Real Time*

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

*connectedthinking

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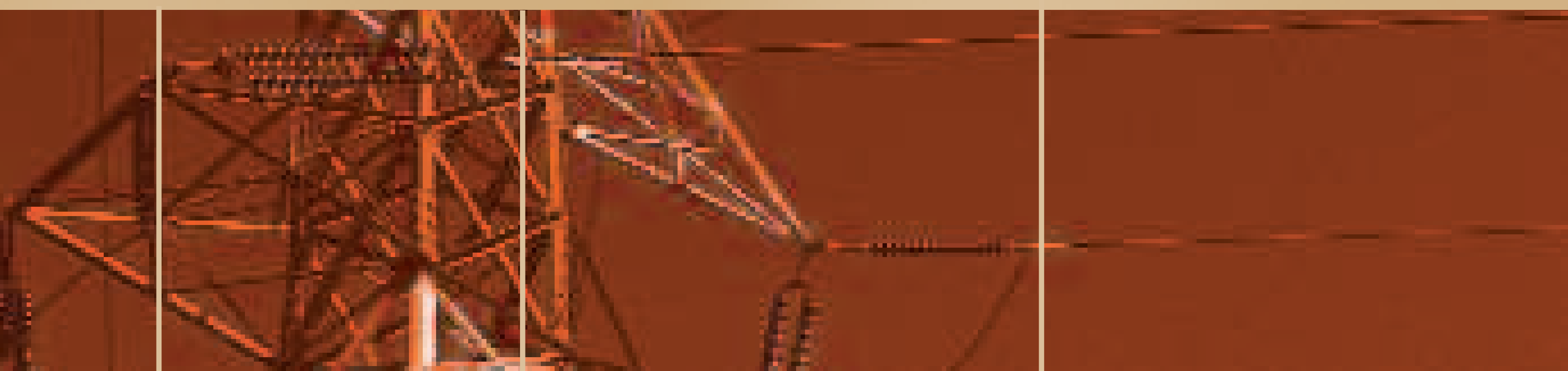
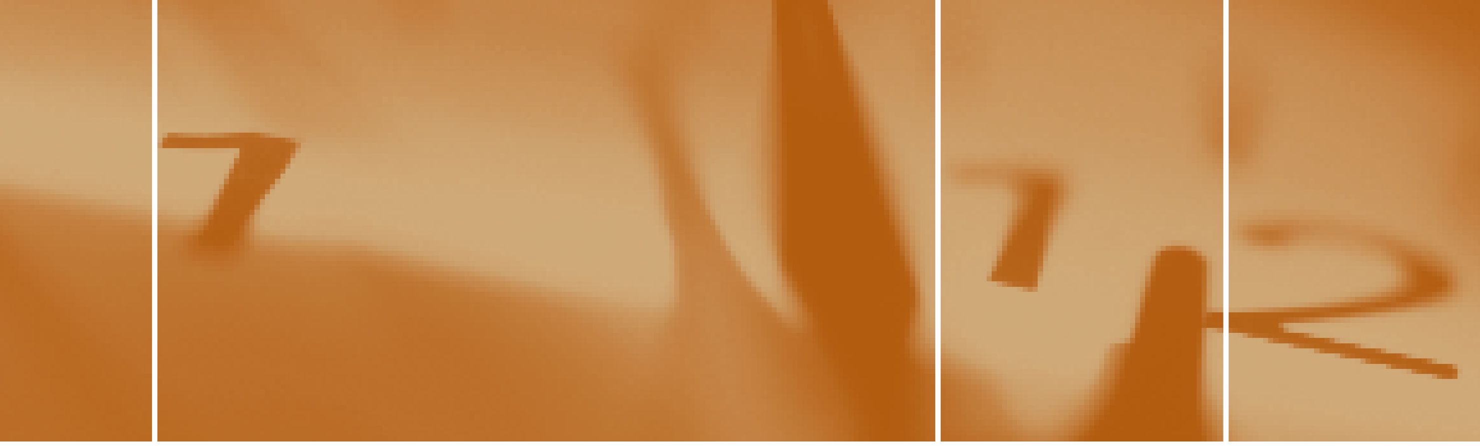


1 Introduction

International Financial Reporting Standards (IFRS) are now very real for companies around the world. With many companies at the end of their first full IFRS reporting period, we publish *Real Time*, which examines the reality of reporting under the new standards for companies in the oil & gas and utilities sectors.

Both industries are characterised by the need for big upfront investment, often with great uncertainty about outcomes over a long-term time horizon. Their geopolitical, environmental, energy and natural resource supply and trading challenges, combined with often complex stakeholder and business relationships, has meant that the transition to IFRS has required some complex judgements about how to implement the new standards.

Real Time looks across the value chain of each industry and discusses in detail how the new standards are being put into practice. We identify areas where companies have to exercise considerable judgement in applying the standards, in particular in respect of derivatives and financial instruments, impairments and the recoverability of costs. Alongside these, we see how developments in the wider environment, such as emissions trading and energy price volatility, are accentuating the reporting challenge faced by companies.



One of the challenges of working with ‘principles based’ standards is that without a ‘rulebook’, management needs to spend more time explaining the judgements they have made to apply the principles. We see companies grappling with issues that appeared at year end – how to present and describe the volatility arising from IAS 39, the difficulty of calculating deferred tax, collecting information for disclosure requirements and still producing financial statements in fewer than 100 pages!

Real Time provides insights into how companies are responding to these challenges and includes examples of accounting policies and other disclosures from published financial statements. As companies move forward, the challenge will be to embed IFRS into the ‘real time’ day-to-day practice of the company. Many companies remain in ‘special project mode’ and are yet to make the successful transition of making the standards integral to ‘business as usual’ activities. In contrast, others have not only achieved this for their external financial reporting but have also successfully aligned their internal management and performance reporting with IFRS.

Richard Paterson
Global Energy, Utilities and Mining Leader,
Global Oil & Gas Leader

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Global Utilities Leader

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The Oil and Gas Industry

The Oil and Gas Value Chain

Exploration and Production	Transportation and Refining	Retail and Distribution
• Exploration: Successful efforts vs. full cost method / IFRS 6 (E&E) • Joint working arrangements • Overlift and underlift • Impairment, CGUs • Revenues & taxation • Production sharing contracts & taxation • Asset componentisation • Asset retirement obligations	• Accounting for pipeline fills & cushion gas (underground storage) • Asset componentisation	• Impairment, CGUs

The impact of IFRS is felt all along the oil and gas value chain but many of the key dilemmas and judgements are greatest at the exploration and production stage. At the very start of the value chain, for example, full cost accounting is allowed to continue under IFRS 6 but only for the exploration and evaluation phase. At the other end of the industry, IFRS is shifting the boundaries of cash generating units (CGUs) right down to the petrol station or the smallest group of retailing assets that generate separately identifiable cash flows. In the following sections we examine the key IFRS decisions companies need to take along the oil and gas value chain.

2.1 Exploration & Production

2.1.1 Exploration

Successful Efforts vs Full Cost Method

Most of the major integrated oil and gas companies, as well as many smaller upstream companies, use the successful efforts method. Using this method for accounting for exploration and development, costs incurred in finding, acquiring and developing reserves are capitalised on a field-by-field basis depending on the nature of operations. Upon discovery of a commercially viable (or proven) mineral reserve, the capitalised costs can be allocated to the discovery. In the event that such a discovery is not achieved, the expenditure is charged to expense.

However, some upstream 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, as opposed to individual fields, 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.

Debate continues within the industry on the conceptual merits of both methods. IFRS 6 was issued to provide an interim solution by allowing entities to continue applying their accounting policy in respect of exploration for and evaluation of mineral resources until a more comprehensive solution is developed. It provides an interim solution for exploration and evaluation costs, but does not for costs incurred once this phase is completed. It is therefore difficult to see how full cost accounting as applied in the past can be sustained beyond the exploration and evaluation (E&E) phase.

Changes made to an entity's accounting policy for E&E assets can only be made if they result in an accounting policy that is closer to the principles of the IFRS Framework. To comply with IFRS 6, the change must result in a new policy that is more relevant and no less reliable, or more reliable and no less relevant, than the previous policy. This restriction on changes to the accounting policy includes changes implemented on adoption of IFRS 6. It is important to emphasise that IFRS 6 only covers the exploration and evaluation phase, until the point when reserves have been determined proved successful or unsuccessful.

Real Time Spotlight

BG Group plc

Exploration expenditure
"BG Group uses the 'successful efforts' method of accounting for exploration expenditure. Exploration expenditure, including licence acquisition costs, is capitalised as an intangible asset when incurred and certain expenditure, such as geological and geophysical exploration costs, is expensed. A review of each licence or field is carried out, at least annually, to ascertain whether proved reserves have been discovered. When proved reserves are determined, the relevant expenditure, including licence acquisition costs, is transferred to property, plant and equipment and depreciated on a unit of production basis. Expenditure deemed to be unsuccessful is written off to the income statement. Exploration expenditure is assessed for impairment when facts and circumstances suggest that its carrying amount exceeds its recoverable amount. For the purposes of impairment testing, exploration and production assets may be aggregated into appropriate cash generating units based on considerations including geographical location, the use of common facilities and marketing arrangements."

Annual Report and Accounts 2005, BG Group plc, p.64

BP plc

Exploration expenditure
"Geological and geophysical exploration costs are charged against income as incurred. Costs directly associated with an exploration well are capitalized as an intangible asset until the drilling of the well is complete and the results have been evaluated. These costs include employee remuneration, materials and fuel used, rig costs, delay rentals and payments made to contractors. If hydrocarbons are not found, the exploration expenditure is written off as a dry hole. If hydrocarbons are found and, subject to further appraisal activity, which may include the drilling of further wells (exploration or exploratory-type stratigraphic test wells), are likely to be capable of commercial development, the costs continue to be carried as an asset. All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off. When proved reserves of oil and natural gas are determined and development is sanctioned, the relevant expenditure is transferred to property, plant and equipment."

Annual Report and Accounts 2005, BP plc, p.32

Example

Entity A has been operating in the upstream oil and gas sector for many years. It is transitioning to IFRS in 2005 with a transition date of 1 January 2004. Management has decided to early adopt IFRS 6 to take advantage of the relief it offers for capitalisation of exploration costs and the impairment testing applied.

Entity A has followed a policy of expensing geological and geophysical costs under its previous GAAP. The geological and geophysical studies that entity A has performed do not meet the Framework definition of an asset in their own right, however management has noted that IFRS 6 permits the capitalisation of such costs [IFRS6.9(b)]. Can entity A's management change A's accounting policy on transition to IFRS to capitalise geological and geophysical costs?

Solution

IFRS 6 restricts changes in accounting policy to those which make the policy more reliable and no less relevant or more relevant and no less reliable. One of the qualities of relevance is prudence. Capitalising more costs than under the previous accounting policy is not more prudent and therefore is not more relevant. Entity A's management should therefore not make the proposed change to the accounting policy.

Reclassification at the end of the exploration and evaluation phase

E&E assets for which commercially viable reserves have been identified are reclassified out of this category to Development Assets. The E&E asset should be tested for impairment under IFRS 6 immediately prior to this reclassification. Once an E&E asset has been reclassified out of the E&E classification, it is subject to the normal IFRS requirements of impairment testing at the CGU level as the relief provided by IFRS 6 in this area is available only up to the point of evaluation

The post-evaluation accounting for an E&E asset for which no commercially viable reserves have been identified is subject to interpretation. Should it be written down to its fair value less costs to sell, or is there is a basis for continuing to classify it within E&E, subject to the segment-wide impairment test under IFRS 6 ? In our view it is not appropriate to sustain such cost within E&E. The consequence of this is that full cost accounting cannot be applied under IFRS without significant modification.

Measurement of production assets

Producing assets should be amortised over their expected total production using a units of production basis. The units of production basis is often the most appropriate amortisation method because it reflects the pattern of consumption of the economic benefits of the reserves. However, straight-line amortisation may be appropriate for some assets. The reserves used for the units of production calculation could be proved and probable reserves or proved developed, but the policy choice taken should be applied consistently. Whichever reserves definition management chooses it should apply this consistently to all production properties.

Real Time Spotlight

BG Group plc

Depreciation and amortisation
"Exploration and production assets are depreciated from the commencement of production in the fields concerned, using the unit of production method based on the proved developed reserves of those fields, except that a basis of total proved reserves is used for acquired interests and for facilities. Changes in these estimates are dealt with prospectively."

Annual Report and Accounts 2005, BG Group plc, p.63

Royal Dutch Shell plc

Depreciation, depletion and amortisation
"Property, plant and equipment related to oil and natural gas production activities are depreciated on a unit-of-production basis over the proved developed reserves of the field concerned, except in the case of assets whose useful life is shorter than the lifetime of the field, in which case the straight-line method is applied. Rights and concessions are depleted on the unit-of-production basis over the total proved reserves of the relevant area. Unproved properties are amortised as required by particular circumstances.

Other property, plant and equipment are generally depreciated on a straight-line basis over their estimated useful lives which is generally 20 years for refineries and chemicals plants, 15 years for retail service station facilities, and major inspection costs are amortised over three to five years which represents the estimated period before the next planned major inspection."

Annual Report 2005, Royal Dutch Shell plc, p.110

If proved and probable reserves are used, then an adjustment should be considered in relation to the amortisation charge to reflect the future development costs that will be required to be incurred to access the undeveloped reserves.

Example

Entity D is preparing its IFRS financial statements. D's management has identified that it should amortise the carrying amount of its producing properties on a units of production basis over the reserves preset for each field.

However, D's management is debating whether to use proved reserves or proved and probable reserves for the units of production calculation. What class of reserves should be used for the units of production calculation?

Solution

Entity D's management may choose to use either proved reserves or proved and probable reserves for the units of production amortisation calculation.

The total production used for amortisation of reserves that are subject to a lease or licence should be restricted to the total production expected to be produced during the licence/lease term. Renewals of the licence/lease are only assumed if there is evidence to support probable renewal without significant cost.

2.1.2 Joint working arrangements

The demand for capital and long lead time has given rise to a practice in the industry of sharing the burden and risk of exploration and start-up with other industry players, governments or users of output. These arrangements are seen in multiple forms, like investments with less than joint control, including undivided interests; production sharing arrangements and concessions; co-located assets; and joint ventures.

Joint ventures

A joint venture is distinguished by the presence of joint control: the contractually agreed sharing of control over an economic activity. Joint control requires all substantive decisions to be unanimously agreed by all parties sharing joint control. The requirement for a large voting majority, for example 80%, will not necessarily be sufficient to establish joint control.

Joint ventures in which one of the partners sharing control has a very small ownership interest should also be carefully considered. The reasons behind the other partners being prepared to share control with a very small stakeholder should be understood. One venturer acting as operator for practical day-to-day purposes does not necessarily prevent joint control from existing.

The most common type of joint venture in the O&G industry is jointly controlled assets.

BP plc

Licence and property acquisition costs
"Exploration and property leasehold acquisition costs are capitalized within intangible fixed assets and amortized on a straight-line basis over the estimated period of exploration. Each property is reviewed on an annual basis to confirm that drilling activity is planned and it is not impaired. If no future activity is planned, the remaining balance of the licence and property acquisition costs is written off.

Upon determination of economically recoverable reserves ('proved reserves' or 'commercial reserves'), amortization ceases and the remaining costs are aggregated with exploration expenditure and held on a field-by-field basis as proved properties awaiting approval within other intangible assets. When development is approved internally, the relevant expenditure is transferred to property, plant and equipment."

Revenue
"Generally, revenues from the production of oil and natural gas properties in which the group has an interest with other producers are recognized on the basis of the group's working interest in those properties (the entitlement method)."

Annual Report and Accounts 2005, BP plc, p.32 and p.37

BG Group plc

Proved reserves
"BG Group utilises SEC definitions of proved reserves and proved developed reserves in preparing estimates of its gas and oil reserves. Proved reserves are the estimated quantities of gas and oil which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those reserves which can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are those quantities that are expected to be recovered from new wells on undrilled acreage or from existing wells where relatively major expenditure is required for completion.

The net movement in proved reserves during the year includes extensions, discoveries and reclassifications (22 mmboe), and revisions to previous estimates (197 mmboe). Included within revisions are the net effect of increases in year end prices (188mmboe decrease) and a revision in the treatment of fuel gas (89 mmboe increase). Production in the period was 183 mmboe (net of Canadian royalty production 0.6 mmboe)."

Annual Report and Accounts 2005, BG Group plc, p.128

Jointly controlled assets

In the oil and gas industry, jointly controlled assets are commonplace. A jointly controlled asset is usually constructed by the joint owners, provides an essential shared service and is not a separate legal entity. The venturers will hold joint legal title over the asset. An example would be a pipeline, refinery or offshore loading platform that is jointly constructed and owned by the oil companies with production facilities in a large field or group of fields. The venturers may also contribute existing assets or sell a share of an existing asset to a co-venturer but these are more likely to result in a jointly controlled entity rather than a jointly controlled asset.

Each party to a jointly controlled asset should recognise:

- its share of the jointly controlled asset, classified according to the nature of the asset;
- any liabilities the venturer has incurred;
- its proportionate share of any liabilities that arise from the jointly controlled asset;
- its share of expenses from the operation of the asset; and
- any income arising from the operation of the asset (for example, ancillary fees from use by third parties).

Jointly controlled assets tend to reflect the sharing of costs and risks rather than the sharing of profits.

The contribution of assets to a jointly controlled asset arrangement will result in a partial disposal of that asset by the contributing venturer, with the gain or loss being recognised in the income statement. The interest in that asset by the other venturers will be at their share of the fair value of the asset at the date of contribution. The accounting for an interest in jointly controlled assets is similar to the proportional consolidation model applied for jointly controlled entities.

Example

Entities A, B and C together own and operate an offshore loading platform close to producing fields which they own and operate independently from each other. They own 45%, 40% and 15% respectively of the platform and have agreed to share services and costs accordingly. Local legislation requires the dismantlement of the platform at the end of its useful life. Decisions regarding the platform require the unanimous agreement of the three parties. Is this a joint venture?

Solution

Yes, this is a joint venture. The platform is a jointly controlled asset, and neither a jointly controlled entity nor a jointly controlled operation. Each venturer recognises its share of the liability associated with the decommissioning of the platform. It should also disclose as a contingent liability the other venturers' share of the obligation to the extent that it is contingently liable for their share.

Real Time Spotlight

Eni SpA

Revenues and costs
"Revenues are recognized upon shipment when, at that date, the risks of loss are transferred to the acquirer.

Revenues from the sale of crude oil and natural gas produced in properties in which Eni has an interest together with other producers are recognized on the basis of Eni's working interest in those properties (entitlement method). Differences between Eni's net working interest volume and actual production volumes are recognized at current prices at period-end."

Annual Report 2005, Eni SpA, p.132

Jointly controlled entities

Jointly controlled operations and jointly controlled assets typically represent the sharing of costs and physical operations. In contrast, jointly controlled entities may include the sharing of physical operations but generally also include the sharing of financial results rather than just the sharing of costs.

The venturers often contribute fixed assets (or the commitment to construct such), mineral rights or cash and other assets. The formation of a jointly controlled entity requires the venturer to account for the assets it has contributed as a partial disposal.

Example

A jointly controlled entity is established in which each venturer has a 50% interest. One party contributes mineral rights and the other party contributes production facilities. Each party has disposed of 50% of its interest in its own assets and acquired a 50% interest in the other party's assets. Is any gain/loss recognised on establishment of the joint venture?

Solution

Both venturers will recognise a gain or loss based on their share of the fair value of the asset received less the share of the book value of the asset disposed of.

What are indicators of an entity under IFRS?

A jointly controlled entity is a joint venture that involves the establishment of a corporation, partnership or other entity that the venturer has an ownership interest in [IAS31.24].

In some jurisdictions the term legal entity is defined by local company law. However, IAS 31 refers to an 'entity' rather than a 'legal entity'. The fact that the arrangement might not meet the definition of a legal entity in the country in which the joint venture is based does not preclude it from being an entity according to IAS 31. The substance of an arrangement should be considered to determine whether an entity exists.

Features that commonly indicate the presence of an entity include:

- The use of a separate identity that is known and recognised by third parties;
- The ability to enter into contracts in its own name;
- Maintaining its own bank accounts; and
- Raising and settlement of its own liabilities.

Activities that have no contractual arrangement to establish joint control are not joint ventures for the purposes of IAS 31. However, a separate joint venture agreement is not required; a clause included the articles of association that establishes the requirement for parties to agree for any decisions to be taken is sufficient to meet the definition of a joint venture.

Jointly controlled entities – presentation

The IASB has been undertaking a research project on joint venture accounting. In December 2005 the Board provisionally decided to remove the option of proportional consolidation for jointly controlled entities and therefore to allow only equity accounting, but also decided to expand its project to consider joint ventures because they felt the current standard does not adequately address the difference between a joint venture entity and an undivided interest in the assets and liabilities of a joint arrangement. In the meantime, the Board has decided, in view of the potential effects of current projects (e.g. consolidations, conceptual framework, short-term convergence) on joint-venture accounting, to suspend work on the long-term research project pending the outcome of these other projects.

Investments with less than joint control including undivided interests

Energy and utilities entities may take an ownership interest in a joint venture or other legal entity but not be one of the venturers. This can arise with shared assets such as a pipeline where the group of users is too wide for joint control to be practical. It also may result where the investor wishes to retain influence and access to information but not joint control. Often the legal entity will own a single asset or closely related group of assets such as a cracking plant or storage facility.

Joint venture accounting, as set out in IAS 31, cannot be applied if there is not joint control. The accounting treatment is dependent on the nature of the investment and level of voting power held.

Where the investment is held in a separate entity, the interest is treated as an investment and is either accounted for as an associate under IAS 28 (where the investor has significant influence) or an available for sale asset under IAS 39. It is not appropriate to carry the investment at cost less impairment when a reliable fair value can be determined. Management must obtain the information to allow equity accounting or develop a process to estimate the fair value at every reporting date.

An undivided interest in an asset is normally accompanied by a requirement to incur a proportionate share of the operating and maintenance costs of the asset. These costs should be recognised as expenses in the income statement when incurred and classified in the same way as equivalent costs for wholly owned assets.

2.1.3 Overlift and underlift

Many joint ventures, particularly in the oil industry, share the physical output (for example crude oil) between the joint venture partners. Each joint venture partner is then responsible for either using or selling the oil it takes.

The physical nature of the lifting of oil is such that it is more efficient for each partner to lift a full tanker-load of oil at a time. A lifting schedule is therefore prepared which identifies the order and frequency with which each partner can lift. Consequently at each balance sheet date the amount of oil lifted by each partner will not be equal to its equity interest in the field. Some partners will have taken more than their share (overlifted) and others will have taken less than their share (underlifted).

Overlift and underlift represents a sale of oil at the point of lifting by the underlifter to the overlifter. Overlift is therefore treated as a purchase of oil by the overlifter from the underlifter.

The sale of oil by the underlifter to the overlifter should be recognised at the market price of oil at the date of lifting [IAS18.9]. Similarly the overlifter should reflect the purchase of oil at the same value.

At any point in time, the extent of underlift by a partner is reflected as an asset in the balance sheet and the extent of overlift is reflected as a liability. An underlift asset is the right to receive additional oil from future production without the obligation to fund the production of that additional oil. An overlift liability is the obligation to deliver oil out of the entity's equity share of future production.

The initial measurement of the overlift liability and underlift asset is at the market price of oil at the date of lifting, consistent with the measurement of the sale and purchase. Subsequent measurement depends on the terms of the joint venture agreement. Joint venture agreements which allow the net settlement of overlift and underlift balances in cash will fall within the scope of IAS 39 unless the own use exemption can be claimed.

Unless they fall within the scope of IAS 39, overlift and underlift balances should be measured at the lower of carrying amount and current market value. Any remeasurement should be included in other income/expense rather than revenue or inventory.

Overlift and underlift balances which fall within the scope of IAS 39 must be remeasured to the current market price of oil at the balance sheet date. The change arising from this remeasurement is included in the income statement as other income/expense rather than revenue or cost of sales.

2.1.4 Impairment & Cash generating units

Once an impairment indicator has been identified, an impairment test must be performed at the individual Cash generating unit (CGU) level, even if the indicator was identified at a regional level.

A CGU is the smallest group of assets that generates cash flows largely independent of other assets or groups of assets. A CGU in a petroleum upstream entity will often be identified as a field and its supporting infrastructure assets. Production, and therefore cash flows, can be associated with individual wells. The field investment decision is made based on expected field production, not a single well, and all wells are dependent on the field infrastructure.

Interaction of decommissioning provisions and impairment calculations

The cash flows associated with the decommissioning obligations of an asset being tested for impairment are excluded from the value in use (VIU) cash flows because the provision for the decommissioning liability is already recognised. Similarly the carrying amount of the decommissioning provision is not included in the carrying amount of the CGU.

Including the decommissioning cash outflows without the carrying amount of the provision would be inconsistent and vice versa. It is preferable to exclude both the carrying amount and the associated cash outflows because the measurement of VIU and the measurement of the provision may require different discount rates to be applied.

Determination of Fair Value Less Costs To Sell (FVLCTS) should be consistent in the treatment of decommissioning. The FVLCTS should be determined gross of the obligation to decommission and compared with the carrying value of the CGU gross of the decommissioning liability.

Subsequent measurement of exploration and evaluation assets

E&E assets should be tested for impairment when there are facts and circumstances that suggest that the book value of the asset may not be recoverable, for example because:

- The entity's right to explore in an area has expired or will expire in the near future without renewal;
- No further exploration or evaluation is planned or budgeted;
- The decision to discontinue exploration and evaluation in an area because of the absence of commercial reserves; or
- Sufficient data exists to indicate that the book value will not be fully recovered from future development and production.

E&E assets do not yet themselves generate cash inflows. They are therefore tested for impairment generally as part of a larger group of assets including producing cash generating units (CGUs). An entity should develop a policy for allocating E&E assets to groups of CGUs and apply that policy consistently. The level at which E&E assets are grouped with producing CGUs must not be larger than the entity's segments under IAS 14.

Real Time Spotlight

BP plc

Business combinations and goodwill
"As at the acquisition date, any goodwill acquired is allocated to each of the cash-generating units expected to benefit from the combination's synergies. For this purpose, cash-generating units are set at one level below a business segment."

Exploration and Production
"During 2005, Exploration and Production recognized total charges of $266 million for impairment in respect of producing oil and gas properties. The major element of this was a charge of $226 million relating to fields in the Shelf and Coastal areas of the Gulf of Mexico. The triggers for the impairment tests were primarily the effect of Hurricane Rita, which extensively damaged certain offshore and onshore production facilities, leading to repair costs and higher estimates of the eventual cost of decommissioning the production facilities and, in addition, reduced estimates of the quantities of hydrocarbons recoverable from some of these fields."

Annual Report and Accounts 2005, BP plc, p.31 and p.56

2.1.5 Revenues & taxation

Petroleum taxes generally fall into two categories – those that are calculated on profits earned (income taxes) and those calculated on production cost or sales revenues (royalty or excise taxes). The categorisation is crucial.

Petroleum taxes – royalty and excise

Petroleum taxes that are calculated by applying a tax rate to a measure of revenue or production volumes do not fall within the scope of IAS 12 and are not income taxes. They do not form part of revenue and a liability for revenue-based and volume-based taxes is recognised when the production occurs or revenue arises [IAS18.8]. These taxes are most often described as royalty or excise taxes. They are measured in accordance with the relevant tax legislation and a liability is recorded for amounts collected or due that have not yet been paid to the government. No deferred tax is calculated. The smoothing of the estimated total tax charge over the life of a field is not appropriate.

Royalty and excise taxes are in effect the government's share of the natural resources exploited. They are a share of production for the government free of cost. They may be paid in cash or in kind. If in cash, the entity sells the oil or gas and remits to the government its share of the proceeds. Royalty payments in cash or in kind are mostly excluded from gross revenues and costs.

Petroleum taxes based on profits

Petroleum taxes that are calculated by applying a tax rate to a measure of profit fall within the scope of IAS 12. The profit measure used to calculate the tax is that required by the tax legislation and will, accordingly, differ from the IFRS profit measure. Profit in this context is revenue less costs. Examples of profit-based taxes include Petroleum Revenue Tax in the UK and Norwegian Petroleum Tax.

Petroleum taxes on income are often 'super' taxes applied in addition to ordinary corporate income taxes. The tax may apply only to profits arising from specific geological areas or sometimes on a field by field basis within larger areas. The petroleum tax may or may not be deductible when determining corporate income tax; this does not change its character as a tax on income. The computation of the tax is often complicated. There may be a certain number of barrels or bcm that are free of tax, accelerated depreciation and additional tax credits for investment. Often there is a minimum tax computation as well. Each complicating factor in the computation must be separately evaluated and accounted for in accordance with IAS 12.

Deferred tax must be calculated in respect of all taxes which fall within the scope of IAS 12 including petroleum taxes based on profits. The deferred tax is calculated separately for each tax by identifying the temporary differences between the IFRS carrying amount and the corresponding tax base for each tax. Petroleum income taxes may be assessed on a field specific basis or a regional basis. As a result, an IFRS balance sheet and a tax balance sheet will be required for each area or field subject to separate taxation.

The tax rate applied to the temporary differences will be the statutory rate. The statutory rate may be adjusted for allowances and reliefs in certain limited circumstances where the tax is calculated on a field-specific basis without the opportunity to transfer profits or losses between fields [IAS12.47] [IAS12.51].

Tax paid in cash or in kind

Tax is usually paid in cash to the relevant tax authorities. However, some governments allow payment of tax through the delivery of oil instead of cash for income taxes, royalty and excise taxes and amounts due under licences, production sharing contracts and the like.

The accounting for the tax charge and the settlement through oil should reflect the substance of the arrangement. Determining the accounting is straightforward if it is an income tax (see definition above) and is calculated in monetary terms. The volume of oil used to settle the liability is then determined by reference to the market price of oil. The entity has in effect 'sold' the oil and used the proceeds to settle its tax liability. These amounts are appropriately included in gross revenue and tax expense.

Arrangements where the liability is calculated by reference to the volume of oil produced without reference to market prices can make it more difficult to identify the appropriate accounting. These are most often a royalty or volume based tax. The accounting should reflect the substance of the agreement with the government. Some arrangements will be a royalty fee, some will be a traditional profit tax, some will be an appropriation of profits and some will be a combination of these and more.

The agreement or legislation under which oil is delivered to a government must be reviewed to determine the substance and hence the appropriate accounting.

Different agreements with the same government must each be reviewed as the substance of the arrangement and hence the accounting may differ from one to another.

2.1.6 Production sharing agreements & taxation

A Production Sharing Agreement (PSA) is the method whereby governments facilitate the exploitation of their country's mineral resources by taking advantage of the expertise of a commercial oil and gas entity. Governments, particularly in emerging nations, try to provide a stable regulatory and tax regime to create sufficient certainty for commercial entities to invest in an expensive and long lived development process. An oil and gas entity will undertake exploration, supply the capital, develop the resources found, build the infrastructure and lift the natural resources. The government retains title to the mineral resources (whatever the quantity that is ultimately extracted) and often the legal title to all fixed assets constructed to exploit the resources. The government will take a percentage share of the output which may be delivered in product or paid in cash under an agreed pricing formula.

The operating entity may only be entitled to recover specified costs plus an agreed profit margin. It may have the right to extract resources over a specified period of time.

A concession agreement is much the same although the entity will retain legal title to its assets and does not share production with the government. The government will still be compensated based on production quantities and prices – this is often described as a concession rent, royalty or a tax.

There are as many forms of PSAs and concessions as there are combinations of national, regional and municipal governments in oil producing areas. Consequently, the accounting will vary depending on the nature of the PSAs.

PSAs and concessions are not standard even with the same legal jurisdiction. The more significant a new field is expected to be, the more likely that the relevant government will write specific legislation or regulations for it.

Each should be evaluated and accounted for in accordance with the substance of the arrangement.

The entity's previous experience of dealing with the relevant government will also be important as it is not uncommon for governments to force changes in PSAs or concessions based on changes in market conditions or environmental factors. An agreement may contain a right of renewal with no significant incremental cost. The government may have a policy or practice with regard to renewal. These should be assessed when estimating the expected life of the agreement.

Revenue and costs of PSAs and concessions

The entity should record only its own share of oil under a PSA as revenue. Oil extracted on behalf of a government is not revenue or a production cost. The entity acts as the government's agent to extract and deliver the oil or sell the oil and remit the proceeds. Many PSAs specify that income taxes owed by the entity are paid in delivered oil rather than cash. 'Tax oil' is recorded as revenue and as a reduction of the current tax liability to reflect the substance of the arrangement where the entity delivers oil to the value of its current tax liability.

Taxes in PSAs

A crucial question arises as to the taxation of PSAs – when are amounts paid to the government an income tax (and thus form part of revenue) and when are amounts a royalty and excluded from revenue? Some PSAs include a requirement for the national oil company or another government body to pay income tax on behalf of the operator of the PSA. When does tax paid on behalf of an operator form part of revenue and income tax expense?

The revenue arrangements and tax arrangements are unique in each country and can vary within a country, such that each major PSA is usually unique. However, there are common features that will drive the assessment as income tax, royalty or government share of production. Among the common features that should be considered in making this determination are whether a well established income tax regime exists, whether the tax is computed on a measure of profits, and whether the PSA requires the payment of income taxes, the filing of a tax return and establishes a legal liability for income taxes until such liability is discharged by payment from the entity or a third party.

2.1.7 Asset componentisation

Large oil and gas assets can comprise a significant number of components, many of which will have differing useful lives. Examples include gas treatment installations, LNG terminals, refineries, major pipelines and big offshore platforms.

The cost of the significant components of these types of assets must be separately identified and depreciated to their residual values over the useful life. Identifying the significant components can be a complex process for large and advanced plants.

An offshore drilling platform is a major installation that will require decommissioning at the end of its useful life. The platform has a number of components that will require replacement once or more during its working life such as compressors. Depreciation in upstream is usually calculated on a units of production (UOP) of basis over the proved reserves. The application of component depreciation in an upstream environment is therefore complex.

Example

An entity has a number of offshore drilling platforms. It estimates that the major mechanical components require replacement every three years. The accounting systems are set up to calculate depreciation only on a UOP basis. Management proposes to estimate annual production based on normal conditions and use three years of production as the expected UOP for the shorter lived components.

Is this proposal acceptable?

Solution

Management's proposal may be acceptable. The mechanical components are more likely to be consumed by time and exposure to salt water and extremes of weather than the amount of production. When production is in line with forecasts, depreciation on a UOP basis will be roughly equivalent to what would have been recorded on a time basis. The relatively short useful life of three years means that absent interruptions in production depreciation should be reasonably accurate.

2.1.8 Asset retirement obligations

Obligations to decommission or remove an asset are created at the time the asset is put in place. An offshore drilling platform, for example, must be removed at the end of its useful life. However, the obligation to remove arises from its placement. If its useful life is 10,000 barrels or 1,000,000 the obligation will not change in substance.

Provisions for decommissioning and restoration are recognised even if the decommissioning is not expected to be performed for a long time, for example 80 to 100 years. The effect of the time to expected decommissioning will be reflected in the discounting of the provision.

Revisions to decommissioning provisions

The decommissioning provisions are updated at each balance sheet date for changes in the estimates of the future cash flows and changes in the discount rate [IAS37.59]. Changes to provisions that relate to the removal of an asset are added to or deducted from the carrying amount of the asset [IFRIC1.5]. The adjustments to the asset are restricted, however. The asset cannot decrease below zero and cannot increase above recoverable amount [IFRIC1.5].

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

Deferred tax on decommissioning obligations

The amount of the asset and liability recognised at initial recognition of decommissioning or on subsequent revisions of estimates are generally viewed as being within the scope of the current 'initial recognition exemption' in IAS 12 [IAS12.15] [IAS12.24]. The asset and liability do not affect accounting profit or taxable profit and so do not attract deferred tax. The amount of accretion in the provision from unwinding of the discount gives rise to a book/tax difference and will result in a deferred tax asset, subject to an assessment of recoverability. IFRIC considered a similar question at its April and June 2005 meetings of whether the IAS 12 initial recognition exemption applied to the recognition of finance leases. IFRIC acknowledged that there was diversity in practice in the application of the initial recognition exemption for finance leases but decided not to issue an interpretation because of the IASB's short-term convergence project with the FASB. Accordingly some entities might take an alternative view that the IAS 12 initial recognition exemption should not be applied for finance leases and decommissioning liabilities. However a consistent policy should be adopted for deferred tax accounting for decommissioning liabilities and finance leases [IAS8.13].

Real Time Spotlight

BP plc

Decommissioning
"Liabilities for decommissioning costs are recognized when the group has an obligation to dismantle and remove a facility or an item of plant and to restore the site on which it is located, and when a reasonable estimate of that liability can be made. Where an obligation exists for a new facility, such as oil and natural gas production or transportation facilities, this will be on construction or installation. An obligation for decommissioning may also crystallize during the period of operation of a facility through a change in legislation or through a decision to terminate operations. The amount recognized is the present value of the estimated future expenditure determined in accordance with local conditions and requirements.

A corresponding item of property, plant and equipment of an amount equivalent to the provision is also created. This is subsequently depreciated as part of the capital costs of the facility or item of plant.

Any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding property, plant and equipment."

Annual Report and Accounts 2005, BP plc, p.35

BG Group plc

Decommissioning costs
"The estimated cost of decommissioning at the end of the producing lives of fields is reviewed periodically and is based on engineering estimates and reports, including a review by an independent expert. Provision is made for the estimated cost of decommissioning at the balance sheet date. The payment dates of total expected future decommissioning costs are uncertain but are currently anticipated to be between 2006 and 2040. BG Group periodically completes a full review of its exploration and production decommissioning liabilities.Transfers and other adjustments include changes to existing provisions following the review."

Annual Report and Accounts 2005, BG Group plc, p.96

2.2 Transportation and Refining

2.2.1 Accounting for pipeline fills and cushion gas (underground storage)

Some items of property plant and equipment, such as pipelines, refineries and gas storage, require a certain minimum level of inventory to be maintained in them in order for them to operate efficiently. Such inventory should be classified as part of the property, plant and equipment because it is necessary to bring the PPE to its required operating condition. The inventory will therefore be recognised as a component of the PPE at cost and subject to depreciation to estimated residual value.

A gas utility distribution company may create caves and plugs in order to store its own natural gas inventories. An example is the purchase of salt caverns to be used as underground gas storage. The natural gas is injected and as the volume of gas injected increases, so does the pressure. The salt cavern therefore acts as a pressurised container. The pressure established within the salt cavern is used to push out the gas when it needs to be extracted. As the pressure within the cavern drops below a certain threshold there is no pressure differential to push out the remaining natural gas. This remaining gas within the cavern is physically unrecoverable and known as 'cushion gas'. The process is in some respects similar to an oil entity transporting its oil through pipelines.

These cushion gas/pipeline fills are classified and accounted for as a component of the entity's property, plant and equipment being the gas storage facilities/pipelines.

The cushion gas/pipeline fills will not be extracted from the cavern/pipelines but are necessary for the cavern to perform its function as a gas storage facility/for the pipeline to perform the function of means of transport. The cost of the cushion gas/pipeline fills are therefore capitalised at the initial recognition and depreciated over the useful life of the relevant fixed asset.

The natural gas in excess of the cushion gas that is injected into the cavern is classified and accounted for as inventory in accordance with IAS 2. (Pipeline oil in excess of the linefill is accounted for in accordance with its originally intended purpose.)

The cost of an item of PPE includes any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. The cost of cushion gas/pipeline fill does not include any internal profits when internally generated gas/oil is capitalised. Neither is the cost of abnormal amounts of wasted material, labour, or other resources incurred in the internal generation of the gas/oil included.

Technical developments may mean the cushion gas/pipeline fills quantities can be reduced and used as inventory. The related carrying amount of the fill is transferred from PPE to inventories at that date. Any profits are recognised in accordance with IAS 18 for recognising revenue from the sale of goods when these inventories are disposed of. The costs of these inventories are determined by using the FIFO or weighted average cost formula depending on the choice the entity has made in accordance with IAS 2.

2.2.2 Asset componentisation

Refinery turnarounds

Parts of some items of property, plant and equipment may require repair or replacement at regular intervals. An entity recognises these parts as separate components at initial recognition and depreciates them over the period up to the expected replacement. Turnaround costs that do not relate to the replacement of components nor to the installation of new assets, should be expensed when incurred. Turnaround costs should not be accrued over the period between the turnarounds because there is no legal or constructive obligation to perform the turnaround. The entity could choose to cease operations at the plant and hence avoid the turnaround costs. When replacement occurs the items are de-recognised and the cost of the replacement parts is capitalised.

How is this concept applied in accounting for refinery turnarounds?

Example

Entity Y operates a major refinery. Management estimates that a turnaround is required every 30 months. The costs of a turnaround are approximately $500,000; $300,000 for parts and equipment and $200,000 for labour to be supplied by employees of Entity Y. Management proposed to accrue the cost of the turnaround over the 30 months of operations between turnaround and create a provision for the expenditure. Is management's proposal acceptable?

Solution

No. It is not acceptable to accrue the costs of a refinery turnaround. Management has no constructive obligation to undertake the turnaround; the assets can be removed from service instead. The cost of the turnaround should be identified as a separate component of the refinery at initial recognition and depreciated over a period of thirty months. Note this will result in the same expense being recognised in the income statement over the total period as if Y had accrued the costs of the turnaround.

2.3 Retail and Distribution

2.3.1 Impairment & Cash generating units

Management should be alert to impairment indicators on a CGU basis, for example learning of a fire at an individual petrol station would be an indicator of impairment for that station as a separate CGU. Impairment must be assessed at the level of cash generating units.

What might constitute internal impairment indicators in retail petrol operations?

Example

A company owns retail petrol stations across Europe. It monitors profitability on a regional basis for larger countries such as Spain, Italy, France, Germany and the UK. Geographically smaller countries such as Greece, Austria, Switzerland and Portugal are monitored on a country basis. The costs of shared infrastructure for supply, logistics and regional management are grouped with the regions or countries that they support.

Regions and countries are measured against profit targets and return on capital employed. Failure to meet targets or poor performance is highlighted on a regional basis, which may then trigger further scrutiny and analysis of performance of individual stations.

Management has identified that the chain of stations in Austria is not meeting performance targets. Further analysis indicates that city centre stations with four sets of pumps or fewer are unprofitable. The chain of stations is profitable on an overall basis. Does the poor performance constitute an indicator of impairment?

Solution

Yes. The poorer than expected performance is an indicator of impairment, the chain does not need to be unprofitable. Once an indicator is present the stations should normally be individually tested for impairment. The cash flows of the stations are then grouped for the purposes of assessing impairment of shared infrastructure assets.

The level at which impairment testing is performed is the CGU – the smallest identifiable group of assets that generate separately identifiable cash flows. It is the availability of cash flow information that identifies a CGU, not the level of cash flow information that management uses to make business decisions. Management may group cash flows from separate CGUs to assess the profitability of a group of similar assets that may use shared infrastructure, such as a chain of petrol stations in a region supported by a shared supply depot and regional office.

Management should assess at each reporting date if there are any indicators that assets are impaired. Indicators of impairment include external and internal factors. Relevant internal factors include: evidence of damage or obsolescence; adverse changes that might drive a decision to restructure or discontinue operations; or evidence that economic performance is worse than expected.

3 The Utilities Industry

The Utilities Value Chain

Fuel Sourcing	Generation	Trading	Transmission and Distribution	Retail
• Fuel sourcing and supply contracts (IAS 39): valuations, hedge accounting	• Components approach • Impairment: CGU, Indicators	• Contracts (IAS 39): fair value and own-use	• Regulatory assets • Accounting for Networks • Cushion gas and inventory	• Connection fees

IAS 39 and the prospect of accounting for derivatives, and related issues of hedge accounting, loom large at key stages along the utilities value chain. The variety and complexity of contracts in the industry present some key IFRS reporting issues for both electricity and water utilities. In the following sections we move along the industry value chain to highlight these and other key considerations companies need to take into account.

3.1 Fuel Sourcing

3.1.1 Fuel sourcing and supply contracts (IAS 39)

A company solely engaged in buying, producing, and selling commodities might assume it is outside the scope of IAS 39 and continue to account for its contracts on the basis of actual purchases and sales as under national GAAP. This is seldom the case given the increasing deregulation of markets and the complexity of today's utility companies. IFRS 7 also raises questions of the need for additional disclosures.

A power generator makes decisions about how much power to generate and how much to purchase based upon demand and the differential between gas and electricity prices, the 'spark spread'. It buys and sells in the market as these factors change in the run up to delivery. This 'reoptimisation' or churning of purchase and sales contracts makes it difficult to identify which contracts are settled net (IAS 39 paragraphs 5, 6 and 7). Identifying some contracts as derivatives under IAS 39 and treating others as executory contracts appears inconsistent with the business model of certain companies.

Demand is unpredictable in practice and it may be necessary to sell off excess contracts. Applying the rules of IAS 39, purchase contracts can only be excluded from the scope of IAS 39 if the commodity purchased is always used to supply the entity's customers. So own use contracts are not fair-valued, whilst derivatives are.

Valuations

Market prices aren't always available for the periods of many contracts that the entity is required to fair value. Many contracts may have volume flexibility because the buyer (or seller) has a choice about the volumes to take. Pricing in some contracts is derived from a basket of indices such as oil and related products, power, coal, gas and inflation measures. Therefore, assumptions have to be made about future variables. Two important aspects of valuation are the derivation of forward price curves and the modelling of volume flexibility.

For many long term contracts to be fair valued, a 'forward curve' for future commodity prices will need to be derived, often for many years into the future.

Real Time Spotlight

RWE AG

Derivative financial instruments and hedging transactions
"Contracts that were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with the company's expected purchase, sale or usage requirements (own-use contracts) are not recognised as derivative financial instruments and are accounted for as pending contracts. Written options to buy or sell a non-financial item, that can be settled in cash, are not own-use contracts."

Annual Report 2005, RWE AG, p.113

Fortum Corporation

Accounting for derivative financial instruments and hedging activities
"Within the ordinary course of business the Group routinely enters into sale and purchase transactions for commodities. The majority of these transactions take the form of contracts that were entered into and continue to be held for the purpose of receipt or delivery of the commodity in accordance with the Group's expected sale, purchase or usage requirements. Such contracts are not within the scope of IAS 39. All other net settled commodity contracts are measured at fair value with gains and losses taken to the income statement."

Annual Report 2005, Fortum Corporation, p.24

Typically price curves have two distinct periods: an active market period where price information is readily available (liquid period); and a non active market period where prices are estimated, typically based upon assumptions and inputs into a model (illiquid period). The two curves need to be connected.

Normally, the active market period prices are the same for all preparers of financial statements. However, there are many variables in determining other parts of the curves, for example:

- No distinct end date to the active market period but volumes fall to a very low level. Companies may have different views on when the liquid period ends.
- What assumptions and inputs are appropriate for the illiquid period and what linkage is there between different commodities, e.g. oil and gas, or gas, power and carbon?
- When and how often should curves be reviewed and changed?

IAS 39 prohibits 'Day One' recognition of profits because the company's view of future prices differs from the contract price. Significant practical valuation difficulties arise in the IFRS conversion, among other things, at the first-time valuation for contracts signed many years ago.

Sometimes a significant part of a contract price can be attributed to the optionality within a contract, for example the ability to choose to purchase more or less gas in a particular period. Often, complex contract terms stipulate how much commodity must be taken in different time periods. Option valuation is a complex topic with market price volatility measures being one key input. Companies may take a variety of approaches to valuing optionality. A contract may be ascribed a different fair value by each party to the contract.

Fair value accounting for long-term derivative type contracts will require use of valuation models. Inevitably, companies will have different views about future prices. Transparency therefore is critical, so companies need to provide full disclosure about their pricing assumptions and risks faced. Companies may be reluctant to disclose information that is commercially sensitive. It may be appropriate for industry to develop, in consultation with other stakeholders, a framework for providing meaningful disclosures in this area.

Hedge accounting

IAS 39 sets out some stringent requirements to be met to apply hedge accounting. Many companies have found that activities undertaken for ‘hedging purposes’ don’t qualify for hedge accounting treatment.

Example

- An entity needs to procure power to meet its customers’ requirements. Customers consume most power in the daytime (peak) and less at night (off-peak).
- The entity can’t buy power in the delivery profile it needs. Therefore, to create ‘shape’, it purchases power under fixed volume contracts and enters into sales contracts to get rid of excess power in the off-peak period. The entity sees both these activities as part of its hedging strategy. Sales and purchase contracts are not always entered into at the same time since there is limited liquidity in the market. The entity enters agreements when the required contracts are available at an acceptable target price.
- Hedge accounting under IAS 39 isn’t easily achievable for the sale and purchase contracts. Two contracts can be treated together as a hedging instrument, but where purchases and sales are entered into at different times this is much more complex to achieve.

The contract price in a long-term gas purchase contract may escalate in line with a basket of different indices including oil and foreign exchange rates. Derivatives may mitigate exposures in relation to some of these risks, for example, exposure to oil prices by commodity swaps, or exposure to foreign exchange by currency swaps.

Real Time Spotlight

RWE AG

Derivative financial instruments and hedging transactions
“Fair value hedges are used to hedge the risk of a change in the fair value of an asset or liability carried on the balance sheet. Hedges of unrecognised firm commitments are also recognised as fair value hedges. For fair value hedges changes in the fair value of the hedging instrument are stated in the income statement, analogously to the changes in the fair value of the respective underlying transaction, i.e. gains and losses from the fair valuation of the hedging instrument are allocated to the same line items of the income statement as those of the related hedged item. In this regard, changes in the fair value must pertain to the hedged risk. In the event that unrecognized firm commitments are hedged, changes in the fair value of the firm commitments with regard to the hedged risk result in the recognition of an asset or liability with an effect on income.

Cash flow hedges are used to hedge the risk of variability in cash flows related to an asset or liability carried in the balance sheet or related to a highly probable forecast transaction. If a cash flow hedge exists, unrealised gains and losses from the hedge are initially stated as other comprehensive income. Such gains or losses are disclosed in the income statement as soon as the hedged underlying transaction has an effect on income. If forecast transactions are hedged and such transactions lead to the recognition of a financial asset or financial liability in subsequent periods, the amounts that were recognized in equity until this point in time must be recognized in the income statement in the period during which the asset or liability affects the income statement. If non-financial assets or liabilities result from the transaction, the amounts recognised in equity without an effect on income are included in the initial cost of the asset or liability.”

Annual Report 2005, RWE AG, p.112-113

The hedged item under IAS 39 can only be designated for either foreign currency risk or for the risk of changes in fair value for the entire item. So in the example above the currency risk can be the hedged item, but the oil indexation on its own cannot. The standard cites difficulties in isolating and measuring the appropriate portion of the cash flows or fair value changes of the hedged item as the reason for not permitting the designation of the oil indexation risk.

There are also challenges in relation to how amounts are disclosed in the income statement. Companies also need to consider the disclosures required by IAS 32 or, by 2007 at the latest, IFRS 7, including increased information about credit, liquidity and market risk. However, the divergence between accounting and economic effects adds complexity, for example, because not all contracts are fair valued in the financial statements. It is likely to be difficult to explain the overall situation clearly and concisely.

Is it correct to report both realised and unrealised profits and losses as part of the headline net income figure or should unrealised results be reported differently? Time is still needed to consider reactions to the significant changes introduced by IAS 39. In the meantime, disclosures will be critical for an understanding of every company's position.

3.2 Generation

3.2.1 Components approach

Large network or infrastructure assets comprise a significant number of components, many of which will have differing useful lives. Examples include refineries, chemical plants, and distribution networks.

The cost of the significant components of these types of assets must be separately identified and depreciated to their residual values over their useful lives [IAS16.43-44]. Identifying the significant components can be a complex process for very large, advanced plants.

Some components can be identified by considering the routine shutdown or overhaul schedules for power stations and the replacement and maintenance routines associated with these. Consideration should also be given to those components that are prone to technological obsolescence, corrosion or wear and tear more severe than that of the other portions of the larger asset.

Real Time Spotlight

Vattenfall AB

Property, plant and equipment
Subsequent costs
"Subsequent costs are only added to cost if it is likely that there will be future financial benefits associated with the asset for the company and the cost can be calculated in a reliable manner. All other future costs are reported as expenses in the period when they arise. When a subsequent cost is added to cost it is crucial for the assessment if the cost concerns the replacement of identified components, or parts of them, at which costs of this kind are capitalised. Also in those cases where new components are created, the cost is added to cost of the asset. Any undepreciated reported value of replacement components, or parts of components, are discarded and carried as an expense in connection with the replacement. Repairs are carried as an expense continuously."

Annual Report 2005, Vattenfall AB, p.80

3.2.2 Impairment

Utility assets should be tested for impairment whenever indicators of impairment exist [IAS36.9]. The normal measurement rules for impairment apply to utility assets.

Heavy investment in fixed assets leaves the industry exposed to adverse economic conditions and therefore impairment charges. Some impairment triggers relevant for the utilities sector include potential declines in market prices for electricity and gas, and increased regulation or tax changes.

Utilities, particularly power companies, are exposed to overcapacity, changes in the regulatory environment, environmental legislation, falling retail prices and rising fuel costs. Indicators of impairment include external and internal factors. Relevant external indicators in utilities might include changes in the regulatory regime [IAS36.12(c)]. A recent interpretation from IFRIC concluded that introduction of an emissions reduction scheme is an impairment indicator for assets that produce greenhouse gases [IFRIC 3.9 (withdrawn June 2005)].

Example

The government has committed to reduce greenhouse emissions. Distributors of electricity to domestic customers are required to use a minimum of 5 per cent of electricity sourced from renewable sources (wind, wave power). X owns sufficient generating capacity – coal and gas fired – to meet its domestic retail demand. X will be required to purchase electricity from renewable sources at prices substantially in excess of its own cost to generate. Management indicates that overall the utility will continue to be profitable and do not consider the regulatory change to be an indicator of impairment. Is this assessment appropriate?

Solution

No. The regulatory change is an indicator of impairment. Once an indicator is identified, management must test the generating capacity on the basis of the individual CGUs, generally each individual generating station.

Deregulation in the electricity industry often includes the introduction of price competition on the wholesale side and consumer choice of suppliers on the retail side.

Example

Z is an integrated electric utility with generation capacity and a retail distribution network. It has excess generating capacity over its retail demand but its generation base is high cost compared to several market entrants. The government has recently undertaken a deregulation initiative and has allowed domestic retail customers to choose suppliers.

Management indicates that overall the utility will continue to be profitable and does not consider the regulatory change to be an indicator of impairment. Is this assessment appropriate?

Solution

No. The introduction of competition by regulation will generally be a significant change and an indicator of impairment. Once an indicator is identified, management must test the generating capacity on the basis of the individual CGUs, generally each individual generating station.

Impairment indicators can also be internal. Evidence that an asset or CGU has been damaged or become obsolete is an impairment indicator. Other indicators of impairment are a decision to sell or restructure a CGU or evidence that business performance is below expectations.

Further internal factors include: evidence of damage or obsolescence; adverse changes that might drive a decision to restructure or discontinue operations; or evidence that economic performance is worse than expected [IAS36.12(e)-(g)].

Cash generating units

Impairment must be assessed at the level of cash CGUs. A CGU is the smallest identifiable group of assets that generate separately identifiable cash flows [IAS36.68]. It is the availability of cash flow information that identifies a CGU, not the level of cash flow information that management uses to make business decisions.

Management may group cash flows from separate CGUs to assess a group of similar assets that use shared infrastructure.

Power generation assets will form CGUs by location or possibly by a single generating facility on a multiple turbine site. The determination of how many CGUs will depend on the extent of shared infrastructure and the ability to generate largely separate (not wholly separate) cash flows. The determination of CGUs is not driven by how management chooses to use the asset.

Example

An entity operates more than one power station in order to generate the power the entity is committed to deliver to its clients. Each power station has different characteristics in respect of fixed and variable costs, purchases of required raw materials, degrees of capacity utilisation, lives of capacity utilisation, and overhaul. Management of the entity deploys the power stations taking into account these different characteristics, and treats them as a portfolio of power stations to be optimally utilised.

The following considerations play a role in the business practice of the entity's power stations:

- Each power station is able to sell its generated power to its own clients, as if the power station were in a stand-alone situation; and
- The entity acquired or constructed each power station separately.

However:

- Each power station generates power for the entity's sales at a country level.
- Nationwide and local clients are indifferent as to which power station generates the delivered power.
- The management decision on usage of each power station depends on the related variable and fixed costs and the possible optimisation of capacity utilization (considering required breaks for overhaul and maintenance).

An indication of an impairment exists for one of the power stations in the entity's portfolio. Should management test that power station separately as a CGU or should the whole portfolio be classified as a single CGU and tested together for impairment?

Solution

Management should separately test for impairment the individual power station which has an indicator of impairment.

Each power station is a separate cash generating unit because each one generates cash flows independently of the others. Each customer is indifferent to which power station generates the electricity it purchases.

Impairments are recognised if the carrying amount of a CGU exceeds its recoverable amount. Recoverable amount is the higher of fair value less costs to sell (FVLCTS) and value in use (VIU) [IAS36.6].

The VIU calculation should reflect management's best estimate of the future cash flows expected to be generated from the assets concerned.

However, management should use the contracted price in its VIU calculation for any commodities unless the contract is already on the balance sheet at fair value. A commodity contract that can be settled net in cash and for which the own use exception cannot be claimed, for example, is recognised separately on the balance sheet at fair value. Including the contracted prices of such a contract would be to double count the effects of the contract. Impairment of financial instruments that are within the scope of IAS 39 is addressed by IAS 39 and not IAS 36.

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

The cash flows associated with the decommissioning obligations of an asset being tested for impairment are excluded from the VIU cash flows because the provision for the decommissioning liability is already recognised [IAS36.43]. Similarly the carrying amount of the decommissioning provision is not included in the carrying amount of the CGU.

Determination of FVLCTS should be consistent in the treatment of decommissioning. The FVLCTS should be determined gross, undiminished by the obligation to decommission, and be compared with the corresponding gross carrying value of the CGU.

The cash flows included in the VIU calculation should include maintenance expenditures but not capital expenditure that is expected to arise from improving or enhancing an asset's performance [IAS36.44]. The use of fair value less cost to sell as an alternative to VIU, when calculating recoverable amount, provides more flexibility to include expansion cash flows, which must be realistic. However, assumptions used for fair value calculations must use market-based data arising from recent relevant transactions.

3.2.3 Arrangements that contain leases

Determining whether or not coal/gas tolling agreements, where the purchaser controls the dispatch of power, contain a lease is normally straightforward. A PPA for 100% of the output of a wind farm will often meet the requirement for finance lease accounting under IFRIC 4 and IAS 17.

For example, a wind farm contract could:

- be for 100% of the output of the wind farm;
- be for substantially all of the asset's life;
- guarantee a level of availability when the wind is blowing in a suitable range; and
- allow the purchaser to agree the timing of maintenance outages.

Government requirements or incentives for the production of power from renewable sources have led to the development of many wind farms and other 'green' generating sources. The developer and owner of the wind farm typically recovers its operating costs, debt service cost and a development premium, from a single purchaser.

3.2.4 Decommissioning

Power generation and other utilities create environmental change in the ordinary course of business. Entities are usually required to perform some kind of decommissioning or environmental restoration work at the end of the useful life of a plant or other installation. There may also be environmental clean up obligations arising from contamination of land.

A provision is recognised when an obligation exists to perform the clean up [IAS37.14]. Obligations to decommission or remove an asset are created at the time the asset is put in place and are recognised at the present value of the expected future cash flows that will be required to perform the decommissioning [IAS37.45]. This is recognised as part of the cost of the asset when it is placed in service and depreciated over the asset's useful life [IAS16.16(c)]. The total cost of the fixed asset, including the cost of decommissioning, is depreciated on the basis that best reflects the consumption of the economic benefits of the asset; generally time based for a power station.

Provisions for decommissioning and restoration are recognised even if the decommissioning is not expected to be performed for a long time, for example 80 to 100 years. The effect of the time until expected decommissioning will be reflected by the discounting of the provision.

Real Time Spotlight

Centrica plc

Leases
"The determination of whether an arrangement is, or contains a lease, is based on the substance of the arrangement and requires an assessment of whether the fulfilment of the arrangement is dependent on the use of a specific asset or assets and the arrangement conveys a right to use the asset."

Finance lease – third-party power station tolling arrangement
"The Group has entered into a long-term tolling arrangement with the Spalding power station and has determined that, based on the substance of the contractual terms, the arrangement is a finance lease."

Annual Report 2005, Centrica plc, p.47 and 52

RWE AG

Provisions
"The settlement amount also includes the cost increases to be taken into account as of the balance-sheet date. For decommissioning, restoration and similar provisions, changes in the estimated timing or amount of the payments and changes in the discount rate are taken into account at the same amount in measuring the existing provision as well as the respective asset, for example a power plant. If the decrease in the provision exceeds the carrying amount of the underlying asset, the excess is recognised immediatly in profit or loss. Releases of provisions are credited to the same expense account on which the provision was originally recognised."

"Waste management provisions in the nuclear energy sector are based on obligations under public law and restrictions included in operating licenses. The amount recognised for the disposal of spent nuclear fuel assemblies covers the expected costs, in particular reprocessing costs on the basis of contractual agreements and costs for direct final disposal. The cost of transporting, treating and taking back waste, including the cost of temporary storage are included accordingly.

The amount recognised for the decommissioning of nuclear power station facilities is also based on the expected costs. The calculation of expected costs for the post-shutdown phase and dismantling is based on outside expert opinions working on the assumption that the facilities are dismantled completely."

Annual Report 2005, RWE AG, p.110 and p.111

Decommissioning provisions are updated at each balance sheet date for changes in the estimates of the future cash flows and changes in the discount rate [IAS37.59]. Changes to provisions that relate to the removal of an asset are added to or deducted from the carrying amount of the asset [IFRIC1.5]. The adjustments are restricted, however, in that the asset cannot decrease below zero and cannot increase above recoverable amount [IFRIC1.5].

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

IFRIC1 provides guidance on how to account for existing decommissioning, restoration and similar liabilities. These types of liability arise for utilities (particularly for nuclear facilities), and upstream oil and gas companies. There are a number of areas where careful consideration is required:

- Measurement of the liability can be difficult. The timing of future cashflows is often uncertain, and future price increases can be difficult to estimate. In practice, situations can arise where the liability in the financial statements could be lower than a current appraisal of the cost, because future price rises are expected to be lower than the discount rate used.
- The decommissioning cost has to be allocated to components of the related asset. How to do this is not prescribed, but a systematic approach based upon cost or book value may be appropriate.
- A decrease in the liability results in a decrease in the related assets as well.
- How are decommissioning funds to be accounted for? There is separate detailed guidance on this topic in IFRIC5.

Vattenfall AB

Obligations for decommissioning etc. in nuclear power operations
"In Sweden, payments are made to the Swedish Nuclear Waste Fund for the purpose of covering the future costs for the nuclear power producers' obligations. The fee paid to the Swedish Nuclear Waste Fund is determined by the Swedish government. Vattenfall's share in the Swedish Nuclear Waste Fund is of such a nature that it shall be reported as an asset in the balance sheet."

Property, plant and equipment
"Within nuclear power operations in Germany and Sweden, cost at the time of acquisition includes a calculated present value for estimated costs for decommissioning and removing the plant and restoring the site where the plant is located. Further, this obligation also encompasses the safeguarding and final storage of spent radioactive materials used by the plants."

Annual Report 2005, Vattenfall AB, p.84 and p.80

Real Time Spotlight

Fortum Corporation

Nuclear related assets and liabilities
"Fortum owns the Loviisa nuclear power plant in Finland. Based on the Nuclear Energy Act in Finland Fortum has a legal liability to fund the decommissioning of the power plant and 30 nuclear related assets and liabilities disposal of spent fuel through the Nuclear Waste Fund. As at 31 December the following carrying values regarding nuclear related assets and liabilities are included in the balance sheet.

Fortum´s legal liability and share of the Nuclear Waste Fund at year end are as follows:

EUR million	2005	2004
Liability for nuclear waste management according to the Nuclear Energy Act	618	596
Fortum´s share of reserves in the Nuclear Waste Fund	-610	-581
Difference covered by real estate mortgages	8	15

The legal liability calculated according to the Nuclear Energy Act in Finland and decided by the governmental authorities is EUR 618 (596) million at 31 December 2005 (and 2004 respectively). The carrying value of the liability in the balance sheet calculated according to IAS 37 is EUR 418 (401) million at 31 December 2005. The main reason for the difference in the liability is the fact that the legal liability is not discounted to net present value.

Fortum´s share of the Nuclear Waste Fund at 31 December 2005 is EUR 610 (581) million. The carrying value in the balance sheet is EUR 418 (401) million. The difference is due to the fact that IFRIC 5 limits the carrying amount of Fortum´s share of the Nuclear Waste Fund to the amount of the related liability since Fortum does not have control or joint control over the Fund.

Fortum´s share of the legal liability towards the fund is fully funded. The difference between the liability and Fortum´s share of the Nuclear Waste Fund at year-end is due to timing of the annual calculation of the liability and will be paid during the first quarter of the following year. Fortum has given real estate mortgages as security, which also covers unexpected events according to the Nuclear Energy Act. The real estate mortgages are included in contingent liabilities.

Fortum uses the right to borrow back from the Nuclear Waste Fund according to certain rules. The loans are included in interest-bearing liabilities."

Annual Report 2005, Fortum Corporation, p.60

3.3 Trading

3.3.1 Contracts at fair value and those for 'own use' (IAS 39)

The IAS 39 criteria are forcing widespread accounting for contracts as derivatives. However, many contracts the entity may regard as having value are not recognised in the financial statements. Examples of this are storage and pipeline capacity contracts, where there are generally no active trading markets.

	Accounting treatment	Business perspective
Capacity contracts	Outside the scope of IAS 39 because there is no net settlement	Business recognises value that can be derived from the difference in commodity price either end of the pipeline or between the injection and withdrawal dates for storage

Capacity contracts mostly aren't actively traded and because they don't meet the net settlement criteria in IAS 39, therefore are outside the scope of the standard and cannot be fair valued. This can result in an unusual accounting result for speculative traders who use capacity as part of a wider strategy. We illustrate this using two examples:

- A speculative trader contracts to buy power in the future in France and sell power on the same day in England. He holds capacity in the UK-France interconnector to transmit from one location to the other. Under IFRS he can't fair value the capacity contract or recognise the connectivity between the two markets. The sale and purchase contracts are fair valued using local quoted prices. This can give a different periodic result from the value the trader believes has been created (cash flow, ultimately).

- A speculative trader enters into a contract to buy gas in the future. He has storage capacity to hold the gas for six months and enters a sales contract to sell the gas six months later in the winter. The trader views this as a 'closed' position. The capacity contract remains off balance sheet and the fair value of the position will continue to change with movements in gas market prices.

The timing of the reported results in the financial statements is not consistent with the value that the trader believes has been created (and, potentially, his bonus calculation!). It is often possible, for example, to value capacity even though there isn't an active market for the capacity itself. The contract value can be derived by comparing prices at either end of the pipeline or interconnector, or by comparing prices prior to and after storage capacity periods.

Real Time Spotlight

Vattenfall AB

Cash flow hedges
"For derivative instruments that constitute hedges in a cash flow hedge, the effective part of the change in value is reported under equity while the ineffective part is reported directly in the income statement. That part of the change in value that is reported under equity is then transferred to the income statement for the period when the hedged item affects the income statement. In those cases where the hedged item refers to a future transaction, which is later activated as a non-financial asset or liability in the balance sheet (for example, when hedging future purchases of non-current assets in a foreign currency), that part of the change in value reported under equity is transferred to and included in the acquisition value of the asset or liability.

If the conditions for hedging are no longer met, the accumulated changes in value that were reported under equity are transferred to the income statement for the later period when the hedged item affects the income statement.

Changes in value from the day on which the conditions for hedging ceased to be met are reported directly in the income statement. If the hedged transaction is no longer expected to occur, the hedge's accumulated changes in value are immediately transferred from equity to the income statement.

Cash flow hedges are used primarily in the following cases: i) when forward electricity contracts are used to hedge electricity price risk in future purchases and sales; ii) when forward exchange rate contracts are used to hedge currency risk in future purchases and sales in foreign currencies; and iii) when interest rate swaps are used to replace borrowing at a floating interest rate with a fixed interest rate.

Hedges of fair value
For hedges of fair value, the hedge is reported at fair value with changes in value directly in the income statement while gains or losses on the hedged item, which are attributable to the hedged risk, adjust the reported value of the hedged item and are reported in the income statement.

A hedge of fair value is primarily used in cases where interest rate swaps are used for hedging interest rate risk on borrowings at a fixed interest rate."

Annual Report 2005, Vattenfall AB, p.79

3.4 Transmission and Distribution

3.4.1 Regulatory assets

Some countries have proceeded with the privatisation of the transmission/transportation and distribution networks associated with utilities. This is counterbalanced by regulation of grid fees or end-prices to address concerns over monopolies that inevitably arise.

The nature of the agreements that utility entities reach with regulators vary from country to country. A thorough understanding of the terms of the agreements is therefore necessary in order to determine the appropriate accounting for these agreements.

A common feature of price-regulated markets is the agreement of the regulator to allow future price increases in compensation for certain identified past costs or to require future price reductions for perceived overcharging.

The costs associated with these price increases or reductions can be considered in two broad categories: those that are operating in nature and those that are capital.

Examples of the operating costs include employee costs, or costs of material. The required accounting for these costs under IFRS is to include them in cost of sales in the income statement in the period in which the employee service is received and the material is consumed. These costs have been incurred directly in transmitting/transporting or distributing power or gas sold in that period [IAS2.12] [IAS2.38].

Examples of capital costs include damage to fixed assets from extreme weather, such as hurricanes, or from other unexpected and uninsured events. The required accounting treatment for such events is separately to recognise an impairment charge for the damaged asset and to capitalise the cost of the replacement asset as PPE [IAS16.66]. Any 'compensation' receivable through an increased future price is not recognised until that amount becomes receivable, which is when the future network services are provided [IAS16.66(c)].

Price regulation can also lead to the requirement from a regulator for a network utility entity to reduce its prices in a future period. Just as an increase in prices will generally not result in the recognition of an asset, so a decrease in prices generally will not lead to the recognition of a liability. The only occasions on which recognition of a liability would be appropriate would be if the entity was obliged to repay cash to the customers (or perhaps to the government) or if the reduction in prices was so significant that it represented an onerous contract in the context of IAS 37; both of these circumstances are extremely rare. The benefit of reduced prices is only received by the customer if it continues to purchase the commodity which is delivered through the network system.

Some national GAAPs provide specific guidance that requires the utility to depart from the regular treatment of such costs and to recognise a regulatory asset or liability. This is intended to reflect the increase or decrease in future prices agreed with the regulator. Thus a regulatory asset is the deferral of costs to a future period to match with the higher prices charged in that period. Regulatory assets and liabilities are generally not recognised under IFRS.

The acquisition of a utility in a business combination requires the recognition of all identifiable assets, at their fair values. The rights of a utility to charge a higher tariff in the future as a result of past costs represents an increase in the value of the licence as described above. Consequently the value of the higher tariff will be reflected in the fair value of the licence recognised on acquisition rather than the recognition of a separate regulatory asset.

3.4.2 Accounting for networks

Some network companies applied renewals accounting for expenditure related to their networks under national GAAP. Expenditure was fully expensed and no depreciation was charged against the network assets. There is no equivalent accounting standard under IFRS that would permit this approach. The normal fixed asset accounting rules apply as set out in IAS 16. This is a big change for network companies and introduces some interesting application challenges:

- How do you split the total asset down into its significant parts?

IAS 16 requires that this analysis be done, but how many parts should there be and how should the split be achieved? It would seem sensible to consider a number of factors in doing this – the cost of different parts, how the asset is split for operational purposes, physical location of the asset and technical design considerations.

- When should expenditure be expensed and when should it be capitalised?

For example, if part of a pipeline is repaired or replaced, how are the costs accounted for? Materiality should be a key consideration when deciding this. If replacement costs are material to a significant part of the asset then, provided recognition criteria are met (cost can be reliably measured and future economic benefits are probable), these costs should be capitalised.

- How do you determine useful life?

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

- In calculating depreciation charges a residual value must also be determined.

This value in many cases is likely to be scrap only or zero since IAS 16 defines it as the disposal proceeds if the asset were already of an age and in the condition expected at the end of its useful life.

An entity is required to allocate costs at initial recognition to its significant parts. Each part is then depreciated separately over its useful life. Separate parts that have the same useful life and depreciation method can be grouped together to determine the depreciation charge [IAS16.44-45].

Network assets such as an electricity transmission system, a water-or sewage-system or a gas pipeline are comprised of many separate components. Many individual components may not be significant. How should components be identified and depreciated in such circumstances?

Example

A privatised water and sewage utility has a network that covers a major metropolitan area. The system includes reservoirs, treatment plants, major aqueducts, pumping stations and networks of pipes and drains, among other necessary elements. The system has grown from its initial installations over a period of 150 years.

The utility is a first time adopter of IFRS and management is considering how to identify components.

Management's first proposal is to consider the system as a single 'network asset' and depreciate it over its historical useful life of 150 years. The basis for this proposal is that the system is constantly repaired and renewed. All repair and maintenance expenditure will be added to the 'network asset'. Is this proposal appropriate?

Solution

It is unlikely the system can be considered to be a single asset with an aggregate useful life. Management needs to identify those components that are individually significant and have distinct useful lives. A practical approach to identifying components is to consider the entity's mid-/ long-term capital budget, which should identify significant capital expenditures and pinpoint major components of the network that will need replacement over the next few years. The entity's engineering staff should also be involved in identification components based on repairs and maintenance schedules and planned major renovations or replacements.

3.4.3 Cushion gas and inventory

Some items of property plant and equipment, such as pipelines, and gas storage, require a certain minimum level of inventory to be maintained in them in order for them to operate efficiently. Such inventory should be classified as part of the property, plant and equipment because it is necessary to bring the PPE to its required operating condition [IAS16.16(b)], recorded at cost and subject to depreciation to estimated residual value.

However, inventory that an entity owns but stores in PPE owned by a third party continues to be classified as inventory, for example all gas in a rented storage facility. It does not represent a component of the third party's PPE nor a component of PPE owned by the entity. Such inventory should therefore be measured at FIFO or weighted average cost (see Oil & Gas discussion).

3.5 Retail

3.5.1 Connection fees

A regional electricity supply company owning and operating a electricity grid typically buys electricity in bulk and resells it to its customers. A new customer that connects to the electricity grid may pay one or more or several types of fees, for example:

a) a one-time upfront connection fee;
b) a regular monthly 'electricity distribution' fee; and
c) a price for the electricity consumed payable to the supplier, who may be a third party supplier.

Example

A connection fee may only be paid once for a new customer to connect physically to the grid, and not be paid again if others move in to the already connected site. Electricity distribution charges, including the connection fee, are limited by the regulator. The connection fee is 50% of actual costs incurred in connecting a new customer at the capacity required. If the supplier installs higher capacity for expected future connections, a formula set by the regulator ensures that the customer only pays for the required capacity (and not for the excess installed). Should connection fees received be deferred or recognised upfront as revenue?

Solution

Connection fees charged to customers may be recognised upfront as income where they represent a separate service to give access to the electricity grid. Separability is supported by the facts that the fee only has to be paid once and the connection can be used to source electricity from third party providers without paying a new connection fee.

Real Time Spotlight

Fortum Corporation

Connection fees
"Fees paid by the customer when connected to the electricity, heat or cooling network are recognised as income to the extent that the fee does not cover future commitments. If the connection fee is linked to the contractual agreement with the customer, the income is recognised over the period of the agreement with the customer. Fees paid by customers when connected to the electricity network before 2003 are refundable in Finland if the customer would ever disconnect the initial connection. These connection fees have not been recognised in the income statement and are included in other liabilities in the balance sheet."

Annual Report 2005, Fortum Corporation, p.19

4 Embedding IFRS in the organisation

In the rush to deliver the first year of IFRS reporting, many companies have tended to rely on operationally independent central project teams to produce the new financial information on time. They now need to manage without a special project team and make IFRS (as well as other new regulatory requirements) part of business as usual. The challenge is to move from the *Crunch Time* urgency of the first year to successfully embed IFRS practices and processes so that they can achieve *Real Time* 'business as usual' reporting.

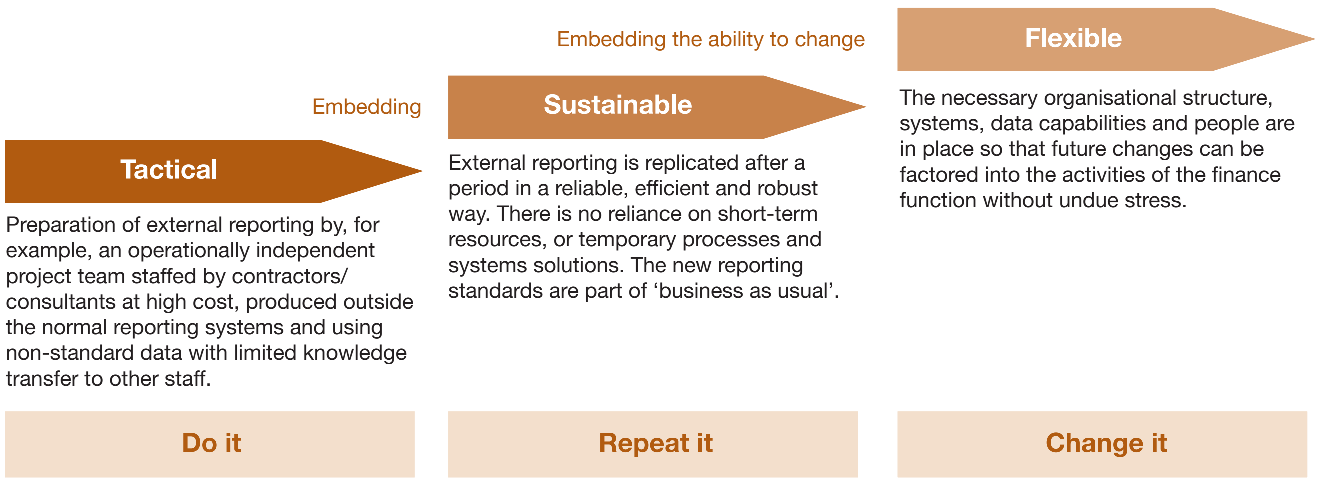
4.1 From crunch time to real time

Without the development of IFRS compliant systems and processes, and the transfer of knowledge to staff within the business, companies may find that providing timely and reliable information when the next set of accounts fall due is difficult, costly and time-consuming. Without embedding the necessary changes companies may find that their reporting processes are unsustainable and that they have to balance cost and efficiency with an unacceptably increased risk of control deficiencies and material errors.

Embedding is about changing tactical approaches, designed to meet the immediate IFRS reporting deadlines, into more sustainable, efficient and effective procedures. It is about being able to apply IFRS as business as usual.

Moving from tactical to sustainable to flexible

Embedding at a glance



IFRS financial reporting needs to underpin how companies look and think about their operations – it is not just an issue for the finance function. If IFRS does not yet permeate your organisation, management could find it increasingly difficult to meet the expectations of both their internal and external stakeholders.

Companies already experiencing the most benefit from the change to IFRS are those that are approaching the change as an opportunity to position their entity for future success, rather than simply an exercise in meeting externally imposed IFRS reporting requirements. They are using the change as a catalyst for better day-to-day management of their companies. They are also making the finance function more effective. Management needs to establish disciplines and procedures that can be repeated, period after period, in an efficient and robust manner – without reliance on resources, processes and systems that can only be assured in the short-to medium-term.

Embedding IFRS in your company means taking a longer view to meet the demands of today's business environment and being ready for tomorrow's as well. It is about building on tactical solutions, designed to meet the immediate IFRS reporting deadlines, to create more sustainable and efficient procedures that enable effective management of the business in a changing environment.

Embedding means acquiring the ability to change, to be flexible in your approach. Your company must have the necessary organisational structure, systems, data capabilities and people in place to succeed and to ensure that future changes can be factored into the activities of the finance function without undue stress.

4.2 Minimising operational risk

Some organisations have paid a high price to meet their IFRS deadlines. The overall robustness of their control environment as well as their underlying processes and systems may have deteriorated as a result of changes that had to be made quickly. In addition, staff may have failed to gain the relevant experience and understanding of IFRS, and this may have contributed to reduced efficiency.

Manual intervention and spreadsheets are part of the solution for some, which can increase the risk of error, be inefficient and make effective control more difficult. A potentially significant operational risk can also be created during the IFRS transition if internal management accounting is not aligned with the new external reporting requirements.

IFRS is a major change to the accounting regime, and its impacts clearly extend beyond the realm of the CFO, financial controller or head of accounting. Skills and understanding of the implications of IFRS are therefore required across the organisation.

4.2.1 How to embed sustainable reporting

Embedding IFRS into your company requires careful scrutiny of six key enablers:
1. Processes
2. Data systems/technology
3. Controls
4. People capability
5. Organisational structure
6. Planning strategies and reporting

These enablers do not all have to be addressed at the same time. The focus should be on immediate deliverables and priorities – seizing each opportunity for greater effectiveness, efficiency and control – while also building in the capacity to deal with future developments.

4.2.2 Processes

How are you planning to streamline your processes and introduce efficiencies that will help you ‘close the books’ faster and smarter?

Effective processes ensure that reporting is timely and accurate, with a minimum of human intervention. Management should focus on the day-to-day activities required to generate the necessary financial reports. The processes include the inputs, transfer, outputs and review of data.

4.2.3 Data, systems and technology

How can you get maximum return on your IT spend? Can your data, systems and technology cope today and in the future?

The type and amount of data required for compliance with IFRS may significantly differ from national GAAP. It is not exceptional to see the number of data entry points increase by a factor of three. Some data may be available but not in the right format. Management may need to tighten controls to obtain more accurate and timely outputs.

Reporting disciplines need to be able to cope with increased data collection and disclosure. Technologies such as XBRL may be useful to eliminate communication difficulties and duplication between systems. Underlying hardware, software and applications need to be assessed. These should have sufficient functionality, capacity and scalability to support the role of the finance function. The data model on which the systems are built should minimise rework and reconciliations.

Many companies will need to upgrade or replace their data collection and reporting systems. The precise changes they have to make will vary according to individual circumstances. Organisations with extensive hedging operations or operations across a number of jurisdictions, for example, are likely to have heavy workloads.

The amount of work required to embed IFRS deep in the organisation will depend on the state and complexity of the existing reporting systems. Fragmented systems – those with a different subsystem for each part of the business, legacy systems inherited from recent acquisitions, or manual systems still operating in subsidiaries – represent particular challenges.

Embedding IFRS also means reconciling internal management information systems with external reporting. IFRS numbers differ from those produced under national GAAPs. Staff will need to prepare budgets and forecasts that make sense in the IFRS environment and enable management to act with a full understanding of the impact of its decisions on the business and, separately, on the published results.

4.2.4 Controls

How can you be confident that your controls are adequate and consistent across the company?

Controls are the internal mechanisms, including corporate governance, that provide assurance over the output from the finance function. The output should be understandable, auditable and of high quality. There should also be regular evidence that these internal mechanisms are working effectively. Controls and procedures need to be reviewed to ensure they remain appropriate and relevant to IFRS. Where necessary, revised policies and procedures need to be implemented. This should be visibly supported by management to be effective. Accounting manuals used throughout the organisation should be updated to aid proper understanding and implementation of IFRS.

4.2.5 People capability

How confident are you that you are equipping your people with the skills and approaches required to make IFRS work in your business?

Personnel should be motivated to embrace IFRS, instead of feeling excluded from it. This target needs to be built into training, development and reward structures. Proper resourcing for these initiatives will be critical to success. Many companies are already providing regular training and updates to their staff, but few have embedded IFRS so that it forms part of the business language. For example, IFRS needs to be used when and where business is done. It should not be just the domain of a remote central accounting function.

All management, not only those in finance, need to be aware of the requirements and implications of IFRS relevant to their roles. Few companies will have sufficient internal expertise without implementing a skills development programme. Buying in the necessary skills and knowledge is not a realistic option – not only are appropriate resources scarce, but this approach may not address the long-term need to embed IFRS. Use of outside consultants should be supplemented by internal resources to enable a genuine transfer of knowledge to take place. This will enable consultants to focus on areas where they can add more value after the initial implementation has been completed.

Involving in-house staff in developing new systems, and training them once the changes are in place, will help to embed IFRS. This extends beyond preparing the external financial statements. Employees who work in management information systems, corporate treasury and tax, for example, must also understand how to apply IFRS for external reporting. They will also learn the new processes and systems required to support the different accounting regime.

4.2.6 Organisational structure

How can you maximise the contribution of the finance function? How can you ensure that IFRS helps you keep on top of your regulatory requirements, for example with national governance requirements?

The structure of the finance function should allow highly qualified finance teams to focus on adding value to the business, for example by supporting management decisions rather than just closing the books. Frequent transactions should be standardised, simplified or automated as much as possible, or even outsourced.

4.2.7 Planning strategies and reporting

How can you help to make ongoing compliance with IFRS part of the future success of the business?

Revisions to management reporting, forecasting and budgeting processes will be required to make them consistent with IFRS. Strategic planning, resource planning, operational planning and monitoring should enable the finance function to optimise current and future activities. This includes making timely, proactive choices about how to influence and cope with future changes. In practice, this means more focus on the strategic plan for finance and not just on the annual budget process. Planning, budgeting and forecasting reports should also model the impact on the company's externally-reported financial performance. These internal reports should be reconciled to various external reporting requirements.

The PricewaterhouseCoopers Embedding Review

PricewaterhouseCoopers has developed an Embedding Review designed to assist management in assessing the extent to which the new IFRS reporting requirements have been embedded throughout their organisation. It also enables them to consider how IFRS reporting can be made more sustainable in the short to medium term.

What are the main benefits of the Embedding Review?
It provides a timely, high-level assessment of the current status of IFRS reporting throughout an organisation:

- Enabling you to take stock through a high-level assessment of the progress made towards embedding IFRS;
- Identifying areas that require attention, both in the short term (for example, to address year-end disclosures) and in the medium term to move the group towards more sustainable reporting;
- Helping you to prioritise these activities and achieve real improvements in a sensible time frame.

How does the Embedding Review work?
The review is carried out through a series of structured interviews, involving key members of the finance and operations teams, both in the group office and in the business units. This would typically include:

- Finance Director;
- Financial Controller;
- Finance personnel at key business units;
- Key finance or operations personnel thought to have particular insights into the IFRS reporting process.

Communicating our findings and recommendations
Following the interview process the PricewaterhouseCoopers team will provide you with feedback through a workshop and a written report.
We would plan to:

- Give feedback on our findings, observations and recommendations;
- Share insights and different perspectives from the interview participants;
- Assist with your prioritisation of areas highlighted for future development;
- Provide the basis of a feedback communication for business units.

4.3 Deferred Tax Management

Deferred Tax Management is one of the more challenging tasks in the course of conversions to IFRS. Not only do technical aspects make high demands on companies, but the group-wide organizational conversion may also be highly demanding. The processes for the preparation of the financial statements must include substantial tax know-how. Three key aspects of Deferred Tax Management are presented below:

4.3.1 Deferred taxes

Empirical evidence from the USA indicates that, among the types of errors which have resulted in restatements of published (U.S. GAAP) financial statements, misstatements of deferred taxes are a substantial group. For IFRS conversions, too, accounting for deferred taxes raises a multiplicity of technical questions, some of which are specific to energy companies. It is still contentious whether Decommissioning Liabilities, which generally represent an increase in the IFRS opening balance sheet value of assets compared to local GAAP, are to be regarded as so-called initial differences.

Further deferred taxes topics important to the energy sector include joint venture partnerships, for example, for the construction of power plants, and public subsidy of investments in various countries via Tax Credits, and reductions in tax rates. Issues also arise in the conversion of local GAAP accounts with regard to deferred taxes. Also, according to survey data, some companies do not strictly observe, for quarterly reporting, IAS 34.30(c) which prescribes that the tax calculation be on the basis of an expected effective tax rate for the entire financial year.

Relatively few companies have fully provided onerous disclosures, required by IAS 12.74(b), to present deferred taxes separately according to tax types. These examples show that accounting practice for deferred taxes is not yet entirely harmonised with the accounting regulations.

Furthermore, the organisation of a company’s tax planning strategy gains significance. In the course of the IFRS conversion, many companies opt to change their way of planning. Profit planning takes place mainly on basis of larger company units such as segments or divisions, but taxation is tied to the legal company unit. Tax departments are challenged to find a suitable process for the allocation of the results to the tax units.

The intensified use of highly developed IT solutions can simplify the generation and use of the necessary data, and assist in strengthening internal controls.

Apart from these numerous challenges in the course of the IFRS conversion for deferred taxes, chances also arise to improve process cycles within this area. Businesses should use these in order to achieve cost reductions and greater security and quality of the data on a long-term basis.

4.3.2 Tax rate reconciliation

For corporate tax departments, investors, and financial analysts alike, there is an ongoing focus on the presentation and disclosure of the 'tax rate of the group'. IFRS financial statements require detailed and extensive disclosures in the notes, which will generally be more substantial than had been required under local commercial law, and must include a tax rate reconciliation. The presentational lines for the reconciliation are not internationally uniform. However, in practice, it seems that some ‘standard’ lines have been developed.

If the disclosure issues are resolved appropriately, the performance of a corporate tax department can be measured on the basis of the group's resulting tax rate.

The tax rate reconciliation can also be used for tax controlling. The missing transparency of tax decisions by corporate tax departments could be alleviated. The group’s tax rate would be not only a ‘fashionable’ reporting feature, but a genuine measuring stick against which tax optimisation by the company could be viewed. Pressure from financial analysts requires companies to focus on why their group’s tax rate is not lower. PricewaterhouseCoopers can advise enterprises on improving their tax reporting to analyse and potentially lower the group’s reported tax rate.

4.3.3 Tax contingencies

In the international context, provisions made for uncertain tax positions are designated as ‘uncertain tax positions’, ‘tax cushions’, or ‘reserves for tax contingencies’. Local GAAP may not have required much in the way of disclosure on these items. These, as a rule, very ‘sensitive’ items must be addressed appropriately for IFRS financial statements, including adequate disclosure in the notes. Complexity is increased where there is a large group, with complex fiscal unity structures, and activities in many different countries. The background of the tax liabilities for past periods can be highly complex and requires a considerable and highly specialised knowledge, since the underlying tax risks can encompass the entire tax law.

Recently, there has been an increased international focus on accounting for ‘Tax Cushions’, and the requirements of companies to follow their tax obligations will not become simpler.

Tax accounting and reporting is an ongoing and dynamic challenge for both companies and advisors alike. Tax departments are increasingly being called upon to find intelligent solutions to increasingly complex sets of regulations. With our experience and expertise, we help those departments find solutions that are intelligent and as beneficial as possible to the company.

5 Looking ahead

You only have to look at the International Accounting Standards Board's (IASB) busy agenda to know that the stable platform of requirements for reporting in 2005/6 will not remain stable for very long. The IASB is looking at how to resolve some of the important issues that could not be ironed out in time to form part of the platform.

IFRS 7, Financial Instruments: Disclosures, for example, is at the forefront of the new wave of reform. The new standard is designed to augment the core elements of IAS 30, IAS 32 and IFRS 4. It requires more details about the risks being run and the procedures in place to mitigate them. In practice, it is likely to demand increased emphasis on the embedding of IFRS by requiring that disclosures are based on the information provided internally to the entity's key management personnel.

This ongoing change, along with growing stakeholder expectations, is likely to place even greater pressure on reporting capabilities already stretched by the initial introduction of IFRS. Flexibility thus needs to be another goal of implementing IFRS. In addition to the demands of today's IFRS requirements, further challenges are emerging in the form of increasingly complex regulatory and compliance frameworks and stakeholder expectations.

The International Accounting Standards Board's ambitious agenda means that many of the existing standards include short-term fixes that arose from the IFRS improvements project. There is already an agenda for further changes. The rate of change is expected to be faster than has historically been the case with many national GAAPs. Companies must have the flexibility to be part of the dialogue of standard setting to accommodate these future changes.

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