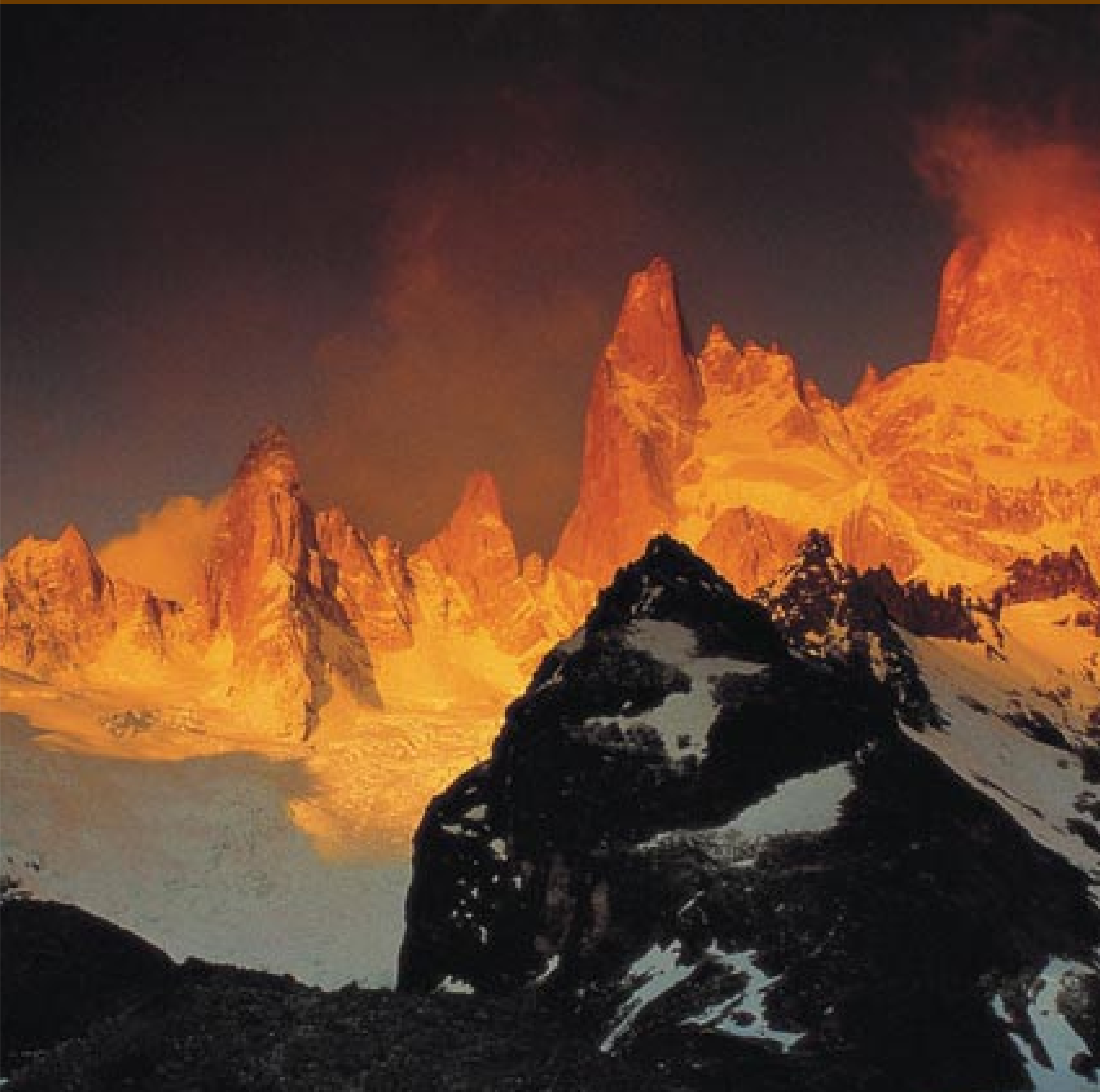
Crunch Time

Embedding International Financial Reporting Standards in the Oil and Gas and Utilities Industries



Contents

1 Introduction

The European Union (EU) has recently endorsed the regulation that requires listed European companies to comply with International Financial Reporting Standards (IFRS) in 2005 for their group financial statements. Many countries around the world are joining the process; the era of IFRS is dawning. The new global standards carry profound implications for companies and pose specific challenges in different sectors. In *Crunch Time*, we examine in detail the effect on oil and gas, electricity and water companies. We dissect both the oil and gas and utilities value chain to look at the crunch issues for different parts of the business. As we show, the challenges are much more than mere number-crunching, and extend deep into the way companies conduct and shape their accounting and reporting practices.

The move to IFRS reaches far beyond the territories where their adoption will be a mandatory requirement, such as the EU, Australia and Russia. Other territories will join the list and, indeed, harmonisation of IFRS and the US Generally Accepted Accounting Principles (US GAAP) is being actively pursued. IFRS reporting will be a vital passport to the capital markets. Transparency and comparability form a critical currency in investor relations, and companies which are slow to move to IFRS will face an added burden of proof that will place them at a competitive disadvantage.

Oil and gas entities and power utilities face contrasting challenges. The oil and gas industry is one of the earliest examples of global enterprise drawing on global capital markets. US GAAP has provided a common denominator, and includes a well-developed range of specific reporting rules for the oil and gas sector. But it remains uncertain how these rule-based precedents will sit with the emerging principles-based approach of the International Accounting Standards Board (IASB). In contrast, the expansion of utilities from their national spawning grounds to a more global footing is relatively recent, and industry reporting is still conditioned by national requirements. A more common reporting standard will both raise the bar and also provide opportunities for communicating value in an industry that is undergoing rapid change.

Across the whole oil and gas and utilities sectors, a fundamental challenge for both regulatory standard-setters and company Chief Financial Officers will be to explore how the evolving standards can heighten transparency, by ensuring that the bases of external financial reporting and internal management reporting are as seamless as possible. Such consistency is pivotal to both company efficiency and investor confidence. Ultimately, it will be key to IFRS effectiveness. Our goal in providing this report is to highlight the issues that require attention and consideration, and to add to the debate. We highlight the opportunities, tensions and challenges that oil and gas and utilities companies will face as they embrace the new standards and set their own course.

Richard Paterson

Global Oil and Gas Leader

Manfred Wiegand

Global Utilities Leader

1.1 IFRS Transition Environment

Timing

The anticipated move to IFRS in 2005 is the biggest change in financial reporting in 25 years and the biggest challenge for those companies that currently report under national Generally Accepted Accounting Principles (GAAP). Countries outside the EU, including Australia, Russia and several Middle Eastern and African countries, have also agreed on mandatory compliance to IFRS. The regulation applies to consolidated financial statements for accounting periods starting on or after 1 January 2005. To manage stakeholder expectations, and those of market analysts and regulators, many companies are likely to produce IFRS financial information in advance of 2005.

Logistics

Companies currently reporting under national GAAP face the greatest challenge, as the change from local GAAP to IFRS involves almost the whole company. Embedding this new basis of financial reporting and performance measurement across the entire organisation is critical. IFRS needs to become part of companies' budgeting and forecasting processes. It will affect how assets, liabilities and profit are measured and how companies explain the impact of a big new contract or joint venture (JV) to the outside world. And for listed companies, the market's expectations of a company's future performance will be in IFRS measurement terms and not local GAAP. Even the criteria for bonuses will change, as investors, for example, would react strongly if a company's managers were paid bonuses based on a set of measures no longer used for external reporting. The new reporting process also needs to be embedded within the current reporting processes and procedures and will require the full roll-out of new group reporting packages and a review of group reporting manuals, instructions and formats to identify areas where changes have been previously identified and are now required. In addition, specific data needs will be identified as part of the detailed review of individual accounting areas. This will include disclosure requirements. Some data needs will require software system changes in order to automate the required data capture. Last but not least, employees involved in preparing financial statements need to be trained.

Mergers and Acquisitions

There is an ongoing trend within the oil and gas and utilities industries for consolidation, especially through means of vertical integration. The treatment of goodwill will have significant consequences for companies seeking to demonstrate the benefits of combinations. With the new 'impairment-only approach' about to be decided on, consequences of business combinations will have a more significant impact than they had before.

IFRS/GAAP Convergence or Divergence?

The oil and gas industry comprises enterprises that operate on an international basis and exert great economic influence worldwide. There is currently great diversity in accounting and disclosure practices by oil and gas companies. In its extractive industries issues paper, the IASB noted that information disclosed should enable users to compare the financial position and financial performance of oil and gas companies in different countries, and that information which oil and gas companies provide should be comparable with information disclosed about similar transactions by enterprises that are not in the oil and gas sector. Furthermore, the IASB would continue to make use of the IASB's Framework for the Preparation and Presentation of Financial Statements, in developing the principles to be set out in a final standard on the extractive industries.

Changes in IFRS

The IASB has an aggressive work programme and is expected to introduce a number of changes in IFRS through the second quarter of 2004. These changes will be applicable for all companies adopting in 2005. The work programme includes major projects on business combinations, share-based payments, convergence with US GAAP, improvements to 10 standards and amendments to accounting for financial instruments. The broad proposals of the IASB are not expected to change substantially, but there will continue to be modifications to all exposure drafts until these are published as final standards. This document identifies some of the significant proposed changes that will affect oil and gas and utilities companies that have been discussed by the IASB through July 2003. It is not a comprehensive summary of the proposed changes to IFRS and has not attempted to predict the direction of the IASB's work. Companies should monitor developments at the IASB for those areas of particular relevance to themselves. The IFRS website of PricewaterhouseCoopers includes up-to-date information on the IASB's activities at www.pwc.com/ifrs.

1.2 Looking Down the Value Chain

We look in detail at the different components of the oil and gas value chain and, in Section 3, the utilities value chain, we analyse the IFRS issues the sector is facing. Preparing well ahead of time and getting the right approach to these issues will be vital not just to fulfilment of the new standards but to effective investor relations and ultimately to company performance and competitiveness.

2

The Oil and Gas Industry

Value Chain and Significant IFRS Accounting Issues

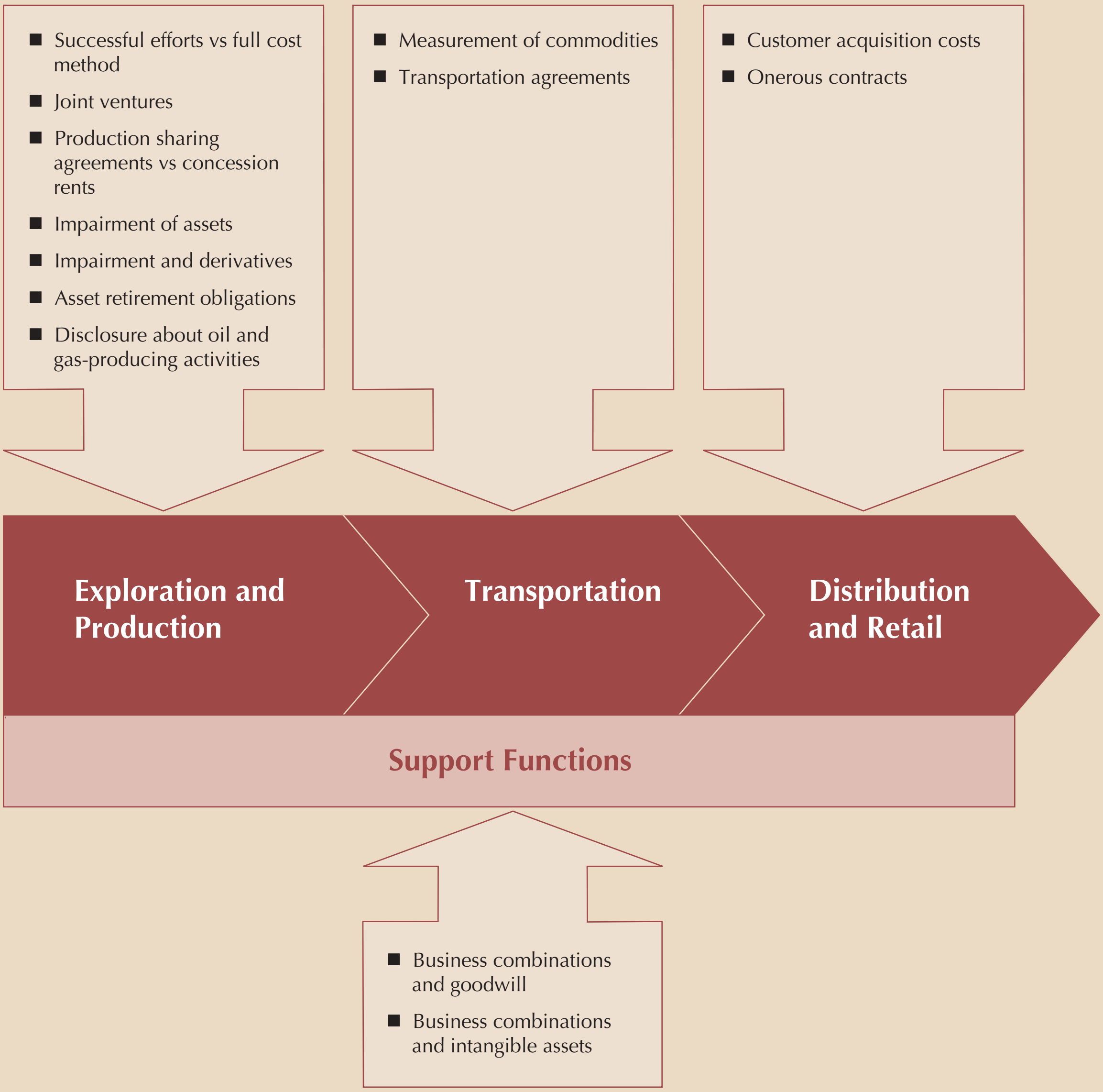


Figure 1: **Oil and Gas Company Value Chain and Significant IFRS Accounting Issues**

The IASB published an Issues Paper on extractive industries in November 2000. The paper considered reporting issues relevant to the oil and gas and the mining industries, and requested comments. This topic is not currently on the IASB's main agenda, although the project is active, and national standard setters, led by the Australian Accounting Standards Board, are continuing the work. A standard addressing the significant and different issues that the extractive industries face, for example exploration for, development of and evaluation of reserves, is likely to be published after 2005. The Board may, however, publish an interim standard providing guidance for those entities transitioning to IFRS before a comprehensive standard is developed. An interim standard may allow the continued use of national GAAP practices for exploration, development and production costs until a comprehensive standard is published.

An entity reporting under IFRS in the absence of either a comprehensive or an interim extractive industries standard must refer to the IASB Framework to develop accounting policies for those activities in which extractive industries are currently scoped out of existing IFRS. Entities may also refer to applicable standards of other standard setters in developing their accounting policies, provided that the accounting policies used are consistent with the IASB Framework.

This section discusses accounting practices commonly applied to the oil and gas industry in many countries under existing national GAAPs where there is no specific IFRS guidance. It considers the extent to which these common industry practices are consistent with the IASB Framework. The upcoming issues regarding emission rights trading are discussed in the Utilities section of this report.

2.1 Exploration and Production

Oil and gas exploration carries high risks, as the significant levels of investment required may not result in the discovery of commercially viable quantities of oil and gas. An oil and gas entity often shares the exploration and development risks by agreeing to jointly explore and develop particular areas and sites with other entities. The accounting for exploration, development and production activities must therefore reflect this joint control.

The legal rights to explore for, develop and produce oil and gas vary considerably between countries. The most straightforward are those where the entity owns the rights outright, which typically is the case in the United States for example. The mineral rights in many countries, however, are retained by the government, which leases the right to explore and produce oil and gas under licence. The terms of the licence, usually known as a concession, will specify the terms under which the licensee may explore for, develop and produce, oil and gas. The licences also often require the licensee to undertake specified minimum exploration activities, and set out the licensees decommissioning responsibilities.

The governments of developing oil regions increasingly use production sharing agreements (PSAs) to set out the terms under which oil and gas exploration, development and production may be undertaken. The oil and gas entity will normally assume all costs and risks associated with exploration and development. The PSA allows the entity to recover the allowable exploration and development costs from a share of the oil and gas produced (cost oil). The remaining oil and gas produced (profit oil) is shared between the company and the government in an agreed proportion. The government usually retains title to the assets, but many PSAs increasingly require that the oil company is responsible for decommissioning. Additionally, the company will pay bonuses to the government on signing the PSA, achieving commercial levels of production or reaching specified levels of production.

It is imperative that the method of accounting applied under IFRS for the different legal and risk-sharing arrangements reflect the substance of those arrangements, and this will be discussed later in this report.

Successful Efforts vs Full Cost Method

Currently, there is no specific guidance for the oil and gas industry's upstream activities under IFRS, though some activities, for example IAS 16 "Property, Plant and Equipment" and IAS 38 "Intangible Assets" are scoped out in several relevant Standards. The two primary methods commonly used, however, to account for upstream oil and gas activities are the 'successful efforts method' and the 'full cost method', both allowed under US GAAP.

> **Spotlight on the Standard**
>
> **IAS 16p2**
>
> This Standard does not apply to ... mineral rights, the exploration for and extraction of minerals, oil, natural gas and similar non-regenerative resources.

Most of the major, integrated oil and gas companies, as well as many smaller upstream companies, utilise the successful efforts method. Costs incurred in finding, acquiring and developing reserves are capitalised on a field-by-field or well-by-well basis depending on the nature of operations. A basic premise of successful efforts accounting is that capitalisation of costs is permitted when there has been a discovery of commercially viable (or proven) mineral reserves. When a commercial discovery has not been achieved, such costs are charged to expense. The complex nature of oil and gas exploration means it is often difficult to determine immediately whether or not commercial quantities of reserves have been discovered. During the time period when this determination is being made, there are varying treatments of the costs incurred under different local GAAP. Some allow temporary capitalisation until the determination period is completed and some do not. Capitalisation of these 'suspended well' costs is at odds with the IASB Framework definition of an asset, as is discussed below. It is clear, based on the Framework, that all exploration costs should be expensed as soon as it is determined that a commercial discovery has not been made. Once it is determined that commercially viable mineral reserves have been discovered, further costs of evaluation and development of the reserves should be capitalised, consistent with the IAS 38 treatment of development costs.

Some upstream oil and gas companies have historically used the full cost method. All costs incurred in searching for, acquiring and developing the reserves in a large geographic cost centre are capitalised. Cost centres are typically grouped on a country-by-country basis, although sometimes countries may be grouped together if the fields have similar or linked economic or geological characteristics. Since this method initially allows the capitalisation of all costs, stringent conventions for the assessment of impairment are typically prescribed.

Debate continues within the industry on the conceptual merits of both methods. These arguments typically involve performance measurement over time, volatility of earnings, matching, timing of loss recognition, and consistency with current definitions and concepts with local GAAP. However, the capitalisation of costs for unsuccessful exploration projects that is permitted under the full cost method is at odds with current definition and concepts under IFRS. Costs should be capitalised under IFRS only when it is probable that the recognised amount will be recoverable in full. Methods akin to the full cost method are unlikely to be acceptable once the IASB develops specific guidance for upstream oil and gas activities. A method similar to the successful efforts is more consistent with the conceptual definition of an asset under IFRS. Nevertheless, as indicated above, it still may be hard to justify that suspended well costs meet the definition of an asset under the conceptual framework. These factors need to be carefully considered when adopting IFRS. Until more IFRS guidance is developed that specifically addresses upstream oil and gas development activities, we believe it is reasonable for the preparer to consistently follow local GAAP, with clear disclosure of the methods followed and the circumstances under which costs are capitalised and expensed. Preparers should understand, however, that future development of IFRS is likely to change conventions for capitalisation of costs.

Joint Ventures – Accounting for Interest in Joint Ventures

Many oil and gas company activities involve jointly controlled operations, jointly controlled assets or jointly controlled entities. Joint control is defined under IFRS as the contractually agreed sharing of control over an economic activity.

The three forms of joint venture that IAS 31 addresses are summarised in the following table.

Type of joint venture	Description	Accounting treatment by the venturer
■ Jointly controlled operations	■ Each venturer uses its own property, plant and equipment and carries its own inventories. It also incurs its own expenses and liabilities and raises its own finance. The activities may be carried out by the venturer's employees alongside the venturer's similar activities. The joint venture (JV) agreement usually provides a means by which the revenue from the sale of the joint product and any expenses incurred in common are shared among the venturers.	■ The venturer should recognise: – The assets it controls and the liabilities it incurs – The expenses it incurs and its share of the income that it earns from the sale of goods or services by the JV
■ Jointly controlled assets	■ The venturers jointly control and jointly own one or more assets contributed to, or acquired for, the purpose of the JV and dedicated to the purposes of the JV. The assets are used to obtain benefits for the venturers. Each venturer may take a share of the output from the assets and each bears an agreed share of the expense incurred.	■ The venturer should recognise: – Its share of the jointly controlled assets, classified according to the nature of the assets – Any liabilities it has incurred – Its share of any liabilities incurred jointly with the other venturers in relation to the JV – Any income from the sale or use of its share of the output of the JV, together with its share of any expenses incurred by the JV – Any expenses it has incurred in respect of its interest in the JV
■ Jointly controlled entities	■ A jointly controlled entity is a JV that involves the establishment of a corporation, partnership or other entity in which the venturer has an interest. The entity operates in the same way as other entities, except that a contractual arrangement between the venturers establishes joint control over the economic activity of the entity. Each venturer is entitled to a share of the results of the jointly controlled entity, although some jointly controlled entities also involve a sharing of the output of the JV.	■ There is a choice under IFRS. The venturer should account for its interests in jointly controlled entities consistently either: – By proportionate consolidation; or – Using the equity method

Figure 2: **Joint Ventures Addressed by IAS 31**

Many activities in the oil and gas extractive industries involve jointly controlled assets; for example, a number of oil production companies may jointly control and operate an oil pipeline. Each venturer typically owns a percentage of the pipeline capacity and then has the right to ship its own product or the product of third parties on its portion of the pipeline capacity owned, in return for which it bears an agreed proportion of the expenses of operating the pipeline.

Joint Ventures – Accounting by Joint Ventures

IFRS does not provide guidance on how JV entities themselves should account for their activities. Although the ongoing business transactions need to comply with the normal IFRS standards, the JVs accounting for their creation is not addressed.

There are two alternative accounting treatments for the formation of JV: the 'step-up' method, and the 'predecessor-basis' method. The step-up method, whereby the JV recognises assets contributed at fair value, is similar to acquisition accounting except that all assets contributed are recognised at fair value. This method is sometimes referred to as 'fresh-start' accounting. Fair values are attributed to the assets and liabilities contributed to the JV. This treatment is consistent with the accounting by the venturer in recognising a gain or loss on the assets contributed by reference to their fair values, in accordance with the Standing Interpretations Committee (SIC) 13 "Jointly Controlled Entities – Non-Monetary Contributions by Venturers".

The second approach, predecessor-basis method, is based on the view that the formation of the JV is very similar to the uniting of interests (as described in IAS 22). The contributed assets are recorded by the JV at the predecessor-carrying values – i.e. using the values at which each venturer previously recorded them.

The IASB has yet to address the formation of JVs. The IASB's recent work has increasingly leaned towards the use of fair values in financial statements to provide more relevant information to readers. Many expect that when the IASB addresses the formation of JVs it will require use of the step-up method. Preparers need to choose a method of accounting for the formation of JVs and apply it consistently.

Spotlight on the Standard

IASB Framework p35

If information is to represent faithfully the transactions and other events that it purports to represent, it is necessary that they are accounted for and presented in accordance with their substance and economic reality and not merely their legal form.

Production-Sharing Agreements vs Concession Rents

The treatment of exploration and development costs incurred under a PSA needs careful consideration, even within the context of successful efforts accounting. Typically, the oil company will incur the costs of constructing assets, even though the title to oil and gas fixed assets rests with the government. The absence of title to these assets does, however, not prevent the oil company from capitalising the development costs. Acquisition, development and exploration costs that are expected to be recoverable through future cost oil and profit oil are generally capitalised or expensed pursuant to successful efforts accounting criteria. Similarly, costs that are not allowable for cost oil recovery under the terms of the PSA shall also be capitalised or expensed pursuant to successful efforts accounting rules. The substance of the transaction and the nature of the costs incurred should determine the accounting treatment and classification as tangible fixed assets or intangible assets.

The oil company should reflect as revenue only its share of the oil. It is not appropriate for the oil company to include revenue in respect of 100 per cent of the oil produced with a corresponding production cost for the oil belonging to the government.

The depreciation and amortisation of costs capitalised under a PSA should reflect the consumption of the economic benefits embodied in the assets. A unit of production basis, applied to proved reserves associated with the term of the PSA, will be appropriate in many cases.

A PSA will often specify that the oil company's payment of income taxes should be made in oil rather than cash ('oil-in-kind'). Settlement of taxes through the reallocation of oil produced rather than by cash should not affect the accounting treatment. The oil company should therefore report tax expense and corresponding revenue, and disclose details of the arrangement in the notes to the financial statements. The transaction will not be reflected in the cash flow statement, but disclosure should be made of all significant non-cash transactions.

Similar considerations should be made to the capitalisation and depreciation of costs incurred under a concession agreement. The principal difference between a PSA and a concession is that under a concession agreement the oil company is not required to share the oil with the government and retains title to the assets constructed. Costs incurred should therefore be capitalised following the successful efforts method. Depreciation and amortisation of the capitalised costs should reflect the pattern of consumption of the associated economic benefits. The unit of production basis is expected to be the most appropriate depreciation and amortisation method for concession agreements. The assets should be fully depreciated by the end of the concession.

Impairment of Assets

IAS 36 "Impairment of Assets" requires that an entity assess at each balance sheet date whether there are any indications that an asset may be impaired. The entity should estimate the recoverable amount of the asset if any such indication exists. The impairment test for assets under IAS 36 is based on the concept that an asset's carrying value should not be greater than its recoverable amount, which is the higher of its 'value in use' and its selling price. The value in use is determined by discounting the future cash flows expected to be realised from the asset's continuing use. The estimated future cash flows should reflect management's best estimate of the economic conditions that will exist over the asset's remaining life. An impairment loss should be recognised if the recoverable amount is less than the asset's carrying value.

IAS 36 describes some indications of when an impairment loss might have occurred (IAS 36p7 – 11). These indications are generally applicable to all companies; however, there are certain impairment indicators that have particular relevance to oil and gas companies, due to their regulated status and specific industry characteristics. Typical impairment indicators include:

- Governmental actions (such as new environmental regulations, imposition of price/tariff controls, etc.)
- Declines in prices of products, increases in production costs or changes in technology
- Significant downward revisions of reserves estimates
- Increases in the anticipated period over which reserves will be produced
- Loss or restriction of access to suitable markets (for example, loss of pipeline access, imposition of export restrictions or marketing restrictions)
- Increases in market interest rates

IAS 36 determines that, if possible, impairment should be assessed for individual assets. The entity determines the carrying amount of the cash-generating unit (CGU) to which the asset belongs if the recoverable amount cannot be determined for the individual asset. A 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.

The determination of CGUs for oil and gas exploration companies has particular difficulties because of the nature of their activities. For example, an individual asset, such as an oil well, would not be considered a CGU if it is dependent on other assets to generate cash inflows. Some oil and gas companies reporting under national GAAPs with similar requirements to IAS 36 identify CGUs on a field-by-field basis. A field approach to CGUs is often taken because all assets within the field usually share common production facilities, which are integral to the operations and cannot be separated and sold or transferred for alternative use.

However, several oil or gas fields may use common production and transportation facilities, and thus may constitute one CGU. The determination of a CGU may also be impacted by laws and regulations governing the operation or sale of assets or licences to extract; for example, if the licence required a company to operate a number of specific fields, even though one was loss-making. However, the inclusion of more than one field within a CGU should be done cautiously.

We believe that determination of the CGU for the extractive industries should be based on how the activity is managed, for example a geological basis, – on an individual field or property basis, taking into account that the focus should always be on the possibility to generate independent cash flows. However, there will be instances where a larger degree of aggregation will be required. For example, when several fields are tied into a common gathering system or common processing facilities and therefore individual fields or properties are not capable of generating cash flows that are substantially independent of each other.

Impairment and Derivatives

Oil and gas companies often enter into derivative transactions such as futures or forward contracts to hedge cash flows against volatile commodity prices or to lock in a margin for sales of commodities. The use of hedging strategies raises practical questions in determining value in use under IAS 36. For example, should a seller of oil, which has used a derivative instrument to place a ‘floor‘ on its future selling prices, consider the ‘floor‘ for determining the related assets’ discounted estimated future cash flows for the impairment test purposes?

IAS 39 requires that the derivative financial instrument be recorded on the balance sheet at fair value. These derivatives contracts represent financial assets or liabilities that are already reflected on the company's balance sheet under IAS 39, and therefore inclusion of their effect into estimated future discounted cash flows for impairment test computation would effectively result in recognising the derivative asset or liability twice in the financial statements. Therefore, expected future commodity spot prices, before considering the effects of derivative financial instruments, should be used for impairment calculations.

Please refer to the Utilities section of this report for a discussion of the accounting for the embedded derivatives as they relate to long-term purchase and sales contracts as well as take-or-pay agreements.

Asset Retirement Obligations

Most oil and gas companies have an obligation to decommission (plug and abandon uneconomical wells) their production assets at the end of the production term. In accordance with agreements and legislation, the well head, production assets, pipelines and other installations may have to be dismantled.

The obligation to decommission the asset normally arises the moment an asset is constructed. Historically, many oil companies assumed that salvage values would be equal to the cost of dismantling the facilities and carrying out the clean-up and reclamation activities. Consequently, dismantling costs were typically ignored. Provisions for decommissioning costs, in those instances where dismantling costs were significantly greater than the salvage value, were often accrued under the national GAAP, on a unit of production basis, as the related oil and gas was produced.

Retirement obligations must be treated differently under IFRS. The present value of the full decommissioning liability must be recognised as soon as the obligation exists, in accordance with IAS 37 "Provisions, Contingent Liabilities and Contingent Assets". This will often be when the asset is first constructed. The corresponding cost of the retirement obligation represents part of the cost of accessing the oil and gas, and is capitalised as part of the development costs in accordance with IAS 16 "Property, Plant and Equipment". The cost included in property, plant and equipment is amortised as part of the amortisation of the development cost. The decommissioning provision is accreted to the undiscounted liability, with the accretion of the discount being classified as interest expense.

Spotlight on the Standard

IASB Framework p21

The financial statements also contain notes and supplementary schedules and other information. For example, they may contain additional information that is relevant to the needs of users about the items in the balance sheet and income statement. They may include disclosures about the risks and uncertainties affecting the enterprise and any resources and obligations not recognised in the balance sheet (such as mineral reserves).

Disclosure about Oil and Gas Producing Activities

A key indicator for evaluating the performance of oil and gas entities are their existing reserves and the future production and cash flows expected from them. Some national accounting standards and securities regulators require supplemental disclosure of reserve information, most notably the Statement on Financial Accounting Standards (FAS) 69 and Securities and Exchange Commission (SEC) regulations. However, there are no reserve disclosure requirements under IFRS. IAS 1 "Presentation of Financial Statements" requires that an entity's financial statements should provide additional information which is not presented on the face of the financial statements but which is necessary for a fair presentation. IAS 1 allows an entity to consider the pronouncements of other standard-setting bodies and accepted industry practices in the absence of specific IFRS guidance when developing accounting policies.

We believe that it is best practice to include oil and gas supplemental information with the financial statements because of the unique nature of the oil and gas industry and the clear desire of investors and other users of the financial statements to receive information about reserves. Such information should be supplemental to the financial statements, and would not be covered by the independent auditor's opinion.

Information about quantities of oil and gas reserves and changes therein is essential for understanding and comparing oil and gas companies' financial position and performance. Entities should consider presenting reserve quantities and changes in them separately on a reasonable aggregate basis. Where certain reserves are subject to particular risks, those risks should be identified and communicated. Reserve disclosures accompanying the financial statements should be limited to those reserves used for financial statement purposes. For example, proven and probable reserves or proved developed and undeveloped reserves might be used for depreciation, depletion and amortisation calculations. The categories of reserves used and their definitions should be clearly described.

Reporting a 'value' for reserves and a common means of measuring that value have long been debated, and there is no consensus among national standard setters permitting or requiring value disclosure. We believe companies should avoid disclosures that purport to represent the value of reserves because of the subjectivity and the lack of common definitions of 'value'. However, there are globally accepted engineering definitions of reserves that take into account economic factors. These definitions may be a useful benchmark for disclosing future cash flow information about reserves for investors and other users of financial statements to evaluate. The basis of measurement and key assumptions used should be clearly disclosed if companies believe disclosure of this type of information is appropriate. All methods and assumptions used should be consistently applied. Such information would be outside the financial statements.

Other information – for example, potential future costs to be incurred to acquire, develop and produce reserves, may help users of financial statements to assess the entity's performance. We believe supplementary disclosure of such information with IFRS financial statements would be useful, but it should be based on a common guideline or practice, such as Society of Petroleum Engineers definitions, consistently reported and the underlying basis clearly disclosed.

Companies already presenting supplementary information regarding reserves under their national GAAP may want to continue providing such information until the IASB publishes a comprehensive standard, setting out the supplementary information disclosure requirements under IFRS.

2.2 Transportation

Crude oil and natural gas often needs to travel long distances to reach buyers, by means of pipelines and shipping – a phase in the value chain that is often referred to as the 'midstream'.

The costs of constructing a pipeline, including capitalised borrowing costs, should be depreciated according to the pipeline's expected economic useful life.

The issue whether the arrangements give rise to a service or a lease contract is discussed in the Utilities section of this report under 'Accounting for Transmission Contracts'.

Pipelines are often built and operated by more than one company in order to share costs and risks. These arrangements give rise to jointly controlled assets, operations or entities, the accounting of which we have described in the previous section.

Measurement of Commodities

Oil and gas transportation pipelines always contain a significant amount of oil or gas that is currently being transported, and the owner of this oil or gas must recognise it as an asset and value it appropriately. Similarly, oil and gas held in storage facilities must also be recognised and valued. IAS 2 "Inventories" currently requires inventories to be carried at the lower of cost and net realisable value, but allows inventories of commodities to be carried at market value. The proposed changes to IAS 2 are expected to require that all inventories of commodities are carried at market value. This proposed change to IAS 2, if confirmed, may lead to a significant change in inventory measurement practice in the industry.

A specific issue related to gas storage is leakage. The gas-storing company should allow for gas losses due to leakage. If leakage is not measured on a regular basis, the allowance should be prepared based on historical experience.

Transportation Agreements

The two major types of pipeline agreements for gas transportation are 'firm' and 'interruptible'. A firm transportation agreement means that one party conveys to the other party a certain volume of available pipeline capacity to use over a specified period of time. Payment is made regardless of whether that party uses the capacity provided or not. However, the pipeline operator is allowed to temporarily stop or reduce the capacity in an interruptible transportation agreement. In this case, the other party only has to pay for the amounts or time it actually used the pipeline.

Accounting for both types of contract is straightforward. The pipeline operator recognises revenue according to the contract (normally a straight-line basis) for a firm contract and according to actual use for an interruptible agreement. The shipper of the gas incurs cost of sales or cost of services received and, in addition, in a firm agreement needs to assess whether the contract gives rise to an onerous contract under IAS 37 "Provisions, Contingent Liabilities and Contingent Assets".

2.3 Distribution and Retail

Crude oil, piped from storage tanks into the refinery, is processed and converted into useable products. These refined products are transported from the refinery by pipeline, road or rail to arrive at the wholesalers and retail outlets for delivery to consumers and industrial users.

Customer Acquisition Costs

Oil and gas companies may have developed a portfolio of customers, or a market share, as the result of marketing efforts in building customer relationships and loyalty. The recurrent costs in respect of maintaining those relationships may be substantial.

The company may expect that, due to its marketing efforts, the customers will continue to trade with the company. However, in the absence of legal rights to protect, or other ways to control the loyalty and relationships with the customers, the company usually has insufficient control over the associated economic benefits to recognise an asset. Consequently, all costs in respect of self-developed customer relationships and loyalty are immediately charged to the income statement.

However, if the company concludes a contractual agreement with a customer to continue its relationship, the costs directly attributable to the contract should be capitalised and amortised to reflect the pattern of economic benefits expected under the contract. Costs should only be capitalised, however, if the company has control over the relationship through contract terms and future economic benefits are expected to be received. Any costs previously charged to income are not reinstated as an asset.

The accounting might be different if one oil and gas company acquires another. The acquirer may recognise at the acquisition date an intangible asset in respect of the acquired company's client list. The client list might be recognised separately from goodwill as an intangible asset, whether or not the list had been recognised as an asset in the acquired company's financial statements before the business combination. This will be the case when the list meets the definition of an asset and is identifiable; that is, is separable or arises from contractual or other legal rights and the future economic benefits that flow from other assets used in the same revenue earning activity are not disposed. The acquiring company should measure the intangible asset at fair value and may very likely require the services of professional valuers to establish the value.

In summary, intangible assets may be recognised in a business combination as follows:

Acquired intangible	Recognise as asset?
■ Customer list that can be sold	Yes
■ Customer contract that is 'in the money'	Yes
■ Customer relationship that is not controllable through contractual or other rights	No

Figure 3: **Intangible Assets**

Onerous Contracts

Oil and gas companies often enter into long-term contractual arrangements. These arrangements can become onerous. Some examples of contracts, which under certain circumstances may become onerous, are:

- Lease contracts when leased capacity is unused
- Fixed-price purchase or sale agreements (to the extent these are not financial instruments)
- Take-or-pay contracts
- Tolling agreements (refineries)
- Exploratory drilling commitments
- Drill rig commitments beyond the date that the decision has been made to abort exploratory activities

IAS 37 requires an entity to recognise its present obligation under the contract as a provision if the contract becomes onerous. A contract is onerous if the unavoidable costs of meeting the obligations under the contract exceed the economic benefits expected to be received under it.

The unavoidable costs under a contract is the least net cost of exiting the contract, which is the lower of the cost of fulfilling it and any compensation or penalties arising from failure to fulfil it. The amounts have to be discounted if the effect is material. An entity recognises any impairment loss that has occurred on assets dedicated to a contract before a separate onerous contract provision is established for it.

A contract that is unfavourable to the entity, for example a fixed purchase agreement at higher than current prices, is not necessarily onerous. The contract would continue to be accounted for as an executory contract if the commodity purchased under the contract could be used profitably in operations.

2.4 Mergers and Acquisitions

Business Combinations and Goodwill

Business combinations are almost never accounted for as uniting of interests (mergers). Business combinations are therefore treated as acquisitions. IAS 22 requires that the purchase method of accounting be used.

There is currently a rebuttable presumption under IAS 22 that the useful life of goodwill does not exceed 20 years. Goodwill is currently reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable, and annually if the estimated useful life exceeds 20 years.

The IASB has issued an Exposure Draft (ED 3 "Business Combinations") on business combinations seeking international convergence on the accounting for business combinations. ED 3 proposes to (a) disallow the uniting of interests method; (b) require the initial measurement at fair value of the identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination; (c) require immediate recognition in the income statement of any excess of the acquirer's interest in the fair values of identifiable net assets acquired in a business combination over the cost of the combination (negative goodwill); and (d) require the acquirer to recognise positive goodwill acquired in a business combination as an asset. The ED 3 proposals prohibit the amortisation of goodwill and instead require it to be tested for impairment at least annually. This proposed replacement of the annual amortisation charge with an annual impairment review by the ED increases the importance of the fair value measurement of the identifiable tangible and intangible assets.

Until recently, typically oil and gas companies did not recognise goodwill in business combinations. Companies had presumed that the fair value of consideration paid in a business combination is supported by proved, probable and possible reserves, and by any upside potential of the producing and non-producing properties. IFRS require that positive or negative goodwill be recognised, measured as the difference between the fair value of the consideration given and the fair value of the share of net assets acquired. As a consequence, if the acquirer determines that the fair value of the share of the net assets acquired equals the fair value of the consideration given, this leads to no goodwill being recognised under IFRS as well. However, if reasonable and supportable fair value methodologies lead to the conclusion that in fact the fair value of the net assets acquired is lower than the fair value of the consideration given, goodwill has to be recognised under IFRS.

Business Combinations and Intangible Assets

ED 3 also proposes significant new guidance for the recognition and measurement of intangible assets in a business combination.

Currently, IAS 38 (and IAS 22 for business combinations) contains strict criteria for recognition of intangible assets. ED 3 proposes that intangible assets acquired in a business combination will be recognised separately if they arise from contractual or legal rights, or are separable from the business. The new standard will include a list of items that are presumed to satisfy the recognition criteria. Some of these assets may not have been recognised in previous business combinations under the old guidance.

Another change proposed to the existing IAS 38 is the removal of the rebuttable presumption that an intangible asset's useful life is no more than 20 years. The cost of acquired and internally generated intangible assets will be amortised over their useful economic life, and assets with an indefinite life will be tested for impairment each year in accordance with IAS 36 under the proposed changes.

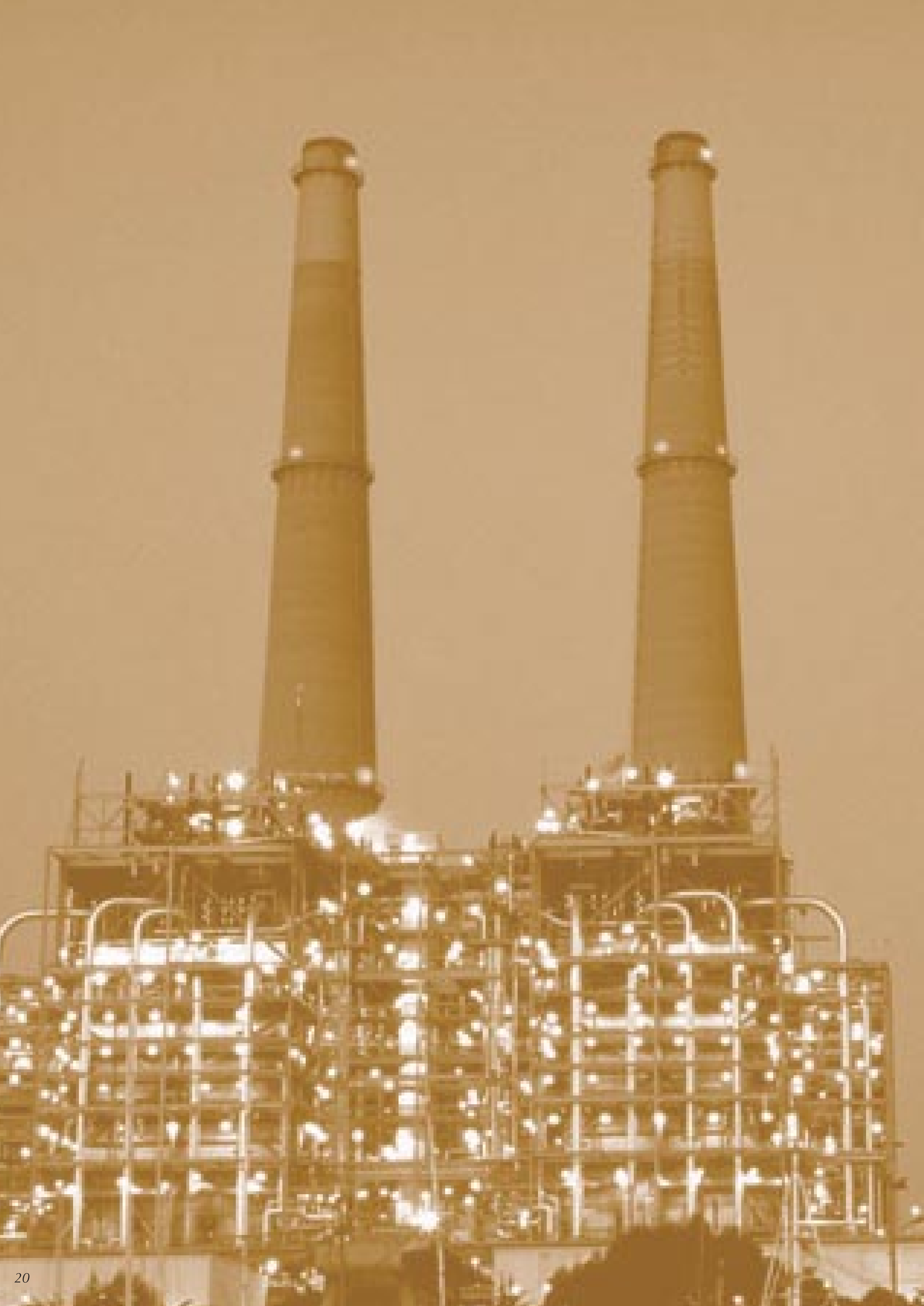
The proposed changes are likely to lead to more intangibles being recognised on future acquisitions, and most of these will be amortised. More extensive assessments before a transaction of the impact on post-acquisition results of recognising and amortising separate intangible assets will be necessary. Determining provisional amounts for these intangibles should now be part of the planning for any combination.

Spotlight on the Standard

ED 3, Basis for Conclusions p68

Changes during 2001 to the requirements in Canadian and United States standards on the separate recognition of intangible assets acquired in a business combination prompted the Board to consider whether it also should consider this issue as part of the first phase of its Business Combinations project. The Board observed that intangible assets make up an increasing proportion of the assets of many entities, and that intangible assets acquired in a business combination are often included in the amount recognised as goodwill, despite the requirements in IAS 22 and IAS 38 that they should be recognised separately from goodwill. The Board also agreed with the conclusion reached by the Canadian and US standard setters that the usefulness of financial statements would be enhanced if intangible assets acquired in a business combination were distinguished from goodwill.

The above-mentioned list of items that should satisfy the new recognition criteria includes trademarks, trade names, service and certification marks, Internet domain names, customer lists, customer contracts, use rights (such as drilling, water, mineral, etc.), patented/unpatented technology, etc. many of which will apply to oil and gas companies. The new IFRS guidance for intangible assets and business combinations is likely to lead to significant changes for some oil and gas companies compared with current practice.



The Utilities Industry: Electricity And Water

The Electricity Utility

Value Chain and Significant IFRS Accounting Issues

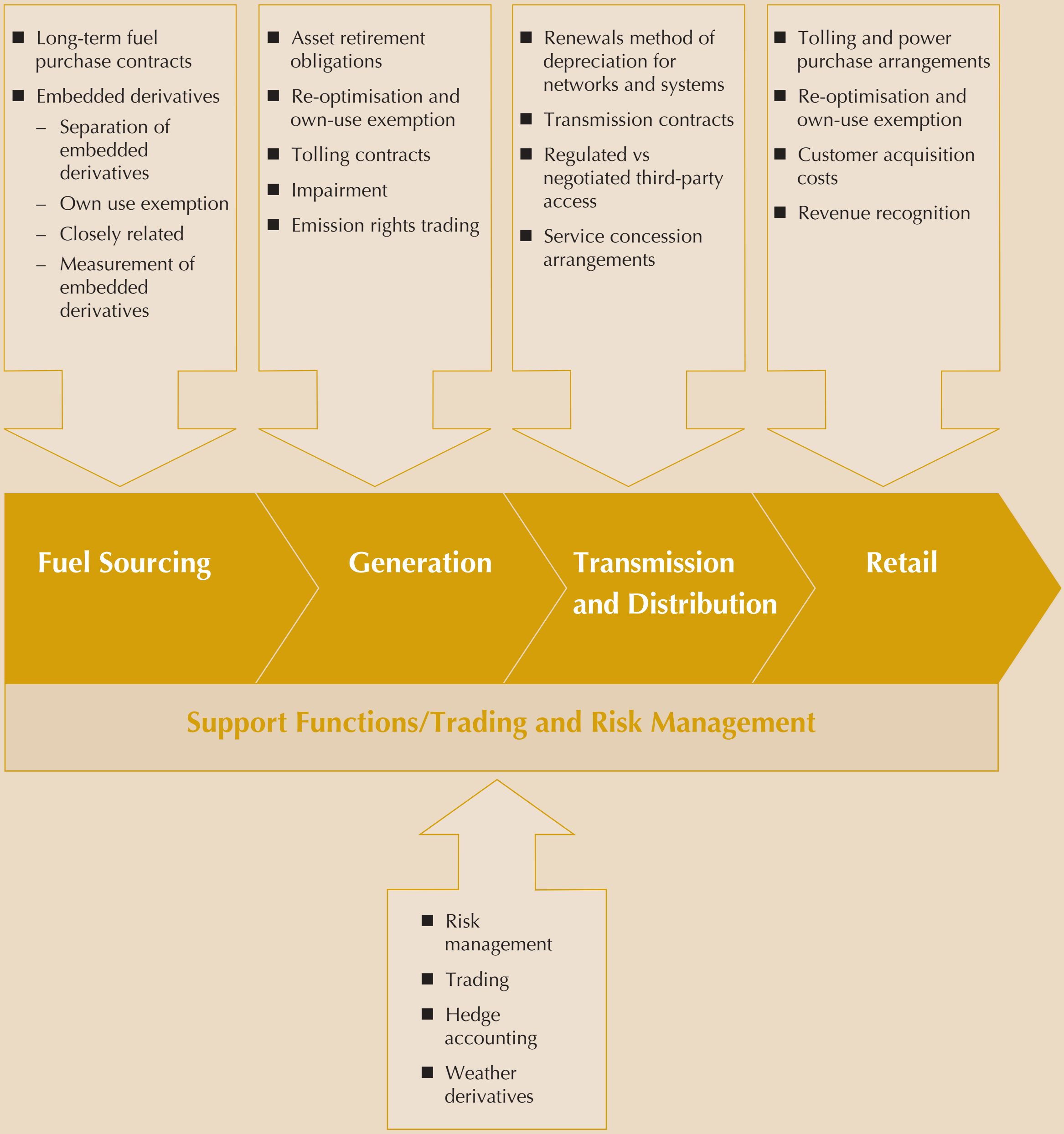


Figure 4: **Electricity Utility Company Value Chain and Significant IFRS Accounting Issues**

3.1 Fuel Sourcing

Background

The process of electricity generation begins with a source of primary energy to be used in the generation process, and most electricity is produced by burning fossil fuels such as coal or gas, or through the use of nuclear fuel and renewables. Electricity generators need to purchase most of these fuels in order to be able to generate electricity. To do so, they usually enter into long-term contractual agreements, which often incorporate variable pricing rules.

Long-Term Fuel Purchase Contracts

A key business risk that generators face is maintaining continuity of supply and stable pricing of coal, gas or other fuels. Generators will enter into long-term fuel purchase contracts with their primary suppliers to mitigate these risks. Long-term purchase contracts often fall into the category of derivatives under IAS 39 or may contain common contract provisions that create embedded derivatives. Derivatives and embedded derivatives are accounted for at fair value with changes in value recognised in the income statement. Fuel contracts can become a significant source of unwanted income statement volatility.

A derivative is any contract that requires little or no net investment, will be settled at a future date and changes in value by reference to a specified variable. Many long-term purchase and sale contracts in the electricity industry are caught by this definition. A fuel purchase contract that requires the purchaser to accept a fixed quantity of fuel at a price fixed at the inception of the contract may well be a derivative. A purchase contract of fixed quantity at market price on date of delivery is a derivative but one that has no value to the holder. Any contract that allows for a greater or lesser quantity to be delivered in any period (even if there are financial penalties levied), or that has a pricing formula other than the market price of the fuel itself, could be a derivative.

Executory Contract Exemption

Derivatives principally must be fair valued, with changes in value recognised in the income statement. However, IAS 39 allows certain commodity contracts to be accounted for as executory contracts (i.e. allows off-balance sheet treatment until completed) if the contract meets three strict criteria. Qualification for the exemption will significantly reduce the volatility that often arises from these contracts. The criteria are:

- The contracts are entered into and continue to meet the entity's own purchase, sale or usage criteria
- The contracts were designated for that purpose at inception
- The contracts are expected to be settled by physical delivery

This is described as 'the executory contract exemption', the 'own-use exemption', or the 'normal purchase and sales exemption'.

The ability to 'net settle' (i.e. not accept delivery and pay cash) may put such a contract outside the exemption because it will not meet the three criteria outlined above.

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 executory contract treatment. The inherent variability in amount and the ability to 'net settle' will put such a contract outside the exemption because it will not meet the three criteria outlined above.

For example, a utility that is party to the balancing mechanisms for gas and electricity owns a gas generating station. The station requires 80,000 therms of gas daily to run at capacity. The utility has purchased gas under two long-term agreements. The first contract requires the utility to take a minimum of 50,000 therms a day, and the option to take an additional 20,000 therms a day, all at €0.20 per therm. The second contract allows the utility to take between 0 and 30,000 therms a day at €0.21 per therm. The first contract is designated as being for own use. On a day when the market price of gas is €0.22 per therm, the generator takes 70,000 therms from the first contract, which it uses to generate electricity. It also takes 30,000 therms from the second contract from which it uses 10,000 to generate electricity and sells the remaining 20,000 for a profit in the open market. On a day when the market price of gas is €0.18 per therm, the utility takes 50,000 therms from the supplier and buys 30,000 in the open market, all of which it uses to generate electricity.

The utility should account for the first contract as an executory contract, being a firm commitment for 50,000 therms and a right to purchase for 20,000 therms. The second contract, however, should be accounted for as a derivative contract and recognised at fair value, with changes in fair value recognised in the income statement. However, one instance where the utility sold gas acquired under the first contract on the open market would result in the inability to continue to claim the own-use exemption for that contract.

Many utilities will have long-term purchase or supply contracts off-balance sheet under national GAAP. These contracts will need to be examined, as well as the utility's history in terms of manner of settlement and business practices, to determine which contracts will qualify for executory contract treatment. The entity may well choose to change some of its contracting terms and practices to ensure that a larger proportion of contracts qualify for the exemption.

Embedded Derivatives

The contractual terms of long-term purchase and sale contracts will have a significant impact on the application of IFRS. Long-term purchase and sale contracts will often contain pricing clauses that base the price on some commodity or index other than the commodity being delivered. Contracts may also be denominated in a currency that is not the contracting parties' measurement currency. Either of these common contractual terms gives rise to an embedded derivative.

An embedded derivative causes a modification to the contracts' cash flows, based on changes in a specified variable. An embedded derivative can arise as a result of deliberate financial engineering – an acknowledged attempt to shift certain risks arising from a contract among the parties. Many, however, arise through market practices and common contracting arrangements.

Spotlight

Implementation Guidance Committee (IGC), Question 25 – 8

Embedded derivatives: purchase price subject to a cap and a floor

'Can the economic characteristics and risks of an embedded derivative be considered closely related to the economic characteristics and risks of the host contract if the host contract is a sales or purchase contract and the embedded derivative establishes a higher and lower limit on the price of the asset that is subject to the sales or purchase contract?'

Yes. IAS 39.25(b) specifies that the economic characteristics and risks of an embedded derivative are considered to be closely related to the economic characteristics and risks of the host contract if the host contract is a debt instrument and the embedded derivative is an out-of-the-money floor or an out-of-the-money cap on interest rates when the instrument is issued. In these circumstances, an enterprise does not account for the embedded derivative separately from the host contract under IAS 39. The same principle applies to contractual provisions in a sales or purchase contract that has a higher and lower limit on the price of the asset that is subject to the sale or purchase contract.

To illustrate: A manufacturer enters into a long-term contract to purchase a specified quantity of a commodity from a supplier. In future periods, the supplier will provide the commodity at the current market price but within a specified range, for example the purchase price may not exceed 120 per unit or fall below 100 per unit. The current market price at the inception of the contract is 110 per unit. The commodity-based contract is not within the scope of IAS 39 because it will be settled by making and taking delivery in the normal course of business (IAS 39.14).

From the manufacturer's perspective, the price limits specified in the purchase contract can be viewed as a purchased call on the commodity with a strike price of 120 per unit (a cap) and a written put on the commodity with a strike price of 100 per unit (a floor). At inception, both the cap and floor on the purchase price are out of the money. Therefore, they are considered closely related to the host purchase contract – consistent with IAS 39.25(b) – and are not separately recognised as embedded derivatives.

Identification of Embedded Derivatives

Purchase and sale contracts that qualify for the executory contract exemption may often contain such embedded derivatives. A coal purchase contract may include a clause that links the price of the coal to a pricing formula based on the prevailing electricity price or a related index at the date of delivery. The fuel purchase contract, which qualifies for the executory contract exemption, is described as the host contract, and the pricing formula is the embedded derivative. The pricing formula is an embedded derivative because it is not based on the market price of coal at the date of delivery.

Another common category of embedded derivatives involves those arising from foreign currency. The coal purchase contract above may, for example, be between a Polish supplier and a German generator, denominated in US dollars. The US dollar is not the measurement currency of either the generator or the supplier and coal prices are not quoted exclusively, worldwide, in the US dollar. The US dollar represents an additional embedded derivative in the contract and must be fair valued.

All embedded derivatives must be separated from the host contract (which by definition is not a derivative itself or qualifies for the executory contract exemption) and accounted for at fair value with changes in fair value in the income statement. The only exception to this rule is where an embedded derivative is deemed to be 'closely related' to the host contract.

Closely Related

IFRS does not provide extensive guidance on how to make the closely related judgement for commodity and energy contracts. There are a number of examples provided in IAS 39, principally related to purely financial contracts. Assessment of closely related thus depends on an understanding of the principles underlying embedded derivatives, the nature of the economic risks inherent in the host contract and the embedded derivative and consideration of the examples in IAS 39 by analogy.

An embedded derivative is not closely related to the host contract when it modifies risks other than those inherent in the contract itself. An interest-rate swap embedded in a commercial paper that changes fixed interest to floating-rate interest modifies the interest-rate risk in an interest-bearing asset or liability and is thus related closely to the host contract.

A pricing formula that is based on something other than the commodity to be delivered exposes the purchaser to risks different from those of the commodity's price. In our example above, the generator is not exposed to changes in the price of coal but changes in the price of electricity. The use of the pricing formula has changed the risks of the contract from those inherent in the coal price to those inherent in the pricing formula – which are different and not closely related.

There are some long-term pricing formulae for certain commodities, such as gas, that were developed as a proxy for market prices because there was no observable market price. Such formulae, after the emergence of observable market prices, would most likely fail to be classified as closely related to the market price. The continued use of these formulae to determine contract prices would therefore result in an embedded derivative, which would have to be separated and accounted for at fair value. The use of the closely related exemption would only be possible if the entity could establish a long-term sustained correlation between the pricing formula and the gas price. The correlation would have to be explained by economic fundamentals, and it would have to be highly probable that it would continue before it might be considered closely related.

Contracts denominated in a foreign currency that is not either party's measurement currency are deemed to have an embedded derivative that is not closely related to the host contract. An exception may be where prices of the relevant commodity are predominantly quoted, worldwide, in a single currency and that currency is being used in that contract.

Spotlight

If a published price quotation is not available, the estimate of fair value should be based on the best information available in the circumstances. Examples of valuation techniques include the present value of estimated expected future cash flows using discount rates commensurate with the risks involved, option-pricing models, matrix pricing, option-adjusted spread models and fundamental analysis.

Measurement of Embedded Derivatives

Embedded derivatives that are not closely related to the host contract must be separated from the host contract and accounted for at fair value with changes in fair value recognised in the income statement. When separated, how should embedded derivatives be fair valued?

Published price quotations in an active market are normally the best evidence of fair value. Where no active market exists that matches the exact terms of the embedded derivative, there are two approaches generally used, one which calculates the fair value of the derivative explicitly and the other which calculates it implicitly.

For example, a utility has purchased gas under a contract indexed to the prices of gasoil. The gasoil pricing component is an embedded derivative. The host contract, the purchase of gas, qualifies for the executory contract exemption. The embedded derivative is essentially a contract for the difference between the gas price and gasoil price. If there is an active and liquid market with forward price curves for gas and gasoil, these prices are obtained and used to value the embedded derivative.

There may be incomplete market data. For example, if the contract above had delivery dates over a seven-year period, there may not be price quotes for delivery on all relevant dates. The company should derive price quotes for the relevant dates based on consistent and realistic assumptions about price movements.

The implicit valuation approach is applicable in limited circumstances. If a price is available for the contract in its entirety (host and embedded derivative), then the value of the embedded derivative can be estimated by comparing the value of the entire contract to the value of host contract (quantity at current market price). The difference is an estimate of the embedded derivative's value.

Valuing embedded derivatives can be difficult if there is a lack of reliable market value. IFRS are, however, inflexible on this point. IAS 39, in particular, makes an explicit assumption that reliable fair values can be determined for financial instruments, including embedded derivatives. There are a handful of limited exceptions to the presumption that fair value can be reliably estimated – commodity contracts are not adressed.

Valuation techniques are available for almost all embedded derivatives. Where assumptions are made about future prices, these should be tested, documented and applied consistently. However, if an embedded derivative cannot be separately fair valued, IAS 39 requires that the entire contract be fair valued with changes in fair value in the income statement.

Accounting for Embedded Derivatives

Once embedded derivatives have been identified and measurement established, they are recorded at fair value as separate financial assets or liabilities, classified as trading assets or liabilities. All changes in fair value form part of financial income or expense and are recognised in the income statement in the current period.

Summary

A desire to manage operational risks will lead generators to enter into long-term purchase contracts for fuel. The contracts that result from this risk management activity may well expose the generator to immediate income statement volatility. Companies need to examine contracting practices and contract terms to ensure, to the full extent possible, that fuel purchase contracts for own use qualify for the executory contract exemption under IAS 39. Contracts should also be scrutinised for embedded derivatives. Methodologies must be developed to value and account for existing embedded derivatives. Companies should consider changing contracting practices where current practices produce exposure to unwelcome income statement volatility.

3.2 Generation

Background

Electricity is usually generated by using a turbine. Fossil fuels or nuclear power are typically used to turn water into steam, which drives the turbine. Alternatively, the turbine may be driven directly by renewable sources such as water or wind.

A utility company will invest considerable time and effort and incur substantial costs before it can begin operations. It has to find a site, obtain all relevant regulatory approvals and construct the power plant. The company may be required to carry out significant research and development activities to compete successfully or to comply with regulatory requirements.

The costs to construct the plant, including interest, must be capitalised and depreciated over the plant's useful life. The company is often obliged to decommission the plant at the end of an agreed period. Decommissioning, also referred to as asset retirement obligations, must be estimated and recorded as part of the cost to construct under IFRS. The capital-intensive nature of the business, coupled with long asset lives and rate-regulated pricing, inevitably makes impairment a significant issue.

Electricity generation typically carried out under contractual arrangements will have significant financial statements impacts under IFRS. The issues are similar to those related to fuel sourcing (as discussed under Section 3.1), but are inherently more complex because of the non-storable nature of power. The regulatory environment, pressure to reduce emissions and other pollutants, increasing competition and continuing government involvement in pricing all impact on how business is conducted, and give rise to some difficult accounting issues.

Asset Retirement Obligations

Purchase or construction of a power station is likely to give rise to an obligation (contractual, statutory or constructive) to decommission the power station or to restore the site to certain minimum standards at the end of the asset's life. Decommissioning and restoration obligations can be particularly burdensome for nuclear power plants.

Decommissioning and site restoration costs are considered a directly attributable cost to bring an asset to working condition under IAS 16 "Property, Plant and Equipment". All such costs must be estimated in accordance with IAS 37 "Provisions, Liabilities and Contingent Assets" and capitalised at the date the obligation to decommission or restore is incurred.

The payment of decommissioning costs will not be made until some future date, possibly several decades in the future. There will be uncertainty over the amount of the cash flows and the timing of payment. Management should record its best estimate of the entity's obligations.

Cash flows are discounted when calculating the provision to reflect the delayed payment. The amount recorded as a component of the asset cost and the initial provision is the amount of estimated cash flows, discounted from the date payments are expected to be made.

The costs added to the asset are depreciated in accordance with the depreciation methodology selected for the asset. The provision is accreted to undiscounted value over time by the recognition of the discount as interest expense. By the end of the asset's useful life, when the decommissioning and restoration costs will be paid, the full estimate of these costs will have been recognised in the income statement through depreciation and interest expense.

Management should periodically reassess the estimated accrued decommissioning costs to see if there are any material changes that need to be reflected. New environmental or restoration regulations may cause a significant increase in the amount of work that will be required. Equally, specific costs may change and this may be clear with the passage of time. The International Financial Reporting Interpretations Committee (IFRIC) proposed that material changes to the estimate of the provision, whether to the cash flows or the discount rate, are reflected by a change in both the provision and the amount of the asset if the change relates to future periods. The part of the revised estimate that relates to the current or prior periods should be recognised as profit or loss of the current period.

Impairment

Generating stations are complex and expensive to build. Construction time can be interrupted or extended by protesters or government intervention, adding to the costs. At the same time, power-generating companies may find themselves operating in markets with excess generating capacity, subject to new competitive or regulatory forces, facing higher fuel costs and rising decommissioning costs. All these factors may result in a generating plant not generating sufficient incremental cash flows to recover the costs incurred to build or acquire and decommission it. The generating station may well be impaired in these circumstances. Market forces may be such that the entity's management will contemplate abandoning the generating capacity.

This section looks at impairment triggers, measurement of impairment and presentation of discontinued operations. IAS 36 "Impairment of Assets" requires that assets be tested for impairment individually or at the lowest level that cash flows can be attributed, described as cash-generating units or CGUs. An individual generating station is normally classified as a CGU for the purposes of applying the impairment standard.

Impairment Triggers

An impairment trigger is any indication that an asset may not generate sufficient cash flows to recover its carrying value. Some of the impairment triggers that may impact on a power generator are overcapacity, adverse changes in the regulatory environment, falling prices, rising fuel costs that cannot be passed to customers, and rising interest rates.

Overcapacity may arise from new market entrants, increased efficiency, falling demand or increased competition from alternative fuel sources. Overcapacity may be inherent where state monopolies or a highly regulated environment previously existed. Overcapacity can lead to plants running at suboptimal levels, and in extreme circumstances management may consider abandoning the generating assets.

Power generation is subject to a wide range of government regulation, which may cover all aspects of operations, including prices charged to customers. There is a wide variety of potential adverse developments in regulation. Adverse developments might include an expansion of restoration obligations, price caps that ignore short-term fuel cost fluctuations and installation of equipment mandated by regulators and others. Regulation will negatively impact on expected cash flows by increasing the amount of expected outflows (increased cash flows to decommission or fit environmental equipment) or reducing inflows by restricting prices.

Changes in interest rates, either for power-generating assets or specific to the entity, are also impairment triggers. A general change in interest rates may well result in an increase in the discount rate used to calculate the impairment charge, which would decrease an asset's value in use. A credit downgrade of the power-generating company would also indicate that interest rates used for value-in-use calculations would need to be increased.

Measurement of Impairment

Impairment in IFRS is governed by IAS 36, which states that the carrying value of an asset or CGU should be compared to the higher of its value in use and net selling price.

Net selling price is selling price between knowledgeable willing parties less any costs of disposal. It does not assume forced sale conditions. There may not be a ready market for generation assets, especially if there are impairment triggers such as overcapacity or adverse regulation. There may be no readily observable market prices. Valuation experts might be utilised in such circumstances to determine a net selling price.

Value in use is the net present value of the discounted future cash flows arising from continuing use of the asset or CGU, including any disposal proceeds. The crucial elements of a value-in-use calculation are the cash flows and the selection of the discount rate.

The cash flows exclude cash flows related to financing activities (including interest paid), taxes, uncommitted planned restructuring and any capital expenditure. Cash flows include decommissioning costs. Cash flows should be based on the most recent budgets and forecasts that management has approved, and based on reasonable and supportable assumptions.

The discount rate selected should be a pre-tax rate that reflects current market assumptions about the risks specific to the asset or the business. Most companies will consider their weighted average cost of capital and incremental borrowing, compared to observable market rates, when determining an appropriate discount rate.

Spotlight on the Standard

ED IAS 39p7

Contracts to buy or sell a non-financial item, such as a contract to buy or sell a commodity for a fixed price at a future date, do not meet the definition of a financial instrument (see IAS 32). Nevertheless, such a contract meets the definition of a derivative and is within the scope of this Standard if the entity has a practice of settling such contracts net in cash (either with the counterparty or by entering into offsetting contracts) or 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 dealer's margin. Those practices indicate that the contract is not entered into for the purpose of making or taking delivery of the non-financial item in accordance with the entity's expected purchase, sale or usage requirements. If an enterprise follows a pattern of entering into offsetting contracts that effectively accomplish settlement on a net basis, those contracts are not entered into to meet the enterprise's expected purchase, sale or usage requirements.

Presentation of Discontinued Operations

Overcapacity or impairment may lead a power company to consider sale or abandonment of assets. IAS 35 sets out the disclosure requirements for discontinued operations. There are no specific measurement requirements in IAS 35, but an entity would need to assess impairment under IAS 36 and consider any necessary incremental provisions for restructuring and employee liabilities under IAS 37 and IAS 19.

Re-Optimisation and Own-Use Exemption

The re-optimisation of the production profile of a power plant and the simultaneous execution of a financial or derivative instrument to adjust the power plant's obligations (i.e. the purchase of electricity in the market to satisfy the company's electricity sales commitments) have a significant impact on the application of IAS 39 and the own-use exemption.

Generating stations may be operated to maximise returns by reference to the external market. Future generation profiles are based on the expected returns available in the market. Factors involved in this decision are market prices for fuel and power; marginal costs for each unit of power generated; and plant constraints, such as maximum and minimum load capacities.

The generating station will adjust expected output on a short-term basis to maximise financial return. A generating station sells 1,000MWh of power for year+1 into the market using trading contracts. The contract is designated as an own-use transaction, since the generator expects to deliver electricity it has produced.

Subsequently, the generating station re-optimises and adjusts its expected physical output to 800MWh for year+1, as a result of changes in market prices (i.e. fuel costs and electricity prices). The business is now physically 'out of balance' and is required to purchase 200MWh of power from the market. The decision to purchase power in the wholesale market, and to deliver that instead of own-generated power, undermines the own-use assertion.

In the revisions to IAS 39, the definition of own-use and net settlement has been clarified. Under the new rule the practice of settling contracts net in cash, either with the counterparty or through offsetting contracts, could mean that the own-use exemption cannot be used. IAS 39 (draft revisions) clarifies that taking delivery of the commodity, and reselling it to benefit from short-term price movements or to make a dealer's margin, also does not meet the criteria for own-use.

Companies must look carefully at the scope, scale and structures of their re-optimisation activities to ensure they use the appropriate method of accounting (derivative versus own-use) for their set of facts and circumstances.

Tolling Contracts

A company may provide fuel to a third-party generator and receive the electricity in return. The generator earns a fee for providing the service.

Tolling contracts usually require the physical delivery of the output, being the electricity generated, and are not settled on a net basis. They are, therefore, not treated as derivatives. Although these contracts are generally accounted for as executory contracts, consideration has to be given to lease accounting, which we discuss later under 'Accounting for Transmission Contracts'.

A utility company may determine that it is no longer economically feasible to continue to meet its obligations under a tolling contract, if the unavoidable costs of the contract exceed the economic benefits the company expects to receive. The company should consider whether to recognise a provision for an onerous contract.

Provisions for Nuclear Waste

Nuclear generators have special legal obligations to treat and store nuclear waste as well as decommission generating facilities. The obligation for decommissioning is linked to the construction of the nuclear power plant and is an asset retirement obligation. The accounting for these has been discussed before. Another part of the obligation does not relate to the removal of the nuclear power plant, but arises through the actual operation, i.e. the generation of nuclear power. These latter costs are recognised as a liability as they arise.

As with decommissioning and restoration obligations, the company must make its best estimate of the expected amount and timing of the cash flows relating to subsequent processing and disposal of the fuel rods. The company should discount the provisions, where the effect of the time value of money is material, using a pre-tax discount rate that reflects current market assessments of the time value of money and those risks specific to the liability that have not been reflected in the best estimate of the expenditure. Where discounting is used, the increase in the provision due to the passage of time is recognised as an interest expense. It should also take into account future events, such as changes in the law and technological changes, where there is sufficient objective evidence that they will occur. Proceeds or gains from the expected disposal of assets are not offset against the provision.

The total costs of storing and reprocessing the nuclear fuel rods have to be estimated when the rods are placed in the reactor. The costs are then amortised over the period of time the fuel rods are in use.

Management should periodically reassess the provision for disposal of nuclear waste to see if there are any material changes that need to be reflected. New regulations may cause a significant increase in the amount of work that will be required. Equally, specific costs may increase more or less than expected, and this may be clear with the passage of time. Material changes to the estimate of the provision are reflected as described earlier in this chapter under 'Asset Retirement Obligations'.

Investment in External Funds for Nuclear Waste

National law requires many nuclear operators to make contributions to a fund established to reimburse costs for nuclear waste and decommissioning when these are incurred. The fund may be set up to meet the costs of a single operator or a group of operators. Group funds are often organised to cover the nuclear industry in an entire country.

Each fund will have specific arrangements. It may be that the fund is deemed to be a special purpose entity of a particular operator, in which case the operator should consolidate the fund. The operator may have a claim against a specific proportion of a pooled fund's assets or have a right to claim the total amount of contributions it has made, plus an agreed rate of investment return on those assets. If the fund is not consolidated, the operator must account for its interest in the fund in accordance with the manner in which the fund operates. The interest is most likely to be a type of financial asset.

The fund assets are not offset against the amount of the related provision. The presence of the fund assets does not relieve the operator of its obligations; rather they represent an asset on which the operator can draw. If a contributor in a pooled fund becomes bankrupt and is unable to make contributions, then the remaining fund participants' contributions will often be increased. Each fund participant should also consider whether it has a contingent liability or an actual liability because of the bankruptcy. All contingent liabilities, other than those that are remote, must be disclosed under IFRS.

Emission Rights Trading

Existing and proposed regulations and compliance mechanisms have the goal to reduce emissions of pollutants, especially greenhouse gases. The mechanisms use market forces, establishing a cap and trade model whereby participants are allocated emission rights or allowances equal to the target level of emissions. Although allowances might be distributed free of charge, every allowance the company uses to cover emissions incurs an opportunity cost, since the allowance might also have been sold. Thus company behaviour is influenced.

The emission rights trading raises various accounting issues. The IFRIC recently considered the following, related to emission rights trading:

- Allowances, whether allocated by government or purchased, are intangible assets that shall be accounted for under IAS 38 "Intangible Assets". Allowances that are allocated for less than fair value shall be measured initially at their fair value. Allowances shall not be amortised but may be impaired.
- Where allowances are allocated for less than fair value, the difference between the amount paid and fair value is a government grant that shall be accounted for under IAS 20 "Accounting for Government Grants and Disclosure of Government Assistance". Accordingly, the grant is initially recognised as deferred income in the balance sheet and subsequently recognised as income on a systematic basis over the compliance period for which the allowances were allocated.
- As emissions are made, a liability is recognised for the obligation to deliver allowances equal to emissions that have been made. This liability is a provision that falls within the scope of IAS 37 "Provisions, Contingent Liabilities and Contingent Assets". The liability is settled by delivering allowances, incurring a penalty or a combination of both. The liability shall be measured at the best estimate of the expenditure required to settle the present obligation at the balance sheet date. This will normally be the present market price of the number of allowances required to cover emissions made up to the balance sheet date. However, if the participant's best estimate is that some or all of the obligation will be settled by incurring a cash penalty, it shall measure that part of its obligation at the cost of the penalty rather than at the market price of the relevant number of allowances.

The existence of an emission rights scheme may cause certain assets to become impaired if the cash flows that those assets are expected to generate are reduced as a result of the scheme.

3.3 Transmission and Distribution

Once electricity is generated, it travels along cables to a transformer. The transformer steps-up the voltage to between 220kV and 750kV. Transmission lines, usually part of a national or regional grid, carry the electricity around a country or region to local substations. Substations have transformers that step-down the high-voltage electricity into lower-voltage electricity.

Distribution businesses take the electricity from the transmission network substations. Using a series of transformers, they step-down the voltage of the electricity to a safer level that can be distributed to businesses and homes. Most countries' domestic electricity is supplied at between 110V and 240V.

A utility company incurs construction costs when it sets up the transformers and transmission lines. These costs have to be capitalised as technical equipment, which has to be depreciated over its useful life according to IAS 16 "Property, Plant and Equipment". However, there are special legal and contractual circumstances for which accounting is not as straightforward.

Renewals Method of Depreciation for Networks and Systems

The renewals method of approximating depreciation expense can be accepted practice under local GAAP. The renewals method requires that major components and assets within an infrastructure system or grid (such as a transmission system) with determinable economic lives should be separately identified and depreciated over the economic life. The remaining system infrastructure or network asset is deemed to be not separately identifiable, and no useful life can be reliably estimated. The annual maintenance expenditure is deemed to be equivalent to a depreciation charge for those parts of the system and is described in the income statement as depreciation. The cost of any identifiable assets is capitalised and depreciated.

Renewals accounting is not acceptable under IFRS, which require the cost or fair value of fixed assets to be depreciated over the expected useful life. IFRS 1 "First Time Adoption of IFRS" grants some relief to first-time adopters. Companies will be allowed to record fixed assets at fair value, which then becomes deemed cost. Companies that lack adequate records to calculate cost-based depreciation will be able to have transmission or system assets professionally valued. The results of the valuation can then be used to calculate a cost-based measure of depreciation for IFRS.

Accounting for Transmission Contracts

A utility company may enter into a contractual arrangement conveying the right to use a part of its transmission grid to a third party. The contractual arrangement may constitute a lease in some circumstances, or a service contract. The accounting will differ, based on conclusions about the substance of the arrangement.

There are three key elements, all of which must be present, to determine if an access contract is a lease. The access must be to a specific identifiable part of the grid, the third party must obtain control of that part of the grid for a particular period of time and the third party must be making payments for the right to use the grid rather than for actual usage. The price for access would be time-based and not measured based on units (x per day instead of x per kV transmitted). Contracts to acquire output (electricity, gas, water) may appear very similar to access contracts, but they are fundamentally different and should be accounted for as a forward sale of output by the utility company and a forward purchase by the third party.

A contractual arrangement for access that constitutes a lease must be evaluated to determine if it is an operating lease or a finance lease and is then accounted for accordingly. A lease is a finance lease if it conveys substantially all of the risks and rewards of ownership to the lessee, which is normally the case if one of the following criteria is fulfilled:

- The lease transfers ownership of the asset to the lessee by the end of the lease term
- The lessee has the option to purchase the asset at a price which is expected to be sufficiently lower than the fair value at the date the option becomes exercisable such that, at the inception of the lease, it is reasonably certain that the option will be exercised
- The lease term is for the major part of the economic life of the asset even if title is not transferred
- At the inception of the lease the present value of the minimum lease payments amounts to at least substantially all of the fair value of the leased asset
- The leased assets are of a specialised nature such that only the lessee can use them without major modifications being made

An arrangement that does not constitute a lease is accounted for as a service contract. Revenues are recognised as services are rendered. Revenue would be recognised based on the contract provisions, either on a time basis or the basis of units transmitted. Usually the outcome of the transaction is immediately determinable, since the contracts typically do not result in a certain success besides the fact that the grid is being made available to the customer.

Regulated vs Negotiated Third-Party Access

Many governments have taken steps to liberalise the provision of utilities to customers through the introduction of competition among suppliers of water, natural gas or electricity. A fundamental element of liberalised markets is granting third-party access to transmission grids and similar infrastructure assets. Without grid access, Supplier A could not practically compete for Supplier B's customers, because it would have no infrastructure to provide them with electricity.

Admission to grid assets owned by others can be regulated either with access based on published tariffs, supervised or set by the regulator, or via negotiation between the parties. Negotiated access implies that there is no regulatory intervention or price-capping: access fees are left to the parties. The regulator will only ensure that access is allowed when fees are paid and that access is not unreasonably restricted by the owner of the grid assets.

Regulated third-party access leads to regulatory asset issues for the owner of the grid. Since the tariffs are set (or supervised) by the regulator, the effect is often that price negotiations with the regulator lead to specific price increases to enable the recovery of identified costs previously incurred or planned by the owner of the grid. Accounting rules in some countries allow the recognition of an asset in certain circumstances, where recovery of the costs is probable and clearly linked to the costs previously incurred. So-called regulatory assets do not meet the definition of an asset under the Framework of the IASB and therefore cannot be recognised. This issue is discussed in more detail in the Water Utility section of this report.

Negotiated third-party access introduces an element of uncertainty in costs. Independent power producers are dependent on access to the grid for distribution, and the price of grid access can erode profit margins substantially. Parties may enter into long-term contracts for grid access rights that include variable pricing formulae. The long-term contracts may qualify for the executory contract exemption, but the variable pricing formula will represent an embedded derivative. That derivative might be separated from the host contract and accounted for at fair value with changes in the income statement.

Long-term access contracts at fixed prices may well become onerous if market conditions shift, and these need to be periodically re-evaluated.

Service Concession Arrangements

Utility companies will enter into agreements with governmental bodies or public sector enterprises to provide a public service such as electricity or water supply. Agreements are often a requirement of national law, and give the public the right of access to major economic and social facilities. The utility is the concession operator and the government is the concession provider. Often, the concession is an exclusive right to provide the relevant public service.

Concessions may confer the right to use certain public sector assets on the concession operator in exchange for the agreement to provide the services. The concession period may be limited (although concessions as long as 50 years are not unknown). The related terms and conditions may include limitations on tariffs and mandatory service-level requirements.

IFRS do not have specific accounting requirements for concession arrangements. Related assets and liabilities are accounted for according to the general substance over form principle, i.e. on economic ownership. In contrast, extensive disclosure of material concessions is explicitly required.

3.4 Retail

Background

Billing customers for electricity use is normally undertaken by retailers, who pay to use the distribution network and buy the electricity created by the generating companies.

Retail businesses may be independent companies or part of an integrated utility, though in some countries, a part of or the entire power generation and supply business is state-owned.

Tolling and Power Purchase Arrangements

A retail company may obtain power through tolling arrangements or through power purchase contracts. Tolling contracts have been discussed under 'Generation'.

A power purchase contract is where a company makes agreed payments to a generator in return for the rights to electricity that the generator produces. Power purchase contracts usually require the physical delivery of the electricity generated, and are not settled on a net basis. They will usually be accounted for as executory contracts. However, under certain circumstances, for example if a plant is being built on the premises of a customer, lease accounting, as discussed under 'Accounting for Transmission Contracts', needs to be considered.

The liability for the power is recognised as the electricity is delivered. Long-term power purchase contracts should be reviewed to ensure that the retail business has not assumed all of the generator's risks and rewards.

Re-Optimisation and Own-Use Exemption

A retail profile will change as the result of market factors associated with expected customer numbers and expected customer demand. This could result in changes to the physical requirements of the business and the termination of purchased contracted volume via the execution of offsetting contracts or net cash settlement/contract termination.

Only contracts designated for the entity's own-use, expected to result in physical settlement and resulting in physical delivery, qualify for own-use exemption. A retail distribution business might identify a group of contracts to meet minimum profile requirements. These contracts could be managed so as to qualify for the own-use exemption. The remaining sale or purchase contracts, which may or may not result in physical delivery, could be accounted for as derivatives under IAS 39. Please refer also to our discussion of the subject under 'Generation'.

Revenue Recognition

The costs of connecting a customer to the network will often be billed, either in full or in part, to the customer. These are sometimes known as construction grants. These grants should normally be recognised as income over the period of the customer contract.

Customer Acquisition Costs

Please refer to the Oil and Gas section of this report for a discussion of the accounting for customer acquisition costs.

Accounting for the Effects of Regulation

The prices the electricity utility charges are regulated in many countries. The effect of regulation regarding regulatory assets is the same as prescribed under regulated third-party access. Those regulatory assets cannot be recognised under IFRS since they do not meet the definition of an asset. This issue is discussed in more detail in the Water Utility section of this report.

3.5 Trading and Risk Management

Background

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 risky part of a utility's business. Effective trading can limit volatility and protect profit margins. Energy-trading operations must be closely controlled. The key elements are segregation of duties, independent risk management procedures including trading limits.

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 scale and scope of the units' activities vary from market risk management through to dynamic profit optimisation. An integrated utility company is 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. A pattern of speculative activity or trading directed to profit maximisation is unlikely to result in any contracts qualifing for the own-use exemption. In this case all external contracts will 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 transactions for two purposes:

(a) 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. This is often characterised by management as price-risk management, with volume risks relating to operational assets and customer demand remaining within the operational divisions (i.e. no re-optimisation to take advantage of market-price movements). Such activity is sometimes held in a 'physical book'.

(b) To achieve risk management returns from wholesale trading activities. Such activity is sometimes held in a 'trading book'.

Spotlight on the Standard

IAS 39 p142

A hedging relationship qualifies for hedge accounting if all of the following conditions are met:

- Formal documentation at inception of the hedge
- The hedge is expected to be highly effective
- For cash flow hedges, a forecast transaction that is the subject of the hedge must be highly probable and must present an exposure to variations in cash flows that could ultimately affect reported profit or loss
- The effectiveness of the hedge can be reliably measured
- The hedge is assessed on an ongoing basis and determined actually to have been highly effective throughout the financial reporting period.

The result of carrying out the transactions in (a) in an optimal manner without re-optimisation would be the elimination of price risk and the management of revenues and costs in future periods. If a company maintains separate physical and trading books, the contracts in the physical book may qualify for the own-use exemption. Nevertheless, as discussed before, a physical book when combined with re-optimisation could lead to separation and individual measurement of embedded derivatives.

Hedge Accounting

Hedge accounting can mitigate the volatile impact of these transactions. Practical experience of hedge accounting has shown that complying with the requirements can be onerous. Companies that are able to qualify for the own-use exemption may find it operationally easier to use than hedge accounting.

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. IFRS do not permit the own-use exemption or 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. However, a company can put hedge documentation in place and test effectiveness at a later date and claim hedge accounting from that later date. Companies should consider developing pro-forma documentation in respect of their commodity hedging activities.

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 method for testing hedge effectiveness in IAS 39. 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 of assessing effectiveness must be reasonable and consistent with other similar hedges unless different methods are explicitly justified. 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 shown to be effective on a prospective basis, i.e. that the hedge is indeed expected to be effective. The level of effectiveness that IAS 39 requires is that the risks are almost fully offset, which is viewed as meaning, in practice, that the changes in the value or cash flows of the hedged item are expected to be between 95 per cent and 105 per cent of the changes in value or cash flows of the hedging instrument. The hedge must also be highly effective on a retrospective basis, the range being given as 80 – 125 per cent effective. The proposed revisions to IAS 39 will relax the prospective effectiveness test requirements to the same as those used for the retrospective test, i.e. 80 – 125 per cent. The requirement for testing can be quite onerous. Prospective and retrospective effectiveness tests need to be performed for each hedging relationship at least as frequently as financial information is published, 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 in – or outflow related to forecasted transactions, therefore cash flow hedges. Under IFRS, only a highly probable 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.

A company is not allowed to use cash flow hedge accounting if it cannot forecast transactions 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 under IAS 39p21 are contracts that require a payment based on climatic variables. These are commonly used as insurance policies. As a consequence, although weather derivatives have a character of financial instruments, they are not accounted for as such, rather they are accounted for as executory contracts. They cannot be used as cash flow hedges.

However, many weather derivatives, that do not meet the definition of an insurance contract, will fall within the scope of IAS 39 as a result of proposed consequential changes to IAS 39 from ED 5, released August 2003. Such weather derivatives will need to be recognised at fair value, with changes in fair value recognised in the income statement if the changes proposed in ED 5 are made.

The Utilities Industry: Electricity And Water

The Water Utility

Value Chain and Significant IFRS Accounting Issues

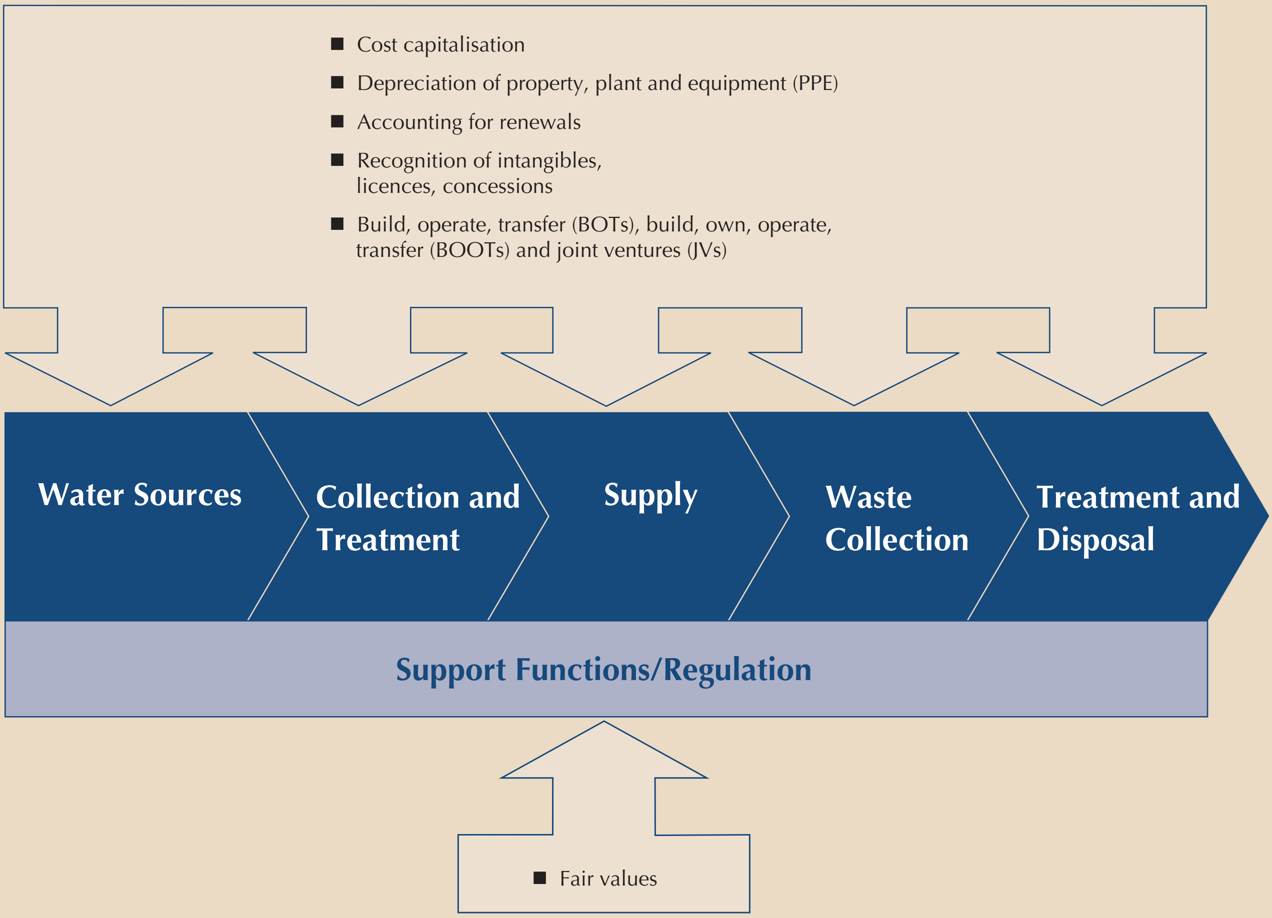


Figure 5: **Water Utility Company Value Chain and Accounting Issues**

The water industry encompasses the acquisition of water, its distribution to customers and the disposal of waste water after use. Throughout the supply chain, the quality of the water must meet required standards for supply to users and for disposal into the environment at the end of the chain.

The water industry is heavily regulated in most countries. Regulators specify the quality levels that must be met and the prices that water companies may charge customers. Regulators often also specify facility and infrastructure improvements that the water companies must make. Water companies generally have a monopoly to supply water to customers in a specified geographical region, therefore customers are unable to choose their supplier because of the physical constraints of the supply of water. The absence of competition is therefore addressed through heavy regulation. A company's right to supply water to a particular area is normally controlled by licence, although licences may have lives of 50 years or more in some countries.

The necessity for high water standards and secure supply and distribution channels also drives a higher level of regulation. Business decisions reflect this degree of regulation, with considerable focus on the regulator's views. Regulation has influenced financial reporting by water companies in some countries and resulted in practices that diverge from those of other commercial companies. This divergence has led to practices under national GAAPs that are not acceptable under IFRS.

The physical delivery of water requires extensive networks of pipes that must be maintained to minimise leaks and prevent contamination of water. The water industry is therefore highly capital-intensive, requiring continual maintenance, repairs and improvements. The network and other assets used and constructed by the water companies will often be owned by the government, or transferred to government ownership at some point. The accounting treatment of assets the water company uses should reflect the substance of the arrangement.

Accounting Issues

Impact of Price Regulation on Accounting

Regulation of the water industry includes price regulation. This aims to balance the customer's requirements, such as reliable supply at an affordable price – with the shareholders' desire for a reasonable return on their investment. The form of regulation may be a 'cost-plus' approach or a 'price-cap' approach to prices.

Spotlight on the Standard

IASB Framework p49

An asset is a resource controlled by the enterprise as a result of past events and from which future economic benefits are expected to flow to the enterprise.

The mechanism for price regulation varies from country to country, and the different regulatory mechanisms have been reflected in the national accounting practices that have developed. Regulators may allow a water company to recoup investments in the network over a defined period by increasing the prices over that period. The focus may be on the water company's cash needs. The periods over which the investment is recovered is often much shorter than the assets' useful lives, and is sometimes as short as one year. National GAAP in some countries allows an asset to be recognised in the year of investment. The calculation of the asset is based on the additional price that can be charged to customers in the following year to recover the current year's investment in cash terms. This 'regulatory asset' is recognised in addition to the property, plant and equipment that has been constructed.

A typical regulatory asset does not meet the definition of an asset under IFRS because the water company does not control it as a result of past events. The realisation of the economic benefits associated with these 'assets' arises from future sales to customers. The water company cannot sell the 'asset' separately from the business and, because the company's customers continually change over time, it is not possible to identify who the asset will be recoverable from, other than 'the customers' in general. The water company cannot recognise the asset associated with the right to charge a higher price until it has supplied water to customers at that higher price. The right to charge a higher price in the future does not represent an asset; neither does the obligation to charge a lower price represent a liability.

Build, Operate, Transfer (BOTs), Build, Own, Operate, Transfer (BOOTs) and Joint Ventures (JVs)

The regulator may require a water company to construct a significant new piece of infrastructure and then operate it as part of the water company's network. At the end of the water company's licence period, control of the asset will be transferred to the government. Since the date of the transfer of ownership can be before the end of the useful life of the related assets, in these cases the contract term should determine the depreciation and amortisation period.

In order to achieve this, a water company may form a JV with a construction company to construct major assets, such as a dam or an acquaduct. The construction company will normally be involved only in the contract's construction phase. The accounting for the contract therefore needs to be carefully considered to ensure that the appropriate parties recognise the revenues and profits earned during the construction phase at the appropriate times. IAS 11 "Construction Contracts" may require the accounting for the different phases of the contract to be accounted for as separate contracts.

The accounting for a contract's construction phase will be determined using the percentage of completion method. This will normally be calculated by reference to the costs incurred to date compared with the costs expected to be incurred to completion; however, there may be other significant milestones within the contract that require the percentage of completion to be calculated on a different basis.

Where the contract to construct infrastructure is won through a competitive process, the costs incurred in developing and preparing the bid and the contract should not be capitalised unless it is probable that the contract will be won and that the costs incurred will be recovered under the contract. It is not possible to meet the capitalisation criteria while competitors are still bidding for the same contract.

Capitalisation of Property, Plant and Equipment

The assets that a water company uses to provide water services to customers may be owned by the government, or may be temporarily owned by the water company and transferred to the government at the end of the licence period. The water company should reflect these assets as property, plant and equipment if it has the risks and rewards associated with those assets, even if the government has legal title.

The accounting for the assets under IFRS should reflect the substance of the licence terms and the water company's rights and obligations under the licence. The water company will not recognise the infrastructure assets where it is merely providing an operating service. Similarly, the infrastructure assets will not be recognised where the licence terms restrict the water company's risk to such an extent that its return is guaranteed as long as the company fulfils its responsibilities under the licence.

However, the water company will recognise the infrastructure assets as property, plant and equipment where it faces the major risks associated with the assets and where it has access to the benefits of using them. This includes assets that the water company constructs and operates, even if the asset's useful life extends far beyond the end of the licence term. However, the useful life for the purposes of calculating depreciation should reflect the period over which the water company will use the asset and any consideration receivable from the government at the end of the licence. This receives further consideration below.

The water company capitalises all costs directly attributable to the asset's acquisition and construction. The directly attributable costs are those that are necessary to bring the asset to its required working condition. These include labour costs of own employees, for example site workers, in-house architects, surveyors, etc. and incremental costs that would have been avoided if the asset had not been constructed. Directly attributable costs also include directly attributable overheads; however, site-selection costs, other pre-construction costs and general administrative costs not directly attributable to the asset's acquisition, construction or commissioning should be expensed as incurred.

Depreciation of Fixed Assets/Renewals Accounting

The fixed assets the water company recognises must be depreciated to its recoverable amount (usually zero) over their useful lives. Where the licence term is less than the useful life, the asset should be depreciated over the licence term. The depreciation method should reflect the pattern in which the economic benefits of the asset are consumed. Many assets will therefore be depreciated on a straight-line basis; however, some may be depreciated based on the volume of water processed. A water company with a very long or indefinite length licence may have assets with very long useful lives (100 years or more). However, whatever the useful life, the water company must calculate a depreciation charge for the asset.

The useful life for depreciation purposes is the period over which the company expects to use the asset. A water company will plan to replace different components of the network at different times, usually on a rolling basis for practical reasons. The water company should therefore calculate the depreciation for each component separately over the period to its next scheduled replacement.

Calculating the depreciation charge requires a sufficiently detailed fixed assets register to enable identification of the separate components and their useful lives. The water companies in some countries inherited vast networks on privatisation. Industry practice has been to assume that ongoing maintenance expenditure was roughly equal to the depreciation charge that would have been calculated if the records had been available. Assumptions such as this are not acceptable under IFRS, and those companies converting to IFRS that are in this situation will need to create appropriate fixed asset registers, possibly making use of the exemptions available for first-time adopters under IFRS 1 "First-time Adoption of International Financial Reporting Standards", which allow the capitalisation of fair values as initial cost base in the opening IFRS financial statements.

Intangible Assets

The right to supply customers with water services is an intangible asset. It should be recognised under IFRS if it meets the recognition criteria in IAS 38 "Intangible Assets". A water company will therefore recognise the intangible asset at cost if it has purchased the licence from the government or, if acquired through a business combination, will recognise it at fair value at the date of acquisition. A water company could not follow the alternative accounting treatment under IAS 38 of revaluing such intangible assets to fair value at each balance sheet date, because the exclusive nature of the licences prevents there being an active market of homogenous assets.

Business Combinations: Differing Views on fair values

A water company that acquires another must consolidate the acquired entity's results from the date on which control passes (refer also to the oil and gas part where business combinations are discussed). The assets and liabilities acquired must be recognised at their fair values at the date on which control is obtained. The fair value that must be used under IFRS is the amount for which an asset could be exchanged or a liability settled between knowledgeable, willing parties in an arm's length transaction.

Fair values will, ordinarily, equate to the present value of the cash flows that can be generated from them. The regulator will determine the cash flows that can be generated by a water business, so the acquirer's view of the acquired business's fair value and the regulator's view of it should be very close. The differences that might arise could be as a result of different:

- Views of the cost of capital over the licence's life, resulting in a different present value
- Expectations of price inflation
- Views of environmental obligations that affect cash outflows and inflows
- Volumes supplied to current customer base
- Volumes supplied due to demographic changes and changes in industrial patterns

Goodwill will arise if the acquirer has paid more than the fair value of the individual assets acquired. This might arise as a result of one of the following:

- Synergy benefits either from other businesses and assets that the acquirer controls or from the acquirer's use of the assets acquired
- Overpayment by the acquirer
- Errors made in identifying the fair values of the consideration paid or the identifiable assets acquired, including intangible assets

4 EMBEDDING IFRS IN THE ORGANISATION

We have discussed the potential impact of IFRS on oil and gas, electricity and water companies – specifically in terms of the key accounting issues for each part of the value chain in each sort of business. But the overall implications extend far beyond the realm of the CFO.

Any company wishing to make the transition to IFRS will need to collect new information and modify its current reporting systems, or install new systems. It will need to align its internal management information systems with its external reporting systems; train its employees to comply with the new standards; and reassess its remuneration and pension schemes, in the light of the proposed alterations to their treatment.

It will also have to communicate the significance of any changes to internal and external stakeholders, including investors, analysts and governments (if it is partly state-owned). Last, it will have to be prepared for an enormous amount of work and upheaval. IFRS have rightly been described as the biggest change in the accounting regime over the past 25 years, but it is a change that has consequences for the entire organisation.

Systems

Both the type and amount of data a company must produce to comply with IFRS may be different from those it is used to collecting to satisfy its national GAAP. Indeed, some companies find that the number of data points they must include within their accounting controls increases by a factor of three. And though the data is often available somewhere within the organisation, it may not be available in the format that is needed, may not be produced in a sufficiently stringent environment, or may not be capable of being produced sufficiently quickly.

Most companies will therefore need to upgrade or replace their data collection and reporting systems. The precise changes they have to make will vary according to their individual circumstances, but organisations with extensive hedging operations or operations across a number of jurisdictions will be particularly hard hit. Almost all oil and gas companies rely heavily on derivatives and operate on a global basis, but a growing number of electricity and water companies also qualify on both counts – and their information requirements will increase dramatically under IFRS.

The amount of work required to convert to IFRS will likewise depend on the state of the existing reporting systems. Companies that have fragmented systems with, for example, a different system for each office or part of the business, legacy systems inherited from recent acquisitions or manual systems still operating in subsidiaries or local business units, will face significant challenges.

Moreover, any company that wants to make the transition to IFRS will need to align its internal management information systems with its external reporting systems. This is not simply because senior and middle managers will have to prepare budgets and forecasts that meet the requirements of IFRS. It is also because, when companies report their results under IFRS, the figures are often quite different from those produced by using national accounting rules, and it is obviously essential that the management of any organisation acts with a full understanding of the impact of its decisions on the results it will ultimately publish.

Fortunately, the development of eXtensible Business Reporting Language (XBRL) has alleviated some of the difficulties of integrating different forms of business-reporting data. The advantages of XBRL include the fact that data produced by a company's internal management systems can be easily converted into different formats and transferred from subsidiary to parent, and from parent to investors, regulators or analysts, without loss of clarity or accuracy. But though XBRL has a major role to play in re-engineering the 'pipes' of the corporate reporting supply chain, it does not replace the need to define a new business-reporting framework and ensure that the necessary data is collected in the first place.

Training

Changing a company's systems demands a considerable investment of money, time and effort; training is an even bigger challenge. A few companies with particularly sophisticated finance functions may already possess sufficient internal expertise. However, most oil, gas and utility companies will not be in this happy position. Nor will they be able to buy in the necessary skills and knowledge, because the number of people proficient in the application of IFRS is simply too small.

All such companies will therefore need to involve in-house staff in the development of new systems, and train them once the changes are in place. This is not just a matter of training those who prepare the external accounts. Employees who work in management information systems, corporate treasury and tax must also understand how to apply the principles of IFRS. And not only must they understand the new rules, they must be trained in the new processes and systems required to support a very different accounting regime.

One of the most important elements in making a successful transition to IFRS is thus a proper conversion methodology, a disciplined approach that ensures widespread acquisition of the necessary skills and the creation of a culture that is entrenched in the new ways of working. Any company that uses outside consultants to supplement its internal resources will also need to make sure that there is a genuine transfer of knowledge, if it is to avoid having to call the consultants back once the initial implementation has been completed.

Changes in Business Processes

The move to IFRS has other ramifications, in particular for the way in which companies conduct various aspects of their business. IFRS changes some companies' reported profits, losses and capital assets – so much so that, under the new regime, it may no longer be sensible to engage in certain transactions or business lines.

Some companies may find, for example, that they have embedded derivatives they were previously unaware of and, since IFRS specify that all derivatives must be recorded on the balance sheet at fair value, this may have a significant impact on their income volatility. Similarly, since the rules governing what constitutes debt and equity are different under IFRS, some companies will have to reclassify equity-type instruments as debts. In either instance, such companies may need to reconsider the way they operate in order to minimise the effect on their income statements and balance sheets.

The Potential Impact on Remuneration and Pension Schemes

The treatment of stock options and pension schemes under IFRS is also likely to be very different. Although the IASB is still drafting the relevant standard, it is already clear that the rules will be more stringent than those that apply under most national accounting regimes, and that, in turn, may trigger a substantial change in corporate policy.

Many companies now reward managers and employees with performance-related bonus schemes and stock options. This is especially true in the US and UK, but the practice is growing rapidly in mainland Europe and other parts of the world. Under IFRS, most such companies will have to produce a fair valuation of the shares or options they issue, at the date they are granted; and they will have to charge the value of those shares or options as an expense against net income during the same period as that in which the shares or options vest.

However, the burden of data collection is considerable. Most share-based compensation plans also include performance conditions designed to motivate employees to meet certain specified targets – conditions that might include revenue targets, market-share growth and/or increases in share price. It can therefore be difficult to determine the fair value of share-based compensation. Finally, charging the value of shares or options to expenses reduces a company's net income and basic earnings per share, and in the case of awards to large numbers of employees, the effect could be quite significant.

One potential result of IFRS is thus that they may encourage companies to reassess their remuneration schemes. They may want to dispense with widespread employee share-option schemes altogether, grant fixed awards that vest immediately in order to obtain a stable charge, or change the balance of their remuneration schemes with a greater emphasis on cash and other benefits, and lesser emphasis on shares or options.

The potential implications of IFRS are not confined to share-based payment schemes, though; they will also affect the treatment of pension plans. Many companies will be forced, for the first time, to put such exposures on their balance sheets, and experience in the UK shows that the impact of pension obligations can be substantial.
Since variations in the value of these obligations will go through the profit-and-loss account, some oil, gas and utility companies may want to emulate the UK practice of trying to reduce the scale of their commitments and pass more risk to employees – by replacing 'defined benefit' with 'defined contribution' schemes.

However, communicating any changes in remuneration or pension schemes to employees requires great sensitivity on the part of both the finance and the human resources functions. This is especially true in the current economic climate: the fall in the value of the global stock markets has already eroded the portfolios of companies with pension schemes that invest in external funds, and employees are likely to take a very jaundiced view of any changes in policy that they fear will leave them even worse off.

Communications with Internal and External Stakeholders

If the communication of changes in pay and pension structure demands sensitivity, so will the communication of other changes emerging from the application of IFRS. Any company switching to the new regime will have to explain the significance of the changes in its figures to every interested party, including employees and external stakeholders such as governments, institutional investors and financial analysts. This is primarily the task of the investor relations and public relations departments, which must ensure that the markets understand the reason for any shifts in reported profits or asset values.

However, it is important to provide such information as soon as possible, rather than delaying until 2005. Many analysts are already preparing their own assessments of the impact of IFRS, without waiting for the companies they follow to do so – a fact that is hardly surprising, since an understanding of the effects of IFRS is as critical for analysts as it is for management in assessing capital structure, performance and returns.

The vast majority of oil and gas and utility companies will also have to improve the quality of their external communications in general, and not just because they will have to disclose more information. The express aim of IFRS is to produce a global convergence in accounting standards – to increase transparency and make it easier for potential and actual investors to compare the performance of companies in different jurisdictions. IFRS will thus expand the pool of capital in which companies can fish, and promote cross-border investment, but it will also increase the competition for funds between companies engaged in similar activities. Institutional investors and fund managers will still want to spread their risk with investments in different sectors, but they will have a greater choice of companies in each sector to choose from.

Change Management

The magnitude and strategic significance of the alterations required to implement IFRS will also necessitate a rigorous programme of change management. An estimated 70 per cent of all major change initiatives do not realise their full potential as a result of ineffective management and failure to create programmes that guide employees through the process.

Happily, most efforts to adopt IFRS work because so much hangs on them. But any company that is making the transition will need to put an appropriate management team in place, including a project manager, steering committee and sponsor (preferably a member of the main board as distinct from someone in the finance function). It will also need to develop a clear vision and measurable targets; secure buy-in, particularly from front-line managers who have the potential to 'make or break' the move; explain the reasons for the change to its staff; and educate them in the use of the systems and processes that underpin the new accounting regime.

It is all too easy to underestimate the sheer volume and complexity of the work that is involved in implementing IFRS. But the transition is rarely a straightforward process, and never a technical exercise of concern to the finance function alone. On the contrary, those oil and gas and utility companies that have already made the switch know that it places an enormous responsibility on management and has significant financial reporting ramifications.


RAILROAD
CROSSING

5

Contacts

PricewaterhouseCoopers (www.pwc.com) is the world's largest professional services organisation. Drawing on the knowledge and skills of more than 125,000 people in 142 countries, we build relationships by providing services based on quality and integrity.

The Global Energy, Utilities and Mining group (www.pwc.com/energy) is the professional services leader, advising clients through a global network of fully dedicated oil and gas, utilities and mining specialists.

PricewaterhouseCoopers refers to the network of individual member firms of PricewaterhouseCoopers International Limited, each of which is a separate and independent legal entity.

Global Enquiries:

For more information about *Crunch Time – Embedding International Financial Reporting Standards in the Oil and Gas and Utilities Industries*, and related PricewaterhouseCoopers' services to the energy, utilities and mining industries, please visit our website at www.pwc.com/energy

Or contact:

Global contacts

Global Oil and Gas Leader

Richard Paterson
Telephone: +1 972 444 1229
Email: richard.paterson@us.pwc.com

Global Utilities Leader

Manfred Wiegand
Telephone: +49 211 981 2812
Email: manfred.wiegand@de.pwc.com

Territory contacts

Austria

Gerhard Prachner
Telephone: +43 1 501 88 1800
E-mail: gerhard.prachner@at.pwc.com

Australia

Derek Kidley
Telephone: +61 2 8266 9267
E-mail: derek.kidley@au.pwc.com

Derrick Ryley
Telephone: +61 2 8266 3578
E-mail: derrick.ryley@au.pwc.com

Belgium

Ronald Tiebout
Telephone: +32 2 710 7226
E-mail: ronald.tiebout@be.pwc.com

China

Raymund Chao
Telephone: +86 10 6505 3333
+86 10 6505 4884 (Beijing)
Email: raymund.chao@cn.pwc.com

Czech Republic

Helena Cadanova
Telephone: +420 2 5115 2011
E-mail: helena.cadanova@cz.pwc.com

Petr Sobotnik
Telephone: +420 2 5115 2016
E-mail: petr.sobotnik@cz.pwc.com

Finland

Johan Kronberg
Telephone: +358 2 274 1016
E-mail: johan.kronberg@fi.pwc.com

Jani Laakso
Telephone: +358 9 22800
E-mail: jani.laakso@fi.pwc.com

France

Xavier Aubry
Telephone: +33 1 56 57 10 23
E-mail: xavier.aubry@fr.pwc.com

Emmanuelle Levard
Telephone: +33 1 55 56 12 61
E-mail: emmanuelle.levard@fr.pwc.com

Germany

Martin Theben
Telephone: +49 201 438 11 06
Email: martin.theben@de.pwc.com

Lutz Granderath
Telephone: +49 211 981 28 09
Email: lutz.granderath@de.pwc.com

Greece

Dinos Michalatos
Telephone: +30 1 6874 730
E-mail: dinos.michalatos@gr.pwc.com

Ireland

Carmel O'Connor
Telephone: +353 1 6626417
E-mail: carmel.oconnor@ie.pwc.com

John McDonnell
Telephone: +353 1 7048559
E-mail: john.mcdonnell@ie.pwc.com

Italy

John McQuiston
Telephone: +390 6 57025 2439
E-mail: john.mcquiston@it.pwc.com

Middle East

Paul Suddaby
Telephone: +968 563 717
E-mail: p.suddaby@om.pwc.com

The Netherlands

Aad Groenenboom
Telephone: +31 26 3712 509
E-mail: aad.groenenboom@nl.pwc.com

Fred Konings
Telephone: +31 70 3426 150
E-mail: fred.konings@nl.pwc.com

Norway

Ketil Reed Aasgaard
Telephone: +47 23 16 0507
E-mail: ketil.reed.aasgaard@no.pwc.com

Gunnar Slettebø
Telephone: +47 5167 6211
E-mail: gunnar.slettebo@no.pwc.com

Poland
Wilhem Simons
Telephone: +48 22 523 4150
E-mail: wilhem.simons@pl.pwc.com

Portugal

Luis Ferreira
Telephone: +351 213 197 158
E-mail: luis.s.ferreira@pt.pwc.com

Russia and Central and Eastern Europe

Keith Rowden
Telephone: +7 095 967 6320
E-mail: keith.rowden@ru.pwc.com

Spain

Jose Luis Fernandez
Telephone: +34 93 253 27 16
E-mail: jose.luis.fernandez@es.pwc.com

Sweden

Evy Jakobsson
Telephone: +46 8 555 332 22
E-mail: evy.jakobsson@se.pwc.com

Mats Edvinsson
Telephone: +46 8 555 337 06
E-mail: mats.edvinsson@se.pwc.com

Switzerland

Lucas Monn
Telephone: +41 1 630 27 00
E-mail: lucas.monn@ch.pwc.com

United Kingdom

Paul Rew
Telephone: +44 20 7804 4071
E-mail: paul.rew@uk.pwc.com

United States

Randol Justice
Telephone: +1 713 356 8009
E-mail: randol.justice@us.pwc.com

Further information

Ralph Welter, Technical Accounting Project Manager – *Crunch Time*
Telephone: +49 211 981 2956
E-mail: ralph.welter@de.pwc.com

Olesya Hatop, Marketing Project Manager – *Crunch Time*
Telephone: +49 211 981 2123
E-mail: olesya.hatop@de.pwc.com

For copies of the report, order online at:

www.pwc.com/energy

www.pwc.com/energy

Your worlds  Our people