Option Schemes# (number of shares 000s)	Weighted average exercise price (pence)	PacifiCorp Stock Incentive Plan## (number of shares 000s)	Weighted average exercise price (pence)	Total (number of shares 000s)
Outstanding at 1 April 2000	19,945	339.2	1,078	147.1	263	297.0	19,073	528.5	40,359
Granted	2,459	453.0	–	–	–	–	457	440.6	2,916
Exercised	(3,615)	299.0	(786)	145.7	(122)	274.6	(304)	528.2	(4,827)
Lapsed	(2,577)	400.7	(13)	159.9	(1)	–	(4,318)	596.0	(6,909)
Outstanding at 1 April 2001	16,212	355.6	279	149.3	140	316.1	14,908	588.8	31,539
Granted	4,378	386.0	–	–	2,354	483.0	3,299	452.1	10,031
Exercised	(6,718)	283.3	(189)	144.7	(78)	278.4	(99)	474.3	(7,084)
Lapsed	(2,115)	420.6	(7)	154.9	(19)	483.0	(2,240)	576.4	(4,381)
Outstanding at 1 April 2002	11,757	396.7	83	159.1	2,397	479.9	15,868	563.6	30,105
Granted	3,316	323.0	–	–	7,327	388.0	–	–	10,643
Exercised	(1,992)	309.3	(68)	159.4	(16)	298.8	–	–	(2,076)
Lapsed	(5,640)	409.3	(15)	157.4	(252)	411.1	(2,255)	539.0	(8,162)
Outstanding at 31 March 2003	**7,441**	**377.7**	**–**	**–**	**9,456**	**411.5**	**13,613**	**500.8**	**30,510**

The Executive Share Option figures shown for 2002/03 and 2001/02 are a combination of the options outstanding under the Executive Share Option Scheme and the Executive Share Option Plan 2001.

PacifiCorp Stock Incentive Plan ("PSIP") are options over ScottishPower ADSs; for the purpose of the table above, ADSs have been converted to ScottishPower shares as follows: one ScottishPower ADS equals four ScottishPower shares. Eligibility for participation in the ExSOP was extended during the year to certain senior managers in the US. Consequently, no new options were granted in the year under the PSIP, nor is it intended to grant any new PSIP options in the future.

Notes to the Group Balance Sheet
as at 31 March 2003 – continued

25 Share capital continued

(ii) Analysis of share options outstanding at 31 March 2003

	Date of grant	Number of participants	Number of shares (000s)	Option price (pence)	Normal exercisable date
ScottishPower Sharesave Schemes	20 June 1997	3	3	307.0	6 months to March 2003
	12 June 1998	1,005	919	440.0	6 months to March 2004
	11 June 1999	878	825	429.0	6 months to March 2003 or 2005
	9 June 2000	1,172	677	453.0	6 months to March 2004 or 2006
	8 June 2001	1,787	1,966	386.0	6 months to March 2005 or 2007
	7 June 2002	2,000	3,051	323.0	6 months to March 2006 or 2008
Executive Share Option Scheme	17 December 1993	13	20	454.8	1996-2003
	27 May 1994	1	1	354.0	1997-2004
	12 May 1995	3	26	335.0	1998-2005
Executive Share Option Plan 2001*	21 August 2001	158	2,318	483.0	21 August 2004 to 21 August 2011
	2 May 2002	265	7,091	406.0	2 May 2005 to 2 May 2012
PacifiCorp Stock Incentive Plan**	3 June 1997	56	897	538.6	29 November 1999 to 3 June 2007
	12 August 1997	18	177	579.4	29 November 1999 to 12 August 2007
	10 February 1998	82	1,579	654.3	29 November 1999 to 10 February 2008
	13 May 1998	4,692	1,083	632.4	29 November 1999 to 13 May 2008
	9 February 1999	95	2,383	518.0	9 February 2000 to 9 February 2009##
	11 May 1999	4,962	1,144	468.7	11 May 2000 to 11 May 2009***
	16 February 2000	93	1,956	426.0	16 February 2001 to 16 February 2010###
	24 March 2000	4	1,343	502.1	24 March 2001 to 24 March 2010
	25 January 2001	2	457	396.3	25 January 2002 to 25 January 2011####
	24 April 2001	104	2,594	406.4	24 April 2002 to 24 April 2011

* Includes 935,054 options granted over ScottishPower ADSs (expressed in the above as 3,740,216 options over ScottishPower ordinary shares), the exercise price for which is US$23.55 per ADS (equal to US$5.887 per ordinary share).

** Options granted under the PacifiCorp Stock Incentive Plan are over ScottishPower ADSs; for the purpose of the table above, options have been converted to ScottishPower ordinary shares as follows: one ScottishPower ADS equals four ScottishPower ordinary shares. The US$ ADS option price was converted so that it may be represented in terms of ScottishPower ordinary shares. The price was further converted at the closing exchange rate on 31 March 2003 to be quoted in pence in the table above.

Options became exercisable in the proportions of one-third on 9 February 2000, one-third on 9 February 2001 and the remaining one-third on 9 February 2002.

*** Options became exercisable in the proportions 50% on 11 May 2000 and the remaining 50% on 11 May 2001.

Options became exercisable in the proportions of one-third on 16 February 2001, one-third on 16 February 2002 and the remaining one-third on 16 February 2003.

Options became exercisable in the proportions of one-third on 25 January 2002, one-third on 25 January 2003 and the remaining one-third becomes exercisable on 25 January 2004.

Where reference is made to PacifiCorp Stock Incentive Plan, this is to identify the scheme under which the options over ScottishPower ADSs have been granted. For the PacifiCorp Stock Incentive Plan, the date of grant refers to the date the original PacifiCorp Common Stock options were granted. These options were exchanged for options over ScottishPower ADSs following the acquisition on 29 November 1999.

26 Analysis of movements in shareholders' funds

	Notes	Number of shares 000s	Share capital £m	Share premium £m	Revaluation reserve £m	Capital redemption reserve £m	Merger reserve £m	Other reserve £m	Profit and loss account £m	Total £m
At 1 April 2000		1,847,586	923.8	3,733.8	220.5	18.3	406.4	–	260.5	5,563.3
Retained loss for the year		–	–	–	–	–	–	–	(169.8)	(169.8)
Share capital issued										
– Employee sharesave scheme		304	0.1	1.4	–	–	–	–	–	1.5
– Executive share option scheme		122	0.1	0.1	–	–	–	–	–	0.2
– ESOP		1,014	0.5	4.4	–	–	–	–	–	4.9
Revaluation surplus realised		–	–	–	(3.4)	–	–	–	3.4	–
Exchange movement on translation of overseas results and net assets	(b)	–	–	–	–	–	–	–	493.1	493.1
At 1 April 2001		1,849,026	924.5	3,739.7	217.1	18.3	406.4	–	587.2	5,893.2
Retained loss for the year		–	–	–	–	–	–	–	(1,927.2)	(1,927.2)
Share capital issued										
– Employee sharesave scheme		99	0.1	0.5	–	–	–	–	–	0.6
– Executive share option scheme		78	–	0.2	–	–	–	–	–	0.2
– ESOP		3,444	1.7	13.7	–	–	–	–	–	15.4
Goodwill realised on disposals	(c)	–	–	–	–	–	–	–	753.3	753.3
Goodwill realised on demerger of Thus	34	–	–	–	–	–	–	–	14.7	14.7
Reduction of share premium	(d)	–	–	(1,500.0)	–	–	–	–	1,500.0	–
Unrealised gains on fixed asset disposals		–	–	–	–	–	–	4.9	–	4.9
Gains realised on Thus demerger		–	–	–	–	–	–	(4.9)	4.9	–
Revaluation surplus realised		–	–	–	(3.4)	–	–	–	3.4	–
Fixed asset revaluation gains realised on disposal		–	–	–	(168.2)	–	–	–	168.2	–
Exchange movement on translation of overseas results and net assets	(b)	–	–	–	–	–	–	–	(4.2)	(4.2)
Translation differences on foreign currency hedging	(b)	–	–	–	–	–	–	–	(19.5)	(19.5)
At 1 April 2002		1,852,647	926.3	2,254.1	45.5	18.3	406.4	–	1,080.8	4,731.4
Retained loss for the year		–	–	–	–	–	–	–	(46.9)	(46.9)
Share capital issued										
– Executive share option scheme		15	–	0.1	–	–	–	–	–	0.1
– ESOP		3,271	1.7	10.2	–	–	–	–	–	11.9
Revaluation surplus realised		–	–	–	(2.0)	–	–	–	2.0	–
Exchange movement on translation of overseas results and net assets	(b)	–	–	–	–	–	–	–	(387.0)	(387.0)
Translation differences on foreign currency hedging	(b)	–	–	–	–	–	–	–	357.6	357.6
Tax on translation differences on foreign currency hedging		–	–	–	–	–	–	–	(28.8)	(28.8)
Balance at 31 March 2003		**1,855,933**	**928.0**	**2,264.4**	**43.5**	**18.3**	**406.4**	**–**	**977.7**	**4,638.3**

(a) Cumulative goodwill written off to the profit and loss account reserve as at 31 March 2003 was £572.3 million (2002 £572.3 million, 2001 £1,349.9 million).

(b) The pre-tax cumulative foreign currency translation adjustments at 31 March 2003 amount to £464.9 million (2002 £494.3 million, 2001 £518.0 million).

(c) The goodwill realised on disposals related to Appliance Retailing (£15.1 million) and the impairment of goodwill in connection with the provision for loss on disposal of Southern Water (£738.2 million).

(d) The company applied to the Court of Session ('the Court') to approve a reduction in the share premium account which had previously been approved by the company's shareholders at an Extraordinary General Meeting on 21 January 2002. On 5 March 2002, the Court approved the reduction of the company's share premium account by £1,500 million. This amount was transferred to the company's profit and loss account reserve. The reduction in the share premium account created sufficient distributable reserves to facilitate payment of a dividend in specie to demerge Thus.

Notes to the Group Balance Sheet
as at 31 March 2003 – continued

27 Minority interests

	Note	Equity 2003 £m	Non-equity 2003 £m	Total 2003 £m	Equity 2002 £m	Non-equity 2002 £m	Total 2002 £m
At 1 April		**1.5**	**85.2**	**86.7**	128.2	157.6	285.8
Additions		**–**	**–**	**–**	1.0	–	1.0
Disposals		**–**	**–**	**–**	2.2	–	2.2
Thus open offer		**–**	**–**	**–**	34.4	–	34.4
Demerger of Thus	34	**–**	**–**	**–**	(127.4)	–	(127.4)
Redemption of preferred stock of PacifiCorp		**–**	**(5.1)**	**(5.1)**	–	(69.5)	(69.5)
Profit and loss account		**0.5**	**4.7**	**5.2**	(41.8)	6.9	(34.9)
Unrealised gains on fixed asset disposals		**–**	**–**	**–**	4.9	–	4.9
Dividends paid to minority interests		**–**	**(4.8)**	**(4.8)**	–	(8.1)	(8.1)
Exchange		**–**	**(8.1)**	**(8.1)**	–	(1.7)	(1.7)
At 31 March		**2.0**	**71.9**	**73.9**	1.5	85.2	86.7

Non-equity minority interests include 100% of the preferred stock and preferred stock subject to mandatory redemption of PacifiCorp. Of the total preferred stock subject to mandatory redemption at 31 March 2003, £2.3 million (2002 £2.6 million) is due to be redeemed within 1 year, £2.3 million (2002 £2.6 million) is due to be redeemed in each of the next 4 years with the remaining £30.5 million (2002 £39.2 million) being redeemable after 5 years.

The fair value of preferred stock subject to mandatory redemption is £49.4 million (2002 £57.4 million). The fair value of other preferred stock is not materially different from book value.

The weighted average rate of return on preferred stock subject to mandatory redemption is 7.6% (2002 7.6%) and on other preferred stock is 5.1% (2002 5.1%).

Preferred stockholders have first preference in the event of a liquidation of PacifiCorp and first rights to dividends. The holders of these shares only have rights against the PacifiCorp group of companies.

28 Pensions and other post-retirement benefits

At 31 March 2003, ScottishPower had six statutorily approved defined benefit pension schemes, one statutorily approved defined contribution scheme and one unapproved scheme. Details of the principal schemes are set out below:

Pension fund	Scheme type	Funded or unfunded	Pension charge for the year 2003 £m	2002 £m	2001 £m	(Provision)/ prepayment as at 31 March 2003 £m	2002 £m
ScottishPower	Defined benefit	funded	**7.0**	–	–	**(2.0)**	5.0
Manweb	Defined benefit	funded	**5.2**	3.6	4.3	**–**	–
Southern Water(i)	Defined benefit	funded	**0.2**	4.1	3.7	**–**	–
Final Salary LifePlan	Defined benefit	funded	**3.1**	3.4	3.0	**–**	–
PacifiCorp(ii),(iii)	Defined benefit	funded	**25.6**	7.5	63.7	**(83.6)**	(88.4)

(i) The Southern Water figures for 2003 relate only to the period until its sale on 23 April 2002. Refer to Note 28(d) for further details.

(ii) The PacifiCorp figures include the unfunded Supplementary Executive Retirement Plan ("SERP"). The SERP accounts for less than 5% of the PacifiCorp liabilities.

(iii) The PacifiCorp figures for 2003 include a credit adjustment of £2.5 million (2002 £0.6 million charge, 2001 £54.8 million charge) to Special Termination Benefits. Also included in the figure for 2003 is a £3.1 million contribution to the PacifiCorp/International Brotherhood of Electrical Workers ("IBEW") Local Union 57 Retirement Trust Fund.

The components of the pension charge are as follows:

Pension fund	2003 Regular cost £m	2003 Interest (credit)/ cost on prepayment/ provision £m	2003 Variation (credit)/ cost £m	2003 Net pension charge £m	2002 Regular cost £m	2002 Interest (credit)/ cost on prepayment/ provision £m	2002 Variation credit £m	2002 Net pension charge £m
ScottishPower	**17.9**	**(0.3)**	**(10.6)**	**7.0**	21.8	(0.3)	(32.5)(i)	–
Manweb	**6.0**	**–**	**(0.8)**	**5.2**	5.1	–	(1.5)	3.6
Southern Water(ii)	**0.2**	**–**	**–**	**0.2**	4.8	–	(0.7)	4.1
Final Salary LifePlan	**3.1**	**–**	**–**	**3.1**	3.4	–	–	3.4
PacifiCorp	**13.5**	**5.8**	**6.3(iii)**	**25.6**	10.4	6.7	(9.6)(iv)	7.5

(i) In the year to 31 March 2002, the net pension charge was set to a minimum of £nil where the variation credit exceeded regular cost less interest.

(ii) The Southern Water figures for 2003 relate only to the period until its sale on 23 April 2002. Refer to Note 28(d) for further details.

(iii) Being a normal variation cost of £8.8 million decreased by the credit adjustment relating to the Special Termination Benefits of £2.5 million.

(iv) Being a normal variation credit of £10.2 million decreased by the cost of Special Termination Benefits of £0.6 million.

28 Pensions continued

The prepayment/(provision) as at the year end can be reconciled as follows:

Pension fund	Prepayment/ (provision) at 1 April 2002 £m	Employer contribution £m	Pension charge £m	Exchange £m	Provision at 31 March 2003 £m	Prepayment/ (provision) at 1 April 2001 £m	Employer contribution £m	Pension charge £m	Exchange £m	Prepayment/ (provision) at 31 March 2002 £m
ScottishPower	**5.0**	**–**	**(7.0)**	**–**	**(2.0)**	5.0	–	–	–	5.0
Manweb	**–**	**5.2**	**(5.2)**	**–**	**–**	–	3.6	(3.6)	–	–
Southern Water (i)	**–**	**0.2**	**(0.2)**	**–**	**–**	–	4.1	(4.1)	–	–
Final Salary LifePlan	**–**	**3.1**	**(3.1)**	**–**	**–**	–	3.4	(3.4)	–	–
PacifiCorp(ii)	**(88.4)**	**21.5**	**(25.6)**	**8.9**	**(83.6)**	(85.9)	5.1	(7.5)	(0.1)	(88.4)

(i) The Southern Water figures for 2003 relate only to the period until its sale on 23 April 2002. Refer to Note 28(d) for further details.
(ii) The employer contribution rate to the PacifiCorp Scheme increased from 1.8% of pensionable salaries in 2001/02 to 10.3% of pensionable salaries in 2002/03.

The individual scheme funding details based on the latest full actuarial valuations are as follows:

Pension fund	Latest full actuarial valuation	Valuation carried out by	Value of assets based on valuation £m	Market value of assets £m	Valuation method adopted	Principal actuarial assumptions: Average investment rate of return	Average salary increases	Average pension increases	Value of fund assets/ accrued benefits
ScottishPower	31 March 2000	Mercer HR Consulting	1,930.4	2,090.4	Projected unit	6.0%	4.5%	2.5%	129%
Manweb	31 March 2001	Bacon & Woodrow	640.8	623.6	Projected unit	6.8%(i)	4.3%	2.5%	111%
Southern Water	31 March 2001	Watson Wyatt	296.0	296.0	Projected unit	6.2%	4.5%	2.5%	107%
Final Salary LifePlan	31 March 2002	Mercer HR Consulting	4.8	4.8	Projected unit	6.0%	4.3%	2.8%	94%
PacifiCorp	1 January 2002	Hewitt Associates	519.5	519.5	Projected unit	7.50%(ii)	4.0%	–	83%

(i) 4.8% post-retiral.
(ii) 7.50% represents the liability discount rate.

(a) Group pension arrangements

Following a review of the group's UK pension arrangements, the ScottishPower Pension Scheme, Manweb Pension Scheme and Southern Water Pension Scheme were closed to new members from 31 December 1998.

The group introduced two new group pension plans for new UK employees effective from 1 January 1999. The new plans are a defined benefit plan (Final Salary LifePlan) and a defined contribution plan (Money Purchase LifePlan) which are open to continuous contract employees aged between 16 and 60.

Following the acquisition of PacifiCorp on 29 November 1999, the associated US pension arrangements are now included in the group's Accounts. Further details of these US arrangements are given in sub-note (f) below.

Each of the pension schemes are invested in an appropriately diversified range of equities, bonds, property and private markets. The broad proportions of each asset class in which the schemes aim to be invested are as follows, however it is important to note that this may vary from time to time as markets change and as cash may be held for strategic reasons.

	Equities %	Bonds %	Property %	Private markets %	Total %
ScottishPower	75	19	6	–	100
Manweb	70	30	–	–	100
Final Salary LifePlan	100	–	–	–	100
PacifiCorp	52	35	–	13	100

(b) ScottishPower

Scottish Power UK plc operates a funded pension scheme of the company providing defined retirement and death benefits based on final pensionable salary. This scheme was open prior to 1 January 1999 to employees of ScottishPower. Members are required to contribute to the Scheme at a rate of 5% of pensionable salary. Scottish Power UK plc meets the balance of cost of providing benefits, and company contributions paid are based on the results of the actuarial valuation of the Scheme and are agreed by Scottish Power UK plc and the Scheme Trustees.

The assets of the Scheme are held separately from those of the company in a trustee administered fund. Included in the Scheme assets are 140,400 ScottishPower shares (£527,904, based on market value as at 31 March 2003), purchased only as part of a pooled strategy to match the relative weightings in the UK Stock Exchange index.

The pension charge for the year is based on the advice of the Scheme's independent qualified actuary and is calculated using the same assumptions as those used at the last formal actuarial valuation of the Scheme. The Scheme assets were taken at an adjusted market value at that time.

The amount included in the balance sheet represents the difference between the accumulated excess of the actual contributions paid to the Scheme and the pension accounting charge. The net pension charge is derived from a regular cost of 19.8% of salaries, offset by a variation credit. The variation credit is calculated as the assessed surplus (updated to allow for significant market changes in the interim period), as adjusted for the balance sheet amount, spread as a fixed percentage of pensionable salaries over nine years. In the year to 31 March 2002, the net pension charge was set to a minimum of £nil where the variation credit exceeded the regular cost less interest.

The actual contributions payable by participating employers during the year were £nil, except where required by a business transfer agreement. Employer contributions have recommenced at the rate of 4.8% of pensionable salaries with effect from April 2003. The rate is expected to rise on the completion of the 2003 triannual actuarial valuation. The results will be known in the autumn of 2003 and are likely to lead to an increase in the employer contribution rate.

Notes to the Group Balance Sheet
as at 31 March 2003 – continued

28 Pensions continued

(c) Manweb

Prior to 1 January 1999, most of the Manweb employees were entitled to join the Manweb Group of the Electricity Supply Pension Scheme, which provides pension and other related benefits based on final pensionable salary to employees throughout the Electricity Supply Industry in England & Wales. The ongoing contributions to the Scheme are based on the results of the actuarial valuation of the Scheme and the advice of the Scheme Actuary.

The assets are held in a separate trustee administered fund. The Scheme assets no longer include any ScottishPower shares. For funding and expensing purposes the Scheme assets are taken at market value plus a smoothing adjustment appropriate at the valuation date.

The regular cost for the year, of 14.6% of pensionable salaries, is based on the advice of the Scheme's independent qualified actuary and is calculated using the basis of the 2001 valuation. The variation credit is calculated as a spreading of the assessed surplus over 14 years.

The actual contributions payable by participating employers during the year ranged between 8.1% and 14.1% for different sections of membership (but tending towards the higher rates), or other rates for particular groups or as required by a business transfer agreement. There are no immediate plans to alter the contributions payable.

(d) Southern Water

The sale of Southern Water to First Aqua Limited ("First Aqua") was concluded on 23 April 2002. The figures in this note relate purely to the charge arising prior to this date. There is no impact in respect of pensions on the group's balance sheet as a result of the sale of Southern Water, as the Southern Water Scheme had not given rise to any prepayment or provision at the time of the sale.

Southern Water operated a funded pension scheme. The Scheme details above relate to the principal defined benefit scheme which covered the majority of the Southern Water employees. Members were required to contribute to the Scheme at varying rates of pensionable salary depending upon category of membership. The company met the balance of the cost of the accruing benefits. Contributions paid were based on the results of the actuarial valuation of the Scheme and were agreed by the company and the Scheme Trustees.

The assets are held in a separate trustee administered fund. For funding and expensing purposes, the scheme assets were taken at market value.

The pension charge for the period, of 10% of pensionable salaries, plus employer augmentation costs, is based on the advice of the scheme's independent qualified actuary and is calculated using the same assumptions as at the last actuarial valuation of the scheme. The variation credit for 2001/02 was calculated as the assessed surplus spread over 17 years.

The actual contributions payable by participating employers during the year were 10% of pensionable salaries, except where required by a business transfer agreement.

Following the sale of Southern Water on 23 April 2002, the sponsorship of the Southern Water Scheme passed to First Aqua, with no further payments due by ScottishPower after that date. Therefore there are no consequent liabilities in respect of this Scheme.

(e) Final Salary LifePlan

The group operates a funded pension scheme providing defined retirement and death benefits based on final pensionable salary for eligible UK employees of the group. The assets of the LifePlan are held in a separate trustee administered fund. The pension charge for the year, of 11.4% of pensionable salaries, is based on the advice of the LifePlan's independent qualified actuary, representing the assessed balance of cost of the accruing benefits after allowing for members' contributions of 5% of pensionable salaries. The same actuarial assumptions have been adopted for both funding and expensing purposes.

The actual contributions payable by participating employers during the year were 11.4% of pensionable salaries, except where required by a business transfer agreement. There are no planned changes to employer contribution requirements.

(f) PacifiCorp

PacifiCorp operates pension plans covering substantially all its employees. Benefits are based on the employee's years of service and final pensionable salary, adjusted to reflect estimated social security benefits. Pension costs are funded annually by no more than the maximum amount of pension expense which can be deducted for federal income tax purposes. The PacifiCorp pensions figures in these Accounts include the unfunded SERP. The SERP accounts for less than 5% of the PacifiCorp liabilities. PacifiCorp meets the entire cost of accruing benefits under PacifiCorp plans. The assets for the funded Plan are held in a separate fund. For funding and expensing purposes, the Plan assets are valued at market levels, and liabilities costed on financial assumptions in line with market return expectations. The pension charge for the year is based on the advice of the Plan's independent qualified actuary. The actual contributions payable by participating employers during the year were 10.3% of pensionable earnings. The planned contributions for 2003/04 are expected to increase to 10.5% of pensionable earnings.

PacifiCorp also provides other post-retirement benefits to certain employees. The group has provided £55.0 million as at 31 March 2003 (2002 £62.6 million) for these benefits. The related charge for the year was £14.3 million (2002 £8.8 million). Further details of these benefits are disclosed in Note 35.

(g) Additional pension arrangements

The group operates an approved defined contribution pension scheme (Money Purchase LifePlan) for eligible employees. Contributions are paid by the member and employer at fixed rates. The benefits secured at retirement or death reflect each employee's accumulated fund and the cost of purchasing benefits at that time. The assets of the scheme are held in a separate trustee administered fund. The pension charge for the year represents the defined employer contribution and amounted to £0.1 million. The group also operates pension arrangements for senior executives, namely the ScottishPower Executive Top-Up Plan (for benefits which are held within UK Inland Revenue limits) and the Unfunded Unapproved Retirement Benefit Scheme ("UURBS") for benefits beyond these limits. The UURBS has no invested assets and the group has provided £9.5 million as at 31 March 2003 (2002 £9.3 million) for the benefit promises which will ultimately be paid by the group.

Further details of the group's pensions arrangements are disclosed in Note 35.

28 Pensions continued

(h) Financial Reporting Standard ("FRS") 17 'Retirement benefits'

The pension figures shown above comply with the current pension accounting standard, Statement of Standard Accounting Practice ("SSAP") 24. However, under the transitional arrangements of the new accounting standard, FRS 17, the group is required to disclose the following information about its pension and other post-retirement benefit schemes and the figures that would have been shown under FRS 17 in the balance sheet as at 31 March 2003 and 2002.

The major assumptions used by the actuary for both the pensions and other post-retirement benefits arrangements were:

	UK arrangements at 31 March 2003	UK arrangements at 31 March 2002	**US arrangements at 31 March 2003**	US arrangements at 31 March 2002
Rate of increase in salaries	**3.9% p.a.**	4.3% p.a.	**4.0% p.a.**	4.0% p.a.
Rate of increase in deferred pensions	**2.4% p.a.**	2.8% p.a.	**n/a**	n/a
Rate of increase in pensions in payment	**2.4% p.a.**	2.8% p.a.	**n/a**	n/a
Discount rate	**5.4% p.a.**	6.0% p.a.	**6.5% p.a.**	7.5% p.a.
Inflation assumption	**2.4% p.a.**	2.8% p.a.	**3.0% p.a.**	4.0% p.a.

Pensions

The group operates defined benefit and defined contribution pension schemes as described earlier in this Note. Full actuarial valuations were carried out as described earlier and updated to 31 March 2003 by a qualified independent actuary. Figures are shown separately for the UK and US arrangements.

The assets in the schemes and the expected long-term rates of return were as follows:

	UK pension arrangements Value at 31 March 2003 £m	UK pension arrangements Value at 31 March 2002 £m	**US pension arrangements Value at 31 March 2003 £m**	US pension arrangements Value at 31 March 2002 £m
Equities	**1,241.4**	1,882.0	**204.2**	293.2
Bonds	**363.4**	551.1	**139.3**	206.8
Property	**147.2**	164.3	**–**	–
Cash	**21.3**	26.0	**–**	–
Private markets	**–**	–	**50.0**	81.9
Total market value of assets	**1,773.3**	2,623.4	**393.5**	581.9
Present value of schemes' past service liabilities	**(2,102.6)**	(2,362.3)	**(738.2)**	(760.1)
(Deficit)/surplus of schemes' assets over past service liabilities	**(329.3)**	261.1	**(344.7)**	(178.2)
Resulting balance sheet (liability)/asset	**(329.3)**	176.9*	**(344.7)**	(178.2)
Related deferred tax asset/(liability)	**98.8**	(53.1)	**131.0**	67.7
Net pension (liability)/asset	**(230.5)**	123.8	**(213.7)**	(110.5)

* The balance sheet asset which would have arisen under FRS 17 at 31 March 2002 is lower than the total calculated excess of schemes' assets over past service liabilities, due to part of the ScottishPower Pension Scheme's past service 'surplus' being designated as "non-recoverable" in FRS 17 terms and therefore excluded from the balance sheet.

The UK pension arrangements net pension (liability)/asset comprises assets (net of deferred tax) of £nil (2002 £159.1 million) and liabilities (net of deferred tax) of £230.5 million (2002 £35.3 million).

	UK pension arrangements Long-term rates of return expected at 31 March 2003	UK pension arrangements Long-term rates of return expected at 31 March 2002	**US pension arrangements Long-term rates of return expected at 31 March 2003**	US pension arrangements Long-term rates of return expected at 31 March 2002
Equities	**7.2% p.a.**	8.0% p.a.	**9.25% p.a.**	9.75% p.a.
Bonds	**4.5% p.a.**	5.3% p.a.	**6.5% p.a.**	6.5% p.a.
Property	**6.2% p.a.**	7.0% p.a.	**n/a**	n/a
Cash	**3.45% p.a.**	3.8% p.a.	**n/a**	n/a
Private markets	**n/a**	n/a	**14.0% p.a.**	14.5% p.a.

Notes to the Group Balance Sheet
as at 31 March 2003 – continued

28 Pensions continued

Analysis of the amount charged to operating profit	UK pension arrangements Year to 31 March 2003 £m	US pension arrangements Year to 31 March 2003 £m
Current service cost	31.2	13.9
Special termination benefits	–	(2.5)
Total operating profit charge	31.2	11.4

Analysis of amount credited/(charged) to other finance income	UK pension arrangements Year to 31 March 2003 £m	US pension arrangements Year to 31 March 2003 £m
Expected return on pension scheme assets	168.4	46.5
Interest on pension liabilities	(120.6)	(49.6)
Net return on assets/(interest cost)	47.8	(3.1)

Analysis of amount recognised in statement of total recognised gains and losses ("STRGL")	UK pension arrangements Year to 31 March 2003 £m	US pension arrangements Year to 31 March 2003 £m
Actual return less expected return on assets	(647.2)	(96.5)
Experience gains and losses on liabilities	68.4	6.0
Changes in assumptions	(76.4)	(106.1)
Actuarial loss recognised in STRGL	(655.2)	(196.6)
Adjustment due to surplus cap	84.2	–
Net loss recognised	(571.0)	(196.6)

Movement in surplus/(deficit) in pension schemes during the year	UK pension arrangements Year to 31 March 2003 £m	US pension arrangements Year to 31 March 2003 £m
Surplus/(deficit) in pension schemes at beginning of year	261.1	(178.2)
Movement in year:		
Current service cost	(31.2)	(13.9)
Gain on settlement/curtailment/special termination	39.4	2.5
Contributions	8.8	21.5
Net return on assets/(interest cost)	47.8	(3.1)
Actuarial loss	(655.2)	(196.6)
Exchange	–	23.1
Deficit in pension schemes at end of year	(329.3)	(344.7)

Other post-retirement benefits

PacifiCorp provides post-retirement healthcare and life insurance benefits as described in Note 35(e). Actuarial valuations were carried out as at 31 March 2003 by a qualified independent actuary. The major assumptions used by the actuary are described in Note 35(e).

The assets in the schemes and the expected long-term rates of return were as follows:

	Value at 31 March 2003 £m	Value at 31 March 2002 £m
Equities	88.6	113.0
Bonds	52.4	67.3
Private markets	3.7	4.6
Total market value of assets	144.7	184.9
Present value of schemes' liabilities	(341.4)	(331.3)
Deficit in the schemes	(196.7)	(146.4)
Related deferred tax asset	74.7	55.6
Net other post-retirement benefits liability	(122.0)	(90.8)

	Long-term rates of return expected at 31 March 2003	Long-term rates of return expected at 31 March 2002
Equities	9.25% p.a.	9.75% p.a.
Bonds	6.5% p.a.	6.5% p.a.
Private markets	14.0% p.a.	14.5% p.a.

28 Pensions continued

Analysis of the amount charged to operating profit	Other post-retirement benefits Year to 31 March 2003 £m
Current service cost	**3.6**
Adjustment to special termination benefits	**(0.6)**
Total operating profit charge	**3.0**

Analysis of amount charged to other finance income	Other post-retirement benefits Year to 31 March 2003 £m
Expected return on other post-retirement benefits scheme's assets	**14.9**
Interest on other post-retirement benefits scheme's liabilities	**(22.1)**
Net interest cost	**(7.2)**

Analysis of amount recognised in statement of total recognised gains and losses ("STRGL")	Other post-retirement benefits Year to 31 March 2003 £m
Actual return less expected return on assets	**(31.0)**
Experience gains and losses on liabilities	**(2.9)**
Changes in assumptions	**(39.1)**
Actuarial loss recognised in STRGL	**(73.0)**

Movement in deficit during the year	Other post-retirement benefits Year to 31 March 2003 £m
Deficit in schemes at beginning of year	**(146.4)**
Movement in year:	
Current service cost	**(3.6)**
Adjustment to special termination benefits	**0.6**
Contributions	**16.0**
Net interest cost	**(7.2)**
Actuarial loss	**(73.0)**
Exchange	**16.9**
Deficit in schemes at end of year	**(196.7)**

	Year to 31 March 2003		
History of experience gains and losses	UK pension schemes £m	US pension schemes £m	Other post-retirement benefits £m
Difference between expected and actual return on scheme assets:			
Amount	**(647.2)**	**(96.5)**	**(31.0)**
Percentage of scheme's assets	**(36)%**	**(24)%**	**(21)%**
Experience gains and losses on scheme liabilities:			
Amount	**68.4**	**6.0**	**(2.9)**
Percentage of scheme's liabilities	**3%**	**1%**	**(1)%**
Total amount recognised in statement of total recognised gains and losses:			
Amount	**(571.0)**	**(196.6)**	**(73.0)**
Percentage of scheme's liabilities	**(27)%**	**(27)%**	**(21)%**

Summary
If the above FRS 17 pensions and other post-retirement benefits assets and liabilities (net of deferred tax) were recognised in the balance sheet as at 31 March 2002 and 31 March 2003, the group's net assets and profit and loss reserve would be as follows:

	At 31 March 2003 £m	At 31 March 2002 £m
Net assets	**4,712.2**	4,818.1
Reversal of SSAP 24 net pensions/other post-retirement benefits liability (net of deferred tax)	**94.0**	96.3
Reversal of capitalisation of SSAP 24 costs of pensions/other post-retirement benefits (net of deferred tax)	**(8.0)**	–
Net assets excluding effect of FRS 17	**4,798.2**	4,914.4
Capitalisation of FRS 17 costs of pensions/other post-retirement benefits (net of deferred tax)	**1.5**	–
Net assets excluding FRS 17 pensions/other post-retirement benefits assets and liabilities (net of deferred tax)	**4,799.7**	4,914.4
FRS 17 pensions assets (net of deferred tax)	**–**	159.1
FRS 17 pensions/other post-retirement benefits liabilities (net of deferred tax)	**(566.2)**	(236.6)
Net assets including FRS 17 pensions/other post-retirement benefits liabilities (net of deferred tax)	**4,233.5**	4,836.9
Profit and loss reserve	**977.7**	1,080.8
Reversal of SSAP 24 net pensions/other post-retirement benefits liability (net of deferred tax)	**94.0**	96.3
Reversal of capitalisation of SSAP 24 costs of pensions/other post-retirement benefits (net of deferred tax)	**(8.0)**	–
Profit and loss reserve excluding effect of FRS 17	**1,063.7**	1,177.1
Capitalisation of FRS 17 costs of pensions/other post-retirement benefits (net of deferred tax)	**1.5**	–
Profit and loss reserve excluding FRS 17 pensions/other post-retirement benefits assets and liabilities (net of deferred tax)	**1,065.2**	1,177.1
FRS 17 pensions/other post-retirement benefits assets and liabilities (net of deferred tax)	**(566.2)**	(77.5)
Profit and loss reserve including FRS 17 pensions/other post-retirement benefits assets and liabilities (net of deferred tax)	**499.0**	1,099.6

Notes to the Group Balance Sheet
as at 31 March 2003 – continued

29 Contingent liabilities

Thus Flotation
In November 1999, the group floated a minority stake in its internet and telecommunications business, Thus plc. This gave rise to a contingent liability to corporation tax on chargeable gains, estimated at amounts up to £570 million.
On 19 March 2002, the group demerged its residual holding in Thus Group plc (the new holding company of Thus plc). The charge referred to above could still arise, in certain circumstances, before 19 March 2007. Members of the ScottishPower group have agreed to indemnify Thus Group plc for any such liability, except in circumstances arising without the consent of the ScottishPower group.

Legal proceedings
The group's businesses are parties to various legal claims, actions and complaints, certain of which involve material amounts. Although the group is unable to predict with certainty whether or not it will ultimately be successful in these legal proceedings or, if not, what the impact might be, the directors currently believe that disposition of these matters will not have a materially adverse effect on the group's consolidated Accounts.

30 Financial commitments

(a) Analysis of annual commitments under operating leases	2003 £m	2002 £m
Leases of land and buildings expiring:		
Within one year	**0.4**	0.2
Between one and two years	**0.3**	1.3
Between two and three years	**1.4**	0.1
Between three and four years	**0.8**	–
Between four and five years	**0.1**	1.8
More than five years	**2.5**	1.0
	5.5	4.4
Other operating leases expiring:		
Within one year	**1.1**	3.9
Between one and two years	**1.9**	3.6
Between two and three years	**2.4**	2.5
Between three and four years	**–**	0.7
Between four and five years	**–**	0.9
More than five years	**–**	0.2
	5.4	11.8

(b) Capital commitments	2003 £m	2002 £m
Contracted but not provided	**127.4**	238.9

(c) Other contractual commitments
(i) UK contractual commitments
Under contractual arrangements in the UK, the group has the following power and other purchase commitments at 31 March 2003:

	2004 £m	2005 £m	2006 £m	2007 £m	2008 £m	Thereafter £m	Total £m
Commitments to purchase in year	696.7	612.7	298.5	295.5	303.9	1,267.2	3,474.5

UK contractual commitments as at 31 March 2003 principally comprise the purchase of electricity, gas and coal to manage both generation and supply activities.

(ii) PacifiCorp contractual commitments
Long-term wholesale sales and purchased power contracts
In the US, PacifiCorp manages its energy resource requirements by integrating long-term firm, short-term and spot market purchases with its own generating resources to economically operate the system (within the boundaries of Federal Energy Regulatory Commission requirements) and meet commitments for wholesale sales and retail load growth. The long-term wholesale sales commitments include contracts with minimum sales requirements of £198.2 million, £166.8 million, £141.2 million, £115.8 million and £89.6 million for the years 2004 to 2008 respectively and £0.7 billion thereafter. As part of its energy resource portfolio, PacifiCorp acquires a portion of its power through long-term purchases and/or exchange agreements which require minimum fixed payments of £244.1 million, £230.2 million, £213.3 million, £231.7 million and £156.5 million for the years 2004 to 2008 respectively, and £1.4 billion thereafter.

Excluded from the minimum fixed annual payments above are commitments to purchase power from several hydro-electric projects under long-term arrangements with public utility districts. These purchases are made on a 'cost-of-service' basis for a stated percentage of project output and for a like percentage of project annual costs (operating expenses and debt service). PacifiCorp is required to pay its portion of operating expenses and its portion of the debt service, whether or not any power is produced. The arrangements provide for non-withdrawable power and the majority also provide for additional power, withdrawable by the public utility districts upon one to five years' notice. For 2003, these purchases represented approximately 2.4% of PacifiCorp's energy requirements. At 31 March 2003, PacifiCorp's share of long-term arrangements with public utility districts were as follows:

Generating facility	Year contract expires	Percentage of output	Capacity (kw)	Annual costs* £m
Wanapum	2009	18.7%	155,444	4.4
Priest Rapids	2005	13.9%	109,602	2.5
Rocky Reach	2011	5.3%	64,297	2.2
Wells	2018	6.9%	59,617	1.4
Total			388,960	10.5

*The annual costs include debt service costs of £4.1 million. PacifiCorp's minimum debt service obligation at 31 March 2003 was £5.4 million and for the years 2004 to 2008 are £5.1 million, £4.4 million, £5.8 million, £7.7 million and £7.8 million respectively.

Short-term wholesale sales and purchased power contracts

At 31 March 2003, PacifiCorp had short-term wholesale forward sales commitments that included contracts with minimum sales requirements of £138.1 million, £77.6 million and £10.4 million for the years 2004 to 2006 respectively. At 31 March 2003, short-term forward purchase agreements require minimum fixed payments of £113.0 million, £296.4 million and £19.3 million for the years 2004 to 2006 respectively.

Fuel contracts

PacifiCorp has 'take or pay' coal and natural gas contracts that require minimum fixed payments of £163.6 million, £146.7 million, £117.8 million, £97.5 million and £100.4 million for the years 2004 to 2008 respectively, and £589.5 million thereafter.

(iii) PPM contractual commitments
At 31 March 2003, PPM had purchase commitments of £350.0 million of which £284.4 million relates to the years 2004 to 2008. PPM's contractual commitments primarily consist of electricity and gas purchases made to optimise returns from generation resources and commercial activities.

31 Related party transactions

(a) Trading transactions and balances arising in the normal course of business

Related party	Related party relationship to group	Sales/(purchases) to/(from) other group companies during the year 2003 £m	2002 £m	2001 £m	Amounts due from/(to) other group companies as at 31 March 2003 £m	2002 £m
Sales by related parties						
Scottish Electricity Settlements Limited	50% owned joint venture	**5.0**	5.3	6.2	**1.1**	1.1
ScotAsh Limited	50% owned joint venture	**0.6**	0.6	0.4	**0.2**	0.2
South Coast Power Limited	50% owned joint venture	**74.2**	46.5	25.1	**9.3**	3.0
CeltPower Limited	50% owned joint venture	**2.0**	1.7	1.7	**0.3**	0.3
Calanais Limited*	50% owned joint venture	**–**	–	69.0	**–**	–
Thus**	Subsidiary	**–**	0.9	–	**–**	12.0
Purchases by related parties						
Scottish Electricity Settlements Limited	50% owned joint venture	**(0.2)**	(0.2)	(0.2)	**–**	–
ScotAsh Limited	50% owned joint venture	**(0.2)**	(0.2)	(0.2)	**–**	–
South Coast Power Limited	50% owned joint venture	**(35.3)**	(7.8)	(3.2)	**(4.1)**	(0.5)
Klamath co-generation plant	Joint arrangement	**(24.8)**	(24.1)	–	**(5.0)**	(2.2)
CeltPower Limited	50% owned joint venture	**–**	(0.3)	(0.3)	**–**	–
Calanais Limited*	50% owned joint venture	**–**	–	(13.0)	**–**	–
Thus**	Subsidiary	**–**	(0.1)	–	**–**	(5.2)
N.E.S.T. Makers Limited	50% owned joint venture	**(1.6)**	(0.3)	–	**–**	–
Southern Water***	Subsidiary	**(2.7)**	–	–	**(0.2)**	–

In addition to the above, during the year ended 31 March 2003, PacifiCorp made management and similar charges to Powercor of £nil as a result of the disposal of Powercor by PacifiCorp in September 2000 (31 March 2002 £nil, 31 March 2001 £1.4 million). At 31 March 2003, Powercor owed the group £nil (2002 £nil, 2001 £nil).

During the year ended 31 March 2003, ScottishPower made management and similar charges to ScotAsh Limited of £0.1 million (2002 £0.4 million, 2001 £0.2 million).

*On 23 March 2001 the group disposed of its 50% holding in Calanais Limited; as a result it ceased to be a joint venture from this date.

**On 19 March 2002 the group demerged Thus. The related party sales and purchases in 2002 represent those transactions between ScottishPower and Thus for the period from 20 March to 31 March 2002.

***On 23 April 2002, the group disposed of Southern Water; as a result it ceased to be a subsidiary from this date. The sales and purchases for 2003 represent those transactions between ScottishPower and Southern Water for the period from 24 April 2002 to 31 March 2003.

(b) Funding transactions and balances arising in the normal course of business

Related party	Related party relationship to group	Note	Interest payable to other group companies during the year 2003 £m	2002 £m	Amounts due to other group companies as at 31 March 2003 £m	2002 £m
Scottish Electricity Settlements Limited	50% owned joint venture		**(0.8)**	(1.1)	**(12.2)**	(14.7)
ScotAsh Limited	50% owned joint venture		**–**	–	**(3.7)**	(2.4)
South Coast Power Limited	50% owned joint venture		**(1.2)**	(1.1)	**(18.2)**	(13.5)
RoboScot (38) Limited	50% owned joint venture		**–**	–	**(5.4)**	(5.4)
Thus**	Subsidiary	(i)	**–**	–	**–**	(5.4)
N.E.S.T. Makers Limited	50% owned joint venture		**–**	–	**(0.7)**	(0.8)

(i) This balance represents £nil (2002 £1.1 million) of loans and £nil (2002 £4.3 million) payable in respect of finance leases.

Notes to the Group Balance Sheet
as at 31 March 2003 – continued

32 Acquisition

On 9 December 2002 PPM completed the acquisition of the Katy gas storage facility and certain other trade and assets from Aquila, Inc. for a cash consideration, including expenses, of £101.3 million. The acquisition method of accounting has been adopted and the goodwill on the purchase has been capitalised and is being amortised over 20 years. The directors have estimated the useful economic life of the goodwill acquired having regard to the economic life of the facility and the duration of the contracts acquired. The details of the transaction, results and provisional fair value adjustments arising from the change in ownership are shown below.

Fair value of Katy consideration	Book values at 9 December 2002 £m	Revaluation £m	Provisional fair values at 9 December 2002 £m
Tangible fixed assets	80.6	7.7	88.3
Stocks	1.5	–	1.5
Creditors: amounts falling due within one year	(0.9)	–	(0.9)
Net assets	81.2	7.7	88.9
Goodwill arising on acquisition of Katy			12.4
Purchase consideration			101.3

(a) A valuation adjustment of £7.7 million has been made to the book value of Katy's tangible fixed assets to record them at their depreciated replacement cost.

(b) Due to the proximity of the acquisition to the balance sheet date, the fair values attributed to the Katy business are provisional and may be revised.

The results of Katy, based on Katy's accounting policies under US GAAP prior to acquisition and excluding fair value adjustments arising from the acquisition, for the year to 31 December 2001 and for the pre-acquisition period from 1 January 2002 to 8 December 2002 are shown below expressed in US dollars:

Results	Period from 1 Jan 2002 to 8 Dec 2002 $m	Year to 31 Dec 2001 $m
Turnover	13.0	9.7
Operating profit	6.2	1.6
Profit on ordinary activities before taxation	6.2	1.4
Taxation	–	–
Profit for the financial period/year	6.2	1.4
Dividends	–	–
Profit attributable to shareholders	6.2	1.4

33 Southern Water disposal

On 23 April 2002, the group completed the sale of Aspen 4 Limited (the holding company of Southern Water plc) to First Aqua Limited for a total consideration, before expenses, of £2.05 billion including repayment and acquisition of intra-group non-trading indebtedness and assumption by First Aqua Limited of Southern Water's non-trading debt due to third parties. The net assets disposed of were as follows:

	Notes	£m
Tangible fixed assets	16, (i)	2,474.7
Fixed asset investments	17	1.9
Current assets		193.1
Creditors: amounts falling due within one year		
– Loans and other borrowings:		
– Inter-company loan		(756.4)
– Bank overdraft		(6.2)
– Other creditors		(291.2)
Creditors: amounts falling due after more than one year		
– Loans and other borrowings		(100.0)
Provisions for liabilities and charges		
– Other provisions	22	(5.6)
– Deferred tax	23	(361.0)
Deferred income	24	(37.4)
Book value of Southern Water net assets disposed		1,111.9
Gain on disposal	(i)	–
Net disposal proceeds		1,111.9
Satisfied by:		
Cash received for net assets	(ii)	1,187.3
Cash expenses		(47.9)
Net disposal cash proceeds		1,139.4
Accrued expenses		(27.5)
Net disposal proceeds		1,111.9

(i) In the year ended 31 March 2002, an exceptional impairment provision of £449.3 million was made to reduce the carrying value of Southern Water's net assets to their recoverable amount. In addition, a further exceptional charge of £738.2 million was recognised representing the impairment of goodwill on the acquisition of Southern Water previously written off to reserves. As a consequence of these charges to profits in the year ended 31 March 2002, there is no further gain or loss required to be recognised for the year ended 31 March 2003 on completion of the sale.

(ii) Analysis of total consideration before expenses	£m
Cash received for net assets	1,187.3
Cash received on repayment to ScottishPower of inter-company loan	756.4
Cash consideration before expenses	1,943.7
Debt due to third parties assumed by First Aqua Limited (including premium of £6.3 million)	106.3
Total consideration before expenses	2,050.0

34 Thus Group plc demerger

On 19 March 2002, the group demerged Thus Group plc ("Thus"). The demerger of Thus was preceded by an open offer of approximately £275 million of new equity shares in Thus which resulted in ScottishPower's equity interest in Thus temporarily increasing from 50.1% to 72.4%, and an increase in goodwill of £34.4 million. Thus' results for the period to 19 March 2002 were reported under discontinued operations in the ScottishPower Accounts for the year ended 31 March 2002 and the prior year. The demerger of Thus was accounted for as a dividend in specie.

	Notes	£m
Intangible fixed assets – goodwill	15	62.6
Tangible fixed assets	16	468.8
Fixed assets investments	17	24.2
Current assets		104.5
Creditors: amounts falling due within one year		(109.9)
Provisions for liabilities and charges		
– Other provisions	22	(0.9)
Book value of Thus net assets disposed		549.3
Minority interest share of net assets	27	(127.4)
ScottishPower's share of Thus net assets disposed		421.9
Goodwill previously charged to reserves written back	26	14.7
Dividend in specie		436.6

Notes to the Group Balance Sheet
as at 31 March 2003 – continued

35 Summary of differences between UK and US Generally Accepted Accounting Principles ('GAAP')

The consolidated Accounts of the group are prepared in accordance with UK GAAP which differs in certain significant respects from US GAAP. The effect of the US GAAP adjustments to profit/(loss) for the financial year and equity shareholders' funds are set out in the tables below.

(a) Reconciliation of profit/(loss) for the financial year to US GAAP:	Notes	Year ended 31 March 2003 £m	2002 £m	2001 £m
Profit/(loss) for the financial year under UK GAAP		**482.6**	(987.1)	307.5
US GAAP adjustments:				
Amortisation of goodwill	(i)	**139.0**	(23.5)	(35.9)
Disposal of businesses	(ii)	**–**	279.1	–
US regulatory net assets	(iii)	**(121.6)**	95.3	73.8
Pensions	(iv)	**20.1**	40.0	95.5
Impairment on demerger of Thus	(v)	**–**	(243.7)	–
Depreciation on revaluation uplift	(vi)	**2.0**	3.4	3.4
Decommissioning and mine reclamation liabilities	(vii)	**(38.3)**	(21.8)	(32.3)
PacifiCorp Transition Plan costs	(viii)	**(19.1)**	(29.9)	108.2
Business combinations	(i)	**(31.6)**	–	–
FAS 133	(ix)	**205.5**	144.5	–
Other	(xv)	**(10.8)**	(17.7)	(0.4)
Re-classification as extraordinary item	(x)	**–**	12.0	–
		627.8	(749.4)	519.8
Deferred tax effect of US GAAP adjustments	(xi)	**20.4**	(67.6)	(133.0)
		648.2	(817.0)	386.8
Extraordinary item (net of tax)	(x)	**–**	(8.4)	–
Profit/(loss) for the financial year under US GAAP before cumulative adjustment for C15 and C16 (2002 FAS 133)		**648.2**	(825.4)	386.8
Cumulative adjustment for C15 and C16 (2002 FAS 133)	(ix)	**141.1**	(61.6)	–
Profit/(loss) for the financial year under US GAAP		**789.3**	(887.0)	386.8
Earnings/(loss) per share under US GAAP	(xiv)	**42.81p**	(48.26)p	21.13p
Diluted earnings/(loss) per share under US GAAP	(xiv)	**42.70p**	(48.26)p	21.05p

(b) Effect on equity shareholders' funds of differences between UK GAAP and US GAAP:	Notes	31 March 2003 £m	31 March 2002 £m
Equity shareholders' funds under UK GAAP		**4,638.3**	4,731.4
US GAAP adjustments:			
Goodwill	(i)	**572.3**	572.3
Business combinations	(i)	**(226.3)**	(174.2)
Amortisation of goodwill	(i)	**51.0**	(84.2)
ESOP shares held in trust	(xii)	**(38.2)**	(38.9)
US regulatory net assets	(iii)	**1,007.9**	1,042.8
Pensions	(iv)	**(412.8)**	222.9
Cash dividends	(xiii)	**132.2**	126.1
Revaluation of fixed assets	(vi)	**(54.0)**	(54.0)
Depreciation on revaluation uplift	(vi)	**10.5**	8.5
Decommissioning and mine reclamation liabilities	(vii)	**0.4**	60.7
PacifiCorp Transition Plan costs	(viii)	**56.1**	86.9
FAS 133	(ix)	**(66.8)**	(308.2)
Other	(xv)	**(12.1)**	(3.4)
Deferred tax:			
Effect of US GAAP adjustments	(xi)	**(157.4)**	(316.9)
Effect of differences in methodology	(xi)	**(21.4)**	(21.3)
Equity shareholders' funds under US GAAP		**5,479.7**	5,850.5

(i) Goodwill and business combinations

Goodwill

Under UK GAAP, goodwill arising from the purchase of operating entities before 31 March 1998 has been written off directly to reserves. Additionally, UK GAAP requires that on subsequent disposal of these entities any goodwill previously taken directly to reserves is then charged in the profit and loss account against the profit or loss on disposal. Goodwill arising on acquisitions after 31 March 1998 is capitalised and amortised through the profit and loss account over its useful economic life.

The goodwill adjustment is made to recognise goodwill previously written off to reserves under UK GAAP as an intangible asset under US GAAP.

Under US GAAP, following the introduction of Statement of Financial Accounting Standard ("FAS") 142 'Goodwill and Other Intangible Assets' which was effective for the group from 1 April 2002, goodwill arising from the purchase of operating entities should be held as an indefinite lived intangible asset in the balance sheet and is no longer amortised. Instead goodwill is subject to an impairment test performed at least annually. The adjustment 'Amortisation of goodwill' for the year ended 31 March 2003 represents the reversal of amortisation of goodwill charged under UK GAAP.

The group has completed its transitional and annual goodwill impairment analysis under FAS 142 and has concluded that goodwill is not impaired. The following table provides an analysis of goodwill included in the balance sheet under US GAAP for the year ended 31 March 2003 and for the year ended 31 March 2002.

35 Summary of differences between UK and US Generally Accepted Accounting Principles ('GAAP') continued

	Notes	2003 £m	2002 £m
Net book value of goodwill capitalised under US GAAP:			
At 1 April		**2,937.7**	3,794.1
Acquisition		**12.4**	–
Disposal of businesses		**–**	(680.1)
Business combinations	(a)	**(36.7)**	–
Amortisation for the year		**–**	(172.5)
Exchange		**(235.8)**	(3.8)
As at 31 March	(b)	**2,677.6**	2,937.7

(a) The Business combinations adjustment of £36.7 million relates to deferred tax provisions recognised on the acquisition of PacifiCorp.

(b) The net book value of goodwill capitalised under US GAAP is analysed by business segment in the table below:

	31 March 2003 £m	31 March 2002 £m
UK Division – Integrated Generation and Supply	**562.9**	562.9
US Division		
PacifiCorp	**2,102.3**	2,374.8
PPM	**12.4**	–
United States total	**2,114.7**	2,374.8
Total	**2,677.6**	2,937.7

(c) The impact of reporting under FAS 142 for the year ended 31 March 2002 would have been to reduce the loss under US GAAP by £172.5 million to £714.5 million (2001 increase earnings by £163.5 million to £550.3 million) and to reduce the loss per share under US GAAP by 9.38 pence per share to 38.88 pence per share (2001 increase earnings per share by 8.93 pence per share to 30.06 pence per share).

Business combinations
In addition to re-instating the goodwill calculated under UK GAAP as described above, goodwill must also be recalculated in accordance with US GAAP. This is required due to differences between UK GAAP and US GAAP in the determination of acquisition price and valuation of assets and liabilities at the acquisition date. The adjustment referred to as Business combinations reflects principally the impact of recalculating the goodwill arising on the acquisitions of Manweb and PacifiCorp under US GAAP. The Business combinations adjustment of £31.6 million (£22.1 million net of tax) reflected in the reconciliation of profit/(loss) to US GAAP for the year ended 31 March 2003 represents the difference between UK GAAP and US GAAP in accounting for accruals recognised under UK GAAP when PacifiCorp was acquired.

In cases where traded equity securities are exchanged as consideration, UK GAAP requires the fair value of consideration to be determined at the date the transaction is completed, while US GAAP requires the fair value of such consideration to be determined at the date the acquisition is announced.

(ii) Disposal of businesses
Under UK GAAP the loss on disposal of and withdrawal from Appliance Retailing and the provision for loss on disposal of Southern Water were calculated based on net asset value, together with the goodwill previously written off to reserves.

Under US GAAP the same methodology was applied, however the net asset value under US GAAP differed from that under UK GAAP. The principal differences relate to the amortisation of goodwill which had been recognised as an intangible asset under US GAAP but had been written off to reserves under UK GAAP and the revaluation of certain tangible fixed assets, which is not permitted under US GAAP but is permitted under UK GAAP.

(iii) US regulatory net assets
FAS 71 'Accounting for the Effects of Certain Types of Regulation' establishes US GAAP for utilities in the US whose regulators have the power to approve and/or regulate rates that may be charged to customers. FAS 71 provides that regulatory assets may be capitalised if it is probable that future revenue in an amount at least equal to the capitalised costs will result from the inclusion of that cost in allowable costs for ratemaking purposes. Due to the different regulatory environment, no equivalent GAAP applies in the UK.

Under UK GAAP, the group's policy is to recognise regulatory assets established in accordance with FAS 71 only where they comprise rights or other access to future economic benefits which have arisen as a result of past transactions or events which have created an obligation to transfer economic benefits to a third party.

The impact of the application of different accounting policies is that US regulatory assets amounting to £1,007.9 million (2002 £1,042.8 million) are not recognised under UK GAAP, including deferred excess power costs, certain FAS 133 regulatory balances and certain pension regulatory balances.

Profits under US GAAP are consequently decreased by £121.6 million in 2003 (2002 profit increased by £95.3 million).

US regulatory net assets relating to the PacifiCorp Transition Plan costs are discussed in note (viii) below.

(iv) Pension costs
The fundamental differences between UK GAAP and US GAAP are as follows:

(a) Under UK GAAP, the annual pension charge is determined so that it is a substantially level percentage of the current and expected future payroll. Under US GAAP, the aim is to accrue the cost of providing pension benefits in the year in which the employee provides the related service in accordance with FAS 87, which requires re-adjustment of the significant actuarial assumptions annually to reflect current market and economic conditions.

(b) Under UK GAAP, pension liabilities are usually discounted using an interest rate that represents the expected long-term return on plan assets. Under US GAAP, pension liabilities are discounted using the current rates at which the pension liability could be settled.

(c) Under UK GAAP, variations from plan can be aggregated and amortised over the remaining employee service lives. Under US GAAP, variations from plan must be amortised separately over remaining service lives.

(d) Under UK GAAP, alternative bases can be used to value plan assets. Under US GAAP, plan assets should be valued at market or at market related values and where the fair/market value of the plan assets is less than the accumulated benefit obligation a minimum pension liability is then recognised as a charge to other comprehensive income under the provisions of FAS 87 unless and to the extent that FAS 71 can be applied in which case a pension regulatory asset is recognised.

Notes to the Group Balance Sheet
as at 31 March 2003 – continued

35 Summary of differences between UK and US Generally Accepted Accounting Principles (‘GAAP’) continued

(v) Impairment on demerger of Thus
Under UK GAAP, the demerger dividend was calculated based on the book value of the net assets disposed of as a result of demerger.

Under US GAAP, the demerger dividend was calculated based on the market value of the shares at the demerger date and the difference between this and the book value of net assets disposed of was disclosed as an impairment charge under US GAAP.

(vi) Revaluation of fixed assets
The revaluation of assets is not permitted under US GAAP. The reconciliation therefore adjusts fixed assets to historical cost and the depreciation charge has been adjusted accordingly.

(vii) Decommissioning and mine reclamation liabilities
Under UK GAAP, future decommissioning costs are provided for, on a discounted basis, generally at the inception of the asset life with a corresponding increase to the cost of the asset. This increased cost is depreciated over the useful life of the asset. Under US GAAP, for regulated industries, decommissioning costs are accounted for by depreciating the related tangible fixed asset to a negative amount which equates to the estimated decommissioning costs. In respect of mine reclamation costs UK GAAP requires the discounted future costs of reclamation to be provided for, with a corresponding increase to the cost of the mine assets. Under US GAAP, anticipated mine reclamation costs are accrued over the life of the mine asset.

(viii) PacifiCorp Transition Plan costs
Under UK GAAP, PacifiCorp Transition Plan costs were recognised as an expense in the profit and loss account at the date of the announcement of the Plan. Costs were provided for in accordance with FRS 12 ‘Provisions, contingent liabilities and contingent assets’.

Under US GAAP, PacifiCorp Transition Plan costs are accounted for as regulatory assets and are being amortised through the income statement. Costs have been accounted for in accordance with Emerging Issues Task Force No. 94-3 ‘Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)’ and FAS 88 ‘Employers’ Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits’.

(ix) FAS 133 – derivative instruments and hedging activities
Under UK GAAP derivatives designated as used for non-trading purposes are accounted for on a consistent basis with the asset, liability or position being hedged. Under US GAAP, the group applies FAS 133 ‘Accounting for Derivative Instruments and Hedging Activities’, as amended by FAS 137 ‘Accounting for Derivative Instruments and Hedging Activities – Deferral of the Effective Date of FASB Statement No. 133’ and FAS 138 ‘Accounting for Certain Derivative Instruments and Certain Hedging Activities’. Effective from 1 April 2002, the group adopted revised FAS 133 guidance issued by the Derivatives Implementation Group under Revised Issue C15 ‘Normal Purchases and Normal Sales Exception for Certain Option-Type Contracts in Electricity’ and Issue C16 ‘Applying the Normal Purchases and Normal Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract’. This new guidance had the effect of including an increased number of the group’s contracts within the scope of FAS 133. The cumulative adjustment to profit under US GAAP for the year ended 31 March 2003 as a result of adopting Revised Issue C15 and Issue C16 was an increase to profit of £228.6 million (£141.1 million, net of tax). FAS 133 requires recognition of all derivatives, as defined in the standard, on the balance sheet at fair value. Derivatives, or any portion thereof, that are not an effective hedge, are adjusted to fair value through income. If a derivative qualifies as an effective hedge, changes in the fair value of the derivative are either offset against the change in fair value of the hedged asset, liability, or firm commitment recognised in income, or are recognised in accumulated other comprehensive income until the hedged items are recognised in earnings. The effects of changes in fair value of certain derivative instruments entered into to hedge future retail resource requirements in the group’s US regulated business are subject to regulation and therefore are deferred pursuant to FAS 71. The FAS 133 adjustment included within equity shareholders’ funds of £66.8 million at 31 March 2003 is offset by a US regulatory net asset of £320.6 million relating to PacifiCorp’s regulated activities which have been deferred as a regulatory asset under FAS 71.

Contracts that qualify as normal purchases and normal sales are excluded from the requirements of FAS 133. The realised gains and losses on these contracts are reflected in the income statement at the contract settlement date.

(x) Extraordinary item
Under UK GAAP, certain costs of early debt repayment have been treated as exceptional interest costs. Under US GAAP, costs of early debt repayment are classified as extraordinary items. The tax credit on the extraordinary item was £3.6 million for the year ended 31 March 2002.

(xi) Deferred tax
Under UK GAAP, FRS 19 ‘Deferred tax’, requires full provision for deferred tax at future enacted rates. Provision is only made in respect of assets revalued for accounting purposes where a commitment exists to sell the asset at the balance sheet date.

Under US GAAP, full provision for deferred tax is required to the extent that accounting profit differs from taxable profit due to temporary timing differences. Provision is made based on enacted tax law.

The item ‘Effect of US GAAP adjustments’ reflects the additional impact of making full provision for deferred tax in respect of adjustments made in restating the balance sheet to US GAAP.

The item ‘Effect of differences in methodology’ reflects the impact of making full provision for deferred tax under US GAAP compared to UK GAAP.

(xii) ESOP shares held in trust
Under UK GAAP, shares held by employee share ownership trusts are recorded as fixed asset investments at cost less amounts written off. Under US GAAP, shares held in trust are recorded at cost in the balance sheet as a deduction from shareholders’ funds. Details of the group’s employee share ownership trusts are set out in Note 17.

(xiii) Cash dividends
Under UK GAAP, final ordinary cash dividends are recognised in the financial year in respect of which they are proposed by the Board of Directors. Under US GAAP, such dividends are not recognised until they are formally declared by the Board of Directors.

35 Summary of differences between UK and US Generally Accepted Accounting Principles ('GAAP') continued

(xiv) Earnings/(loss) per share
Earnings/(loss) per ordinary share have been calculated by dividing the profit/(loss) for the financial year under US GAAP by the weighted average number of ordinary shares in issue during the financial year, based on the following information:

	2003	2002	2001
Profit/(loss) for the financial year under US GAAP (£ million)	**789.3**	(887.0)	386.8
Basic weighted average share capital (number of shares, millions)	**1,843.9**	1,837.8	1,830.3
Diluted weighted average share capital (number of shares, millions)	**1,848.4**	1,840.1	1,837.4
Earnings/(loss) per share			
Earnings per share under US GAAP – continuing operations	**35.76p**	19.15p	13.48p
(Loss)/earnings per share under US GAAP – discontinued operations	**(0.60)p**	(63.60)p	7.65p
Loss per share under US GAAP – extraordinary item (net of tax)	**–**	(0.46)p	–
Earnings/(loss) per share under US GAAP before cumulative adjustment for C15 and C16 (2002 FAS 133)	**35.16p**	(44.91)p	21.13p
Earnings/(loss) per share under US GAAP – cumulative adjustment for C15 and C16 (2002 FAS 133)	**7.65p**	(3.35)p	–
Earnings/(loss) per share under US GAAP	**42.81p**	(48.26)p	21.13p
Diluted earnings/(loss) per share			
Diluted earnings per share under US GAAP – continuing operations	**35.67p**	19.15p	13.43p
Diluted (loss)/earnings per share under US GAAP – discontinued operations	**(0.60)p**	(63.60)p	7.62p
Diluted loss per share under US GAAP – extraordinary item (net of tax)	**–**	(0.46)p	–
Diluted earnings/(loss) per share under US GAAP before cumulative adjustment for C15 and C16 (2002 FAS 133)	**35.07p**	(44.91)p	21.05p
Diluted earnings/(loss) per share under US GAAP – cumulative adjustment for C15 and C16 (2002 FAS 133)	**7.63p**	(3.35)p	–
Diluted earnings/(loss) per share under US GAAP	**42.70p**	(48.26)p	21.05p

The difference between the basic and the diluted weighted average share capital is wholly attributable to outstanding share options and shares held in trust for the group's Employee Share Ownership Plan. In accordance with FAS 128 'Earnings per Share' the diluted loss per share for the year ended 31 March 2002 does not assume the exercise of securities that have an antidilutive effect on the loss per share. The (loss)/earnings per share detailed above for discontinued operations have been calculated based on US GAAP earnings which are net of £3.0 million (2002 £37.0 million, 2001 £36.3 million) of interest and similar charges and a tax credit of £4.6 million (2002 £18.8 million tax charge, 2001 £5.8 million tax credit). The group's charge for interest and similar charges has been allocated between continuing and discontinued operations on the basis of external and internal borrowings of the respective operations.

As permitted under UK GAAP, earnings/(loss) per share have been presented including and excluding the impact of exceptional items and goodwill amortisation to provide an additional measure of underlying performance. UK GAAP permits the presentation of more than one measure of earnings/(loss) per share provided that all such measures are clearly explained and given equal prominence on the face of the profit and loss account. In accordance with US GAAP, earnings/(loss) per share have been presented above based on US GAAP earnings/(loss), without adjustments for the impact of UK GAAP exceptional items and goodwill amortisation. Such additional measures of underlying performance are not permitted under US GAAP.

(xv) Other
Other differences between UK and US GAAP are not individually material and relate to post-retirement benefits other than pensions, capitalisation of finance costs, available-for-sale securities, energy exchange contracts and stock option compensation expense.

UK GAAP permits the use of long-term discount rates in determining the provision for post-retirement benefits other than pensions. US GAAP requires the use of current market rates.

Under UK GAAP, only interest on debt funding may be capitalised during the period of construction. Under US GAAP, as applied by regulated electricity utilities, both the cost of debt and the cost of equity applicable to domestic utility properties are capitalised during the period of construction.

Under UK GAAP, obligations under energy exchange contracts are valued based on the forecast cost at the balance sheet date of delivering energy under the contract. Under US GAAP, for regulated utilities, obligations under energy exchange contracts are valued based on the cost avoided in receiving delivery of energy under the contract.

Available-for-sale securities
UK GAAP permits current asset investments to be valued at the lower of cost and net realisable value. US GAAP requires that such investments, insofar as they are available-for-sale securities, are marked to market with movements in market value being included in other comprehensive income.

The book value and estimated fair value of available-for-sale securities were as follows:

	At 31 March 2003			
	Book value £m	Gross unrealised gains £m	Gross unrealised losses £m	Estimated fair value £m
Money market account	**2.5**	**–**	**–**	**2.5**
Mutual fund account	**19.4**	**–**	**(0.2)**	**19.2**
Debt securities	**10.8**	**0.4**	**(1.7)**	**9.5**
Equity securities	**35.0**	**0.5**	**(6.3)**	**29.2**
Total	**67.7**	**0.9**	**(8.2)**	**60.4**

	At 31 March 2002			
	Book value £m	Gross unrealised gains £m	Gross unrealised losses £m	Estimated fair value £m
Money market account	1.9	–	–	1.9
Debt securities	14.4	0.3	(1.8)	12.9
Equity securities	27.7	2.7	(5.3)	25.1
Total	44.0	3.0	(7.1)	39.9

The quoted market price of securities at 31 March is used to estimate the securities' fair value.

Notes to the Group Balance Sheet
as at 31 March 2003 – continued

35 Summary of differences between UK and US Generally Accepted Accounting Principles (‘GAAP’) continued

The book value and estimated fair value of debt securities by contractual maturities at 31 March 2003 and 2002 are shown below. Actual maturities may differ from contractual maturities because borrowers may have the right to call or pre-pay obligations with or without call or prepayment penalties.

	At 31 March 2003		At 31 March 2002	
	Book value £m	Estimated fair value £m	Book value £m	Estimated fair value £m
Debt securities				
Due within one year	**0.5**	**0.5**	–	–
Due between one and five years	**1.6**	**1.4**	3.2	2.9
Due between five and ten years	**4.5**	**4.0**	4.6	4.4
Due after ten years	**4.2**	**3.6**	6.6	5.6
Money market account	**2.5**	**2.5**	1.9	1.9
Mutual fund accounts	**19.4**	**19.2**	–	–
Equity securities	**35.0**	**29.2**	27.7	25.1
Total	**67.7**	**60.4**	44.0	39.9

Proceeds, gross gains and gross losses from realised sales of available-for-sale securities using the specific identification method were as follows:

	Year ended 31 March		
	2003 £m	2002 £m	2001 £m
Proceeds	**56.3**	56.4	54.0
Gross gains	**1.1**	2.1	5.3
Gross losses	**(3.7)**	(5.6)	(3.6)
Net (losses)/gains	**(2.6)**	(3.5)	1.7

Stock-based compensation

Under US GAAP, the group applies Accounting Principles Board Opinion No. 25 (“APB 25”), ‘Accounting for Stock Issued to Employees’, and related interpretations in accounting for its plans and a compensation expense has been recognised accordingly for its share option schemes. As the group applies APB 25 in accounting for its plans, under FAS 123, ‘Accounting for Stock-Based Compensation’, it has adopted the disclosure only option in relation to its share option schemes. Had the group determined compensation cost based on the fair value at the grant date for its share options under FAS 123, the group’s profit/(loss) for financial year under US GAAP and earnings/(loss) per share under US GAAP would have been reduced to the pro forma amounts below:

	2003	2002	2001
Profit/(loss) for the financial year under US GAAP (£ million)	**789.3**	(887.0)	386.8
Reversal of APB 25 stock compensation expense (included within the ‘Other’ adjustment) (£ million)	**3.6**	4.4	5.0
Stock compensation expense calculated under FAS 123 (£ million)	**(6.1)**	(7.4)	(11.2)
Pro forma profit/(loss) for the financial year under US GAAP (£ million)	**786.8**	(890.0)	380.6
Basic earnings/(loss) per share under US GAAP	**42.81p**	(48.26)p	21.13p
Pro forma basic earnings/(loss) per share under US GAAP	**42.67p**	(48.43)p	20.79p
Diluted earnings/(loss) per share under US GAAP	**42.70p**	(48.26)p	21.05p
Pro forma diluted earnings/(loss) per share under US GAAP	**42.57p**	(48.43)p	20.71p

The weighted average fair value of options granted during the year was £6.3 million (2002 £8.6 million, 2001 £1.6 million). The fair value of each option grant was estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions used:

	2003	2002	2001
Dividend yield	8.3%	6.7%	6.4%
Risk-free interest rate	4.6%	4.8%	4.9%
Volatility	30.0%	30.0%	24.0%
Expected life of the options (years)	6	4	4

The weighted average life of the share options outstanding as at 31 March 2003, March 2002 and March 2001 was as follows:

	2003 (years)	2002 (years)	2001 (years)
ScottishPower Sharesave Schemes	**3**	3	2
Southern Water Sharesave Scheme	**–**	2	2
Executive Share Option Scheme	**2**	2	2
Executive Share Option Plan 2001	**9**	9	–
PacifiCorp Stock Incentive Plan	**6**	6	6

35 Summary of differences between UK and US Generally Accepted Accounting Principles ('GAAP') continued

(xvi) Reclassifications

The reconciliations of profit/(loss) for the financial year and equity shareholders' funds at the year end from UK GAAP to US GAAP only include those items which have a net effect on profit/(loss) or equity shareholders' funds. There are other GAAP differences, not included in the reconciliations, which would affect the classification of assets and liabilities or of income and expenditure. The principal items which would have such an effect are as follows:

– under UK GAAP debt issue costs are deducted from the carrying value of the related debt instrument. US GAAP requires such costs to be included as an asset

– under UK GAAP customer contributions in respect of fixed assets are generally credited to a separate deferred income account. Under US GAAP such contributions are netted off against the cost of the related fixed assets

– items included as exceptional items under UK GAAP are either classified as extraordinary items or operating items under US GAAP

– under US GAAP, transmission and distribution costs would be included in cost of sales, and gross profit from continuing operations would be calculated after deducting these expenses

– under UK GAAP, the investor's interest in the turnover and results of a joint venture or associate are disclosed gross. The investor's share of the interest and taxation are disclosed separately as a component of the group interest and taxation lines. Under US GAAP, the investor's interest in the net results of joint ventures and associates is disclosed as a single line in the income statement, net of interest and taxation.

Consolidated statement of comprehensive income/(loss)

Under US GAAP, certain items shown as components of common equity must be more prominently reported in a separate statement as components of comprehensive income/(loss).

The consolidated statement of comprehensive income/(loss) is set out below:

	2003 £m	2002 £m	2001 £m
Profit/(loss) for the financial year under US GAAP after cumulative income adjustment	**789.3**	(887.0)	386.8
Other comprehensive income/(loss)			
– Foreign currency translation adjustment	**(114.1)**	(29.7)	671.2
– Unrealised loss on available-for-sale securities, net of tax credit of £1.4 million (2002 £0.1 million, 2001 £4.0 million)	**(2.3)**	(0.1)	(6.5)
– Pensions, net of tax credit of £154.1 million (2002 £23.6 million)	**(358.8)**	(38.5)	–
– Cumulative effect of accounting change (2002 FAS 133, net of tax charge of £261.4 million)	**–**	421.3	–
– FAS 133 – loss on derivative financial instruments recognised in net income, net of tax credit of £0.7 million (2002 £47.6 million)	**(1.6)**	(76.6)	–
– FAS 133 – unrealised gain/(loss) on derivative financial instruments, net of tax charge of £9.5 million (2002 tax credit of £219.9 million)	**15.4**	(354.7)	–
Total comprehensive income/(loss) under US GAAP	**327.9**	(965.3)	1,051.5

The accumulated balances related to each component of other comprehensive income/(loss) are as follows:

	2003 £m	2002 £m	2001 £m
Foreign currency translation adjustment	**552.5**	666.6	696.3
Unrealised loss on available-for-sale securities, net of tax credit of £3.4 million (2002 £2.0 million)	**(5.5)**	(3.2)	(3.1)
Pensions, net of tax credit of £177.7 million (2002 £23.6 million)	**(397.3)**	(38.5)	–
Unrealised gain/(loss) on derivative financial instruments, net of tax charge of £2.7 million (2002 tax credit of £6.1 million)	**3.8**	(10.0)	–

Consolidated statement of cash flows

The consolidated statement of cash flows prepared in accordance with FRS 1 (Revised) presents substantially the same information as that required under US GAAP. Under US GAAP, however, there are certain differences from UK GAAP with regard to the classification of items within the cash flow statement and with regard to the definition of cash and cash equivalents.

Under UK GAAP, cash flows are presented separately for operating activities, dividends received from joint ventures, returns on investments and servicing of finance, taxation, capital expenditure and financial investment, acquisitions and disposals, equity dividends paid, management of liquid resources, and financing. Under US GAAP, only three categories of cash flow activity are reported; operating activities, investing activities and financing activities. Cash flows from dividends received from joint ventures, returns on investments and servicing of finance and taxation would be included as operating activities under US GAAP. Equity dividends paid would be included under financing activities under US GAAP.

Under US GAAP, cash and cash equivalents are not offset by bank overdrafts repayable within 24 hours from the date of the advance, as is the case under UK GAAP and instead such bank overdrafts are classified within financing activities.

The consolidated cash flow statement prepared in conformity with UK GAAP is set out on page 84. In this statement an additional measure, free cash flow, is included which is not an accepted measure under US GAAP. This measure represents cash flow from operations after adjusting for dividends received from joint ventures, returns on investments and servicing of finance and taxation. UK investors regard free cash flow as the money available to management annually to be allocated among a number of options including capital expenditure, payments of dividends and the financing of acquisitions.

Notes to the Group Balance Sheet
as at 31 March 2003 – continued

35 Summary of differences between UK and US Generally Accepted Accounting Principles (‘GAAP’) continued

The consolidated statement of cash flows under US GAAP is set out below:

	2003 £m	2002 £m	2001 £m
Cash inflow from operating activities	**1,412.9**	1,248.4	1,411.6
Dividends received from joint ventures	**0.9**	0.3	2.1
Returns on investments and servicing of finance	**(297.0)**	(377.8)	(373.5)
Taxation	**(191.3)**	(85.0)	(152.6)
Net cash provided by operating activities	**925.5**	785.9	887.6
Capital expenditure and financial investment	**(704.9)**	(1,148.3)	(1,081.4)
Acquisitions and disposals	**1,792.8**	98.7	482.9
Net cash provided/(used) in investing activities	**1,087.9**	(1,049.6)	(598.5)
Financing	**(1,184.5)**	929.1	196.1
Movement in bank overdrafts	**(4.9)**	(17.8)	11.1
Equity dividends paid	**(523.4)**	(496.8)	(471.3)
Net cash (required)/provided by financing activities	**(1,712.8)**	414.5	(264.1)
Net increase in cash and cash equivalents	**300.6**	150.8	25.0
Exchange movement on cash and cash equivalents	**(16.8)**	(0.2)	19.9
Cash and cash equivalents at beginning of financial year	**380.8**	230.2	185.3
Cash and cash equivalents at end of financial year	**664.6**	380.8	230.2

All liquid investments with maturities of three months or less at the time of acquisition are considered to be cash equivalents.

Significant non-cash investing or financing activities	2003 £m	2002 £m	2001 £m
Movement of share of debt in joint arrangement	**–**	100.5	–

Additional information required under US GAAP

(a) Infrastructure accounting

The group’s accounting policy in respect of Southern Water’s infrastructure assets and related maintenance and renewals expenditure, as set out and explained in the accounting policies, was not generally accepted under US GAAP which required historical cost depreciation accounting for these assets. The difference between the infrastructure renewals depreciation charge and depreciation accounting under US GAAP was not material to profit and equity shareholders’ funds. This difference no longer exists following the disposal of Southern Water in April 2002.

(b) Doubtful debts

The group provided £36.8 million, £57.5 million and £29.7 million for doubtful debts in 2003, 2002 and 2001 respectively. Write-offs against the provision for doubtful debts for uncollectable amounts were £61.2 million, £36.6 million and £26.1 million in 2003, 2002 and 2001 respectively.

(c) Deferred tax

The additional components of the estimated net deferred tax liability that would be recognised under US GAAP are as follows:

	2003 £m	2002 £m
Deferred tax liabilities:		
Excess of book value over taxation value of fixed assets	**83.6**	142.6
Other temporary differences	**99.3**	200.7
	182.9	343.3
Deferred tax assets:		
Other temporary differences	**(4.1)**	(5.1)
Net deferred tax liability	**178.8**	338.2
Analysed as follows:		
Current	**(4.1)**	(5.1)
Non-current	**182.9**	343.3
	178.8	338.2

The deferred tax balance in respect of leveraged leases at the year end is £101.1 million (2002 £145.1 million).

Investment tax credits for PacifiCorp are deferred and amortised to income over periods prescribed by the group’s various regulatory jurisdictions under US GAAP.

(d) Pensions

At 31 March 2003, ScottishPower had six statutorily approved defined benefit pension schemes, one statutorily approved defined contribution scheme and one unapproved scheme.

Benefits under the UK defined benefit plans reflect each employee’s basic earnings, years of service and age at retirement. Funding of the defined benefit plans is based upon actuarially determined contributions, with members paying contributions at fixed rates and the employers meeting the balance of cost as determined by the scheme actuaries.

Under the UK defined contribution plan, contributions are paid by the member and employer at a fixed rate. Benefits under the UK defined contribution plan reflect each employee’s fund at retirement and the cost of purchasing benefits at that time.

35 Summary of differences between UK and US Generally Accepted Accounting Principles ('GAAP') continued

Reconciliations of the beginning and ending balances of the projected pension benefit obligation and the funded status of these plans for the years ending 31 March 2003, 31 March 2002 and 31 March 2001 are as follows:

Change in projected benefit obligation	**2003 £m**	2002 £m	2001 £m
Projected benefit obligation at beginning of year	**3,112.2**	3,051.0	2,827.6
Service cost (excluding plan participants' contributions)	**52.6**	62.2	66.6
Interest cost	**168.6**	182.5	179.8
Plan amendments	**–**	12.6(ii)	(15.7)
Special termination benefits	**(2.5)**(i)	0.6(iii)	54.8
Plan participants' contributions	**8.1**	11.9	12.9
Actuarial loss	**69.7**	29.0	27.4
Benefits paid	**(191.5)**	(209.5)	(187.0)
Settlements(iv)	**(317.9)**	(29.0)	–
Exchange	**(68.3)**	0.9	84.6
Projected benefit obligation at end of year	**2,831.0**	3,112.2	3,051.0

(i) The period to commence the enhanced early retirement benefits under the Workforce Transition Retirement Program ("WTRP") ended on 31 December 2002. A credit adjustment of £2.5 million for prior special termination benefits was necessary to reflect the impact of those participants who did not commence their WTRP benefits by 31 December 2002 because they revoked their earlier election.
(ii) Ad hoc cost of living benefit increase for certain retired employees that was approved on 13 March 2002.
(iii) The acquisition of PacifiCorp by ScottishPower triggered special termination benefits from the SERP during 2002.
(iv) Assets and liabilities were transferred in 2002 to the PacifiCorp/IBEW Local Union 57 Retirement Trust Fund and in 2003 in relation to the sale of Southern Water.

Change in plans' assets	**2003 £m**	2002 £m	2001 £m
Fair value of plans' assets at beginning of year	**3,204.6**	3,586.6	3,886.8
Actual return on plans' assets	**(509.8)**	(163.0)	(248.2)
Employer contributions	**27.2**	18.5	32.7
Plan participants' contributions	**8.1**	11.9	12.9
Benefits paid	**(191.5)**	(209.5)	(187.0)
Settlements*	**(278.5)**	(39.4)	–
Exchange	**(55.9)**	(0.5)	89.4
Fair value of plans' assets at end of year	**2,204.2**	3,204.6	3,586.6

* Assets and liabilities were transferred in 2002 to the PacifiCorp/IBEW Local Union 57 Retirement Trust Fund and in 2003 in relation to the sale of Southern Water.

Reconciliation of funded status of the plans to prepaid benefit cost	**2003 £m**	2002 £m	2001 £m
Funded status of the plans	**(626.8)**	92.4	535.6
Unrecognised net actuarial loss/(gain)	**852.4**	121.9	(348.9)
Unrecognised prior service cost	**(1.3)**	(1.5)	(15.2)
Unrecognised transition obligation asset	**(0.9)**	(1.6)	(2.5)
Prepaid benefit cost	**223.4**	211.2	169.0

Amounts recognised in balance sheet (UK arrangements)	**2003 £m**	2002 £m	2001 £m
Prepaid benefit cost*	**–**	270.4	237.4
Accrued benefit liability	**(252.1)**	–	–
Accumulated other comprehensive loss	**507.9**	–	–
Total recognised	**255.8**	270.4	237.4

* £nil where scheme has accrued benefit liability or where asset value is below accumulated benefit obligation.

Amounts recognised in balance sheet (US arrangements)	**2003 £m**	2002 £m	2001 £m
Accrued benefit liability	**(241.9)**	(121.3)	(68.4)
Accumulated other comprehensive loss	**67.1**	62.1	–
US Regulatory assets*	**148.4**	–	–
Exchange	**(6.0)**	–	–
Total recognised	**(32.4)**	(59.2)	(68.4)

* For the US pension arrangements the fair value of the plan assets was less than the accumulated benefit obligation. Under FAS 87 a minimum pension liability is then recognised. This liability was recorded as a non-cash increase of £148.4 million to regulatory assets and £67.1 million to accumulated other comprehensive loss. Accounting orders were received from the regulatory commissions in Utah, Oregon and Wyoming to classify this charge as a regulatory asset instead of a charge to other comprehensive income. This increase to regulatory assets will be adjusted in future periods as the difference between the fair value of the plan assets and the accumulated benefit obligation changes.

The value of plan assets exceed the accumulated benefit obligation at the end of the year except in the following cases:

	Value of plan assets at 31 March 2003 £m	Value of plan assets at 31 March 2002 £m	**Accumulated benefit obligation at 31 March 2003 £m**	Accumulated benefit obligation at 31 March 2002 £m
ScottishPower	**1,310.5**	–	**1,438.4**	–
Manweb	**449.2**	–	**563.0**	–
PacifiCorp	**430.9**	581.8	**672.2**	700.8

The value of plan assets exceed the projected benefit obligation at the end of the year except in the following cases:

	Value of plan assets at 31 March 2003 £m	Value of plan assets at 31 March 2002 £m	**Projected benefit obligation at 31 March 2003 £m**	Projected benefit obligation at 31 March 2002 £m
ScottishPower	**1,310.5**	–	**1,487.3**	–
Manweb	**449.2**	–	**591.0**	–
Final Salary LifePlan	**12.8**	10.2	**13.5**	11.6
PacifiCorp	**430.9**	581.8	**528.4**	760.1

Notes to the Group Balance Sheet
as at 31 March 2003 – continued

35 Summary of differences between UK and US Generally Accepted Accounting Principles ('GAAP') continued

The components of pension benefit costs for the years ended 31 March 2003, 2002 and 2001 were as follows:

	31 March 2003 £m	31 March 2002 £m	31 March 2001 £m
Service cost	**55.7***	62.2	66.6
Curtailment/settlement cost	**26.3****	–	–
Interest cost	**168.6**	182.5	179.8
Expected return on plans' assets	**(232.2)**	(261.2)	(287.2)
Amortisation of experience losses/(gains)	**0.1**	(5.8)	(36.0)
Amortisation of prior service cost	**–**	(1.1)	(1.1)
Amortisation of transition obligation asset	**(0.7)**	(0.9)	(0.8)
Net periodic benefit cost/(credit)	**17.8**	(24.3)	(78.7)

* Includes the contribution of £3.1 million to the PacifiCorp/IBEW Local Union 57 Retirement Trust Fund.
** Sale of Southern Water, and consequent removal of pre-paid benefit cost in relation to this scheme.

The actuarial assumptions adopted in arriving at the above figures are as follows:

UK arrangements – assumptions at:	**31 March 2003**	31 March 2002	31 March 2001
Expected return on plans' assets	**6.8% p.a.**	7.5% p.a.	7.0% p.a.
Discount rate	**5.4% p.a.**	6.0% p.a.	5.75% p.a.
Rate of earnings increase	**3.9% p.a.**	4.3% p.a.	4.5% p.a.
Pension increases	**2.4% p.a.**	2.8% p.a.	2.5% p.a.

US arrangements – assumptions at:	**31 March 2003**	31 March 2002	31 March 2001
Expected return on plans' assets	**8.75% p.a.**	9.25% p.a.	9.25% p.a.
Discount rate	**6.75% p.a.**	7.5% p.a.	7.75% p.a.
Rate of earnings increase	**4.0% p.a.**	4.0% p.a.	4.0% p.a.
Inflation rates	**3.0% p.a.**	4.0% p.a.	4.0% p.a.

(e) Other post-retirement benefits

PacifiCorp provides healthcare and life insurance benefits through various plans for eligible retirees on a basis substantially similar to those who are active employees. The cost of post-retirement benefits is accrued over the active service period of employees. Except for a few groups of former employees, PacifiCorp funds post-retirement benefit expense through a combination of funding vehicles. Over the period from 1 April 2002 to 31 March 2003, PacifiCorp made contributions totalling £16.3 million in respect of these arrangements. These funds are invested in common stocks, bonds and US government obligations.

The net periodic post-retirement benefit cost and significant assumptions are summarised as follows:

	2003 £m	2002 £m	2001 £m
Service cost	**3.6**	3.6	3.5
Interest cost	**22.1**	20.0	18.8
Expected return on plan assets	**(18.5)**	(20.4)	(19.1)
Amortisation of experience losses	**1.3**	–	–
Net periodic post-retirement benefit cost	**8.5**	3.2	3.2

The change in the accumulated post-retirement benefit obligation, change in plan assets and funded status are as follows:

Change in accumulated post-retirement benefit obligation	**2003 £m**	2002 £m	2001 £m
Accumulated post-retirement benefit obligation at beginning of year	**331.3**	268.0	220.3
Service cost	**3.6**	3.6	3.5
Interest cost	**22.1**	20.0	18.8
Plan participants' contributions	**3.9**	3.8	3.2
Special termination benefit (gain)/loss	**(0.6)***	–	11.4
Actuarial loss/(gain)	**26.4**	53.8	(3.1)
Benefits paid	**(21.8)**	(18.8)	(13.6)
Exchange	**(34.5)**	0.9	27.5
Accumulated post-retirement obligation at end of year	**330.4**	331.3	268.0

* The period to commence the enhanced early retirement benefits under the WTRP ended on 31 December 2002. A credit adjustment of £0.6 million for special termination benefits was necessary to reflect the impact of those participants who did not commence their WTRP benefits by 31 December 2002 because they revoked their earlier election.

Change in plan assets	**2003 £m**	2002 £m	2001 £m
Plan assets at fair value at beginning of year	**184.9**	201.9	200.2
Actual return on plan assets	**(13.8)**	(12.6)	(18.2)
Company contributions	**3.0**	10.4	6.8
Plan participants' contributions	**3.9**	3.8	3.2
Benefits paid	**(21.8)**	(18.8)	(13.6)
Exchange	**(18.3)**	0.2	23.5
Plan assets at fair value at end of year	**137.9**	184.9	201.9

Reconciliation of accrued post-retirement costs and total amount recognised	**2003 £m**	2002 £m	2001 £m
Funded status of plan	**(192.5)**	(146.4)	(66.1)
PacifiCorp unrecognised net loss	**140.2**	93.5	6.0
Final contribution made after measurement date but before 31 March 2003	**13.3**	–	–
Accrued post-retirement benefit cost	**(39.0)**	(52.9)	(60.1)

35 Summary of differences between UK and US Generally Accepted Accounting Principles ('GAAP') continued

The actuarial assumptions adopted in arriving at the above figures are as follows:

US arrangements – assumptions at:	**31 March 2003**	31 March 2002	31 March 2001
Expected return on plans' assets	**8.75% p.a.**	9.25% p.a.	9.25% p.a.
Discount rate	**6.75% p.a.**	7.50% p.a.	7.75% p.a.
Initial healthcare cost trend – under 65	**9.5% p.a.**	10.5% p.a.	6.0% p.a.
Initial healthcare cost trend – over 65	**11.5% p.a.**	12.5% p.a.	6.5% p.a.
Initial healthcare cost trend rate	**5.0% p.a.**	5.0% p.a.	4.5% p.a.

The assumed healthcare cost trend rate gradually decreases over four to seven years. The healthcare cost trend rate assumption has a significant effect on the amounts reported. Increasing the assumed healthcare cost trend rate by one percentage point would have increased the accumulated post-retirement benefit obligation (the "APBO") as of 31 March 2003 by £16.4 million (2002 £18.5 million, 2001 £13.1 million) and the annual net periodic post-retirement benefit costs by £1.4 million (2002 £1.3 million, 2001 £1.1 million). Decreasing the assumed healthcare cost trend rate by one percentage point would have reduced the APBO as of 31 March 2003 by £14.3 million (2002 £17.1 million, 2001 £16.0 million), and the annual net periodic post-retirement benefit costs by £1.2 million (2002 £1.2 million, 2001 £1.4 million).

Post-employment benefits
PacifiCorp provides certain post-employment benefits to former employees and their dependants during the period following employment but before retirement. The costs of these benefits are accrued as they are incurred. Benefits include salary continuation, severance benefits, disability benefits and continuation of healthcare benefits for terminated and disabled employees and workers' compensation benefits. The provision for post-employment benefits was £9.5 million at 31 March 2003 (2002 £13.5 million).

Employee savings and stock ownership plan
PacifiCorp has an employee savings and stock ownership plan that qualifies as a tax-deferred arrangement under Section 401(a), 401(k), 409, 501 and 4975(e)(7) of the Internal Revenue Code. Participating US employees may defer up to 20% of their compensation, subject to certain regulatory limitations. PacifiCorp matches a portion of employee contributions with ScottishPower ADSs, vesting that portion over five years. PacifiCorp makes an additional contribution of ScottishPower ADSs to qualifying employees equal to a percentage of the employee's eligible earnings. These contributions are immediately vested. Employer contributions to the savings plan were £10.0 million for the year ended 31 March 2003 (2002 £14.7 million, 2001 £12.2 million).

(f) Southern Water disposal
On 23 April 2002, the group completed the sale of Aspen 4 Limited (the holding company of Southern Water plc) to First Aqua Limited. A summary of the net assets disposed of calculated under US GAAP are detailed in the table below:

	£m
Tangible fixed assets	2,474.7
Fixed asset investments	1.9
Current assets	193.1
Creditors: amounts falling due within one year	(1,053.8)
Creditors: amounts falling due after more than one year	
Loans and other borrowings	(100.0)
Provisions for liabilities and charges	(366.6)
Deferred income	(37.4)
Net assets	1,111.9

(g) Environmental, decommissioning and mine reclamation costs
The group's mining operations in the US are subject to reclamation and closure requirements. Reclamation and closure costs are estimated based on engineering studies. The group monitors these requirements and periodically revises its cost estimates to meet existing legal and regulatory requirements of the various jurisdictions in which it operates.

The group believes that it has adequately provided for its reclamation obligations, assuming ongoing operations of its mines. Total estimated final reclamation costs, including joint owners' portions, for all mines with which the group is involved was £136.0 million at 31 March 2003. These amounts are expected to be paid over the next 30 years.

The liabilities for environmental, decommissioning and mine reclamation costs are generally recorded on an undiscounted basis. These liabilities are recorded in the UK GAAP balance sheet within 'Provisions for liabilities and charges', and balances under US GAAP are detailed below:

		Balance sheet liability	
	Notes	**31 March 2003 £m**	31 March 2002 £m
Environmental costs	(i)	**35.7**	39.5
Decommissioning costs	(ii)	**12.3**	13.2
Mine reclamation costs	(iii)	**92.9**	102.4
Total costs		**140.9**	155.1

(i) Expected to be paid over 19 years.

(ii) Expected to be paid over 22 years.

(iii) Amounts include the group's and joint owners' portion of mine reclamation costs.

The group had trust fund assets of £43.3 million and £57.0 million at 31 March 2003 and 2002, respectively, relating to mine reclamation, including joint owners' portions.

(h) Leveraged leases
The pre-tax (loss)/income from leveraged leases during the year was £(27.8) million (2002 £4.2 million), the tax (credit)/charge on the pre-tax (loss)/income was £(10.7) million (2002 £1.4 million) and the investment tax credit recognised in the income statement was £0.9 million (2002 £1.0 million).

(i) Commitments and contingencies
(i) Environmental issues
UK businesses
The group's UK businesses are subject to numerous regulatory requirements with respect to the protection of the environment, including environmental laws which regulate the construction, operation and decommissioning of power stations, pursuant to legislation implementing environmental directives adopted by the EU and protocols agreed under the auspices of international bodies such as the United Nations Economic Commission for Europe. The group believes that it has taken and continues to take measures to comply with applicable laws and regulations for the protection of the environment. Applicable regulations and requirements pertaining to the environment change frequently, however, with the result that continued compliance may require material investments, or that the group's costs and results of operation are less favourable than anticipated.

Notes to the Group Balance Sheet

as at 31 March 2003 – continued

35 Summary of differences between UK and US Generally Accepted Accounting Principles ('GAAP') continued

US Division – PacifiCorp
PacifiCorp is subject to numerous environmental laws including: the Federal Clean Air Act, as enforced by the Environmental Protection Agency and various state agencies; the 1990 Clean Air Act Amendments; the Endangered Species Act of 1973, particularly as it relates to certain potentially endangered species of fish; the Comprehensive Environmental Response, Compensation and Liability Act of 1980, relating to environmental cleanups; along with the Federal Resource Conservation and Recovery Act of 1976 and Clean Water Act relating to water quality. These laws could potentially impact future operations. For those contingencies identified at 31 March 2003, principally Clean Air matters, which are the subject of discussions with the United States Environmental Protection Agency and state regulatory authorities, future costs relating to these matters may be significant and consist primarily of capital expenditures. However, PacifiCorp expects these costs will be included within rates and, therefore, are not expected to have a material impact on the group's results and financial position.

(ii) Mine reclamation
US Division – PacifiCorp
All of PacifiCorp's mining operations are subject to reclamation and closure requirements. Compliance with these requirements could result in higher expenditures for both capital improvements and operating costs.

(iii) Deferred net power costs
US Division – PacifiCorp
At 31 March 2003, PacifiCorp had deferred net power costs for the states of Utah, Oregon and Idaho. While PacifiCorp is pursuing full recovery of these costs, there can be no assurance that this will be achieved. Denial of recovery would result in the write-off of £87.2 million of deferred net power costs (net of amortisation), under US GAAP, reported under US regulatory assets in the UK/US GAAP reconciliation of equity shareholders' funds.

(iv) Regulation
US Division – PacifiCorp
The Emerging Issues Task Force ("EITF") of the FASB concluded in 1997 that FAS 71 should be discontinued when detailed legislation or regulatory orders regarding competition are issued. Additionally, the EITF concluded that regulatory assets and liabilities applicable to businesses being deregulated should be written-off unless their recovery is provided through future regulated cash flows. PacifiCorp continuously evaluates the appropriateness of applying FAS 71 to each of its jurisdictions. At 31 March 2003, the group concluded that FAS 71 was appropriate. However, if efforts to deregulate progress, the group may in the future be required to discontinue its application of FAS 71 to all or a portion of its business. Based on the group's US regulatory net asset balance under US GAAP at 31 March 2003, if the group stopped applying FAS 71 to its remaining regulated US operations, it would have recorded an extraordinary loss, after tax, of £580.8 million under US GAAP.

(v) Hydro-electric relicensing
US Division – PacifiCorp
Approximately 97% of the installed capacity of PacifiCorp's hydro-electric portfolio is regulated by the Federal Energy Regulatory Commission through 20 individual licences. Nearly all of PacifiCorp's hydro-electric projects are at some stage of relicensing under the Federal Power Act. Hydro-electric relicensing and the related environmental compliance requirements are subject to uncertainties. PacifiCorp expects future costs relating to these matters may be significant and consist primarily of additional environmental requirements. The group has accumulated approximately £38.2 million in costs for ongoing hydro-electric relicensing and it is expected that these and other future costs will be included in rates, and as such, will not have a material adverse impact on the group's results and financial position under US GAAP.

(j) Guarantees
In accordance with FASB Interpretation No. 45 ("FIN 45") 'Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others: an Interpretation of FASB Statements No. 5, 57 and 107 and rescission of FASB Interpretation No. 34', the group is required to disclose certain guarantees as defined in FIN 45. These guarantees principally relate to the group's disposal of its former operations and are typical of these types of transactions. Furthermore, disclosure is required under FIN 45 of guarantees even where the likelihood that a liability will crystallise is remote. FIN 45 also requires recognition of liabilities under US GAAP of the fair value of certain guarantees issued or modified after 31 December 2002. No such guarantees have been identified. The disclosures required to be made under FIN 45 are detailed below:

The group has entered into a number of transactions involving the sale of parts of its business and the purchase of certain businesses and assets in accordance with overall group strategy. These transactions include the disposal of Southern Water, the demerger of Thus plc, the sale and disposal of the group's Appliance Retailing business and the disposal of other non-core activities.

It is standard practice in such transactions to obtain or grant contractual assurances, including in the form of warranties and indemnities. In conducting merger, disposal or acquisition transactions the group takes significant steps to quantify and mitigate risk at the outset of any transaction and as the transaction progresses. Steps include carrying out, or granting the facility for the conduct of, a thorough due diligence exercise to ascertain any likely liabilities and, where the group is the vendor, the use of caps and threshold levels for liability, inserting time limits on claim periods and detailed disclosure.

Under certain of the business disposals, indemnities under the Transfer of Undertakings (Protection of Employment) Regulations 1981 ("the Regulations") are still outstanding. These indemnities relate to potential liabilities with respect to former employees of the group in relation to their period of employment in the group. Typically there is no maximum limit on claims under these indemnities.

Recourse via tax warranties and indemnities remains outstanding on the same basis as stated above and in relation to the disposal of ScottishPower Telecommunications (Services) Limited, a former subsidiary of Thus plc. These expire on 30 October 2005. The maximum financial exposure under these arrangements is £7.5 million. No claims have been intimated in relation to this arrangement and the directors consider it extremely unlikely that there will be any material financial exposure to the group under this arrangement.

On 23 April 2002, the group sold Aspen 4 Limited, the owner of the Southern Water group of companies. In such transactions it is standard practice for the vendor to give assurances, in the form of warranties and indemnities to the purchaser. In relation to this transaction the warranty liability period commenced on 23 April 2002 and ends on 23 April 2007 for environmental warranties, 23 April 2009 for tax warranties and 23 April 2004 for all other warranties. The sale and purchase agreement contains a number of limitations to and exclusions of liability and maximum financial exposure for breach of the warranties (apart from tax warranties) is capped at £900.0 million. For the tax warranties the maximum exposure is approximately £1,950.0 million. There are also minimum threshold claim levels to be reached before a potential claim arises at all and thereafter as to whether it can be made. The directors consider it extremely unlikely that there will be any material financial exposure to the group under these arrangements as a detailed due diligence exercise was carried out pre-disposal and detailed disclosures were made to the purchaser so as to make them aware of all relevant information concerning the business and, consequentially, to reduce the likelihood of claims being made against the group.

On 8 October 2001, certain business and assets of the group's former Appliance Retailing business were sold and the remainder of the business was closed. In such transactions it is standard practice for the vendor to give assurances in the form of certain warranties and indemnities to the purchaser. In relation to this transaction the warranty liability period commenced on 8 October 2001 and ends on the earlier of 8 October 2003 or, with respect to the sale of the shares, the date of receipt by the purchaser of audited accounts for the group's former subsidiary, Domestic Appliance Insurance Limited ("DAIL") for the year ended 31 March 2002. Maximum financial exposure for breach of the other warranties is £10.0 million. Protection relating to DAIL was given in relation to any shortfall in the provisions for claims for which DAIL was liable under the "Cashback" warranty scheme. For the tax warranties and cashback indemnity the limit is £75.0 million. Certain threshold levels must be exceeded before claims can be made against the group. Although a potential claim has been received with respect to the adequacy of the cashback provisions in the DAIL accounts (and discussions have taken place with respect to such a claim) the directors consider it extremely unlikely that there will be any material financial exposure to the group under these arrangements. Indemnities were also given in respect of any liability arising in relation to the Regulations for employment claims prior to 8 October 2001, long-term sick employees and employees who are deemed to transfer pursuant to the Regulations but were not disclosed as transferring employees. Under the transaction a number of properties were assigned to the purchaser. By operation of law and through the putting in place of standard agreements in the event that the purchaser becomes insolvent the liability for rent and certain other items due under certain lease arrangements could revert to the group. The annual liability to the group for rental payments in the event of insolvency of the purchaser is approximately £9.0 million. It is extremely unlikely that the group would become liable to this extent as steps would be taken to mitigate any such liability which could include surrendering leases to landlords and putting in place new tenants to take over the liability.

35 Summary of differences between UK and US Generally Accepted Accounting Principles ('GAAP') continued

On 3 August 2000, the group agreed to sell Powercor Australia Ltd. In such transactions it is standard practice for the vendor to give certain warranties and indemnities to the purchaser. The group agreed to indemnify the purchaser for any breaches of representations relating to tax warranties or tax claims as defined therein until August 2005. The indemnity is limited by a AUD$15.0 million (£5.7 million) basket, with the group liable for the excess over this amount only and an overall cap of AUD$300.0 million (£114.5 million). No claims have been intimated in relation to the above noted arrangements and the directors consider it extremely unlikely that there will be any material financial exposure to the group under these arrangements.

In November 2000, the group sold its interests in Hazelwood Holdings Inc. and PacifiCorp Global Inc. In such transactions it is standard practice for the vendor to give certain warranties and indemnities to the purchaser. In relation to this transaction the tax warranty period commenced in November 2000 and ends in November 2005. The maximum financial exposure for breach of these warranties is AUD$88.0 million (£33.6 million). The directors consider it extremely unlikely that there will be any material financial exposure under these arrangements as a detailed due diligence exercise was carried out pre-disposal and detailed disclosures were made to the purchaser to reduce the likelihood of claims being made against the group.

To the extent that claims based upon the arrangements below are limited by applicable statutes, the limitation periods generally vary from three to six years, depending on the jurisdiction and the nature of the claim.

On 22 July 2000, a subsidiary company, PacifiCorp Trans, Inc. ("PacifiCorp Trans") sold two Cessna Citation Excel aircraft for US$16.6 million (£10.5 million), and agreed to indemnify the purchaser for any claims asserted against the purchaser in connection with the inaccuracy of any representation or warranty made by PacifiCorp Trans.

On 4 May 2000, the group and other joint owners completed the sale to Transalta of a power plant and coal mine located in Centralia, Washington. Under the agreement relating to the plant, the joint owners agreed to indemnify Transalta if it were to incur certain losses after the closing date and arising as a result of certain breaches of covenants. Under the agreement relating to the mine, the group provided similar indemnity. The maximum indemnification obligation under these agreements, with respect to the group, is limited to $556.0 million (£351.7 million), less a deductible of 1% of the purchase price (approximately $1.0 million (£0.6 million)). No indemnity claims have been made to date.

In connection with the sale of PacifiCorp's Montana service territory, PacifiCorp entered into a purchase and sale agreement with Flathead Electric Cooperative ("Flathead") dated 9 October 1998. Under the agreement, PacifiCorp indemnified Flathead for losses, if any, occurring after the closing date and arising as a result of certain breaches of warranty or covenants. The indemnification has a cap of $6.0 million (£4.0 million). One indemnity claim relating to environmental issues has been tendered, but remediation costs for this claim, if any, are not expected to create a material financial exposure for the group.

On 15 October 2001, the group sold its synthetic fuels operation. In such transactions it is standard practice for the vendor to give certain warranties and indemnities to the purchaser. The group agreed to indemnify the purchaser from losses suffered as a result of fraud or breach of representation or warranty, within 30 days of the expiration of the applicable statutory period of limitations. The established basket and cap do not apply to the surviving representations and warranties. The group also agreed to indemnify the purchaser for tax liabilities up to the closing date; this indemnity also expires within 30 days of the expiration of the statutory period of limitations. No claims have been intimated in relation to the above noted arrangements and the directors consider it extremely unlikely that there will be any material financial exposure to the group under these arrangements.

On 11 June 1997, PacifiCorp Group Holdings Company ("PGHC"), a subsidiary of the company, sold Pacific Telecom, Inc. ("PTI"). In such transactions it is standard practice for the vendor to give certain warranties and indemnities to the purchaser. PGHC agreed to indemnify and hold harmless the purchaser from losses or claims arising from breach of representation or warranty of PGHC resulting from any liability of PTI with respect to tax years ending prior to the closing date; and resulting from material breaches of agreements and covenants under the agreement. The indemnity includes a $5.0 million (£3.2 million) basket, with the group being liable for the excess over this amount only and an overall cap of $300.0 million (£189.7 million). Most of the indemnities survive for six months beyond the applicable statute of limitations. PGHC is currently defending one environmental indemnity claim under this provision and apart from this no claims have been intimated in relation to the above noted arrangements.

On 10 October 1997, PGHC agreed to sell Pacific Generation Company. In such transactions it is standard practice for the vendor to give certain warranties and indemnities to the purchaser. The group agreed to indemnify the purchaser for breaches of representations and warranties relating to tax matters, which continue until the expiration of the applicable statute of limitations. The indemnity includes an aggregate cap of $66.0 million (£41.7 million) and a basket of $3.0 million (£1.7 million). No claims have been intimated in relation to the above noted arrangements and the directors consider it extremely unlikely that there will be any material financial exposure to the group under these arrangements.

On 9 February 1999, PGHC agreed to sell TPC Corporation. In such transactions it is standard practice for the vendor to give certain warranties and indemnities to the purchaser. The group provided indemnification to the purchaser for breaches of representations and warranties relating to environmental matters, tax matters and employee benefits for the period ending 9 February 2004 with regard to the environmental matters, and through the applicable statute of limitations on tax and employee benefit matters. The indemnification is limited to a $1.0 million (£0.6 million) basket, with the group liable for the excess over this amount only and an overall $10.0 million (£6.3 million) cap. In addition, certain special indemnities were provided with respect to certain specified matters. No claims have been intimated in relation to the above noted arrangements and the directors consider it extremely unlikely that there will be any material financial exposure to the group under these arrangements.

ScottishPower Energy Retail Limited ("SPERL") has entered into an agreement with Lloyds TSB in relation to energy marketing and services. This agreement contains indemnities in relation to transfer of staff by operation of the Regulations from SPERL to Lloyds TSB. The maximum liability is limited to £5.0 million. No claims have been intimated.

Under certain cash collateral agreements, Automated Power Exchange (UK) Limited, UK Power Exchange and Elexon can draw down and use cash collateral in event of default situations including upon a change in credit rating. The maximum financial exposure under these arrangements is £10.3 million.

Under the group's arrangements carried out in accordance with the standard terms and conditions of the International Swap Dealers Association Inc ("ISDA") Master Agreement there is a provision that the group will indemnify the counter-party for certain withholding taxes incurred under relevant tax laws. A liability under this indemnification will only arise on the occurrence of certain changes to tax laws in the jurisdiction of a relevant counterparty. The directors are not aware of any such contemplated changes.

(k) Derivative Instruments and Hedging Activities

The group uses derivative instruments in the normal course of business, to offset fluctuations in earnings, cash flows and equity associated with movements in exchange rates, interest rates and commodity prices.

FAS 133 'Accounting for Derivative Instruments and Hedging Activities', as amended by FAS 137 and FAS 138, was adopted by the group with effect from 1 April 2001. Effective from 1 April 2002, the group adopted revised FAS 133 guidance issued by the Derivatives Implementation Group under Revised Issue C15 'Normal Purchases and Normal Sales Exception for Certain Option-Type Contracts in Electricity' and Issue C16 'Applying the Normal Purchases and Normal Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract'. This new guidance had the effect of including an increased number of the group's contracts within the scope of FAS 133. The cumulative adjustment to profit under US GAAP for the year ended 31 March 2003 as a result of adopting Revised Issue C15 and Issue C16 was an increase to profit of £228.6 million (£141.1 million, net of tax).

FAS 133 establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities. FAS 133 requires that an entity recognise all derivatives as either assets or liabilities in the consolidated balance sheet and measure those instruments at fair value. FAS 133 prescribes requirements for designation and documentation of hedging relationships and ongoing assessments of effectiveness in order to qualify for hedge accounting.

Hedge effectiveness is assessed consistently with the method and risk management strategy documented for each hedging relationship. On at least a quarterly basis, the group assesses the effectiveness of each hedging relationship retrospectively and prospectively to ensure that hedge accounting was appropriate for the prior period and continues to be appropriate for future periods. The group applies the short cut method of assessing effectiveness when possible. The group considers hedge accounting to be appropriate if the assessment of hedge effectiveness indicates that the change in fair value of the designated hedging instrument is 80% to 125% effective at offsetting the change in fair value arising on the hedged risk of the hedged item or transaction.

The effect of changes in fair value of certain derivative instruments entered into to hedge PacifiCorp's future retail resource requirements are subject to regulation in the US and therefore are deferred pursuant to FAS 71. PacifiCorp requested and received deferred accounting orders for the effects of FAS 133 as it relates to the change in value of certain long-term wholesale electricity contracts not meeting the definition of normal purchases and normal sales contracts.

Notes to the Group Balance Sheet
as at 31 March 2003 – continued

35 Summary of differences between UK and US Generally Accepted Accounting Principles ('GAAP') continued

Categories of derivatives
Derivatives are classified into four categories: fair value hedges, cash flow hedges, overseas net investment hedges and trading.

If a derivative instrument qualifies as a fair value hedge the change in the fair value of the derivative and the change in the fair value of hedged risk arising on the hedged item is recorded in earnings. The corresponding change is recorded against the book values of the derivative and hedged item on the balance sheet.

If a derivative instrument qualifies as a cash flow hedge, the effective portion of the hedging instrument's gain or loss is reported in shareholders' funds under US GAAP (as a component of accumulated other comprehensive income) and is recognised in earnings in the period during which the transaction being hedged affects earnings. The ineffective portion of the derivative's fair value change is recorded in earnings.

For derivative instruments designated as a hedge of the foreign currency risk in an overseas net investment, gains or losses due to fluctuations in foreign exchange rates are recorded in the cumulative translation adjustment within shareholders' funds under US GAAP (as a component of accumulated other comprehensive income).

If a derivative instrument does not qualify as either a net investment hedge or a cash flow hedge under the applicable guidance, the change in the fair value of the derivative is immediately recognised in earnings or as an adjustment to the FAS 71 regulatory asset as appropriate.

Derivative instruments are not generally held by the company for speculative trading purposes. To the extent such instruments are held they are measured at fair value with gains or losses recorded in earnings. The fair value of trading derivatives at 31 March 2003 was £0.4 million.

Certain contracts that meet the definition of a derivative under FAS 133 may qualify as a normal purchase or a normal sale and be excluded from the scope of FAS 133. Specific criteria must be met in order for a contract that would otherwise be regarded as a derivative to qualify as a normal purchase or a normal sale. The group has evaluated all commodity contracts to determine if they meet the definition of a derivative and qualify as a normal purchase or a normal sale.

The group also evaluates contracts for "embedded" derivatives, and considers whether any embedded derivatives have to be separated from the underlying host contract and accounted for separately in accordance with FAS 133 requirements. Where embedded derivatives have terms that are not clearly and closely related to the terms of the host contract in which they are included, they are accounted for separately from the host contract as derivatives, with changes in the fair value recorded in earnings, to the extent that the hybrid instrument is not already accounted for at fair value.

Discontinued hedge accounting
When hedge accounting is discontinued due to the group's determination that the derivative no longer qualifies as an effective fair value hedge, the group will continue to carry the derivative on the balance sheet at its fair value. The related hedged asset or liability will cease to be adjusted for changes in fair value relating to the previously hedged risk.

When the group discontinues hedge accounting in a cash flow hedge because it is no longer probable that the forecasted transaction will occur in the expected period, the gain or loss on the derivative remains in accumulated other comprehensive income and is reclassified into earnings when the forecasted transaction affects earnings. However, if it is probable that a forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter, the gains and losses that were accumulated in other comprehensive income will be recognised in earnings.

Where a derivative instrument ceases to meet the criteria for hedge accounting, any subsequent gains and losses are recognised in earnings.

Fair value hedges
The group seeks to maintain a desired level of floating rate debt, and uses interest rate and cross currency interest rate swaps to manage interest rate and foreign currency risk arising from long-term debt obligations denominated in sterling and foreign currencies. The group does not exclude any component of derivative gains and losses from the assessment of hedge effectiveness. The ineffective portion of fair value hedges as at 31 March 2003 resulted in a loss of £0.2 million.

Cash flow hedges
A desired level of fixed rate debt is maintained through the use of interest rate and cross currency interest rate swaps. Foreign currency forward contracts are used to fix the exchange rate on future contracted purchases of assets. These transactions are accounted for as cash flow hedges. The group does not exclude any component of derivative gains and losses from the assessment of ineffectiveness. The amount of ineffectiveness for cash flow hedges recorded for the year ended 31 March 2003 was £nil. Net realised losses on cash flow hedges totalling £13.9 million were transferred from accumulated other comprehensive income into income during the year to match the underlying hedged items recognised in the income statement. The group estimates that losses of £5.7 million on cash flow hedges in place at the year end will be transferred from accumulated other comprehensive income into income during 2003/04.

Net investment hedges
The group uses foreign currency forwards and cross currency swaps to protect the value of its investments in operations denominated in foreign currencies. The group excludes the spot-forward difference from the assessment of hedge effectiveness. In the year ended 31 March 2003 the group recorded a £158.8 million translation adjustment gain related to net investment hedges.

Recent US accounting pronouncements
In June 2001 the FASB issued FAS 143 'Accounting for Asset Retirement Obligations' which became effective for the group on 1 April 2003. The statement requires the fair value of an asset retirement obligation to be recorded as a liability in the period in which the obligation was incurred. At the same time the liability is recorded, the costs of the asset retirement obligation must be recorded as an addition to the carrying amount of the related asset. Over time, the liability is accreted to its present value and the addition to the carrying amount is depreciated over the asset's useful life. Upon retirement of the asset, the group will settle the retirement obligation against the recorded balance of the liability. Any difference in the financial retirement obligation cost and the liability will result in either a gain or loss. The group has considered the application of this standard to its operations and has completed an assessment of the impact of this standard. The group estimates that the cumulative post-tax effect of adopting FAS 143 will increase net income under US GAAP by £1.7 million, which will be recorded primarily as a net US net regulatory liability if PacifiCorp receives regulatory approval.

In April 2002, the FASB issued FAS 145, 'Rescission of FASB Statements No. 4,44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections'. FAS 145 became effective for the group on 1 April 2003. This statement is not expected to have a material impact on the group's results and financial position under US GAAP.

In June 2002, the FASB issued FAS 146 'Accounting for Costs Associated with Exit or Disposal Activities', which requires that a liability for a cost associated with an exit or disposal activity be recognised when the liability is incurred instead of at the date of the company's commitment to the exit plan. FAS 146 is effective for exit or disposal activities that are initiated after 31 December 2002 and therefore has had no effect on the group's results and financial position under US GAAP.

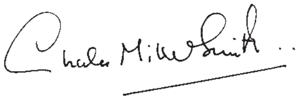
In January 2003, the FASB issued FAS Interpretation No. 46 ('FIN 46'), 'Consolidation of Variable Interest Entities', which requires existing unconsolidated variable interest entities to be consolidated by their primary beneficiaries if the entities do not effectively disperse risks among parties involved. FIN 46 applies immediately to variable interest entities created after 31 January 2003 and applies to accounting periods beginning after 15 June 2003 to variable interest entities acquired before 1 February 2003. This interpretation is not expected to have a material impact on the group's results and financial position under US GAAP.

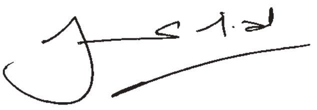
In April 2003, the FASB issued FAS 149, 'Amendment of Statement 133 on Derivative Instruments and Hedging Activities'. FAS 149 amends and clarifies financial reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. This statement is effective for contracts entered into or modified after 30 June 2003. The group is currently evaluating the effect FAS 149 will have on its results and financial position under US GAAP.

Company Balance Sheet
as at 31 March 2003

	Notes	2003 £m	2002 £m
Fixed assets			
Investments	36	**4,088.3**	4,769.4
Current assets			
Debtors	37	**504.2**	141.0
Short-term bank and other deposits		**1.7**	–
		505.9	141.0
Creditors: amounts falling due within one year			
Loans and other borrowings	38	**(313.4)**	(266.3)
Other creditors	39	**(215.1)**	(137.3)
		(528.5)	(403.6)
Net current liabilities		**(22.6)**	(262.6)
Net assets		**4,065.7**	4,506.8
Called up share capital	40	**928.0**	926.3
Share premium	40	**2,264.4**	2,254.1
Capital redemption reserve	40	**18.3**	18.3
Profit and loss account	40	**855.0**	1,308.1
Equity shareholders' funds	40	**4,065.7**	4,506.8

Approved by the Board on 7 May 2003 and signed on its behalf by





Charles Miller Smith
Chairman

David Nish
Finance Director

The Accounting Policies and Definitions on pages 70 to 73, together with the Notes on pages 78 to 83, 85 to 87, 89 to 126 and 128 to 130 form part of these Accounts.

Notes to the Company Balance Sheet
as at 31 March 2003

36 Fixed asset investments

	Note	Subsidiary undertakings Shares £m	Subsidiary undertakings Loans £m	Own shares held under trust £m	Total £m
Cost or valuation:					
At 1 April 2002		2,233.6	2,491.3	44.5	4,769.4
Additions	(i)	2,376.0	–	36.1	2,412.1
Disposals and other		(595.7)	(2,491.3)	(6.2)	(3,093.2)
At 31 March 2003		**4,013.9**	**–**	**74.4**	**4,088.3**

(i) The company received a dividend in cash from SP Finance of £250 million on 9 December 2002. On the same date, the company entered into certain guarantees and undertakings with SP Finance and Scottish Power UK plc as a consequence of which the dividend was not recognised as income but recorded as a liability. The company has subsequently fulfilled its obligations under these guarantees and undertakings through the purchase from Scottish Power UK plc of preference shares in SP Finance for a consideration of £250 million (plus interest). Consequently, the purchase of the preference shares has been accounted for as settlement of this liability rather than as an addition to fixed asset investments. The preference shares were converted to ordinary shares in SP Finance on 28 March 2003.

37 Debtors

	2003 £m	2002 £m
Amounts falling due within one year:		
Loans to subsidiary undertakings	**495.5**	140.2
Amounts due from subsidiary undertakings	**8.6**	–
Interest due from subsidiary undertakings	**0.1**	0.8
	504.2	141.0

38 Loans and other borrowings due within one year

	2003 £m	2002 £m
Loans from subsidiary undertakings	**313.4**	166.3
Committed bank loans	**–**	100.0
	313.4	266.3

39 Other creditors

	2003 £m	2002 £m
Amounts falling due within one year:		
Amounts due to subsidiary undertakings	**8.6**	–
Interest due to subsidiary undertakings	**0.1**	–
Corporate tax	**65.1**	–
Accrued expenses	**9.1**	11.2
Proposed dividend	**132.2**	126.1
	215.1	137.3

40 Analysis of movements in shareholders' funds

	Number of shares 000s	**Share capital £m**	**Share premium £m**	**Capital redemption reserve £m**	**Profit and loss account £m**	**Total £m**
At 1 April 2002	1,852,647	926.3	2,254.1	18.3	1,308.1	4,506.8
Retained loss for the year	–	–	–	–	(453.1)	(453.1)
Share capital issued						
– Executive share option scheme	15	–	0.1	–	–	0.1
– ESOP	3,271	1.7	10.2	–	–	11.9
At 31 March 2003	**1,855,933**	**928.0**	**2,264.4**	**18.3**	**855.0**	**4,065.7**

41 Profit and loss account

As permitted by Section 230 of the Companies Act 1985, the company has not presented its own profit and loss account. The company's profit and loss account was approved by the Board on 7 May 2003. The profit for the financial year per the Accounts of the company was £76.4 million (2002 £91.8 million). The retained loss for the year of £453.1 million is stated after dividends of £529.5 million.

Notes to the Company Balance Sheet
as at 31 March 2003 – continued

42 Contingent liabilities

In consideration of Scottish Power UK plc agreeing to subscribe for preference shares in SP Finance, the company has unconditionally and irrevocably agreed to:

a) indemnify and hold harmless Scottish Power UK plc against any liability or loss incurred as a direct result of Scottish Power UK plc being or having been a member of SP Finance; and

b) procure that, for the period from 28 November 2002 until the date being 12 months after Scottish Power UK plc ceases to be a member of SP Finance, SP Finance shall not engage in any trading activities nor incur any liabilities other than in respect of its obligations under its Articles of Association.

Principal Subsidiary Undertakings and Other Investments

Subsidiary undertakings	Class of share capital	Proportion of shares held	Activity
Core Utility Solutions Limited	'A' Ordinary shares £1*	100%	Multi-utility design and construction service
CRE Energy Limited (Northern Ireland)	Ordinary shares £1	100%	Wind-powered electricity generation
NA General Partnership##	Not applicable	100%	Investment holding
PacifiCorp (USA)	Common stock	100%	Regional electricity company
PacifiCorp Financial Services, Inc. (USA)	Common stock	100%	Finance company
PacifiCorp Group Holdings Company (USA)	Common stock	100%	Investment holding
PacifiCorp Holdings, Inc. (USA)	Common stock	100%	US holding company
PacifiCorp UK Limited***	Voting shares $1	100%	Finance company
PPM Energy, Inc. (USA)	Common stock	100%	Wholesale power marketer, developer of wind-power projects and provider of natural gas/hub services
ScottishPower Energy Retail Limited	Ordinary shares £1	100%	Supply of electricity and gas to domestic and business customers
ScottishPower Energy Trading Limited	Ordinary shares £1	100%	Wholesale trading company engaged in purchase and sale of electricity, gas and coal
ScottishPower Energy Trading (Agency) Limited	Ordinary shares £1	100%	Agent for trading activity of ScottishPower Energy Trading Limited and Scottish Power UK plc
ScottishPower Generation Limited	Ordinary shares £1	100%	Electricity generation
ScottishPower Insurance Limited (Isle of Man)	Ordinary shares £1	100%	Insurance
ScottishPower Investments Limited	Ordinary shares £1	100%	Holding company
ScottishPower NA 1 Limited#	Ordinary shares £1	100%	Holding company
ScottishPower NA 2 Limited#	Ordinary shares £1	100%	Holding company
Scottish Power UK Holdings Limited#	Ordinary shares 50p	100%	Holding company
Scottish Power UK plc	Ordinary shares 50p	100%	Holding company
SP Dataserve Limited	Ordinary shares £1	100%	Data collection, data aggregation, meter operation and revenue protection
SP Distribution Limited	Ordinary shares £1	100%	Ownership and operation of distribution network within the ScottishPower area
SP Finance#	Ordinary shares £1	100%	Holding company
SP Finance 2 Limited#	Ordinary shares £1	100%	Holding company
SP Manweb plc	Ordinary shares 50p	100%	Ownership and operation of distribution network within the Mersey and North Wales area
SP Power Systems Limited	Ordinary shares £1	100%	Provision of asset management services
SP Transmission Limited	Ordinary shares £1	100%	Ownership and operation of transmission network within the ScottishPower area

Fixed asset investments			
Joint ventures			
CeltPower Limited	'B' Ordinary shares £1*	100%	Wind-powered electricity generation
N.E.S.T. Makers Limited	'B' Ordinary shares £1*	100%	Energy efficiency agent for the 'fuel poor'/benefit market
ScotAsh Limited	'B' Ordinary shares £1*	100%	Sales of ash and ash-related cementitious products
Scottish Electricity Settlements Limited	Ordinary shares £1	50%	Scottish electricity settlements
Shoreham Operations Company Limited	'B' Ordinary shares £1*	100%	Management services
South Coast Power Limited	'B' Ordinary shares £1*	100%	Electricity generation
Associated undertaking			
Wind Resources Limited	'B' Ordinary shares £1**	100%	Wind-powered electricity generation

Notes

* Represents 50% of the total issued share capital.

** Represents 45% of the total issued share capital.

*** 100% of the following classes of shares in PacifiCorp UK Limited are also indirectly held: 'A' Non-Voting Shares of $3,189.26 each; 'B' Non-Voting Shares of $3,446.41 each; 'C' Non-Voting Shares of $4,874.18 each; 'D' Non-Voting Shares of $2,924.90 each; 'E' Non-Voting Shares of $4,874.18 each; 'F' Non-Voting Shares of $3,883.54 each.

The investment in this company is a direct holding of Scottish Power plc.

NA General Partnership is a partnership and therefore has no defined class of share capital.

The directors consider that to give full particulars of all undertakings would lead to a statement of excessive length. The information above includes the undertakings whose results or financial position, in the opinion of the directors, principally affect the results or financial position of the group.

All companies are incorporated in Great Britain, unless otherwise stated.

Independent Auditors' Report

to the members of Scottish Power plc

We have audited the Accounts which comprise the Accounting Policies and Definitions, the Group Profit and Loss Accounts, the Statement of Total Recognised Gains and Losses, the Note of Historical Cost Profits and Losses, the Reconciliation of Movements in Shareholders' Funds, the Group Cash Flow Statement, the Reconciliation of Net Cash Flow to Movement in Net Debt, the Group Balance Sheet, the Statement of Principal Subsidiary Undertakings and Other Investments, the Company Balance Sheet and the related notes. We have also audited the disclosures required by Part 3 of Schedule 7A to the Companies Act 1985 contained in the Remuneration Report of the Directors ('the auditable part').

Respective responsibilities of directors and auditors

The directors' responsibilities for preparing the Annual Report and Accounts in accordance with applicable United Kingdom law and accounting standards are set out in the statement of directors' responsibilities. The directors are also responsible for preparing the Remuneration Report of the Directors.

Our responsibility is to audit the Accounts and the auditable part of the Remuneration Report of the Directors in accordance with relevant legal and regulatory requirements and United Kingdom Auditing Standards issued by the Auditing Practices Board. This report, including the opinion, has been prepared for and only for the company's members as a body in accordance with Section 235 of the Companies Act 1985 and for no other purpose. We do not, in giving this opinion, accept or assume responsibility for any other purpose or to any other person to whom this report is shown or into whose hands it may come save where expressly agreed by our prior consent in writing.

We report to you our opinion as to whether the Accounts give a true and fair view and whether the Accounts and the auditable part of the Remuneration Report of the Directors have been properly prepared in accordance with the Companies Act 1985. We also report to you if, in our opinion, the Report of the Directors is not consistent with the Accounts, if the company has not kept proper accounting records, if we have not received all the information and explanations we require for our audit, or if information specified by law regarding directors' remuneration and transactions is not disclosed.

We read the Chairman's Statement, the Chief Executive's Review, the Business Review, the Financial Review, the Corporate Governance statement, the unaudited part of the Remuneration Report of the Directors and the other information contained in the Annual Report and Accounts and consider the implications for our report if we become aware of any apparent misstatements or material inconsistencies with the Accounts.

We review whether the Corporate Governance statement reflects the company's compliance with the seven provisions of the Combined Code specified for our review by the Listing Rules of the Financial Services Authority, and we report if it does not. We are not required to consider whether the board's statements on internal control cover all risks and controls, or to form an opinion on the effectiveness of the company's or group's corporate governance procedures or its risk and control procedures.

Basis of audit opinion

We conducted our audit in accordance with Auditing Standards issued by the Auditing Practices Board. An audit includes examination, on a test basis, of evidence relevant to the amounts and disclosures in the Accounts and the auditable part of the Remuneration Report of the Directors. It also includes an assessment of the significant estimates and judgements made by the directors in the preparation of the Accounts, and of whether the accounting policies are appropriate to the group's circumstances, consistently applied and adequately disclosed.

We planned and performed our audit so as to obtain all the information and explanations which we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the Accounts and the auditable part of the Remuneration Report of the Directors are free from material misstatement, whether caused by fraud or other irregularity or error. In forming our opinion we also evaluated the overall adequacy of the presentation of information in the Accounts.

Opinion

In our opinion:

– the Accounts give a true and fair view of the state of affairs of the company and the group at 31 March 2003 and of the profit and cash flows of the group for the year then ended;

– the Accounts have been properly prepared in accordance with the Companies Act 1985; and

– those parts of the Remuneration Report of the Directors required by Part 3 of Schedule 7A to the Companies Act 1985 have been properly prepared in accordance with the Companies Act 1985.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants and
Registered Auditors
Glasgow

7 May 2003

a) The maintenance and integrity of the Scottish Power plc website is the responsibility of the directors; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the Annual Report & Accounts since they were initially presented on the website.

b) Legislation in the United Kingdom governing the preparation and dissemination of financial information may differ from legislation in other jurisdictions.

Five Year Summary

	Notes	2003 $m	2003 £m	2002 £m	2001 £m	2000 £m	1999 £m
		Years ended 31 March					
UK GAAP Information							
Profit and Loss Account Information:							
Turnover							
– continuing operations	(a)	**8,290**	**5,247**	5,523	5,410	3,110	2,334
– discontinued operations		**43**	**27**	791	939	1,005	908
Total turnover		**8,333**	**5,274**	6,314	6,349	4,115	3,242
Operating profit							
– continuing operations	(a)	**1,472**	**932**	636	569	395	527
– discontinued operations		**22**	**14**	141	153	267	276
Total operating profit		**1,494**	**946**	777	722	662	803
Operating profit (as adjusted)	(b)						
– continuing operations	(a)	**1,692**	**1,071**	801	815	676	527
– discontinued operations		**22**	**14**	143	155	285	277
Total operating profit (as adjusted)		**1,714**	**1,085**	944	970	961	804
Profit/(loss) before taxation							
– continuing operations		**1,084**	**686**	276	264	837	362
– discontinued operations		**17**	**11**	(1,215)	116	312	282
Total profit/(loss) before taxation		**1,101**	**697**	(939)	380	1,149	644
Profit before taxation (as adjusted)	(b)						
– continuing operations		**1,304**	**825**	460	509	484	360
– discontinued operations		**17**	**11**	107	119	252	285
Total profit before taxation (as adjusted)		**1,321**	**836**	567	628	736	645
Profit/(loss) for financial year							
– continuing operations		**750**	**475**	214	151	626	210
– discontinued operations		**13**	**8**	(1,201)	157	259	259
Total profit/(loss) for financial year		**763**	**483**	(987)	308	885	469
Cash dividends		**(837)**	**(530)**	(503)	(477)	(341)	(268)
Dividend in specie on demerger of Thus		**–**	**–**	(437)	–	–	–
Balance Sheet Information:							
Total assets		**22,049**	**13,955**	16,315	16,976	15,516	6,232
Capital expenditure (net)	(c)	**1,133**	**717**	1,229	1,095	887	754
Long-term liabilities		**11,453**	**7,249**	8,318	7,793	6,895	2,852
Net debt		**6,827**	**4,321**	6,208	5,285	4,842	2,421
Equity shareholders' funds		**7,328**	**4,638**	4,731	5,893	5,563	1,203
Net assets		**7,445**	**4,712**	4,818	6,179	5,863	1,204
Basic weighted average share capital (number of shares, million)		**1,844**	**1,844**	1,838	1,830	1,390	1,185
Diluted weighted average share capital (number of shares, million)		**1,848**	**1,848**	1,840	1,837	1,399	1,197
Ratios and statistics:							
Earnings/(loss) per ordinary share							
– continuing operations		**$0.407**	**25.76p**	11.65p	8.26p	45.05p	17.73p
– discontinued operations		**$0.0065**	**0.41p**	(65.36)p	8.54p	18.64p	21.87p
Total earnings/(loss) per ordinary share		**$0.4135**	**26.17p**	(53.71)p	16.80p	63.69p	39.60p
Earnings per ordinary share (as adjusted)	(e)						
– continuing operations		**$0.5261**	**33.30p**	21.04p	19.19p	23.65p	17.84p
– discontinued operations		**$0.0065**	**0.41p**	5.08p	8.67p	14.32p	21.86p
Total earnings per ordinary share (as adjusted)		**$0.5326**	**33.71p**	26.12p	27.86p	37.97p	39.70p
Diluted earnings/(loss) per ordinary share		**$0.4125**	**26.11p**	(53.64)p	16.74p	63.25p	39.20p
Earnings/(loss) per ScottishPower ADS	(d)	**$1.66**	**£1.05**	£(2.15)	£0.67	£2.55	£1.58
Earnings per ScottishPower ADS (as adjusted)	(d),(e)	**$2.13**	**£1.35**	£1.04	£1.11	£1.52	£1.59
Diluted earnings/(loss) per ScottishPower ADS	(d)	**$1.64**	**£1.04**	£(2.15)	£0.67	£2.53	£1.57
Cash dividends per ScottishPower ordinary share		**$0.4536**	**28.708p**	27.34p	26.04p	24.80p	22.50p
Cash dividends per ScottishPower ADS	(d)	**$1.83**	**£1.15**	£1.09	£1.04	£0.99	£0.90
Dividend cover (as adjusted)	(e)	**1.2x**	**1.2x**	1.0x	1.1x	1.5x	1.8x
Interest cover (as adjusted)	(e)	**4.3x**	**4.3x**	2.5x	3.0x	4.2x	5.0x
Gearing	(f)	**93%**	**93%**	131%	90%	87%	201%
US GAAP Information							
Total turnover	(a)	**8,333**	**5,274**	6,314	6,349	4,115	3,242
Profit/(loss) for the financial year		**1,247**	**789**	(887)	387	870	451
Earnings/(loss) per ordinary share	(g)	**$0.6764**	**42.81p**	(48.26)p	21.13p	62.59p	38.08p
Diluted earnings/(loss) per ordinary share		**$0.6747**	**42.70p**	(48.26)p	21.05p	62.16p	37.70p
Earnings/(loss) per ScottishPower ADS	(d),(g)	**$2.70**	**£1.71**	£(1.93)	£0.85	£2.50	£1.52
Diluted earnings/(loss) per ScottishPower ADS	(d)	**$2.70**	**£1.71**	£(1.93)	£0.84	£2.49	£1.51
Total assets		**24,109**	**15,259**	17,818	18,646	16,971	7,344
Equity shareholders' funds under US GAAP		**8,658**	**5,480**	5,850	7,463	7,001	2,457

(a) The results for the financial year ended 31 March 2000 included turnover of £711.7 million, operating profit of £114.9 million and operating profit, before goodwill amortisation, of £151.7 million in respect of PacifiCorp for the period of the year following its acquisition on 29 November 1999.

(b) Operating profit (as adjusted) and profit before taxation (as adjusted) exclude the effect of exceptional items and goodwill amortisation.

(c) Capital expenditure is stated net of capital grants and customer contributions.

(d) Earnings/(loss) and cash dividends per ScottishPower ADS have been calculated based on a ratio of four ScottishPower ordinary shares to one ScottishPower ADS. Cash dividends per ScottishPower ADS are shown based on the actual amounts in US dollars.

(e) The adjusted figures for Earnings per ordinary share, Earnings per ScottishPower ADS, Dividend cover and Interest cover exclude the effects of exceptional items and goodwill amortisation as applicable.

(f) Gearing is calculated by dividing net debt by equity shareholders' funds.

(g) As permitted under UK GAAP, earnings/(loss) per share have been presented including and excluding the impact of the exceptional items and goodwill amortisation to provide an additional measure of underlying performance. In accordance with US GAAP, earnings/(loss) per share have been presented based on US GAAP earnings, without adjustments for the impact of UK GAAP exceptional items and goodwill amortisation. Such additional measures of underlying performance are not permitted under US GAAP.

(h) Amounts for the financial year ended 31 March 2003 have been translated, solely for the convenience of the reader, at $1.58 to £1.00, the closing exchange rate on 31 March 2003.

Glossary of Financial Terms and US Equivalents

UK Financial Terms used in Annual Report & Accounts	US equivalent or definition
Accounts	Financial statements
Associates	Equity investees
Capital allowances	Tax depreciation
Capital redemption reserve	Other additional capital
Creditors	Accounts payable and accrued liabilities
Creditors: amounts falling due within one year	Current liabilities
Creditors: amounts falling due after more than one year	Long-term liabilities
Employee share schemes	Employee stock benefit plans
Employee costs	Payroll costs
Finance lease	Capital lease
Financial year	Fiscal year
Fixed asset investments	Non-current investments
Freehold	Ownership with absolute rights in perpetuity
Gearing	Leverage
Investment in associates and joint ventures	Securities of equity investees
Loans to associates and joint ventures	Indebtedness of equity investees not current
Net asset value	Book value
Operating profit	Net operating income
Other debtors	Other current assets
Own work capitalised	Costs of group's employees engaged in the construction of plant and equipment for internal use
Profit	Income
Profit and loss account (statement)	Income statement
Profit and loss account (in the balance sheet)	Retained earnings
Profit/(loss) for financial year	Net income/(loss)
Profit on sale of fixed assets	Gain on disposal of non-current assets
Provision for doubtful debts	Allowance for bad and doubtful accounts receivable
Provisions	Long-term liabilities other than debt and specific accounts payable
Recognised gains and losses (statement)	Comprehensive income
Reserves	Shareholders' equity other than paid-up capital
Severance costs	Early release scheme expenses
Share premium account	Additional paid-in capital or paid-in surplus (not distributable)
Shareholders' funds	Shareholders' equity
Stocks	Inventories
Tangible fixed assets	Property, plant and equipment
Trade debtors	Accounts receivable (net)
Turnover	Revenues

Investor Information

Nature of trading market

The principal trading market for the ordinary shares of ScottishPower is the London Stock Exchange. In addition, American Depositary Shares (“ADSs”) (each of which represents four ordinary shares) have been issued by JPMorgan Chase Bank, as depositary (the “Depositary”) for the company’s ADSs, and are traded on the New York Stock Exchange following listing on 8 September 1997.

Table 45 sets out, for the periods indicated, the highest and lowest middle market quotations for the ordinary shares, as derived from the Daily Official List of the London Stock Exchange and the range of high and low closing sale prices for ADSs, as reported on the New York Exchange Composite Tape.

On 31 March 2003, there were 534 registered holders of 315,296 ordinary shares with addresses in the US and 62,359 registered holders of 68,859,341 ADSs (equivalent to 275,437,364 ordinary shares). The combined holdings of these shareholders represented 14.86% of the total number of ordinary shares outstanding as at 31 March 2003. UK registered shareholders held 84.90% of the total number of ordinary shares, and all shareholders other than those registered in the UK or the US held 0.24% of the total number of ordinary shares outstanding as at 31 March 2003. As certain of the ordinary shares and ADSs are held by brokers and other nominees, these numbers may not be representative of the actual number of beneficial owners in the US or elsewhere or the number of ordinary shares or ADSs beneficially held by US persons.

Table 46 – Analysis of Ordinary Shareholdings at 31 March 2003

Range of holdings	No. of shareholdings	No. of shares
1-100	18,436	732,327
101-200	174,505	28,957,720
201-600	178,703	55,273,513
601-1,000	39,280	30,763,853
1,001-5,000	48,442	90,686,464
5,001-100,000	4,223	62,322,104
100,001 and above	781	1,587,196,821
Total	464,370	1,855,932,802

Share capital and options

As a result of the exercise of options under the Executive Share Option Scheme and the issue of shares to the Trustee of the Employee Share Ownership Plan, a total of 3,285,818 ordinary shares of 50p each were issued during the year. Accordingly, the number of ordinary shares in issue was 1,855,932,802 as at 31 March 2003. During the year, 3,316,143 options over ordinary shares were granted to 2,188 employees under the ScottishPower Sharesave Scheme. A total of 7,327,043 options were granted under the Executive Share Option Plan 2001. No options were granted under the Executive Share Option Scheme, which was replaced in 1996 by the introduction of the Long Term Incentive Plan. Awards in respect of 1,028,417 shares were made under the Plan during the year and these awards are subject to the achievement of specified performance criteria. Details are contained in the Remuneration Report.

Between 31 March 2003 and 7 May 2003, a further 225,182 ordinary shares have been issued as a result of the allotments in respect of the Employee Share Ownership Plan. At the Annual General Meeting of the company last year, shareholders granted authority to the directors to purchase up to 185,298,702 ordinary shares. The directors have not exercised this authority.

Table 45 – Historical share prices

	Ordinary shares[1]		American Depositary Shares	
Period	High (p)	Low (p)	High ($)	Low ($)
1998/99	675.00	521.00	44.63	34.13
1999/00	601.50	359.50	39.11	22.97
2000/01	576.00	422.00	33.88	26.15
2001/02				
First quarter	521.84	430.64	30.24	24.90
Second quarter	513.06	351.14	29.66	20.90
Third quarter	412.59	355.78	24.51	21.05
Fourth quarter	426.49	350.00	24.75	20.10
2002/03				
First quarter	416.00	342.00	24.80	19.90
Second quarter	384.00	298.75	24.00	18.84
Third quarter	373.00	336.00	23.75	20.55
Fourth quarter	388.00	330.75	24.45	21.40
October 2002	373.00	343.50	23.75	21.15
November 2002	373.00	338.00	23.65	20.55
December 2002	362.50	336.00	23.45	20.88
January 2003	372.75	330.75	24.05	21.40
February 2003	373.50	332.00	24.00	21.80
March 2003	388.00	333.50	24.45	21.51

Note:
1 The past performance of the ordinary shares is not necessarily indicative of future performance.

Substantial shareholdings

As at 7 May 2003, the company had been notified that the following companies were substantial shareholders:

Capital Research and Management Company	7.38%
Barclays plc	3.58%
Prudential plc	3.55%
Legal & General Investment Management	3.38%

The substantial shareholders enjoy the same voting rights as all other shareholders.

Control of company

As far as is known to the company, it is not directly or indirectly owned or controlled by another corporation or by any foreign government.

As at 7 May 2003, no person known to the company, other than as shown above, owned more than 5% of any class of the group's voting securities.

As at 7 May 2003, the total amount of voting securities owned by directors and executive officers of ScottishPower as a group is shown in Table 47 below.

Table 47 – Voting securities

Title of Class Identity of Group	Amount Owned	Percentage of Class
Ordinary shares Directors and officers (18 persons)	409,261	0.02%

Full details of the directors' interests in ScottishPower shares are shown in Tables 43 and 44 in the Remuneration Report. None of the officers had a beneficial interest in 1% or more of the issued share capital.

In addition, as at 7 May 2003, the directors and officers of the company, as a group, held options to purchase 4,466,130 ordinary shares, all of which were issued pursuant to the Long Term Incentive Plan, Executive Share Option Scheme, Executive Share Option Plan 2001, ScottishPower's Sharesave Schemes or the PacifiCorp Stock Incentive Plan.

The company does not know of any arrangements the operation of which might result in a change in control of the group.

Exchange rates

The group publishes its consolidated Accounts in pounds sterling. In this document, references to "pounds sterling", "pounds", "pence" or "p" are to UK currency and references to "US dollars", "US$" or "$" are to US currency. Solely for the convenience of the reader, this report contains translations of certain pounds sterling amounts into US dollars at specified rates, or, if not so specified, at the Noon Buying Rate in New York City for cable transfers in pounds sterling as certified for customs purposes by the Federal Reserve Bank of New York ("Noon Buying Rate") on 31 March 2003 of £1.00 = $1.58. On 7 May 2003, the Noon Buying Rate was $1.59 to £1.00. No representation is made that the pound sterling amounts have been, could have been or could be converted into US dollars at the rates indicated or at any other rates.

Table 48 sets out, for the periods indicated, certain information concerning the Noon Buying Rate for US dollars per £1.00.

Dividends

Although dividends were historically declared and paid and financial reports published semi-annually, following completion of the merger with PacifiCorp, the company moved to quarterly reporting and the quarterly payment of dividends.

A dividend of 7.177 pence per share on the ordinary shares will be paid on 16 June 2003 to shareholders on the register on 16 May 2003. This makes total dividends for the year of 28.708 pence per share. A dividend of $0.4609 per ADS will also be paid on 16 June 2003 to ADS holders of record on 16 May 2003. This makes total dividends for the year of $1.8268 per ADS.

As stated at the time of announcing the proposed disposal of Southern Water, with effect from the financial year commencing 1 April 2003, ScottishPower intends to target dividend cover, based on full year earnings excluding goodwill amortisation and exceptional items, in the range 1.5 - 2.0 times and ideally towards the middle of that range. ScottishPower will aim to grow dividends broadly in line with earnings thereafter.

To implement this policy, in the absence of unforeseen circumstances, ScottishPower intends to pay an identical dividend for each of the first three quarters of each year, with the dividend for the fourth quarter representing the balance of the total dividend for each year. In respect of each of the quarters ending 30 June 2003, 30 September 2003 and 31 December 2003, ScottishPower aims to declare a dividend of 4.75 pence per share.

Table 48 – Historical exchange rates

Period	High	Low	Average[1]	Year end
1998/99	$1.72	$1.60	$1.65	$1.61
1999/00	$1.68	$1.55	$1.61	$1.59
2000/01	$1.61	$1.40	$1.52	$1.42
2001/02	$1.48	$1.37	$1.43	$1.42
2002/03	$1.65	$1.43	$1.55	$1.58
October 2002	$1.57	$1.54	$1.56	
November 2002	$1.59	$1.54	$1.57	
December 2002	$1.61	$1.56	$1.59	
January 2003	$1.65	$1.60	$1.62	
February 2003	$1.65	$1.57	$1.61	
March 2003	$1.61	$1.56	$1.58	

Note:
1 The average of the Noon Buying Rates on the last day of each month during the relevant period.

Investor Information
continued

Table 49 – Historical dividend payments

	Notes	**2002/03**	2001/02	2000/01	1999/00	1998/99
Pence per ordinary share	1					
Interim		**–**	–	–	8.27p	7.50p
Pre-completion		**–**	–	–	8.10p	–
Quarter (29 Nov 1999 – 31 Dec 1999)		**–**	–	–	2.23p	–
Quarter (1 Jan 2000 – 31 Mar 2000)		**–**	–	–	6.20p	–
Quarter (1 April – 30 June)		**7.177p**	6.835p	6.51p	–	–
Quarter (1 July – 30 Sept)		**7.177p**	6.835p	6.51p	–	–
Quarter (1 Oct – 31 Dec)		**7.177p**	6.835p	6.51p	–	–
Quarter (1 Jan – 31 Mar)		**7.177p**	6.835p	6.51p	–	–
Final		**–**	–	–	–	15.00p
Total		**28.708p**	27.34p	26.04p	24.80p	22.50p
US dollars per ADS	1,2					
Interim		**–**	–	–	$0.5324	$0.48
Pre-completion		**–**	–	–	$0.5215	–
Quarter (29 Nov 1999 – 31 Dec 1999)		**–**	–	–	$0.1413	–
Quarter (1 Jan 2000 – 31 Mar 2000)		**–**	–	–	$0.3856	–
Quarter (1 April – 30 June)		**$0.4472**	$0.3907	$0.3928	–	–
Quarter (1 July – 30 Sept)		**$0.4479**	$0.3979	$0.3702	–	–
Quarter (1 Oct – 31 Dec)		**$0.4708**	$0.3863	$0.3805	–	–
Quarter (1 Jan – 31 Mar)		**$0.4609**	$0.3972	$0.3721	–	–
Final		**–**	–	–	–	$0.97
Total		**$1.8268**	$1.5721	$1.5156	$1.5808	$1.45

Notes:

1 Dividends per share and per ADS are shown net of any associated UK tax credit available to certain holders of ordinary shares and ADSs. See "Taxation of Dividends". Dividends paid by the Depositary in respect of ADSs are paid in US dollars based on a market rate of exchange that differs from the Noon Buying Rate.

2 Calculated based on a ratio of four ordinary shares for one ADS.

Table 49 sets out the dividends paid on ordinary shares and ADSs in respect of the past five financial years, excluding any associated UK tax credit in respect of such dividends. A person resident in the UK for tax purposes who receives a dividend from the company is generally entitled to a tax credit, currently at a rate of 1/9th of the dividend ("associated UK tax credit"). For further information, see "Taxation of Dividends".

Memorandum and Articles of Association

A summary of certain provisions of the company's Memorandum and Articles of Association will be filed with the company's report to the US Securities and Exchange Commission on Form 20-F.

Exchange controls and other limitations affecting security holders

There are currently no UK laws, decrees or regulations that restrict the export or import of capital, including, but not limited to, foreign exchange capital restrictions, or that affect the remittance of dividends or other payments to non-UK resident holders of the company's securities except as otherwise set forth in "Taxation".

There are no limitations imposed by UK law or by the company's Memorandum and Articles of Association that restrict the right of non-UK resident or non-UK citizen owners to hold or to vote the ordinary shares.

Taxation

The following discussion of UK tax and US federal income tax consequences is set forth with respect to US tax considerations in reliance upon the advice of Milbank, Tweed, Hadley & McCloy LLP, special US counsel to the company, and with respect to UK tax considerations in reliance upon the advice of Freshfields Bruckhaus Deringer, the company's UK lawyers. The discussion is intended only as a summary of the principal US federal income tax and UK tax consequences to investors who hold the ADSs or ordinary shares as capital assets and does not purport to be a complete analysis or listing of all potential tax consequences of the purchase, ownership and disposition of ADSs or ordinary shares. The summary does not discuss special tax rules that may be applicable to certain classes of investors, including banks, insurance companies, tax exempt entities, dealers, traders who elect to mark to market, investors with a functional currency other than the US dollar, persons who hold ADSs as part of a hedge, straddle or conversion transaction, or holders of 10% or more of the voting stock of the company. The statements of UK and US tax laws and practices set out below are based on the laws in force and as interpreted by the relevant taxation authorities as of the date of this report. The statements are subject to any changes occurring after that date in UK or US law or practice, in the interpretation thereof by the relevant taxation authorities, or in any double taxation convention between the US and the UK. On 24 July 2001, the US and the UK signed a new convention between the two countries for the avoidance of double taxation with respect to taxes on income and capital gains ("the New Income Tax Convention"). Instruments of ratification with respect to the New Income Tax Convention were exchanged on 31 March 2003, putting the New Income Tax Convention into force, subject to certain effective date provisions that result in the delayed implementation of certain withholding and income tax provisions.
As of the time of this report, all prior distributions by the company since

publication of our last annual statement were governed by the rules of the treaty in force prior to 1 April 2003, (the "Expiring Income Tax Convention"). As a result, unless otherwise noted, the following discussion is based on the Expiring Income Tax Convention. The company believes, and the discussion therefore assumes, that it is not a passive foreign investment company for US federal income tax purposes.

Each investor is urged to consult their own tax adviser regarding the tax consequences of the purchase, ownership and disposition of ordinary shares or ADSs under the laws of the US, the UK and their constituent jurisdictions and any other jurisdiction where the investor may be subject to tax.

If the obligations contemplated by the Deposit Agreement are performed in accordance with its terms, a beneficial owner of ADSs will be treated as the owner of the underlying ordinary shares for the purposes of the Expiring Income Tax Convention and the US Internal Revenue Code of 1986, as amended ("Code").

For the purposes of this summary, the term "US Holder" means a beneficial owner of the ADSs that is a US citizen or resident, a domestic corporation or partnership, a trust subject to the control of a US person and the primary supervision of a US court, or an estate, the income of which is subject to US federal income tax regardless of its source.

For the purposes of this summary, the term "Eligible US Holder" means a US holder that is a resident of the US for the purposes of the Expiring Income Tax Convention and that satisfies the following conditions:

- is not also resident in the UK for UK tax purposes;
- is not a corporation which, alone or together with one or more associated corporations, controls, directly or indirectly, 10% or more of the voting stock of the company;
- whose holding of the ADSs is not attributable to a permanent establishment in the UK through which such holder carries on a business or with a fixed base in the UK from which such holder performs independent personal services; and
- under certain circumstances, is not a company 25% or more of the capital of which is owned, directly or indirectly, by persons that are neither individual residents of, nor nationals of the US.

Taxation of dividends

Save as set out below in relation to the UK withholding tax applied to the UK tax credit (as defined below), the company is not required to withhold any UK taxes from its dividend payments to US Holders. Therefore the amount of a dividend paid to a US Holder will not be reduced by any UK withholding tax. Under UK tax law and the Expiring Income Tax Convention, an Eligible US Holder that makes the appropriate election with respect to dividends paid prior to 1 May 2003, and, as described below, if elected, with respect to dividends paid before 1 May 2004, is in theory entitled to an additional payment from the UK ("UK tax credit") equal to 1/9th of the amount of any dividend paid by the company to the holder. While, as noted above, the dividend paid by the company is not subject to any UK withholding tax, under the Expiring Income Tax Convention and under current UK law, the UK tax credit that otherwise would be payable by the UK is completely offset by a UK withholding tax equal to 100% of that UK tax credit. Accordingly, US Holders will receive the full amount of any dividend declared by the company (without deduction for UK tax) but will not be entitled to an additional cash payment from the UK in respect of the UK tax credit. An Eligible US Holder who elects to claim a credit (as described below) against the holder's US federal income tax liability with respect to the UK withholding tax imposed on the UK tax credit amount, is required to include, in addition to the gross amount of the dividend paid by the company, the amount of UK tax credit in taxable income for US federal income tax purposes, even though none of the amount of the UK tax credit is paid by the UK. An Eligible US Holder who so elects to include the amount of the UK tax credit in taxable income, generally will be entitled to credit against the holder's US tax liability, the amount of the UK tax credit that the holder is deemed to have received, which US tax credit may result in a reduction in the holder's effective US tax rate on the cash dividend received. Following is a simplified numerical example of the US tax treatment of dividends paid to an Eligible US Holder who is subject to tax at a rate of 35% and is eligible for and claims a US tax credit for the complete amount of the UK tax credit:

	$
Dividend received	90.00
UK tax credit	10.00
US taxable income	**100.00**
US tax @ 35%	35.00
US tax credit for UK withholding tax	(10.00)
US tax liability	**25.00**
Cash dividend received	90.00
US tax liability	(25.00)
After-tax cash amount	**65.00**
Approximate effective US tax rate on cash received	27.8%

Note that the US federal income tax consequences of dividends paid to an Eligible US Holder will depend upon the holder's particular circumstances and, consequently, the US federal income tax consequences applicable to a particular holder may differ from those set out in the above example and some US Holders may not be able to make full or partial use of the UK tax credit. Eligible US Holders are urged to consult their own tax advisers regarding the tax consequences to them of the payment of a dividend by the company.

The full procedures for determining and claiming a US tax credit, with respect to dividends received from a UK corporation, are outlined in US Internal Revenue Service Revenue Procedure 2000 – 13, 2000 – 6 I.R.B. 1.

A US Holder recognises income when the dividend is actually or constructively received by the holder, in the case of ordinary shares, or by the Depositary, in the case of ADSs. The dividend will not be eligible for the dividends received deduction generally allowed to US corporations in respect of dividends received from other US corporations. Distributions in excess of current and accumulated earnings and profits, as determined for US federal income tax purposes, will be treated as a return of capital to the extent of the Eligible US Holder's basis in the ordinary shares or ADSs and thereafter as a capital gain. In determining the amount of the distribution, a US Holder will use the spot currency exchange rate on the date the dividend is included in income. Any difference between that amount and the dollars actually received may constitute a foreign currency gain or loss.

Investor Information
continued

However, an Eligible US Holder that is an individual is not required to recognise a gain of less than $200 from the exchange of foreign currency in a “personal transaction” as defined in Section 988(e) of the Code.

Subject to certain limitations and requirements, an Eligible US Holder will be entitled under the Expiring Income Tax Convention to credit the UK withholding tax imposed with respect to the UK tax credit against the Eligible US Holder’s US federal income tax liability, provided the holder includes the gross amount of the UK tax credit in the holder’s gross income as described above. Claiming a US foreign tax credit with respect to the UK withholding tax imposed under the Expiring Income Tax Convention with respect to the UK tax credit, may result in a lower effective US federal income tax rate on dividends paid by the company for certain Eligible US Holders as demonstrated in the above numerical example. An Eligible US Holder is not required to affirmatively make a claim to the UK Inland Revenue to be entitled to the US foreign tax credit, although an Eligible US Holder electing to claim the credit must complete an Internal Revenue Service Form 8833 (Treaty Based Return Position Disclosure) and file such Form with the holder’s US federal income tax return for each year that the tax credit is claimed. Eligible US Holders that include the amount of the UK tax credit in gross income, but do not elect to claim foreign tax credits may instead claim a deduction for UK withholding tax deemed paid. For foreign tax credit limitation purposes, the dividend (grossed-up to include the UK tax deemed paid) will be income from sources outside the US. The rules relating to the computation of foreign tax credits are complex and Eligible US Holders should consult their own tax advisers to determine whether, and to what extent, a credit would be available and whether any filings or other actions may be required to substantiate an Eligible US Holder’s foreign tax credit claim.

If the US Holder is a US partnership, trust or estate, the UK tax credit will be available only to the extent that the income derived by such partnership, trust or estate is subject to US federal income tax as the income of a resident either in its hands or in the hands of its partners or beneficiaries, as the case may be. Whether holders of ADSs who reside in countries other than the US are entitled to a tax credit in respect of dividends on ADSs depends in general upon the provisions of conventions or agreements, if any, as may exist between such countries and the UK.

Under the New Income Tax Convention, US Holders are not entitled to claim the UK tax credit with respect to dividends paid by the company on or after 1 May 2003. Notwithstanding this effective date, an Eligible US Holder may continue to claim the UK tax credit with respect to dividends paid before 1 May 2004, if the holder elects to apply all the provisions of the Expiring Income Tax Convention during such period. Each investor is urged to consult their own tax adviser regarding the tax consequences of electing to apply the Expiring Income Tax Convention in lieu of the New Income Tax Convention.

Taxation of capital gains

In general, for US tax purposes, US Holders of ADSs will be treated as the owners of the underlying ordinary shares that are represented by such ADSs and deposits and withdrawals of ordinary shares by US Holders in exchange for ADSs will not be treated as a sale or other disposition for US federal income tax purposes. Upon a sale or other disposition of ordinary shares or ADSs, US Holders will recognise a gain or loss for US federal income tax purposes in an amount equal to the difference between the US dollar value of the amount realised and the US Holder’s tax basis (determined in US dollars) in such ordinary shares or ADSs. Generally, such gain or loss will be a long-term capital gain or loss if the US Holder’s holding period for such ordinary shares or ADSs exceeds one year. Any such gain or loss generally will be income from sources within the US for foreign tax credit limitation purposes. Long-term capital gain for an individual US Holder is generally subject to a maximum tax rate of 20%.

A US Holder who is not resident or ordinarily resident for UK tax purposes in the UK will not generally be liable for UK tax on capital gains recognised on the sale or other disposition of ADSs or ordinary shares, unless the ADS holder carries on a trade, profession or vocation in the UK through a branch or agency and the ADSs are, or have been, used, held or acquired for the purposes of such trade, profession or vocation or such branch or agency.

US citizens resident or ordinarily resident in the UK, US corporations resident in the UK by reason of their business being managed or controlled in the UK and US citizens who or US corporations which are trading or carrying on a trade, profession or vocation in the UK through a branch or agency and who or which have used, held or acquired ADSs or ordinary shares for the purposes of such trade, profession or vocation or such branch or agency may be liable for both UK and US tax in respect of a gain on the disposal of the ADSs. Such holders may not be entitled to a tax credit against their US federal income tax liability for the amount of UK capital gains tax or UK corporation tax on chargeable gains, as the case may be, paid in respect of such gain unless the holder appropriately can apply the credit against tax due on income from foreign sources.

For companies, the UK Inland Revenue has proposed that, in relation to accounting periods commencing on or after 1 January 2003, UK statutory references to “branch or agency” should be replaced with references to “permanent establishment” and the references to branch or agency above should be read accordingly.

US information reporting and backup withholding

In general, information reporting requirements will apply to dividend payments (or other taxable distributions) in respect of ordinary shares or ADSs made within the US to a non-corporate US person. Accordingly, individual US Holders will receive an annual statement showing the amount of taxable dividends (or other reportable distributions) paid to them during the year. “Backup withholding” will apply to such payments (i) if the holder or beneficial owner fails to provide an accurate taxpayer identification number in the manner required by US law and applicable regulations, (ii) if there has been notification from the Internal Revenue Service of a failure by the holder or beneficial owner to report all interest or dividends required to be shown on its federal income tax returns or, (iii) in certain circumstances, if the holder or beneficial owner fails to comply with applicable certification requirements.

In general, payment of the proceeds from the sale of ordinary shares or ADSs to or through a US office of a broker is subject to both US backup withholding and information reporting requirements, unless the holder or beneficial owner establishes an exemption. Different rules apply to payments made outside the US through an office outside the US.

UK inheritance tax

An individual who is domiciled in the US for the purposes of the convention between the US and the UK for the avoidance of double taxation with respect to estate and gift taxes ("Estate Tax Convention") and who is not a national of the UK for the purposes of the Estate Tax Convention will not generally be subject to UK inheritance tax in respect of the ADSs or ordinary shares on the individual's death or on a gift of the ADSs or ordinary shares during the individual's lifetime, unless the ADSs or ordinary shares are part of the business property of a permanent establishment of the individual in the UK or pertain to a fixed base in the UK of an individual who performs independent personal services. Special rules apply to ADSs held in trust. In the exceptional case where the shares are subject both to UK inheritance tax and to US federal gift or estate tax, the Estate Tax Convention generally provides for the tax paid in the UK to be credited against tax paid in the US.

UK stamp duty and stamp duty reserve tax

In practice, no UK stamp duty need be paid on the acquisition or transfer of ADSs provided that any instrument of transfer is executed outside the UK and subsequently remains at all times outside the UK. An agreement to transfer ADSs will not give rise to a liability to stamp duty reserve tax.

Subject to certain exceptions, a transfer on sale of ordinary shares, as opposed to ADSs will generally be subject to UK stamp duty at a rate of 0.5% (rounded up, if necessary, to the nearest £5) of the consideration given for the transfer. An agreement to transfer such shares will normally give rise to a charge to UK stamp duty reserve tax at a rate of 0.5% of the consideration payable for the transfer, provided that stamp duty reserve tax will not be payable if stamp duty has been paid. Where such ordinary shares are later transferred to the Depositary's nominee, further stamp duty or stamp duty reserve tax will normally be payable at the rate of 1.5% (rounded up, if necessary, to the nearest £5) of the value of the ordinary shares at the time of the transfer.

A transfer of ordinary shares by the Depositary or its nominee to the relative ADS holder when the ADS holder is not transferring beneficial ownership gives rise to a UK stamp duty liability of £5 per transfer.

Taxation of Thus demerger dividend in specie

Information pertaining to the tax position of shareholders following the demerger of Thus can be obtained from the Company Secretary at the company's registered office and from the company's website: www.scottishpower.com.

Financial Calendar

16 June 2003	Dividend payment date – US and UK (final dividend for the year ended 31 March 2003)
July 2003	Announcement of results for quarter ending 30 June 2003 – Q1
25 July 2003	Annual General Meeting
September 2003	Q1 Dividend payable
November 2003	Announcement of results for quarter ending 30 September 2003 – Q2
December 2003	Q2 Dividend payable
February 2004	Announcement of results for quarter ending 31 December 2003 – Q3
March 2004	Q3 Dividend payable
May 2004	Announcement of Preliminary Results for the year ending 31 March 2004
June 2004	Q4 Dividend payable (final dividend for the year ending 31 March 2004)

Annual General Meeting
The Annual General Meeting will be held at the Glasgow Royal Concert Hall, Sauchiehall Street, Glasgow on Friday 25 July 2003 at 11.00 am. Details of the resolutions to be proposed at the Annual General Meeting are contained in the Notice of Meeting.

Quarterly results
Copies of the quarterly results may be obtained, free of charge, on request from the Company Secretary at the company's registered office. Quarterly results will also be published on the company's website: www.scottishpower.com

Half-year results
The company, as permitted by the London Stock Exchange, publishes its half-year results in one UK national newspaper. In 2003, it is expected that the half-year results will be published in The Telegraph and on the company's website. Copies of the half-year results may be obtained, free of charge, on request from the Company Secretary at the company's registered office.

Environmental and Social Impact Report
Copies of the Environmental and Social Impact Report may be obtained, free of charge, on request from the Company Secretary at the company's registered office. This Report, together with fuller information about environmental, marketplace/community and workplace issues, is also published on the company's website.

Press releases and up-to-date information on the company can be found on the company's website.

The Annual Review 2002/03 is also available on CD, free of charge, from the Company Secretary at the company's registered office.

Shareholder Services

Ordinary Shares

Share registration enquiries

The Registrar
Lloyds TSB Registrars Scotland
PO Box 28448
Edinburgh EH4 1WQ

Tel: +44 (0)870 600 3999
Fax: +44 (0)870 900 0030
Textphone: +44 (0)870 600 3950

Website: www.shareview.co.uk

Dividend Reinvestment Plan

The Dividend Reinvestment Plan provides ordinary shareholders with the facility to invest cash dividends by purchasing further ScottishPower shares. For further details, please contact Lloyds TSB on telephone number 0870 241 3018.

Share consolidation and ISAs

Share consolidation is a facility which allows a number of holdings, and especially family holdings, to be consolidated into one holding. This service is provided free of charge.

Individual Savings Accounts ("ISAs") are suitable for UK resident private investors who wish to shelter their ScottishPower shares from Income and Capital Gains Tax. Details of the ScottishPower ISA service are available from Lloyds TSB at the following address. Alternatively, please call the ISA helpline on 0870 242 4244.

Lloyds TSB Registrars ISAs
The Causeway
Worthing BN99 6UY

Share dealing

ScottishPower ordinary shares may be bought or sold at competitive rates by post or telephone. For further details, please contact Stocktrade on 0845 601 0979, quoting LOW C0070.

American Depositary Shares ("ADSs")

Exchange and stock transfer enquiries

JPMorgan Chase Bank
Shareholder Relations
PO Box 43013
Providence, RI 02940-3013

Tel: 1 (866) SCOTADR (Toll Free)
1 (866) 726 8237 (Toll Free)
+1 (781) 575 2678 (Outside US not Toll Free)

Fax: +1 (781) 575 4082

Website: www.adr.com/shareholder

Dividend Reinvestment Plan Global Invest Direct

Global Invest Direct is the Direct Share Purchase and Dividend Reinvestment Plan for ADS holders which allows existing and first time investors to purchase ADSs without a broker. Global Invest Direct encourages investors to make initial and ongoing investments in the company by providing investors with the convenience of investing directly in ScottishPower's ADSs, with reduced brokerage commissions and service costs. For further details, please contact JPMorgan Chase Bank as detailed above.

Agent for US federal securities laws

The agent for ScottishPower for US federal securities law purposes is:

Puglisi & Associates,
850 Library Avenue, Suite 204
PO Box 885
Newark
Delaware 19715

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Figures in brackets refer to Notes to the Accounts

Glossary of Terms

Term – Definition

ADS – American Depositary Share (*US*)

The Authority – The Gas and Electricity Markets Authority, the body which determines energy market regulation in Great Britain (*UK*)

BE – British Energy plc (*UK*)

BETTA – British Electricity Trading and Transmission Arrangements (*UK*)

btu – British thermal unit (*UK*)

Billion – One thousand million (1,000,000,000)

British Isles – The United Kingdom and The Republic of Ireland

Churn – The turnover of existing customers leaving, and new customers joining, the company's customer list

CO_2 – Carbon Dioxide

Combined Code – Guidelines setting out corporate governance principles regarded as good practice for UK registered companies (*UK*)

Company – Scottish Power plc

Competition Commission – The UK regulatory body concerned with competition policy and the abuse of market power (*UK*)

Demand side management – Encouraging customers to reduce their electricity consumption

Distribution – The transfer of electricity from the transmission system to customers (US equivalent is Power Distribution)

DTI – Department of Trade and Industry (*UK*)

EA – Environment Agency (*UK*)

EBITDA – Earnings before interest, tax, depreciation, goodwill amortisation and deferred income released to the profit and loss account

EU – European Union

EPA – Environmental Protection Agency (*US*)

Energy supply – Sales of electricity and gas to residential, commercial and industrial customers (*UK*)

ESOP – Employee Share Ownership Plan (*UK*)

ExSOP – Executive Share Option Scheme open to the company's executive directors and senior managers

FERC – Federal Energy Regulatory Commission (*US*)

GAAP – Generally Accepted Accounting Principles

Gas – Natural gas

Giga (G) – One thousand million (1,000,000,000) units

Great Britain – England, Scotland and Wales

Group – Scottish Power plc and its consolidated subsidiaries

Guaranteed Standards – Standards of performance agreed between the company and Ofgem for transmission, distribution and supply (*UK*)

Home area – The geographical area in which a company was previously the sole licensed supplier of residential customers (*UK*)

Interconnectors – The high voltage links connecting the transmission system of Scotland with those of England & Wales and Northern Ireland (*UK*)

ISA – Individual Savings Account (*UK*)

Kilo (k) – One thousand (1,000) units

LTIP – Long Term Incentive Plan

Mega (M) – One million (1,000,000) units

MSP – The multi-state process through which PacifiCorp and the six states it serves are working to clarify roles and responsibilities concerning the regulation of PacifiCorps' business activities (*US*)

NEA – Nuclear Energy Agreement, between British Energy, ScottishPower and Scottish & Southern (*UK*)

NETA – New Electricity Trading Arrangements (*UK*)

NOx – Oxides of Nitrogen

Ofgem – Office of Gas and Electricity Markets, the gas and electricity regulator in Great Britain (*UK*)

OFWAT – Office of Water Services, the water regulator in England & Wales (*UK*)

PED – Public Electricity Distributor (*UK*)

plc – Public limited company (*UK*)

Power production – The US term for the generation of electricity

PSCs – Public Services Commissions, the individual bodies which regulate utilities in each of the states (*US*)

Rates – The US term for Tariffs

Retail sales – Sales of electricity to residential, commercial and industrial customers (*US*)

ROE – Return on Equity *(US)*

ROSPA – Royal Society for the Prevention of Accidents (*UK*)

RPI – Retail Price Index, the equivalent of the US Consumer Price Index – CPI (*UK*)

SEC – Securities and Exchange Commission (*US*)

SEE – Social, environmental and ethical

SEPA – Scottish Environment Protection Agency (*UK*)

SO_2 – Sulphur Dioxide

Tera (T) – Indicates a measure of 10^{12}, for example terawatthours

Transmission – The transfer of electricity from power stations to the distribution system

Transportation (of gas) – Transfer of gas from on-shore terminals to consumers through the national pipeline network (*UK*)

UK – United Kingdom, comprising England, Scotland, Wales and Northern Ireland

US – United States of America

Volt (V) – Unit of electrical potential

Watt (W) – Unit of electrical power, the rate at which electricity is produced or used

Watt hour (Wh) – Unit of electrical energy, the production or consumption of one Watt for one hour

WECC – Western Electricity Coordinating Council (*US*)

Wholesale – The dealing of bulk power with another power supplier

Windfarm – A group of wind-driven turbines intended to generate electricity

(US) or (UK) in the definitions above indicates that the term is applicable to the United States or the United Kingdom, respectively.

Conversion Factors			
	Metres		**Yards**
	0.91	**1**	1.09
	Km		**Miles**
	1.61	**1**	0.62
	Litres		**US Gallons**
	3.78	**1**	0.26

ScottishPower

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www.scottishpower.com

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