

Implementation Challenge*

International Financial Reporting Standards
for the Oil & Gas and Utility Industries

*connectedthinking

PRICEWATERHOUSECOOPERS 

EU listed companies generally have had to prepare their financial statements in compliance with International Financial Reporting Standards (IFRS) since the beginning of 2005. Many other countries, such as Australia, are also choosing to adopt IFRS as their national regulatory bodies move to converge with the standards. With the experience of IFRS becoming real and widespread, we brought together over 80 participants from 14 different countries and 23 oil, gas and utility companies to discuss the challenges, lessons and dilemmas of implementing IFRS within their businesses.

The roundtable event, held in Autumn 2005, came soon after some of the companies had published their first interim information under IFRS. Others were further down the IFRS road, having adopted the standards in previous years. For all of them the decisions and difficulties around applying IFRS are immediate and real. The task of interpreting and applying IFRS in the context of their own companies and industries is especially demanding at the point of first-time adoption, but is also a continual challenge rather than a one-off. This report highlights both the leading themes and the specific issues that these companies are grappling with as they use IFRS in the oil, gas and utility sector.

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challenge

The IFRS journey: the view from roundtable participants

A big question for companies is where the current standards journey is leading us. Everyone shared the goals of improved comparability, decision-usefulness, and understanding. As one participant from a large multi-utility company put it: “IFRS is close to our basic belief about how we want to present ourselves. Transparency to investors is better than it was in the past. IFRS should not be seen as the negative that it is often portrayed as in the press today. It has increased comparability globally and that is very important in this industry.” However, views were more mixed on whether achievement of these goals is moving nearer in all areas or remains distant. The same IFRS practitioner said: “We are seeing some distressing trends that are going to be critical for preparers and users.”

Worries about complexity

Oil, gas and utility companies alike expressed concerns about increasing complexity and, alongside this, the risks of decreased reliability and understandability. A Vice-President of one company wryly observed: “Changes in standards are getting more frequent. IFRS 3, for example, is important but it is difficult even to have enough time for people to read the statement. Indeed, I suspect IAS 39 is only understood by 1% of the accounting profession. We are losing the audience. It is becoming too complex.”

The importance of looking hard at the underlying purpose and framework driving the standards was emphasised by some speakers. The Group Controller of a leading oil and gas company pointed out: “Accounting standards have changed quite quickly but now people are realising there can be problems with unexpected effects on financial indicators and apparent inconsistencies with the framework. It should be the other way round, there needs to be more attention to the driving purpose of reporting.” Another participant echoed this: “Sometimes the solution is looking for a problem to solve.”

“we are seeing some distressing trends”*

“the volume of our footnote disclosures increased by 50%”*

Addressing the uncertainties

The importance of moving now to reduce complexities was stressed time and time again: “If we don’t solve the uncertainties then there is a big challenge for the future.” The importance of resolving fundamental worries was given extra emphasis by concerns about the dangers of geographical divergence in the IFRS family. “Many countries are using IFRS but not all have adopted without modification and we are seeing the rise of ‘local’ IFRS. It would be good to see the IASB and IFRIC as the single interpreting bodies but that would be difficult for countries to accept, not least the US.”

Maintaining a focus on what investors and the capital markets require was viewed as a fundamental part of the way forward. One participant put it: “Changes in standards need to be driven by their potential to give useful information to the marketplace, and I worry that that need is not being met. I can’t see, for example, how BC2 (Phase II of the IASB’s Business Combinations Project, with a new exposure draft on business combinations) is going to be useful to the markets.” Greater involvement of preparers and users of financial statements in the process of standard setting was seen as critical and, here, it was acknowledged that the onus is as much on the investment community and companies to articulate their own proposed solutions as it is on the standards setters.

Impact on companies

While there was little doubt that the IFRS journey was raising difficulties of interpretation and anxieties about increasing complexity, the actual impact within companies and on their reported figures was more positive. In many respects, the larger the company, the more containable is the impact. However, while the scale of adjustment may not be particularly large, the thought and effort that needs to go into it can be quite big. For one major oil and gas company, the transition has had only a marginal impact on the financial figures. In contrast, an early IFRS adopter in the utility sector, whose transition had coincided with utility market liberalisation, reported: “The financial implications were huge. The most challenging things looking back were the nuclear and mining waste and environmental restoration provisions, interpreting issues that nobody had discussed before, with no real precedents around the world. We had to book prior year adjustments, rethink equity accounting and consider how to harmonise internal and external reporting. The volume of our footnote disclosures increased by 50%.”

Inside the energy sector

Converting to IFRS was always likely to be a tough proposition, requiring sound judgement on how the new standards can fit within a company's unique operational and market environment. The difficulties that the IASB itself has faced in producing standards, for example, on emission rights where an interpretation was developed by IFRIC only to be withdrawn by the IASB, have added to the judgement calls that companies have had to make. Oil, gas and utility companies operate in environments that can pose tricky questions for reporting. Here we look at the key issues from inside the sector that led to most roundtable discussion.

Shared issues

Emission rights

Emission rights schemes pose dilemmas for reporting. The IASB has withdrawn IFRIC 3 which addressed the issue, while confirming that the IFRIC 3 approach (see panel) is a valid interpretation of existing IFRS. The roundtable participants had little doubt of the difficulties of applying IFRIC 3, in particular its mixed measurement concept. "We looked at what it would mean for our quarterly results. We were quite happy that IFRIC 3 was withdrawn. It does not reflect economic substance since it is obvious that we will use our emission rights to cover our obligations," observed one utility company executive.

Few companies have deemed IFRIC 3 to be an attractive choice to achieve IFRS compliance. The standard opens the prospect of a fundamental mismatch in the income statement, exacerbated by the difficulties the IASB have faced in developing standards on performance reporting. Two alternative approaches are summarised in the side panels.

A PricewaterhouseCoopers partner commented: "You can get very different effects on the income statement with these different methods. The crucial thing is to look at the pattern of how you actually use allowances, the timing of purchases and their trading. Both methods work and you need to model each against the operational plans for emissions." The discussion also emphasised that it was important to account for emission rights on the basis of annual allocations and returns of allowances and not to delay recognition of liabilities until the end of the three year life of the EU emissions trading scheme.

"look at the pattern of how you actually use allowances"*

IFRIC 3

1. Recognise allowances when able to exercise control; corresponding entry to government grant, at fair value if granted, at cost if purchased.
2. Allowances are subsequently carried at cost or revalued amount.
3. Government grant amortised on a systematic and rational basis over compliance period.
4. Recognise liabilities when incurred.
5. Liabilities are remeasured fully based on the market value of allowances at each period end, whether the allowances are on hand or would be purchased from the market.

Alternative 1

1. Recognise allowances when able to exercise control; corresponding entry to government grant, at fair value if granted, at cost if purchased.
2. Allowances are subsequently carried at cost or revalued amount.
3. Government grant amortised on a systematic and rational basis over compliance period.
4. Recognise liabilities when incurred.
5. Remeasure liabilities at each period end – for allowances on hand, at the carrying amount of those allowances (i.e. market value at the date of initial recognition if cost model is used; market value at the date of revaluation if revaluation model is used) on either a FIFO or weighted average basis; any excess emission would be measured at the market value of allowances at the period end.

Alternative 2

1. Recognise allowances when able to exercise control.
2. Allowances granted are initially recognised at zero.
3. Allowances purchased are initially recognised at cost.
4. Allowances are subsequently carried at cost or revalued amount.
5. Recognise liabilities when incurred.
6. Remeasure liabilities at each period end – for allowances on hand, at the carrying amount of those allowances (i.e. zero, cost or revalued amount) on a FIFO or weighted average basis; any excess emission would be measured at the market value of allowances at the period end.

IAS 39 – Embedded derivatives

One of IAS 39's objectives is to ensure that any foreign currency risk which an entity introduces outside of its normal business activities should be 'fair valued', with changes in value reported in the income statement.

However, IAS 39 states that foreign currency risks embedded in commercial contracts need not be 'fair valued' if the foreign currency risk arises because the good or service being purchased or sold is 'routinely denominated' in that currency in commercial transactions around the world. This has resulted in anomalous results for many contracts, such as shipping, where no single currency is used worldwide, but in Europe the Euro dominates and elsewhere the US dollar dominates. Similarly, while most commodity transactions are conducted in US dollars, the buyer and seller may not have US\$ functional currencies. In such cases, embedded derivatives may have to be recognised even though the currency used is the normal business currency for all such transactions in the region in which the company operates.

IAS 39 also allows for an embedded foreign currency derivative not to be valued if it is denominated in the same currency as the functional currency of any substantial party to the contract. However, in practice it is often difficult to determine the functional currency of the other party to a contract.

IFRIC 4

IFRIC 4, and the related IAS 17, is set to produce interesting results and changes to how companies have historically seen items such as power purchase agreements presented, both on the balance sheet and on the income statement. IFRIC 4 helps companies assess if they have a mere 'plain-vanilla' supply contract or whether, in substance, there is actually a lease embedded in the contract.

The following power purchase example illustrates this well: an industrial company is purchasing power from a generator, who may have four different power plants. A key question is whether power is being purchased from a specific plant or if the generator can provide the power from any of the plants. The former would point towards a lease.

IFRIC 4, paragraph 9, sets out the criteria to determine whether an arrangement contains a lease, such as whether the purchaser (lessee) has the right to operate the asset, has physical control of the facility and it is unlikely that another party will take 'more than an insignificant amount' of the output. There are two exceptions – where the price is 'contractually fixed per unit of output' or where a purchaser is paying the market price for the output. The issue was raised of what does 'contractually fixed per unit of output' mean? For example does a price that is index-linked qualify as fixed? The view was expressed that this does not qualify as fixed because the indexation will lead to a change in the amount payable. Similarly, the market price is the spot price on the day of delivery so if a contract price includes a cap or a floor, then in principle it would not qualify for the market price exception.

In practice, the lease is not the only question that has to be considered. The reality of many power purchase agreements is that there is flow through of substantially all of the cost of the fuel that is used to power the station so the power purchaser probably has a fuel purchase contract. It may also have a service contract for the actual running of the plant so there is an important judgement to be made on how to treat the total cash flows under the electricity sales agreement and how to divide them into the individual components. In many respects, companies face a difficult choice. As a PricewaterhouseCoopers advisor put it: "It is a bit like a poisoned chalice. You have either a lease with a fuel purchase contract, a derivative energy contract, or an own-use energy contract with an embedded derivative. Each will generally have a significant impact on your financial statements."

**“it is a bit like a
poisoned chalice”***

Income statement presentation¹

Divergent practice has emerged this year on the presentation of the income statement. The critical question companies need to consider is which format communicates best to the marketplace and complies with the accounting standards. The roundtable heard that companies new to IFRS are struggling with this, especially when they come from environments where different presentations of the income statement were routine. The difficulties have been exacerbated to some extent by the impact of IAS 39 which has led to substantial changes in energy company income presentation compared to previous reporting. The desire by companies to explain why results are so different has created a plethora of practices:

- use of subtotals, columns and boxes – ‘exceptional items’ and ‘underlying performance’ – the return of proformas
- mix of presentation by function and by nature
- use of ‘EBIT’, ‘EBITDA’, and the like, on the face of the Income Statement,

and varying approaches to the presentation of:

- finance costs
- results of associates
- derivative gains and losses
- non-derivative assets and liabilities designated at fair value through profit and loss
- foreign exchange differences

The dilemma that companies face is whether to keep their income statements simple and conduct marketplace communications through other means. If they do this, however, the audited financial statements can start to disconnect from the information that the market is relying on. As one speaker put it: “This is a huge challenge facing the accounting profession. The greater the divergence then the more you undermine the credibility of the financial statements and financial reporting itself.”

“this is a huge challenge facing the accounting profession”*

IAS 39 – Income statement presentation

Commodity prices have been volatile over the past two years. Since some changes in contract valuations are now recognised in the income statement, this means reported results will be more volatile as well. The results for a year can be significantly impacted by the forward price curve at the year end.

In the early stages of IFRS implementation the instinct for some preparers and users is to highlight these items and show the impact of the new standard in a separate column. The guidance on the extent to which this can be done is unclear but in the transition period whilst the standards are ‘bedding down’ such an approach is understandable. Finding a consistent presentational approach for energy companies would be desirable but first difficult questions need to be addressed.

- Where should changes in fair value be reported in the income statement?
- Where these changes relate to sales contracts how do you link fair value movements with reported revenues? For instance, if a sales contract is fair valued and changes in fair value are shown in one line in the income statement then what value is turnover recorded at when the contract delivers? If contract price is used then could this be interpreted as ‘recycling’ an amount already reported in the income statement?
- Are columnar presentation approaches helpful or confusing?
- How should ‘recognised’ profits and unrecognised profits be clearly shown?
- Is there a way of clearly disclosing how much of the reported result is based upon management derived assumptions?

¹ For guidance on income statement presentation see www.pwc.com/ifrs

*quotes from oil & gas and utility participants in the roundtable

Talking points

Balance sheet – classification of a hedging derivative

If you have a contract that does not qualify for own use then, by default, it is a trading contract. The whole amount of a trading contract has to be presented as current. So once you are into derivative accounting you are into current assets and current liabilities. That's for something that is trading. But you could also have a derivative that is used in a hedging relationship. In a hedging relationship, the classification of the derivative follows the hedged item. So if the hedge item is classified as non-current, the hedging derivative is, too. However, for hedging contracts with multiple maturities, for example monthly gas derivatives for five years, the value of the portion of the contract that matures within 12 months could be classified as current whereas the portion that is due after the twelve months could be classified as non-current.

Trading – be clear about the income statement geography

The 'gross vs. net' and the 'other income vs. turnover' debate is going on apace. It is not just affecting oil and gas but many other industries – anyone who is exposed to commodities. It is also getting attention from the regulator. What properly belongs in the top line and what belongs somewhere else in the geography of the income statement? The standards indicate that the results of trading and use of financial instruments belong in a separate 'other income' line, unless the main business of the entity is trading. The critical thing is to be transparent about what is in the number and transparent in your accounting policy on what you are doing.

Oil and gas

IFRS 6: how much shelter?

IFRS 6 (exploration for and evaluation of mineral resources) allows companies to retain existing practices in accounting for exploration and evaluation expenditures.

IFRS 6 confirms that the requirements of all IFRSs are applicable to entities involved in the exploration for and evaluation of mineral resources, except where specific types of transaction and activities are excluded from IFRS. The accounting for exploration and evaluation of mineral resources is explicitly excluded from the scope of IAS 16: Property, plant and equipment and IAS 38: Intangible assets. The IASB did not have time to develop a comprehensive standard on extractive industries in time for entities converting to IFRS in 2005. IFRS 6 provides an interim solution by allowing entities to continue applying their accounting policy in respect of exploration and evaluation until a more comprehensive solution is developed. The standard enables accounting policies to be retained even if they are inconsistent with the treatment of similar expenditures that are addressed by existing IFRSs or if they are inconsistent with the IFRS framework. However, an entity that chooses to make changes in its accounting policies can only do so if those changes bring the policy closer in line with the treatment of similar expenditures set out in IFRSs and the IFRS Framework.

IFRS 6 is applicable to accounting periods beginning on or after 1 January 2006. First time adopters of IFRS who choose to apply IFRS 6 before 1 January 2006 are not required to present the disclosures required by IFRS 6 for comparative periods in their first IFRS annual accounts.

The main purpose of the standard is to allow most companies to continue with their recognition policies but to specify the circumstances in which entities should test exploration and evaluation costs for impairment. The recent period of high oil prices has meant that, to some extent, companies have not had to contend so much with impairment and, thus, the potential impact of this part of IFRS has been masked. This makes it even more important that companies consider this carefully since the policy decisions that are made now will need to be sustainable for a long time, including periods when oil prices may not be so favourable.

Full Cost Accounting

It is difficult to see how full cost accounting as applied in the past can be sustained beyond the exploration and evaluation phase. Companies can continue to use different policies to account for exploration and evaluation costs, including full cost. This makes comparison of different companies difficult, and some narrowing of the alternatives is necessary. However, it will be difficult to establish a single approach that caters for all mining and upstream oil and gas companies – given that the geological and economic characteristics of exploration and evaluation can vary significantly from commodity to commodity.

Once a project has progressed to the production phase, the requirements of IAS 8 and IAS 16 become relevant. For the oil and gas industry, in particular, this may be difficult to reconcile with the 'full cost pools' of exploration and evaluation costs already incurred if the pool embraces many different areas of interest. Once past the exploration and evaluation phase, the special cash generating unit (CGU) rules fall away; costs must be allocated to CGUs. The CGU is usually the field or a group of fields supported by shared infrastructure. This may result in pooled expenditure being written off.

**“high oil prices
have masked IFRS
impairment impact”***

Roundtable participants were keen to check that the unit of production (UOP) approach for depreciating and amortising additional assets was compatible with IFRS. Compatibility can be achieved, in principle, but it requires the carrying value based on UOP to achieve a salvage value at the end of the life of each individual asset component respectively. This is difficult in practice. The UOP charge needs to reflect the way in which economic benefits are consumed through use. If the life of an asset component is shorter than the life of the related field (for instance 5 years vs 10 years) and depreciation is based upon units of production, companies would need to determine the life based upon expected/planned production for the first five years, when the component will be replaced. There is the added complication that production volume in the first five years is often greater than in the subsequent period. For larger companies these variations across fields will even out but smaller companies are more exposed. All companies need to ensure that they do not run the risk of failing to match the depreciation with the consumption of benefits and thus inappropriately postponing impairment charges to the end of the field's life. Some companies may need to make manual adjustments as they don't have accounting systems to comply with component accounting.

A few exploration companies use the 'full cost' approach. It is important to emphasise that IFRS 6 only covers the exploration and evaluation phase, allowing larger CGUs only until the point when reserves have been determined. If a full cost company had reached the end of the exploration and evaluation phase and no commercial viable reserves had been detected, it might become appropriate to reclassify the activities out of e&e and the items would then be subject to other standards. However, as a PricewaterhouseCoopers partner stressed: "IFRS doesn't give you any special rules for development or production. What is clear, however, is that you only get the shelter in the e&e phase and not when you move beyond that."

Impairment and cash generating units

The roundtable had a broader discussion of impairment, in particular, in respect of the identification of CGUs. There was a lively interest in the definition and scope of the CGU for IFRS purposes. A PricewaterhouseCoopers presenter commented: "My sense is that market practice in retail business is moving to define the individual retail outlet as the CGU, so in downstream that means the individual petrol station." Some participants pointed out the need for each retailer to be supported by a logistics network. A critical test as to whether this constitutes a distinct CGU is does it have separately identifiable cash flows (see the 'exploded' question below). The PricewaterhouseCoopers presenter went on to observe: "We are likely to see a move to individual outlets as the CGU but, at the same time, management will tend to monitor them on a regional basis. So you would probably become aware of triggers for impairment at a regional level, and then test individual petrol stations for impairment".

A question was raised on how to go about reflecting synergies in CGUs and impairment tests. The principal difficulty is ensuring that the allocation of synergies to CGUs does not exceed 100% of those synergies when determining value-in-use.

Questions were also raised on which discount rate should be used for upstream assets. One company mentioned that it should be adjusted for risks. Under IFRS, risk needs to be recognised, and, while the result should reflect the weighted average of all possible future outcomes, this can be done through adjusting the discount rate or the cash flows. In practice the latter is quite difficult and it is usually easier to adjust the discount rate. The starting point for the discount rate will usually be the Company's WACC, but when the company is more than just a single-asset company the WACC needs to be adjusted to arrive at a discount rate that reflects the risks of the asset being tested for impairment.

"Hurricane Katrina was proof that a CGU is not a whole continent. It is pretty hard to justify defining it wider than the field or the reservoir..."

"If it exploded, could you run the rest of the business? Yes? Well, then it has separately identifiable cash flows"*

Overlift and underlift

One effect of IFRS is that more items are likely to fall under derivative standards than in US GAAP. Overlift and underlift with net settlement at a future date moves companies into the scope of IAS 39. There are various solutions, depending on whether the settlement is by product or by cash. A reporting goal is to avoid a ‘meaningless’ gross profit line. The PricewaterhouseCoopers’ view is that the underlifter has generally sold its share to the overlifter. Subsequently, the overlifter sells this output to third parties and recognises it as sales, but recognises no margin to the extent the sold volumes are attributable to the underlifter. In effect the combined revenues reported by the joint venturers are more than 100% of actual output.

At each balance sheet date, overlift/underlift balances that fall within the scope of IAS 39 get remeasured to the current oil price. The net gain or loss on remeasurement is included in the income statement. One company asked where to present these net movements? The answer is that this should be under ‘other income’/‘other expense’, rather than in revenue.

It was assumed that most companies would have net settlement agreements included in their joint venture agreements. However, this appears not to be the case for example in Norway. The accounting treatment in these circumstances is still under debate. Can the underlifter recognise a sale? Should balances be revalued in the intermediate period until settlement? If the overlift/underlift is always physically settled, a cost-based approach to valuation can be applied.

If, instead of a sale of the overlifted quantity, it were to be recorded in inventory at market value or at cost, should the fair value route (IAS 39) be followed? However, does IFRS allow fair value accounting for items outside IAS 39? One company observed that, in their experience, underlift and overlift balances can be substantial, especially for gas companies. Here again, the effect is more significant for smaller companies who are less likely to be able to even out the impact across different fields and by being both underlifter and overlifter in different situations in the same period.

“again, the effect is more significant for smaller companies”*

Definitions

Overlift and underlift occurs when two or more parties jointly control a production property. In any particular period the amount of output taken by each party won’t always equal their share of production as set out in a joint venture agreement. The extent to which this differs is described as overlift or underlift and needs to be accounted for. The terms of production contracts vary and underlift/overlift can sometimes be settled in cash and sometimes through delivery of additional oil. In practice these types of contract are often within the scope of IAS 39 (if there is net settlement) which needs to be followed in conjunction with IAS 18 on revenue recognition to determine the appropriate accounting.

Types of production sharing contracts (PSCs)

Upstream companies enter into contractual arrangements where a foreign government owns reserves and, in some cases, equipment, but provides the company with a licence to be a contractor to perform or manage specified oil and gas activities. The upstream company may earn a fee under a production sharing contract (PSC) designed to reimburse the company for operational and capital costs incurred, and to provide a return. PSCs may include terms which require payment of royalties based upon volumes produced or sales amounts, along with cost recovery and profit sharing mechanisms. They may also stipulate the amounts of income tax to be paid. PSCs vary considerably by country and the accounting for these contracts under IFRS needs careful consideration.

*quotes from oil & gas and utility participants in the roundtable

Jointly controlled assets, operations and entities

Arrangements that fully meet the IFRS definition of a joint venture do not generally cause significant accounting and reporting problems. Difficulties arise with ventures and alliances that are not true joint ventures. This would be the case, for example, where resolutions can be passed without the agreement of all of the 'partners'. As IAS 31 makes clear: "Joint control exists only when the strategic financial and operating decisions relating to the economic activity require the unanimous consent of the parties sharing control".

The interest in a joint venture is recorded using proportionate consolidation, or the equity method in accordance with IAS 28. A participation that does not qualify as a joint venture may fall under IAS 39. This is the case if the arrangement can be identified to be a separate entity, for example, because it is able to hold cash or generates cash inflows to its participants. If there is no separate entity, the venture will not fall under IAS 39, as is commonly the case with joint assets such as oil platforms, power plants and pipelines that are not owned by a legal entity. Here there is an undivided interest in the asset and it probably would qualify as non-current investments.

"participations in entities that do not qualify as joint ventures may fall under IAS 39"*

Production sharing contracts

Every jurisdiction is different with regard to production sharing contracts, and these must be considered on a case-by-case basis. Critical questions at the roundtable revolved around reserves and the issue of who is taking the risk.

There was some discussion around grossing-up of reported sales revenues for income tax paid in kind and the view was that there would need to be robust grounds to support it. One consequence of grossing-up is that companies then move into the tax accounting standard, IAS 12. Under US GAAP grossing-up is sometimes appropriate if prescribed by the tax authorities and tax regimes (creditable taxes).

Snapshot: revenue

1. Substance over form – accounting must reflect the true nature of the item and not necessarily the legal form of wording in the contract
2. Royalties – normally excluded since contractor is purely collecting amounts on behalf of government
3. Income Taxes – which are paid on investor's behalf are included in revenue and taxes provided the tax is based on income
4. Reminder: only contractor's share is presented as revenue since the rest is collected on behalf of government

Snapshot: IFRS & US GAAP – common reconciling items for SEC filers

1. Impairment of assets: One step approach (IFRS) vs. two step approach (US GAAP)
2. Reversals of impairment losses required under IFRS, prohibited under US GAAP
3. (Upward) Revaluations of intangible assets and property, plant and equipment permitted under IFRS, prohibited under US GAAP
4. Inventory valuation: LIFO prohibited under IFRS, permitted under US GAAP
5. Decommissioning: under IFRS discount rate updated at each balance sheet date, but not permitted under US GAAP
6. Use of enacted tax rates under IFRS and US GAAP, but substantively enacted rates only under IFRS

Utilities

IAS 39: executory contracts, embedded derivatives and hedging

IAS 39 (revised 2003) poses arguably some of the hardest challenges, among all IAS/IFRS standards, for IFRS preparers in the industry. Considerable conceptual and practical difficulties arise as a result of the ‘mixed’ measurement bases associated with executory contracts, derivatives and generation assets. Commodity derivatives that can be settled net in cash are, in principle, measured at fair value. Accrual accounting, though, is permitted where an executory contract is held for the purpose of the entity’s normal purchase, sale or usage requirements. Much of the discussion between utility companies at the roundtable centred on the difficulties of categorising contract types. For example, a company will typically have contracts for many different purposes, such as own-use, optimisation and trading. If there are no clear policy and related organisational and book structures to separate contracts into the respective categories, a company has to treat all contracts as similar contracts under IAS 39. Thus, both contracts selling to final customers (own use, and normally requiring accrual accounting) and contracts selling to the spot market (trading, to be recorded at fair value) are treated as trading contracts.

A further difficulty arises because, under IAS 39, companies are unable to claim ‘own use’ treatments for contracts that contain a written option. Electricity supply contracts often give the buyer the right to take any amount of energy based on the contract requirements. Different views were expressed around the table on when volume flexibility in a gas or electricity supply contract constitutes a written option. A critical issue is whether a price premium is paid to compensate the supplier for the additional risk incurred. A PricewaterhouseCoopers partner observed that “a contract does not contain a written option if the buyer did not pay any premium to receive the flexibility and, where this is the case, the contract may qualify for the own-use exemption”. One participant pointed out that even a paid premium might not always lead to the conclusion that a written option existed, a view which is hard to support given the text of the standard.

‘Own use’ vs. valuation

A company sources gas for its customers from long- and short-term purchase contracts, storage, and from its own gas fields. Its overall aim is to optimise its portfolio to derive maximum value. Demand from its customers is seasonal. To optimise its position it will vary what it takes under contracts, from fields, and from the wholesale market, in response to physical demand and market prices. Gas is also sold on the wholesale market when this is economic. Under IAS 39 this means some contracts need to be valued (because not all the gas is going to the company’s customers) but differentiation is problematic. If all are managed within a single risk management framework, they are all to be treated as trading contracts as it is impracticable to identify which contracts are settled net.

A power generator makes decisions about how much power to generate and how much to purchase for its customers under contracts, based upon levels of 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 the delivery period. This process of ‘reoptimisation’ or constant churning of purchase and sales contracts makes it difficult to identify which contracts are settled net and which are not under IAS 39. Identifying some contracts for valuation and treating others as executory contracts for accrual accounting appears inconsistent with the business model of many companies; however this is what is required under the standard.

“discussion between utility companies at the roundtable centred on the difficulties of categorising contract types”*

The roundtable then considered issues of embedded derivatives and IAS 39, in particular the assessment of the ‘closely related’ test to determine whether a derivative needs to be separated from the host contract and accounted for at fair value. Proper assessment requires a qualitative evaluation, which then may need to be supplemented by quantitative analysis. For example, qualitative analysis may initially suggest that electricity be linked to the price of coal since coal is a major input to the electricity generation process. But this might not be supported in a market environment by quantitative analysis which in certain regions shows that coal prices are not highly correlated with electricity prices, as the price of electricity is impacted by supply and demand as well as other fuel sources. Companies also need to consider when to assess contracts for embedded derivatives. IFRIC D15 indicates that the assessment should take place at the time the entity first becomes a party to the contract and cannot be subsequently reassessed unless and until a new assessment is required by ‘significant modifications’ to the contract terms.

Finally, there was a lively discussion about hedging and the use of hedge accounting to reduce volatility in the profit and loss account from derivative instruments. Companies were reminded of the importance of formal designation and documentation of the hedging relationship and an objective/strategy for undertaking the hedge (including identification of the hedging instrument, the hedged item, the nature of the risk being hedged and the design of prospective and retrospective effectiveness tests). Evidence must be gathered of the prospective and retrospective effectiveness of the hedge (at inception and in subsequent periods) and the forecast transaction must be assessed as highly probable to occur to qualify for hedge accounting.

“Practical problems arise as IAS 39 does not provide extensive guidance on assessing whether economic characteristics and risks are ‘closely related’ for commodity and energy contracts.”*

Cash generating units (CGUs)

A key practical issue revolves around the determination of CGUs, which should be approached top-down from the perspective of the highest level of executive management until the ‘smallest identifiable group of assets’ is reached.

The accounting policy decision as to whether to treat joint ventures (JVs) at equity or to consolidate their assets proportionately could be highly significant for impairment testing in the utilities sector. In the former case, for example, technological obsolescence triggering a write-down of significant plant of the JV could affect the carrying value of the investor in the JV only indirectly, whereas proportionate consolidation of JV assets would result in a direct effect on the investor.

Component approach

New challenges arise from IAS 16 which requires the mandatory application of the component approach. If the costs of separate components of property, plant and equipment are recognised, the carrying amounts of those components replaced have to be derecognised. If subsequent costs are to be capitalised, these costs have to meet the general recognition criteria. Where property, plant and equipment is recognised for the first time, each material component of the greater asset must be recorded and measured separately.

A PricewaterhouseCoopers expert emphasised the importance of “identifying property, plant and equipment with separate components that have to be recognised separately and setting up corresponding accounts for the fixed asset detail ledger.”

Practical implementation issues are associated with necessary internal control process changes, in developing internal group guidelines for setting materiality thresholds to define ‘significant’ components and for performing accounting allocations. Further, for a turnkey power plant investment, the qualitative identification of individual components may be reasonably straightforward, but the apportionment of a total project value to these components in the absence of detailed knowledge of the constructor’s margin will require some estimates.

Looking ahead

As companies move forward with IFRS, it is clear that the interpretation and application of the standards will evolve and move on rather than remain static. The roundtable raised many questions. In some cases, the answers are clear. In others, they are less so. We are closely studying emerging practice as companies implement IFRS and, in Spring 2006, will be publishing a follow-up to our Crunch Time report on how best to embed IFRS in the oil and gas, utility and mining industries.

It is also clear that many challenges and issues close to the heart of the industry will move to centre stage as the standard setting process itself moves on to new ground. Part of the challenge for energy and utility companies is to highlight the particular issues the sector is facing at a time when a lot of the standards' focus is elsewhere – on industries such as financial services and issues such as financial instruments. The IASB extractive industries group is central to this process. The roundtable heard, for example, that some IASB members believe that reserves are assets and deserve recognition. Concerted industry engagement with the board through the extractive industries working group will be important for companies who want to have input. A discussion paper from the group is scheduled for late 2006 so engagement now, early in the process, will be timely. It will also be important to broaden the focus on the group's work – for example to paragraphs 5, 6, 7 and 8 in IAS 39 which have a major impact on power commodity contracts.

Much of the onus is placed on the standard setters, not least in media coverage of some of the implications of the standard setting process for companies. However, if standards are to develop in an effective way that brings us closer to the goals of transparency, comparability and bringing useful information to the market, preparers and users need to engage in a proactive dialogue with the standard setters. Oil, gas and utility companies need to play their part in this process as the agenda of the IASB and its extractive industry group gains momentum.

“there’s a danger of reserves being picked off and put into the fair value world”*

*quotes from oil & gas and utility participants in the roundtable



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