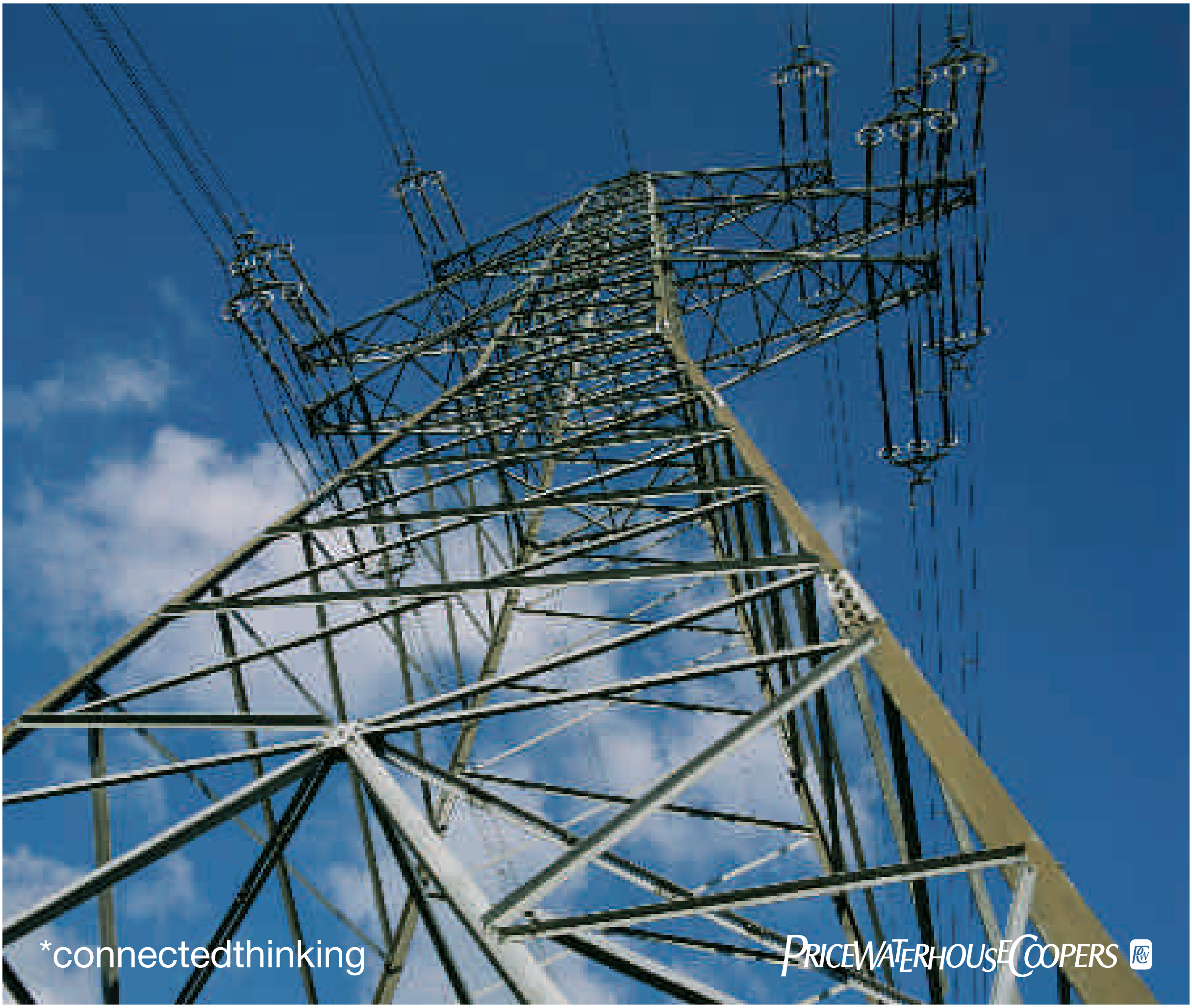
Energy, Utilities & Mining

Financial reporting in the utilities industry*

International Financial Reporting Standards

April 2008



Foreword

The move to International Financial Reporting Standards (IFRS) is advancing the transparency and comparability of financial statements around the world. Many countries now require companies to prepare their financial statements in accordance with IFRS. National standards in other countries are being converged with IFRS. The global trend towards IFRS has gained significant further momentum with the US Securities and Exchange Commission's (SEC) commitment to the standards, beginning with its decision to drop the requirement for foreign-listed companies in the US to reconcile to US GAAP.

The utilities industry is key to the world economy, and an increasing number of companies are now operating on an international and, sometimes, global scale. The development of IFRS offers considerable long-term advantages for many utilities companies but, along the way, it brings considerable challenges. The utilities industry is characterised, for example, by the need for significant upfront investment, often with uncertainty about outcomes over a long-term time horizon. Its geopolitical, environmental, energy and natural resource supply and trading challenges, combined with often complex stakeholder and business relationships, has meant that the transition to IFRS has required some complex judgements about how to implement the new standards.

This edition of 'Financial reporting in the utilities industry' describes the financial reporting implications of IFRS across a number of areas selected for their particular relevance to utilities companies. It provides insights into how companies are responding to the various challenges, and includes examples of accounting policies and other disclosures from published financial statements. It examines key developments in the evolution of IFRS in the industry.

This publication does not describe all IFRSs applicable to utilities entities. The ever-changing landscape means that management should conduct further research and seek specific advice before acting on any of the more complex matters raised. PricewaterhouseCoopers has a deep level of insight into and commitment to helping companies in the sector report effectively. For more information or assistance, please do not hesitate to contact your local office or one of our specialist utilities partners.

Manfred Wiegand
Global Utilities Leader

Contents

Contents

Introduction

What is the focus of this publication?

This publication considers the major accounting practices adopted by the utility industry under International Financial Reporting Standards (IFRS).

The need for this publication has arisen due to:

- the adoption of IFRS by utility entities across a number of jurisdictions, with overwhelming acceptance that applying IFRS in this industry will be a continual challenge; and
- ongoing transition projects in a number of other jurisdictions, for which companies can draw on the existing interpretations of the industry.

Who should use this publication?

This publication is intended for:

- executives and financial managers in the utility industry, who are often faced with alternative accounting practices;
- investors and other users of utility industry financial statements, so they can identify some of the accounting practices adopted to reflect unusual features unique to the industry; and
- accounting bodies, standard-setting agencies and governments throughout the world interested in accounting and reporting practices and responsible for establishing financial reporting requirements.

What is included?

Included in this publication are issues that we believe are of financial reporting interest due to:

- their particular relevance to utility entities; and/or
- historical varying international practice.

The utility industry has not only experienced the transition to IFRS, it has also seen:

- significant growth in corporate acquisition activity;
- increased globalisation;
- continued increase in its exposure to sophisticated financial instruments and transactions; and
- an increased focus on environmental and restoration liabilities.

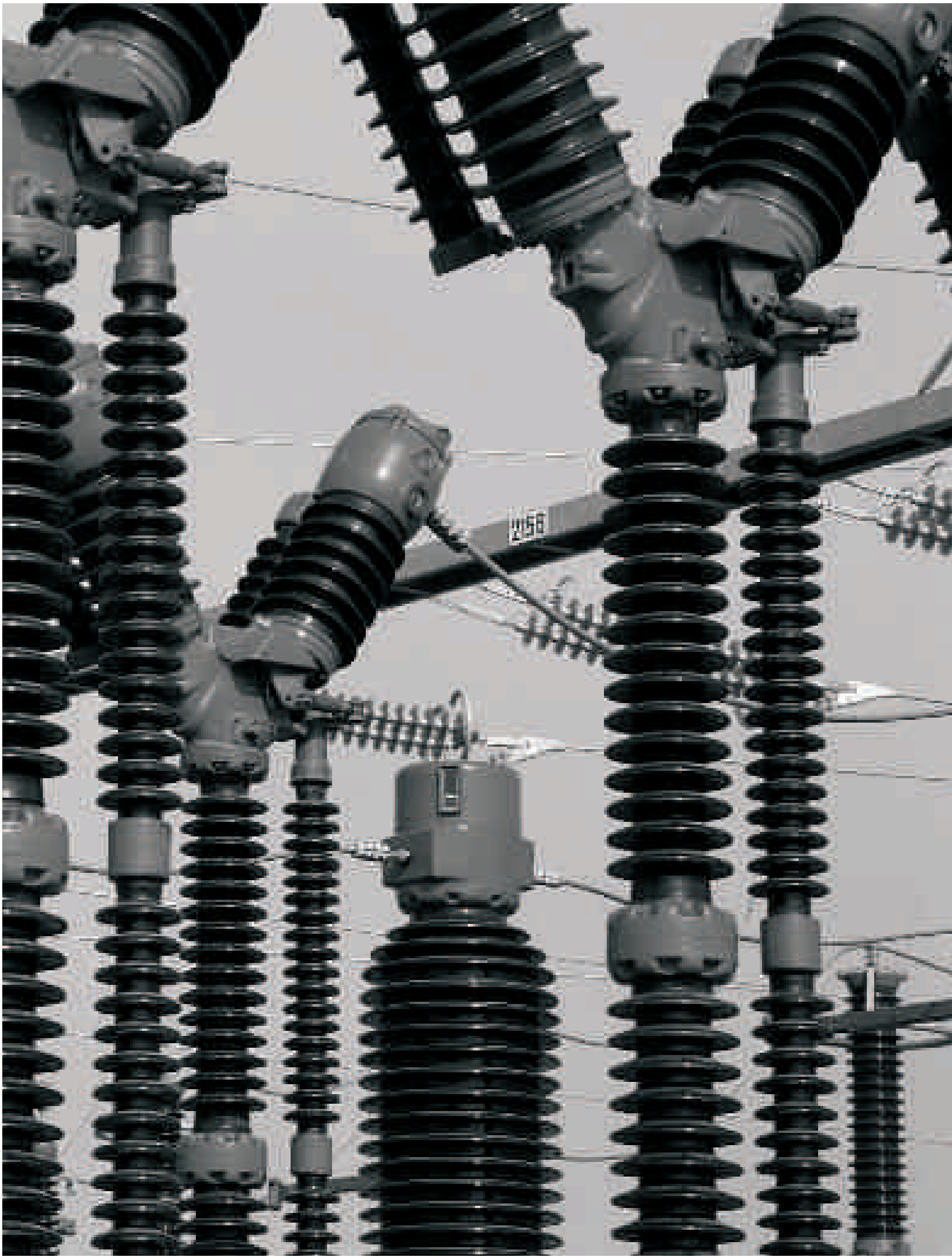
This publication has a number of chapters designed to cover the main issues raised.

PricewaterhouseCoopers' experience

This publication is based on the experience gained from the worldwide leadership position of PricewaterhouseCoopers in the provision of accounting services to the utility industry. This leadership position enables PricewaterhouseCoopers' Global Utility Industry Group to make recommendations and lead discussions on international standards and practice.

We hope you find this publication useful.

1 Utilities Value Chain & Significant Accounting Issues



1 Utilities Value Chain & Significant Accounting Issues

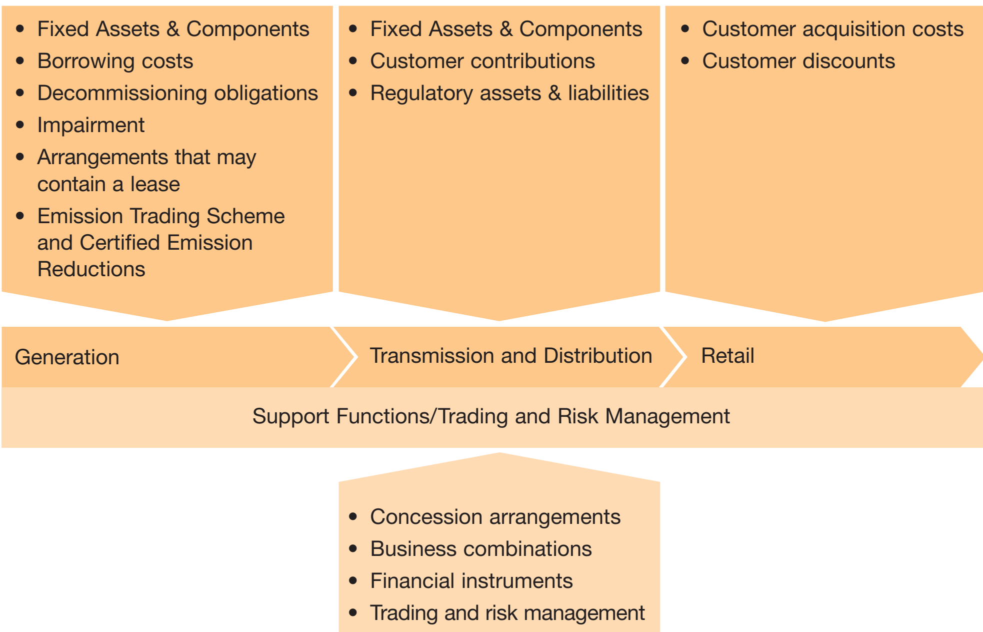
All utility entities, whether gas, power or water utilities, face similar issues associated with sourcing the item, delivering it to the customer, and maintaining the infrastructure used to do so. Power utilities face the added complexity of handling a commodity that cannot be stored in the way that other commodities can be stored.

A traditional integrated power company (utility) generates electricity and sends it around the country or region via high-voltage transmission lines, finally delivering it to customers through a retail distribution network. The industry continues to evolve, and many different operational and regulatory models are now seen. Generators continue to diversify supplies; fossil fuels still dominate but there is an increasing focus on bio-fuels, co-generation and renewable sources such as wind and wave power. Some Western governments are considering the construction of new nuclear power plants, a move that would have been unthinkable even a few years ago.

The regulatory environment differs from country to country, or even within a country and can be complex and challenging. Pressure to introduce and increase competition and to diversify supply is apparent, as well as schemes that create financial incentives to reduce emissions and increase the use of renewable sources.

Previously integrated businesses may be split by regulation into generation, transmission, distribution and retail businesses. Competition may then be introduced for the generation and retail segments. Generators will look to compete on price and secure long-term fuel supplies, balancing this against potentially volatile market prices for wholesale power. The distribution business may see the incumbent operator forced to grant access to other suppliers to its network. Power customers are beginning to behave like any other group of retail customers and exercise choice, develop brand loyalty, shop for the best rates or look for an attractive bundle of services

Utilities Value Chain and Significant Accounting Issues



that might include gas, phone, water and internet services as well as power.

The regulatory environment with continuing government involvement in pricing, security of supply, pressure to reduce emissions and other pollutants and increasing competition all impact on how business is conducted, and give rise to some difficult accounting issues. This publication examines the accounting issues that are most significant for the utilities industry. The issues are addressed following the utilities value chain: generation, transmission & distribution, retail and issues that impact on the entire entity.

For published financial disclosure examples, see Section 4 on page 45.

1.1 Generation

1.1.1 Fixed assets & components

IFRS has a specific requirement for 'component' depreciation, as described in IAS 16 *Property, plant and equipment*. Each significant part of an item of property, plant and equipment is depreciated separately. Significant parts of an asset that have similar useful lives and pattern of consumption can be grouped together. This requirement can create complications for utilities entities, as there are many assets that include components with a shorter useful life than the asset as a whole.

Identification of components of an asset

Generating assets are often large and complex installations. They are expensive to construct, tend to be exposed to harsh operating conditions and require periodic replacement or repair. Generating assets might comprise a significant number of components, many of which will have differing useful lives. The significant components of these types of assets must be separately identified. It can be a complex process, particularly on transition to IFRS, as the detailed recordkeeping may not have been required to comply with national GAAP. This can particularly be an issue for old power-generating plants. However, some regulators may require detailed asset records, which can be useful for IFRS component identification purposes.

An entity might look to its operating data if the necessary information for components is not readily identified by the accounting records. Some components can be identified by considering the routine shutdown or overhaul schedules for power stations and the replacement and maintenance routines associated with these. Consideration should also be given to those components that are prone to technological obsolescence, corrosion or wear and tear more severe than that of the other portions of the larger asset.

Depreciation of components

Those identified components that have a shorter useful life than the remainder of the asset should be depreciated to their recoverable amount over that shorter useful life. The remaining carrying amount of the component is derecognised on replacement and the cost of the replacement part is capitalised.

The costs of performing a turnaround/overhaul are capitalised as a component of the plant, provided this provides access to future economic benefits, but turnaround/overhaul costs that do not relate to the replacement of components or the installation of new assets should be expensed when incurred. Turnaround/overhaul costs should not be accrued over the period between the turnarounds/overhauls because there is no legal or constructive obligation to perform the turnaround/overhaul – the entity could choose to cease operations at the plant and hence avoid the turnaround/overhaul costs.

1.1.2 Borrowing costs

The cost of an item of property, plant and equipment may include borrowing costs incurred for the purpose of acquiring or constructing it. Such borrowing costs may be capitalised if the asset takes a substantial period of time to get ready for its intended use. The capitalisation of borrowing costs under IAS 23 *Borrowing Costs* (Issued 1993) is an option, but one which must be applied consistently to all qualifying assets. However, amendments to IAS 23 that were published in 2007 and become effective from 1 January 2009 will require that all applicable borrowing costs be capitalised.

Borrowing costs should be capitalised while acquisition or construction is actively underway. These costs include the costs of specific funds borrowed for the purpose of financing the construction of the asset, and those general borrowings that would have been avoided if the expenditure on the qualifying asset had not been made. The general borrowing costs attributable to an asset's construction should be calculated by reference to the entity's weighted average cost of general borrowings.

1.1.3 Decommissioning obligations

The utilities industry can have a significant impact on the environment. Decommissioning or environmental restoration work at the end of the useful life of a plant or other installation may be required by law, the terms of operating licences or an entity's stated policy and past practice. An entity that promises to remediate damage, even when there is no legal requirement, may have created a constructive obligation and thus a liability under IFRS. There may also be environmental clean-up obligations for contamination of land that arises during the operating life of a power plant or other installation. The associated costs of remediation/restoration can be significant. The accounting treatment for decommissioning costs is therefore critical.

Decommissioning provisions

A provision is recognised when an obligation exists to remediate or restore. The local legal regulations should be taken into account when determining the existence and extent of the obligation. Obligations to decommission or remove an asset are created at the time the asset is placed in service. Entities recognise decommissioning provisions at the present value of the expected future cash flows that will be required to perform the decommissioning. The cost of the provision is recognised as part of the cost of the asset when it is placed in service and depreciated over the asset's useful life. The total cost of the fixed asset, including the cost of decommissioning, is depreciated on the basis that best reflects the consumption of the economic benefits of the asset: generally time-based for a power station.

Provisions for decommissioning and restoration are recognised even if the decommissioning is not expected to be performed for a long time, for example 80 to 100 years. The effect of the time to expected decommissioning will be reflected in the discounting of the provision. The discount rate used is the pre-tax rate that reflects current market assessments of the time value of money. Entities also need to reflect the specific risks associated with the decommissioning liability. Different decommissioning obligations will, naturally, have different inherent risks, for example different uncertainties associated with the methods, the costs and the timing of decommissioning. The risks specific to the liability can be reflected either in the pre-tax cash flow forecasts prepared or in the discount rate used.

A similar accounting approach is taken for nuclear fuel rods. These rods are classified as inventory, and an obligation to reprocess them is triggered when the rods are placed into the reactor. A liability is recognised for the reprocessing obligation when the rods are placed into the reactor, and the cost of reprocessing added to the cost of the fuel rods.

Revisions to decommissioning provisions

Decommissioning provisions are updated at each balance sheet date for changes in the estimates of the amount or timing of future cash flows and changes in the discount rate. Changes to provisions that relate to the removal of an asset are added to or deducted from the carrying amount of the related asset in the current period. The adjustments to the asset are restricted, however. The asset cannot decrease below zero and cannot increase above its recoverable amount:

- if the decrease of provision exceeds the carrying amount of the asset, the excess is recognised immediately in profit or loss;
- adjustments that result in an addition to the cost of the asset are assessed to determine if the new carrying amount is fully recoverable or not. An impairment test is required if there is an indication that the asset may not be fully recoverable.

The accretion of the discount on a decommissioning liability is recognised as part of finance expense in the income statement.

1.1.4 Impairment

The power industry is distinguished by the significant capital investment required, exposure to commodity prices and heavy regulation. The required investment in fixed assets leaves the industry exposed to adverse economic conditions and therefore impairment charges. Utilities assets should be tested for impairment whenever indicators of impairment exist. The normal measurement rules for impairment apply.

Impairment indicators

External impairment triggers relevant for the utilities industry include falling retail prices, rising fuel costs, overcapacity and increased or adverse regulation or tax changes.

Impairment indicators can also be internal in nature. Evidence that an asset or Cash Generating Unit (CGU) has been damaged or become obsolete is an impairment indicator; for example a power plant destroyed by fire is, in accounting terms, an impaired asset. Other indicators of impairment are a decision to sell or restructure a CGU or evidence that business performance is less than expected. Performance of an asset or group of assets that is below that expected by management in operational and financial plans is also an indicator of impairment.

Management should be alert to indicators on a CGU basis; for example learning of a fire at an individual generating station would be an indicator of impairment for that station as a separate CGU. However, generally management is likely to identify impairment indicators on a regional, country or other asset grouping basis, reflective of how they manage their business. Once an impairment indicator has been identified, the impairment test must be performed at the individual CGU level, even if the indicator was identified at a regional level.

Cash generating units

A CGU is the smallest group of assets that generates cash inflows largely independent of other assets or groups of assets.

Power generation assets will form CGUs by location or possibly by single generating facility on a multiple turbine site. The determination of how many CGUs will depend on the extent of shared infrastructure and the ability to generate largely separate cash inflows. The determination of CGUs is not driven by how management chooses to use its assets. For example, an entity may have three generating stations in a large metropolitan area, which can be run independently. Management makes the decision to produce based on expected prices, demand and efficiency. It uses the three stations to meet demand in a most efficient to least efficient basis. The three stations remain separate CGUs.

Calculation of recoverable amount

Impairments are recognised if the carrying amount of a CGU exceeds its recoverable amount. Recoverable amount is the higher of fair value less costs to sell (FVLCTS) and value in use (VIU).

Fair value less costs to sell (FVLCTS)

Fair value less costs to sell is the amount that a market participant would pay for the asset or CGU, less the costs of sale. The use of discounted cash flows for FVLCTS is permitted where there is no readily available market price for the asset or where there are no recent market transactions for the fair value to be determined through a comparison between the asset being tested for impairment and a recent market transaction. However, where discounted cash flows are used, the inputs must be based on external, market-based data.

The projected cash flows for FVLCTS therefore include the assumptions that a potential purchaser would include in determining the price of the asset. Thus industry expectations for the development of the asset may be taken into account, which may not be permitted under VIU. However the assumptions and resulting value must be based on recent market data and transactions.

Post-tax cash flows are used when calculating FVLCTS using a discounted cash flow model. The discount rate applied in FVLCTS will be a post-tax market rate based on a typical industry participant's cost of capital.

Value in use (VIU)

VIU is the present value of the future cash flows expected to be derived from an asset or CGU in its current condition. Determination of VIU is subject to the explicit requirements of IAS 36 *Impairment of Assets*. The cash flows are based on the asset that the entity has now and must exclude any plans to enhance the asset or its output in the future but includes expenditure necessary to maintain the current performance of the asset. The VIU cash flows for assets that are under construction and not yet complete should include the cash flows necessary for their completion and the associated additional cash inflows or reduced cash outflows.

Any foreign currency cash flows are projected in the currency in which they will be earned and discounted at a rate appropriate for that currency. The resulting value is translated to the entity's functional currency using the spot rate at the date of the impairment test.

The discount rate used for VIU is always pre-tax and applied to pre-tax cash flows. This is often the most difficult element of the impairment test, as pre-tax rates are not available in the market place. Grossing up the post tax rate does not give the correct answer unless no deferred tax is involved. Arriving at the correct pre-tax rate is a complex mathematical exercise.

Contracted cash flows in VIU

The cash flows prepared for a VIU calculation should reflect management's best estimate of the future cash flows expected to be generated from the assets concerned. Purchases and sales of commodities are included in the VIU calculation at the spot price at the date of the impairment test, or if appropriate, prices obtained from the forward price curve at the date of the impairment test.

There may be commodities – both fuel and the resultant electricity output – covered by purchase and sales contracts. Management should use the contracted price in its VIU calculation for any commodities unless the contract is already on the balance sheet at fair value. A commodity contract that can be settled net in cash and for which the own use exception cannot be claimed, for example, is recognised separately on the balance sheet at fair value as a derivative. Including the contracted prices of such a contract would double count the effects of the contract. Impairment of financial instruments that are within the scope of IAS 39 *Financial Instruments: Recognition and Measurement* is addressed by IAS 39 and not IAS 36.

The cash flow effects of hedging instruments such as caps and collars for commodity purchases and sales are also excluded from the VIU cash flows. These contracts are also accounted for in accordance with IAS 39.

1.1.5 Arrangements that may contain a lease

IFRS requires that arrangements that convey the right to use an asset in return for a payment or series of payments be accounted for as a lease even if the arrangement does not take the legal form of a lease. Some common examples of such arrangements might include a series of power plants built to exclusively supply the rail network; a generator located on the site of an aluminium smelter or a generator constructed on a build–own–operate–transfer arrangement with a national utility. Tolling arrangements may also convey the use of the asset to the party that supplies the fuel.

IFRIC 4 *Determining whether an Arrangement contains a Lease* sets out guidelines to determine when an arrangement might contain a lease. Once a determination is reached that an arrangement contains a lease, the lease arrangement must be classified as either finance or operating. The principles in IAS 17 *Leases* apply: a lease that conveys the majority of the risks and rewards of operation is a finance lease. A lease other than a finance lease is an operating lease.

The classification has significant implications; a lessor in a finance lease would find itself derecognising its generating assets and recognising a finance lease receivable in return. A lessee in a finance lease would recognise fixed assets and a corresponding lease liability rather than an executory contract, as in the past.

Classification as an operating lease leaves the lessor with the fixed assets on the balance sheet and the lessee with an executory contract.

Operating lease classification might be achieved where the utility has other customers and most of the capacity production is sold to third parties.

Power purchase agreements

Power purchase agreements where the purchaser controls the dispatch of power, takes all of the output and has guaranteed a return to the operator or provides a de facto guarantee of the obligation assumed to finance the facility are not difficult to classify as a finance lease. Difficulties tend to arise where there is a power purchase agreement (PPA) for substantially all, or all, of the output of a wind farm or hydro facility because the amount of generation is determined by an uncontrollable factor, in this case the wind or the amount of rain/snowfall.

For example, a typical wind farm contract would be:

- for 100% of the output of the wind farm;
- for substantially all of the asset's life;
- guarantees a level of availability when the wind is blowing;
- allows the purchaser to agree the timing of maintenance outages;
- has pricing which is fixed per unit of output rather than a time-based payment.

Government requirements or incentives for the production of power from renewable sources have led to the development of many wind farms and other green generating sources. The developer and owner of the wind farm typically agrees to sell 100% of the output of the wind farm to a single purchaser, allowing the developer to recover its operating costs, debt service cost and a development premium. Available wind studies are used to help site wind farms and assess the economic viability early in the development stage of the project.

A PPA for 100% of the output of a wind farm with a guaranteed minimum production may meet the requirement for finance lease accounting. The developer may establish the contract so that it will get its full return from a single contract, even though the generation of electricity is contingent on the wind.

Co-located assets

Power companies may construct generating facilities at customer locations on property owned or controlled by a customer. This may occur where a customer is a heavy user of power and steam. These arrangements may also be found where the customer produces waste by-products that can be burned to produce electricity.

These arrangements may have the substance of a finance lease under IAS 17 where the customer has the majority of the risks and rewards incidental to ownership of the asset. Some of the characteristics consistent with a finance lease are where the customer takes most of the output and makes payments for the asset to 'stand ready' in addition to payments for output received. A common indicator of a finance lease is that the customer provides a de facto guarantee of obligations assumed to finance the facility. The guarantee may take the form of a take or pay contract or an outright guarantee of indebtedness.

1.1.6 Emission Trading Scheme and Certified Emission Reductions

The ratification of the Kyoto Protocol by the EU required total emissions of greenhouse gases within the EU member states to fall to 92% of their 1990 levels in the period between 2008 and 2012. The introduction of the EU Emissions Trading Scheme (EU ETS) on 1 January 2005 represents a significant EU policy response to the challenge. Under the scheme, EU member states have set limits on carbon dioxide emissions from energy intensive companies. The scheme works on a 'cap' and 'trade' basis, and each member state of the EU is required to set an emissions cap covering all installations covered by the scheme.

The EU cap and trade scheme is expected to serve as a model for other governments seeking to reduce emissions.

There are also several non-Kyoto carbon markets in existence. These include the New South Wales Greenhouse Gas Abatement Scheme, the Regional Greenhouse Gas Initiative and Western Climate Initiative in the United States and the Chicago Climate Exchange in North America.

Accounting for ETS

The emission rights permit an entity to emit pollutants up to a specified level. The emission rights are either given or sold by the government to the emitter for a defined compliance period.

Schemes in which the emission rights are tradable allow an entity to:

- emit fewer pollutants than it has allowances for and sell the excess allowances;
- emit pollutants to the level that it holds allowances for; or
- emit pollutants above the level that it holds allowances for and either purchase additional allowances or pay a fine.

IFRIC 3 *Emission Rights* was published in December 2004 to provide guidance on how to account for cap and trade emission schemes. The interpretation proved controversial and was withdrawn in June 2005 due to concerns over the consequences of the required accounting because it introduced significant income statement volatility. The withdrawal of IFRIC 3 means there is no specific comprehensive accounting for cap and trade schemes.

The guidance in IFRIC 3 remains valid but entities are free to apply variations provided that the requirements of all relevant IFRS standards are met. Several approaches have emerged in practice under IFRS. The scheme can result in the recognition of assets (allowances), expense of emissions, a liability (obligation to submit allowances) and potentially a government grant.

The allowances are intangible assets and are recognised at cost if separately acquired. Allowances that are received free of charge from the government are recognised either at fair value with a corresponding deferred income (liability), or at cost (nil) as allowed by IAS 20 *Accounting for Government Grants and Disclosure of Government Assistance.*

The allowances recognised are not amortised provided residual value is at least equal to carrying value. The cost of allowances is recognised in the income statement in line with the profile of the emissions produced.

The government grant (if initial recognition at fair value under IAS 20 is chosen) is amortised to the income statement on a straight line basis over the compliance period. An alternative to the straight line basis can be used if it is a better reflection of the consumption of the economic benefits of the government grant.

The entity may choose to apply the revaluation model in IAS 38 *Intangible Assets* for the subsequent measurement of the emissions allowances. The revaluation model requires that the carrying amount of the allowances is restated to fair value at each balance sheet date, with changes to fair value recognised directly in equity except for impairment, which is recognised in the income statement. This is the accounting that is required by IFRIC 3 and is seldom used in practice.

A provision is recognised for the obligation to deliver allowances or pay a fine to the extent that pollutants have been emitted. The allowances reduce the provision when they are used to satisfy the entity's obligations through delivery to the government at the end of the scheme year. However, the carrying amount of the allowances cannot reduce the liability balance until the allowances are delivered.

Certified Emission Reductions (CERs)

There is another scheme under the Kyoto Protocol for fast-growing countries and countries in transition that are not subject to a Kyoto target on emissions reduction. Entities in these countries can generate Certified Emissions Reductions (CERs). CERs represent a unit of greenhouse gas reduction that has been generated and certified by the United Nations under the Clean Development Mechanism (CDM) provisions of the Kyoto Protocol. The CDM allows industrialised countries that are committed to reducing their greenhouse gas emissions under the Kyoto protocol to earn emissions reductions credits towards Kyoto targets through investment in 'green' projects. Examples of projects include reforestation schemes and investment in clean energy technologies. Once received, the CERs have value because they are exchangeable for EU ETS allowances and hence can be used to meet obligations under that particular scheme.

An entity that acquires CERs accounts for these as described under ETS; they are accounted for at cost at initial recognition and then subsequently in accordance with the accounting policy chosen by the entity. There is no specific accounting guidance under IFRS that covers the generation of CERs. Entities that generate CERs should develop an appropriate accounting policy.
Most entities that need CERs are likely to acquire them from third parties and account for them as separately acquired assets.

The key question that drives the accounting for self-generated CERs by 'green' entities is: what is the nature of the CERs? The answer to this question lies in the specific circumstances of the green entity's core business and processes. If the CERs generated are held for sale in the entity's ordinary course of business, CERs are within the scope of IAS 2 *Inventories*. If they are not they should be considered as identifiable non-monetary assets without physical substance ie, intangible assets.

The accounting for CERs is also driven by the applicability of IAS 20. If CERs are granted by government the accounting would be as follows:

- recognition when there is a reasonable assurance that the entity will comply with the conditions attached to the CERs and the grant will be received;
- initial measurement at nominal amount or fair value, depending on the policy choice;
- subsequent measurement depends on the classification of CERs and should follow the relevant standard ie, IAS 2 for inventory, IAS 38 for intangible assets, IFRS 5 for non-current assets held for sale.

1.2 Transmission & Distribution

1.2.1 Fixed assets & components

Some network companies applied renewals accounting for expenditure related to their networks under national GAAP. Expenditure was fully expensed and no depreciation was charged against the network assets. This accounting treatment is not acceptable under IFRS as the normal fixed asset accounting and depreciation requirements apply. This may be a significant change for network companies and introduces some application challenges.

Network assets such as an electricity transmission system or a gas pipeline comprise many separate components. Many individual components may not be significant. A practical approach to identifying components is to consider the entity's mid/long-term capital budget, which should identify significant capital expenditures and pinpoint major components of the network that will need replacement over the next few years. The entity's engineering staff should also be involved in identification of components based on repairs and maintenance schedules and planned major renovations or replacements.

A network must be broken down into its significant parts that have different useful lives. The determination of the number of parts and the split is specific to the circumstances of the entity. A number of factors might be considered in doing the analysis; the cost of different parts, how the asset is split for operational purposes, physical location of the asset and technical design considerations.

An entity that has a history of expensing all current expenditure may struggle initially to reinstate what should have been capitalised and what should have been expensed. Materiality is a useful guide; if replacement costs are material to the asset then, provided recognition criteria are met (cost can be reliably measured and future economic benefits are probable), these costs should be capitalised.

Network companies may be used to a working assumption that assets have an indefinite useful life. All significant assets under IAS 16 *Property, Plant and Equipment* will have a finite life to be determined, being the time remaining before the asset needs to be replaced. Maintenance and repair activities may extend this life, but ultimately the asset will need to be replaced.

A residual value must be determined for all significant components. This value in many cases is likely to be scrap only or zero, since IAS 16 defines it as the disposal proceeds if the asset were already of an age and in the condition expected at the end of its useful life. An entity is required to allocate costs at initial recognition to its significant parts. Each part is then depreciated separately over its useful life. Separate parts that have the same useful life and depreciation method can be grouped together to determine the depreciation charge.

1.2.2 Customer contributions

The provision of utility services to customers requires some form of physical connection, whether the service is gas, water or power. The investment required to provide that connection to the customer from the national or regional network may be significant. This is likely when the customer is located far from the network or when the volume of the utility that will be purchased requires substantial equipment. An example may be the provision of power to a remote location where the construction of a substation is required to connect the user to the national network.

Many utility entities require the customer to contribute to the cost of the connection, and in return the customer receives the right to access the utility services. The utility entity constructs the connecting infrastructure and retains responsibility for maintaining it. Common accounting practice is for the utility entity to capitalise the connection equipment as property, plant and equipment (PPE) and recognise the contribution as deferred income, which is amortised to the income statement over an appropriate period – usually over the life of the PPE.

Major connection expenditures, such as substations or network spurs, will often benefit more than one customer and contributions may be received from several of these. However, when major connection equipment is constructed for the sole benefit of one customer and can be distinguished from the general network, consideration should be given to whether the equipment has, in substance, been leased to the customer. IFRIC 4 and IAS 17 should be applied to determine whether the arrangement is in substance a lease and whether it should be classified as an operating or finance lease.

A recent draft interpretation published by the IFRIC, D24 *Customer Contributions*, is broadly consistent with the approach described above, although some detailed requirements may need to be considered when the interpretation is finalised.

1.2.3 Regulatory assets & liabilities

Complete liberalisation of utilities is not practical because of the physical infrastructure required for the transmission and distribution of the commodity. Privatisation and the introduction of competition is often balanced by price-regulation. Some utilities continue as monopoly suppliers with prices limited to a version of cost plus margin overseen by the regulator.

The regulatory regime is often unique to each country. The two most common types of regulation are incentive-based regulation and rate-based regulation. The regulator governing an incentive-based regulatory regime usually sets the ‘allowable revenues’ for a period with the intention of encouraging cost efficiency from the utility. A utility entity operating under rate-based regulation is usually permitted the recovery of an agreed level of operating costs, together with a return on assets employed.

An entity’s accounting policies should take account of the regulatory regime and the requirements of IFRS. Any regulatory type asset or liability recognised under IFRS needs to be a financial asset, an intangible asset or a financial liability in its own right, as there are no special recognition requirements for regulatory assets or liabilities under IFRS.

Future price increases

A common feature of price-regulated markets is the agreement of the regulator to allow future price increases in compensation for certain identified past costs. These price increases are above those that otherwise might have been permitted by the regulator in normal cost plus calculations.

The costs associated with these price increases can be considered in two broad categories: those that are operating in nature and those that are capital. Examples of operating costs might include previously unbudgeted employee costs (for example, pension cost increases) and increased fuel costs in volatile market conditions. These costs are expensed as incurred under

IFRS and included in cost of sales in the period in which the employee service is rendered or the fuel is consumed. These costs have been incurred directly in generating the power sold in that period.

Examples of capital costs include damage to fixed assets from extreme weather, such as hurricanes and ice storms, or from other unexpected and uninsured events. An impairment charge is recognised under IFRS for any damaged assets. The cost of replacement assets are capitalised as appropriate as PPE.

The regulator may grant the utility permission to add an additional charge per unit to future billings to customers. This gives rise to a financial receivable only as the power, water or gas is delivered to the customer, not when the rate agreement is reached. The rate agreement does not give rise to the recognition of an intangible asset as it does not change the nature of the existing licence. Any 'compensation' receivable through an increased future price is not recognised until that amount becomes receivable, which is when the future electricity, water, or gas is delivered. A regulatory adjustment, billable to identifiable existing customers with no further obligation to deliver services, might meet the recognition criteria as a financial asset. Few regulatory regimes allow this kind of retroactive pricing adjustment.

Future price decreases

Price regulation can also lead to the requirement from a regulator for a utility entity to reduce its prices in a future period. A decrease in prices seldom leads to the recognition of a liability, as it does not constitute a refund of past amounts collected. The benefit of reduced prices is only received by customers if they continue to purchase the commodity. This is not sufficient to cause the recognition of a liability. It might be appropriate to recognise a liability if the entity was obliged to repay cash to the customers (or perhaps to the government) or if the reduction in prices was so significant that it represented an onerous contract. An obligation to pay cash to customers or the government would be recognised as a financial liability. An onerous contract would be recognised as a provision. It is extremely rare that the recognition of a liability under IAS 39 or IAS 37 *Provisions, Contingent Liabilities and Contingent Assets* is met in the context of price regulation because the customer must purchase future services or commodity to receive the benefits.

The IFRIC has considered the topic of regulatory assets and liabilities twice; once when dealing with service concessions and a second time in response to a question about whether FAS 71 could be applied under IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors*. The IFRIC concluded on both occasions that the recognition criteria in FAS 71 were not fully consistent with IFRS and that any assets or liabilities recognised in relation to rate-regulated utilities needed to meet the normal recognition criteria in the IFRS standards.

Regulatory assets and business combinations

The acquisition of a utility in a business combination requires the recognition of all of the utility's identifiable assets and liabilities at their fair values. A utility's rights to charge a higher tariff in the future or to reduce future prices provides additional information about the value of the licence. The tariff value will usually be reflected in the fair value of the licence recognised on acquisition rather than the recognition of a separate regulatory asset.

Stranded costs

Stranded costs are a particular type of regulatory asset that are not associated with a utility's normal day-to-day operations. They arise as a result of a regulator requiring a utility to dispose of capital assets at a loss in order to achieve greater liberalisation of the utility. The loss incurred is known as a stranded cost, and typically the regulator allows the utility entity to charge a higher tariff to customers in the future in order to compensate it for the loss incurred on disposal of the capital assets. There may be unusual circumstances in which recognising such stranded costs as an asset could be justified; for example, if the entity had a substantial change to the terms of its operating licence such that it had exchanged its existing licence (an intangible asset under IAS 38) for a new operating licence.

1.3 Retail

1.3.1 Customer acquisition costs

Deregulation of markets and the introduction of competition often provides customers with the ability to switch from one supplier to another. Utility entities invest in winning and developing their relationships with their customers. The costs of acquiring and developing these customer relationships are capitalised if certain conditions are met. The costs directly attributable to concluding a contractual agreement with a customer are capitalised and amortised over the life of the contract. These costs include commissions or bonuses paid to sign the utility customers where the utility entity has the systems to separately record and assess the customer contract for future economic benefits.

However, expenditure relating to the general development of the business, such as providing service in a new location or an advertising campaign for new customers, represents the development of internally-generated goodwill and cannot be capitalised. Such general expenditure is not capitalised because the specific costs associated with individual customers cannot be separately identified or because the entity has insufficient control over the new relationship for it to meet the definition of an asset.

However, customer relationships must be recognised when they are acquired through a business combination. Customer-related intangibles such as customer lists, customer contracts and customer relationships are recognised by the acquirer at fair value at the acquisition date.

1.3.2 Customer discounts

Utility entities may offer discounts and other incentives to customers to encourage them to sign up to certain tariffs or payment plans. The costs associated with these programmes need to be identified carefully to ensure that they are appropriately separated from the sales revenue. For example, when customers receive a lower tariff for paying monthly compared with other customers who pay quarterly, consideration should be given to whether separation of the sales revenue from the finance income that is embedded in the price charged to the customers who pay quarterly is required.

1.4 Company-wide Issues

1.4.1 Service concession arrangements

Public/private partnerships are one method whereby governments attract private sector participation in the provision of infrastructure services. These services might include, among others, toll roads, prisons, hospitals, public transportation facilities and water and power distribution. These types of arrangements are often described as concessions and many fall with the scope of IFRIC 12 *Service Concession Arrangements*. Arrangements within the scope of the standard are those where a private sector entity may construct the infrastructure, maintain it and provide the service to the public. The entity will be paid for its services in different ways. Many concessions require that the related infrastructure assets are returned or transferred to the government at the end of the concession.

IFRIC 12 applies to arrangements where the grantor (the government or its agents) controls or regulates what services the operator provides with the infrastructure, to whom it must provide them and at what price. The grantor also controls any significant residual interest in the infrastructure at the end of the term of the arrangement.

Water distribution facilities and energy supply networks are examples of infrastructure that might be the subject of service concession arrangements. The government may have authorised the building of a new town. It may grant a concession to a power distribution company to construct the distribution network, maintain it and operate it for a period of 25 years. The distribution network is transferred to the government at the end of the concession period with a specified level of functionality for no consideration. The national regulator sets prices on a cost-plus basis. The concession agreement has base-line service commitments that will trigger substantial penalties if service is interrupted. The government requires that the power company provide universal access to electricity for all residents of the town and regulates the prices at which it is supplied. Customers can be disconnected for non-payment subject to hardship provisions for the poor and elderly.

This arrangement would fall with in the scope of IFRIC 12, as it has many of the common features of a service concession arrangement:

- The grantor of the service agreement is a public sector entity or a private sector entity to which the responsibility for the service is delegated (in this case the government has authorised the new town and granted the licence).
- The operator is not an agent acting on behalf of the grantor but responsible for at least some of the management of the infrastructure (the operator has an obligation to maintain the network and deliver electricity).
- The arrangement is governed by a contract (or by the local law, as applicable) that sets out performance standards, mechanisms for adjusting prices and arrangements for arbitrating disputes (there are financial penalties for poor operating performance and a cost-plus tariff).
- The operator is obliged to hand over the infrastructure to the grantor in a specified condition at the end of the period of the arrangement (transfer with no consideration from the government at the end of the concession period).

There are two accounting models under IFRIC 12 that an operator applies to recognise the rights received under a service concession arrangement:

- Financial asset – an operator with a contractual and unconditional right to receive specified or determinable amounts of cash (or other financial asset) from the grantor recognises a financial asset. The financial asset is within the scope of IAS 32 *Financial Instruments: Presentation*, IAS 39 and IFRS 7 *Financial Instruments: Disclosures*.
- Intangible asset – an operator with a right to charge the users of the public service recognises an intangible asset. There is no contractual right to receive cash when payments are contingent on usage. The licence is within the scope of IAS 38.

IFRIC 12 is a new interpretation, applicable for the first time in 2008. Arrangements between governments and service providers are complex, and seldom will the conclusion be as obvious as the example above. Once within the scope of IFRIC 12, the appropriate accounting model may not always be obvious. Entities should be analysing arrangements in detail to conclude on whether these are within the scope of the interpretation and whether the arrangement falls under the financial asset or intangible asset models. Some complex arrangements may have elements of both models for the different phases. It may be appropriate to separately account for each element of the consideration. Applying IFRIC 12 for the first time will require a retrospective application, ie, comparatives will be restated for those concessions within its scope.

1.4.2 Business combinations

Acquisitions of assets and businesses are common in the utility industry. These may be business combinations or acquisitions of groups of assets. IFRS 3 *Business Combinations* provides guidance on both types of transactions, and the accounting can differ significantly.

All business combinations are accounted for by applying the purchase method. The purchase method is summarised as follows:

(a) identify the acquirer;

(b) measure the cost of the combination; and

(c) record the fair value of assets acquired and liabilities assumed.

Issues commonly encountered in the utility industry include making the judgement about whether a transaction is a business combination or an asset deal, recognition and valuation of intangible assets, goodwill and deferred tax.

Definition of a business

A business is an integrated set of activities managed together to provide a return to investors or other economic benefits. Two key elements of the definition are ‘integration’ and ‘return to investors’. The accounting for a business combination and a group of assets can be substantially different. A business combination will usually result in the recognition of goodwill and deferred tax. An asset transaction qualifies for the initial recognition exemption and therefore there is usually no deferred tax. The consideration in an asset transaction is allocated to individual assets acquired and liabilities assumed based on relative fair values.

Acquisition of an integrated utility or a group of generators located in a country will fall squarely into the scope of IFRS 3 as a business combination. The classification of the acquisition of a single generating facility, or a portion of a transmission network, may not be so clear cut. The acquisition of a generating facility that is contracted out and is within the scope of IFRIC 4 and classified as a finance lease may not be a business combination because often the operator's return is fixed or guaranteed by the contract, and any variability in costs is passed through to the purchaser of the power.

Allocation of the cost of the combination to assets and liabilities acquired

IFRS 3 requires all identifiable assets and liabilities (including contingent liabilities) acquired to be recorded at their fair value. These include assets and liabilities that may not have been previously recorded by the entity acquired, for example customer relationships.

IFRS 3 also requires recognition separately of intangible assets if they arise from contractual or legal rights, or are separable from the business. The standard includes a list of items that are presumed to satisfy the recognition criteria. The intangible assets that might be identified in the acquisition of a utility may differ depending on the regulatory regime. Brand names and customer relationships might be significant assets of a utility in a less regulated and more competitive market. A utility in a monopoly market might have a brand name and a logo, but this would have much less value as customers have no choice of supplier. The transmission network might be a separate business and trade with a number of generators and distribution companies. If it has a monopoly position it has customer relationships, but these again are likely to be of little value. Existing contracts and arrangements, however, might give rise to assets or liabilities for favourable or unfavourable pricing. This could include operating leases, fuel purchase arrangements and contracts that qualify for own-use that might otherwise be derivatives under IAS 39.

The utility usually has a licence or a series of licences to operate. These licences are almost always included in the value of the fixed assets, as the two can seldom be separated. The licence to operate a nuclear power plant is specific to the location, assets and often the current entity (not freely transferable). The licence and fixed assets are usually valued on the basis of expected cash flows and will incorporate any existing rate agreements that will survive the business combination. The regulator, in some countries, may seek to re-negotiate existing rate agreements perhaps as part of agreeing to a change in control.

Fair values of assets are often determined using discounted cash flow models. These models should include the tax amortisation benefit (TAB) available to the typical market participant. The TAB represents the value associated with the tax deductibility for an asset. Asset values obtained through direct market observations rather than the use of discounted cash flows (DCFs) already reflect the general tax benefit associated with the asset. Differences between the general tax benefit of each asset and the specific tax benefits for the acquirer are included within goodwill because these are entity-specific.

Goodwill

IFRS 3 requires that the fair value of the assets acquired and liabilities assumed are recognised. The difference between consideration and the fair value of net assets gives rise to positive or negative goodwill. This residual approach to the calculation of goodwill required by IFRS 3 is likely to result in the recognition of goodwill in business combinations. Any goodwill is likely to represent the value paid for assets that do not qualify for separate recognition on the balance sheet (such as an assembled workforce), synergies paid for by the acquirer, 'development premium' reflecting uncertainty of the completion of the project and, occasionally, overpayments.

However, IFRS 3 requires certain assets and liabilities acquired in a business combination to be recognised on a basis other than fair value. Examples include pension liabilities and deferred tax. Deferred tax is calculated after the fair values of the other identifiable assets and liabilities have been determined by comparing the fair value recognised for accounting purposes with the tax base of each asset and liability. Consequently, the mechanics of the deferred tax calculation and the goodwill calculation might result in goodwill being recognised solely as a result of the recognition of the deferred tax. That is, goodwill might be recognised when there is no expectation of goodwill because there are no unrecognised assets, no synergies and no overpayments. This anomaly will persist until the IASB revises the deferred tax standard, expected in 2009.

1.4.3 Financial instruments

The accounting for financial instruments can have a major impact on a utility entity's financial statements. Many use a range of derivatives to manage the commodity, currency and interest rate risks to which they are operationally exposed. Other, less obvious, sources of financial instruments issues arise through both the scope of IAS 39 and the rules around accounting for embedded derivatives. Many entities that are engaged in generation, transmission and distribution of electricity may be party to commercial contracts that are either wholly within the scope of IAS 39 or contain embedded derivatives from pricing formulas or currency. Other entities may have active energy trading programmes that go far beyond mitigation of risk. This section looks at two broad categories of financial instruments: those that may arise from the scope of IAS 39 and those that arise from active trading and treasury management activity. Separately, it addresses accounting for weather derivatives.

Scope of IAS 39

Contracts to buy or sell a non-financial item, such as a commodity, that can be settled net in cash or another financial instrument, or by exchanging financial instruments, are within the scope of IAS 39. They are treated as derivatives and are marked to market through the income statement. Contracts that are for an entity's 'own-use' are exempt from the requirements of IAS 39 but these 'own-use' contracts may include embedded derivatives, which may be required to be separately accounted for. An 'own-use' contract is one that was entered into and continues to be held for the purpose of the receipt or delivery of the non-financial item in accordance with the entity's expected purchase, sale or usage requirements. In other words, it will result in physical delivery of the commodity. The 'net settlement' notion in IAS 39 is quite broad. A contract to buy or sell a non-financial item can be net settled in any of the following ways:

(a) the terms of the contract permit either party to settle it net in cash or another financial instrument;

(b) the entity has a practice of settling similar contracts net, whether:
- with the counterparty;
- by entering into offsetting contracts; or
- by selling the contract before its exercise or lapse;

(c) the entity has a practice, for similar items, of taking delivery of the underlying and selling it within a short period after delivery for the purpose of generating a profit from short-term fluctuations in price or a dealer's margin; or

(d) the commodity that is the subject of the contract is readily convertible to cash.

Application of 'own-use'

Own-use applies to those contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item. The practice of settling similar contracts net prevents an entire category of contracts from qualifying for the own-use treatment (ie, all similar contracts must then be recognised as derivatives at fair value).

A contract that falls into category (b) or (c) above cannot qualify for own-use treatment. These contracts must be accounted for as derivatives at fair value. Contracts subject to the criteria described in (a) or (d) above are evaluated to see if they qualify for own-use treatment.

Many contracts for commodities such as oil, gas and electricity meet criterion (d) above (ie, readily convertible to cash) when there is an active market for the commodity. An active market exists when prices are publicly available on a regular basis and those prices represent regularly occurring arm's length transactions between willing buyers and willing sellers. Consequently, sale and purchase contracts for commodities in locations where an active market exists must be accounted for at fair value unless own-use treatment can be evidenced. An entity's policies, procedures and internal controls are therefore critical in determining the appropriate treatment of its commodity contracts.

Own-use is not an election. A contract that meets the own-use criteria cannot be selectively fair-valued unless it otherwise falls into the scope of IAS 39.

If an own-use contract contains one or more embedded derivatives, an entity may designate the entire hybrid contract as a financial asset or financial liability at fair value through profit or loss unless:

(a) the embedded derivative(s) does not significantly modify the cash flows of the contract; and

(b) it is clear with little or no analysis that separation of the embedded derivative is prohibited.

However, the IASB has proposed to restrict the ability to designate the entire hybrid instrument as a financial asset or financial liability at fair value through profit or loss. The proposal to be included in the IASB's 2008 Annual Improvements project will restrict this designation to host contracts that are financial instruments in the scope of IAS 39.

Further discussion on embedded derivatives is presented in the following section.

Measurement of long-term contracts that do not qualify for 'own-use'

Long-term commodity contracts are not uncommon, particularly for purchase of fuel and sales of electricity. Some of these contracts may be within the scope of IAS 39 if they contain net settlement provisions and do not get own-use treatment. These contracts are measured at fair value using the valuation guidance in IAS 39 with changes recorded in the income statement. There may not be market prices for the entire period of the contract. For example, there may be prices available for the next three years and then some prices for specific dates further out. This is described as having illiquid periods in the contract. These contracts are valued using valuation techniques in the absence of an active market for the entire contract term.

Valuation is complex and is intended to establish what the transaction price would have been on the measurement date in an arm's length exchange motivated by normal business considerations. Therefore it:

(a) incorporates all factors that market participants would consider in setting a price, making maximum use of market inputs and relying as little as possible on entity-specific inputs;

(b) is consistent with accepted economic methodologies for pricing financial instruments; and

(c) is tested for validity using prices from any observable current market transactions in the same instrument or based on any available observable market data.

The assumptions used to value long-term contracts are updated at each balance sheet date to reflect changes in market prices, the availability of additional market data and changes in management's estimates of prices for any remaining illiquid periods of the contract. Clear disclosure of the policy and approach, including significant assumptions, are crucial to ensure users understand the entity's financial statements.

Day-one profits

Commodity contracts that fall within the scope of IAS 39 and fail to qualify for own-use treatment have the potential to create day-one gains. A day-one gain is the difference between the fair value of the contract at inception as calculated by a valuation model and the amount paid to enter the contract. The contracts are initially recognised under IAS 39 at fair value. Any such profits or losses can only be recognised if the fair value of the contract:

(1) is evidenced by other observable market transactions in the same instrument; or

(2) is based on valuation techniques whose variables include only data from observable markets.

Thus, the profit must be supported by objective market-based evidence. Observable market transactions must be in the same instrument (ie, without modification or repackaging and in the same market where the contract was originated). Prices must be established for transactions with different counterparties for the same commodity and for the same duration at the same delivery point.

Any day-one profit or loss that is not recognised at initial recognition is recognised subsequently only to the extent that it arises from a change in a factor (including time) that market participants would consider in setting a price. Commodity contracts include a volume component, and utility entities are likely to recognise the deferred gain/loss and release it to profit or loss on a systematic basis as the volumes are delivered, or as observable market prices become available for the remaining delivery period.

The recognition of the day-one gain/losses may change as the result of the IASB project on the Fair Value Measurements.

Take or pay contracts

Generators may enter into long-term take-or-pay contracts with key fuel suppliers. These agreements give rise to an obligation for the generator to purchase a minimum quantity or value of the relevant fuel. The actual quantity or value of fuel the generator requires may be less than the minimum agreed amount in any one measurement period. The generator may be required to pay the supplier the equivalent monetary value of the shortfall. The shortfall amount may also be carried forward and used in satisfaction of supply in subsequent periods.

A long-term take-or-pay contract might not qualify for own-use treatment. The inherent variability in amount and the ability to 'net settle' may put such a contract outside the exemption because it will not meet the criteria for own-use.

Volume flexibility (optionality)

Many contracts for the supply of commodities usually give the buyer the right to take either a minimum quantity or any amount based on the buyer's requirements. A minimum annual commitment does not create a derivative as long as the entity expects to purchase all the guaranteed volume for its own-use. However, if it becomes likely that the entity will not take the commodity, and instead pay a penalty under the contract based on the market value of the commodity or some other variable, a derivative or an embedded derivative may well arise. In this situation, since physical delivery is no longer probable, the derivative would be recorded at the amount of the penalty payable. Changes in market price will affect the penalty's carrying value until the penalty is paid. On the other hand, if the amount of the penalty payable is fixed or pre-determined, there is no derivative because the penalty's value remains fixed irrespective of changes in the product's market value. In other words, the entity will need to provide for the penalty payable once it becomes clear that non-performance is likely.

On the other hand, if the quantity specified in the contract is more than the entity's normal usage requirement and the entity intends to net settle part of the contract that it does not need in the normal course of the business, the contract will fail the own-use exemption. For example, the entity could take all the quantities specified in the contract and sell on the excess, or it could enter into an offsetting contract for the excess quantity. In such situations, the entire contract falls within IAS 39's scope and should be marked-to-market.

Embedded derivatives

Long-term commodity purchase and sale contracts frequently contain a pricing clause (ie, indexation) based on a commodity other than the commodity deliverable under the contract. Such contracts contain embedded derivatives that may have to be separated and accounted for under IAS 39 as a derivative. Examples are fuel prices that are linked to the electricity price or other products or a pricing formula that includes an inflation component.

An embedded derivative is a derivative instrument that is combined with a non-derivative host contract (the 'host' contract) to form a single hybrid instrument. An embedded derivative causes some or all of the cash flows of the host contract to be modified, based on a specified variable. An embedded derivative can arise through market practices or common contracting arrangements.

An embedded derivative is separated from the host contract and accounted for as a derivative if:

(a) the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract;

(b) a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative; and

(c) the hybrid (combined) instrument is not measured at fair value with changes in fair value recognised in the profit or loss (ie, a derivative that is embedded in a financial asset or financial liability at fair value through profit or loss is not separated).

Embedded derivatives that are not closely related must be separated from the host contract and accounted for at fair value, with changes in fair value recognised in the income statement. It may not be possible to measure the embedded derivative. Therefore, the entire combined contract must be measured at fair value, with changes in fair value recognised in the income statement.

An embedded derivative that is required to be separated may be designated as a hedging instrument, in which case the hedge accounting rules are applied.

A contract that contains one or more embedded derivatives can be designated as a contract at fair value through profit or loss at inception, unless:

(a) the embedded derivative(s) does not significantly modify the cash flows of the contract; and

(b) it is clear with little or no analysis that separation of the embedded derivative(s) is prohibited.

Assessing whether embedded derivatives are closely related

All embedded derivatives must be assessed to determine if they are 'closely related' to the host contract at the inception of the contract. A pricing formula that is indexed to something other than the commodity delivered under the contract could introduce a new risk to the contract. Some common embedded derivatives that routinely fail the closely related test are indexation to an unrelated published market price and denomination in a foreign currency that is not the functional currency of either party and not a currency in which such contracts are routinely denominated in transactions around the world.

The assessment of whether an embedded derivative is closely related is both qualitative and quantitative, and requires an understanding of the economic characteristics and risks of both instruments.

In the absence of an active market price for a particular commodity, management should consider how other contracts for that particular commodity are normally priced. It is common for a pricing formula to be developed as a proxy for market prices. When it can be demonstrated that a commodity contract is priced by reference to an identifiable industry 'norm' and contracts are regularly priced in that market according to that norm, the pricing mechanism does not modify the cash flows under the contract and is not considered an embedded derivative.

Timing of assessment of embedded derivatives

All contracts need to be assessed for embedded derivatives at the date when the entity first becomes a party to the contract. Subsequent reassessment of embedded derivatives is prohibited unless there is a significant change in the terms of the contract, in which case reassessment is required. A significant change in the terms of the contract has occurred when the expected future cash flows associated with the embedded derivative, host contract, or hybrid contract have significantly changed relative to the previously expected cash flows under the contract.

A first-time adopter assesses whether an embedded derivative is required to be separated from the host contract and accounted for as a derivative on the basis of the conditions that existed at the later of the date it first became a party to the contract and the date a reassessment is required.

The same principles apply to an entity that purchases a contract containing an embedded derivative. The date of purchase is treated as the date when the entity first becomes a party to the contract.

1.4.4 Trading and risk management

Energy trading is the buying and selling of energy-related products, both fuel and power. This practice has many similarities to the trading activities of other commodities, such as gold, sugar or wheat. The introduction of competition in the utilities area was the catalyst for energy trading to start in earnest. Energy trading is an important but potentially risky part of a utility's business. Effective trading can limit volatility and protect profit margins.

Centralised Trading Unit

Many integrated utility companies have established a centralised trading or risk management unit over the last decade in response to the restructuring of the industry. The operation of the Central Trading Unit is similar to the operation of the bank's trading unit.

The scale and scope of the unit's activities vary from market risk management through to dynamic profit optimisation. An integrated utility company is particularly exposed to the movements in the price of fuel and to movements in the price of the power that is generated. The trading unit's objectives and activities are indicative of how management of the utility operates the business.

A unit focused on managing fuel-price risk and sales-price exposure to protect margins is more likely to be entering into many contracts that will qualify for the own-use exemption as previously discussed. A pattern of speculative activity or trading directed to profit maximisation is unlikely to result in many contracts qualifying for the own-use exemption. All external contracts may be treated as derivatives and marked to market. The central trading unit often operates as an internal market place in larger integrated utilities. The generating stations 'sell' their output to and 'purchase' fuel from the trading unit. The retail unit would 'purchase' power to meet its customer demands. The centralised trading function thus 'acquires' all of the company's exposure to the various commodity risks. The trading unit is then responsible for hedging those risks in the external markets. Some centralised trading departments are also given authority to enhance the returns obtained from the integrated business by undertaking a degree of speculative trading. A centralised trading unit therefore undertakes two classes of transaction:

(a) Transactions that are non-speculative in nature: for example, the purchase of fuel to meet the physical requirements of the generation stations and the sale of any excess power generated compared to retail demand, or the purchase of power to meet a shortfall between that generated and that required by retail. Such activity is sometimes held in a 'physical book'.

(b) Transactions that are speculative in nature, to achieve risk management returns from wholesale trading activities. Such activity is sometimes held in a 'trading book' and often involves entering into offsetting sales and purchase contracts that are settled on a net basis. Those contracts and all similar contracts (i.e. all contracts in the trading book) do not qualify for the own-use exemption and are accounted for as derivatives.

A company that maintains separate physical and trading books needs to maintain the integrity of the two books to ensure that the net settlement of contracts in the trading book does not 'taint' similar contracts in the physical book, thus preventing the own-use exemption from applying to contracts in the physical book.

Hedge Accounting

Hedge accounting can mitigate the volatility of trading transactions. Practical experience of hedge accounting has shown that complying with the requirements can be onerous. A company that chooses to apply hedge accounting must comply with the detailed requirements. All derivatives are accounted for at fair value, but changes in fair value are either deferred through reserves, or matched to a significant extent by an adjustment to the value of the hedged item, dependent on the type of hedge. Companies that combine commodity risk from different business units before entering into external transactions might not qualify for hedge accounting, as this usually creates a net exposure and IFRS does not permit hedge accounting for transactions undertaken to hedge net exposures.

Two key hurdles to implementing hedge accounting are the need for documentation and the testing of effectiveness. IAS 39 requires that individual hedging relationships are formally documented, including linkage of the hedge to the company's risk-management strategy, explicit identification of the hedged items and the specific risks being hedged at the inception of the hedge. Failure to establish this documentation at inception will mean that hedge accounting cannot be adopted, regardless of how effective the hedge actually is in offsetting risk.

Hedges must be expected to be highly effective and must prove to be highly effective in mitigating the hedged risk or variability in cash flows in the underlying instrument.

There is no prescribed single method for assessing hedge effectiveness. Instead, a company must identify a method that is appropriate to the nature of the risk being hedged and the type of hedging instrument used. The method an entity adopts for assessing hedge effectiveness depends on its risk management strategy. A company must document at the inception of the hedge how effectiveness will be assessed and then apply that effectiveness test on a consistent basis for the duration of the hedge.

The hedge must be expected to be effective at the inception of the hedge and in subsequent periods and the actual results of the hedge should be within a range of 80-125% (ie, changes in the fair value or cash flows of the hedged item should be between 80% and 125% of the changes in fair value or cash flows of the hedging instrument). Any ineffectiveness of an effective hedge must be recognised in the income statement.

The requirement for testing can be quite onerous. Effectiveness tests need to be performed for each hedging relationship at least as frequently as financial information is prepared, which for listed companies could be up to four times a year. Experience shows that the application of hedge accounting is not straightforward, particularly in the area of effectiveness testing, and a company looking to apply hedge accounting to its commodity hedges needs to invest time in ensuring that appropriate effectiveness tests are developed.

Cash Flow Hedges and 'Highly Probable'

Hedging of commodity-price risk or its foreign exchange component is often based on expected cash inflow or outflow related to forecasted transactions, therefore cash flow hedges. Under IFRS, only a highly probable forecast transaction can be designated as a hedged item in a cash flow hedge relationship. The hedged item must be assessed regularly until the transaction occurs. If the forecasts change and the forecasted transaction is no longer expected to occur, the hedge relationship must be ended immediately and all retained hedging results from the hedging reserve must be recycled to the income statement. Cash flow hedging is not available if an entity is not able to forecast the transaction reliably.

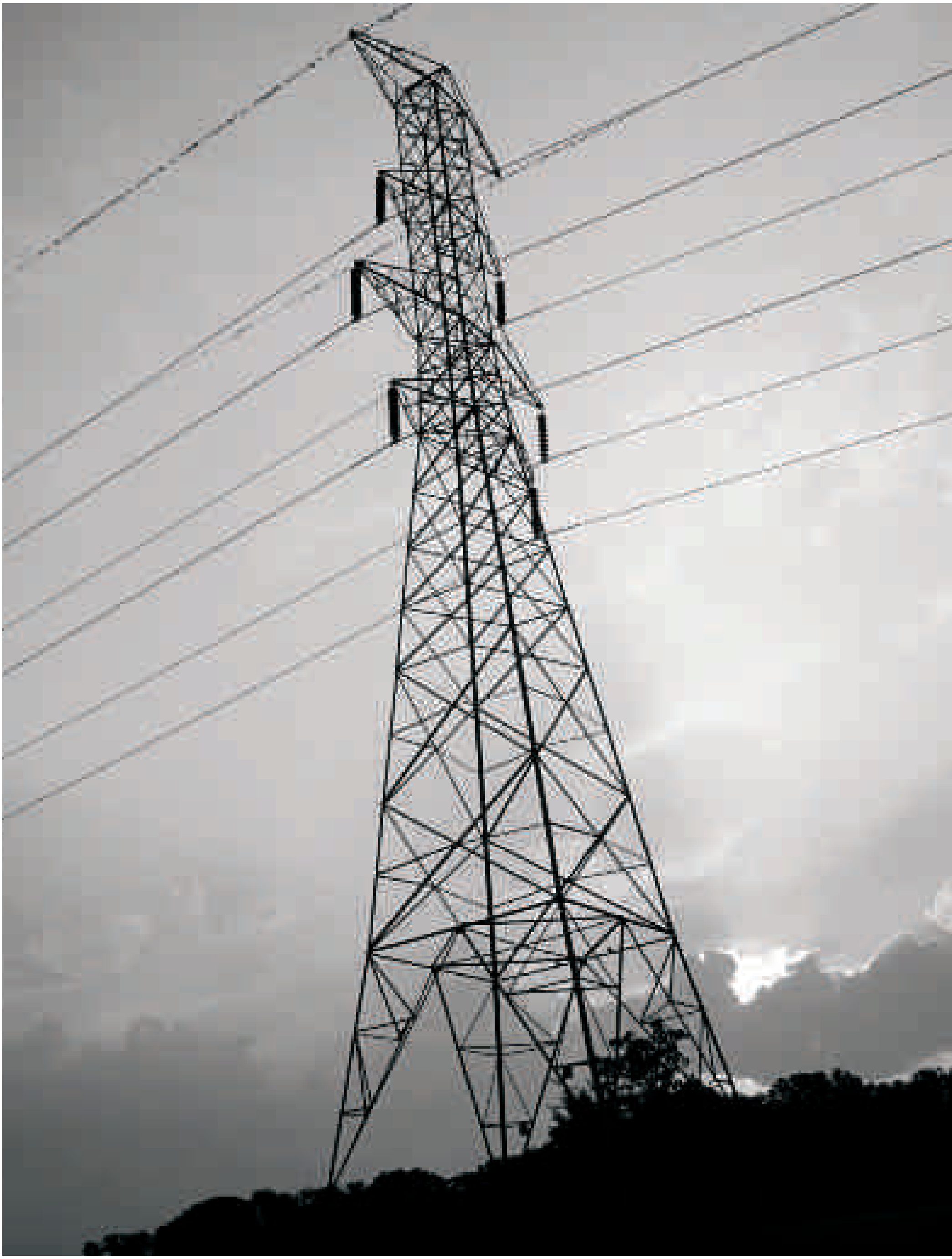
Weather Derivatives

Electricity consumption is heavily influenced by weather. More energy is consumed in cold winters than in mild winters and, due to air conditioning, more in hot summers than in cool summers. The correlation with outside temperatures is high, so load volumes are heavily dependent on weather conditions. Weather derivatives make it possible to manage the concerns related to extreme climate conditions, by paying the generator when the weather is adverse to revenue.

Weather derivatives are contracts that require a payment based on climatic variables or on geological or other physical variables. For such contracts, payments are sometimes made on the amount of loss suffered by the entity and sometimes not. Weather derivatives are either insurance contracts and fall into IFRS 4 *Insurance Contracts* or financial instruments and with the scope of IAS 39. Contracts that require a payment only if a particular level of the underlying climatic, geological, or other physical variables adversely affects the contract holder are insurance contracts. Payment is contingent on changes in a physical variable that is specific to a party to the contract.

Contracts that require a payment based on a specified level of the underlying variable regardless of whether there is an adverse effect on the contract holder are derivatives and are within IAS 39's scope. Derivatives should be recognised at fair value with the changes in fair value recognised in the income statement.

2 Developments from the IASB



2 Developments from the IASB

2.1 Borrowing costs

The IASB issued amendments to IAS 23 *Borrowing Costs* in March 2007. IAS 23R removes the policy choice of either capitalising or expensing borrowing costs and requires management to capitalise borrowing costs attributable to qualifying assets. Qualifying assets are assets that take a substantial time to get ready for their intended use or sale. An example is self-constructed assets such as power plant, buildings, machinery.

The changes to the standard were made as part of the IASB's and FASB's short-term convergence project. The elimination of the option to expense borrowing costs does not achieve full convergence with US GAAP, as some technical differences remain (for example, definitions of borrowing costs and qualifying assets).

The effective date of IAS 23R is 1 January 2009, with earlier adoption permitted. The amendments are to be applied prospectively; comparatives will not need to be restated. The Board has provided additional relief by allowing management to designate a particular date on which it can start applying the amendments. For example, management can decide to designate 1 October 2008 as a starting date, because the company starts a project for which management would like to capitalise interest when it applies IAS 23R in 2009.

2.2 Emissions Trading Schemes

The IASB added the emissions trading topic to its agenda after the withdrawal of IFRIC 3 *Emission Rights* in 2005. The project was temporarily deferred (due to deferral of the project relating to government grants) and again activated in December 2007 with the increasing international interest in emission trading schemes and the diversity in practice that has arisen. The Board decided to limit the scope of the project to the issues that arise in accounting for emissions trading schemes, rather than addressing broadly the accounting for all government grants (which would have involved re-activating the IAS 20 project).

The purpose of the project is to comprehensively address the accounting for emission trading schemes. It will cover the following issues:

- whether the emissions allowances are an asset (considering the different ways of acquiring the asset) and what its nature is;
- recognition and measurement of allowances;
- whether liability exists, what its nature is and how should it be measured.

The project is in the research phase, with the Board gathering information on the characteristics of various emissions trading schemes. This will be the basis for the preparation of a comprehensive package that outlines the alternative models that could be used to account for emissions trading schemes. The timing of an initial due process document and the estimated project completion date is not yet determined.

2.3 Revenue recognition project

The IASB is conducting a joint project with FASB to develop concepts for revenue recognition and a general standard based on those concepts. The general standard would replace the existing standards on revenue recognition: IAS 11 *Construction Contracts* and IAS 18 *Revenue*. The comprehensive standard that is expected to result from this project is planned to apply to all business entities; however, the Boards may conclude that certain transactions or industries requiring additional study should be excluded from the scope of that standard and addressed separately.

The main reasons for undertaking this project are to:

- eliminate weaknesses in existing concepts and standards (eg, revenue recognition requirements – should there be a focus on changes in assets and liabilities rather than the occurrence of critical events; contracts that provide more than one good or service to the customer – when should contracts be divided into components and how much revenue should be attributed to each component);
- converge IFRS and US requirements.

The Board plans to issue a Discussion Paper (jointly with the FASB) for consultation in the second quarter of 2008.

2.4 IFRS 3 Business Combinations (revised) and IAS 27 Consolidated and Separate Financial Statements (revised)

The IASB issued two revised standards in January 2008: IFRS 3R *Business Combinations* and IAS 27R *Consolidated and Separate Financial Statements*. The revised standards are effective for annual periods beginning on or after 1 July 2009. The standards result in more fair value changes being recorded through the income statement and cement the 'economic entity' view of the reporting entity.

The key differences between IFRS 3R and IAS 27R and the previous standards are as follows:

- Business combinations achieved by contract alone and business combinations involving only mutual entities are accounted for under the revised IFRS 3.
- Minor changes in the definition of a business with more significant changes in the application guidance.
- Transaction costs incurred in connection with the business combination are expensed when incurred and are no longer included in the cost of the acquiree.
- An acquirer recognises contingent consideration at fair value at the acquisition date. Subsequent changes in the fair value of such contingent consideration will often affect the income statement.
- The acquirer recognises either the entire goodwill inherent in the acquiree, independent of whether a 100% interest is acquired (full goodwill method), or only the portion of the total goodwill that corresponds to the proportionate interest acquired (as is currently the case under IFRS 3).
- Any previously held non-controlling interest (as a financial asset or associate, for example) is remeasured to its fair value at the date of obtaining control, and a gain or loss is recognised in the income statement.
- There are new provisions to determine whether a portion of the consideration transferred for the acquiree or the assets acquired and liabilities assumed are part of the business combination or part of another transaction to be accounted for separately under applicable IFRS.
- There is new guidance on classification and designation of assets, liabilities and equity instruments acquired or assumed in a business combination on the basis of the conditions that exist at the acquisition date, except for leases and insurance contracts. This guidance includes reassessment of embedded derivatives.
- Intangible assets are recognised separately from goodwill if they are identifiable – ie, if they are separable or arise from contractual or other legal rights. The reliably-measurable criterion is presumed to be met.
- Recognition of deferred tax assets of the acquiree after the initial accounting for the business combination leads to an adjustment of goodwill only if the adjustment is made within the measurement period (not exceeding one year from the acquisition date) and the adjustment results from new information about facts and circumstances that already existed at the acquisition date. Otherwise, it must be reflected in the income statement with no change to goodwill.
- All purchases of equity interests from and sales of equity interests to non-controlling interests are treated as treasury share transactions. Any difference between the amount of consideration received or given and the amount of non-controlling interest is recorded in equity. Entities will no longer be able to report gains on the partial disposal of a subsidiary.
- Additional disclosure requirements.

Several of the requirements may be of more interest to utilities entities. The requirement to re-assess all contracts and arrangements for embedded derivatives may result in more classified as derivatives with subsequent income statement volatility. Contingent consideration is more common in extractive industries, with selling shareholders seeking to profit from previously undiscovered resources or favourable price movements. These arrangements are less common in utilities, but do exist. All such

arrangements will be captured by the contingent consideration guidance and recognised as liabilities of the acquirer whether or not payment is probable at the date of the transaction.
All subsequent changes are income statement items.

2.5 ED 9 Joint Arrangements

The IASB published in September 2007 the exposure draft ED 9 *Joint Arrangements*, which sets out proposals for the recognition and disclosure of interests in joint arrangements. It is intended to replace IAS 31 *Interests in Joint Ventures* and it is another step towards the goals of the Memorandum of Understanding between the IASB and the FASB on the convergence of IFRS and US GAAP. The changes proposed are to IFRS only; there are no changes proposed to US GAAP.

ED 9's core principle is that parties to a joint arrangement recognise their contractual rights and obligations arising from the arrangement. The ED therefore focuses on the recognition of assets and liabilities by the party to the joint arrangement.

The scope of the ED is broadly the same as that of IAS 31. That is, unanimous agreement is required between the key parties that have the power to make the financial and operating policy decisions for the joint arrangement.

There are two principal changes proposed by ED 9. The first is the elimination of proportionate consolidation for a jointly controlled entity. The second change is the introduction of a 'dual approach' to the accounting for joint arrangements.

Elimination of proportionate consolidation

Eliminating proportionate consolidation will have a fundamental impact on the income statement and balance sheet for some entities. Entities that currently use proportionate consolidation to account for jointly controlled entities may need to account for many of these using the equity method. These entities will replace the line-by-line proportionate consolidation of the income statement and balance sheet by a single net result and a single net investment balance.

Switching from proportionate consolidation to equity accounting has the following impacts:

- Revenues are reduced: the venturer cannot present its share of the joint venture's revenue as part of its own revenue.
- Tangible and intangible assets are reduced: the gross presentation of the venturer's share of the JV's tangible assets, intangible assets, other assets and liabilities is replaced by a single net amount, classified as part of its investments.

Although the information about these gross amounts is included in the notes to the financial statements, removing them from the primary statements diminishes their prominence.

The 'dual approach' to joint arrangements

The second change is the introduction of a 'dual approach' to the accounting for joint arrangements. ED 9 carries forward with modification from IAS 31, the three types of joint arrangement; each type having specific accounting requirements. The first two types are Joint Operations and Joint Assets. The description of these types and the accounting for them is consistent with Jointly Controlled Operations and Jointly Controlled Assets in IAS 31. The third type of joint arrangement is a Joint Venture, which is accounted for using equity accounting. A Joint Venture is identified by the party having rights only to a share of the outcome of the joint arrangement, for example a share of the profit or loss of the joint arrangement. The key change is that a single joint arrangement may contain more than one type; for example Joint Assets and a Joint Venture. The party to such a joint arrangement accounts first for the assets and liabilities of the Joint Assets arrangement and then uses a residual approach to equity accounting for the Joint Venture part of the joint arrangement.

The introduction of the dual approach will require all companies to review each of their joint venture agreements. They will need to determine whether each joint arrangement exhibits the properties and characteristics of joint assets/joint operations (typically a direct use of assets/obligation for liabilities) and/or the characteristics of a Joint Venture (an interest in the outcome of the JV, eg, a share of profit generated by the Joint Venture). An interest in the outcome/net result will more commonly arise when the joint arrangement is incorporated; however, unincorporated joint arrangements are capable, in some circumstances, of returning a net result/profit to the partners, and so should also be analysed.

Other considerations

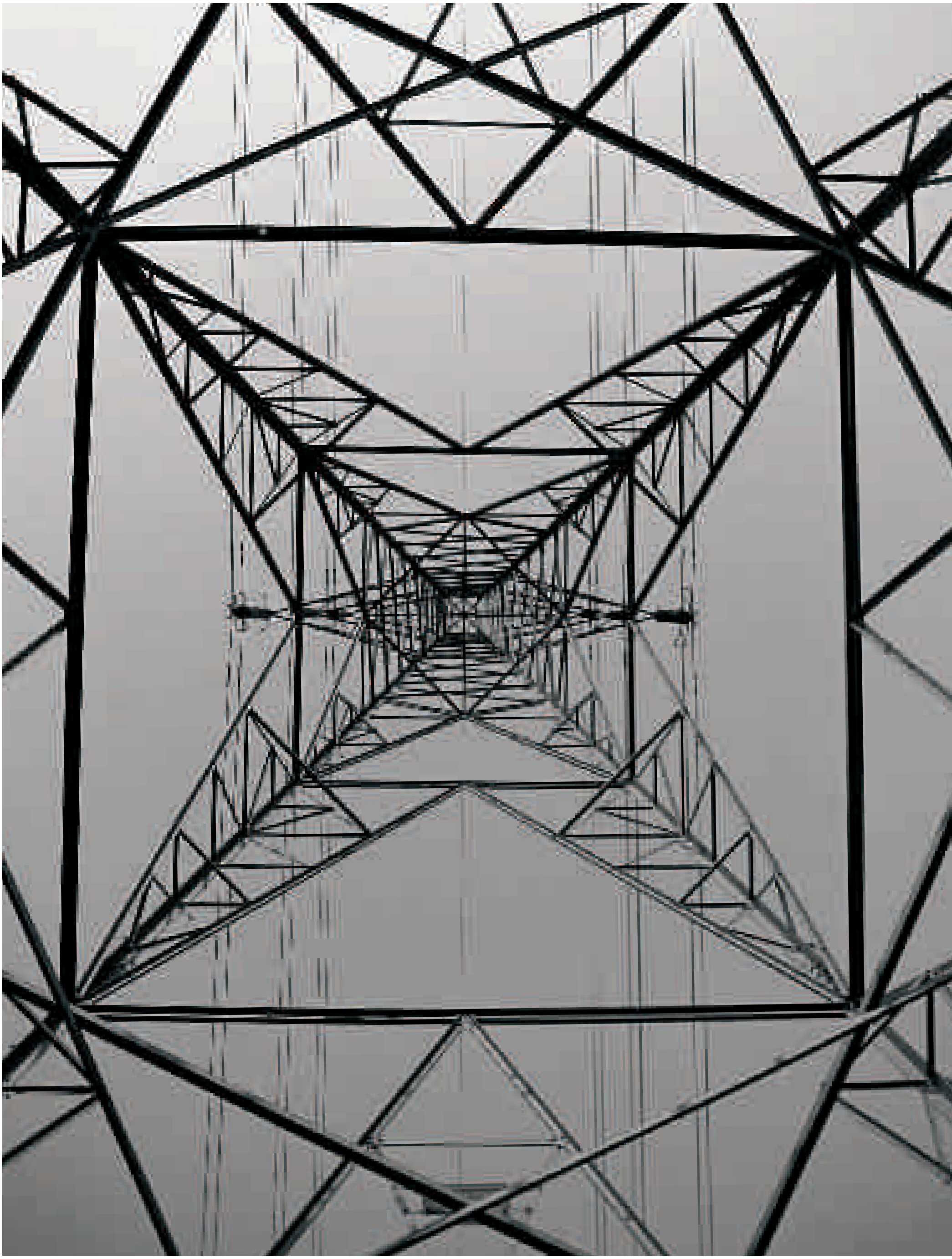
The results presented in financial statements will reflect the cumulative impact of all relevant factors. For example, if a company has an interest in the net result of a joint venture it will account for its interest in the joint venture using equity accounting. However, if it also purchases a share of the output (eg, power) from the joint venture and sells it to a third party, it will record revenue for those third-party sales in addition to equity accounting for its interest in the joint venture, after appropriate eliminations.

A company that finds itself moving from proportionate consolidation to equity accounting may also want to consider the impact of its internal management reporting. IFRS 8 *Operating Segments* requires disclosure of segmental information on the same basis as is provided to the company's chief operating decision-maker (CODM). The accounting basis used for providing information to the CODM is used to present the segment information in accordance with IFRS 8. Accordingly, if the CODM is presented with information prepared using proportionate consolidation, then this is the basis that should be presented in the segment information and reconciled to the primary financial statements.

Timetable

The IASB expects to publish a new IFRS for joint arrangements in quarter 4 of 2008. The implementation date has not been decided yet but might be as early as 2010. Those companies that conduct a significant amount of their business through joint ventures may want to follow the development of this standard carefully.

3 IFRS/US GAAP Differences



3 IFRS/US GAAP Differences

There are a number of differences between IFRS and US GAAP. This section provides a summary description of those IFRS/US GAAP differences that are particularly relevant to utilities entities. These differences relate to: depreciation, decommissioning obligations, impairment, arrangements that may contain a lease, regulatory assets, concessions, business combinations and financial instruments.

3.1 Fixed assets and components

Issue	IFRS	US GAAP
Components of property, plant and equipment	Significant parts (components) of an item of PPE are depreciated separately if they have different useful lives.	Component approach to depreciation not required, however is often followed as a matter of industry practice.

3.2 Decommissioning obligations

Issue	IFRS	US GAAP
Measurement of liability	Liability measured at the best estimate of the expenditure required to settle the obligation. Risks associated with the liability are reflected in the cash flows or in the discount rate. The discount rate is updated at each balance sheet date. Indeterminate life of asset to be decommissioned does not remove the need to measure the decommissioning obligation, but the effect of discounting will have a greater impact on the measurement of the liability.	Range of cash flows prepared and risk weighted to calculate expected values. Risks associated with the liability are only reflected in the cash flows, except for credit risk, which is reflected in the discount rate. The discount rate for an existing liability is not updated. Accordingly, downward revisions to undiscounted cash flows are discounted using the credit adjusted risk-free rate when the liability was originally recognised. Upward revisions, however, are discounted using the current credit adjusted risk-free rate at the time of the revision. Decommissioning liability need not be recognised for assets with indeterminate life.
Recognition of decommissioning asset	The adjustment to PPE when the decommissioning liability is recognised forms part of the asset to be decommissioned.	The asset recognised in respect of a decommissioning obligation is a separate asset from the asset to be decommissioned. This distinction is relevant because of the limits placed on subsequent adjustments to the asset as a result of adjustment to the decommissioning liability. In particular, the limit that the decommissioning asset cannot be reduced below zero for US GAAP compared with the limit that the asset to be decommissioned cannot be reduced below zero for IFRS.

3.3 Impairment

Issue	IFRS	US GAAP
Impairment test triggers	Assets or groups of assets (cash generating units) are tested for impairment when indicators of impairment are present.	Long-lived assets are tested for impairment only if indicators are present and an undiscounted cash flow test suggests that an asset's carrying amount will not be recovered from its use and eventual disposal.
Level at which impairment tested	Assets tested for impairment at the cash generating unit (CGU) level. CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. Testing power stations for impairment on a portfolio basis is not consistent with the CGU approach.	Similar to IFRS except that the grouping of assets is based on largely independent cash flows (in and out) rather than just cash inflows. A pooled approach to impairment testing maybe appropriate in certain circumstances.
Measurement of impairment	Impairment is measured as the excess of the asset's carrying amount over its recoverable amount. The recoverable amount is the higher of its value in use and fair value less costs to sell.	Impairment is measured as the excess of the asset's carrying amount over its fair value. Fair value is determined using a discounted cash flow valuation.
Reversal of impairment charge	Impairment losses, other than those relating to goodwill, are reversed when there has been a change in the economic conditions or in the expected use of the asset.	Impairment losses are never reversed.

3.4 Arrangements that may contain a lease

Issue	IFRS	US GAAP
Retrospective application	Arrangements that convey the right to use an asset in return for a payment or series of payments are required to be accounted for as leases if certain conditions are met. This requirement applies even if the contract does not take the form of a lease. The IFRS guidance that requires this analysis, IFRIC 4, was applicable from 2006 but required all existing arrangements to be analysed.	Similar to IFRS except that the applicable US GAAP guidance, EITF 01-8, was applicable only to new arrangements entered into (or modifications made to existing arrangements) after the effective date.

3.5 Regulatory Assets and Liabilities

Issue	IFRS	US GAAP
Regulatory assets and liabilities	Regulatory assets are generally not recognised in rate regulated regimes because the utility entity does not have control over the recoverability of the future economic benefits. It is not entitled to require payment from customers in respect of past services unless future services are provided. Regulatory liabilities are not recognised except in exceptional circumstances when the utility is obliged through some mechanism to repay cash to the customers without the sale of future services to the customer.	FAS 71 specifically requires recognition of regulatory assets and liabilities in certain circumstances.

3.6 Business combinations

The following summary reflects differences between the requirements of IFRS 3 (Issued 2004) and FAS 141 (Issued 2001).

Issue	IFRS	US GAAP
Purchase method – fair values on acquisition	Assets, liabilities and contingent liabilities of acquired entity are recognised at fair value where fair value can be measured reliably. Goodwill is recognised as the residual between the consideration paid and the percentage of the fair value of the net assets acquired. In-process research and development is generally capitalised. Liabilities for restructuring activities are recognised only when acquiree has an existing liability at acquisition date. Liabilities for future losses or other costs expected to be incurred as a result of the business combination cannot be recognised.	There are specific differences from IFRS. Contingent liabilities of the acquiree are recognised if, by the end of the allocation period: • their fair value can be determined, or • they are probable and can be reasonably estimated. Specific rules exist for acquired in-process research and development (generally expensed). Some restructuring liabilities relating solely to the acquired entity may be recognised if specific criteria about restructuring plans are met.
Purchase method – contingent consideration	Included in cost of combination at acquisition date if adjustment is probable and can be measured reliably.	Generally, not recognised until contingency is resolved and the amount is determinable.
Purchase method – minority interests at acquisition	Stated at minority's share of the fair value of acquired identifiable assets, liabilities and contingent liabilities.	Stated at minority's share of pre-acquisition carrying value of net assets.
Purchase method – intangible assets with indefinite useful lives and goodwill	Capitalised but not amortised. Goodwill and indefinite-lived intangible assets are tested for impairment at least annually at either the cash-generating unit (CGU) level or groups of CGUs, as applicable.	Similar to IFRS, although the level of impairment testing and the impairment test itself are different.
Purchase method – negative goodwill	The identification and measurement of acquiree's identifiable assets, liabilities and contingent liabilities are reassessed. Any excess remaining after reassessment is recognised in the income statement immediately.	Any remaining excess after reassessment is used to reduce proportionately the fair values assigned to non-current assets (with certain exceptions). Any excess is recognised in the income statement immediately as an extraordinary gain.

3.7 Concession arrangements

Issue	IFRS	US GAAP
Identification and classification of concession arrangements	Public-to-private service concession arrangements that meet certain conditions must be analysed to determine whether the concession represents a financial asset or an intangible asset.	No equivalent guidance.

The revisions made to FAS 141 in 2007 and to IFRS 3 in 2008 remove some of the differences between IFRS and US GAAP. The following table identifies those aspects of business combinations accounting from the table above which will become consistent between IFRS and US GAAP as a result of the revisions to the standards.

Issue	IFRS and US GAAP
Acquisition method – fair values on acquisition	Assets and liabilities of the acquired entity are recognised at fair value. This includes acquired in-process research and development. Liabilities for restructuring activities are recognised only when the acquiree has an existing liability at the acquisition date.
Acquisition method – contingent consideration	Contingent consideration recognised at fair value.
Acquisition method – negative goodwill	The identification and measurement of acquiree's identifiable assets, liabilities and contingent liabilities are reassessed. Any excess remaining after reassessment is recognised in the income statement immediately.

The following summary reflects differences between the requirements of IFRS 3 (Revised 2008) and FAS 141 (Revised 2007).

Issue	IFRS	US GAAP
Assets and liabilities arising from contingencies	Recognise contingent liabilities at fair value if fair value can be measured reliably. If not within the scope of IAS 39, measure subsequently at higher of amount initially recognised and best estimate of amount required to settle (under IAS 37). Contingent assets are not recognised.	Liabilities and assets subject to contractual contingencies are recognised at fair value. Recognise liabilities and assets subject to other contingencies only if more likely than not that they meet definition of asset or liability at acquisition date. After recognition, retain initial measurement until new information is received, then measure at the higher of amount initially recognised and amount under FAS 5 for liabilities subject to contingencies, and lower of acquisition date fair value and the best estimate of a future settlement amount for assets subject to contingencies.
Employee benefit arrangements and deferred tax	Measure in accordance with IFRS 2 and IAS 12, not at fair value.	Measure in accordance with FAS 123 and FAS 109, not at fair value.
Non-controlling interest (NCI) – formerly Minority Interest	Measure at fair value or at NCI share of fair value of identifiable net assets.	Measure at fair value.
Contingent consideration	If not within scope of IAS 39, account for subsequently under IAS 37. Measure financial asset or liability contingent consideration at fair value, with changes recognised in earnings or other comprehensive income.	Measure subsequently at fair value, with changes recognised in earnings if classified as asset or liability.
Lessor operating lease assets	Value of asset includes terms of lease.	Value lease separately from asset.

3.8 Financial instruments and trading & risk management

IFRS and US GAAP take broadly consistent approaches to the accounting for financial instruments however many detailed differences exist between the two.

IFRS and US GAAP define financial assets and financial liabilities in similar ways. Both require recognition of financial instruments only when the entity becomes a party to the instrument's contractual provisions. Financial assets, financial liabilities and derivatives are recognised initially at fair value under IFRS and US GAAP. Transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability are added to its fair value on initial recognition unless the asset or liability is measured subsequently at fair value with changes in fair value recognised in profit or loss. Subsequent measurement depends on the classification of the financial asset or financial liability. Certain classes of financial asset or financial liability are measured subsequently at amortised cost using the effective interest method and others, including derivative financial instruments, at fair value through profit or loss. The Available For Sale (AFS) class of financial assets is measured subsequently at fair value through equity (other comprehensive income). These general classes of financial asset and financial liability are used under both IFRS and US GAAP, but the classification criteria differ in certain respects.

Selected differences between IFRS and US GAAP are summarised below.

Issue	IFRS	US GAAP
Definition of a derivative	A derivative is a financial instrument: • whose value changes in response to a specified variable or underlying rate (for example, interest rate); • that requires no or little net investment; and • that is settled at a future date.	Sets out similar requirements, except that the terms of the derivative contract should: • require or permit net settlement; and • identify a notional amount. There are therefore some derivatives that may fall within the IFRS definition, but not the US GAAP definition.

Continued on the next page

Issue	IFRS	US GAAP
Separation of embedded derivatives	Derivatives embedded in hybrid contracts are separated when: • the economic characteristics and risks of the embedded derivatives are not closely related to the economic characteristics and risks of the host contract; • a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative; and • the hybrid instrument is not measured at fair value through profit or loss. Under IFRS, reassessment of whether an embedded derivative needs to be separated is permitted only when there is a change in the terms of the contract that significantly modifies the cash flows that would otherwise be required under the contract. A host contract from which an embedded derivative has been separated, qualifies for the own-use exemption if the own-use criteria are met.	Similar to IFRS except that there are some detailed differences of what is meant by 'closely related'. Under US GAAP, if a hybrid instrument contains an embedded derivative that is not clearly and closely related to the host contract at inception, but is not required to be bifurcated, the embedded derivative is continuously reassessed for bifurcation. The normal purchases and normal sales exemption cannot be claimed for a contract that contains a separable embedded derivative – even if the host contract would otherwise qualify for the exemption.
Own-use exemption	Contracts to buy or sell a non-financial item that can be settled net in cash or another financial instrument are accounted for as financial instruments unless the contract was entered into and continues to be held for the purpose of the physical receipt or delivery of the non-financial item in accordance with the entity's expected purchase, sale or usage requirements. Application of the own-use exemption is a requirement – not an election.	Similar to IFRS, contracts that qualify to be classified as for normal purchases and normal sales do not need to be accounted for as financial instruments. The conditions under which the normal purchase and normal sales exemption is available is similar to IFRS but detailed differences exist. Application of the normal purchases and normal sales exemption is an election.
Offsetting contracts	A practice of entering into offsetting contracts to buy and sell a commodity is considered to be a practice of net settlement. All similar contracts must be accounted for as derivatives.	Similar to IFRS, except that power purchase or sales agreements that meet the definition of a capacity contract are not accounted for as derivatives even if they are entered into to offset other such contracts.

4 Financial disclosure examples

4 Financial disclosure examples

4.1 Decommissioning obligations

Asset retirement obligations and recultivation obligations, & sinking funds

Fortum Corporation

Provisions

"Provisions for environmental restorations, asset retirement obligations, restructuring costs and legal claims are recognised when the Group has a present legal or constructive obligation as a result of past events to a third party, it is probable that an outflow of resources will be required to settle the obligation and the amount can be reliably estimated. Provisions are measured at the present value of the expenditures expected to be required to settle the obligation using a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the obligation. The increase in the provision due to the passage of time is recognised as interest expense.

Asset retirement obligations

Asset retirement obligation is recognised either, when there is a contractual obligation towards a third party or a legal obligation and the obligation amount and the definite lifetime can be estimated reliably. Obligating event is e.g. when a plant is built on a leased land with an obligation to dismantle and remove the asset in the future or when a legal obligation towards Fortum changes. The asset retirement obligation is recognised as part of the cost of an item of property and plant when the asset is put in service or when contamination occurs. The costs will be depreciated over the remainder of the assets' useful life.

Liabilities related to nuclear production

The provision for future obligations for nuclear waste management including decommissioning of Fortum's nuclear power plant and related spent fuel is based on long-term cash-flow forecasts of estimated future costs. The main assumptions are technical plans, timing, costs estimates and discount rate. The technical plans, timing and cost estimates are approved by governmental authorities. Any changes in the assumed discount rate would affect the provision. If the discount rate used would be lowered, the provision would increase. Fortum has contributed cash to the State Nuclear Waste Management Fund based on a non-discounted legal liability, which leads to that the increase in provision would be offset by an increase in the recorded share of Fortum's part of the State Nuclear Waste Management Fund in the balance sheet.

The total effect on the income statement would be positive since the decommissioning part of the provision is treated as an asset retirement obligation. This situation will prevail as long as the legal obligation to contribute cash to the State Nuclear Waste Management Fund is based on a non-discounted liability and IFRS is limiting the carrying value of the assets to the amount of the provision since Fortum does not have control or joint control over the fund.

Annual Report and Accounts 2007, Fortum Corporation, p. 35 and 37

RWE AG

"The vast majority of provisions for nuclear waste management are recognized as non-current provisions, and their settlement amount is discounted to the balance-sheet date. As in the previous year, an interest rate of 5.0% was used as the discount rate. Volume-based increases in the provisions are measured at their present value. In the reporting period, they amounted to Euro 128 million (previous year: Euro 92 million). By releasing Euro 178 million in unused provisions (previous year: Euro 164 million), we have taken into account that waste disposal costs are expected to be lower, according to current estimates. Additions to provisions for nuclear waste management primarily consist of an interest accretion of Euro 425 million (previous year: Euro 416 million). Euro 684 million in prepayments, primarily to foreign reprocessing companies and to the German Federal Office for Radiation Protection (BfS) for the construction of final storage facilities, were deducted from the provisions for nuclear waste management (previous year: Euro 640 million).

In terms of their contractual definition, provisions for nuclear waste management break down as follows:

Provisions for nuclear waste management in Euro millions	12.31.2007	12.31.2006
Provisions for nuclear obligations, not yet contractually defined	7,159	6,895
Provisions for nuclear obligations, contractually defined	1,894	1,939
	9,053	**8,834**

In respect of the disposal of spent nuclear fuel assemblies, the provisions for obligations which are not yet contractually defined cover the estimated long-term costs of direct final storage of fuel assemblies, which is currently the only possible disposal method in Germany, and the costs for the disposal of radioactive waste from reprocessing. The latter essentially consist of costs for transport from centralized storage facilities and the plants' intermediate storage facilities to reprocessing plants and final storage as well as conditioning for final storage and containers. These estimates are mainly based on studies by internal and external experts, in particular by Gesellschaft für Nuklear-Service mbH (GNS) in Essen, Germany. With regard to the decommissioning of nuclear power plants, the costs for the post operational phase and dismantling are taken into consideration, on the basis of data from external expert opinions prepared by NIS Ingenieurgesellschaft mbH, Alzenau Germany, which are generally accepted throughout the industry and are updated continuously. Finally, this item also covers all of the costs of final storage for all radioactive waste, based on data provided by BfS.

Provisions for contractually defined nuclear obligations are related to all nuclear obligations for the disposal of fuel assemblies and radioactive waste as well as for decommissioning, insofar as the value of said obligations is specified in contracts under civil law. They include the anticipated residual costs of reprocessing, return (transport, containers) and intermediate storage of the resulting radioactive waste, as well as the additional costs of the utilization of uranium and plutonium from reprocessing activities. These costs are based on existing contracts with foreign reprocessing companies and with GNS. Moreover, these provisions also take into account the costs for transport and intermediate storage of spent fuel assemblies within the framework of final direct storage. The power plants' intermediate storage facilities are licensed for an operational period of 40 years and commenced operations between 2002 and 2006. Furthermore, the amounts are also stated for the conditioning and intermediate storage of radioactive operational waste, which is primarily performed by GNS.

Provisions for nuclear waste management in Euro millions	12.31.2007	12.31.2006
Decommissioning of nuclear facilities	4,443	4,213
Disposal of nuclear fuel assemblies	4,061	4,168
Disposal of radioactive operational waste	549	453
	9,053	**8,834**

With due consideration of the German Atomic Energy Act (AtG), in particular to Sec. 9a of AtG, the provision for nuclear waste management breaks down as follows:

Provisions for mining damage also consist primarily of non-current provisions. They are recognized at the settlement amount discounted to the balance-sheet date. As in the previous year, an interest rate of 5.0% was used as the discount rate. In the reporting period, additions to provisions for mining damage amounted to Euro 210 million (previous year: Euro 151 million). Of this, an increase of Euro 128 million (previous year: Euro 108 million) did not have an impact on income, as an identical amount was capitalized under property, plant and equipment. The interest accretion of the additions to provisions for mining damage amounted to Euro 123 million (previous year: Euro 113 million).

Provisions for restructuring pertain mainly to measures for socially acceptable payroll downsizing from previous years."

Annual Report and Accounts 2007, RWE AG, p .183 f

4.2 Impairment
Definition of CGUs, e.g. for networks; treatment of deferred taxes

RWE AG
Management estimates and judgments
"(…) The impairment test for goodwill is based on certain assumptions pertaining to the future. Based on current knowledge, changes in these assumptions will not cause the carrying amounts of the cash-generating units to exceed the recoverable amounts, and thus will also not result in an adjustment of the carrying amounts in the next fiscal year. Due to the planned disposal of the North American water business, the valuation of this cash-generating unit is based on market-related data, and changes in such may have an impact on the carrying amount. In particular, the valuation depends on the equity market conditions prevailing at the time of recognition, the development of long-term interest rates on the capital market and the development of assets subject to regulation as well as the decisions of the local regulatory authorities. (…) "

Annual Report and Accounts 2007, RWE AG, p. 155

Intangible assets
"In the reporting period, a total of Euro 74 million (previous year: Euro 73 million) was spent on research and development. Development costs of Euro 52 million (previous year: Euro 62 million) were capitalized. Intangible assets in exploration activities accounted for Euro 209 million in the reporting period (previous year: Euro 101 million).

Goodwill was allocated to cash-generating units at the segment level or at a level beneath the segment level to carry out impairment tests. Goodwill breaks down as follows:

Goodwill in Euro millions	12.31.2007	12.31.2006
RWE Power	829	829
of which: RWE Dea	(30)	(30)
of which: RWE Trading	(434)	(434)
RWE Energy	5,003	5,118
RWE npower	3,876	4,370
Water Division		2,001
	9,708	**12,318**

The goodwill of RWE Energy includes Euro 1,241 million (previous year: Euro 1,270 million) which was recognized in accordance with IAS 32. This goodwill stems from put options granted and forward purchases of minority interests.

In the reporting period, goodwill decreased by Euro 2,090 million (previous year: Euro 3,266 million). Classification of American Water as a discontinued operation resulted in a decline of Euro 1,789 million, and divestments by RWE Energy resulted in disposals of Euro 163 million. In accordance with IAS 12.68, the goodwill of RWE npower was reduced by Euro 138 million (previous year: Euro 48 million), as tax benefits from periods prior to first-time consolidation were realized.

In the period under review, no impairment losses were recognized on goodwill on continued operations (previous year: Euro 6 million). Currency effects decreased the carrying amount of goodwill by Euro 520 million (previous year: Euro 23 million).

The impairment test involves determining the recoverable amount of the cash-generating units, which corresponds to the fair value less costs to sell or the value in use. The fair value reflects the best estimate of the sum that an independent third party would pay to purchase the cash-generating unit as of the balance-sheet date; selling costs are deducted. Value in use is the present value of the future cash flows which are expected to be generated with a cash-generating unit. As of the balance-sheet date, both the fair value less costs to sell and the value in use of the cash-generating units were substantially higher than their carrying amounts.

Fair value and value in use are determined on the basis of a business valuation model, whereby the fair value is assessed from an external perspective and the value in use from a company-internal perspective. Fair values and values in use are determined based on future cash flows, which are based on the business plan for a period of five years, which has been approved by the Executive Board and which is valid when the impairment test is performed. Business plans are based on experience as well as on future expected market trends. If available, market transactions or third-party valuations of similar assets in the same sector are taken as a basis for determining the fair value.

Business plans are based on the general economic data derived from macroeconomic and financial studies and make country-specific assumptions, primarily regarding the development of gross domestic product, consumer prices, interest rates and nominal wages.

The main assumptions underlying the business planning for the divisions active on Europe's electricity and gas markets – RWE Power, RWE Energy and RWE npower – are the premises relating to the development of wholesale prices for electricity, crude oil, natural gas, coal and CO2 emission allowances, and retail prices for electricity and gas, as well as to the development of market shares and regulatory framework conditions. The discount rates used for business valuations are determined on the basis of market data and range from 6.5 to 8.5% for cash-generating units after tax (previous year: 5.7 to 6.9%). As in the previous year, the rate generally applied is 6.5%. By contrast, a discount rate of 8.5% is used for RWE Dea, and in the previous year a rate of 5.7% was used in the water business in North America. Before tax, all of the interest rates used are between 9.5 and 13.0% (previous year: 7.5 and 10.5%).

RWE extrapolates future cash flows going beyond the detailed planning horizon based on constant growth rates of 0.0 to 0.5% (previous year: 0.0 to 1.26%), in order to account for expected inflation. These figures are derived from experience and future expectations for each division and do not exceed the long-term average growth rates of the markets on which the companies are active. The cash flow growth rates are determined subtracting the capital expenditure required to achieve the assumed cash flow growth."

Annual Report and Accounts 2007, RWE AG, p. 166 f

Centrica plc

"Goodwill and indefinite lived intangibles are tested for impairment annually, or more frequently if there are indications that amounts might be impaired. The impairment test involves determining the recoverable amount of the cash-generating units, which corresponds to the fair value less costs to sell or the value in use. Value in use calculations have been used to determine recoverable amounts for the cash-generating units noted above. These are determined using cash flow budgets, which are based on business plans for a period of three years. These business plans have been approved by the Board and are valid when the impairment test is performed. The plans are based on past experience as well as future expected market trends. Cash flows beyond the three-year plan period used in the value in use calculations are increased in line with historic long-term growth rates in the UK, or where applicable the US, Canada, Belgium and the Netherlands. Discount rates applied to the cash flow forecasts in determining recoverable amounts are derived from the Group's weighted average cost of capital. Discount rates applied to North American cash-generating units range from 9.4% to 9.5%, and from 8.5% to 11.2% for UK and Europe cash-generating units on a pre-tax basis. Growth rates used to extrapolate cash flow projections beyond the period covered by the most recent forecasts range from 1% to 2.5%.

The key assumptions in the value in use calculations determining recoverable amounts for the specific cash-generating units noted above are:

British Gas Business
- Budgeted gross margin: for existing contract customers this is based on contracted margins. For new and renewal contract customers this is based on achieved gross margin in the period prior to the approval of the business plan, adjusted in some areas to reflect market conditions. For tariff customers this is based on current prices in the period prior to the approval of the business plan, adjusted for the Group's view of the forward energy curve.
- Budgeted market share: based on the average market share achieved immediately prior to the approval of the business plan, adjusted for growth forecasts based on sales and marketing activity.

British Gas Services – Dyno-Rod
- Budgeted franchise fee income: based on the average income achieved immediately prior to the approval of the business plan, adjusted for growth forecasts based on sales and marketing activity.
- Budgeted cost growth: based on the cost growth in the period prior to the approval of the business plan.

Texas residential energy
- Budgeted gross margin: based on the average gross margin achieved prior to the approval of the business plan, adjusted to reflect market conditions.
- Budgeted market prices: based on a combination of the Group's view of forward gas and power prices immediately prior to the approval of the business plan and the price impact of targeted margins.
- Budgeted consumption: based on past experience of the average consumption per customer prior to the approval of the business plan.
- Budgeted customer numbers: based on past experience in the three years prior to the approval of the business plan adjusted for an expected marginal decline in customer numbers.

Canada mass markets
- Budgeted gross margin: for existing customers this is based on contracted margins. For new and renewal contract customers this is based on gross margin achieved in the period immediately prior to the approval of the business plan.
- Budgeted market share: based on average market share achieved in the period immediately prior to the approval of the business plan, adjusted for growth and decline assumptions specific to each of the competitive and regulated businesses.
- Budgeted market prices: for existing customers this is based on contracted prices. For new or renewal customers this is based on the Group's view of forward gas and power prices in Canada.
- Budgeted cost growth: based on current and forecasted experience required to support customer acquisition, renewal, retention and other servicing activities.

Canada Direct Energy business services
- Budgeted gross margin: based on gross margins achieved through recent sales and renewal activity and potentially adjusted for future expected market conditions.
- Budgeted churn: based on historic actual attrition and renewal rates prior to the approval of the business plan.
- Budgeted revenue growth: based on management's view of forward commodity cost curves as provided by the internal energy management group at the time of approval of the business plan to determine future selling prices. Volume growth is estimated based on average achieved growth in the past, uplifted by expected future growth as a result of the planned sales activities that management believes to be reasonably attainable.

Canada home services
- Budgeted gross margin: based on gross margins achieved in the period immediately prior to the approval of the business plan.
- Budgeted revenue growth: based on the average revenue growth achieved for the three-year period prior to the approval of the business plan, uplifted for additional product offerings.

US home services
- Budgeted gross margin: based on gross margins achieved in the period immediately prior to the approval of the business plan.

- Budgeted revenue growth: based on the average revenue growth achieved over the last three years prior to the approval of the business plan, uplifted for growth targets based on expected market penetration in certain key US state markets.

Europe – Oxxio
- Budgeted revenue growth: based on revenue in the period immediately prior to the approval of the business plan, uplifted for expected growth in customer base, cross-selling of products and reduction of customer churn.
- Budgeted gross margin: based on the average gross margin achieved in periods prior to the approval of the business plan, adjusted for the expected impact arising from the unbundling of the gas and electricity markets going forward.
- Budgeted operating expenditure: based on historical trends, adjusted for cost improvement programmes implemented.

The Group is of the opinion that, based on current knowledge, expected changes in the aforementioned key assumptions on which the determination of the recoverable amounts are based would not cause the recoverable amounts to be less than the carrying amounts of the cash-generating units."

Annual Report and Accounts 2007, Centrica plc, p. 91 f

4.3 Arrangements that may contain a lease

IFRIC 4: Wind parks and other generation plants; contracting

EDF Group

Arrangements containing a lease

"In compliance with interpretation IFRIC 4, the Group identifies agreements that convey the right to use an asset or group of specific assets to the purchaser although they do not have the legal form of a lease contract, as the purchaser in the arrangement benefits from a substantial share of the asset's production and payment is not dependent on production or market price. Such arrangements are treated as leases, and analyzed with reference to IAS 17 for classification as either finance or operating leases."

Annual Report and Accounts 2007, EDF Group, p. 18

4.4 Emission Trading Scheme and Certified Emission Reductions

Fortum Corporation

Emission allowances

"The Group accounts for emission allowances based on currently valid IFRS standards where purchased emission allowances are accounted for as intangible assets at cost, whereas emission allowances received free of charge are accounted for at nominal value. A provision is recognised to cover the obligation to return emission allowances. To the extent that Group already holds allowances to meet the obligation the provision is measured at the carrying amount of those allowances. Any shortfall of allowances held over the obligation is valued at the current market value of allowances. The cost of the provision is recognised in the income statement within materials and services. Gains from sales of emission rights are reported in other income."

CO2 emission allowance price risk

"Fortum manages its exposure to CO2 allowance prices related to own production through the use of CO2 forwards and by ensuring that the costs of allowances are taken into account during production planning. These are own use contracts valued at cost. In addition to own production Fortum has proprietary trading book. These allowances are treated as derivatives in the accounts."

Annual Report and Accounts 2007, Fortum Corporation, p. 31 and 40

Centrica plc

EU Emissions Trading Scheme and renewable obligations certificates

"Granted CO2 emissions allowances received in a period are initially recognised at nominal value (nil value). Purchased CO2 emissions allowances are initially recognised at cost (purchase price) within intangible assets. A liability is recognised when the level of emissions exceed the level of allowances granted. The liability is measured at the cost of purchased allowances up to the level of purchased allowances held, and then at the market price of allowances ruling at the balance sheet date, with movements in the liability recognised in operating profit. Forward contracts for the purchase or sale of CO2 emissions allowances are measured at fair value with gains and losses arising from changes in fair value recognised in the Income Statement. The intangible asset is surrendered at the end of the compliance period reflecting the consumption of economic benefit. As a result no amortisation is recorded during the period.

Purchased renewable obligation certificates are initially recognised at cost within intangible assets. A liability for the renewables obligation is recognised based on the level of electricity supplied to customers, and is calculated in accordance with percentages set by the UK Government and the renewable obligation certificate buyout price for that period. The intangible asset is surrendered at the end of the compliance period reflecting the consumption of economic benefit. As a result no amortisation is recorded during the period."

Annual Report and Accounts 2007, Centrica plc, p. 62 f

4.5 Customer contributions

Revenue recognition; customer subsidies/ contributions for construction projects

Fortum Corporation
Government grants
"Grants from the government are recognised at their fair value where there is a reasonable assurance that the grant will be received and the Group will comply with all attached conditions. Government grants relating to costs are deferred and recognised in the income statement over the period necessary to match them with the costs that they are intended to compensate. Government grants relating to the purchase of property, plant and equipment are deducted from the acquisition cost of the asset and are recognised as income by reducing the depreciation charge of the asset they relate to."

Annual Report and Accounts 2007, Fortum Corporation, p. 31

RWE AG
Revenue (including natural gas tax/electricity tax)
"Revenue is recorded when the risk stemming from a delivery or service has been transferred to the customer. To improve the presentation of business development, RWE reports revenue generated by energy trading operations as net figures, reflecting realized gross margins. By contrast, electricity, gas, coal and oil transactions that are subject to physical settlement are stated as gross figures. Energy trading revenue is generated by RWE Trading. In fiscal 2007, gross revenue (including energy trading) amounted to Euro 65,097 million (previous year: Euro 70,213 million). The segment reporting on pages 196 to 199 contains a breakdown of revenue (including natural gas tax/electricity tax) by division and geographical region. Deconsolidations and first-time consolidations reduced revenue by a net Euro 806 million. Natural gas tax/electricity tax are the taxes paid directly by Group companies."

Annual Report and Accounts 2007, RWE AG, p. 159

E.ON AG
Trade Payables and Other Operating Liabilities
"(…) Construction grants of Euro 3,412 million (2006: Euro 3,470 million) were paid by customers for the cost of new gas and electricity connections in accordance with the generally binding terms governing such new connections. These grants are customary in the industry, generally non-refundable and recognized as revenue according to the useful lives of the related assets. (...)"

Annual Report and Accounts 2007, E.ON AG, p. 183

4.6 Regulatory assets & liabilities

E.ON AG

U.S. Regulation

"Accounting for E.ON's regulated utility businesses, Louisville Gas and Electric Company, Louisville, Kentucky, U.S., and Kentucky Utilities Company, Lexington, Kentucky, U.S., of the U.S. Midwest market unit, conforms to U.S. generally accepted principles as applied to regulated public utilities in the United States of America. These entities are subject to SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71"), under which certain costs that would otherwise be charged to expense are deferred as regulatory assets based on expected recovery of such costs from customers in future rates approved by the relevant regulator. Likewise, certain credits that would otherwise be reflected as income are deferred as regulatory provisions. The current or expected recovery by the entities of deferred costs and the expected return of deferred credits is generally based on specific ratemaking decisions or precedent for each item. The regulatory assets and liabilities under U.S.GAAP do not fulfill the recognition criteria for assets and liabilities under IFRS. As a result, these regulatory assets and liabilities were offset against equity and resulted in an increase in equity of Euro 403 million within the opening balance sheet (December 31, 2006: Euro 279 million)."

Annual Report and Accounts 2007, E.ON AG, p. 206

Fortum Corporation

"(…) The prices charged to customers for the sale of distribution of electricity are regulated. The regulatory mechanism differs from country to country. Any over or under income decided by the regulatory body is regarded as regulatory assets or liabilities that do not qualify for balance sheet recognition due to the fact that no contract defining the regulatory aspect has been entered into with a specific customer and thus the receivable is contingent on future delivery. The over or under income is normally credited or charged over a number of years in the future to the customer using the electricity connection at that time. No retroactive credit or charge can be made."

Annual Report and Accounts 2007, Fortum Corporation, p. 31

4.7 Business combinations

Business combinations, e.g. in-process development projects

Fortum Corporation

"(…) The financial statements of Fortum Group have been consolidated according to the purchase method. The cost of an acquisition is measured as the aggregate of fair value of the assets given and liabilities incurred or assumed at the date of exchange, plus costs directly attributable to the acquisition. Identifiable assets acquired and liabilities assumed in a business combination are measured initially at their fair values at the acquisition date, irrespective of the extent of any minority interest. The excess of the cost of acquisition over the fair value of the Group's share of the identifiable net assets acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognised directly in the income statement. Subsidiaries are fully consolidated from the date on which control is transferred to the Group and are no longer consolidated from the date that control ceases. Intercompany transactions, balances and unrealised gains on transactions between Group companies are eliminated. Unrealised losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred. Where necessary, subsidiaries' accounting policies have been changed to ensure consistency with the policies the Group has adopted."

Annual Report and Accounts 2007, Fortum Corporation, p. 29

4.8 Concession arrangements

IFRIC 12: Concession agreements

EDF Group
IFRIC 12
"The IFRIC issued interpretation IFRIC 12, "Service Concession Arrangements", in November 2006. Subject to completion of the endorsement process by the European Commission, application of this interpretation will be mandatory in the EU for financial years beginning on or after January 1, 2008. EDF has not opted for early application.

Nevertheless, a full review of the concession agreements concerning each of the Group's French and foreign entities was instigated in late 2006 and continued into 2007, to determine the treatment applicable in the light of interpretation IFRIC 12. This treatment depends on whether the grantor has control, as defined by IFRIC 12, over the infrastructures and services during the concession:

- If the grantor controls the infrastructures and services, the concession falls into the scope of IFRIC 12 and the associated infrastructures are recorded in the operator's accounts as either an intangible asset or a financial asset,
- Otherwise, the concession is not governed by IFRIC 12 and the infrastructure is accounted for under the IFRS applicable.

Analysis of the control exercised by the grantor involves examining, for each contract, the type of infrastructure concerned (electricity generation, transmission or distribution) but also the legal aspects (the respective rights and obligations of the grantor and operator as defined in the agreements) and business environments (particularly tariffs and regulations), both in and outside France."

Annual Report and Accounts 2007, EDF Group, p. 27

4.9 Financial instruments

Centrica plc
Derivative financial instruments
"The Group routinely enters into sale and purchase transactions for physical delivery of gas, power and oil. A portion of these transactions take the form of contracts that were entered into and continue to be held for the purpose of receipt or delivery of the physical commodity in accordance with the Group's expected sale, purchase or usage requirements, and are not within the scope of IAS 39.

Certain purchase and sales contracts for the physical delivery of gas, power and oil are within the scope of IAS 39 because they net settle or contain written options. Such contracts are accounted for as derivatives under IAS 39 and are recognised in the Balance Sheet at fair value. Gains and losses arising from changes in fair value on derivatives that do not qualify for hedge accounting are taken directly to the Income Statement for the year.

The Group uses a range of derivatives for both trading and to hedge exposures to financial risks, such as interest rate, foreign exchange and energy price risks, arising in the normal course of business. The use of derivative financial instruments is governed by the Group's policies approved by the Board of Directors. Further detail on the Group's risk management policies is included within the Directors' Report – Governance on pages 39 to 40 and in note 4 to the Financial Statements.

The accounting treatment for derivatives is dependent on whether they are entered into for trading or hedging purposes. A derivative instrument is considered to be used for hedging purposes when it alters the risk profile of an underlying exposure of the Group in line with the Group's risk management policies and is in accordance with established guidelines, which require that the hedging relationship is documented at its inception, ensure that the derivative is highly effective in achieving its objective, and require that its effectiveness can be reliably measured. The Group also holds derivatives which are not designated as hedges and are held for trading.

All derivatives are recognised at fair value on the date on which the derivative is entered into and are re-measured to fair value at each reporting date. Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative. Derivative assets and derivative liabilities are offset and presented on a net basis only when both a legal right of set-off exists and the intention to net settle the derivative contracts is present.

The Group enters into certain energy derivative contracts covering periods for which observable market data does not exist. The fair value of such derivatives is estimated by reference in part to published price quotations from active markets, to the extent that such observable market data exists, and in part by using valuation techniques, whose inputs include data, which is not based on or derived from observable markets. Where the fair value at initial recognition for such contracts differs from the transaction price, a fair value gain or fair value loss will arise. This is referred to as a day-one gain or day-one loss. Such gains and losses are deferred and amortised to the Income Statement based on volumes purchased or delivered over the contractual period until such time observable market data becomes available. When observable market data becomes available, any remaining deferred day-one gains or losses are recognised within the Income Statement. Recognition of the gain or loss that results from changes in fair value depends on the purpose for issuing or holding the derivative. For derivatives that do not qualify for hedge accounting, any gains or losses arising from changes in fair value are taken directly to the Income Statement and are included within gross profit or interest income and interest expense. Gains and losses arising on derivatives entered into for speculative energy trading purposes are presented on a net basis within revenue."

Annual Report and Accounts 2007, Centrica plc, p. 65 and 66

E.ON AG

Derivative Financial Instruments and Hedging Transactions

"Derivative financial instruments and separated embedded derivatives are measured at fair value as of the trade date at initial recognition and in subsequent periods. IAS 39 requires that they be categorized as held for trading as long as they are not a component of a hedge accounting relationship. Gains and losses from changes in fair value are immediately recognized in net income.

Instruments commonly used are foreign currency forwards and swaps, as well as interest-rate swaps and cross-currency swaps. Equity forwards are entered into to cover price risks on securities. In commodities, the instruments used include physically and financially settled forwards and options related to electricity, gas, coal, oil and emission rights. As part of conducting operations in commodities, derivatives are also acquired for proprietary trading purposes. (…)"

Annual Report and Accounts 2007, E.ON AG, p. 137

Fortum Corporation

Accounting for derivative financial instruments and hedging activities

"(…) Derivatives are initially recognised at fair value on the date a derivative contract is entered into and are subsequently re-measured at their fair value. The method of recognising the resulting gain or loss depends on whether the derivative is designated as a hedging instrument, and if so, the nature of the item being hedged. The Group designates certain derivatives as either: (1) hedges of highly probable forecast transactions (cash flow hedges); (2) hedges of the fair value of recognised assets or liabilities or a firm commitment (fair value hedge); or (3) hedges of net investments in foreign operations. The Group documents at the inception of the transaction the relationship between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions. The Group also documents its assessment, both at hedge inception and on an ongoing basis, of whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items. Derivatives are divided into non-current and current based on maturity. Only for those electricity derivatives, which have cash flows in different years, the fair values are split between non current and current assets or liabilities."

Annual Report and Accounts 2007, Fortum Corporation, p. 36

E.ON AG

Valuation of Derivative Instruments

"The fair value of derivative instruments is sensitive to movements in underlying market rates and other relevant variables. The Company assesses and monitors the fair value of derivative instruments on a periodic basis. Fair values for each derivative financial instrument are determined as being equal to the price at which on party would assume the rights and duties of another party, and calculated using common market valuation methods with reference to available market data as of the balance sheet date.

The following is a summary of the methods and assumptions for the valuation of utilized derivative financial instruments in the Consolidated Financial Statements.

- Currency, electricity, gas, oil and coal forward contracts, swaps, and emissions-related derivatives are valued separately at their forward rates and prices as of the balances sheet date. Forward rates and prices are based on spot rates and prices, with forward premiums and discounts taken into consideration. Market data are used to the extent possible.
- Market prices for currency, electricity and gas options are valued using standard option pricing models commonly used in the market. The fair value of caps, floors and collars are determined on the basis of quoted market prices or on calculations based on option pricing models.
- The fair values of existing instruments to hedge interest risk are determined by discounting future cash flows using market interest rates over the remaining term of the instrument. Discounted cash values are determined for interest rate, cross-currency and cross-currency interest rate swaps for each individual transaction as of the balance sheet date. Interest income is recognized in income at the date of payment or accrual.
- Equity forwards are valued on the basis of the stock prices of the underlying equities, taking into consideration any timing components.
- Exchange-traded energy futures and option contracts are valued individually at daily settlement prices determined on the futures markets that are published by their respective clearing houses. Paid initial margins are disclosed under other assets. Variation margins received or paid during the term of such contracts are stated under other liabilities or other assets, respectively.
- Certain long-term energy contracts are valued with the aid of valuation models that use internal data if market prices are not available.

Losses of Euro 11 million (2006: Euro 49 million) and gains of Euro 141 million (2006: Euro 96 million) from the initial measurement of derivative financial instruments at the inception of the contract were deferred and will be recognized in income during subsequent periods as the contracts are fulfilled. The following two tables include both derivatives that qualify for IAS 39 hedge accounting treatment and those that do not qualify.

The carrying amounts of cash and cash equivalents and of trade receivables are considered reasonable estimates of their fair values because of their short maturity.

Where financial instruments are listed on an active market, the respective price quotes at that market constitute the fair value. This applies in particular to equities held and bonds issued.

The fair value of shareholdings in unlisted companies and of debt securities that are not actively traded, such as loans received, loans granted and financial liabilities, is determined by discounting future cash flows. Discounting takes place using current customary market interest rates through the remaining terms of the financial instruments. Fair value measurement was not applied in the case of shareholdings with a carrying amount of Euro 58.3 million (2006: Euro 58.3 million) as cash flows could not be determined reliably for them. Fair values could not be derived on the basis of comparable transactions. The shareholdings are not material by comparison with the overall position of the Group.

The fair value of commercial paper and borrowings under revolving short-term credit facilities and of trade receivables is used as the fair value due to the short maturities of these instruments. (...)

Total Volume of Foreign Currency, Interest Rate and Equity-Based Derivatives

in Euro millions	12.31.2007 Nominal value	12.31.2007 Fair value	12.31.2006 Nominal value	12.31.2006 Fair value
FX forward transactions				
Buy	8,466.8	-24.2	4,352.7	-27.1
Sell	9,738.3	67.3	6,982.4	19.4
FX currency options				
Buy	-	-	7.4	0.1
Sell	-	-	-	-
Subtotal	**18,205.1**	**43.1**	**11,522.5**	**-7.6**
Cross-currency swaps	19,847.2	686.6	18,499.3	7.4
Cross-currency interest rate swaps	301.6	-49.6	321,9	-17.0
Subtotal	**20,148.8**	**637.0**	**18,821.2**	**-9.6**
Interest rate swaps				
Fixed-rate payer	1,894.0	-21.5	2,292.5	-16.4
Fixed-rate receiver	6,153.7	-85.9	6,078.3	-89.8
Interest rate future	1,719.4	30.2		
Subtotal	**9,767.1**	**-77.2**	**8,370.8**	**-106.2**
Other derivatives	117.3	12.0	636.7	31.0
Subtotal	**117.3**	**12.0**	**636.7**	**31.0**
Total	**48,238.3**	**614.9**	**39,351.2**	**-92.4**

Total Volume of Electricity, Gas, Coal, Oil and Emissions-Related Derivatives

in Euro millions	12.31.2007 Nominal value	12.31.2007 Fair value	12.31.2006 Nominal value	12.31.2006 Fair value
Electricity forwards	25,733.5	-794.1	29,049.7	-854.0
Exchange-traded electricity forwards	10,033.6	-98.8	8,089.5	-275.0
Electricity swaps	21.4	-1.1	15.1	0.5
Exchange-traded electricity options	104.9	9.5	0.3	0.2
Coal forwards and swaps	5,024.4	193.1	1,320.2	29.2
Exchange-traded coal forwards	38.1	25.7	58.9	-1.1
Oil derivatives	708.4	11.6	1,213.4	-30.6
Gas forwards	12,932.1	335.3	16,757.1	6.7
Gas swaps	313.8	-36.2	153.4	-17.4
Gas options	4.5	-3.6	5.3	2.8
Exchange-traded gas forwards	1.2	0.1	-	-
Emissions-related derivatives	1,808.0	6.0	461.0	2.8
Exchange-traded emissions-related derivatives	407.8	-0.1	33.9	3.8
Total	**57,203.7**	**-352.6**	**57,157.8**	**-1,132.1**

Additional Disclosures on Financial Instruments

Carrying Amounts and Fair Values by Class Within the Scope of IFRS 7 as of December 31, 2007

in Euro millions	Carrying amounts	Total carrying amounts within the scope of IFRS 7	IAS 39 measurement category	Fair value	Determined using market prices
Equity investments	14,583	14,583	AfS	14,583	13,061
Financial receivables and other financial assets	3,964	3,920		4,140	262
Financial receivables from entities in which an ownership interest exists	899	899	LaR	899	-
Receivables from finance leases*	700	700	n/a	705	-
Other financial receivables and financial assets	2,365	2,321	LaR	2,536	262
Trade receivables and other operating assets	18,653	17,021		16,940	377
Receivables from entities in which an ownership interest exists	846	845	LaR	845	-
Trade receivables	9,064	9,064	LaR	9,064	-
Derivatives with no hedging relationships	4,928	4,928	HfT	4,928	365
Derivatives with hedging relationships	632	632	n/a	632	-
Other operating assets	3,183	1,552	LaR	1,471	12
Securities and fixed-term deposits	10,783	10,783	AfS	10,783	9,635
Cash and cash equivalents	2,887	2,887	AfS	2,887	2,860
Restricted cash	300	300	AfS	300	300
Assets held for sale	577	-	AfS	-	-
Total assets	**51,747**	**49,494**		**49,633**	**26,495**

* Includes finance leases with third parties and with entities in which an ownership interest exists.

Continued on the next page

in Euro millions	Carrying amounts	Total carrying amounts within the scope of IFRS 7	IAS 39 measurement category	Fair value	Determined using market prices
Financial liabilities	21,464	21,464		21,903	12,869
Financial liabilities to entities in which an ownership interest exists	2,085	2,085	AmC	2,085	-
Bonds	14,470	14,470	AmC	14,886	12,823
Commercial paper	1,984	1,984	AmC	1,984	-
Bank loans/Liabilities to banks	2,012	2,012	AmC	1,931	-
Liabilities from finance leases*	193	193	n/a	297	-
Other financial liabilities	720	720	AmC	720	46
Trade payables and other operating liabilities	23,686	17,356		17,356	502
Liabilities to entities in which an ownership interest exists	539	539	AmC	539	-
Trade payables	4,477	4,477	AmC	4,477	-
Derivatives with no hedging relationships	4,630	4,630	HfT	4,630	502
Derivatives with hedging relationships	641	641	n/a	641	-
Put option liabilities under IAS 32	754	754	AmC	754	-
Other operating liabilities	12,645	6,315	AmC	6,315	-
Total liabilities	**45,150**	**38,820**		**39,259**	**13,371**

* Includes finance leases with third parties and with entities in which an ownership interest exists.

Table glossary
AfS – Available for sale
LaR – Loans and receivables
HfT – Held for trading
AmC – Amortized cost

(...) For financial liabilities that bear floating interest rates, the rates that were fixed on the Balances sheet date are used to calculate future interest payments for subsequent periods as well. Financial liabilities that can be terminated at any time are assigned to the earliest maturity time band in the same way as put options that are exercisable at any time.

In gross-settled derivatives (usually currency derivatives and commodity derivatives), outflows are accompanied by related inflows of funds or commodities.

The net gains and losses form financial instruments by IAS 39 category are shown in the following table:

Net Gains and Losses by Category

in Euro millions	12.31.2007	12.31.2006
Loans and receivables	385	520
Available for sale	1,533	847
Held for trading	446	-1,858
Amortized cost	-929	-989
Total	**1,435**	**-1,480**

In addition to interest income and expenses from financial receivables, the net gains and losses in the loans and receivables category consist primarily of valuation allowances on trade payables. Gains and losses on the disposal of available-for-sale securities and equity investments are reported under other operating income and other operating expenses, respectively.

In addition, the interest income and expenses from interest-bearing securities is included in this net result.

The net gains and losses in the held-for-trading category encompass both the changes in fair value of the derivative financial instruments and the gains and losses on realization. (...)

Risk Managment
(...) Price Risks
In the normal course of business, the E.ON Group is exposed to foreign exchange, interest and commodity price risks, and also to price risks in equity investments in the context of cash investments activities. These risks create volatility in earnings, equity and cash flows from period to period. The Company makes use of derivative financial instruments in various strategies to limit or eliminate these risks.

The following discussion of the Company's risk management activities and the estimated amounts generated from profit-at-risk, Value-at-Risk and sensitivity analyses are "forward-looking statements" that involve risks and uncertainties. Actual results could differ materially from those projected due to actual, unforeseeable developments in the global financial markets. The methods used by the Company to analyze risks, as discussed below, should not be considered projections of future events or losses. The Company also faces risks that are either non-financial or non-quantifiable. Such risks principally include country risk, operational risk and legal risk which are not represented in the following analyses.

Foreign Exchange Risk Management
Due to the international nature of some of its business activities, the E.ON Group is exposed to exchange risks related to sales, assets, receivables and liabilities denominated in foreign currencies, investments in foreign operations and anticipated foreign currency payments. The Company's exposure results mainly from transactions in U.S. dollars, British pounds, Hungarian forint, Swedish kronor and Russian rubles, and from net investments in foreign operations.

E.ON AG is responsible for controlling the currency risks to which the E.ON Group is exposed, and sets appropriate risk parameters. The subsidiaries are responsible for controlling their operating currency risks. Recognized assets and liabilities are generally hedged in the full amount. For unrecognized firm commitments, hedging takes place after consultation between the subsidiary and E.ON AG.

The foreign exchange risk arising from net investments in foreign operations with a functional currency other than the euro is reduced at Group level as needed through hedges of net investments. In addition, borrowings are made in foreign currency to control foreign exchange risks.

In line with the Company's internal risk-reporting process and international banking standards, market risk has been calculated using the Value-at-Risk method on the basis of historical market data. The Value-at-Risk (or "VaR") is equal to the maximum potential loss (on the basis of a probability of 99 percent) from foreign-currency positions that could be incurred within the following business day. The calculations take account of correlations between individual transactions; the risk of a portfolio is generally lower than the sum of its individual risks.

The one-day Value-at-Risk from the translation of deposits and borrowings denominated in foreign currency, plus foreign currency derivatives, amounted to Euro 148 million (2006: Euro 54 million) and, as in 2006, resulted primarily from the open positions denominated in British pounds and U.S. dollars. The increase in the VaR over the previous year is due in particular to the increased volatility of the Euro/GBP exchange rate and to overall higher volumes denominated in foreign currency.

This VaR has been calculated in accordance with the requirements of IFRS 7. In practice, however, another value will result, since certain underlying transactions (e.g. scheduled transactions and off-balance-sheet own-use agreements) are not considered in the calculation according to IFRS 7.

Interest Risk Management
Several line item on the Consolidated Balance Sheet and certain financial derivatives are based on fixed interest rates, and are therefore subject to changes in fair value resulting from changes in market rates. In the case of balance sheet items and financial derivatives based on floating interest rates, E.ON is exposed to profit risks. E.ON seeks to maintain a specific mix of fixed- and floating-rate debt in its overall debt portfolio. The company uses interest rate swaps in order to benefit from the spread between short-term and long-term interest rates and from any potential easing of interest rates in general.

As of December 31,2007, the E.ON Group has entered into interest rate swaps with a nominal value of Euro 9,767 million (2006: Euro 8,371 million).

A sensitivity analysis was performed on the Group's short-term and variable-rate borrowings, including interest rate derivatives. A one-percent increase (decline) in the level of interest rates would cause net interest expense to rise (fall) by Euro 30 million per annum (2006: Euro 35 million).

Commodity Price Risk Management
E.ON is exposed to substantial risks resulting from fluctuations in the prices of commodities, both on the supply and demand side. This risk is measured based on potential negative deviation from the target adjusted EBIT.

The maximum permissible risk is determined centrally by the Board of Management in its medium-term planning and translated into a decentralized limit structure in coordination with the market units. Before fixing any limits, the investment plans and all other known obligations and quantifiable risks have been taken into account.

E.ON conducts commodity transactions primarily within the system portfolio, which includes core operations, existing sales and procurement contracts and any energy derivatives used for hedging purposes or for power plant optimization. The risk in the system portfolio thus arises from the open position between planned procurement and generation and planned sales volumes. The risk of these open positions is measured using the profit-at-risk ("PaR") number, which quantifies the risk by taking into account the size of the open position and the prices, the volatility and the liquidity of the underlying commodities. PaR is defined as the maximum potential negative change in the value of the portfolio at a probability of 95 percent in the event that the open position is closed as quickly as possible.

The principal derivative instruments used by E.ON to cover commodity price risk exposures are electricity, gas, coal and oil swaps and forwards, as well as emissions-related derivatives. Commodity derivatives are used by the market units for the purposes of price risk management, system optimization, equalization of burdens and improvement of margins. Proprietary trading is permitted only within very tightly defined limits. The risk metric used for The proprietary trading portfolio is a five-day Value-at-Risk with a 95-percent confidence interval.

The trading limits for proprietary trading as well as for all other trading activities are established and monitored by bodies that are independent from trading operations. Limits used on hedging and proprietary trading activities include five-day Value-at-Risk and profit-at-risk numbers, as well as stop-loss limits. Additional key elements of the risk management system are a set of Group-wide commodity risk guidelines, the clear devision of duties between scheduling, trading, settlement and controlling, as well as a risk reporting system independent of the trading operations. Group-wide developments in commodity risks are reported to the Risk Committee on a monthly basis.

As of December 31, 2007, the E.ON Group has entered into electricity, gas, coal, oil and emissions-related derivatives with a nominal value of Euro 57,204 million (2006: Euro 57,158 million).

The VaR for the proprietary trading portfolio amounted to Euro 13 million as of December 31, 2007 (2006: Euro 16 million). The PaR for the financial instruments in the scope of IFRS 7 included in the system portfolio was Euro 433 million as of December 31, 2007 (2006: Euro 289 million).

The restriction to financial instruments included in the scope of IFRS 7 that has been applied in this calculation does not reflect the economic positions of the E.ON Group. Consequently, none of the off-balance sheet transactions, such as own-use contracts under normal trading relationships, may be included when calculating the PaR according to IFRS 7, even though such transactions represent a material component of the economic position. The PaR reflecting the actual economic position therefore differs significantly from the PaR determined in accordance with IFRS 7."

Annual Report and Accounts 2007, E.ON AG, p. 188 ff

Fortum Corporation
Counterparty Risk
"Exposures against limits and counterparties' creditworthiness are monitored to ensure that the risks are at an accepted level. When changes appear to be leading to unacceptable risks according to approved policies, Corporate Credit Control initiates actions to mitigate risks. Counterparty risk exposures relating to financial derivative instruments are often volatile. The majority of the Group's commodity derivatives

in Euro millions	12.31.2007 Carrying amount	12.31.2007 of which past due	12.31.2006 Carrying amount	12.31.2006 of which past due
Investment grade receivables	173	–	79	–
Electricity exchanges	9	–	101	–
Associated companies	639	–	603	–
Other	219	–	211	–
Total	**1,040**	**–**	**994**	**–**

are cleared by the Nordic electricity exchange, Nord Pool. Derivative transactions are also done with other individual external counterparties on the financial or commodity markets. Counterparty risk in the retail and wholesale business is well diversified over a large number of private individuals and industrial companies.

Amounts disclosed below are presented by counterparties for interest-bearing receivables including leasing receivables and derivative financial instruments recognised as assets."

CO2 emission allowance price risk
"Fortum manages its exposure to CO2 allowance prices related to own production through the use of CO2 forwards and by ensuring that the costs of allowances are taken into account during production planning. These are own use contracts valued at cost. In addition to own production Fortum has proprietary trading book. These allowances are treated as derivatives in the accounts. At 31 December 2007 the trading volumes of sold and bought CO2 emission allowances were 3,101 ktCO2 (2006: 405) and 3,121 ktCO2 (2006: 418). The respective net fair values were Euro – 13 million (2006:0) and Euro 13 million (2006:0)."

Annual Report and Accounts 2007, Fortum Corporation, p. 40 and 43

RWE AG
"Market risks result from fluctuations in prices on financial markets. Changes in exchange rates, interest rates and share prices can have an influence on the Group's results on operating activities. Due to the Group's international profile, exchange rate management is a key issue. The British pound and the US dollar are the two most important foreign currencies for two main reasons: On the one hand, the Group is engaged in business activities in these two currency zones. On the other hand, fuels are traded in these currencies. Group companies are generally required to hedge all currency risks via RWE AG, which determines the net financial position for each currency and hedges it with external market partners if necessary.

Interest rate risks stem primarily from financial debt and the Group's interest-bearing investments. Negative changes in value caused by unexpected interest-rate movements are hedged with non-derivative and derivative financial instruments.

Opportunities and risks from changes in the values of securities are controlled by a professional fund management system. The Group's financial transactions are recorded using centralized risk management software and monitored by RWE AG. This enables the balancing of risks across individual companies.

Group risk management has established directives for commodity operations, stipulating that derivatives may be used to hedge against price risks, optimize power plant schedules and increase margins. Furthermore, commodity derivatives may be traded, subject to strict limits. These limits are defined by independent

Value-at-Risk for financial derivatives in Euro million	Value-at-Risk	
	12.31.2007	12.31.2006
Foreign currency derivatives	43.9	22.7
Forwards	5.3	5.7
Options	0.1	0.9
Interest rate currency derivatives	44.8	25.4
Interest rate derivatives	5.8	3.4
Share-price/index-related derivatives		1.9

organizational units and monitored on a daily basis.

All derivative financial instruments are recognized as assets or liabilities and are measured at fair value. When interpreting the positive and negative fair values of derivative financial instruments, with the exception of the relatively low commodity trading volumes, it must be taken into account that they are generally matched with underlying transactions that carry offsetting risks.

Maturities of interest rate, currency, share price or indexrelated and commodity derivatives are based on the maturities of the underlying transactions and are thus primarily short-term and medium-term in nature. Maturities of up to 30 years have been agreed upon to hedge foreign currency risks of foreign investments.

The Value-at-Risk method is used to quantify the interest rate, foreign currency and share-price risks for financial instruments as well as commodity price risks, in line with the international banking standard. The maximum expected loss arising from changes in market prices is calculated on the basis of historical market volatility and is monitored continuously.

The following Value-at-Risk information relates exclusively to recognized financial instruments, in line with the mandatory rules of IFRS 7. Off-balance-sheet planned positions which are hedged and so-called executory contracts in commodities may not be taken into account. As a result, an incomplete picture of the risk situation of the RWE Group is presented.

As of December 31, 2007, the foreign currency Value-at-Risk for all items to be taken into account pursuant to IFRS 7 amounted to Euro 17.2 million (previous year: Euro 10.9 million). In accordance with IFRS 7, underlying transactions which are the subject of a cash flow hedge were not taken into consideration in determining this position. The Value-at-Risk determined in this manner thus represents a slightly pessimistic scenario, taking into account risk aspects.

As of December 31, 2007, the interest rate Value-at-Risk from financial debts and related hedging transactions amounted to Euro 69.3 million (previous year: Euro 34.5 million). Taking into account the hedges, the Value-at-Risk from interest-bearing assets amounted to Euro 21.2 million (previous year: Euro 18.8 million).

Share price Value-at-Risk was Euro 17.3 million as of December 31, 2007 (previous year: Euro 24.8 million).

As of December 31, 2007, commodity price Value-at-Risk pursuant to IFRS 7 amounted to Euro 35.2 million (previous year: Euro 97.6 million).

The Value-at-Risk figures are based on a confidence interval of 95% and a holding period of one day."

Annual Report and Accounts 2007, RWE AG, p. 192 f

Contact us

Global contacts

Manfred Wiegand
Global Utilities Leader
Telephone: +49 201 438 1517
Email: manfred.wiegand@de.pwc.com

Norbert Schwieters
Global Utilities IFRS Group
Telephone: +49 211 981 2153
Email: norbert.schwieters@de.pwc.com

Territory contacts

Africa

Angola
Julian Ince
Telephone: +244 222 395004
Email: julian.ince@ao.pwc.com

Gabon
Elias Pungong
Telephone: +241 77 23 35
Email: elias.pungong@ga.pwc.com

Nigeria
Uyiosa Akpata
Telephone: +234 1 320 2101
Email: uyi.n.akpata@ng.pwc.com

Southern Africa
Stanley Subramoney
Telephone: +27 11 797 4380
Email: stanley.subramoney@za.pwc.com

Asia-Pacific

Australia
Derek Kidley
Telephone: +61 2 8266 9267
Email:derek.kidley@au.pwc.com

China
Gavin Chui
Telephone: +86 10 6533 2188
Email: gavin.chui@cn.pwc.com

India
Kameswara Rao
Telephone: +91 40 2330 0750
Email: kameswara.rao@in.pwc.com

Indonesia
William Deertz
Telephone: +62 21 521 3975
Email: william.deertz@id.pwc.com

Europe

Austria
Gerhard Prachner
Telephone: +43 1 501 88 1800
Email: gerhard.prachner@at.pwc.com

Central and Eastern Europe
Peter Mitka
Telephone: +420 251 151 231
Email: peter.mitka@cz.pwc.com

Denmark
Per Timmermann
Telephone: +45 3945 3945
Email: per.timmermann@dk.pwc.com

Finland
Juha Tuomala
Telephone: +358 9 2280 1451
Email: juha.tuomala@fi.pwc.com

France
Philippe Girault
Telephone: +33 1 5657 8897
Email: philippe.girault@fr.pwc.com

Germany
Manfred Wiegand
Telephone: +49 201 438 1517
Email: manfred.wiegand@de.pwc.com

Norbert Schwieters
Telephone: +49 211 981 2153
Email: norbert.schwieters@de.pwc.com

Greece
Socrates Leptis-Bourgi
Telephone: +30 210 687 4693
Email: socrates.leptos.-.bourgi@gr.pwc.com

Ireland
Carmel O'Connor
Telephone: +353 1 792 6288
Email: denis.g.oconnor@ie.pwc.com

Italy
John McQuiston
Telephone: +390 6 57025 2439
Email: john.mcquiston@it.pwc.com

Netherlands
Aad Groenenboom
Telephone: +31 26 3712 509
Email: add.groenenboom@nl.pwc.com

Norway
Ståle Johansen
Telephone: +47 9526 0476
Email: staale.johansen@no.pwc.com

Portugal
Luis Ferreira
Telephone: +351 213 599 296
Email: luis.s.ferreira@pt.pwc.com

Russia & CIS
Dave Gray
Telephone: +7 495 967 6311
Email: dave.gray@ru.pwc.com

Spain
Francisco Martinez
Telephone: +34 915 684 704
Email: francisco.martinez@es.pwc.com

Sweden
Mats Edvinsson
Telephone: +46 8 555 33706
Email: mats.edvinsson@se.pwc.com

Switzerland
Ralf Schlaepfer
Telephone: +41 58 792 1620
Email: ralf.schlaepfer@ch.pwc.com

United Kingdom
Ross Hunter
Telephone: +44 20 7804 4326
Email: ross.hunter@uk.pwc.com

Middle East

Reinhard Schulz
Telephone: +971 2 694 6905
Email: reinhard.schulz@ae.pwc.com

The Americas

Canada

John Williamson
Telephone: +1 403 509 7507
Email: john.m.williamson@ca.pwc.com

Alistar Bryden
Telephone: +1 403 509 7354
Email: alistar.e.bryden@ca.pwc.com

Latin America

Jorge Bacher
Telephone: +54 11 4850 6801
Email: jorge.c.bacher@ar.pwc.com

United States

Paul Keglevic
Telephone: +1 213 356 6309
Email: paul.keglevic@us.pwc.com

Global Accounting Consulting Services IFRS

Mary Dolson
Telephone: +44 20 7804 2930
Email: mary.dolson@uk.pwc.com

Michael Stewart
Telephone: +44 20 7804 6829
Email: michael.j.stewart@uk.pwc.com

Further information

Olesya Hatop
Global Energy, Utilities & Mining Marketing
Telephone: +49 201 438 1431
Email: olesya.hatop@de.pwc.com

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