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Financial reporting in the oil and gas industry

International Financial Reporting Standards

2nd edition

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Foreword

International Financial Reporting Standards (IFRS) provide the basis for financial reporting to the capital markets in an increasing number of countries around the world. Over 100 countries either use or are adopting IFRS. Those companies already on IFRS have their own challenges as the pace of standard-setting from the International Accounting Standards Board (IASB) has been intense in recent years with a constant flow of changes for companies to keep up with.

One of the major challenges of any reporting framework is how best to implement it in the context of a specific company or industry. IFRS is a principles based framework and short on industry guidance. PwC looks at how IFRS is applied in practice by oil and gas companies. This publication identifies the issues that are unique to the oil and gas companies industry and includes a number of real life examples to demonstrate how companies are responding to the various accounting challenges along the value chain.

Of course, it is not just IFRS that are constantly evolving but also the operational issues faced by oil and gas companies with the heavy demand for capital and risks faced by the industry driving more cooperative working relationships. We look at some of main developments in this context with a selection of reporting topics that are of most practical relevance to oil and gas companies' activities. The new standards on joint arrangements, consolidated financial statements and disclosure of interests in other entities will be of particular interest to companies in the oil and gas sector. The debate about specific guidance for exploration, evaluation, development and production of oil and gas continues.

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

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Global Energy, Utilities and Mining Leader
September 2011

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Introduction

What is the focus of this publication?

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

The need for this publication has arisen due to:
- the continuing absence of an extractive industries standard under IFRS;
- the adoption of IFRS by oil and gas entities across a number of jurisdictions, with overwhelming acceptance that applying IFRS in this industry will be a continual challenge; and
- ongoing transition projects in a number of other jurisdictions, for which companies can draw on the existing interpretations of the industry.

Who should use this publication?

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

What is included?

Included in this publication are issues that we believe are of financial reporting interest due to:
- their particular relevance to oil and gas entities; and/or
- historical varying international practice.

The oil and gas industry has not only experienced the transition to IFRS, it has also seen:
- significant growth in corporate acquisition activity;
- increased globalisation;
- continued increase in its exposure to sophisticated financial instruments and transactions; and
- an increased focus on environmental and restoration liabilities.

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

PwC experience

This publication is based on the experience gained from the worldwide leadership position of PwC in the provision of services to the oil and gas industry. This leadership position enables PwC's Global Oil and Gas Industry Group to make recommendations and lead discussions on international standards and practice.

We support the IASB's project to consider the promulgation of an accounting standard for the extractive industries; we hope that this will bring consistency to all areas of financial reporting in the extractive industries. The oil and gas industry is arguably one of the most global industries and international comparability would be welcomed.

We hope you find this publication useful.

1 Oil & gas value chain and significant accounting issues

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The objective of oil and gas operations is to find, extract, refine and sell oil and gas, refined products and related products. It requires substantial capital investment and long lead times to find and extract the hydrocarbons in challenging environmental conditions with uncertain outcomes. Exploration, development and production often takes place in joint ventures or joint activities to share the substantial capital costs. The outputs often need to be transported significant distances through pipelines and tankers; gas volumes are increasingly liquefied, transported by special carriers and then regasified on arrival at its destination. Gas remains challenging to transport; thus many producers and utilities look for long-term contracts to support the infrastructure required to develop a major field, particularly off-shore.

The industry is exposed significantly to macroeconomic factors such as commodity prices, currency fluctuations, interest rate risk and political developments. The assessment of commercial viability and technical feasibility to extract hydrocarbons is complex, and includes a number of significant variables. The industry can have a significant impact on the environment consequential to its operations and is often obligated to remediate any resulting damage. Despite all of these challenges, taxation of oil and gas extractive activity and the resultant profits is a major source of revenue for many governments. Governments are also increasingly sophisticated and looking to secure a significant share of any oil and gas produced on their sovereign territory.

This publication examines the accounting issues that are most significant for the oil and gas industry. The issues are addressed following the oil & gas value chain: exploration and development, production and sales of product, together with issues that are pervasive to a typical oil and gas entity.

For published financial statement disclosure examples, see Appendix A.

Upstream activities	Midstream and downstream activities
• Reserves and resources • Depletion and depreciation of upstream assets • Exploration and evaluation • Development expenditures • Borrowing costs • Revenue recognition • Disclosure of reserves and resources • Production sharing agreements and concessions	• Product valuation issues • Revenue recognition issues • Emission trading schemes • Depreciation of downstream assets

Sector-wide Issues:

- Business combinations
- Joint ventures
- Decommissioning
- Impairment
- Royalty and income taxes
- Functional currency
- Leasing
- Financial instruments

2 Upstream activities

2 Upstream activities

2.1 Overview

Upstream activities comprise the exploration for and discovery of hydrocarbons; crude oil and natural gas. They also include the development of these hydrocarbon reserves and resources, and their subsequent extraction (production).

2.2 Reserves and resources

The oil and gas natural resources found by an entity are its most important economic asset. The financial strength of the entity depends on the amount and quality of the resources it has the right to extract and sell. Resources are the source of future cash inflows from the sale of hydrocarbons and provide the basis for borrowing and for raising equity finance.

2.2.1 What are reserves and resources?

Resources are those volumes of oil and gas that are estimated to be present in the ground, which may or may not be economically recoverable. Reserves are those resources that are anticipated to be commercially recovered from known accumulations from a specific date.

Natural resources are outside the scope of IAS 16 "Property, Plant and Equipment" and IAS 38 "Intangible Assets". The IASB is considering the accounting for mineral resources and reserves as part of its Extractive Activities project.

Entities record reserves at the historical cost of finding and developing reserves or acquiring them from third parties. The cost of finding and developing reserves is not directly related to the quantity of reserves. The purchase price allocated to reserves acquired in a business combination is the fair value of the reserves and resources at the date of the business combination but only at that point in time.

Reserves and resources have a pervasive impact on an oil and gas entity's financial statements, impacting on a number of significant areas. These include, but are not limited to:

- depletion, depreciation and amortisation;
- impairment and reversal of impairment;
- the recognition of future decommissioning and restoration obligations; and
- allocation of purchase price in business combinations.

The geological and engineering data available for hydrocarbon accumulations will enable an assessment of the uncertainty/certainty of the reserves estimate. Reserves are classified as proved or unproved according to the degree of certainty associated with their estimated recoverability. These classifications do not arise from any definitions or guidance in IFRS. This publication uses terms as they are commonly used in the industry but there are different specific definitions of reserves and the determination of reserves is complex.

Several countries have their own definitions of reserves, for example China, Russia, Canada, and Norway. Companies that are SEC registrants apply the SEC's own definition of reserves for financial reporting purposes. There are also definitions developed by professional bodies such as the Society of Petroleum Engineers (SPE). Application of different reserve estimation techniques can result in a comparability issue; entities should disclose what definitions they are using and use them consistently.

Proved reserves are estimated quantities of reserves that, based on geological and engineering data, appear reasonably certain to be recoverable in the future from known oil and gas reserves under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made.

Proved reserves are further sub-classified into those described as proved developed and proved undeveloped:

- proved developed reserves are those reserves that can be expected to be recovered through existing wells with existing equipment and operating methods;
- proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled proved acreage, or from existing wells where relatively major expenditure is required before the reserves can be extracted.

Unproved reserves are those reserves that technical or other uncertainties preclude from being classified as proved. Unproved reserves may be further categorised as probable and possible reserves:

- probable reserves are those additional reserves that are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves;

- possible reserves are those additional reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves.

Section 2.9 discusses disclosure requirements for reserves and resources.

2.2.2 Estimation

Reserves estimates are usually made by petroleum reservoir engineers, sometimes by geologists but, as a rule, not by accountants.

Preparing reserve estimations is a complex process. It requires an analysis of information about the geology of the reservoir and the surrounding rock formations and analysis of the fluids and gases within the reservoir. It also requires an assessment of the impact of factors such as temperature and pressure on the recoverability of the reserves. It must also take account of operating practices, statutory and regulatory requirements, costs and other factors that will affect the commercial viability of extraction. More information is obtained about the mix of oil, gas, and water, the reservoir pressure, and other relevant data as the field is developed and then enters production. The information is used to update the estimates of recoverable reserves. Estimates of reserves are revised over the life of the field.

2.3 Exploration and evaluation

Exploration costs are incurred to discover hydrocarbon resources. Evaluation costs are incurred to assess the technical feasibility and commercial viability of the resources found. Exploration, as defined in IFRS 6 "Exploration and Evaluation of Mineral Resources", starts when the legal rights to explore have been obtained. Expenditure incurred before obtaining the legal right to explore is generally expensed; an exception to this would be separately acquired intangible assets such as payment for an option to obtain legal rights.

The accounting treatment of exploration and evaluation ("E&E") expenditures (capitalising or expensing) can have a significant impact on the financial statements and reported financial results, particularly for entities at the exploration stage with no production activities.

2.3.1 Successful efforts and full cost methods

Two broadly acknowledged methods have traditionally been used under local GAAP to account for E&E and subsequent development costs: successful efforts and full cost. Many different variants of the two methods exist. US GAAP has had a significant influence on the development of accounting practice in this area; entities in those countries that may not have specific rules often follow US GAAP by analogy, and US GAAP has influenced the accounting rules in other countries.

The successful efforts method has perhaps been more widely used by integrated oil and gas companies, but is also used by many smaller upstream-only businesses. Costs incurred in finding, acquiring and developing reserves are typically capitalised on a field-by-field basis. Capitalised costs are allocated to commercially viable hydrocarbon reserves. Failure to discover commercially viable reserves means that the expenditure is charged to expense. Capitalised costs are depleted on a field-by-field basis as production occurs.

However, some upstream companies have used the full cost method under local GAAP. All costs incurred in searching for, acquiring and developing the reserves in a large geographic cost centre or pool are capitalised. A cost centre or pool is typically a country. The cost pools are then depleted on a country basis as production occurs. If exploration efforts in the country or the geological formation are wholly unsuccessful, the costs are expensed.

Full cost, generally, results in a greater deferral of costs during exploration and development and higher subsequent depletion charges.

Debate continues within the industry on the conceptual merits of both methods although neither is wholly consistent with the IFRS framework. The IASB published IFRS 6 *'Exploration for and Evaluation of Mineral Resources'* to provide an interim solution for E&E costs pending the outcome of the wider extractive activities project.

Entities transitioning to IFRS can continue applying their current accounting policy for E&E. IFRS 6 does not apply to costs incurred once E&E is completed. The period of shelter provided by the standard is a relatively narrow one, and the componentisation principles of IAS 16 and impairment rules of IAS 36 prevent the continuation of full cost past the E&E phase. The successful efforts method is seen as more compatible with the Framework.

Specific transition relief has been included in IFRS 1 "First-time adoption of IFRSs" to help entities transition from full cost accounting under previous GAAP to successful efforts under IFRS. Further discussion is included in section 6.1.

2.3.2 Accounting for E&E under IFRS 6

An entity accounts for its E&E expenditure by developing an accounting policy that complies with the IFRS Framework or in accordance with the exemption permitted by IFRS 6 [IFRS 6 para 7]. The entity would have selected a policy under previous GAAP of capitalising or expensing exploration costs. IFRS 6 allows an entity to continue to apply its existing accounting policy under national GAAP for E&E. The policy need not be in full compliance with the IFRS Framework [IFRS 6 para 6–7].

An entity can change its accounting policy for E&E only if the change results in an accounting policy that is closer to the principles of the Framework [IFRS 6 para 13]. 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. The policy, in short, can move closer to the Framework but not further away. This restriction on changes to the accounting policy includes changes implemented on adoption of IFRS 6.

The criteria used to determine if a policy is relevant and reliable are those set out in paragraph 10 of IAS 8. That is, it must be:

- Relevant to decision making needs of users;
- Provide a faithful representation;
- Reflect the economic substance;
- Neutral (free from bias);
- Prudent; and
- Complete

Changes to accounting policy when IFRS 6 first applied

Can an entity make changes to its policy for capitalising exploration and evaluation expenditures when it first adopts IFRS?

Background

Entity A has been operating in the upstream oil and gas sector for many years. It is transitioning to IFRS in 20X5 with a transition date of 1 January 20X4. Management has decided to 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 [IFRS 6 para 9(b)].

Can entity A's management change A's accounting policy on transition to IFRS to capitalise geological and geophysical costs?

Solution

No. 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 less prudent and therefore is not more relevant. Entity A's management should therefore not make the proposed change to the accounting policy.

The above solution is based on entity A being a standalone entity. However, if entity A was a group adopting IFRS and at least one entity in the group had been capitalising exploration and evaluation expenditures, entity A as a group could adopt a policy of capitalisation.

A new entity that has not reported under a previous GAAP and is preparing its initial set of financial statements can choose a policy for exploration cost. Management can choose to adopt the provisions of IFRS 6 and capitalise such costs. This is subject to the requirement to test for impairment if there are indications that the carrying amount of any assets will not be recoverable. The field-by-field approach to impairment and depreciation is applied when the asset moves out of the exploration phase.

2.3.3 Initial recognition of E&E under the IFRS 6 exemption

Virtually all entities transitioning to IFRS have chosen to use the IFRS 6 shelter rather than develop a policy under the Framework.

The exemption in IFRS 6 allows an entity to continue to apply the same accounting policy to exploration and evaluation expenditures as it did before the application of IFRS 6. The costs capitalised under this policy might not meet the IFRS Framework definition of an asset, as the probability of future economic benefits has not yet been demonstrated. However, IFRS 6 deems these costs to be assets. E&E expenditures might therefore be capitalised earlier than would otherwise be the case under the Framework.

The shelter of IFRS 6 only covers the exploration and evaluation phase, until the point at which the commercial viability of the property has been established.

2.3.4 Initial recognition under the Framework

Expenditures incurred in exploration activities should be expensed unless they meet the definition of an asset. An entity recognises an asset when it is probable that economic benefits will flow to the entity as a result of the expenditure [F.89]. The economic benefits might be available through commercial exploitation of hydrocarbon reserves or sales of exploration findings or further development rights. It is difficult for an entity to demonstrate that the recovery of exploration expenditure is probable. Where entities do not adopt IFRS 6 and instead develop a policy under the Framework, expenditures on an exploration property are expensed until the capitalisation point.

The capitalisation point is the earlier of:

i) the point at which the fair value less costs to sell of the property can be reliably determined as higher than the total of the expenses incurred and costs already capitalised (such as licence acquisition costs); and
ii) an assessment of the property demonstrates that commercially viable reserves are present and hence there are probable future economic benefits from the continued development and production of the resource.

Cost of survey that provide negative evidence of resources but result in increase in the fair value of the license – Should they be capitalised?

Background

Entity B operates in the upstream oil and gas sector and has chosen to develop accounting policies for exploration and evaluation expenditures that are fully compliant with the requirements of the IFRS Framework rather than continue with its previous accounting policies. It also chooses not to group exploration and evaluation assets with producing assets for the purposes of impairment testing.

Entity B has acquired a transferable interest in an exploration licence. Initial surveys of the licence area already completed indicate that there are hydrocarbon deposits present but further surveys are required in order to establish the extent of the deposits and whether they will be commercially viable.

Management are aware that third parties are willing to pay a premium for an interest in an exploration licence if additional geological and geophysical information is available. This includes licences where the additional information provides evidence of where further surveys would be unproductive.

Question

Can entity B capitalise the costs of a survey if it is probable before the survey is undertaken that the results of the survey will increase the fair value of the licence interest regardless of the survey outcome?

Solution

Yes. Entity B may capitalise the costs of the survey provided that the carrying amount does not exceed recoverable amount. Entity B's management are confident before the survey is undertaken that the increase in the fair value less costs to sell of the licence interest will exceed the cost of the additional survey. Capitalisation of the costs of the survey therefore meets the accounting policy criteria set out by the entity.

Costs incurred after probability of economic feasibility is established are capitalised only if the costs are necessary to bring the resource to commercial production. Subsequent expenditures should not be capitalised after commercial production commences, unless they meet the asset recognition criteria.

2.3.4.1 Tangible/Intangible classification

Exploration and evaluation assets recognised should be classified as either tangible or intangible according to their nature [IFRS 6 para 15]. A test well however, is normally considered to be a tangible asset. The classification of E&E assets as tangible or intangible has a particular consequence if the revaluation model is used for subsequent measurement (although this is not common) or if the fair value as deemed cost exemption in IFRS 1 is used on first-time adoption of IFRS.

The revaluation model can only be applied to intangible assets if there is an active market in the relevant intangible assets. This criterion is rarely met and would never be met for E&E assets as they are not homogeneous. The 'fair value as deemed cost' exemption in IFRS only applies to tangible fixed assets and thus is not available for intangible assets. Classification as tangible or intangible may therefore be important in certain circumstances.

However, different approaches are widely seen in practice. Some companies will initially capitalise exploration and evaluation assets as intangible and, when the development decision is taken, reclassify all of these costs to "Oil and gas properties" within property, plant and equipment. Some capitalise exploration expenditure as an intangible asset and amortise this on a straight line basis over the contractually established period of exploration. Others capitalise exploration costs as "tangible" within "Construction in progress" or PP&E from commencement of the exploration.

Clear disclosure of the accounting policy chosen and consistent application of the policy chosen are important to allow users to understand the entity's financial statements.

2.3.5 Subsequent measurement of E&E assets

Exploration and evaluation assets can be measured using either the cost model or the revaluation model as described in IAS 16 and IAS 38 after initial recognition [IFRS 6 para 12]. In practice, most companies use the cost model.

Depreciation and amortisation of E&E assets usually does not commence until the assets are placed in service. Some entities choose to amortise the cost of the E&E assets over the term of the exploration licence.

2.3.6 Reclassification out of E&E under IFRS 6

E&E assets are reclassified from Exploration and Evaluation when evaluation procedures have been completed [IFRS 6 para 17]. E&E assets for which commercially-viable reserves have been identified are reclassified to development assets. E&E assets are tested for impairment immediately prior to reclassification out of E&E [IFRS 6 para 17]. The impairment testing requirements are described below.

Once an E&E asset has been reclassified from E&E, it is subject to the normal IFRS requirements. This includes impairment testing at the CGU level and depreciation on a component basis. The relief provided by IFRS applies only to the point of evaluation (IFRIC Update November 2005).

An E&E asset for which no commercially-viable reserves have been identified should be written down to its fair value less costs to sell. The E&E asset can no longer be grouped with other producing properties.

2.3.7 Impairment of E&E assets

IFRS 6 introduces an alternative impairment-testing regime for E&E assets. An entity assesses E&E assets for impairment only when there are indicators that impairment exists. Indicators of impairment include, but are not limited to:

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

The affected E&E assets are tested for impairment once indicators have been identified. IFRS introduces a notion of larger cash generating units (CGUs) for E&E assets. Entities are allowed to group E&E assets with producing assets, as long as the policy is applied consistently and is clearly disclosed. Each CGU or group of CGUs cannot be larger than an operating segment (before aggregation). The grouping of E&E assets with producing assets might therefore enable an impairment to be avoided for a period of time.

Once the decision on commercial viability has been reached E&E assets are reclassified from the E&E category. They are tested for impairment under the IFRS 6 policy adopted by the entity prior to reclassification. Subsequent to reclassification the normal impairment testing guidelines of IAS 36 'Impairment', apply. Successful E&E will be reclassified to development and unsuccessful E&E is written down to fair value less costs to sell.

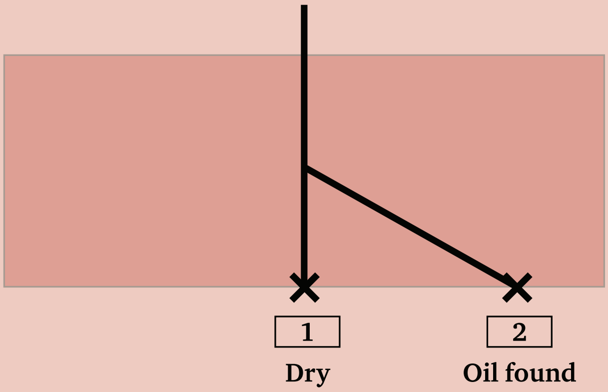
Assets reclassified from E&E are subject to the normal IFRS requirements of impairment testing at the CGU level and depreciation on a component basis. Impairment testing and depreciation on a pool basis is not acceptable. Traditional full cost accounting fails at this point, hence the transition relief described in section 6.1.

2.3.8 Side tracks

Performing exploratory drilling at a particular location can indicate that reserves are present in a nearby location rather than the original target. It may be cost-effective to "side track" from the initial drill hole to the location of reserves instead of drilling a new hole. If this side track is successful in locating reserves, the cost previously incurred on the original target can remain capitalised instead of being written off as a dry hole. The additional costs of the sidetrack are treated in accordance with the company's accounting policy which should be followed consistently. The asset should be considered for impairment if the total cost of the asset has increased significantly. If the additional drilling is unsuccessful, all costs would be expensed.

Cost of side tracks – Should they be expensed?

Background



An entity is drilling a new well in the development phase. It has drilled to spot 1, incurring costs of $5 million, but no reserves were found. Based on test data from the drilling, and a geological study, an alternative drill target was identified (spot 2). The entity could sidetrack to this from a point in the existing drill hole instead of drilling an entirely new well. Reserves were found at spot 2.

Question

How much cost should entity's management write off?

Solution

No costs will be written off as the drilling has proven successful.

2.3.9 Suspended wells

Exploratory wells may be drilled and then suspended or a well's success cannot be determined at the point drilling has been completed. The entity may decide to drill another well and subsequently recommence work on the suspended well at a later date. A question arises as to the treatment of the costs incurred on the original drilling: should these be written off or remain capitalised? The intention of the entity to recommence the drilling process is critical. If the entity had decided to abandon the well, the costs incurred may have to be written off. However, in cases where there is an intention to recommence work on the suspended well at a later date, the related costs may remain capitalised.

FASB ASC-932, *'Extractive Activities – Oil and Gas'* includes guidance on whether to expense or defer exploratory well costs when the well's success cannot be determined at the time of drilling. Capitalised drilling costs can continue to be capitalised when the well has found a sufficient quantity of reserves to justify completion as a producing field and sufficient progress is being made in assessing the reserves and viability of the project. If either criteria is not met, or substantial doubt exists about the economic or operational viability of the project, the exploratory well costs are considered impaired and are written off. Costs should not remain capitalised on the basis that current market conditions will change or technology will be developed in the future to make the project viable. Long delays in assessment or development plans raise doubts about whether sufficient progress is being made to justify the continued capitalisation of exploratory well costs after completion of drilling.

IFRS does not contain specific guidance on measurement of costs for suspended wells. The principles of IFRS 6 would be applied to assess whether impairment has occurred. If the entity intends to recommence drilling or development operations in respect of a suspended well, it may be possible to carry forward these costs in the balance sheet.

2.3.10 Post balance sheet events

2.3.10.1 Identification of dry holes

An exploratory well in progress at the reporting date may be found to be unsuccessful (dry) subsequent to the balance sheet date. If this is identified before the issuance of the financial statements, a question arises whether this is an adjusting or non-adjusting event.

IAS 10 *Events after the reporting period* requires an entity to recognise adjusting events after the reporting period in its financial statements for the period. Adjusting events are those that provide evidence of conditions that existed at the end of the reporting period. If the condition arose after the reporting period, these would result in non-adjusting events.

An exploratory well in progress at period end which is determined to be unsuccessful subsequent to the balance sheet date based on substantive evidence obtained during the drilling process in that subsequent period suggests a non-adjusting event. These conditions should be carefully evaluated based on the facts and circumstances.

Post balance sheet dry holes – Should the asset be impaired?

Background

An entity begins drilling an exploratory well in October 2010. From October 2010 to December 2010 drilling costs totalling GBP 550,000 are incurred and results to date indicate it is probable there are sufficient economic benefits (i.e., no indicators of impairment). During January 2011 and February 2011, additional drilling costs of GBP 250,000 are incurred and evidence obtained indicates no commercial deposits exist. In the month of March 2011, the well is evaluated to be dry and abandoned. Financial statements of the entity for 2010 are issued on April 2011.

Question

How should the entity account for the exploratory costs in view of the post balance sheet event?

Solution

Since there were no indicators of impairment at period end, all costs incurred up to December 2010 amounting to GBP 550,000 should remain capitalised by the entity in the financial statements for the year ended December 31, 2010. However, if material, disclosure should be provided in the financial statements of the additional activity during the subsequent period that determined the prospect was unsuccessful.

The asset of GBP 550,000 and costs of GBP 250,000 incurred subsequently in the months of January 2011 to February 2011 would be expensed in the 2011 financial statements.

2.3.10.2 License relinquishment

Licences for exploration (and development) usually cover a specified period of time. They may also contain conditions relating to achieving certain milestones on agreed deadlines. Often, the terms of the license specify that if the entity does not meet these deadlines, the licence can be withdrawn. Sometimes, entities fail to achieve these deadlines, resulting in relinquishment of the licence. A relinquishment that occurs subsequent to the balance sheet date but before the issuance of the financial statements, must be assessed as an adjusting or non-adjusting event.

If the entity was continuing to evaluate the results of their exploration activity at the end of the reporting period and had not yet decided if they would meet the terms of the licence, the relinquishment is a non-adjusting event. The event did not confirm a condition that existed at the balance sheet date. The decision after the period end created the relinquishment event. If the entity had made the decision before the end of the period that they would not meet the terms of the licence or the remaining term of the licence would not allow sufficient time to meet the requirements then the subsequent relinquishment is an adjusting event and the assets are impaired at the period end. Appropriate disclosures should be made in the financial statements under either scenario.

2.4 Development expenditures

Development expenditures are costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. An entity should develop an accounting policy for development expenditure based on the guidance in IAS 16, IAS 38 and the Framework. Much development expenditure results in assets that meet the recognition criteria in IFRS.

Development expenditures are capitalised to the extent that they are necessary to bring the property to commercial production. Entities should also consider the extent to which “abnormal costs” have been incurred in developing the asset. IAS 16 requires that the cost of abnormal amounts of labour or other resources involved in constructing an asset should not be included in the cost of that asset. Entities will sometimes encounter difficulties in their drilling plans and make adjustments to these, with the “sidetrack” issue discussed in section 2.3.8 being one example. There will be a cost associated with this, and entities should develop a policy on how such costs are assessed as being normal or abnormal.

Expenditures incurred after the point at which commercial production has commenced should only be capitalised if the expenditures meet the asset recognition criteria in IAS 16 or 38.

2.5 Borrowing costs

The cost of an item of property, plant and equipment may include borrowing costs incurred for the purpose of acquiring or constructing it. IAS 23 "Borrowing Costs" (revised 2007) requires borrowing costs be capitalised in respect of qualifying assets. Qualifying assets are those assets which take a substantial period of time to get ready for their intended use.

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

Borrowing costs incurred during the exploration and evaluation ("E&E") phase may be capitalised under IFRS 6 as a cost of E&E if they were capitalising borrowing costs under their previous GAAP. Borrowing costs may also be capitalised on any E&E assets that meet the asset recognition criteria in their own right and are qualifying assets under IAS 23. E&E assets which meet these criteria are expected to be rare.

Entities could develop an accounting policy under IFRS 6 to cease capitalisation of borrowing costs if these were previously capitalised. However the entity would then need to consider whether borrowing costs relate to a qualifying asset and would therefore require capitalisation. The asset would have to meet the IASB framework definition of an asset and be probable of generating future economic benefit. This definition will not be met for many assets. An exploration licence, for example, would not meet the definition of a qualifying asset as it is available for use in the condition it is purchased and does not take a substantial period of time to get ready for use. Additional exploration expenditure, although it can be capitalised under IFRS 6, would not be considered probable of generating future economic benefit until sufficient reserves are located.

2.6 Revenue recognition in upstream

Revenue recognition, particularly for upstream activities, can present challenging issues. Production often takes place in joint ventures or through concessions, and entities need to analyse the facts and circumstances to determine when and how much revenue to recognise. Crude oil and gas may need to be moved long distances and need to be of a specific type to meet refinery requirements. Entities may exchange product to meet logistical, scheduling or other requirements. This section looks at these common issues. Revenue recognition in production-sharing agreements (PSAs) is discussed in sections 4.3.2.2 and 4.3.3.3.

The IASB has an ongoing project to develop a new accounting standard for revenue recognition. The completion of the project may result in changes to current accounting but a final standard is not expected until 2012 at the earliest.

2.6.1 Overlift and underlift

Many joint ventures (JV) share the physical output, such as crude oil, between the joint venture partners. Each JV partner is responsible for either using or selling the oil it takes.

The physical nature of production and transportation of oil is such that it is often more efficient for each partner to lift a full tanker-load of oil. A lifting schedule identifies the order and frequency with which each partner can lift. The amount of oil lifted by each partner at the balance sheet date may not be equal to its working 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 are in effect a sale of oil at the point of lifting by the underlifter to the overlifter. The criteria for revenue recognition in IAS 18 "Revenue" paragraph 14 are considered to have been met. 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 [IAS 18 para 9]. Similarly the overlifter should reflect the purchase of oil at the same value.

Underlift by a partner is an asset in the balance sheet and 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 JV agreement. JV agreements that allow the net settlement of overlift and underlift balances in cash will fall within the scope of IAS 39 unless the 'own use' exemption applies [IAS 39 para 5]. Overlift and underlift balances that 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.

Overlift and underlift balances that do not fall within the scope of IAS 39 are measured at the lower of carrying amount and current market value. Any remeasurement should be included in other income/expense rather than revenue or cost of sales.

Overlift and underlift (1)

Recognition of underlift (including net settlement alternative)

How should underlift be accounted for where the imbalance is routinely net settled?

Background

Entity A and entity B jointly control a producing property. A has a 70% interest and B a 30% interest. At the start of the year there is no overlift or underlift.

During the first half of the year, production costs of C7,500 are jointly incurred and 500 barrels of oil are produced. The cost of producing each barrel is therefore C15. There is no production in the second half of the year.

During the first half of the year A has taken 300 barrels and B has taken 200 barrels. Each sold the oil they took at C32 per barrel, the market price at the time. Entity A has underlifted by 50 barrels at year end and B has overlifted by 50 barrels. The market price of a barrel of oil at year end is C35.

The joint venture agreement allows for net cash settlement of the overlift/underlift balance at the market price of oil at the date of settlement. Net settlement has been used by the JV partners in the past.

How should A account for the underlift balance?

Solution

Entity A should recognise a sale to B for the volume that B has overlifted. The substance of the transaction is that A has sold the overlift oil to B at the point of production. The criteria set out in IAS 18 (revised) paragraph 14(a)-(e) are met and revenue should therefore be recognised by A.

The underlift position represents an amount receivable by A from B in oil or in cash depending on the settlement mechanism selected. The value of the underlift position will change with movements in the oil price. A has the contractual right to demand cash for the underlift balance. The underlift balance is therefore a financial asset (receivable) which should be measured at amortised cost. Amortised cost should reflect A's best estimate of the amount of cash receivable. The best estimate will be the current spot price. The receivable is revised at each balance sheet date to reflect changes in the oil price.

A's income statement and balance sheet:

		Interim		Full year/year end
Income statement		C		C
Revenue	(500*C32*70%)	11,200		11,200
Cost of sales	(C7, 500*70%)	**(5,250)**		**(5,250)**
Gross profit		5,950		5,950
Other income/expense		-	(50*[35-32])	**150**
Net income		5,950		6,100
Balance sheet (extract)				
Underlift receivable	(50*C32)	1,600	(50*C35)	1,750

Overlift and underlift (2)

Settlement of underlift – net cash settlement

How should the settlement in cash of an underlift balance be recognised?

Background

Entity A and entity B jointly control a producing property. A has a 70% interest and B a 30% interest. At the start of the year entity A has recognised an underlift balance of 50 barrels, its JV partner, entity B, having overlifted by this amount. The market price of a barrel of oil at the start of the year is C35. The joint venture agreement allows for net cash settlement of the overlift/underlift balance at the market price of oil at the date of settlement. Net settlement has been used by the JV partners in the past.

During the year entity B settles the underlift/overlift balance through a cash payment to A. The oil price at the time of settlement is C37. The cash paid by B to A is therefore 1,850 (= 50 x C37).

How should A reflect the settlement of the underlift balance?

Solution

Entity A should recognise other income of C100. This is the revaluation of the underlift balance to the current market price at the date of settlement. The underlift receivable balance is derecognised when the cash is received.

The entries required at the date of settlement are:

		Dr	Cr
Dr Underlift	(50*(C37-C35))	C100	
Cr Other income			C100
Being restatement of underlift to current market price			
Dr Cash		C1,850	
Cr Underlift			C1,850
Being derecognition of underlift balance on settlement in cash			

Overlift and underlift (3)

Settlement of overlift – physical settlement (including net settlement alternative)

How should the physical settlement of an overlift balance be recognised when net cash settlement is an alternative?

Background

Entity A and entity B jointly control a producing property. A has a 70% interest and B a 30% interest. At the start of the year entity B has recognised an overlift balance of 50 barrels, its JV partner, entity A, having underlifted by this amount. The market price of a barrel of oil at the start of the year is 30.

The joint venture agreement allows for net cash settlement of the overlift/underlift balance at the market price of oil at the date of settlement. Net settlement has been used by the JV partners in the past.

During the year A and B agree to settle the overlift balance through A taking more than its share of the oil produced during the period. The oil price at the time of settlement is 32.

During the first half of the year, production costs of C7,500 are jointly incurred and 500 barrels of oil produced. The cost of producing each barrel is therefore C15. There is no production in the second half of the year.

During the first half of the year A has taken 400 barrels and B has taken 100 barrels. Each sold the oil they took at C32 per barrel, the market price at the time. Entity A has therefore overlifted during the year by 50 barrels and B has underlifted by 50 barrels.

At year end there is no underlift/overlift balance. The market price of a barrel of oil at year end is C35.

How should B reflect the settlement of the overlift balance?

Solution

Entity B should recognise a sale to A for the volume that A has overlifted. The substance of the transaction is that B has sold the overlift oil to A at the point of production. The criteria set out in IAS 18 (revised) paragraph 14(a)-(e) are met and revenue should therefore be recognised.

Entity B's overlift balance at the start of the year is revalued to current market value when the balance is settled through A overlifting from B. The increase in overlift value is recognised as other expense.

B's income statement and balance sheet:

		Interim	Full year/yearend
Income statement		**C**	**C**
Revenue	(500*C32*30%)	4,800	4,800
Cost of sales	(C7, 500*30%)	**(2,250)**	**(2,250)**
Gross profit		2,550	2,550
Other income/ (expense)	(50*[C32-C30])	**(100)**	**(100)**
Net income		2,450	2,450
Balance sheet (extract)			
Underlift		-	-

2.6.2 Pre-production sales

An entity may produce "test oil" from a development well prior to entering full production. This test oil may be sold to third parties. Where the test oil is considered necessary to the completion of the asset, the proceeds from sales are usually offset against the asset cost instead of being recognised as revenue within the income statement.

2.6.3 Forward-selling contracts to finance development

Oil and gas exploration and development is a capital intensive process and different financing methods have arisen. A Volumetric Production Payment (VPP) arrangement is a structured transaction that involves the owner of oil or gas interests selling a specific volume of future production from specified properties to a third party "investor" for cash. The owner is then able to use this cash to fund the development of a promising prospect. VPPs come in many different forms and each needs to be carefully analysed to determine the appropriate accounting. The buyer in a VPP may assume significant reserve and production risk and all, or substantially all, of the price risk. If future production from the specified properties is inadequate, the seller has no obligation to make up the production volume shortfall. Legally, a VPP arrangement is considered a sale of an oil or gas interest because ownership of the reserves in the ground passes to the buyer. The only specific guidance for a VPP arrangement is found in US GAAP. However, as the US GAAP requirements are consistent with the principles of IFRS many IFRS entities would follow this guidance.

The seller in a VPP arrangement will deem that it has sold an oil and gas interest. Common practice would be to eliminate the related reserves for disclosure purposes. However, typically a gain is not recognised upon entering the arrangement because the seller remains obligated to lift the VPP oil or gas reserves for no future consideration.

In these circumstances the seller records deferred revenue for all of the proceeds received and does not reduce the carrying amount of PP&E related to the specified VPP properties. The amount received is recorded as "deferred revenue" rather than a loan as the intention is that the amount due will be settled in the commodity rather than cash or a financial asset. Sometimes such contracts (subject to the terms relating to volume flexibility and pricing formula) have embedded derivatives in them which require separation (see sections 5.3 and 5.4 for discussions on volume flexibility and embedded derivatives).

Where no gain is recognised the seller will recognise the deferred revenue and deplete the carrying amount of PP&E related to the specified VPP properties as oil or gas is delivered to the VPP buyer. No production would be shown in the supplemental disclosures in relation to the VPP. The revenue arising from the sale under the VPP contract is recognised over the production life of the VPP.

This is a complex area and these transactions occur infrequently. There will be very specific facts for each arrangement. These must be understood and analysed as different accounting treatments may be applicable in certain circumstances.

VPPs are different from derivative forward contracts that would protect the entity against fluctuations in commodity prices (i.e., to buy or sell oil or gas at a specified future time at a price agreed in the present). These arrangements are discussed in section 5.

2.6.4 Provisional pricing arrangements

Sales contracts for certain commodities often incorporate provisional pricing - at the date of delivery of the oil or gas, a provisional price may be charged. The final price is generally an average market price for a particular future period.

Revenue from the sale of provisionally priced commodities is recognised when risks and rewards of ownership are transferred to the customer, which would generally be the date of delivery. At this date, the amount of revenue to be recognised will be estimated based on the forward market price of the commodity being sold.

The provisionally priced contracts are marked to market at each reporting date with any adjustments being recognised within revenue.

2.6.5 Presentation of revenue

Revenue is defined as the gross inflow of economic benefits that arise in the ordinary course of an entity's activities. Cash flows that do not provide benefit to the entity but are collected on behalf of governments or taxing authorities are conceptually not part of revenue. Oil and gas companies are subject to different types of taxes including income taxes, royalties, excise taxes, duty and similar levies. The prevalence of joint ventures and the variety of different taxes and duties levied on the industry may have resulted in different components of these being included or excluded from the reported revenue amount. This can make it difficult to compare revenue across industry participants.

Section 4.2 *Joint ventures* and 4.3 *Production sharing arrangements and concessions* discuss accounting for these arrangements in more detail. Section 4.6 Royalty and income taxes discusses the definition and classification of such items in more detail. The following table sets out the usual treatment for working arrangements and types of taxes that are commonly seen in the industry.

Background

Entity A conducts business through a variety of joint arrangements and is subject to various taxes. These are summarised below.

Business activity	Income statement presentation	Other comments
1. Jointly controlled assets: Entity A is responsible for selling its share of the oil produced from the jointly controlled assets.	Recognise revenue earned on the sale of share of oil.	The sales are made by entity A and meet the IAS 18 definition of revenue.
2. Jointly controlled entity: The JCE sells the oil produced and entity A receives its share of the profits earned by the JCE. The JCE represents 35% of entity A's operations. Entity A actively participates in the joint management of the JCE. Entity A applies equity accounting to JCEs.	Record share of profit earned by the JCE using equity accounting. Do not record revenue in respect of share of sales made by JCE.	Disclose JCE's revenues in notes to financial statements, together with other summary financial information.
3. Duty on refined product sold Entity A pays a fixed monetary amount per litre of product sold to the government.	The duty should be excluded from the revenue recognised.	The duty does not represent economic benefits receivable by entity A on its own account [IAS18.8].
4. Royalty on product sold Entity A pays in kind 30% of the sales proceeds to the government for each litre of product sold.	The royalty should be excluded from the revenue recognised by the entity [IAS18.8] i.e., if gross sales were C100, and the royalty was C10, the reported revenue would be C90.	The royalty collected by the entity is received on behalf of the government. Entity A is acting as agent for the government.

2.7 Asset swaps

An entity may exchange part or all of their future production interest in a field for an interest in another field. The fields may be in different stages of development, and depending on how advanced the development is it could be considered to be a business exchange. The accounting requirements will be different if the transaction represents the exchange of assets or a business combination. The properties exchanged may meet the definition of a business; if control is obtained over a property that meets the definition of a business then a business combination has occurred.

An exchange of one non-monetary asset for another is accounted for at fair value unless (i) the exchange transaction lacks commercial substance, or (ii) the fair value of neither of the assets exchanged can be determined reliably. There may be more than one asset or a combination of cash and nonmonetary assets. The acquired item is measured at the fair value of assets relinquished unless the fair value of asset or assets received is more readily determinable. A gain or loss is recognised on the difference between the carrying amount of the asset given up and fair value recognised for the asset received. It is expected that the entity will be able to determine a fair value for the assets in many circumstances. There may be some situations where a fair value is not available e.g., there is no market data of recent comparable transactions or exploration and evaluation activity is at an early stage with no conclusive data on reserves and resources. If a fair value cannot be determined the acquired item is measured at cost, which will be the carrying amount of the asset given up. There will be no gain or loss.

An entity determines whether an exchange transaction has commercial substance by considering the extent to which its future cash flows are expected to change as a result of the transaction. IAS 16 provides guidance to determine when an exchange transaction has commercial substance.

If the transaction is determined to be a business combination, the more complex requirements of IFRS 3 apply. An entity may also obtain joint control or significant influence when it acquires an interest in a property through a swap. The interest is initially recognised at fair value as determined above and then the requirements of IAS 28 *Investments in Associates* or IAS 31 *Interests in Joint Ventures* apply. (as further discussed in section 4.2.7 *Contributions to jointly controlled entities*). There can also be situations where entities which own assets or exploration rights in adjacent areas enter into a contract to combine these into a larger area, effectively an exchange of a share in a small asset for a share in a bigger asset. Section 4.2.12 *Unitisation agreements* explores this in more detail.

2.8 Depletion, depreciation and amortisation ("DD&A")

This section focuses on the depreciation of upstream assets. The depreciation of downstream assets such as refineries, gas treatment installations, chemical plants, distribution networks and other infrastructure is considered in section 3.5.

The accumulated capitalised costs from E&E and development phases are amortised over the expected total production using a units of production ("UOP") basis. UOP is the most appropriate amortisation method because it reflects the pattern of consumption of the reserves' economic benefits. However, straight-line amortisation may be appropriate for assets that are consumed more by the passage of time. For example, there may be circumstances when straight line deprecation does not produce a materially different result and can be used rather than UOP.

2.8.1 UoP basis

IFRSs do not prescribe what basis should be used for the UOP calculation. Many entities use only proved developed reserves; others use total proved or both proved and probable. Proved developed reserves are those that can be extracted without further capital expenditure. The basis of the UOP calculation is an accounting policy choice, and should be applied consistently. If an entity does not use proved developed reserves, then an adjustment is made to the calculation of the amortisation charge to include the estimated future development costs to access the undeveloped reserves.

The estimated production used for DD&A of assets 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 at the choice of the entity without significant cost.

2.8.2 Change in the basis of reserves

An entity may use one reserves basis for depreciation and subsequently determine that an alternative base may be more appropriate. It may be that the use of proved and probable would be more appropriate as

Unit of production calculation – classes of reserves

What class of reserves should be used for the unit of production calculation?

Background

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

However, D's management is debating whether to use proved reserves or proved and probable reserves for the unit of production calculation.

Solution

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

The IASB Framework identifies assets on the basis of probable future economic benefits and so the use of probable reserves is consistent with this approach. However, some national GAAPs have historically required only proved developed reserves be used for such calculations.

Whichever reserves definition D's management chooses it should disclose and apply this consistently to all similar types of production properties. For example, some entities used proved reserves for conventional oil and gas extraction and proved and probable for unconventional properties. If proved and probable reserves are used, then an adjustment must be made to the amortisation base to reflect the estimated future development costs required to access the undeveloped reserves.

that is the basis management use when assessing their business performance. A change in the basis of reserves from proved reserves to proved and probable reserves (or from proved developed to total proved) is considered acceptable under IFRS.

A change in the basis of reserves constitutes a change in accounting estimate under IAS 8. The entity's policy of depreciating their assets on a UOP basis is unchanged, they have only changed their estimation technique. The effect of the change is recognised prospectively from the period in which the change has been made. Entities which change their UOP basis should ensure that any related changes (such as future capital expenditure to complete any undeveloped assets or access probable reserves) are also incorporated into their depreciation calculation. Appropriate disclosure of the change should be made.

2.8.3 Components

IFRS has a specific requirement for 'component' depreciation, as described in IAS 16. Each significant part of an item of property, plant and equipment is depreciated separately [IAS 16 para 43-44].

Significant parts of an asset that have similar useful lives and patterns of consumption can be grouped together. This requirement can create complications for oil & gas entities, as there may be assets that include components with a shorter useful life than the asset as a whole.

Productive assets are often large and complex installations. Assets are expensive to construct, tend to be exposed to harsh environmental or operating conditions and require periodic replacement or repair. The significant components of these types of assets must be separately identified. 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.

The components that have a shorter useful life than the remainder of the asset are depreciated to their recoverable amount over that shorter useful life. The remaining carrying amount of the component is derecognised on replacement and the cost of the replacement part is capitalised [IAS 16 para 13-14].

2.9 Disclosure of reserves and resources

2.9.1 Overview

A key indicator for evaluating the performance of oil and gas entities are their existing reserves and the future production and cash flows expected from them. Some national GAAPs and securities regulators require supplemental disclosure of reserve information, most notably the FASB ASC 932 and Securities and Exchange Commission (SEC) regulations. There are also recommendations on accounting practices issued by industry bodies such as the UK Statements of Recommended Practice (SORPs) – which cover Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities. However, there are no reserve disclosure requirements under IFRS.

IAS 1 "Presentation of Financial Statements" [IAS 1 para 17] requires that an entity's financial statements should provide additional information when compliance with specific requirements in IFRS is insufficient to enable an entity to achieve a fair presentation.

An entity may consider the pronouncements of other standard-setting bodies and accepted industry practices when developing accounting policies in the absence of specific IFRS guidance. Many entities provide supplemental information with the financial statements because of the unique nature of the oil and gas industry and the clear desire of investors and other users of the financial statements to receive information about reserves. The information is usually supplemental to the financial statements, and is not covered by the auditor's opinion.

Information about quantities of oil and gas reserves and changes therein is essential for users to understand and compare oil and gas companies' financial position and performance. Entities should consider presenting reserve quantities and changes on a reasonably aggregated basis. Where certain reserves are subject to particular risks, those risks should be identified and communicated. Reserve disclosures accompanying the financial statements should be consistent with those reserves used for financial statement purposes. For example, proven and probable reserves or proved reserves might be used for depreciation, depletion and amortisation calculations.

The categories of reserves used and their definitions should be clearly described. Reporting a 'value' for reserves and a common means of measuring that value have long been debated, and there is no consensus among national standard-setters permitting or requiring value disclosure. There is, at present, no globally agreed method to prepare and present 'value' disclosures. However, there are globally accepted engineering definitions of reserves that take into account economic factors. These definitions may be a useful benchmark for investors and other users of financial statements to evaluate.

The disclosure of key assumptions and key sources of estimation uncertainty at the balance sheet date is required by IAS 1. Given that the reserves and resources have a pervasive impact, this normally results in entities providing disclosure about hydrocarbon resource and reserve estimates, for example:

- the methodology used and key assumptions made for hydrocarbon resource and reserve estimates
- the range of reasonably possible outcomes within the next financial year in respect of the carrying amounts of the assets and liabilities affected
- an explanation of changes made to past hydrocarbon resource and reserve estimates, including changes to underlying key assumptions.

Other information such as the potential future costs to be incurred to acquire, develop and produce reserves may help users of financial statements to assess the entity's performance. Supplementary disclosure of such information with IFRS financial statements is useful, but it should be consistently reported, the underlying basis clearly disclosed and based on common guidelines or practices, such as the Society of Petroleum Engineers definitions.

Companies already presenting supplementary information regarding reserves under their local GAAP may want to continue providing information in the same format under IFRS.

2.9.2 *Disclosure of E&E and production expenditure*

Exploration and development costs that are capitalised should be classified as non-current assets in the balance sheet. They should be separately disclosed in the financial statements and distinguished from producing assets where material [IFRS 6 para 23]. The classification as tangible or intangible established during the exploration phase should be continued through to the development and production phases. Details of the amounts capitalised and the amounts recognised as an expense from exploration, development and production activities should be disclosed.

2.9.3 *SEC rules on disclosure of resources and modernisation of requirements*

SEC guidance on the disclosure of reserves is viewed by the industry as a "best practice" approach to disclosure. Oil and gas entities may prepare their reserves disclosures based on this guidance even where they are not SEC-listed. The SEC amended its guidance on disclosure requirements (The Final Rule) and this has been in effect since December 2009.

The main disclosure requirements of the Final Rule are:

- Disclosure of estimates of proved developed reserves, proved undeveloped reserves and total proved reserves. This is to be presented by geographical area and for each country representing 15% or more of a company's overall proved reserves
- Disclosure of reserves from non-traditional sources (i.e., bitumen, shale, coalbed methane) as oil and gas reserves
- Optional disclosure of probable and possible reserves
- Optional disclosure of the sensitivity of reserve numbers to price
- Disclosure of the company's progress in converting proved undeveloped reserves into proved developed reserves. This is to include those that are held for five years or more and an explanation of why they should continue to be considered proved
- Disclosure of technologies used to establish reserves in a company's initial filing with the SEC and in filings which include material additions to reserve estimates
- The company's internal controls over reserve estimates and the qualifications of the technical person primarily responsible for overseeing the preparation or audit of the reserves estimates
- If a company represents that disclosure is based on the authority of a third party that prepared the reserves estimates or conducted a reserves audit or process review, they should also file a report prepared by the third party

'Oil and gas producing activities' include sources of oil and gas from unconventional sources, including bitumen, oil sands and hydrocarbons extracted from coalbeds and oil shale. Reserve definitions are aligned with those from the Petroleum Resources Management System (PRMS) approved by the Society for Petroleum Engineers (SPE).

The definition of 'proved oil and gas reserves' is "the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions" [Rule 4-10a].

Key criteria to meet this definition are:

- There must be at least a 90% probability that the quantities actually recovered will equal or exceed the stated volume (consistent with PRMS) to achieve the definition of 'Reasonable certainty'.
- The reserves must be 'Economically producible' and this requires the use of average prices during the prior 12-month period.
- To extract the reserves there must be 'Reliable technology', this refers to technology that has been field tested and demonstrated consistency and repeatability in the formation being evaluated or in an analogous formation.

Probable and possible reserve estimates allow the use of deterministic and probabilistic methods.

The Final Rule is silent with respect to the treatment of the reserves of an equity method investment. The ASU, however, requires entities to separately disclose the significant oil and gas producing activities of their equity method investments at the same level of detail as consolidated investments (i.e., including Topic ASC 932 supplemental disclosures).

3 Midstream and downstream activities

3 Midstream and downstream activities

3.1 Overview

Midstream and downstream activities in the oil and gas industry include the transportation of crude oil and gas, the refining of crude oil and the sales of the refined products. This part of the value chain is also dependent on significant capital investment. This includes refineries, liquefied natural gas (LNG) facilities, pipeline networks and retail stations. Integrated oil and gas companies may also have divisions that perform speculative trading of oil and gas.

3.2 Inventory valuation

Inventory is usually measured at cost as determined under IAS 2. Various methods are available; specific identification, weighted average or first-in first-out (FIFO). Generally, most entities use cost however in some circumstances inventory of commodities can be valued at net realisable value (NRV) or fair value less costs to sell (FVLCTS). FVLCTS for commodities is usually equivalent to their NRV. The circumstances when FVLCTS/NRV can be used are described below.

3.2.1 Producers' inventories

Inventory of minerals and mineral products should be measured at NRV when this is well-established industry practice [IAS2.3]. It is not usual industry practice for inventories of oil and gas to be measured on this basis, especially by downstream producers. It may however be established practice in certain countries or for commodity trading businesses. Entities operating in those territories may be able to adopt this policy.

Changes in the carrying amount of inventories that are carried at NRV are recognised in the income statement in each period. Determination of NRV reflects the conditions and prices that exist at the balance sheet date [IAS2.30]. Adjustments are not made to valuations to reflect the time that it will take to dispose of the inventory or the effect that the sale of a significant inventory quantity might have on the market price.

The prices of firm sales contracts are used to calculate NRV only to the extent of the contract quantities but only if the contracts are not themselves recognised on the balance sheet under another standard, such as IAS 39.

3.2.2 Broker-dealer inventories

Inventories held by broker-dealers are measured at FVLCTS [IAS2.3]. The fair value used is the spot price at the balance sheet date. It is not appropriate to modify the price to reflect a future expected sale by applying a future expected price from a forward price curve.

The definition of broker-trader within IAS 2, and inventories which will fall into this category, is narrow. Items in this category should be principally acquired for the purpose of resale. It is expected that there would be minimal repackaging of such items, and nothing which would change its underlying nature. This requirement can prevent entities from qualifying for the broker-trader exemption if they perform blending activity as this changes the chemical composition of the product which is sold. A blending process, for example, may occur not only as part of an entity's deliberate repackaging of a product, but also as a by-product of its storage process. Where an entity wishes to treat its inventory as a broker-trader, careful consideration must be given to whether any activities are performed which would change the nature of the product and therefore prevent it from meeting the requirements of IAS 2.

The carrying amount of inventories that are valued at FVLCTS must be disclosed in the notes [IAS2.36].

3.2.3 Line fill and cushion gas

Some items of PP&E, such as pipelines, refineries and gas storage, require a certain minimum level of product to be maintained in them in order for them to operate efficiently. This product is usually classified as part of the property, plant and equipment as it is necessary to bring the PPE to its required operating condition [IAS 16 para 16(b)]. The product will therefore be recognised as a component of the PPE at cost and subject to depreciation to estimated residual value.

However, product owned by an entity that is stored in PPE owned by a third party continues to be classified as inventory This would include, for example, all gas in a rented storage facility. It does not represent a component of the third party's PPE or a component of PPE owned by the entity. Such product should therefore be measured at FIFO or weighted average cost.

Cushion gas

Should cushion gas be accounted for as PPE or as inventory?

Background

Gaseous Giant SA is an entity involved in the production and trading of natural gas. Gaseous Giant (GG) has purchased salt caverns to use as underground gas storage.

The salt cavern storage is reconditioned to prepare it for injection of gas. 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. When the pressure drops below a certain threshold there is no pressure differential to push out the remaining natural gas. This remaining gas within the cavern is therefore physically unrecoverable until the storage facility is decommissioned. This remaining gas is known as "cushion gas".

Should GG's management account for the cushion gas as PPE or as inventory?

Solution

GG's management should classify and account for the cushion gas as PPE.

The cushion gas is necessary for the cavern to perform its function as a gas storage facility. It is therefore part of the storage facility and should be capitalised as a component of the storage facility PPE asset.

The cushion gas should be depreciated to its residual value over the life of the storage facility in accordance with IAS 16.43. However, if the cushion gas is recoverable in full when the storage facility is decommissioned, then depreciation will be recorded against the cushion gas component only if the estimated residual value of the gas decreases below cost during the life of the facility.

When the storage facility is decommissioned and the cushion gas extracted and sold, the sale of the cushion gas is accounted for as the disposal of an item of PPE in accordance with IAS 16.68. Accordingly the gain/loss on disposal is recognised in profit or loss.

The natural gas in excess of the cushion gas that is injected into the cavern should be classified and accounted for as inventory in accordance with IAS 2.

3.2.4 Net Realisable Value ("NRV") of oil inventories

Oil produced or purchased for use by an entity is valued at the lower of cost and net realisable value unless it is raw product which the entity intends to process to create a new product e.g., refining of crude oil. Determining net realisable value requires consideration of the estimated selling price in the ordinary course of business less the estimated costs to complete processing and to sell the inventories. An entity determines the estimated selling price of the oil/oil product using the market price for oil at the balance sheet date, or where appropriate, the forward price curve for oil at the balance sheet date. Use of the forward price curve would be appropriate where the entity has an executory contract for the sale of the oil. Movements in the oil price after the balance sheet date typically reflect changes in the market conditions after that date and therefore should not be reflected in the calculation of net realisable value.

NRV of oil inventories

Should NRV for oil inventories be calculated using the oil price at the balance sheet date or should changes in the market price after the balance sheet date be taken into account?

Background

Entity A is a retailer of oil. It has oil inventories at the balance sheet date. The cost of the oil was 800. Valuing the oil at market price at the balance sheet date, the value is 750. The market price of oil has fallen further since the balance sheet date, and the value of the year end inventory is now 720, based on current prices.

Should entity A calculate NRV for the oil using the market value at the balance sheet date or using the subsequent, lower, price?

Solution

Entity A should calculate the NRV of the oil inventory using the market price at the balance sheet date. The market price of oil changes daily in response to world events. The changes in the oil price since the balance sheet date therefore reflect events occurring since the balance sheet date. These represent non-adjusting events as defined by IAS 10.

Disclosure of the fall in the price of oil since the balance sheet date and its potential impact on inventory values should be made in the financial statements if this is relevant to an understanding of the entity's financial position [IAS 10 para 21(R.05)].

If further processing of the inventory is required into order to convert it into a state suitable for sale, the NRV should be adjusted for the associated processing costs.

3.2.5 Spare part inventories

The plant and machinery used in the refining process can be complex pieces of equipment and entities usually maintain a store of spare parts and servicing equipment for critical components. These are often carried as inventory and recognised in profit or loss as consumed, however, major spare parts stand-by equipment and servicing equipment can also qualify as property, plant and equipment when an entity expects to use them during more than one period. Spare parts in inventory or PP&E should be carried at cost unless there is evidence of damage or obsolescence.

3.3 Revenue recognition in midstream and downstream

Revenue recognition can present some specific challenges in midstream and downstream. Crude oil and gas may need to be moved long distances and need to be of a specific type to meet refinery requirements. Entities may exchange product to meet logistical, scheduling or other requirements. This section looks at these common issues. Trading of commodities and related issues are considered separately in section 5.7.

3.3.1 Product exchanges

Energy companies exchange crude or refined oil products with other energy companies to achieve operational objectives. A common term used to describe this is a "Buy-sell arrangement". These arrangements are often entered to save transportation costs by exchanging a quantity of product A in location X for a quantity of product A in location Y. Variations on the quality or type of the product can sometimes arise,. Balancing payments are made to reflect differences in the values of the products exchanged where appropriate. The settlement may result in gross or net invoicing and payment.

The nature of the exchange will determine if it is a like-for-like exchange or an exchange of dissimilar goods. A like-for-like exchange does not give rise to revenue recognition or gains. An exchange of dissimilar goods results in revenue recognition and gains or losses.

The exchange of crude oil, even where the qualities of the crude differ, is usually treated as an exchange of similar products and accounted for at book value. Any balancing payment made or received to reflect minor differences in quality or location is adjusted against the carrying value of the inventory. There may, however, be unusual circumstances where the facts of the exchange suggest that there are significant differences between the crude oil exchanged. An example might be where one quality of oil, for example light sweet crude, is exchanged for another, for example heavy sour crude, in order to meet the specific mix of crude required for a particular refinery's operations. Such a transaction should be accounted for as a sale of one product and the purchase of the other at fair values in these circumstances.

A significant cash element in the transaction is an indicator that the transaction may be a sale and purchase of dissimilar products.

3.3.2 Cost and Freight vs Free On Board

Oil and gas are often extracted from remote locations and require transportation over great distances. Transportation by tanker instead of pipeline can be a significant cost. Companies often sell prior to shipping but their oil or gas will be held at the port of departure. The resulting revenue contracts have two main variants with respect to future shipping costs – cost, insurance and freight ("CIF") or free on board ("FOB").

CIF contracts mean that the selling company will have the responsibility to pay the costs, freight and insurance until the goods reach a final destination, such as a refinery or an end user. However the risk of the goods is usually transferred to the buyer once the goods have crossed the ship's rail and been loaded onto the vessel.

IAS 18 focuses on whether the entity has transferred to the buyer the significant risks and rewards of ownership of the goods as a key determination of when revenue should be recognised. Industry practice has been that the transfer of significant risks and rewards of ownership occurs when the good's have passed the ship's rail, and accordingly revenue will be recognised at that point even if the seller is still responsible for insuring the goods whilst they are in-transit. However, a full understanding of the terms of trade will be required to ensure that this is the case.

FOB contracts mean that the selling company delivers the goods when the goods pass the ship's rail but is not liable for any other costs following this point. FOB contracts often stipulate that the purchaser will assume the risk of loss upon delivery of the product to an independent carrier – it is the purchaser's responsibility to pay for any insurance costs and they would therefore be assuming the risk of loss. The point at which the goods have passed the ship's rails is usually considered to be the point at which the transfer of significant risks and rewards of ownership is considered to have occurred because the seller has no further obligations.

3.3.3 Oilfield services

Oilfield services companies provide a range of services to other companies within the industry. This can include performing geological and seismic analysis, providing drilling rigs and managing operations.

The contractual terms and obligations are key to determining how revenue from an oilfield services contract is recognised. An entity should define the contract, identify the performance obligations (and whether there are any project milestones) and understand the pricing terms. Where an entity provides drilling rigs, costs of mobilisation and demobilisation are one area where the terms of the contract must be clearly understood in order to conclude on the accounting treatment for costs incurred.

Revenue recognition for the rendering of services often uses the percentage of completion method. Entities using this approach should be aware of any potential loss-making contracts and collectability issues – revenue can only be recognised to the extent of costs incurred which are recoverable.

Entities providing oilfield services should consider whether their contracts fall within the scope of IAS 17 or IFRIC 4 as leases. Refer 4.8 for detailed discussion on leasing.

3.4 Emissions trading schemes

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

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

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

The IASB have an ongoing project for emissions trading but there has been little activity on this project recently. The remainder of this section is based on current IFRS.

3.4.1 Accounting for ETS

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

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

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

IFRIC 3 "Emission Rights" was published in December 2004 to provide guidance on how to account for cap and trade emission schemes. The interpretation proved controversial and was withdrawn in June 2005 due to concerns over the consequences of the required accounting because it introduced significant income statement volatility.

The guidance in IFRIC 3 remains valid, but several alternative approaches have emerged in practice. A cap and trade scheme can result in the recognition of assets (allowances), expense of emissions, a liability (obligation to submit allowances) and potentially income from government grants.

The allowances are intangible assets and are recognised at cost if separately acquired. Allowances that are received free of charge from the government are recognised either at fair value with a corresponding deferred income (liability), or at cost (nil) as allowed by IAS 20 "Accounting for Government Grants and Disclosure of Government Assistance" [IAS 20 para 23].

The allowances recognised are not amortised if the residual value is at least equal to carrying value [IAS 38 para 100]. The cost of allowances is recognised in the income statement in line with the profile of the emissions produced.

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

The entity may choose to apply the revaluation model in IAS 38 Intangible Assets for the subsequent measurement of the emissions allowances. The revaluation model requires that the carrying amount of the allowances is restated to fair value at each balance sheet date, with changes to fair value recognised directly in equity except for impairment, which is recognised in the income statement [IAS 38 para 75 & 85-86]. This is the accounting that is required by IFRIC 3 and is seldom used in practice.

A provision is recognised for the obligation to deliver allowances or pay a fine to the extent that pollutants have been emitted [IAS 37 para 14]. The allowances reduce the provision when they are used to satisfy the entity's obligations through delivery to the government at the end of the scheme year. However, the carrying amount of the allowances cannot reduce the liability balance until the allowances are delivered to the government.

The provision recognised is measured at the amount that it is expected to cost the entity to settle the obligation. This will be the market price at the balance sheet date of the allowances required to cover the emissions made to date (the full market value approach) [IAS 37 (revised) para 37]. An alternative is to measure the obligation in two parts as follows [IAS 37 (revised) para 36]:

i) the obligation for which allowances are already held by the entity – this may be measured at the carrying amount of the allowances held; and
ii) the obligation for which allowances are not held and must be purchased in the market – this is measured at the current market price of allowances.

Entities using the alternative two-part approach should measure the obligation for which allowances are held by allocating the value of allowances to the obligation on either a FIFO or weighted average basis. Entities using this approach should only recognise an obligation at the current market price of allowances to the extent that emissions made to date exceed the volume of allowances held. There is no obligation to purchase additional allowances if emissions do not exceed allowances.

3.4.2 Certified Emissions Reductions (CERs)

The United Nations (United Nations Framework Convention on Climate Change) has created a mechanism, the "Clean Development Mechanism (CDM)" which allows developed nations ("Annexure I countries") to earn emissions-reduction credits towards Kyoto targets through investment in "green" projects in developing countries. Projects could be registered under this mechanism from 2001.

Firms and governments can invest in CDM by buying emissions credits "Certified Emissions Reductions (CERs)" generated by pollution-curbing projects like wind farms and new forests in developing countries. These CERs can be converted into EU Allowances (EUA) which can be used to satisfy their carbon emission obligations. A CER scheme is not a cap and trade scheme.

The United Nations established a CDM Board that selects the entities with environmentally friendly projects ("Green Entities"). These entities receive CERs from the United Nations provided the project is approved by the CDM Board.

The number of CERs that CDM grants to the Green Entities depends on the amount of CO2 that will be reduced through the consumption of the green products. For example, the Green Entity may produce a level of 50,000 units of green product. The use of this green product by consumers will contribute to the reduction of 50,000 tons of CO2 in a year, compared with conventional fossil fuels. The entity will be eligible for 50,000 CERs.

The Green Entity that receives the CERs from the CDM/UN can sell them to other companies irrespective of their locations. These companies can exchange these purchased CERs for EU emissions allowances which can be sold subsequently or used to satisfy obligations under an EU carbon emissions scheme.

The Green Entity will continue to receive CERs for as long as it continues to produce green fuel. No active market for the sale of these CERs has yet developed but is expected to do so. Valuation specialists are typically used to value CERs and sale agreements are negotiated on an individual basis.

CERs are assets that should be recognised by the entity that holds them. They are assets of an intangible nature and should either be accounted for as intangible assets in accordance with IAS 38, or as inventories in accordance with IAS 2. Intangible asset classification is appropriate if the entity plans to use the CERs to satisfy its emissions obligations, for example by exchanging the CERs for EU ETS allowances (or equivalents) and delivering these allowances in satisfaction of its emissions obligations. Inventory classification is appropriate if the entity plans to sell the CERs.

Recognition of CERs produced by an entity should be at cost or at fair value if the fair value model in IAS 20 is applied. The CERs are awarded in accordance with the UN criteria. The UN is similar to a government entity, and so IAS 20 is applied by analogy. Accordingly, CERs may be recognised at cost or at fair value, with a corresponding deferred income balance recognised as the difference between fair value and cost. The cost of CERs produced should be determined using an appropriate cost allocation model, which values the CERs produced and the green fuel produced as joint products.

3.5 Depreciation of downstream assets

This section focuses on the depreciation of downstream assets such as refineries, gas treatment installations, chemical plants, distribution networks and other infrastructure.

Downstream phase assets are depreciated using a method that reflects the pattern in which the asset's future economic benefits are expected to be consumed. The depreciation is allocated on a systematic basis over an asset's useful life. The residual value and the useful lives of the assets are reviewed at least at each financial year-end and, if expectations differ from previous estimates the changes are accounted for as a change in an accounting estimate in accordance with IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors*.

Downstream assets such as refineries are often depreciated on a straight line basis over the expected useful lives of the assets. An alternative approach is using a throughput basis. For example, for pipelines used for transportation depreciation can be calculated based on units transported during the period as a proportion of expected throughput over the life of the pipeline.

IFRS has a specific requirement for 'component' depreciation, as described in IAS 16. Each significant part of an item of property, plant and equipment is depreciated separately [IAS 16 para 43-44]. The requirements of IFRS in respect of components are considered in 2.7.2.

The significant components of these types of assets must be separately identified. It can be a complex process, particularly on transition to IFRS, as the detailed recordkeeping may not have been required to comply with national GAAP. Some components can be identified by considering the routine shutdown/turnaround schedules and the replacement and maintenance routines associated with these.

3.5.1 Cost of turnaround/overhaul

The costs of performing a major turnaround/overhaul are capitalised if the turnaround gives access to future economic benefits. Such costs will include the labour and materials costs of performing the turnaround. However, turnaround/overhaul costs that do not relate to the replacement of components or the installation of new assets should be expensed as incurred [IAS16 para 12]. Turnaround/overhaul costs should not be accrued over the period between the turnarounds/overhauls because there is no legal or constructive obligation to perform the turnaround/overhaul – the entity could choose to cease operations at the plant and hence avoid the turnaround/overhaul costs.

Refinery turnarounds

How should refinery turnarounds be accounted for?

Background

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 turn-around. 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. This will result in the same amount of expense being recognised in the income statement over the same period as the proposal to create a provision.

4 Sector-wide accounting issues

4 Sector-wide accounting issues

4.1 Business combinations

4.1.1 Overview

Acquisition of assets and businesses are common in oil and gas (O&G). Over the past few years market conditions have been challenging but oil prices have been resilient. Acquisitive entities that seek to secure access to reserves or replace depleting reserves face a variety of accounting issues due to significant changes in the accounting for merger and acquisition transactions. This adds more complexity to the already challenging economic conditions. IFRS 3 *Business Combinations ("IFRS 3R")* drives some of these challenges and is mandatory for all calendar year companies from 2010.

The changes introduced by IFRS 3R in accounting for business combinations include:

- Recognition at fair value of all forms of consideration at the date of the business combination;
- Remeasurement to fair value of previously held interests in the acquiree with resulting gains through the income statement as part of the accounting for the business combination;
- Providing more guidance on separation of other transactions from the business combination, including share-based payments and settlement of pre-existing relationships;
- Expensing transaction costs; and
- Two options for the measurement of any non-controlling interest (NCI, previously minority interest) on a combination by combination basis – fair value or proportion of net asset value.

4.1.2 Definition of a business

Significant judgement is required in the determination of what is a business. IFRS 3R has expanded the scope of what is considered to be a business and guidance continues to evolve. However, more transactions are business combinations under IFRS 3R than were considered such under the previous standard.

IFRS 3R amended the definition of a business and provided further implementation guidance. A business is a group of assets that includes; inputs, outputs and processes that are capable of being managed together for providing a return to investors or other economic benefits. Not all of the elements need to be present for the group of assets to be considered a business.

Upstream activities in the production phase will typically represent a business, whereas those at the exploration stage will typically represent a collection of assets. A licence to explore, on its own, is normally just an asset. Where a number of assets are owned and there are additional processes which exist to manage that portfolio, it may represent a business. Projects that lie in the development stage are more difficult to judge and will require consideration of the stage of development and other relevant factors. A development project with significant infrastructure costs remaining and no potential customers is more likely to be an asset. As these matters are resolved and the projects get closer to the production stage, the evaluation as to whether an asset or business exists becomes more complicated. Each acquisition needs to be evaluated based on the specific facts and circumstances.

The accounting for a business combination and a group of assets can be substantially different. A business combination will usually result in the recognition of goodwill and deferred tax.

If the assets purchased do not constitute a business, the acquisition is accounted for as the purchase of individual assets. The distinction is important because in an asset purchase:

- no goodwill is recognised;
- deferred tax is generally not recognised for asset purchases (because of the initial recognition exemption ("IRE") in IAS 12 Income Taxes, which does not apply to business combinations);
- transaction costs are generally capitalised; and
- asset purchases settled by the issue of shares are within the scope of IFRS 2 Share-Based Payments.

Distinguishing between business combinations and purchase of assets – practical examples

IFRS 3R defines a business as 'consisting of inputs and processes applied to those inputs that have the ability to create output' All three elements – input, process and output – should be considered in determining whether a business exists. We demonstrate the practical application of these principles below:

Acquisition	Inputs	Processes	Outputs	Conclusion
Incorporated entity which has one asset in the early exploration phase but the group does not have a production license yet. No proven reserves.	No inputs as the entity is at the exploration stage. Employees insignificant in number.	Exploration program but no processes in place to convert inputs. No production plans.	There is no development plan yet and no planned production. The only potential output might be results of early exploration work.	Likely to be an asset, as there is a lack of the business elements (e.g., inputs, processes and outputs).
Listed company with a portfolio of properties. Active exploration program in place and there are prospective resources. Company normally develops properties to production.	Portfolio of properties and employees.	Exploration program, O&G engineers and expertise, development program, management and administrative processes.	Production has not begun, however, since there is an active portfolio it may be that exploration results could be viewed as output. Consideration required as to whether market participant could produce outputs with the established inputs and processes.	Judgement required.
Listed company with a portfolio of properties. All exploration activities have been suspended and no properties have moved forward into development.	No employees.	No processes as there is not active exploration program in place.	There is no plan to further exploration and no development plans.	Judgement required.

Acquisition	Inputs	Processes	Outputs	Conclusion
Listed company with a portfolio of properties. Active exploration program and prospective resources. Company's policy is to hold portfolio of properties and sell in and out of them after undertaking exploration. The company does not hold the properties to development.	Portfolio of properties with successful exploration activities and employees.	Exploration program.	Exploration asset with associated resource information.	Judgement required.
Listed company. Property in development phase. Some reserves and resources.	O&G reserves and employees.	Operational processes associated with mineral production.	Revenues from O&G production.	Judgement required, but likely to be a business – all three elements exist.
Producing asset owned by a listed company. Only the asset is purchased.	O&G reserves and employees.	Operational processes associated with mineral production.	Revenues from O&G production.	Judgement required, but likely to be a business- all three elements exist. Although the “asset” does not constitute an incorporated entity, it is a business.
Alliance with another company to develop a property.	None	None	None	Jointly controlled asset. Assets acquired do not meet the definition of a business.

4.1.3 Identification of a business combination

Transactions may be structured in a variety of ways, including purchase of shares, purchase of net assets, and establishment of a new company that takes over existing businesses and restructuring of existing entities. Where there are a number of transactions linked together or transactions which are contingent on completion of each other, the overall result is considered as a whole. IFRS focuses on the substance of transactions and not the legal form to determine if a business combination has taken place.

The only exemptions to applying business combination accounting under IFRS are:

- when the assets acquired do not constitute a business (as discussed above);
- when businesses are brought together to form a joint venture (see Chapter 4.2); and
- businesses that are under common control (where no change in ownership takes place).

A business combination occurs when control is obtained. Both existing voting rights and capacity to control in the form of currently exercisable options and rights are considered in determining when control or capacity to control exists.

4.1.4 Acquisition method

IFRS 3R requires the acquisition method of accounting to be applied to all business combinations. The acquisition method comprises the following steps:

- identifying the acquirer and determining the acquisition date;
- recognising and measuring the consideration transferred for the acquiree;
- recognising and measuring the identifiable assets acquired and liabilities assumed, including any NCI; and
- recognising and measuring goodwill or a gain from a bargain purchase.

4.1.4.1 Identifying the acquirer and determining the acquisition date

An acquirer is identified as the first step of any business combination. The acquirer in the combination is the entity that obtains control of one or more businesses. The distinction is significant, as it is only the acquiree's identifiable net assets that are fair valued. The acquirer's net assets remain at existing carrying values.

IFRS 3R provides a set of principles to determine who the acquirer might be, if it is not clearly evident which entity has gained control based on the control indicators given in IAS 27. These principles include:

- in a business combination effected principally by transferring cash or other assets or by incurring liabilities, the acquirer is usually the entity transferring the cash or other assets or incurs the liabilities;
- in a business combination effected principally by exchanging equity interest, the acquirer is usually the entity that issues its equity interests;
- the acquirer is usually the combining entity whose owners as a group retain or receive the largest portion of the voting rights in the combined entity;
- the acquirer is usually the combining entity whose owners have the ability to elect or appoint a majority of the members of a governing body;
- the acquirer is usually the combining entity whose management dominates the management of the combined entity;
- the acquirer is usually the combining entity whose relative size (measured in, for example, assets, revenues or profit) is significantly greater than that of the other combining entity or entities;

This may lead to a reverse acquisition, particularly if the legal form involves creation of a new company or the acquisition of a large company by a smaller company. In such instances, the legal acquirer may not be the accounting acquirer under IFRS 3R.

Acquisition date is 'the date on which the acquirer obtains control of the acquiree'. Although the acquisition date is generally the date that the transaction closes (i.e., the date on which the acquirer transfers consideration and acquires the assets and liabilities of the acquiree), in some cases the acquirer may actually obtain control on a different date. Careful consideration of all facts and circumstances is required as to when the acquirer obtained control.

4.1.4.2 Consideration transferred

The consideration transferred may consist of:

- cash or cash equivalents paid;
- the fair value of assets given, liabilities incurred or assumed and equity instruments issued by the acquirer in exchange for control;
- the fair value of any contingent consideration arrangement as of the acquisition date; and
- a business or a subsidiary of the acquirer.

Transaction costs are expensed and not included as part of the consideration transferred. These transaction costs include investment banking fees and professional fees, such as legal and accounting fees. The direct costs of issuing shares or arranging finance are accounted for as part of the equity proceeds or financial liability rather than as a cost of the acquisition.

Some business combinations might result in gains in the statement of comprehensive income. In a step acquisition, any previously owned interest is seen as being 'given up' to acquire the business and a gain or loss is recorded on its disposal. The existing stake is re-measured to fair value at the date of acquisition, taking any gains to the statement of comprehensive income. A loss on acquisition is theoretically possible but this usually indicates an unrecognised impairment and is seldom seen.

The acquirer must identify any transactions that are not part of what the acquirer and the acquiree exchange in the business combination and separate this from the consideration transferred for the business. Examples include: the amount paid or received for the settlement of pre-existing relationships; and remuneration paid to employees or former owners for future services.

4.1.4.3 Contingent consideration

The purchase consideration may vary depending on future events. The acquirer may want to make further payments only if the business is successful. The vendor, on the other hand, wants to receive the full value of the business. Contingent consideration in the O&G industry often takes the form of:

- royalties payable to the vendor as a percentage of future oil revenue;
- payments based on the achievement of specific levels of production or specific prices of oil; and
- payments on achievement of milestones in the different phases (i.e., exploration, development and production).

An arrangement containing a royalty payable to the vendor is different from a royalty payable to the tax authorities of a country. A royalty payable to the vendor in a business combination is often contingent consideration; essentially a type of earn-out. However, things described as royalties may often instead be the retention of a working interest. If so, different accounting will be applied. Judgement is required as to whether a royalty or a retained working interest exists.

The acquirer should fair value all of the consideration at the date of acquisition including the contingent consideration (earn-out). Since fair value takes account of the probabilities of different outcomes, there is no requirement for payments to be probable. Therefore, contingent consideration is recognised whether it is probable that a payment will be made or not.

This may well be a change for many O&G companies that have treated vendor type royalties as period costs. Any subsequent payment or transfer of shares to the vendor should be scrutinised to determine if these are contingent consideration.

Contingent consideration can take the form of a liability or equity. If the earn-out is a liability (cash or shares to the value of a specific amount), any subsequent re-measurement of the liability is recognised in profit and loss. If the earn-out is classified as equity it is not be remeasured and any subsequent settlement is accounted for within equity.

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

IFRS 3R requires all identifiable assets and liabilities (including contingent liabilities) acquired or assumed to be recorded at their fair value. These include assets and liabilities that may not have been previously recorded by the entity acquired (e.g., acquired reserves and resources – proved, probable and possible).

IFRS 3R also requires recognition separately of intangible assets if they arise from contractual or legal rights, or are separable from the business. The standard includes a list of items that are presumed to satisfy the recognition criteria. The items that should satisfy the recognition criteria include trademarks, trade names, service and certification marks, internet domain names, customer lists, customer and supplier contracts, use rights (such as drilling, water, hydrocarbon, etc.), patented/unpatented technology, etc.

Some of the common identifiable assets and liabilities specific to the O&G industry that might be recognised in a business combination, in addition to inventory or property, plant and equipment, include the following:

- Exploration, development and production licences;
- O&G properties;
- Purchase and sales contracts;
- Environmental/closure provisions.

4.1.4.5 *Undeveloped properties/resources*

Undeveloped properties and resources or exploration potential can present challenges when ascribing fair value to individual assets, particularly those properties still in the exploration phase for which proven or probable reserves have not yet been determined. A significant portion of the consideration transferred may relate to the value of these undeveloped properties.

Management should consider similar recent transactions in the market and use market participant assumptions to develop fair values. The specific characteristics of the properties also need to be taken into account, including the type and volume of exploration and evaluation work on resource estimates previously carried out, the location of the deposits and expected future commodity prices. The challenges associated within this are discussed further in 4.1.7.

4.1.4.6 *Tax amortisation benefit*

In many business combinations, especially related to O&G acquisitions, the fair value of assets acquired uses an after-tax discounted cash flow approach. Inherent in this approach is an amount for the present value of the income tax benefits of deducting the purchase price through higher future depreciation and depletion charges. This is often referred to as the tax amortisation benefit ("TAB").

An asset's fair value in a business combination should reflect the price which would be paid for the individual asset if it were to be acquired separately. Accordingly, any TAB that would be available if the asset were acquired separately should be reflected in the fair value of the asset.

The TAB will increase the value of intangible and tangible assets and reduce goodwill. Assets that are valued via a market observable price rather than the use of discounted cash flows ("DCF") should already reflect the general tax benefit associated with the asset. Where the fair value has been determined using a DCF model the TAB should normally be incorporated into the model.

4.1.4.7 *Key questions*

There are key questions for management to consider in a business combination as they can affect the values assigned to assets and liabilities, with a resulting effect on goodwill. These questions include:

- *Have all intangible assets, such as Geological & Geophysical information, O&G property, exploration potential, been separately identified?* There may be tax advantages in allocating value to certain assets and each will need to be assessed in terms of their useful lives and impact on post acquisition earnings.
- *Have environmental and rehabilitation liabilities been fully captured?* The value the acquirer would need to pay a third party to assume the obligation may be significantly different to the value calculated by the target.
- *Does the acquiree have contracts that are at a price favourable or unfavourable to the market?* Such contracts would have to be fair valued as at the date of acquisition.
- *Do the terms of purchase provide for an ongoing royalty, other payments or transfer of equity instruments?* These arrangements could be contingent consideration that needs to be fair valued as at the date of acquisition.

- *Does the acquiree use derivative instruments to hedge exposures?* Post combination hedge accounting for pre-combination hedging instruments can be complex. The acquirer will need to designate these and prepare new contemporaneous documentation for each hedging relationship.
- *Have all embedded derivatives been identified?* New ownership of the acquired entity may mean that there are changes in the original conclusions reached when contracts were first entered into.

The above questions provide a flavour of the issues that management should consider in accounting for business combinations, and highlight the complexity of this area.

4.1.5 Goodwill in O&G acquisitions

Goodwill remains a residual in business combination accounting; the difference between consideration transferred and the fair value of identifiable assets acquired and liabilities assumed. IFRS 3R has broadened the definition of a business and thus more O&G transactions may be business combinations. Past practice under some national GAAPs and earlier versions of IFRS was that little or no goodwill was recognised in business combinations in O&G. Any residual value after the initial fair value exercise may have been re-allocated to O&G properties (i.e., proved, probable and possible reserves). This approach has largely disappeared with the issuance of IFRS 3R.

Management of the acquirer should carry out a thorough analysis and fair value exercise for all the identifiable tangible and intangible assets of the acquired business. Once this has been completed, any residual forms goodwill. Goodwill may also arise mechanically from requirement to record deferred tax in a business combination, this is further discussed below.

Goodwill can arise from several different sources. For example, goodwill may arise if a specific buyer can realise synergies from shared infrastructure assets (for example oil pipelines) or oil extraction techniques that are not available to other entities. Goodwill may also represent access to new markets, community/ government relationships, portfolio management, technology, expertise, the existence of an assembled workforce and deferred tax liabilities. An O&G entity may be willing to pay a premium to protect the value of other O&G operations that it already owns, and this would also represent goodwill.

As noted above goodwill may also arise from the requirements to recognise deferred tax on the difference between the fair value and the tax value of the assets acquired in a business combination. The fair value uplift to O&G properties and exploration assets is often not tax deductible and therefore results in a deferred tax liability.

The fair value attributed to some intangible assets could increase if their associated amortisation is deemed to be deductible for tax purposes. TAB is discussed above in 4.1.4.6. The impact would be an increase in the value of the asset and a decrease in the value of goodwill.

4.1.5.1 Goodwill and non-controlling interests

IFRS 3R gives entities a choice on the measurement NCI that arises in a less than 100% business combination. The choice is available on a transaction by transaction basis. An acquirer may either recognise the NCI at fair value, which leads to 100% of goodwill being recognised (full goodwill), or at the NCI's proportionate share of the acquiree's identifiable net assets (partial goodwill). This leads to goodwill being recognised only for the parent's interest in the entity acquired.

4.1.5.2 Bargain Purchase

There may situations where there is a forced sale and the consideration paid by the acquirer is less than the fair value of the net assets acquired. This is called a 'bargain purchase'. If a bargain purchase is identified, the gain should be immediately recognised in the income statement.

4.1.6 Deferred tax

An entity recognises deferred tax on the fair value adjustments to the net assets of an acquired O&G company, including any increase in the value of O&G properties and/or exploration assets. No deferred tax liability is recognised on goodwill itself unless the goodwill is tax deductible. Tax deductible goodwill is rare and presents specific accounting issues.

The tax base should reflect the manner in which the value of the asset will be realised. Few tax jurisdictions allow companies to claim tax deductions on acquired O&G properties if the asset will be realised through production of oil and gas. In such cases it is likely that a large deferred tax liability will need to be recognised.

This deferred tax liability can result in the recognition of goodwill because it reduces the net assets of the acquired entity. The extent of such goodwill will depend on the fair value of the O&G properties and the exploration assets and could be significant.

4.1.6.1 Tax losses

An acquired O&G entity may have tax losses. This can arise even if the entity is trading profitably, as a result of the carry forward of exploration costs and allowances for capital projects. Such tax losses are recognised as an asset at the date of the business combination if it is probable they will be utilised by the combined entity.

4.1.7 Provisional assessments of fair values

Acquirers have up to twelve months from the date of an acquisition to finalise the purchase price allocation. This is known as the "measurement period". Acquirers will frequently use this time to evaluate the acquired O&G properties and exploration assets. Any adjustments recognised during this period are recorded as part of the accounting for the initial business combination. Further adjustments beyond the 12-month window are recognised in profit and loss as a change in estimate. Where the 12-month window crosses a period end there may be adjustments to fair values required in the following period. The comparative information for prior periods presented in the current financial statements should be revised as needed, including recognising any change in depreciation, amortisation or other income effects recognised based on the original accounting.

Adjustments to deferred tax assets will only affect goodwill if they are made within the 12-month period for finalising the business combination accounting and if they result from new information about facts and circumstances that existed at the acquisition date. After the 12-month period, adjustments are recorded as normal under IAS 12, through the income statement or the statement of changes in equity, as appropriate.

The process of determining a reliable value for assets still in the early phase of exploration can be challenging. The level of uncertainty in ascribing a value to such assets increases the likelihood of subsequent changes having an effect on reported profit.

4.1.8 Business combinations achieved in stages

A business combination achieved in stages is accounted for using the acquisition method at the acquisition date. Previously held interests are remeasured to fair value at the acquisition date and a gain or loss is recognised in the income statement. The gain or loss would require disclosure in the financial statements. The fair value of the previously held interest then forms one of the components that are used to calculate goodwill, along with the consideration and non-controlling interest less the fair value of identifiable net assets.

4.1.9 Acquisitions of participating interests in jointly controlled assets

Jointly controlled assets that are not incorporated entities are a common method of undertaking development and production within the industry. Acquisition of interests in these assets where there are proven resources (and so in the development or production phase) is common. Section 4.1.3 noted the requirement that control be obtained for a business combination to occur.

A company may well own an interest in a field that is greater than 50% but still be in a joint control situation. Many joint operating agreements require unanimous consent to be providing by the participants in the arrangement. The acquisition of an interest in a field with proven resources (whether producing or not) would often not result in a business combination. As explained in section 4.1.2, an important consequence is that the acquisition would be treated as the purchase of an asset, with no goodwill or deferred tax arising.

Accounting for purchase of an interest in a producing field (1)

Should the acquisition of an interest in a producing field be accounted for as a business combination?

Background

There are three participants in jointly controlled asset Omega, The ownership interest of the participants is as follows:

Entity A	40%
Entity B	40%
Entity C	20%

The terms of the joint operating agreement ("JOA") require decisions relating to the development to be approved by parties representing 75% of the interest in the arrangement.

Entity A purchases entity C's interest of 20% and now holds 60% of the participating interest. Should entity A account for this as a business combination?

Solution

Although the producing field would represent a business and Entity A now owns a majority of the interest in the asset, the factors indicate that this would not be considered to be a business combination as they have still not obtained control. Prior to the transaction, the approval of decisions required agreement by 75% of the participating interests. A joint control situation existed between entity A and B as they controlled a total of 80% of the participating interests. Following the transaction, there is still a joint control situation as entity A does not hold sufficient interest to meet the 75% threshold. As they have not obtained control, a business combination has not occurred and the acquisition will be treated as an asset acquisition. The consideration for the interest will be capitalised and no deferred tax or goodwill will arise.

Accounting for purchase of an interest in a producing field (2)

Should the acquisition of an interest in a producing field be accounted for as a business combination?

Background

There are three participants in jointly controlled asset Infinity. The ownership interest of the participants is as follows:

Entity A	40%
Entity B	40%
Entity C	20%

The terms of the JOA require decisions relating to the development to be approved by parties representing 75% of the interest in the arrangement. The carrying value of the asset in Entity A's financial statements is C15 million.

Entity A purchases entity B's interest of 40%. It has paid consideration equivalent to its fair value of C20 million. A now holds 80% of the participating interest. Should entity A account for this as a business combination?

Solution

Yes. The producing field would represent a business and Entity A now owns the required level of interest to make a decision without requiring the approval of any other parties. They have obtained control of the asset, and a business combination has occurred.

A fair value assessment would be performed of the "business" and the company would consolidate their 80% share of this. The total fair value of the asset has been assessed as C50 million. A will recognise an asset of C40 million, which consists of the C20 million paid for B's share and C20 million for the revised value of the 40% previously recognised. There will be a gain on the previously held interest of C5 million recognised in the income statement.

Deferred tax will also need to be considered.

4.1.10 Business combinations for entities under common control

A combination between entities or businesses under common control is defined as 'a business combination in which all of the combining entities or businesses are ultimately controlled by the same party or parties both before and after the business combination and that control is not transitory'. Typically, business combinations for entities under common control arise as a product of the restructuring of companies within a group for commercial or tax purposes.

There is currently no guidance in IFRS on the accounting treatment for combinations among entities under common control as IFRS 3R excludes such combinations from the standard. Management, therefore, selects an appropriate accounting policy and applies that policy consistently. The policy selected could be in line with the acquisition method in IFRS 3R, or the predecessor accounting method used in some other GAAPs such as US GAAP and UK GAAP.

4.1.11 Restructuring costs

Major restructuring programs often follow business combinations. These costs may only be recognised as part of the business combination if they were previously recognised by the acquiree. Any other costs (such as terminations subsequent to the business combination) must be recorded as an expense in the post combination income statement of the acquired business. Similarly, any restructuring or other costs incurred by the acquirer itself cannot be included in the business combination.

4.1.12 Presentation and disclosure

The disclosure requirements for a business combination are extensive, particularly in the year of the combination.

Information that must be disclosed in the year of the combination for material business combinations and in aggregate for immaterial business combinations (including any post-reporting date acquisitions) includes:

- details of the combining entities or businesses;
- the consideration transferred and details of the components of the consideration;
- the amounts recognised at the acquisition date for each class of the acquiree's assets, liabilities and contingent liabilities.
- the amount of and reason for any gain recognised in a bargain purchase; a description of the factors that contributed to the recognition of goodwill (for example, unrecognised intangibles or buyer synergies);
- the amount of acquisition-related costs expensed and the line item in which the expense is reported;
- the measurement basis selected and the recognised amount of NCI in the acquiree, including the valuation techniques and key model inputs where fair value is used;
- the amount of the acquiree's revenue and profit or loss since the acquisition date included in the acquirer's reported profit or loss for the period (period of ownership); and
- the revenue and profit or loss of the combined entity for the period as if the acquisition had taken place at the start of the period; details of any adjustments arising from changes to provisional accounting, or other adjustments arising from business combination accounting.

4.2 Joint arrangements

4.2.1 Overview

Joint ventures and other similar arrangements (joint arrangements) are frequently used by oil & gas companies as a way to share the higher risks and costs associated with the industry or as a way of bringing in specialist skills to a particular project. The legal basis for a joint arrangement may take various forms; establishing a joint venture might be achieved through a formal joint venture contract, or the governance arrangements set out in a company's formation documents might provide the framework for a joint arrangement The feature that distinguishes a joint arrangement from other forms of cooperation between parties is the presence of joint control. An arrangement without joint control is not a joint arrangement.

The IASB published IFRS 11 *Joint Arrangements* in May 2011. The standard introduces a number of significant changes in the accounting for joint arrangements, which include:

- "Joint arrangement" replaces "joint venture" as the new umbrella term to describe all arrangements where two or more parties have joint control;
- There are two types of joint arrangement, being "Joint operations" and "Joint ventures";
- Contractual rights and obligations drive the categorisation of a joint arrangement as a joint operation or a joint venture;
- The policy choice of proportionate consolidation for joint ventures is eliminated; and
- An "investor in a joint venture" is defined as being a party who does not participate in joint control, with guidance on the appropriate accounting.

Unanimous consent must be present over the financial and operating decisions in order for joint control to exist.

IFRS 11 becomes effective in 2013, although earlier application is allowed. Most companies are expected to adopt the standard only when it becomes mandatory. The requirements of IFRS 11 are discussed in the "Future developments" chapter in section 7.1. This chapter is based on the requirements of IAS 31 although it uses the new umbrella term 'joint arrangements'.

4.2.2 Joint control

Joint control is the contractually-agreed sharing of control over an economic activity. An identified group of venturers must unanimously agree on all key financial and operating decisions. Each of the parties that share joint control has a veto right: they can block key decisions if they do not agree.

Not all parties to the joint venture need to share joint control. Some participants may share joint control and other investors participate in the activity but not in the joint control. Those investors account for their interest in its share of assets and liabilities, an investment in an associate (if they have significant influence) or as an available for sale financial asset in accordance with IAS 39.

Similarly, joint control may not be present even if an arrangement is described as a 'joint venture'. Decisions over financial and operating decisions that are made by "simple majority" rather than by unanimous consent could mean that joint control is not present even in situations where there are only two shareholders but each has appointed a number of directors to the Board or relevant decision-making body.

Joint control will only exist if decisions require the unanimous consent of the parties sharing control. If decisions are made by simple majority, the following factors may undermine the joint control assertion:

- the directors are not agents or employees of the shareholders
- the shareholders have not retained veto rights.,
- there are no side agreements requiring directors vote together
- a quorum of Board members can be achieved without all members being in attendance

If it is possible that a number of combinations of the directors would be able to reach a decision, it may be that joint control does not exist. This is a complex area which will require careful analysis of the facts and circumstances. If joint control does not exist, the arrangement would not be a joint venture. Investments with less than joint control are considered further in section 4.2.8.

A key test when identifying if joint control exists is to identify how disputes between ventures are resolved. If joint control exists, resolution of disputes will usually require eventual agreement between the venturers, independent arbitration or, dissolution of the joint venture.

One of the venturers acting as operator of the joint venture does not prevent joint control. The operator's powers are usually limited to day-to-day operational decisions; key strategic financial and operating decisions remain with the joint venture partners collectively.

4.2.3 Classification of joint ventures

Joint ventures are analysed into three classes under the current standard; jointly controlled operations, jointly controlled assets and jointly controlled entities.

Jointly controlled assets are common in the upstream industry and jointly controlled entities in the downstream sector. Jointly controlled assets exist when the venturers jointly own and control the assets used in the joint venture. Jointly controlled assets are likely to meet the definition of joint operations when companies adopt IFRS 11.

Jointly controlled operations are arrangements where each venture uses their own property, plant and equipment, raise their own finance and incur their own expenses and liabilities. An example would be an arrangement where one party owns an oil refinery and another party owns transportation facilities (such as a pipeline or tankers). The second party will market and deliver the oil produced. Each party will bear its own costs and take a share of the revenue generated by the sale of the oil to third party customers.

Jointly controlled operations

Can an oil sands operation and a related refinery constitute a jointly controlled operation?

Background

Entity A controls mineral rights and operates an oil sands mine. Entity B has processing capacity in the form of a refinery. The refinery is located next to the oil sands operation and processes the bitumen extracted from the mine. Entities A and B have a contractual agreement according to which they share the revenue of the refined product. Entity A retains title and control of the oil sands operation and entity B retains the same for the refinery.

Entities A and B consider the oil sands mine and the refinery to be a jointly controlled operation. They recognise the assets that they control, the liabilities that they incur, an expense and their share of the income that they earn from the sale of the refined products, respectively. Is this an acceptable analysis?

Solution

Yes. The oil sands operation and refinery operations are a jointly controlled operation. The two entities have combined their operations, resources and expertise to produce, refine, market and distribute jointly a particular mineral. They bear their own costs and take a share of the revenue from the sale of the refined mineral, such share being determined in accordance with the contractual arrangement.

Jointly controlled entities exist when the venturers jointly control an entity which, in turn owns the assets and liabilities of the joint venture. A jointly controlled entity is usually, but not necessarily, a legal entity, such as a company. The key to identifying an entity is to determine whether the joint venture can perform the functions associated with an entity, such as entering into contracts in its own name, incurring and settling its own liabilities and holding a bank account in its own right.

Identifying an entity

What are the indicators of an entity?

Background

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".

What are the indicators of an entity?

Solution

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.

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 being an entity under IAS 31.

4.2.4 Accounting for jointly controlled assets ("JCA")

A venturer in a jointly controlled asset arrangement recognises:

- 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 assets;
- its share of expenses from the operation of the assets; and
- its share of any income arising from the operation of the assets (for example, ancillary fees from use by third parties).

Jointly controlled assets tend to reflect the sharing of costs and risk rather than the sharing of profits. An example is an undivided interest in an oil field where each venturer receives its share of the oil produced, in jointly liable for production costs and is part of the joint control decision making.

Decommissioning of offshore loading platform

Does the requirement to decommission the platform at the end of the contract term give rise to a liability for each of the venturers?

Background

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. Decisions regarding the platform require the unanimous agreement of the three parties. The platform is neither a jointly controlled entity nor a jointly controlled operation.

Local legislation requires the dismantlement of the platform at the end of its useful life.

Entity C's management has proposed that it should account for 15% of the decommissioning liability. Is this appropriate?

Solution

Yes. The platform is a jointly controlled asset. A venturer of a jointly controlled asset recognises in its financial statements:

a) its share of the jointly controlled assets, classified according to the nature of the assets;
b) any liabilities that it has incurred;
c) its share of any liabilities incurred jointly with the other venturers in relation to the joint venture;
d) any income from the sale or use of its share of the output of the joint venture, together with its share of any expenses incurred by the joint venture; and
e) any expenses that it has incurred in respect of its interest in the joint venture.

Each venturer should recognise 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.

4.2.5 *Accounting for jointly controlled operations (“JCO”)*

The parties to the joint operation will share the revenue and expenses of the jointly produced end product. Each will retain title and control of its own assets. The venturer should recognise 100% of the assets it controls and the liabilities it incurs as well as its own expenses, its share of income from the sale of goods or services of the joint operation and its share of expenses jointly incurred.

4.2.6 *Accounting for jointly controlled entities (“JCE”)*

Jointly controlled entities can be accounted for either by proportionate consolidation or using equity accounting using the policy choice available under IAS 31. The policy must be applied consistently to all jointly controlled entities. Proportionate consolidation will be eliminated as a policy choice when IFRS 11 is adopted.

The key principles of the equity method of accounting are:

- Investment in the JCE is initially recognised at cost;
- Changes in the carrying amount of investment are recognised based on the venturer’s share of the profit or loss of the JCE after the date of acquisition;
- The venturer only reflects their share of the profit or loss of the JCE; and
- Distributions received from a JCE reduce the carrying amount of the investment.

Comparison of proportionate consolidation and equity accounting

Are there potential differences in presentation of net results between equity accounting and proportionate consolidation?

Background

Entity A has just formed its first jointly controlled entity, J.

A’s management must choose an accounting policy for the joint venture: either proportionate consolidation or the equity method. A’s management understands the implications of the two methods on income statements and balance sheet presentation, but it wonders whether the two methods could lead to a different net result.

Solution

The net result under each method generally will be the same. A difference might arise is if the venture incurs losses to the extent that its equity becomes negative:

- Entity A will continue to recognise its share of each income statement line and its share of each balance sheet line under proportional consolidation if J continues to recognise losses; however
- Entity A will cease to recognise its share of losses under the equity method once the investment in J is reduced to zero.

The results of the joint venture are incorporated by the venturer on the same basis as the venturer's own results – i.e., using the same GAAP (IFRS) and the same accounting policy choices. The growing use of IFRS and convergence with US GAAP has helped in this regard but the basis of accounting should be set out in the formation documents of the joint venture.

Joint venture uses a different GAAP

A venture uses IFRS. Are accounting adjustments required before it can incorporate the results of a joint venture that reports under US GAAP?

Background

Entity J is a jointly controlled entity that prepares its accounts under US GAAP as prescribed in the joint venture agreement. One of the venturers, entity C, prepares its consolidated financial statements under IFRS. C's management believes that for the purpose of applying the equity method, the US GAAP financial statements of J can be used.

Must C's management adjust entity J's US GAAP results to comply with IFRS before applying the equity method?

Solution

Yes the results must be adjusted for all material differences. IAS 27 paragraph 28, IAS 28 paragraph 26 as well as IAS 31 paragraph 28 require that all information contained in IFRS financial statements should be prepared according to IFRS. C's management must therefore make appropriate adjustments to J's US GAAP results to make them compliant with IFRS requirements. There is no exemption in IFRS for impracticability.

The same requirement exists whether entity C applies equity accounting or proportional consolidation for its joint controlled entities. Adjustments to conform accounting policies are also required where both entities use IFRS.

4.2.7 Contributions to jointly controlled entities

It is common for venturers to contribute assets such as cash, non-monetary assets or a business, to a joint venture on formation. Contributions of assets are a partial disposal by the contributing party. The venturer in return receives a share of the assets contributed by the other venturers. Accordingly, the contributor should recognise a gain or loss on the partial disposal. The gain is measured as the proportionate share of the fair value of the assets contributed by the other venturers less the portion of the book value of contributor's disposed asset now attributed to the other venturers.

The venturer recognises its share of an asset contributed by other venturers at its share of the fair value of the asset contributed. This is classified in the balance sheet according to the nature of the asset in the case of jointly controlled assets or when proportionate consolidation is applied. The equivalent measurement basis is achieved when equity accounting is applied; however, the interest in the asset forms part of the equity accounted investment balance.

The same principles apply when one of the other venturers contributes a business to a joint venture; however, one of the assets recognised will normally be goodwill, calculated in the same way as in a business combination.

Contributions to jointly controlled entities

If a joint venture uses the fair value of all contributed assets in its own financial statements, can this be reflected in the venturer's own financial statements through equity accounting?

Background

Entities A and B have brought together their petrol stations in a certain region in order to strengthen their market position and reduce costs. They established entity J and contributed the petrol stations to J. A receives 60% of the shares in J, and entity B receives 40%.

Entity J has recognised the contribution of the petrol stations from entities A and B at fair value. Entity J is compelled to do this by local company law as shares issued must be backed by the fair value of assets recognised. Effectively, J follows the "fresh start" method of accounting for its formation.

Entity A's accounts for jointly controlled entities using the equity method. A's management wants to include its share of J's net assets and profits and losses on the same basis on which they are accounted for in entity J, without adjustment. They point out that Entity J has used an acceptable method under IFRS of accounting for its formation.

Can A's management do this?

Solution

Yes, there is a policy choice available to A in certain circumstances because of the conflict in the accounting standards described below. A can choose partial recognition of the gain or loss being the difference between 40% of the fair value of its petrol stations contributed and 40% of their carrying amount plus its 60% share of the fair value of the petrol stations contributed by B. This is the approach set out in SIC 13. A may also recognise 100% of the gain arising on its disposal of its petrol station business following IAS 27 – see narrative below.

Entity A must therefore eliminate its share (retained) of the fair value of the petrol stations it previously held and that are accounted for at fair value at the level of J when applying the equity method of accounting.

The example above is based on guidance provided within SIC-13 *Jointly Controlled Entities – Non-Monetary Contributions by Venturers*. There is an inconsistency between SIC-13 and IAS 27 *Consolidated and Separate Financial Statements* when the contribution to the jointly controlled entity is considered to represent a business.

IAS 27 has different guidance on the loss of control of a business. Any investment a parent has in the former subsidiary after control is lost is measured at fair value at the date that control is lost and any resulting gain or loss is recognised in profit or loss in full.

The IASB have not dealt with this conflict in IFRS 11 but will do so as part of a wider project on equity accounting. Entities can make a policy choice in these types of transaction whilst this conflict remains.

4.2.8 *Investments with less than joint control*

Some co-operative arrangements may appear to be joint ventures but fail on the basis that unanimous agreement between venturers is not required for key strategic decisions. This may arise when a super majority, for example an 80% majority is required but where the threshold can be achieved with a variety of combinations of shareholders and no venturers are able to individually veto the decisions of others. Accounting for these arrangements will depend on the way they are structured and the rights of each venturer.

Identifying a joint venture

Is an entity automatically a joint venture if more than two parties hold equal shares in an entity?

Background

Entity A, B, C and D (venturers) each hold 25% in entity J, which owns a refinery. Decisions in J need to be approved by a 75% vote of the venturers.

Entity A's management wants to account for its interest in J using proportional consolidation in its IFRS consolidated financial statements because J is a joint venture. Can A's management account for J in this way?

Solution

No. A cannot account for J using proportional consolidation because J is not jointly controlled. The voting arrangements would require unanimous agreement between those sharing the joint control of J to qualify as a joint venture. The voting arrangements of J allow agreement of any combination of three of the four partners to make decisions.

Each investor must therefore account for its interest in J as an associate since they each have significant influence but they do not have joint control. Equity accounting must therefore be applied.

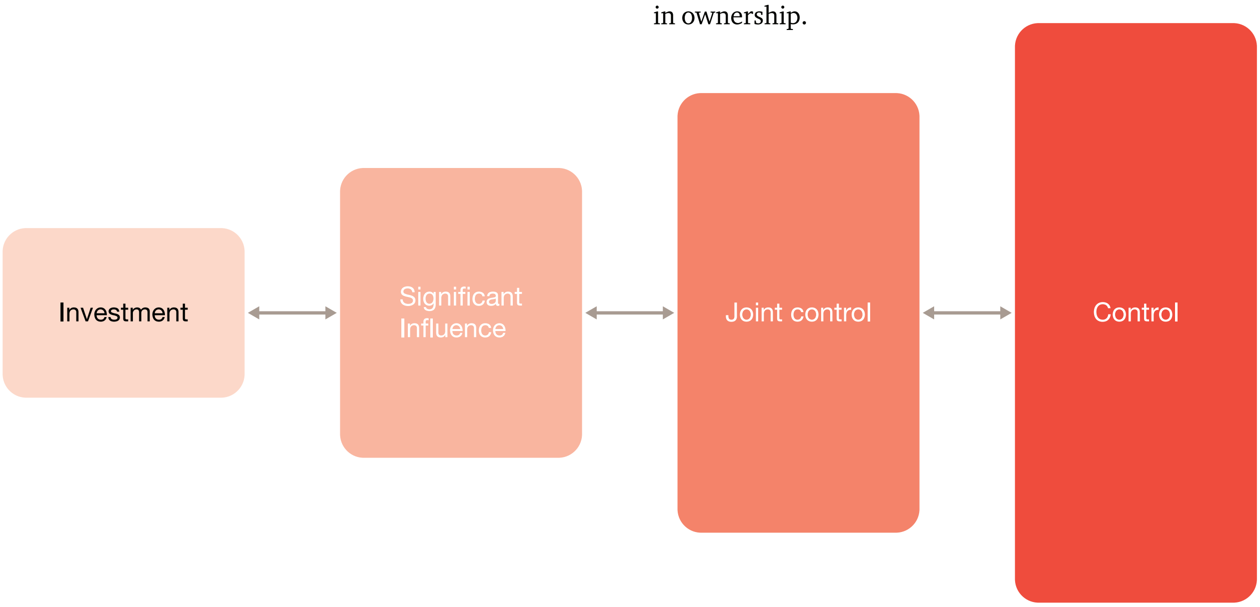
If an entity that doesn't qualify as a joint venture, each investor will account for its investment either using equity accounting in accordance with IAS 28 *Investments in Associates* (if it has significant influence) or at fair value as a financial asset in accordance with IAS 39.

Investors may have an undivided interest in the tangible or intangible assets; they will typically have a right to use a share of the operative capacity of that asset. An example is when a number of investors have invested in an oil pipeline and an investor with a 20% interest has the right to use 20% of the capacity of the pipeline. Industry practice is for an investor to recognise its undivided interest at cost less accumulated depreciation and any impairment charges.

An undivided interest in an asset is normally accompanied by a requirement to incur a proportionate share of the asset's operating and maintenance costs. 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.

4.2.9 Changes in ownership in a joint arrangement

A participant in a joint arrangement may increase or decrease its interest in the arrangement. The appropriate accounting for an increase or decrease in the level of interest in the joint arrangement will depend on the type of joint arrangement and on the nature of the new interest following the change in ownership.



Jointly controlled assets

The accounting for a change in the ownership will depend on whether the assets under the arrangement represent a business and the level of control which exists after the change in ownership. If the arrangement meets the definition of a business and control is obtained, this represents a business combination. The accounting for business combinations is discussed in section 4.1.4. If control is not obtained and the asset remains jointly controlled, the consideration paid for any additional interest is capitalised as the cost of that interest.

Reductions in the interest in jointly controlled assets will result in derecognising an amount of carrying value equivalent to the proportionate share disposed, regardless of whether joint control remains or not. A different approach may be applied in the case of reductions in interests which are accompanied by a promise by the purchaser to undertake work on the seller's remaining interest. This is usually described as a "farm out" and is discussed in more detail in section 4.2.11.

Jointly controlled operations

Entities own 100% of the respective assets they use within jointly controlled operations. It is unlikely that an entity could make a partial disposal of an asset it is using in a joint operation unless another party takes joint control of the asset. This would be accounted for in a similar manner to the interest reduction described above.

Jointly controlled entities

Accounting for increases in interest in a jointly controlled entity will depend on the level of control post acquisition. Where control is obtained, a business combination has taken place. The carrying amount previously recognised under equity accounting or proportionate consolidation would be derecognised, acquisition accounting applies and the entity would be fully consolidated. This would require a fair value exercise and measurement of non-controlling interest and goodwill. There may also be a gain or loss to recognise in the income statement.

A partial disposal of an equity accounted interest that results in no change in joint control or significant influence results in the entity derecognising a proportion of the carrying amount of the investment. It will recognise any gain or loss arising on the disposal in the income statement.

An entity which applied proportionate consolidation and retains joint control would derecognise a proportion of the assets and liabilities and also recognise a gain or loss in the income statement. If only significant influence is retained after the disposal then the entity derecognises the assets and liabilities in full. The entity will adopt equity accounting for the retained interest where it retains significant influence. If no significant influence is retained, the entity will recognise the retained interest at fair value as an available for sale ("AFS") investment.

4.2.10 *Accounting by the joint arrangement*

The preceding paragraphs describe the accounting by the investor in a joint venture. The joint venture itself will normally prepare its own financial statements for reporting to the joint venture partners and for statutory and regulatory purposes. It is increasingly common for these financial statements to be prepared in accordance with IFRS. Joint ventures are typically created by the venturers contributing assets or businesses to the joint venture in exchange for their equity interest in the JV. An asset contributed to a joint venture in exchange for issuing shares to a venturer is a transaction within the scope of IFRS 2 *Share-based Payment*. These assets are recognised at fair value in the financial statements of the joint arrangement. However, the accounting for the receipt of a business contributed by a venturer is not specifically addressed in IFRS as it is outside the scope of IFRS 2 and IFRS 3.

Two approaches have developed in practice. One is to recognise the assets and liabilities of the business, including goodwill, at fair value, similar to the accounting for an asset contribution and the accounting for a business combination. The second is to recognise the assets and liabilities of the business at the same book values as used in the contributing party's IFRS financial statements.

4.2.11 *Farm outs*

A "farm out" occurs when a venturer (the "farmor") assigns an interest in the reserves and future production of a field to another party (the "farmee"). This is often in exchange for an agreement by the farmee to pay for both its own share of the future development costs and those of the farmor. There may also be a cash payment made by the farmee to the farmor. This is a "farm in" when considered from the farmee's perspective. This typically occurs during the exploration or development stage and is a common method entities use to share the cost and risk of developing properties. The farmee hopes that their share of future production will generate sufficient revenue to compensate them for performing the exploration or development activity.

4.2.11.1 Accounting by the farmor

Farm out agreements are largely non-monetary transactions at the point of signature for which there is no specific guidance in IFRS. Different accounting treatments have evolved as a response. The accounting depends on the specific facts and circumstances of the arrangement, particularly the stage of development of the underlying asset.

Assets with proven reserves

If there are proven reserves associated with the property, the farm-in should be accounted for in accordance with the principles of IAS 16. The farm out will be viewed as an economic event, as the farmor has relinquished its interest in part of the asset in return for the farmee delivering a developed asset in the future. There is sufficient information for there to be a reliable estimate of fair value of both the asset surrendered and the commitment given to pay cash in the future.

The rights and obligations of the parties need to be understood while determining the accounting treatment.

The consideration received by the farmor in exchange for the disposal of their interest is the value of the work performed by the farmee plus any cash received. This is presumed to represent the fair value of the interest disposed of in an arm's length transaction.

The farmor should de-recognise the carrying value of the asset attributable to the proportion given up, and then recognise the "new" asset to be received at the expected value of the work to be performed by the farmee. After also recording any cash received as part of the transaction, a gain or loss is recognised in the income statement. The asset to be received is normally recognised as an intangible asset or "other receivable". When the asset is constructed, it is transferred to property, plant and equipment.

Assessing the value of the asset to be received may be difficult, given the unique nature of each development. Most farm out agreements will specify the expected level of expenditure to be incurred on the project (based on the overall budget approved by all participants in the field development). The agreement may contain a cap on the level of expenditure the farmee will actually incur. The value recognised for the asset will often be based on this budget. A consequence is that the value of the asset will be subject to change as the actual expenditure is incurred, with the resulting adjustments affecting the gain or loss previously recognised. The stage of development of the asset and the reliability of budgeting will impact the volatility of subsequent accounting.

Assets with no proven reserves

The accounting is not as clear where the mineral asset is still in the exploration or evaluation stage. The asset would still be subject to IFRS 6 'Exploration for and evaluation of mineral resources' rather than IAS 16. The reliable measurement test in IAS 16 for non-cash exchanges may not be met. Neither IFRS 6 nor IFRS 11 gives specific guidance on the appropriate accounting for farm outs.

Several approaches have developed in practice by farmors:

- recognise only any cash payments received and do not recognise any consideration in respect of the value of the work to be performed by the farmee and instead carry the remaining interest at the previous cost of the full interest reduced by the amount of any cash consideration received for entering the agreement. The effect will be that there is no gain recognised on the disposal unless the cash consideration received exceeds the carrying value of the entire asset held;
- follow an approach similar to that for assets with proven reserves, recognising both cash payments received and value of future asset to be received, but only recognise the future asset when it is completed and put into operation, deferring gain recognition until that point; or
- follow an approach similar to that for assets with proven resources, recognising both cash payments received and value of future asset to be received, and recognise future asset receivable when the agreement is signed with an accompanying gain in the income statement for the portion of reserves disposed of.

All three approaches are used today under current IFRS. There can be volatility associated with determining the value of the asset to be received as consideration for a disposal in a farm out of assets with proven resources. This volatility is exacerbated for assets which are still in the exploration phase. Prevalent industry practice follows the first approach outlined above.

4.2.11.2 Accounting by the farmee

The farmee will only recognise costs as incurred, regardless of the stage of development of the asset.

The farmee is required to disclose their contractual obligations to construct the asset and meet the farmor's share of costs.

The farmee should follow its normal accounting policies for capitalisation, and also apply them to those costs incurred to build the farmor's share.

Accounting for a farm out

Background

Company N and company P participate jointly in the exploration and development of an oil and gas deposit located in Venezuela. Company N has an 18% share in the arrangement, and Company B has an 82% share. Companies N and P have signed a joint venture agreement that establishes the manner in which the area should operate. N and P have a jointly controlled asset (JCA) under IAS 31. The jointly controlled asset comprises the oil and gas field, machinery and equipment. There are no proven reserves.

The companies have entered into purchase and sale agreements to each sell 45% of their participation to a new investor – Company R. Company N receives cash of C4 million and company P receives cash of C20 million. The three companies entered into a revised 'joint development agreement' to establish the rights and obligations of all three parties in connection with the funding, development and operations of the asset.

The composition of the interests of the three companies is presented in the table below:

	Company N	Company P	Company R	Total
Before transaction	18%	82%	-	100%
After transaction	10%	45%	45%	100%
Cash received	C4 million	C20 million	-	C24 million

Each party to the joint development agreement is liable in proportion to their interest for costs subsequent to the date of the agreement. However, 75% of the exploration and development costs attributable to companies N and P must be paid by company R on their behalf. The total capital budget for the exploration and development of the asset is C200 million. Company N's share of this based on their participant interest would be C20 million, however, Company R will be required to pay C15 million of this on behalf of Company N.

The carrying value of the asset in Company N's financial statements prior to the transaction was C3 million.

Question: How should company N account for such transaction?

Solution

This transaction has all the characteristics of a farm out agreement. The cash payments and the subsequent obligation of company R to pay for development costs on behalf of companies N and P appear to be part of the same transaction. Companies N and P act as farmors and company R acts as the farmee. The structure described also meets the definition of a JCA per IAS 31 as company N has joint control both before and after the transaction. Therefore company N should account for its share of the assets and liabilities and share of the revenue and expenses.

The gain on disposal could be accounted for by company N using one of three approaches, as follows:

1. Recognise only cash payments received.

Company N will reduce the carrying value of O&G asset by the C4 million cash received. The C1 million excess over the carrying amount is credited to the income statement as a gain. The C15 million of future expenditure to be paid by Company R on behalf of Company N is not recognised as an asset. As noted above, this approach would be consistent with common industry practice.

2. Recognise cash payments plus the value of the future assets at the agreement date.

Company N will recognise the C4 million as above. In addition, they will recognise a "receivable" or intangible asset for the future expenditure to be incurred by company R on company N's behalf, with a further gain of this amount recognised in the income statement. Company N would have to assess the expected value of the future expenditure. Although one method to estimate this would be the budgeted expenditure of C15 million, Company N would need to assess whether this would be the actual expenditure incurred. Any difference in the final amount would require revision to the asset recognised and also the gain, creating volatility in the income statement.

3. Recognise cash payment plus the value of future assets received when construction is completed.

Company N will recognise the C4 million cash received as in '1.' above. When the future assets are completed, these are recognised in the balance sheet, and a gain of the same amount recognised in the income statement. This approach would avoid the volatility issue associated with approach 2.

4.2.12 Unitisation agreements

Unitisation usually occurs in the exploration or development stage of O&G assets. Entities may own assets or exploration rights in adjacent areas, and enter into a contract to combine these into a larger area and share the costs of exploration, development and extraction. The entity will receive in exchange a share of the expected future output of the larger area. The unitised field is usually a joint operation. Unitisations are often required by governments to reduce the overall cost of extraction through a more efficient deployment of infrastructure.

The share of output allocated to each participant will depend on the contribution their existing asset made to the total production of this area. This is known as a "unitisation". A preliminary assessment of the allocated interest is made on the initial unitisation and the entity will be responsible for future expenditure for the area in accordance with its allocated interest. The interest will be subsequently amended as more certainty is obtained over the final output of each component and redeterminations are made. Adjustments to future production entitlement or cost contributions may be made accordingly. Cash payments may be made between the participants where the there is insufficient production or development remaining to true up contributions to date.

The initial unitisation is accounted for as a pooling of assets. No change is recorded in the carrying amount of existing interests unless cash payments have been made on unitisation. The value of the asset being received is equivalent to the value of the asset being given up. If a cash payment has been paid or received it is adjusted against the carrying value of the oil and gas asset. This will also be the case when a redetermination of the unitisation is performed.

The unitisations and redeterminations will also affect the relevant reserves base to be used for the purposes of the DD&A calculation. The carrying value of the oil and gas asset is depreciated over any revised share of reserves on a prospective basis. The entity will also be required to reassess the decommissioning obligation associated with the asset.

Redetermination of a unitisation

How should an entity account for a redetermination of a unitisation?

Background

Company A and B owned the adjoining oil prospects Alpha and Delta respectively. Both prospects were in the exploration phase with no proven reserves. The companies entered into an agreement to develop the prospects jointly and the combined area, Omega, which is considered to be a jointly controlled asset. The initial unitisation agreement stated that each was entitled to 50% of the output of the combined area. This allocation was subject to future redetermination when the exploration of Alpha and Delta was complete and proven reserves were determined. Additional redetermination would take place on an ongoing basis after that as production commenced and reserve estimates were updated.

The exploration of the two prospects was completed. Both were found to have proven reserves and based on these results the following redetermination was performed:

	Company A	Company B	Total
Initial unitisation	50%	50%	
Redetermination	40%	60%	
Exploration cost to date	C5 million	C5 Million	C10 million
Future development expenditure			C40 million

The companies have agreed that they will take a share of future production in line with the new determination of interests. Additionally, the true-up of costs incurred to date will be made via adjustments to future expenditure rather than an immediate cash payment.

Prior to redetermination Company A had capitalised the C5 million cost incurred as an exploration asset, and transferred this to tangible assets when proven reserves were discovered. How should Company A account for this redetermination?

Solution

Company A has incurred expenditure of C1 million greater than the share required by the revised allocation of interest. In theory, they have a C1 million receivable from Company B. The agreement between the companies indicates that this will be trued-up via adjustment to future development expenditure i.e., Company A will only be responsible for C15 million of future spend rather than C16 million (C40 million*40%). Therefore, it would be appropriate for Company A to retain this C5 million asset as a development asset with no adjustment for the C1 million. They should consider whether the change in the reserve estimates indicates any impairment has occurred in the carrying value of the asset. Based on the revised share of future production and the development costs still to come, impairment would be unlikely.

4.3 Production Sharing Agreements (PSAs)

4.3.1 Overview

A PSA is the method whereby governments facilitate the exploitation of their country's hydrocarbon resources by taking advantage of the expertise of a commercial oil and gas entity. Governments 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. There are as many forms of production sharing arrangements (PSA) and royalty agreements as there are combinations of national, regional and municipal governments in oil producing areas.

An oil and gas entity in a typical PSA will undertake exploration, supply the capital, develop the resources found, build the infrastructure and lift the natural resources. The oil and gas entity (usually referred to as the operator) will have the right to extract resources over a specified period of time; this is typically the full production life of the field such that there would be minimal residual value of the asset at the end of the PSA. The terms of the PSA are likely to include asset decommissioning requirements. The oil and gas entity will be entitled to a share of the oil produced which will allow the recovery of specified costs ("Cost oil") plus an agreed profit margin ("Profit oil"). The government will retain title to all of the hydrocarbon resources and often the legal title to all fixed assets constructed to exploit the resources.

The residual value of the fixed assets in most cases would be minimal and the operator would decommission them under the terms of the PSA. The company is viewed as having acquired the right to extract the oil in the future when it performs the development work under the PSA. The development expenditure is capitalised according to the requirements of IFRS 6 and IAS 16.

The government will take a substantial proportion of the output in PSAs. The oil may be delivered in product or paid in cash under an agreed pricing formula.

An entity should consider its overall risk profile in determining whether it has a service agreement or a working interest. Certain PSA may be more like service arrangements whereby the government compensates the entity for exploration, development and construction activities. These are arrangements where the PSA is substantially shorter than the expected useful life of the production asset or are explicit cost plus arrangements. The entity thus bears the risks of performing this contract rather than traditional exploration and development risks. Expenditure incurred on the exploration and development plus a profit margin is usually capitalised as a receivable from the government rather than an interest in the future production of the field.

A concession or royalty agreement is much the same as a PSA arrangement where the entity bears the exploration risk. The entity will usually retain legal title to its assets and does not directly 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. PSAs and concession agreements are not standard even within 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 PSA must 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 royalty agreements based on changes in market conditions or environmental factors.

The PSA 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 considered when estimating the life of the agreement.

The legal form of the PSA or concession should not impact the principles underpinning the recognition of exploration and evaluation (E&E) assets or production assets. Costs that meet the criteria of IFRS 6, IAS 38 or IAS 16 should be recognised in accordance with the usual accounting policies where the entity is exposed to the majority of the economic risks and has access to the probable future economic benefits of the assets. The revenue project and any clarification provided of the definition of a customer may have an effect on the accounting for PSAs. A final standard is not expected to be completed until 2012 at the earliest.

4.3.2 Entity bears the exploration risk

4.3.2.1 Cost capitalisation

The entity follows a similar approach to non-PSA projects when it bears the exploration risk of the contract. It will capitalise expenditure in the exploration and development phase in accordance with the requirements of IFRS 6, IAS 16 and IAS 38.

The reserves used for depreciating the constructed assets should be those attributable to the reporting entity for the period of the PSA or concession. The probable hydrocarbon resources and current prices should provide evidence that E&E, development and fixed asset investment will be recovered during the concession period.

A PSA is usually a separate CGU for impairment testing purposes once in production. The entity tests for impairment during the exploration and evaluation phase using the guidance in IFRS 6. Once in the development and production phases the guidance in IAS 36 applies.

Offshore field PSA for 25 years

The legal form of the PSA should not impact the recognition of exploration and evaluation (E&E) assets or production assets. How should those assets be accounted for?

Background

Entity A is party to a PSA related to an offshore field. The term of the agreement is 25 years. Entity A will operate the assets during the term of the PSA but the government retains title to the assets constructed. A is entitled to full cost recovery. However, if the resources produced in the future do not cover the costs incurred the government will not reimburse A.

Entity A's management proposes to account for the expenditure as a financial receivable rather than as property, plant and equipment because the government is retaining the title of the assets constructed. Is this appropriate?

Solution

No. Entity A controls the assets during the life of the PSA through its right to operate them. The construction costs that meet the recognition criteria of IFRS 6, IAS 38 or IAS 16 should be recognised in accordance with those standards:

- where the entity is exposed to the majority of the economic risks and has access to the probable future economic benefits of the assets, and
- the period of the PSA is longer than the expected useful life of the majority of the constructed assets, and
- the probable mineral resources at current prices provide evidence that E&E, development and fixed asset investment will be recovered through the cost recovery regime of the PSA.

All assets recognised are then accounted for under entity A's usual policies for subsequent measurement, depreciation, amortisation, impairment testing and de-recognition. The assets should be fully depreciated or amortised on a units-of-production basis by the date that the PSA ends.

4.3.2.2 Revenue recognition

In PSAs where an entity bears the exploration risk it will record its share of oil or gas as revenue (both cost oil and profit oil) only when the oil or gas is produced and sold.

The entity records revenue only when oil production commences and only to the extent of the oil to which it is entitled and sells. 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.

An entity follows the same approach to revenue recognition for royalty agreements.

Revenue in PSAs (1)

How is revenue recognised under a PSA?

Background

The upstream company (or contractor) typically bears all the costs and risks during the exploration phase. The government (or the government-owned oil company) shares in any production. The upstream company generally receives two components of revenue; cost oil and profit oil. Cost oil is a 'reimbursement' for the costs incurred in the exploration phase and some (or all) of the costs incurred during the development and production phase. Profit oil is the company's share of oil after cost recovery or as a result of applying a profit factor. The PSA typically specifies, among other items, which costs are recoverable, the order of recoverability, any limits on recoverability, and whether costs not recovered in one period can be carried forward into a future period.

Total revenue of the PSA is recognised upon the delivery of the volumes produced to a third party (i.e., the purchaser of the volumes) based on the price as set forth in the PSA. The price could be either a market based price or a fixed price depending on the specific terms of the PSA. The revenue of the PSA is then split between the parties based on the specific sharing terms of the PSA. The formation of a PSA does not commonly create an entity that would qualify as a joint venture under IFRS.

The issue is not usually recognition of revenue – the oil has been delivered to third parties and the criteria in IAS 18 paragraph 14 are met. The question is how the revenue from oil sold should be split between the operator, the government oil company and any others.

Solution

The operator is entitled to the oil it has earned as reimbursement for costs (exploration and its share of development and production) and its share of profit oil. The government's share of oil does not form part of revenue even if the operator collects the funds and remits them to the government oil company. Any royalties or excise taxes that are collected on behalf of the government or any other agency of the state do not form revenue of the operator because of the explicit guidance in IAS 18 paragraph 8.

Revenue in PSAs (2)

How is revenue in a PSA split between the participating interests?

Solution

The example below sets out how the revenue from a PSA is split between the operator, the government oil company and the taxation authorities. The government's royalty is 10% of production, the operator has a profit share of 55% and the government oil company's share is 45%. Cost oil is limited to 60% after the government's royalty; any unrecovered costs can be carried forward to future years.

Cost oil components in order of priority are:
1) Operating expenses (share based on profit share,
2) Exploration costs (all incurred by the operator),
3) Development costs (share based on profit share percentage) and
4) Profit oil.

Assumptions:

Exploration costs incurred	$ 50,000
Development costs incurred in Y1	$ 80,000
Operating costs in Y1	$450,000
Production volumes (same as volumes sold)	30,000
Price	$ 97.00

	Total	Gov	Upstream com	GOE
Revenue	$2,910,000			100%
Royalty (10%)	$291,000	$291,000		
Remaining	$2,619,000			
Limit on cost oil (60%)	$1,571,400			
Cost oil:				
Operating	$450,000		$247,500	$202,500
Exploration	$50,000		$50,000	
Development	$80,000		$44,000	$36,000
Total cost oil	$580,000		$341,500	$238,500
Profit oil	$2,039,000		$1,121,450	$917,550
Total revenue	$2,910,000	$291,000	$1,462,950	$1,156,050
Applicable volumes	30,000	3,000	15,082	11,918

The above example is a simple example of the allocation methodology. The applicable volumes are determined by dividing the allocated revenue by the price of the volumes sold.

4.3.3 Entity bears the contractual performance risk

4.3.3.1 Cost capitalisation criteria

Under arrangements where the entity is largely bearing the risks of its performance under the PSA rather than the risks of the exploration and the reserves, it can continue to capitalise E&E and development costs, but although the costs of constructing the fixed assets are capitalised, they are not classified as PPE. The entity instead would have a receivable from the government where it is allowed to retain oil extracted to the extent of costs incurred plus a profit margin. The accounting applied in these circumstances is therefore in accordance with IAS 39/IFRS 9 rather than IAS 16.

4.3.3.2 Impairment assessment

The asset recognised will be accounted as a receivable. Therefore, the impairment testing rules on financial assets in IAS 39/IFRS 9 would be applicable.

4.3.3.3 Revenue recognition

Where it is concluded that the entity bears the risks of performing this contract rather than the actual exploration activity, expenditure incurred on the exploration and development of the asset is capitalised as a receivable from the government rather than as a fixed asset. When the outcome of the contract can be reliably estimated, the percentage of completion method will be used to determine the amount of revenue to be recognised. The expected profit margin will be included in this calculation.

Revenue in PSAs (3)

Background

Government 'V' believes they might find oil reserves on the western coast of the country, designated 'Beta'. After the process, entity 'A' was awarded with the offshore block. The government and company A signed a 15 year PSA to explore develop and exploit this block under the following terms:

- Company 'A' will undertake exploration, development and production activities. Government 'V' will remunerate A for performance of the contracted construction services regardless of the success of the exploration and hold title to the assets constructed.
- National law indicates that the title of all hydrocarbons found in the country remains with government 'V'.
- Government 'V' will reimburse for all expenditures incurred by Company 'A' at the following milestones:
  - Completion of seismic study program
  - Approval of exploration work program
  - Completion of development work program
  - Commencement of commercial production

- Reimbursement is based on approved costs incurred plus an uplift of 5%.

- Reimbursement will be performed in the form of oil produced. Quantities provided will be based on market price. Where insufficient quantities are produced, the government can settle the amount due in cash or oil from another source.

How will entity 'A' recognise revenue on this project?

Solution

The terms of the agreement are such that Company A carries a "contract performance" risk rather than bearing the risk of exploration. Accordingly, costs will be capitalised as a recoverable from the government. There are multiple performance obligations within the agreement, and the company can only recognise revenue as each of these obligations is achieved. As the terms provide that approved costs can be recovered with a 5% uplift, the company will initially carry the costs incurred as work in progress. When the entity is able to reliably estimate the outcome of the contract, they may use the percentage of completion method recognise revenue, which will include the expected uplift of 5% on costs incurred.

4.3.4 Decommissioning in PSAs

Section 4.4 explains that decommissioning of oil and gas production assets may be required by law, the terms of operating licences or an entity's stated policy and past practice. All of these create an obligation and thus a liability under IFRS.

PSAs sometimes require a decommissioning fund be created with the objective of settling decommissioning costs to be incurred in the future. The PSA may require contributions to these funds be made by participating entities on an annual basis until the date of decommissioning or allow them to be made on a voluntary basis prior to the decommissioning date.

The decommissioning arrangements can have a number of structures:

- The operating entity is expected to perform the decommissioning activity using the established fund;
- The participating entities are required to pay for the decommissioning activity and claim for reimbursement from the fund; and
- The government has the right to take control of the asset at the end of the PSA term (there may still be reserves to produce), take over the decommissioning obligation and be entitled to the decommissioning fund established.

IFRIC 5 is applicable to funds which are both administered separately and where the contributor's right to access the assets is restricted.

The participants should recognise their obligation to pay the decommissioning costs as a liability and recognise their interest in the decommissioning fund separately. They should determine the extent of their control over the fund (full, joint or significant influence) and account for their interest in the fund in accordance with the relevant accounting standard.

4.3.5 Taxes on PSAs

A crucial question arises about the taxation of PSAs – when are amounts paid to the government as an income tax (part of revenue), when are amounts a royalty (excluded from revenue) and when are amounts to be treated as a production cost. 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?

4.3.5.1 Classification as income tax or royalty

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 net 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.

Classification of profit oil as income tax or royalty (1)

The upstream company or operator generally receives two components of revenue, most often described as cost oil and profit oil. Cost oil is calculated as a 'reimbursement' for the costs incurred in the exploration phase and some (or all) of the costs incurred during the development and production phase. Profit oil is the company's share of oil after cost recovery or as a result of applying a profit factor. The PSA typically specifies, among other items, which costs are recoverable, the order of recoverability, any limits on recoverability, and whether costs not recovered in one period can be carried forward into a future period (see Example in section 4.3.2.2 for a worked example).

Is a share of profit oil an income tax or royalty?

Background

Mammoth Oil has a PSC in Small Republic in Africa. The PSC agreement calls for a 10% royalty of gross proceeds of all revenue to be paid to the Ministry of Taxation. The cost oil is calculated as 10% of exploration costs, plus 10% of costs of production assets plus all current operating costs subject to a ceiling. The profit oil is then split 50% to Mammoth and 50% to the National Oil Company. The PSC calls for a further payment to the National Oil Company if Mammoth's share of profit oil exceeds its cost oil and is calculated at 10% of the excess in these circumstances.

Management has deemed the further payment as an income tax because it is calculated on a formula that includes items described as profit and costs. The amounts are included in revenue and income tax expense. Is this treatment appropriate?

Solution

No. The further payment to the National Oil Company is simply a further apportionment of the profit oil and thus is excluded from revenues. It may be described as an 'income tax' in the PSC but it is not an income tax as described in IAS 12 (revised).

Classification of profit oil as income tax or royalty (2)

The upstream company or operator generally receives two components of revenue, most often described as cost oil and profit oil. Cost oil is calculated as a 'reimbursement' for the costs incurred in the exploration phase and some (or all) of the costs incurred during the development and production phase. Profit oil is the company's share of oil after cost recovery or as a result of applying a profit factor. The PSC typically specifies, among other items, which costs are recoverable, the order of recoverability, any limits on recoverability, and whether costs not recovered in one period can be carried forward into a future period (see example in section 4.3.2.2 for a worked example).

Is a share of profit oil an income tax or royalty?

Background

Mammoth Oil has a PSC in Utopia. The PSC agreement calls for a 10% royalty of gross proceeds of all revenue to be paid to the Ministry of Taxation. The cost oil is calculated as 10% of exploration costs, plus 10% of costs of production assets plus all current operating costs subject to a ceiling. The profit oil is then split 50% to Mammoth and 50% to the National Oil Company.

The PSC is explicit that the operations of Mammoth Oil in Utopia are subject to the tax rules and regulation of Utopia. The company files a tax return and pays income tax under the normal tax rules. The tax regulations include a 10% surcharge on any income tax that is due under the ordinary tax rules. The PSC requires the National Oil Company to pay this surcharge on behalf of Mammoth and notify Mammoth that it has been paid. The tax counsel of Mammoth has legal advice that Mammoth is liable for the tax until it is paid; if the National Oil Company does not pay, Mammoth must pay the tax and then attempt to recover it from National Oil Company.

Management has deemed this an income tax and is including it in revenue and income tax expense.

Solution

Yes. The payment by the National Oil Company qualifies as an income tax. It is based on taxable profits as defined in the tax code. Mammoth is liable for the tax until it is paid by National Oil Company. It is appropriately included revenues and income tax expense. The tax rate used to calculate deferred tax assets and liabilities should include the amount of the tax surcharge. The fact that the government calls the payment "a royalty" does not determine the accounting; it is the nature of the payment that is relevant to its classification.

4.3.5.2 Tax paid in kind

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. Volume-based levies are usually accounted for as royalty or excise tax within operating results. See section 4.6 for further details.

4.3.5.3 'Tax paid on behalf' ("POB")

POBs can arise under a PSA where the upstream entity is the operator of fields and the government entity is the national oil company that holds the government's interest in the PSA. POB arrangements are varied, but generally arise when the government entity will pay the income tax due by the foreign upstream entity to the government on behalf of the foreign upstream entity. The crucial issue in accounting for tax POB arrangements is to determine if they are akin to a tax holiday or if the upstream entity retains an obligation for the income tax. POB arrangements that represent a tax holiday such that the upstream company has no legal tax obligation are accounted for as a tax holiday. The upstream company, under a tax holiday scenario, presents no tax expense and does not gross up revenue for the tax paid on its behalf by the government entity. If the upstream company retains an obligation for the income tax, it would follow the accounting described in section 4.6.3 *Taxes paid in cash or in kind*.

4.4 Decommissioning

The oil and gas industry can have a significant impact on the environment. Decommissioning or environmental restoration work at the end of the useful life of a plant or other installation may be required by law, the terms of operating licences or an entity's stated policy and past practice.

An entity that promises to remediate damage or has done so in the past, even when there is no legal requirement, may have created a constructive obligation and thus a liability under IFRS. There may also be environmental clean-up obligations for contamination of land that arises during the operating life of an installation. The associated costs of remediation/restoration can be significant. The accounting treatment for decommissioning costs is therefore critical.

4.4.1 Decommissioning provisions

A provision is recognised when an obligation exists to perform the clean-up [IAS 37 para 14]. The local legal regulations should be taken into account when determining the existence and extent of the obligation. Obligations to decommission or remove an asset are created at the time the asset is put in place. An offshore drilling platform, for example, must be removed at the end of its useful life. The obligation to remove it arises from its placement. However, there is some diversity in practice as to whether the entire expected liability is recognised when activity begins, or whether it is recognised in increments as the development activity progresses. There is also diversity in whether decommissioning liabilities are recognised during the exploration phase of a project. The asset and liability recognised at any particular point in time needs to reflect the specific facts and circumstances of the project and the entity's obligations.

Decommissioning provisions are measured at the present value of the expected future cash flows that will be required to perform the decommissioning [IAS 37 para 45]. The obligation does not change in substance if the platform produces 10,000 barrels or 1,000,000.

The cost of the provision is recognised as part of the cost of the asset when it is put in place and depreciated over the asset's useful life [IAS 16 para 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 (typically UoP). Provisions for decommissioning and restoration are recognised even if the decommissioning is not expected to be performed for a long time, for example 80 to 100 years.

The effect of the time to expected decommissioning will be reflected in the discounting of the provision. The discount rate used is the pre-tax rate that reflects current market assessments of the time value of money. Entities also need to reflect the specific risks associated with the decommissioning liability. Different decommissioning obligations will, naturally, have different inherent risks, for example different uncertainties associated with the methods, the costs and the timing of decommissioning. The risks specific to the liability can be reflected either in the pre-tax cash flow forecasts prepared or in the discount rate used. The future cash flows expected to be incurred in performing the decommissioning may be denominated in a foreign currency. When this is relevant the foreign currency future cash flows are discounted at a discount rate relevant for that currency. The present value is translated into the entity's functional currency using the exchange rate at the balance sheet date.

4.4.2 Revisions to decommissioning provisions

Decommissioning provisions are updated at each balance sheet date for changes in the estimates of the amount or timing of future cash flows and changes in the discount rate [IAS 37 para 59]. This includes changes in the exchange rate when some or all of the expected future cash flows are denominated in a foreign currency. Changes to provisions that relate to the removal of an asset are added to or deducted from the carrying amount of the related asset in the current period [IFRIC 1 para 5]. However, the adjustments to the asset are restricted. The asset cannot decrease below zero and cannot increase above its recoverable amount [IFRIC 1 para 5]:

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

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

4.4.3 Deferred tax on decommissioning provisions

The amount of the asset and liability recognised at initial recognition of decommissioning are generally viewed as being outside the scope of the current 'initial recognition exemption' in IAS 12 [para 15 and 24]. The amount of accretion in the provision from unwinding of the discount gives rise to a book/tax difference and will result in a further deferred tax asset, subject to an assessment of recoverability. The IFRS IC considered a similar question at its April and June 2005 meetings of whether the IAS 12 IRE applied to the recognition of finance leases. IFRS IC acknowledged that there was diversity in practice in the application of the IRE 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 IRE should 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 [IAS 8 (revised) para 13].

4.5 Impairment of development, production and downstream assets

4.5.1 Overview

The oil and gas industry is distinguished by the significant capital investment required and volatile commodity prices. The heavy investment in fixed assets leaves the industry exposed to adverse economic conditions and therefore impairment charges.

Oil and gas assets should be tested for impairment whenever indicators of impairment exist [IAS 36 para 9]. The normal measurement rules for impairment apply to assets with the exception of the grouping of E&E assets with existing producing cash generating units ("CGUs") as described in section 2.3.7.

Impairments are recognised if a CGU's carrying amount exceeds its recoverable amount [IAS 36 para 6]. Recoverable amount is the higher of fair value less costs to sell ("FVLCTS") and value in use ("VIU").

4.5.2 Impairment indicators

Entities must use judgement in order to assess whether an impairment indicator has occurred. If an impairment indicator is concluded to exist, IAS 36 requires that the entity perform an impairment test.

Impairment triggers relevant for the petroleum sector include declining long-term market prices for oil and gas, significant downward reserve revisions, increased regulation or tax changes, deteriorating local conditions such that it may become unsafe to continue operations and expropriation of assets.

Impairment indicators (1)

Would a decline in market prices of oil and gas be an indicator of impairment?

Background

An entity has producing oil and gas fields. There has been a significant decline in the prices of oil and gas during the last six months.

Is such decline in the prices of oil and gas an indicator of impairment of the field?

Solution

Not automatically. The nature of oil and gas assets is that they often have a long useful life. Commodity price movements can be volatile and move between troughs and spikes.

Price reductions can assume more significance over time. If a decline in prices is expected to be prolonged and for a significant proportion of the remaining expected life of the field, an impairment indicator will have occurred.

Short term market fluctuations may not be impairment indicators if prices are expected to return to higher levels within the near future. Such assessments can be difficult to make, with price forecasts becoming difficult where a longer view is taken. Entities should approach this area with care. In particular, entities should consider any downward movements carefully for fields which are high cost producers.

Impairment indicators (2)

Might a change in government be an indicator of impairment?

Background

An upstream company has a production sharing contract (PSC) in a small country in equatorial Africa. The company's investment in the PSC assets is substantial. There is a coup in the country and the democratically elected government is replaced by a military regime. Management of the national oil company (NOC), partner in the PSC, is replaced. The NOC has been paying income tax on behalf of the operator of the PSC.

New management of the NOC announces that it will no longer pay the income taxes on behalf of the operator. The operator will be required to pay income taxes and the petroleum excess profits tax from its share of the PSC profit oil. The combined effective tax rate is 88%.

The operator of the PSC expects that operating costs will increase principally due to increased wages and bonuses for expatriate employees and not be recovered under the terms of the PSC.

Does the change in government constitute an indicator of impairment?

Solution

Yes. The change in government is a change in the legal and economic environment that will have a substantial negative impact on expected cash flows. The PSC assets should be tested for impairment.

Impairment indicators can also be internal in nature. Evidence that an asset or CGU has been damaged or become obsolete is likely to be an impairment indicator; for example a refinery destroyed by fire is, in accounting terms, an impaired asset. Changes in development costs, such as a well requiring significant rework, or significantly increased decommissioning costs may also be impairment indicators. Other common indicators are a decision to sell or restructure a CGU or evidence that business performance is less than expected.

Management should be alert to 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. However, generally, management is likely to identify impairment indicators on a regional or area basis, reflective of how they manage their business. Once an impairment indicator has been identified, the impairment test must be performed at the individual CGU level, even if the indicator was identified at a regional level.

4.5.3 Cash generating units

A CGU is the smallest group of assets that generates cash inflows largely independent of other assets or groups of assets [IAS 36 para 6]. A field and its supporting infrastructure assets in an upstream entity will often be identified as a CGU. Production, and therefore cash flows, can be associated with individual wells. However, the field investment decision is made based on expected field production, not a single well, and all wells are typically dependent on the field infrastructure. An entity operating in the downstream business may own petrol stations, clustered in geographic areas to benefit from management oversight, supply and logistics. The petrol stations, by contrast, are not dependent on fixed infrastructure and generate largely independent cash inflows.

Identifying the CGU (1)

What is the CGU in upstream oil and gas operations?

Background

Entity GBO has upstream operations in a number of locations around the world. The majority of operations are in production sharing contracts for single fields or major projects. However it owns a number of properties in the Gulf of Mexico. The fields are supported by a shared loading platform and connected to a pipeline to the loading platform.

Management considers that the CGU for impairment testing purposes is a region or country. Is management's proposal appropriate?

Solution

No. Each field is generally capable of generating cash inflows largely independently from the other fields. It is unlikely that an outage on one field would require the shut-down of another field. However where this would be the case then it would be appropriate to group such fields together.

The Gulf of Mexico fields might meet this criterion if all depend on the shared loading platform to generate future cash flows. Thus if all these fields would have to be shut down if the shared loading platform was out of operation, then it could be argued that the fields it serves do not generate cash flows independently from each other. However, if alternative loading facilities are readily available, then each field should be treated as a separate cash generating unit and the shared loading platform should be treated as a common asset and allocated to each CGU.

Identifying the CGU (2)

What is the CGU in retail petroleum operations?

Background

The company owns retail petrol stations across Europe. It monitors profitability on 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.

Station and regional managers are compensated based on performance of their station or stations, cash flow and profitability information is available at the level of the individual stations.

Management considers that the CGU for impairment testing purposes is a region or country. Is management's proposal appropriate?

Solution

No. The regions and countries are not CGUs. The lowest level at which largely separate cash flows are generated is at the level of an individual petrol station. Management assesses business performance on a station specific basis to compensate station managers and on a regional basis to assess return on investment incorporating shared infrastructure assets.

When impairment testing is required because of the presence of impairment indicators, petrol stations should be individually tested for impairment. The cash flows of the stations are then grouped for the purposes of assessing impairment of shared infrastructure assets.

4.5.4 *Shared assets*

Several fields located in the same region may share assets (for example, pipelines to transport gas or oil onshore, port facilities or processing plants). Judgement is involved in determining how such shared assets should be treated for impairment purposes. Factors to consider include:

- whether the shared assets generate substantial cash flows from third parties as well as the entity's own fields – if so, they may represent a separate CGU
- how the operations are managed

Any shared assets that do not belong to a single CGU but relate to more than one CGU still need to be considered for impairment purposes. There are two ways to do this and management should use the method most appropriate for the entity. Shared assets can be allocated to individual CGUs or the CGUs can be grouped together to test the shared assets.

Under the first approach, the assets should be allocated to each individual CGU or group of CGUs on a reasonable and consistent basis. The cash flows associated with the shared assets, such as fees from other users and expenditure, forms part of the cash flows of the individual CGU.

The second approach has the group of CGUs that benefit from the shared assets grouped together to test the shared assets. The allocation of any impairment identified to individual CGUs should be possible for shared assets used in the processing or transportation of the output from several fields and, for example, could be allocated between the fields according to their respective reserves/resources.

4.5.5 *Fair value less costs to sell ("FVLCTS")*

Fair value less costs to sell is the amount that a market participant would pay for the asset or CGU, less the costs of sale. The use of discounted cash flows ("DCF") for FVLCTS is permitted where there is no readily available market price for the asset or where there are no recent market transactions for the fair value to be determined through a comparison between the asset being tested for impairment and a recent market transaction.

FVLCTS is less restrictive in its application than VIU and can be easier to work with. It is more commonly used in practice, particularly for recently-acquired assets. The underlying assumptions in a FVLCTS model are usually, but not always, closer to those that management have employed in their own forecasting process. The output of a FVLCTS calculation may feel intuitively more correct to management.

The assumptions and other inputs used in a DCF model for FVLCTS should incorporate observable market inputs as much as possible. The assumptions should be both realistic and consistent with what a typical market participant would assume. Assumptions relating to forecast capital expenditures that enhance the productive capacity of a CGU can therefore be included in the DCF model, but only to the extent that a typical market participant would take a consistent view.

The amount calculated for FVLCTS is a post-tax recoverable amount. It is therefore compared against the carrying amount of the CGU on an after-tax basis; that is, after deducting deferred tax liabilities relating to the CGU/group of CGUs. This is particularly relevant in upstream businesses when testing goodwill for impairment. A major driver of goodwill in upstream acquisitions is the calculation of deferred tax on the reserves and resources acquired. Marginal tax rates in the 80 to 90% region are not unheard of, thus the amount of goodwill can be substantial. The use of FVLCTS can alleviate the tension of substantial goodwill associated with depleting assets.

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

4.5.6 *Value in use ("VIU")*

VIU is the present value of the future cash flows expected to be derived from an asset or CGU in its current condition [IAS 36 para 6]. Determination of VIU is subject to the explicit requirements of IAS 36. The cash flows are based on the asset that the entity has now and must exclude any plans to enhance the asset or its output in the future but include expenditure necessary to maintain the current performance of the asset [IAS 36 para 44]. The VIU cash flows for assets that are under construction and not yet complete (e.g., an oil or gas field that is part-developed) should include the cash flows necessary for their completion.

The cash flows used in the VIU calculation are based on management's most recent approved financial budgets/forecasts. The assumptions used to prepare the cash flows should be based on reasonable and supportable assumptions. Assessing whether the assumptions are reasonable and supportable is best achieved by benchmarking against market data or performance against previous budgets.

The discount rate used for VIU is pre-tax and applied to pre-tax cash flows [IAS 36 par 55]. This is often the most difficult element of the impairment test, as pre-tax rates are not available in the market place. Arriving at the correct pre-tax rate is a complex mathematical exercise. Computational short cuts are available if there is a significant amount of headroom in the VIU calculation. However, grossing up the post tax rate seldom gives an accurate estimate of the pre-tax rate.

4.5.6.1 Period of projections

The cash flow projections used to determine VIU can include specific projections for a maximum period of five years, unless a longer period can be justified. A longer period will often be appropriate for oil and gas assets based on the proven and probable reserves and expected annual production levels. After the five year period a VIU calculation should use assumptions consistent with those used in the final period of specific assumptions to arrive at a terminal value. Assumptions on the level of reserves expected to be produced should be consistent with the latest estimates by reserve engineers, annual production rates should be consistent with those for the preceding five years, and price and cost assumptions should be consistent with the final period of specific assumptions.

4.5.6.2 Commodity prices in VIU

Estimates of future commodity prices will need to be included in the cash flows prepared for the VIU calculation. Management usually takes a longer term approach to the commodity price; this is not always consistent with the VIU rules. Spot prices are used unless there is a forecast price available as at the impairment test date. In the oil and gas industry there are typically forward price curves available and in such circumstances these provide a reference point for forecast price assumptions. Those forecast prices should be used for the future periods covered by the VIU calculation. Where the forward price curve does not extend far enough into the future, the price at the end of the forward curve is generally held steady, unless there is a compelling reason to adjust it.

The future cash flows relating to the purchase or sale of commodities might be known from forward purchase or sales contracts. Use of these contracted prices in place of the spot price or forward curve price for the contracted quantities will generally be appropriate. However, some forward purchase and sales contracts will be accounted for as derivative contracts at fair value in accordance with IAS 39 and are recognised as current assets or liabilities. They are therefore excluded from the IAS 36 impairment test. The cash flow projections used for the VIU calculation should exclude the pricing terms of the sales and purchase contracts accounted for in accordance with IAS 39.

4.5.6.3 Foreign currencies in VIU

Foreign currencies may be relevant to impairment testing for two reasons:

(a) When all the cash flows of a CGU are denominated a single currency that is not the reporting entity's functional currency; and
(b) When the cash flows of the CGU are denominated in more than one currency.

(a) CGU cash flows differ from entity's functional currency

All future cash flows of a CGU may be denominated in a single currency, but one that is different from the reporting entity's functional currency. The cash flows used to determine the recoverable amount are forecast in the foreign currency and discounted using a discount rate appropriate for that currency. The resulting recoverable amount is translated into the entity's functional currency at the spot exchange rate at the date of the impairment test [IAS 36.54].

(b) CGU cash flows are denominated in more than one currency

Some of the forecast cash flows may arise in different currencies. For example, cash inflows may be denominated in a different currency from cash outflows. Impairment testing involving multiple-currency cash flows can be complex and may require consultation with specialists.

The currency cash flows for each year for which the forecasts are prepared should be translated into a single currency using an appropriate exchange rate for the time period. The spot rate may not be appropriate when there is a significant expected inflation differential between the currencies. The forecast net cash flows for each year are discounted using an appropriate discount rate for the currency to determine the net present value. If the net present value has been calculated in a currency different from the reporting entity's functional currency, it is translated into the entity's functional currency at the spot rate at the date of the impairment test [IAS 36.54].

The use of the spot rate, however, can generate an inconsistency, to the extent that future commodity prices denominated in a foreign currency reflect long-term price assumptions but these are translated into the functional currency using a spot rate. This is likely to have the greatest impact for operations in countries for which the strength of the local currency is significantly affected by commodity prices. Where this inconsistency has a pronounced effect, the use of FVLCTS may be necessary.

4.5.6.4 Assets under construction in VIU

The VIU cash flows for assets that are under construction and not yet complete should include the cash flows necessary for their completion and the associated additional cash inflows or reduced cash outflows. An oil or gas field that is part-developed is an example of a part-constructed asset. The VIU cash flows should therefore include the cash flows to complete the development to the extent that they are included in the original development plan and the associated cash inflows from the expected sale of the oil and gas.

4.5.7 Interaction of decommissioning provisions and impairment testing

Decommissioning provisions and the associated cash flows can be either included or excluded from the impairment test, provided the carrying amount of the asset and the cash flows are treated consistently. IAS 36 requires the carrying amount of a liability to be excluded from the carrying amount of a CGU unless the recoverable amount of the CGU cannot be determined without consideration of that liability [IAS 36.76, 78]. This typically applies when the asset/CGU cannot be separated from the associated liability.

Decommissioning obligations are closely linked to the asset that needs to be decommissioned, although the cash flows associated with the asset may be independent of the cash flows of the decommissioning liability. If the carrying value of the decommissioning provision is included in the carrying amount of the CGU, the estimated future cash outflows are included in the DCF model used to determine recoverable amount. However, if the carrying amount is excluded, the cash flows should also be excluded.

Interaction of decommissioning provision and impairment testing

How is a decommissioning provision included in an impairment test?

Background

Entity A incurs expenditure of C100 constructing an oil production platform. The present value of the decommissioning obligation at the date on which the platform is put into service is C25. The present value of the future cash inflows from expected production is C180. The present value of the future cash outflows from operating the platform is C50, and the present value of the future cash outflows from performing the decommissioning of the platform is C25.

Solution

The following example illustrates the results of both the inclusion and exclusion of the decommissioning liability in the carrying amount of the CGU and the cash flow projections.

The net present value of future cash flows associated with operating the field is as follows:

VIU calculation	**Including**	**Excluding**
Cash inflows from sale of oil produced	180	180
Operating cash outflows	(50)	(50)
Cash outflows from decommissioning at end of field life	(25)	(-)
Net present value of cash flows (recoverable amount)	**105**	**130**
Carrying amount of PPE (including cost of future decommissioning)	125	125
Carrying amount of decommissioning provision	(25)	(-)
Net carrying amount of CGU	**100**	**125**

Determination of carrying amount
The recoverable amount in both cases exceeds the carrying amount of the assets and hence, no impairment charge is required. However, if the discount rate used for arriving at the cash outflows from decommissioning is different from that used for the carrying amount of decommissioning provision, a difference in their values could arise.

4.5.8 Goodwill impairment testing

IAS 36 requires goodwill to be tested for impairment at least annually and tested at the lowest level at which management monitors it. The lowest level cannot be higher than the operating segment to which goodwill belongs to under IFRS 8, 'Operating segments'.

The grouping of CGUs for impairment testing should reflect the lowest level at which management monitors the goodwill. If that is on an individual CGU basis, testing goodwill for impairment should be performed on that individual basis. However, when management monitors goodwill based on a group of CGUs the impairment testing of the goodwill should reflect this.

Goodwill is tested for impairment annually and when there are impairment indicators. Those indicators might be specific to an individual CGU or group of CGUs.

IAS 36 requires a bottom up then top down approach for impairment testing and the order in which the testing is performed is crucial. The correct approach is particularly important if there is goodwill, indefinite lived assets, shared assets or corporate assets. First, any individual CGUs with indicators of impairment must be tested and the impairment loss recorded in the individual CGU. Then CGUs can be grouped for the purposes of testing shared assets, indefinite lived intangibles, goodwill and corporate assets. The amended carrying values of any individual CGUs that have been adjusted for an impairment charge are used as part of the second stage of the impairment test.

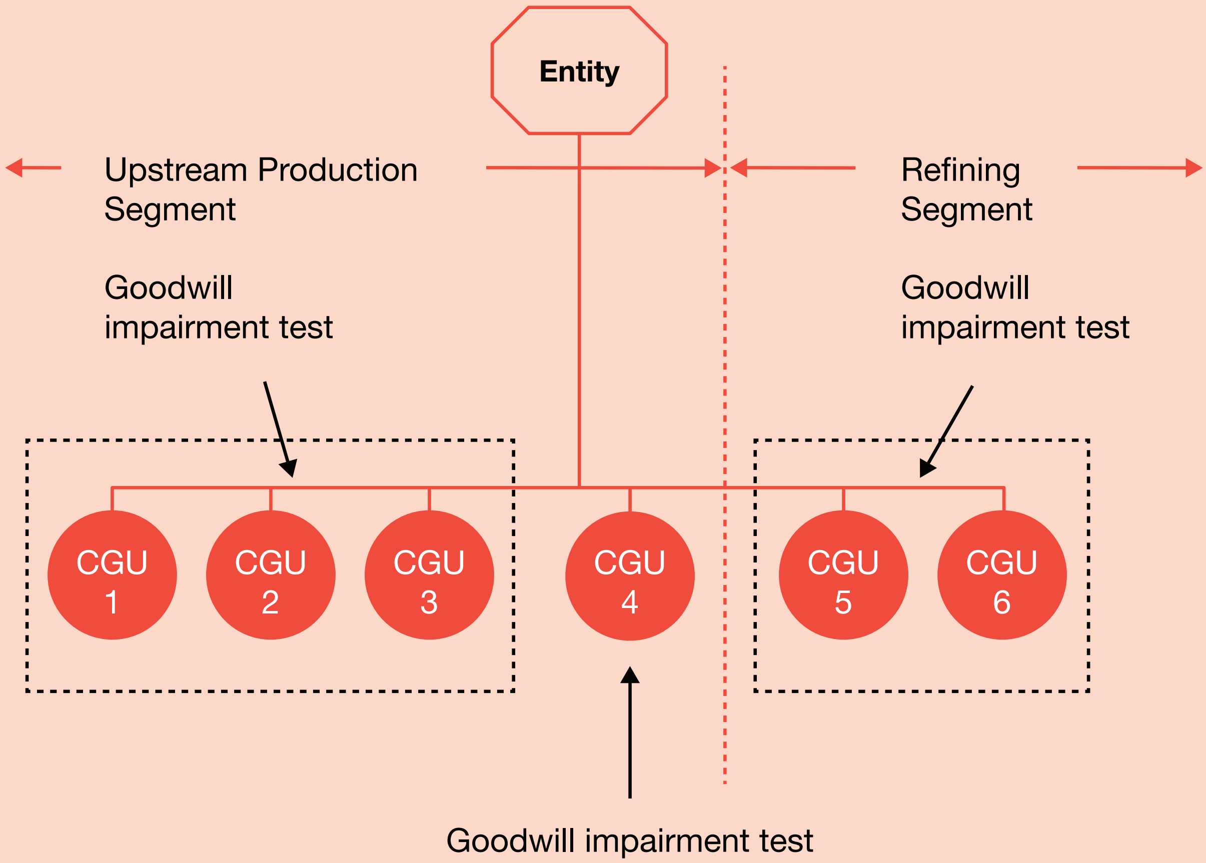
If the impairment test shows that the recoverable amount of the group of CGUs exceeds the carrying amount of that group of CGUs (including goodwill), there is no impairment to recognise. However, if the recoverable amount is less than the combined carrying value, the group of CGUs and the goodwill allocated to it is impaired. The impairment charge is allocated first to the goodwill balance to reduce it to zero, and then pro rata to the carrying amount of the other assets within the group of CGUs.

Goodwill is also tested for impairment when there is an indicator that it is impaired, or when there is an indicator that the CGU(s) to which it is allocated is impaired. When the impairment indicator relates to specific CGUs, those CGUs are tested for impairment separately before testing the group of CGUs and the goodwill together.

Impairment testing of goodwill

At what level is goodwill tested for impairment?

The diagram below illustrates the levels at which impairment testing may be required. The entity has two operating segments, Upstream Production and Refining. The Upstream Production segment comprises four producing fields which each represent CGUs; the Refining segment comprises two refineries which represent separate CGUs. There is goodwill allocated to each CGU. The goodwill within the Upstream Production segment is monitored in two parts. The goodwill allocated to CGUs 1, 2 and 3 is monitored on a collective basis; the goodwill allocated to CGU 4 is monitored separately. The goodwill within the Refining segment is monitored at the Refining level – that is, goodwill allocated to CGUs 5 and 6 is monitored on a combined basis.



If there is an impairment indicator for CGU 2, the CGU is tested for impairment separately, excluding the goodwill allocated to it. Any impairment loss calculated in this impairment test is allocated against the assets within the CGU. This allocation of the impairment charge is made on a pro rata basis to the carrying value of the assets within the CGU. The testing of CGU 2 at this level excludes goodwill, so no impairment is allocated against goodwill in this part of the impairment test.

After recording any impairment arising from testing CGU 2 for impairment, CGUs 1, 2 and 3 and the goodwill allocated to them is then tested for impairment on a combined basis. Any impairment loss calculated in this impairment test is allocated first to the goodwill. If the impairment charge in this test exceeds the value of goodwill allocated to CGUs 1, 2 and 3, the remaining impairment charge is allocated against the fixed and intangible assets of CGUs 1, 2 and 3 pro rata to the carrying value of the assets within those CGUs.

A similar approach is taken for CGU 4. However, because no other CGU is combined with CGU 4 for goodwill impairment testing, there is no need to test CGU 4 for impairment separately from the goodwill allocated to it.

4.5.9 Impairment reversals

The actual results in subsequent periods should be compared with the cash flow projections (used in impairment testing) made in the previous year. Where performance has been significantly better than previously estimated, this is an indicator of potential impairment reversal. Impairment charges are reversed (other than against goodwill) where the increase in recoverable amount arises from a change in the estimates used to measure the impairment. Estimates of variables, such as commodity prices, reflect the expectations of those variables over the period of the forecast cash flows, rather than changes in current spot prices. The use of medium to long term prices for commodities means that impairment charges and reversals tend not to reflect the same volatility as current spot prices.

4.6 Royalties and income taxes

Petroleum taxes generally fall into two main categories – those that are calculated on profits earned (income taxes) and those calculated on sales (royalty or excise taxes). The categorisation is crucial: royalty and excise taxes do not form part of revenue, while income taxes usually require deferred tax accounting but form part of revenue. In some countries the autorities may also charge “production taxes”: charges which are based on a specified tax rate per quantity of oil or gas extracted regardless of whether that oil or gas is subsequently sold. Such taxes may be recognised as operating expenses.

4.6.1 Petroleum taxes – royalty and excise

Petroleum taxes that are calculated by applying a tax rate to volume or a measure of revenue which has not been adjusted for expenditure do not fall within the scope of IAS 12 Income Taxes and are not income taxes. Determining whether a petroleum tax represents an income tax can require judgement.

Petroleum taxes outside the scope of IAS 12 do not form part of revenue or give rise to deferred tax liabilities. Revenue-based and volume-based taxes are recognised when the revenue is recognised [IAS 18 para 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 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 [IAS 37 para 15, 36].

Royalty and excise taxes are in effect the government’s share of the natural resources exploited and are a share of production 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 excluded from gross revenues and costs.

4.6.2 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 [IAS 12 para 5]. 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 as defined by the relevant tax legislation, and thus might include costs that are capitalised for financial reporting purposes. However it is not, for example, an allocation of profit oil in a PSA. Examples of taxes based on profits include Petroleum Revenue Tax in the UK, Norwegian Petroleum Tax and Australian Petroleum Resource Rent Tax.

Classification as income tax or royalty

Does Petroleum Revenue Tax (PRT) in Utopia fall within the scope of IAS 12?

Background

Entity A has an interest in an oil field in Utopia. The field is subject to Petroleum Revenue Tax (PRT) levied by the government of Utopia.

The determination of the amount of PRT payable by an entity is set out in the tax legislation created by the Utopian government. The PRT payable by an entity is calculated based on the profits earned from the production of oil.

The profits against which PRT is calculated are determined by legislation. The PRT taxable profit is calculated as the revenue earned from the sale of oil, on an accruals basis, less the costs incurred to produce and deliver the oil to its point of sale.

The deductible costs permitted by the legislation include all direct costs of production and delivery. Capital type costs are allowable as incurred – there is no spreading/amortisation of capital costs as occurs in financial reporting or corporation tax calculations.

The non-deductible costs are financing costs, freehold property costs and certain other types of costs. However, an additional allowance ("uplift") against income is permitted in place of interest costs. The uplift deduction is calculated as 35% of qualifying capital expenditure.

Solution

PRT falls within the scope of IAS 12.

PRT is calculated by applying the PRT tax rate to a measure of profit that is calculated in accordance with the PRT tax legislation.

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 that fall within the scope of IAS 12 [IAS 12 para 15, 24]. 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. An IFRS balance sheet and a tax balance sheet will be required for each area or field subject to separate taxation for the calculation of deferred tax.

The tax rate applied to the temporary differences will be the statutory rate for the relevant tax. The statutory rate may be adjusted for certain allowances and reliefs (e.g., tax-free barrels) in certain limited circumstances where the tax is calculated on a field-specific basis without the opportunity to transfer profits or losses between fields [IAS 23 para 47, 51].

How should management account for PRT tax losses?

Background

Entity A has an interest in an oil field in Utopia. The field is subject to Petroleum Revenue Tax (PRT) levied by the government of Utopia. Entity A has incurred PRT losses in prior years of 30,000. These losses arose because a deduction for capital expenditure can be made in the year in which agreement is reached with the tax authorities rather than spread over future periods. The PRT rules allow the losses to be carried forward indefinitely, and used against future PRT. The losses include the 100% basic deduction and the 35% super deduction (uplift) permitted by the tax authorities for qualifying capital expenditure.

The statutory PRT tax rate for Utopia is 45%.The effective PRT rate that reflects reliefs such as oil allowance and safeguard is 41%. The deduction for tax losses is taken in priority to the oil allowance and safeguard reliefs. Entity A's management expect that the oil field will be sufficiently profitable over its life to absorb all of the 30,000 PRT losses carried forward.

At what value should A's management recognise deferred PRT in respect of the PRT losses carried forward?

Solution

Entity A's management should recognise a deferred tax asset of 13,500 (30,000 x 45%). The temporary difference arising in respect of the PRT losses is a deductible temporary difference of 30,000. The appropriate PRT rate to apply to the temporary difference is the statutory rate. The use of PRT losses is not affected by the oil allowance and safeguard reliefs. Application of the effective rate incorporating oil allowance and safeguard is therefore not appropriate.

Should deferred tax be recognised on super deductions receivable on Income tax?

Background

Entity A has an interest in an oil field and the field is subject to Petroleum Revenue Tax (PRT) levied by the government of Utopia. Entity A receives 'uplift' in respect of the cost of the qualifying capital expenditures for PRT purposes. Uplift provides A with an additional deduction against profits chargeable to PRT of 35% of qualifying capital expenditures. Entity A is able to recognise a deduction of 100% of the costs of qualifying capital expenditure in calculating profits subject to PRT when the tax authorities agree the deductibility. A further 35% deduction is allowed when the tax authorities agree that the specific expenditure qualifies for uplift. The test for deductibility for the 35% uplift is more restrictive than the test for the base 100% deduction. The deductions are made in full against the calculation of profits subject to PRT in the period in which the respective agreements are received from the tax authorities. The cumulative amount of depreciation charged for financial reporting purposes under IFRS remains at 100% over the life of the asset i.e., the regulations allow for a higher deduction to be charged than the depreciation charge over the life of the asset.

The following is an illustration of how super deduction works.

Say the company has developed four assets A, B, C and D having a capital cost of say 1000, 1500, 2000 and 2500 GBP respectively. All these assets are qualifying capital expenditures and assets A and C qualify for an additional deduction (uplift) of 35%. In such case the following will the amounts deductible:

Asset	Capital cost (GBP)	Amount of deduction allowed	Uplift
A	1,000	1,350=1,000+350	35% of 1,000
B	1,500	1,500	Not eligible
C	2,000	2,700=2,000+700	35% of 2,000
D	2,500	2,500	Not eligible

Deduction for uplift is allowed in the year in which the tax authorities agree that the specific expenditure qualifies for uplift which may be different from the year in which the capital expenditure is incurred or the year in which the 100% deduction is claimed.

At what value should A's management recognise deferred PRT in respect of the capital assets?

Solution

The portion of the PRT tax base relating to the uplift arises on initial recognition of the asset. As per paragraph 24 of IAS 12, a deferred tax asset shall be recognised for all deductible temporary differences to the extent that it is probable that taxable profit will be available against which the deductible temporary difference can be utilised, unless the deferred tax asset arises from the initial recognition of an asset or liability in a transaction that:

a) is not a business combination; and
b) at the time of the transaction, affects neither accounting profit nor taxable profit (tax loss).

From the above, it can be seen that the deferred PRT would be covered under the IRE and deferred taxes on the same would not be recognised. The availability of the super-deduction would have been factored into any final price agreed between the seller and buyer for the transaction. Accordingly, the cost of the acquisition to the purchaser would represent its full value and no additional uplift should be made to this in respect of the super-deduction. US GAAP allows a gross up of the asset and a related deferred tax liability in respect of such a super-deduction, however, this is not permitted under IAS 12.

4.6.3 Taxes 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.

4.6.4 Deferred tax and acquisitions of participating interests in jointly controlled assets

The deferred tax consequences of the acquisition of a participating interest in a jointly controlled asset are discussed in section 4.1.9. The initial recognition exemption applies and deferred tax is not recognised if the transaction is not deemed to be a business combination.

4.6.4.1 Why does deferred tax not arise on acquisition of an interest in a joint venture?

The initial recognition exemption is applicable on the acquisition of an asset and no deferred tax is recognised. The IRE applies to temporary timing differences which arise from transactions which are not business combinations and affect neither accounting profit nor taxable profit. These criteria would be considered to apply to:

- Acquisitions of participating interests in jointly controlled assets; and
- Acquisitions of interests in jointly controlled entities (regardless of whether equity accounting or proportionate consolidation is used)

Application of the IRE is mandatory and must be used when the tax base of the acquisition costs differs from the accounting base. The IRE is not applied where there is no such difference, but this has the same result of no deferred tax being recognised.

From a tax perspective, acquisitions of an additional interest in an asset or entity are treated the same as if the asset or entity were being acquired for the first time. The application of the IRE is required for each acquisition of an additional interest that does not provide control over the asset or entity.

4.6.4.2 Timing differences arising subsequent to acquisition

Timing differences between the carrying value of the investment and the tax base will often arise subsequent to the initial acquisition for investment in jointly controlled entities. Investors should consider whether the exemption in IAS12.39 for interests in joint ventures where the venturer is able to control the timing of reversal of the temporary difference can be applied to avoid recognition of a deferred tax liability.

The exemption allows a joint venturer not to recognise a deferred tax liability where they are able to control the timing of the reversal of the related temporary difference and be able to conclude that it is probable it will not reverse in the future. In joint ventures, the determining factor will be whether the contractual arrangement provides for the retention of profit in the joint venture, and whether the venturer can control the sharing of profits. From a tax perspective, the ability to control the sharing of profits is viewed as the ability to prevent their distribution rather than enforce their distribution.

4.6.5 Discounting of petroleum taxes

Under IAS 12, tax liabilities shall be measured at the amount expected to be paid to the taxation authorities and accordingly would not be discounted. Accordingly, petroleum taxes which fall within the scope of IAS 12 would not be discounted. Petroleum taxes outside the scope of IAS 12 can be measured after considering the effects of discounting.

4.6.6 Royalties to non-governmental bodies and retained interests

Petroleum "taxes" do not always relate to dealings with government authorities. Sometimes arrangements with third parties are such that they result in the payment of a royalty. For example, one party may own the licence to a field which is used by an operating party on the terms that once the operator starts producing, it must pay the license holder a percentage of its profits or a percentage of production.

In cases where the license holder receives a fixed payment per unit extracted or sold, it would generally be in the nature of royalty. However, if the licence holder is entitled to a portion of the oil or gas extracted, it could potentially mean that the licence holder retains an interest in the field.

It would be important to consider whether the license holder has a claim on the profits of the entity or on its net assets. If the license holder retains an interest in the net assets of the entity, it would have to be accounted for under the relevant IFRS.

4.7 Functional Currency

4.7.1 Overview

Oil and gas entities commonly undertake transactions in more than one currency, as commodity prices are often denominated in US dollars and costs are typically denominated in the local currency. Determination of the functional currency can require significant analysis and judgement.

An entity's functional currency is the currency of the primary economic environment in which it operates. This is the currency in which the entity measures its results and financial position. A group comprised of multiple entities must identify the functional currency of each entity, including joint ventures and associates. Different entities within a multinational group often have different functional currencies. The group as a whole does not have a functional currency.

An entity's presentation currency is the currency in which it presents its financial statements. Reporting entities may select any presentation currency (subject to the restrictions imposed by local regulations or shareholder agreements). However, the functional currency must reflect the substance of the entity's underlying transactions, events and conditions; it is unaffected by the choice of presentation currency. Exchange differences can arise for two reasons: when a transaction is undertaken in a currency other than the entity's functional currency; or when the presentation currency differs from the functional currency.

4.7.2 Determining the functional currency

Identifying the functional currency for an oil and gas entity can be complex because there are often significant cash flows in both the US dollar and local currency. Management should focus on the primary economic environment in which the entity operates when determining the functional currency. The denomination of selling prices is important but not determinative. Many sales within the oil and gas industry are conducted either in, or with reference to, the US dollar. However, the US dollar may not always be the main influence on these transactions. Although entities may buy and sell in dollar denomination they are not exposed to the US economy unless they are exporting to the US or another economy closely tied to the US.

Dollar denomination is a pricing convention rather than an economic driver. Instead, the main influence on the entity is demand for the products and ability to produce the products at a competitive margin, which will be dependent on the local economic and regulatory environment. Accordingly, it is relatively common for oil and gas entities to have a functional currency which is their local currency rather than the US dollar, even where their sales prices are in dollars.

Functional currency is determined on an entity by entity basis for a multi-national group. It is not unusual for a multi-national oil and gas company to have many different functional currencies within the group.

There are three primary indicators of functional currency: the currency of sales prices, the currency of the country that will consume and regulate the products and the currency of the cost of labour.

It is difficult to identify a single country whose competitive forces and regulations mainly determine selling prices in oil and gas. If the primary indicators do not provide an obvious answer to the functional currency question , the currency in which an entity's finances are denominated should be considered i.e., the currency in which funds from financing activities are generated and the currency in which receipts from operating activities are retained.

How to determine the functional currency of an entity with products normally traded in a non-local currency (1)

What is the functional currency of an entity which is based in Saudi Arabia but prices all products sold in US dollars?

Background

Entity A operates an oil refinery in Saudi Arabia. All of the entity's income is denominated and settled in US dollars. Refined product is primarily exported by tanker to the US. The oil price is subject to the worldwide supply and demand, and crude oil is routinely traded in US dollars around the world. Around 55% of entity A's cash costs are imports or expatriate salaries denominated in US dollars. The remaining 45% of cash expenses are incurred in Saudi Arabia and denominated and settled in riyal. The non-cash costs (depreciation) are US dollar denominated, as the initial investment was in US dollars.

Solution

The factors point toward the functional currency of entity A being the US dollar. The product is primarily exported to the US. The revenue analysis points to the US dollar. The cost analysis is mixed. Depreciation (or any other non-cash expenses) is not considered, as the primary economic environment is where the entity generates and expends cash. Operating cash expenses are influenced by the riyal (45%) and the US dollar (55%). Management is able to determine the functional currency as the US dollar, as the revenue is clearly influenced by the US dollar and expenses are mixed.

How to determine the functional currency of an entity with products normally traded in a non-local currency (2)

What is the functional currency of an entity which is based in Russia but prices all products sold in US dollars?

Background

Entity A operates a producing field and an oil refinery in Russia and uses their product to supply independent petrol stations in Moscow. All of the entity's income is denominated in US dollars but is settled in a mixture of dollars and local currency. Around 45% of entity A's cash costs are expatriate salaries denominated in US dollars. The remaining 55% of cash expenses are incurred and settled in Roubles.

Solution

The factors point toward the functional currency of entity A being the Russian Rouble. Although selling prices are determined in dollars, the demand for the product is clearly dependent on the local economic environment in Russia. Although the cost analysis is mixed based on the level of reliance on the Moscow marketplace for revenue and margin management is able to determine the functional currency as Russian Rouble.

Determining the functional currency of holding companies and treasury companies may present some unique challenges; these have largely internal sources of cash although they may pay dividends, make investments, raise debt and provide risk management services. The underlying source of the cash flows to such companies is often used as the basis for determining the functional currency.

4.7.3 Change in functional currency

Once the functional currency of an entity is determined, it should be used consistently, unless significant changes in economic facts, events and conditions indicate that the functional currency has changed.

Oil and gas entities at different stages of operation may reach a different view about their functional currency. A company which is in the exploration phase may have all of its funding in US dollars and be reliant on their parent company. They may also incur the majority of its exploration costs in US dollars (the availability of drilling rigs may require these to be sourced from the US). At this stage they may conclude US dollars as being the functional currency.

However, when it reaches the development phase, its transactions may be predominantly denominated in local currency as they are more reliant on the local workforce and suppliers to perform the development activity. The functional currency may then change to being the local currency.

The functional currency may then change again when the project reaches the production phase and revenue is generated in US dollars. As explained above a selling price in dollars would not automatically mean that the functional currency is US dollars and factors such as the territory the company sells to and marketplace in which they operate would have to be considered. This does, however, illustrate that determination of the functional currency can be an ongoing process and conclusions may change depending on the current facts and circumstances.

A change in functional currency should be accounted for prospectively from the date of change. In other words, management should translate all items (including balance sheet, income statement and statement of comprehensive income items) into the new functional currency using the exchange rate at the date of change. Because the change was brought about by changed circumstances, it does not represent a change in accounting policy and a retrospective adjustment under IAS 8, *'Accounting policies, changes in accounting estimates and correction of errors'*, is not required.

The resulting translated amounts for non-monetary items are treated as their historical cost. It would be consistent that the equity items are also translated using the exchange rate at the date of the change of functional currency. This means that no additional exchange differences arise on the date of the change.

Entities should also consider presentation currency when there is a change in functional currency. A change in functional currency may be accompanied by a change in presentation currency, as many entities prefer to present financial statements in their functional currency. A change in presentation currency is accounted for as a change in accounting policy and is applied retrospectively, as if the new presentation currency had always been the presentation currency. It may be that the presentation currency does not change when there is a change in functional currency.

For example, an entity previously presented its financial statements in its functional currency being Euros. Subsequently on account of certain change in economic facts its functional currency changes to US dollar. Since it is based in a country where Euros is the local currency, it does not wish to change its presentation currency and so continues to present its financial statements in Euros. In such a case the numbers in the entity's financial statements for the period up to the change in functional currency do not change in presentational currency terms. From the point that the functional currency changes new foreign exchange differences will arise in the entity's own financial statements when items expressed in the new functional currency are translated into the presentation currency.

4.8 Leasing

4.8.1 Overview

The IASB Leases project is ongoing. The new standard is likely to contain a model for lessee accounting whereby all existing and new leases will be recognised on balance sheet. A final standard is not expected to be issued until 2012 at the earliest. This section deals with the current requirements of IAS 17 Leases.

IAS 17 excludes application to leases to explore for or use oil, natural gas and similar non-regenerative resources. The exemption includes exploration and prospecting licences. IAS 17 is, however, applicable to other arrangements that are in substance a lease, and this would include the plant and machinery used to perform the exploration activity.

Many oil and gas entities enter into other arrangements that convey a right to use specific assets and these may need to be classified as leases. Examples of such arrangements include:

- service agreements;
- throughput arrangements;
- tolling contracts;
- energy-related contracts; and
- transportation service contracts

4.8.2 When does a lease exist?

IFRIC 4 *Determining whether an Arrangement contains a lease* establishes criteria for determining whether a contract should be accounted for as a lease.

The following conditions must be met for an arrangement to be considered a lease:

- fulfilment of the arrangement is dependent on the use of a specific asset; and
- the arrangement conveys the right to use the asset.

4.8.2.1 Use of a specific asset

A specific asset is identified either explicitly or implicitly in an arrangement. A specific asset is implicitly identified when:

- it is not economically feasible or practical for the supplier to use alternative assets;
- the supplier only owns one suitable asset for the performance of the obligation;
- the asset used needs to be at a particular location or is specialised; or
- the supplier is a special purpose entity formed for a limited purpose.

An arrangement that involves the use of assets located at or near an oil or gas field, where the geographical isolation precludes any practical form of substitution of the assets, would often meet this test.

4.8.2.2 Right to use the specific asset

Payment provisions under an arrangement should be analysed to determine whether the payments are made for the right to use the asset, rather than for the actual use of the asset or its output. This requires a consideration of whether any of these conditions are met:

- the purchaser has the ability (or right) to operate or direct others to operate the asset in a manner it determines while obtaining (or controlling) more than an insignificant amount of the output of the asset;
- the purchaser has the ability (or right) to control physical access to the asset while obtaining (or controlling) more than an insignificant amount of the output of the asset; and
- the purchase price is not a fixed/market price per unit of output, and it is remote that any third party will take more than an insignificant amount of the output of the asset.

Arrangements in which an oil and gas entity takes substantially all of the output from a dedicated asset will often meet one of the above conditions, resulting in treatment as a lease. This occurs sometimes in the oil and gas industry because of the remote location of fields.

4.8.2.3 Reassessment of whether an arrangement contains a lease

The reassessment of whether an arrangement contains a lease after inception is required if any of the following conditions are met:

- a change is made to the contractual terms, other than renewals and extensions;
- a renewal option is exercised or an extension is agreed that had not been included in the initial arrangement;
- a change is determined in relation to the assessment of whether fulfilment is dependent on a specified asset; or
- there is a substantial change to the asset.

The above conditions require arrangements to be continued to be assessed for treatment as a lease, however a change in the determination of whether other parties obtain more than an insignificant amount from an asset is not a reassessment trigger.

For example, where a third party previously identified as obtaining more than an insignificant amount of an assets output shuts production, the entity continuing to operate is not required to reassess the arrangement under IFRIC 4.

4.8.3 Accounting for a lease

When an arrangement is within the scope of IFRIC 4, cash flows under the arrangement must be separated into their respective components. The components frequently include the right to use the asset, service agreements, maintenance agreements, and fuel supply. The payments for the right to use the asset are accounted for as a lease in accordance with the guidance in IAS 17. This includes the classification of the right of use as either an operating lease or a finance lease. The accounting for the other components is in accordance with the relevant guidance in IFRS.

4.8.3.1 Operating lease

If an arrangement contains an operating lease, the specific asset leased remains on the balance sheet of the lessor. Operating lease payments are recognised by the lessee on a straight-line basis over the life of the lease.

4.8.3.2 Finance lease

If an arrangement contains a finance lease, the specific asset leased is recorded on the balance sheet of the lessee and not the lessor. The lessor recognises a lease receivable which falls within the scope of IAS 39's derecognition and impairment provisions.

The impact of this accounting treatment to the lessee is a gross-up on the Statement of Financial Position of both assets and liabilities, whilst earnings will be impacted by the depreciation of the leased asset as well as an imputed interest charge. As a result of the finance lease accounting treatment, the earnings profile and key financial ratios may be materially impacted.

4.8.4 Presentation and disclosure

IAS 17 contains detailed disclosure requirements for leases. Common disclosures required include:

- a general description of an entity's significant lease arrangements;
- the total of future minimum lease payments and the present value for each of the following periods:
  - no later than one year;
  - later than one year and not later than five years; and
  - later than five years; and
- the carrying amount of assets held under finance leases.

5 Financial instruments, including embedded derivatives

5 Financial instruments, including embedded derivatives

5.1 Overview

Accounting for financial instruments will be seeing some significant change in the coming years as the IASB's projects in this area reach completion. IFRS 9 has already been published as a final standard and is mandatorily applicable from 2015 (as tentatively agreed by recent Board decisions – this is expected to be confirmed by end of 2011). Few entities have early adopted IFRS 9; it is not yet available for adoption within the European Union as it has not been endorsed. Accordingly, this section is presented based on the current requirements of IAS 39 and does not address any changes that may be necessary once IFRS 9 is applicable. The requirements of IFRS 9 are instead discussed in *Future Developments* Section 7.3. IFRS 13 Fair Value Measurement issued in May 2011, mandatorily applicable from 2013, is also discussed in section 7.2. IFRS 13 is unlikely to result in substantial change as it is largely consistent with current valuation practices. The IASB also have an ongoing project on hedge accounting that may result in simplification in current requirements, however, a final standard is yet to be issued.

The accounting for financial instruments can have a major impact on an oil and gas entity's financial statements. Some entities have specific energy trading activities and those are discussed in section 5.7. Many entities use a range of derivatives to manage the commodity, currency and interest-rate risks to which they are operationally exposed. Other, less obvious, sources of financial instruments issues arise through both the scope of IAS 39 and the rules around accounting for embedded derivatives. Many entities that are solely engaged in producing, refining and selling commodities may be party to commercial contracts that are either wholly within the scope of IAS 39 or contain embedded derivatives from pricing formulas or currency.

5.1.1 Scope of IAS 39

Contracts to buy or sell a non-financial item, such as a commodity, that can be settled net in cash or another financial instrument, or by exchanging financial instruments, are within the scope of IAS 39. They are accounted for as derivatives and are marked to market through the income statement. Contracts that are for an entity's 'own use' are exempt from the requirements of IAS 39 but these 'own use' contracts may include embedded derivatives that may be required to be separately accounted for. An 'own use' contract is one that was entered into and continues to be held for the purpose of the receipt or delivery of the non-financial item in accordance with the entity's expected purchase, sale or usage requirements. In other words, it will result in physical delivery of the commodity. Some practical considerations for the own use assessment are included in section 5.7.

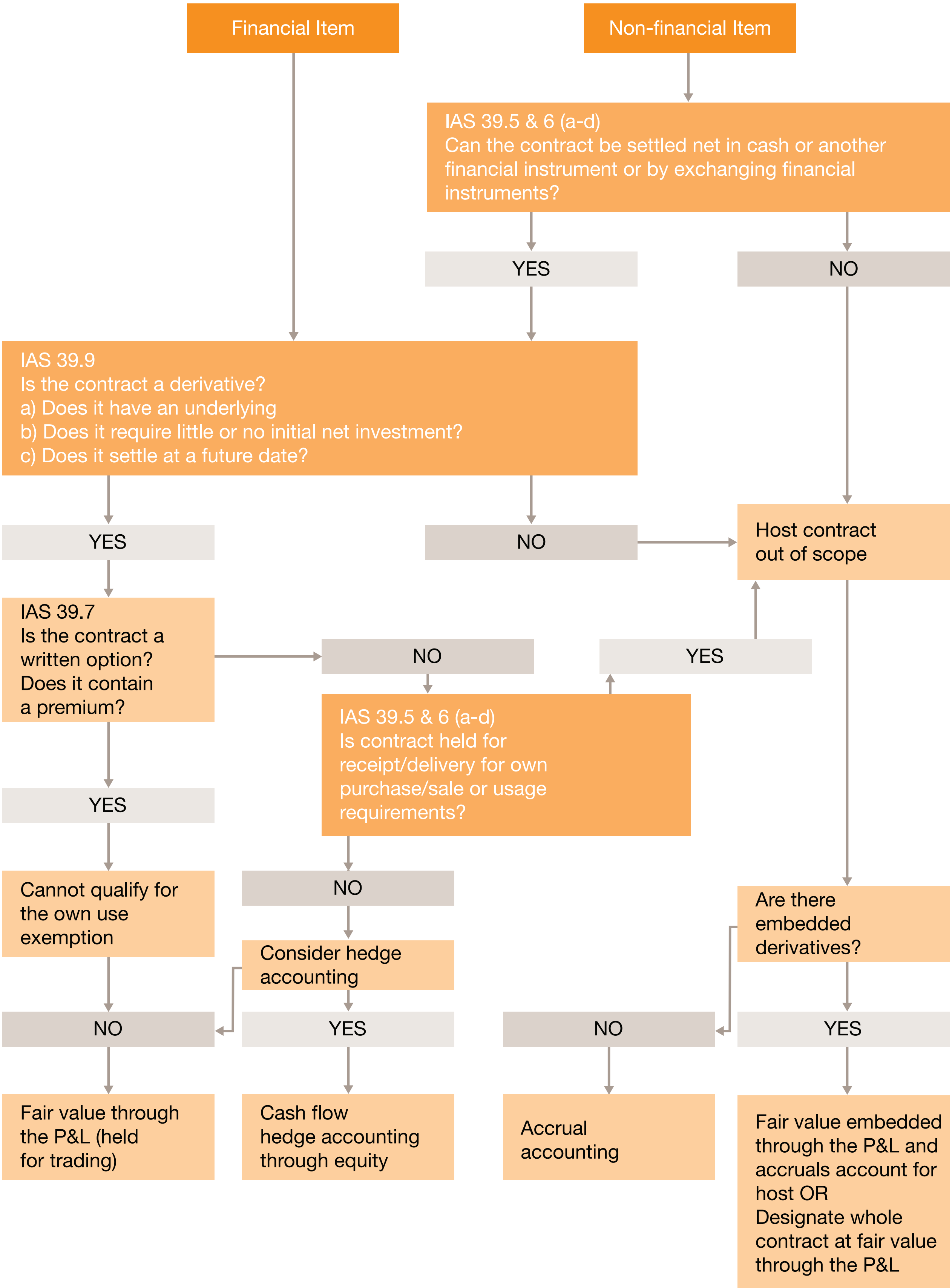
The 'net settlement' notion in IAS 39.6 is quite broad. A contract to buy or sell a non-financial item can be net settled in any of the following ways:

(a) the terms of the contract permit either party to settle it net in cash or another financial instrument;
(b) the entity has a practice of settling similar contracts net, whether:
- with the counterparty;
- by entering into offsetting contracts; or
- by selling the contract before its exercise or lapse;

(c) the entity has a practice, for similar items, of taking delivery of the underlying and selling it within a short period after delivery for the purpose of generating a profit from short-term fluctuations in price or dealer's margin; or
(d) the commodity that is the subject of the contract is readily convertible to cash [IAS 39.6].

The process for determining the accounting for a commodity contract can be summarised in the following decision tree:

Commodity contracts decision tree (IAS 39)



5.1.2 *Application of 'own use'*

'Own use' applies to those contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item. The practice of settling similar contracts net (in cash or by exchanging another financial instrument) can prevent an entire category of contracts from qualifying for the 'own use' treatment (i.e., all similar contracts must then be recognised as derivatives at fair value). A level of judgement will be required in this area as net settlements caused by unique events beyond management's control may not necessarily prevent the entity from applying the 'own use' exemption to all similar contracts. This should be assessed on a case by case situation. Judgement will also be required on what constitutes "similar" in the context of the 'own use' assessment – contracts with "similar" legal terms may be "dissimilar" if they are clearly segregated from each other from inception via book structure.

A contract that falls into IAS 39.6(b) or (c) cannot qualify for 'own use' treatment. These contracts must be accounted for as derivatives at fair value. Contracts subject to the criteria described in (a) or (d) are evaluated to see if they qualify for 'own use' treatment.

Many contracts for commodities such as oil and gas meet the criterion in IAS 39.6(d) (i.e., readily convertible to cash) when there is an active market for the commodity. An active market exists when prices are publicly available on a regular basis and those prices represent regularly occurring arm's length transactions between willing buyers and willing sellers.

Consequently, sale and purchase contracts for commodities in locations where an active market exists must be accounted for at fair value unless 'own use' treatment can be evidenced. An entity's policies, procedures and internal controls are critical in determining the appropriate treatment of its commodity contracts. It is important to match the own use contracts with the physical needs for a commodity by the entity. A well-managed process around forecasting these physical levels and matching them to contracts are both very important.

‘Own use’ contracts

Background

Entity A, the buyer, is engaged in power generation and Entity B, the seller, produces natural gas. A has entered into a 10 year contract with B for purchase of natural gas.

Entity A extends an advance of USD 1 billion to Entity B which is the equivalent of the total quantity contracted for 10 years at the rate of USD 4.5 per MMBtu (forecasted price of natural gas). This advance carries interest of 10% per annum which is settled by way of supply of gas.

As per the agreement, predetermined/fixed quantities of natural gas have to be supplied each month. There is a price adjustment mechanism in the contract such that upon each delivery the difference between the forecasted price of gas and the prevailing market price is settled in cash.

If Entity B falls short of production and does not deliver gas as agreed, Entity A has the right to claim penalty by which Entity B compensates Entity A at the current market price of gas.

Is this contract an ‘own use’ contract?

Solution

The ‘own use’ criteria are met. There is an embedded derivative (being the price adjustment mechanism) but it does not require separation. See further discussion of embedded derivatives at section 5.4.

The contract seems to be net settled because the penalty mechanism requires Entity B to compensate Entity A at the current prevailing market price. This will meet the condition in IAS 39.6(a). The expected frequency/intention to pay a penalty rather than deliver does not matter as the conclusion is driven by the presence of the contractual provision. Further, if natural gas is readily convertible into cash in the location where the delivery takes place, the contract will be considered net settled.

However, the Contract will still qualify as ‘own use’ as long as it has been entered into and continues to be held for the expected counterparties’ sales/usage requirements. However, if there is volume flexibility then the contract is to be regarded as a written option. A written option is not entered into for ‘own use’.

Therefore, although the Contract may be considered net settled (depending on how the penalty mechanism works and whether natural gas is readily convertible into cash in the respective location), it can still claim an ‘own use’ exemption provided the contract is entered into and is continued to held for the parties own usage requirements.

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

A written option to buy or sell a non-financial item that can be settled net cannot be considered to be entered into for the purpose of the receipt or delivery of the non-financial item in accordance with the entity's expected purchase, sale or usage requirements. This is because an option written by the entity is outside its control as to whether the holder will exercise or not. Such contracts are, therefore, always within the scope of IAS 32 and IAS 39 [IAS 32.10; IAS 39.7]. Volume adjustment features are also common, particularly within commodity and energy contracts and are discussed within section 5.3.

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

(a) the embedded derivative(s) does not significantly modify the cash flows of the contract; or
(b) it is clear with little or no analysis that separation of the embedded derivative is prohibited [IAS 39.11A]

Further discussion of embedded derivatives is presented in section 5.4.

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

Long-term commodity contracts are not uncommon, particularly for purchase and sale of natural gas. Liquefied Natural Gas ("LNG") is also a growing market and is discussed in section 5.5.

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

Valuation is complex and is intended to establish what the transaction price would have been on the measurement date in an arm's length exchange motivated by normal business considerations. The valuation of a contract should:

(a) incorporate all factors that market participants would consider in setting a price, making maximum use of market inputs and relying as little as possible on entity-specific inputs;
(b) be consistent with accepted economic methodologies for pricing financial instruments; and
(c) be tested for validity using prices from any observable current market transactions in the same instrument or based on any available observable market data.

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

5.2.1 Day-one profits

Commodity contracts that fall within the scope of IAS 39 and fail to qualify for 'own use' treatment have the potential to create day-one gains.

A day-one gain is the difference between the fair value of the contract at inception as calculated by a valuation model and the amount paid to enter the contract. The contracts are initially recognised under IAS 39 at fair value. Any such profits or losses can only be recognised if the fair value of the contract:

(1) is evidenced by other observable market transactions in the same instrument; or
(2) is based on valuation techniques whose variables include only data from observable markets.

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

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

5.3 Volume flexibility (optionality), including 'Take or pay' arrangements

Long-term commodity contracts frequently offer the counterparty flexibility in relation to the quantity of the commodity to be delivered under the contract. A supplier that gives the purchaser volume flexibility may have created a written option. Volume flexibility to the extent that a party can choose not to take any volume and instead pay a penalty is referred to as a 'Take or pay' contract. Such flexibility will often prevent the supplier from claiming the 'own use' exemption.

A contract containing a written option must be accounted for in accordance with IAS 39 if it can be settled net in cash, e.g., when the item that is subject of the contract is readily convertible into cash. Contracts need to be considered on a case-by-case basis in order to determine whether they contain written options.

The nature of end user commodity contracts is that they often have volume optionality but they are accounted for as "own use". Although they may include volume flexibility they will not contain a true written option if the purchaser did not pay a premium for the optionality. Receipt of a premium to compensate the supplier for the risk that the purchaser may not take the optional quantities specified in the contract is one of the distinguishing features of a written option.

The premium might be explicit in the contract or implicit in the pricing. Therefore it would be necessary to consider whether a net premium is received either at inception or over the contract's life in order to determine the accounting treatment. Any penalty payable for non-performance by the buyer may well amount to the receipt of a premium. Another factor which may be used to determine if a premium exists is whether usage of a volume option by the purchaser is driven by market conditions or their own physical requirements. In practice, it may be difficult to determine the rationale for the behaviour of a counterparty, but an assessment of the liquidity of the market may provide assistance. A volume option in a contract delivered to a tradable market is more likely than not to cause the contract to fail the 'own use' test.

If no premium can be identified, other terms of the contract may need to be examined to determine whether it contains a written option; in particular, whether the buyer is able to secure economic value from the option's presence by net settlement of this contract as defined in IAS 39.6.

5.4 Embedded derivatives

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

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

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

(a) the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract;
(b) a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative; and
(c) the hybrid (combined) instrument is not measured at fair value with changes in fair value recognised in the profit or loss (i.e., a derivative that is embedded in a financial asset or financial liability at fair value through profit or loss is not separated).

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

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

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

(a) the embedded derivative(s) does not significantly modify the cash flows of the contract; and
(b) it is clear with little or no analysis that separation of the embedded derivative(s) is prohibited.

5.4.1 Assessing whether embedded derivatives are closely related

All embedded derivatives must be assessed to determine if they are 'closely related' to the host contract at the inception of the contract.

A pricing formula that is indexed to something other than the commodity delivered under the contract could introduce a new risk to the contract. Some common embedded derivatives that routinely fail the closely-related test are indexation to an unrelated published market price and denomination in a foreign currency that is not the functional currency of either party and not a currency in which such contracts are routinely denominated in transactions around the world. The assessment of whether an embedded derivative is closely related is both qualitative and quantitative, and requires an understanding of the economic characteristics and risks of both instruments.

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

Embedded derivatives

Entity A enters into a gas delivery contract with Entity B, which is based in a different country. There is no active market for gas in either country. The price specified in the contract is based on Tapis-crude, which is the Malaysian crude price used as a benchmark for Asia and Australia. Does this pricing mechanism represent an embedded derivative?

Background

Management has a contract to purchase gas. There is no market price. The contract price for gas is therefore linked to the price of oil, for which an active market price is available. Oil is used as a proxy market price for gas.

Solution

No. The indexation to oil does not constitute an embedded derivative. The cash flows under the contract are not modified. Management can only determine the cash flows under the contract by reference to the price of oil.

5.4.2 Timing of assessment of embedded derivatives

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

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

The same principles apply to an entity that purchases a contract containing an embedded derivative and also when an entity acquires a subsidiary that holds a contract with an embedded derivative. The date of purchase or acquisition is treated as the date when the entity first becomes party to the contract. Therefore from the new owner's perspective an embedded derivative may now require separation if market conditions have changed since the original assessment date by the entity.

5.5 LNG contracts

The LNG market has been developing and becoming more active over recent years. This development has been mostly emphasised by the fact that more LNG contracts are currently managed with a dual objective:

- To provide a security of supply via long-term bilateral contracts, and
- To benefit from the potential arbitrage between various gas networks across the world which are not connected otherwise.

The application of the 'own use' exemption could become quite complex particularly for the definition of net settlement. The principles of IAS 39.5 to 7 should be still applied however there may be some practical challenges to this. The explanation of how energy trading units operate in section 5.7 provides some of the practical considerations.

In the absence of a global LNG reference price most contracts are currently priced based on other energy indices (e.g., Henry Hub Natural gas index, Brent Oil index, etc.). An assessment of the existence of embedded derivatives is required in order to determine whether they are 'closely related' to the host contract at the inception of the contract. In practice it is not uncommon that the pricing within LNG contracts is considered to be closely related if it is based on proxy pricing typical to the industry.

5.6 Hedge accounting

5.6.1 Principles and types of hedging

Entities often manage exposure to financial risks (including commodity price risks) by deciding to which risk, and to what extent, they should be exposed, by monitoring the actual exposure and taking steps to reduce risks to within agreed limits, often through the use of derivatives.

The process of entering into a derivative transaction with a counterparty in the expectation that the transaction will eliminate or reduce an entity's exposure to a particular risk is referred to as hedging. Risk reduction is obtained because the derivative's value or cash flows are expected, wholly or partly, to move inversely and, therefore, offset changes in the value or cash flows of the 'hedged position' or item. Hedging in an economic sense, therefore, concerns the reduction or elimination of different financial risks such as price risk, interest rate risk, currency risk, etc, associated with the hedged position. It is a risk management activity that is now commonplace in many entities.

Once an entity has entered into a hedging transaction, it will be necessary to reflect the transaction in the financial statements of the entity. Accounting for the hedged position should be consistent with the objective of entering into the hedging transaction, which is to eliminate or reduce significantly specific risks that management considers can have an adverse effect on the entity's financial position and results. This consistency can be achieved if both the hedging instrument and the hedged position are recognised and measured on symmetrical bases and offsetting gains and losses are reported in profit or loss in the same periods. Without hedge accounting mismatches would occur under recognition and measurement standards and practices set out in IFRS. Hedge accounting practices have been developed to avoid or mitigate these mismatches.

Hedge accounting rules therefore allow modifying the normal basis for recognising gains and losses (or revenues and expenses) on associated hedging instruments and hedged items so that both are recognised in profit or loss in the same accounting period. Hedge accounting therefore affords management the opportunity to eliminate or reduce the income statement volatility that otherwise would arise if the hedged items and hedging instruments were accounted for separately, without regard to the hedge's documented and designated business purpose.

IAS 39 defines three types of hedge:

1. Cash flow hedge – a hedge of the exposure to variability in cash flows that (i) is attributable to a particular risk associated with a recognised asset or liability (such as all or some future interest payments on variable rate debt) or a highly probable forecast transaction and (ii) could affect profit or loss. This is the most common type of a hedge in the oil and gas industry.
2. Fair value hedge – a hedge of the exposure to changes in fair value of a recognised asset or liability or an unrecognised firm commitment, or an identified portion of such an asset, liability or firm commitment, that is attributable to a particular risk and could affect profit or loss.
3. Hedge of a net investment in a foreign operation as defined in IAS 21.

To comply with the requirements of IAS 39 hedges must be:

- Documented from inception of hedge relationship;
- Expected to be highly effective; and
- Demonstrated to have been highly effective in mitigating the hedged risk in the hedged item.

There is no prescribed single method for assessing hedge effectiveness. Instead, a company must identify a method that is appropriate to the nature of the risk being hedged and the type of hedging instrument used. The method an entity adopts for assessing hedge effectiveness depends on its risk management strategy. A company must document at the inception of the hedge how effectiveness will be assessed and then apply that effectiveness test on a consistent basis for the duration of the hedge. The hedge must be expected to be effective at the inception of the hedge and in subsequent periods and the actual results of the hedge should be within a range of 80-125% (i.e., changes in the fair value or cash flows of the hedged item should be between 80% and 125% of the changes in fair value or cash flows of the hedging instrument). The effective part of a cash flow hedge and a net investment hedge is recognised in Other Comprehensive Income and the effective part of a fair value hedge is adjusted against the carrying amount of the hedged item. Any ineffectiveness of an effective hedge must be recognised in the income statement. The requirement for testing effectiveness can be quite onerous.

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

Companies that combine commodity risk from different business units before entering into external transactions to offset the net risk position might not qualify for hedge accounting, as IFRS does not permit a net position to be designated as a hedged item. However it may be possible to obtain hedge accounting by designating the hedged item as a part of one of the gross positions.

The IASB has an ongoing project on hedge accounting. Two significant expected developments for energy companies are a proposed relaxation in the requirements for hedge effectiveness and the ability to hedge non-financial portions in some circumstances. These may make hedge accounting much more attractive. Entities should monitor the progress on this and assess what the impact on their current accounting will be.

5.6.2 Cash flow hedges and 'highly probable'

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

Companies that buy or sell commodities (e.g., energy companies) may designate hedge relationships between hedging instruments, including commodity contracts that are not treated as 'own use' contracts, and hedged items. In addition to hedges of foreign currency and interest rate risk, energy companies primarily hedge the exposure to variability in cash flows arising from commodity price risk in forecast purchases and sales.

5.6.3 Hedging of non-financial Items

It is difficult to isolate and measure the appropriate portion of the cash flows or fair value changes attributable to specific risks other than foreign currency risks. Therefore, a hedged item which is a non-financial asset or non-financial liability may be designated as a hedged item only for:

a. Foreign currency risks;
b. In its entirety for all risks; or
c. All risks apart from foreign currency risks

In practice the main sources of ineffectiveness in hedging non-financial items arise from differences in location and differences in grade or quality of commodities delivered in the hedged contract compared to the one referenced in the hedging instrument.

5.6.4 Reassessment of hedge relationships in business combinations

An acquirer re-designates all hedge relationships of the acquired entity on the basis of the pertinent conditions as they exist at the acquisition date (i.e., as if the hedge relationship started at the acquisition date). Since derivatives previously designated as hedging derivatives were entered into by the acquired entity before the acquisition, these contracts are unlikely to have a zero fair value at the time of the acquisition. For cash flow hedges in particular, this is likely to lead to more hedge ineffectiveness in the financial statements of the post-acquisition group and also to more hedge relationships failing to qualify for hedge accounting as a result of failing the hedge effectiveness test.

Some of the option–based derivatives that the acquired entity had designated as hedging instruments may meet the definition of a written option when the acquiring entity reassesses them at the acquisition date. Consequently the acquiring entity won't be able to designate such derivatives as hedging instruments.

5.7 Centralised trading units

Many entities have established centralised trading or risk management units in response to the increasing volatilities and further sophistication of energy markets. The operation of such a central trading unit may be similar to the operation of the trading units of banks.

The scale and scope of the unit's activities vary from market risk management through to dynamic profit optimisation. An integrated entity with significant upstream and downstream operations is particularly exposed to the movements in the prices of commodities such as different oil grades, fuel products and gas (LNG). The trading unit's objectives and activities are indicative of how management of the company operates the business. The central trading unit often operates as an internal market place in larger integrated businesses. The centralised trading function thus 'acquires' all of the entity's exposure to the various commodity risks, and is then responsible for hedging those risks in the external markets.

Some centralised trading departments are also given the authority to enhance the returns obtained from the integrated business by undertaking a degree of speculative trading. A pattern of speculative activity or trading directed to profit maximisation is likely to result in many contracts failing to qualify for the 'own use' exemption.

A centralised trading unit therefore undertakes two classes of transaction:

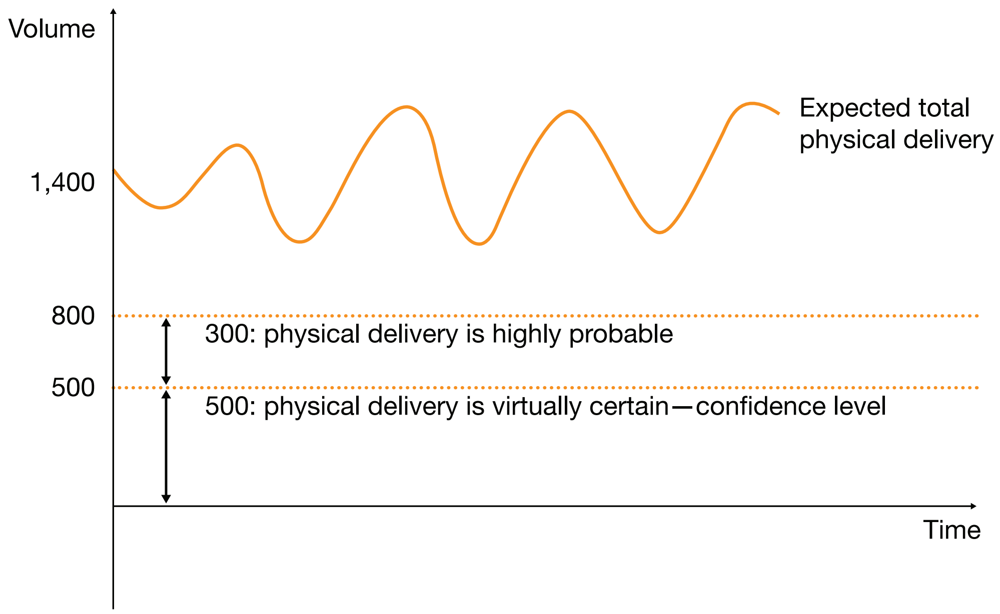
a. Transactions that are non-speculative in nature: for example, the purchase of oil to meet the physical requirements of the physical assets and the sale of any fuel produced by refinery. Contracts for such an activity are sometimes held in a 'physical book'.
b. Transactions that are speculative in nature, to achieve risk management returns from wholesale trading activities. Contracts for such activity is sometimes held in a 'trading book' and often involves entering into offsetting sales and purchase contracts that are settled on a net basis. Those contracts and all similar contracts (i.e., all contracts in the trading book) do not qualify for the 'own use' exemption and are accounted for as derivatives.

A company that maintains separate physical and trading books needs to maintain the integrity of the two books to ensure that the net settlement of contracts in the trading book does not 'taint' similar contracts in the physical book, thus preventing the 'own use' exemption from applying to contracts in the physical book. Other entities may have active energy trading programmes that go far beyond mitigation of risk. This practice has many similarities to the trading activities of other commodities, such as gold, sugar or wheat.

A contract must meet the 'own use' requirements to be included in the 'own use' or physical book. Contracts must meet the physical requirements of the business at inception and continue to do so for the duration of the contract as discussed in section 5.1.2.

Practical requirements for a contract to be 'own use' are:

- At inception and through its life, the contract has to reduce the market demand or supply requirements of the entity by entering into a purchase contract or a sale contract respectively.
- The market exposure is identified and measured following methodologies documented in the risk management policies of production and distribution. These contracts should be easily identifiable by recording them in separate books.
- If the contract fails to reduce the market demand or supply requirements of the entity or is used for a different purpose, the contract will cease to be accounted for as a contract for 'own use' purposes.
- Own-use treatment could be applied at a gross level i.e., sale of the oil production does not have to be offset against purchases of oil by the refinery in order to determine an 'own use' level.
- The number of own-use contracts would be capped by reference to virtually certain production and distribution volumes ('confidence levels') to avoid the risk of 'own use' contracts becoming surplus to the inherent physical requirements. If in exceptional circumstances the confidence levels proved to be insufficient they would have to be adjusted.



The only reason that physical delivery would not take place at the confidence level would be unforeseen operational conditions beyond control of the management of the entity (such as a refinery closure due to a technical fault). Entities would typically designate contracts that fall within the confidence level (with volumes up to 500 in the above diagram) as 'own use', contracts with physical delivery being highly probable (up to 800) as 'all in one' hedges and other contracts where physical delivery is expected but is not highly probable (over 800) as at fair value through profit or loss.

We would expect the result of the operations that are speculative in nature to be reported on a net basis on the face of the income statement. The result could be reported either within revenue or preferably as a separate line (e.g., trading margin) above gross operating profit. Such a disclosure would provide a more accurate reflection of the nature of trading operations than presentation on a gross basis.

6 First time adoption

6 First time adoption

IFRS 1 *'First time adoption of International Financial Reporting Standards'* provides transition relief and guidance for entities adopting IFRS. However, it is regularly updated and amended by the IASB. The amendments either update IFRS 1 for new standards and interpretations or address newly identified issues. However, keeping abreast of these changes can be challenging.

Entities in the oil and gas industry face many of the same transition issues as entities in other industries. This section focuses on the specific transition issues and reliefs provided by IFRS 1 that are of particular importance in the industry.

6.1 Deemed cost

Many upstream oil and gas companies used a variant of full cost under local GAAP and will need to make some changes on to IFRS. Successful efforts or a field by field based approach needs more detailed information; entities using full cost may not have maintained the detailed records to allow reconstruction of historical cost carrying amounts.

IFRS1 contains specific relief for entities who have previously used full cost accounting. The relief enables a first time adopter to measure oil and gas assets at the date of transition to IFRS at a "deemed cost" basis. Exploration and evaluation assets are measured at the carrying value determined under the entity's previous GAAP, this becomes deemed cost for IFRS purposes. The full cost pools are adjusted for the specific allocation of exploration and evaluation. The adjusted cost is then allocated across producing assets and assets under development based on a reasonable method. The assets are then tested for impairment at the date of transition.

This relief applies only to assets used in the exploration, evaluation, development or production of oil and gas. There is a broader "deemed cost" exemption which can be applied on an asset by asset basis to all tangible assets. The broader exemption allows an entity to assess the deemed cost as being:

- the fair value of the asset; or
- a previous GAAP revaluation as deemed cost if the revaluation was broadly comparable to fair value, or to the IFRS cost or depreciated cost adjusted to reflect changes in a price index.

Few first-time adopters have chosen to use the fair value approach. Those that have used it have done so selectively as permitted under the standard. Fair value as deemed cost often results in a significant increase in carrying value with the corresponding credit adjusting retained earnings. There is also a higher depreciation charge in subsequent years.

There is also an exemption that allows the use of fair value for intangible assets at transition to IFRS. However, it requires there to be an active market in the intangible assets as defined in IAS 38; this criterion is not met for common intangibles in the oil and gas industry such as licenses and patents.

6.2 Componentisation

IFRS requires that major assets are depreciated using a componentisation approach. The requirement for component depreciation is the major reason that full cost pools must be allocated to field size groups of assets. Component deprecation may represent a significant change from practice under national GAAP for oil and gas companies for both upstream and downstream assets.

Refineries are a particular downstream asset where implementing the component approach creates challenges. These are large, complex assets and if detailed asset records had not previously been maintained it can be a major exercise to try to recreate this information. Entities can use the deemed cost exemption previously described if a fair value for the refinery can be determined. It may also be possible to identify the significant components that will require replacement or renewal through looking at capital budgets and planned replacements. The depreciated carrying amount at transition to IFRS could be estimated through considering replacement cost and timing and making appropriate adjustments.

The deemed cost exemption is only available on initial transition. Subsequent acquisitions will need to follow the componentisation rules prospectively. These are discussed in more detail in sections 2.8 and 3.5.

6.3 Decommissioning provisions

Decommissioning provisions are recognised at the present value of expected future cash flows, discounted using a pre-tax discount rate. The discount rate should be updated at each balance sheet date if necessary and should reflect the risks inherent in the asset.

The requirements for a pre-tax rate and periodic updating can also result in differences on adoption of IFRS. An entity's previous GAAP may not have required an obligation to be recognised, allowed a choice of rate or not required the rate to be updated.

Changes in a decommissioning liability are added to or deducted from the cost of the related asset under IFRIC1. There is an optional short cut method for recognition of decommissioning obligations and the related asset at the date of first time adoption. The entity calculates the liability in accordance with IAS 37 as of the date of transition (the opening balance sheet date). The related asset is derived by discounting the liability back to the date of installation of the asset from the opening balance sheet date. This estimated asset amount at initial recognition is then depreciated to the date of transition using the appropriate method.

Use of the full cost exemption described in section 6.1 means that the IFRIC 1 exemption cannot be used. The entity must measure the decommissioning liability at the date of transition to IFRS and recognise any difference from the carrying amount under previous GAAP as an adjustment to retained earnings.

6.4 Functional currency

IFRS distinguishes between the functional currency and the presentation currency. An entity can choose to present its financial statements in any currency; the functional currency is that of the primary economic environment in which an entity operates. Functional currency must be determined for each entity in the group and is the currency that of the primary economic environment in which the specific entity operates. Functional currency is determined by the denomination of revenue and costs and the regulatory and economic environment that has the most significant impact on the entity.

A first-time adopter must determine the functional currency for each entity in the group. Changes of functional currency on adoption of IFRS are not unusual as previous GAAP may have required the use of the domestic currency or allowed a free choice of functional currency. This can result in a significant amount of work to determine the opening balance sheet amounts for all non-monetary assets. An entity needs to determine the historical purchase price in functional currency for all non-monetary assets. These amounts may have been recorded in US dollars, for example. There is no exemption in IFRS 1 for this situation although use of the fair value as deemed cost exemption may prove less complex and time consuming than reconstruction of historical cost.

Other common foreign currency challenges for oil and gas entities on adoption of IFRS include the impact of hyper-inflation, revaluations of fixed assets in a currency other than the functional currency and the impact on hedging strategies. These can involve considerable time and effort to address and need to be considered early during the planning process for transition to IFRS.

IFRS 1 does provide an exemption that allows all cumulative translation differences in equity for all foreign operations to be reset to nil at the date of transition. This exemption is used by virtually all entities on transition to IFRS as the alternative is to recast the results for all foreign operations under IFRS for the history of the entity.

6.5 Assets and liabilities of subsidiaries, associates and joint ventures

A parent or group may well adopt IFRS at a different date from its subsidiaries, associates and joint ventures ("subsidiaries"). Adopting IFRS for the group consolidated financial statements means that the results of the group are presented under IFRS even if the underlying accounting records are maintained under national GAAP, perhaps for statutory or tax reporting purposes.

IFRS 1 provides guidance on a parent adopting IFRS after one or more of its subsidiaries and for subsidiaries adopting after the group. When a parent adopts after one or more subsidiaries the assets and liabilities of the subsidiary are measured at the same carrying value as in the IFRS financial statements of the subsidiaries after appropriate consolidation and equity accounting adjustments.

A subsidiary that adopts after the group can choose to measure its assets and liabilities at the carrying amounts in the group consolidated financial statements as if no consolidation adjustments (excludes purchase accounting adjustments) were made, or as if the subsidiary was adopting IFRS independently.

6.6 *Disclosure requirements*

A first-time adopter is required to present disclosures that explain how the entity's financial statements were affected by the transition from previous GAAP to IFRS. These include:

- an opening balance sheet, prepared as at the transition date, with related footnote disclosure
- reconciliation of equity reported in accordance with previous GAAP to equity in accordance with IFRS
- reconciliation of total comprehensive income in accordance with IFRSs to the latest period in the entity's most recent annual financial statements
- sufficient disclosure to explain the nature of the main adjustments that would make it comply with IFRS
- If the entity used the deemed cost exemption, the aggregate of the fair values used and aggregate adjustment to the carrying amounts reported under previous GAAP.
- IAS 36 disclosures if impairment losses are recognised in the opening balance sheet.

Some common adjustments applicable to first-time adopters of the oil and gas industry are:

- Use of deemed cost as fair value for assets,
- Depletion for oil and gas properties on UOP method under IFRS,
- Reversal of impairment losses recognised under previous GAAP,
- Componentisation approach for major refineries based on the capitalisation criteria of major turnarounds under IFRS,
- Derivative contracts that do not qualify for hedging under IFRS,
- Downstream petroleum product inventory valued using FIFO or weighted average method as opposed to LIFO,
- Consequential adjustments to deferred tax under IFRS produced by some of the previous adjustments.

7 Future developments – standards issued and not yet effective

7 Future developments – standards issued and not yet effective

The IASB has been very active over the last several years. The 2008 global financial crisis accelerated the timetable for a number of projects including fair value measurement, consolidation, joint arrangements and accounting for financial instruments. The IASB has also been working with the FASB on major convergence projects on revenue recognition and leasing. These latter projects could well impact every entity. None of these projects were completed to the IASB's expected timetable: fair value measurement, consolidation and joint arrangements were published in May 2011. Portions of the revenue recognition and leasing projects have been re-exposed and no final standards are expected before late 2012 at the earliest.

A portion of the financial instruments project was published as IFRS 9 with an implementation date of xx. This date is expected to be deferred as major portions of the project, including impairment and hedge accounting, are incomplete. The final versions of these standards could be significantly different from the published proposals.

No decision has been taken on next steps for the Extractive Activities project. It will be considered as part of the wider agenda consultation.

This section focuses on those standards which have been issued and are not yet effective. Ongoing projects which have not been finalised will be examined in separate publications as the development of those standards progresses.

7.1 Consolidation and Joint arrangements

The IASB has largely finished its project on the reporting entity with the publication of three new standards in May 2011: IFRS 10 *Consolidation*, IFRS 11 *Joint arrangements* and IFRS 12 *Disclosure*. The standards replace IAS 27 *Consolidated and Separate Financial Statements* (which is amended to become IAS 27 *Separate Financial Statements*) and IAS 31 *Interests in Joint Ventures*. There have also been consequential amendments to IAS 28 *Investments in Associates* (which is now IAS 28 *Investments in Associates and Joint Ventures*). The standards are effective for 2013, and early adoption is permitted where all five standards are adopted at the same time.

7.1.1 Consolidation

IFRS 10 confirms consolidation is required where control exists but does not affect the mechanics of consolidation. However, the standard redefines control: where an investor has the power and exposure to variable returns and the ability to use that power it controls the investee.

Cooperative working arrangements are common in the oil & gas industry and the determination of the type of control that exists is important. The rights of investors to make decisions over relevant activities (now defined as those which significantly affect the investee's returns) are critical in this determination.

Factors to be assessed to determine control under the new standard include:

- The purpose and design of an investee;
- Whether rights are substantive or protective in nature;
- Existing and potential voting rights;
- Whether the investor is a principal or agent; and
- Relationships between investors and how they affect control.

Only substantive rights are considered in the assessment of power – protective rights, designed only to protect an investor's interest without giving power over the entity and which may only be exercised under certain conditions, are not relevant in the determination of control.

Potential voting rights are defined as 'rights to obtain voting rights of an investee, such as those within an option or convertible instrument.' Potential voting rights with substance should be considered when determining control. This is a change from the previous standard where all and only presently exercisable rights were considered in the determination of control.

The "principal vs. agent" determination is also important. Parties in upstream arrangements will often be appointed to operate the project on behalf of the investors. A principal may delegate some of its decision authority to the agent, but the agent would not be viewed as having control when it exercises such powers on behalf of the principal.

Economic dependence in an arrangement, such as a refinery which relies on crude oil to be provided by a specific supplier, is not uncommon, but is not a priority indicator. If the supplier has no influence over management or decision-making processes, dependence would be insufficient to constitute power.

7.1.2 *Joint arrangements*

"Joint arrangement" is the new term for all cooperative working arrangements where two or more parties have joint control. The definition of joint control is unchanged from IAS 31, and exists only when key decisions require unanimous consent. There is some clarification that key decisions must be over relevant activities (previously IAS 31 referred to "strategic financial and operating decisions"). IFRS 10 defines these activities as those which significantly affect the investee's returns.

The standard also introduces other new terminology:

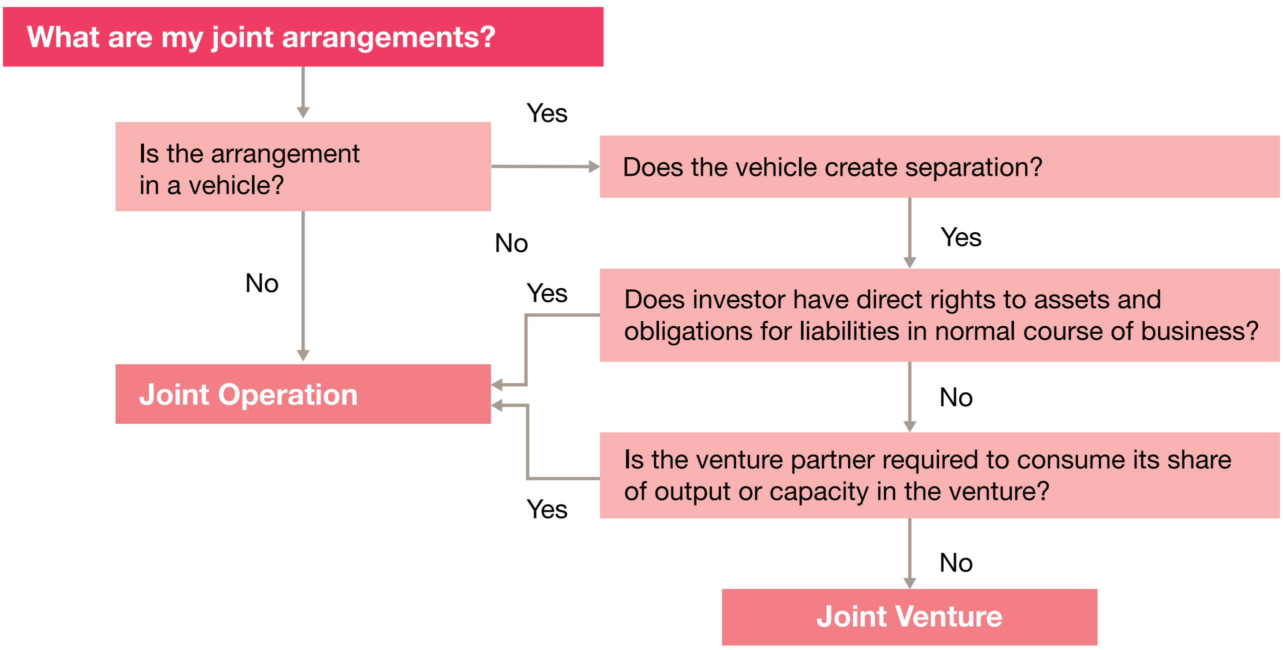
Under IAS 31	Under new IFRS 11	IFRS 11 definition
Jointly controlled asset	Joint operation	Parties have rights to the assets and obligations for the liabilities relating to the arrangement
Jointly controlled operation	Joint operation	Parties have rights to the assets and obligations for the liabilities
Jointly controlled entity	Joint venture	Parties have rights to the net assets of the arrangement

7.1.2.1 *Classification*

The classification of the joint arrangement is now based on the rights and obligations of the parties to the arrangements. This represents a significant change from IAS 31, where the classification was instead based on the legal form of the arrangement.

Determination of the type of joint arrangement can be a complex decision under IFRS 11. Legal form remains relevant for determining the type of joint arrangement but is less important than under the previous standard. A joint arrangement that is not structured through a separate vehicle is a joint operation. However, not all joint arrangements in separate vehicles are joint ventures. A joint arrangement in a separate vehicle can still be a joint operation; classification depends on the rights and obligations of the venturers and is further influenced by the economic purpose of the joint arrangement.

The flowchart below, based on our preliminary understanding of the standard, attempts to illustrate the decision making process and what needs to be considered to properly classify joint arrangements as operations or ventures.



There are many different types of vehicles used for joint arrangements in the oil and gas sector including partnerships, unincorporated entities, limited companies and unlimited liability companies. Venturers will have to assess all their joint arrangements and identify those that are operated through vehicles.

The legal structure of the vehicle or the contractual terms between the venturers may not provide for legal separation of the venture from the venture partners i.e., the venturers remain exposed to direct interest in the assets and liabilities of the venture. General partnerships, for example, may not create separation from the partners because the contractual terms provide direct rights to assets and expose the partners to direct obligations for liabilities of the partnership in the normal course of business. Similarly, unlimited liability companies provide direct rights and obligations to the venture partners. A joint arrangement conducted in a vehicle that does not create separation is a joint operation.

The parties' rights and obligations arising from the arrangement are assessed as they exist in the 'normal course of business' (IFRS 11.B14). Hence, legal rights and obligations arising in circumstances which are other than in the 'normal course of business' such as liquidation and bankruptcy are much less relevant. A separate vehicle may give the venture partners rights to assets and obligations to liabilities as per the terms of their agreement. However, in case of liquidation of the vehicle, secured creditors have the first right to the assets and the venture partners only have rights in the net assets remaining after settling all third party obligations. The vehicle could still be classified as a joint operation since in the 'normal course of business', as the venture partners have direct interest in assets and liabilities. Separate vehicles that give venture partners direct rights to assets and obligation for liabilities of the vehicle are joint operations.

Separate vehicles structured in a manner that all of their outputs must be purchased or used by the venture partners may also be joint operations. However, the contractual terms and legal structure of the vehicle need to be carefully assessed. There must be a contractual agreement or commitment between the venture parties that requires the parties to purchase or use their share of the output or capacity in the venture. If the venture can sell the output to third parties at prices market prices this criteria is unlikely to be met.

Upstream joint working arrangements generally do not operate through separate vehicles. Such arrangements are generally classified as jointly controlled assets or jointly controlled operations under the current IAS 31 and would be joint operations under IFRS 11. Investors would continue to account for their share of assets and liabilities under IFRS 11 (as they had done for jointly controlled assets and operations under IAS 31) and would not be impacted by the new standard. Midstream and downstream joint working arrangements generally operate through separate vehicles and incorporated entities. Assessing whether such arrangements are joint ventures or joint operations will pose challenges to the venturers.

The conclusions above are the result of our initial reading of the new standard. Practice may evolve and change as the standard is applied and accounting regulators make their views known.

7.1.2.2 Accounting

The classification of the joint arrangement is important as IFRS 11 requires equity-accounting for all joint arrangements classified as joint ventures. Therefore, investors who previously had a choice between equity accounting and proportionate consolidation will no longer have that choice. Investors in joint operations are required to account for their share of assets and liabilities. Again, this would mean a change in accounting where they had chosen equity accounting for a jointly controlled entity, but that arrangement was concluded to be a joint operation under IFRS 11. It should also be noted that the share of assets and liabilities is not the same as proportionate consolidation. "Share of assets and liabilities" means that the investor should consider their interest or obligation in each underlying asset and liability under the terms of the arrangement – it will not necessarily be the case that they have a single, standard percentage interest in all assets and liabilities. This is also an important consideration when transitioning to the new standard.

7.1.2.3 Transition

Entities must re-evaluate the terms of their existing contractual arrangement to ensure that their involvement in joint arrangements are correctly accounted for under the new standard. Joint arrangements that were previously accounted for as joint operations may need to be treated as joint ventures or vice versa on transition to the new standard.

When transitioning from the proportionate consolidation method to the equity method, entities should recognise their initial investment in the joint venture as the aggregate of the carrying amounts that were previously proportionately consolidated.

To transition from the equity method to proportionate consolidation, entities will derecognise their investment in the jointly controlled entity and recognise their rights and obligations to the assets and liabilities of the joint operation. Their interest in those assets and liabilities may be different from their interest in the jointly controlled entity.

Moving from the equity method to a share of assets and liabilities will not always be a simple process. For example, parties may have contributed specific assets to a joint arrangement. When evaluating interest based on share of assets and liabilities, parties will account for their interest in the arrangement based on the share of assets contributed by them. The interest calculated based on assets contributed will not necessarily result in the same interest that the party may have in the equity of that entity. Where there is a difference between the value recorded under equity accounting and the net value of the gross assets and liabilities, this is written off against opening retained earnings.

Similarly, moving from proportionate consolidation to equity method could pose challenges. For example, the liabilities of a joint arrangement assessed to be a joint venture may exceed the assets. Netting these may result in the venturer's investment becoming negative. The venturers will then have to assess whether they need to record a liability in respect of that negative balance. This will depend on whether the venturer has an obligation to fund the liabilities of the joint arrangement. If there is no obligation, then the balance is written off against opening retained earnings. If there is an obligation, further consideration should be given as to whether the assessment of the arrangement as a joint venture was correct.

7.1.2.4 Farm outs and unitisations

The new standard was expected to address some of the accounting questions that arise in farm outs and unitisations, as these had been included as examples in ED9. The final standard did not contain these examples, and the accounting described in section 4.2 is still considered applicable.

7.1.2.5 Impact in the oil and gas sector

Entities in the sector that are likely to be most significantly impacted include those that:

- Participate in a significant number of joint arrangements
- Enter into new joint arrangements
- Currently apply proportionate consolidation for jointly controlled entities
- Currently apply equity method for jointly controlled entities which are assessed to be joint operations under IFRS 11
- Have old joint arrangements with limited documentation detailing the terms of the arrangement

7.2 Fair value measurement

The IASB released IFRS 13 Fair Value Measurement in May 2011. This consolidates fair value measurement guidance across various IFRSs into a single standard, and applies when another IFRS requires or permits fair value measurements, including fair value less costs to sell. Share based payments, leasing transactions and measurements similar to fair value but which are not fair value (such as net realisable value in IAS 2 *Inventories* or value in use in IAS 36 *Impairment of Assets*) are out of the scope of the standard.

There may be some changes on adoption of the new standard but this is not expected to be widespread as the requirements are largely consistent with current valuation practices.

IFRS 13 will be most relevant for certain financial assets and derivatives in the oil and gas industry as few entities use fair value for non-financial assets outside of business combinations. The most significant impact will be on entities that are involved in trading activities with non-financial contracts measured at fair value through profit or loss.

The other main changes introduced are:

- An introduction of fair value hierarchy levels for non-financial assets similar to current IFRS 7 requirements
- A requirement for the fair value of financial liabilities (including derivatives) to be determined based on the assumption that the liability will be transferred to another party rather than settled or extinguished
- The removal of the requirement for bid prices to be used for actively-quoted financial assets and ask prices to be used for actively-quoted financial liabilities. Instead, the most representative price within the bid-ask spread should be used. Identifying this price could be challenging
- Additional disclosure requirements

The new standard is available for immediate adoption, and is mandatory from 2013. It can be adopted separately from IFRS 9.

7.3 Financial instruments

7.3.1 New Standard IFRS 9

IFRS 9 Financial Instruments has been issued by the IASB and addresses the classification and measurement of financial assets and liabilities. It replaces the existing guidance under IAS 39. It is applicable from January 1, 2015 (as tentatively agreed by recent Board decisions – this is expected to be confirmed by end of 2011) early adoption is permitted. IFRS 9 should be applied retrospectively; however, if adopted before January 2012, comparative periods do not need to be restated.

The main feature of IFRS 9 is that it emphasises the entity's business model when classifying financial assets. Accordingly, the business model and the characteristics of the contractual cash flows of the financial asset determine whether the financial asset is subsequently measured at amortised cost or fair value. This is a key difference to current practice.

7.3.2 How does it impact the oil & gas sector?

The effect of IFRS 9 on the financial reporting of oil & gas entities is expected to vary significantly depending on entities' investment objectives. Oil & gas entities will be impacted by the new standard if they hold many or complex financial assets. The degree of the impact will depend on the type and significance of financial assets held by the entity and the entity's business model for managing financial assets.

For example, entities that hold bond instruments with complex features (such as interest payments linked to company performance or foreign exchange rates) will be significantly impacted. In contrast, oil & gas entities that hold only shares in publicly listed companies that are not held for trading won't be impacted as these continue to be measured at fair value with changes taken to the income statement.

7.3.3 What are the key changes for financial assets?

IFRS 9 replaces the multiple classification and measurement models in IAS 39 *Financial instruments: Recognition and measurement* with a single model that has only two classification categories: amortised cost and fair value. A financial instrument is measured at amortised cost if two criteria are met:

a) the objective of the business model is to hold the financial instrument for the collection of the contractual cash flows; and
b) the contractual cash flows under the instrument solely represent payments of principal and interest.

If these criteria are not met, the asset is classified at fair value. This will be welcome news for most oil & gas entities that hold debt instruments with simple loan features (such as bonds that pay only fixed interest payments and the principal amount outstanding) which are not held for trading.

The new standard removes the requirement to separate embedded derivatives from the rest of a financial asset. It requires a hybrid contract to be classified in its entirety at either amortised cost or fair value. In practice, we expect many of these hybrid contracts to be measured at fair value. The convertible bonds held by oil & gas entities are often considered to be hybrid contracts and may need to be measured at fair value.

IFRS 9 prohibits reclassifications from amortised cost to fair value (or vice versa) except in rare circumstances when the entity's business model changes. In cases where it does, entities will need to reclassify affected financial assets prospectively.

There is specific guidance for contractually linked instruments that create concentrations of credit risk, which is often the case with investment tranches in a securitisation. In addition to assessing the instrument itself against the IFRS 9 classification criteria, management should also 'look through' to the underlying pool of instruments that generate cash flows to assess their characteristics. To qualify for amortised cost, the investment must have equal or lower credit risk than the weighted-average credit risk in the underlying pool of other instruments, and those instruments must meet certain criteria. If 'a look through' is impractical, the tranche must be classified at fair value through profit or loss.

Under IFRS 9 all equity investments should be measured at fair value. However, management has an option to present in other comprehensive income unrealised and realised fair value gains and losses on equity investments that are not held for trading. For an oil & gas company, this may include an interest in a listed junior explorer. Such designation is available on initial recognition on an instrument-by-instrument basis and it's irrevocable. There is no subsequent recycling of fair value gains and losses on disposal to the income statement; however, dividends from such investments will continue to be recognised in the income statement. This is good news for many because oil & gas entities may own ordinary shares in public entities. As long as these investments are not held for trading, fluctuations in the share price will be recorded in other comprehensive income. Under the new standard, recent events such as the global financial crisis will not yield volatile results in the income statement from changes in the share prices.

7.3.4 How could current practice change for oil & gas entities?

Type of instrument/ Categorisation of instrument	Accounting under IAS 39	Accounting under IFRS 9	Insight
Investments in equity instruments that are not held for trading purposes (e.g., equity securities of a listed entity). Note. This does not include associates or subsidiaries unless entities specifically make that election.	Usually classified as 'available for sale' with gains/losses deferred in other comprehensive income (but may be measured at fair value through profit or loss depending on the instrument).	Measured at fair value with gains/losses recognised in the income statement or through other comprehensive income if applicable.	Equity securities that are not held for trading can be classified and measured at fair value with gains/ losses recognised in other comprehensive income. This means no charges to the income statement for significant or prolonged impairment on these equity investments, which will reduce volatility in the income statement as a result of the fluctuating share prices.
Available for sale debt instruments (e.g., corporate bonds)	Recognised at fair value with gains/ losses deferred in other comprehensive income.	Measured at amortised cost where certain criteria are met. Where criteria are not met, measured at fair value through profit and loss.	Determining whether the debt instrument meets the criteria for amortised cost can be challenging in practice. It involves determining what the bond payments represent. If they represent more than principal and interest on principal outstanding (for example, if they include payments linked to a commodity price), this would need to be classified and measured at fair value with changes in fair value recorded in the income statement.

Type of instrument/ Categorisation of instrument	Accounting under IAS 39	Accounting under IFRS 9	Insight
Convertible instruments (e.g., convertible bonds)	Embedded conversion option split out and separately recognised at fair value. The underlying debt instrument is usually measured at amortised cost.	The entire instrument is measured at fair value with gains/losses recognised in the income statement.	Many entities found the separation of conversion options and the requirement to fair value the instrument separately challenging. However, management should be aware that the entire instrument will now be measured at fair value. This may result in a more volatile income statement as it will need to have fair value gains/ losses recognised not only on the conversion option, but on the entire instrument.
Held-to-maturity investments (e.g., government bonds)	Measured at amortised cost.	Measured at amortised cost where certain criteria are met. Where criteria are not met, measured at fair value through profit and loss.	Determining whether the government bond payments meet the criteria for amortised cost remains a challenge. For example, if the government bond includes a component for inflation, as long as the payment represents only compensation for time value of money, it may still meet the criteria for amortised cost. In contrast, a government bond that is linked to foreign currency exchange rates would not meet the criteria for amortised cost; instead this would need to be measured at fair value through profit and loss.

7.3.5 What are the key changes for financial Liabilities?

The main concern in revising IAS 39 for financial liabilities was potentially showing, in the income statement, the impact of 'own credit risk' for liabilities recognised at fair value – that is, fluctuations in value due to changes in the liability's credit risk. This can result in gains being recognised in income when the liability has had a credit downgrade, and losses being recognised when the liability's credit risk improves. Many users found these results counterintuitive, especially when there is no expectation that the change in the liability's credit risk will be realised. In view of this concern, the IASB has retained the existing guidance in IAS 39 regarding classifying and measuring financial liabilities, except for those liabilities where the fair value option has been elected.

IFRS 9 changes the accounting for financial liabilities that an entity chooses to account for at fair value through profit or loss, using the fair value option. For such liabilities, changes in fair value related to changes in own credit risk are presented separately in other comprehensive income (OCI).

In practice, a common reason for electing the fair value option is where entities have embedded derivatives that they do not wish to separate from the host liability. In addition, entities may elect the fair value option where they have accounting mismatches with assets that are required to be held at fair value through profit or loss.

Financial liabilities that are required to be measured at fair value through profit or loss (as distinct from those that the entity has chosen to measure at fair value through profit or loss) continue to have all fair value movements recognised in profit or loss with no transfer to OCI. This includes all derivatives (such as foreign currency forwards or interest rate swaps), or an entity's own liabilities that it classifies as being held for trading. Fair valuing derivatives could result in the instrument changing from an asset to a liability; this means that it would reflect a different credit risk adjustment depending on the movements in the market prices, which could be volatile.

Amounts in OCI relating to own credit are not recycled to the income statement even when the liability is derecognised and the amounts are realised. However, the standard does allow transfers within equity.

7.3.6 What else should entities in the oil & gas sector know about the new standard?

Entities that currently classify their investments as loans and receivables need to carefully assess whether their business model is based on managing the investment portfolio to collect the contractual cash flows from the financial assets. To meet that objective the entity does not need to hold all of its investments until maturity, but the business must be holding the investments to collect their contractual cash flows. We expect most oil & gas entities to be managing their loans and receivables (normally trade receivables) to collect their contractual cash flows. As a result, for many entities these new rules will not have a significant impact on their financial assets.

Entities in the oil & gas sector that manage their investments and monitor performance on a fair value basis will need to fair value their financial assets with gains and losses recognised in the income statement. Primarily that's because their business model is not considered to be based on managing the investment portfolio to collect the contractual cash flows and so a different accounting treatment is required. We expect only a minority of entities in the sector to be managing their investments on this basis.

Some entities made use of the cost exception in the existing IAS 39 for their unquoted equity investments. Under the new standard, these entities can continue to use cost only where it is an appropriate estimate of fair value. Oil & gas entities should be aware that the scenarios in which cost would be an appropriate estimate of fair value are limited to cases when insufficient recent information is available to determine the fair value. Therefore, entities will need to implement mechanisms to determine fair value periodically. There will be a substantial impact on entities that hold investments in unlisted entities where the investing entity doesn't have significant influence. This could significantly affect businesses as IFRS 9 requires a process or system in place to determine the fair value or range of possible fair value measurements.

Entities that currently classify their financial assets as available-for-sale and plan to make use of the "other comprehensive income option" to defer fair value gains should be aware that it is only available for equity investments on an instrument-by-instrument basis. These entities will not be able to use other comprehensive income for debt instruments. Once this election is chosen, it will irrevocably prevent the entity from recycling gains and losses through the income statement on disposal. For some entities in the sector this will remove some of the freedoms they currently enjoy with the accounting for debt instruments.

Entities in the oil & gas sector may want to consider early adopting the standard, particularly where they have previously recorded impairment losses on equity investments that are not held for trading or where entities would like to reclassify their financial assets. Upon adoption of this standard, entities need to apply the new rules retrospectively. This will allow some entities to reverse some impairment charges recognised on listed equity securities as a result of the global financial crisis. However, an important requirement here is that the entity must still be holding the investment. We expect that some oil & gas entities will consider early adopting the standard to take advantage of this.

Management should bear in mind that the financial instruments project is evolving. IFRS 9 is only the first part of the project to replace IAS 39. Other exposure drafts have been issued in respect of Asset-Liability Offsetting and Hedge accounting with the intention of improving and simplifying hedge accounting.

Appendices

Appendix A – Financial statement disclosure examples

The following financial statement disclosure examples represent extracts from the annual reports and accounts of the relevant companies. These should be read in conjunction with the relevant full annual report and accounts for a full understanding.

1 Exploration and Evaluation

1.1 Successful Efforts Method

Royal Dutch Shell Plc

Shell follows the successful efforts method of accounting for oil and natural gas exploration costs. Exploration costs are recognised in income when incurred, except that exploratory drilling costs are included in property, plant and equipment, pending determination of proved reserves. Exploration costs capitalised in respect of exploration wells that are more than 12 months old are written off unless (a) proved reserves are booked, or (b) (i) they have found commercially producible quantities of reserves, and (ii) they are subject to further exploration or appraisal activity in that either drilling of additional exploratory wells is underway or firmly planned for the near future or other activities are being undertaken to sufficiently progress the assessing of reserves and the economic and operating viability of the project.

Extract from Annual Report and Accounts 2010, Royal Dutch Shell Plc, see p. 104 for full details

Petrochina Company Limited

The successful efforts method of accounting is used for oil and gas exploration and production activities. Under this method, all costs for development wells, support equipment and facilities, and proved mineral interests in oil and gas properties are capitalised. Geological and geophysical costs are expensed when incurred. Costs of exploratory wells are capitalised as construction in progress pending determination of whether the wells find proved oil and gas reserves. Proved oil and gas reserves are the estimated quantities of crude oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The costs shall be that prevailing at the end of the period.

Extract from Annual Report and Accounts 2010, Petrochina Company Limited, see p. 175 for full details

1.2 Capitalisation and amortisation of exploration costs

1.2.1 Capitalisation with no amortisation

BP Plc

Licence and property acquisition costs

Exploration licence and leasehold property acquisition costs are capitalized within intangible assets and are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review includes confirming that exploration drilling is still under way or firmly planned or that it has been determined, or work is under way to determine, that the discovery is economically viable based on a range of technical and commercial considerations and sufficient progress is being made on establishing development plans and timing. If no future activity is planned, the remaining balance of the licence and property acquisition costs is written off. Lower value licences are pooled and amortized on a straight-line basis over the estimated period of exploration. Upon recognition of proved reserves and internal approval for development, the relevant expenditure is transferred to property, plant and equipment.

Extract from Annual Report and Accounts 2010, BP Plc, see p. 151 for full details

1.2.2 Capitalisation of geological and geophysical costs

OMV Aktiengesellschaft

The acquisition costs of geological and geophysical studies before the discovery of proved reserves form part of expenses for the period. The costs of wells are capitalized and reported as intangible assets until the existence or absence of potentially commercially viable oil or gas reserves is determined. Wells which are not commercially viable are expensed. The costs of exploration wells whose commercial viability has not yet been determined continue to be capitalized as long as the following conditions are satisfied:

1. Sufficient oil and gas reserves have been discovered to justify completion as a production well.
2. Sufficient progress has been made in assessing the economic and technical feasibility to justify beginning field development in the near future.

License acquisition costs and capitalized exploration and appraisal activities are generally not depreciated as long as they are related to unproved reserves, but tested for impairment.

Extract from Annual Report and Accounts 2010, OMV Aktiengesellschaft, see p. 80 for full details

1.2.3 No capitalisation of geological and geophysical costs

Total S.A.

Exploration costs

Geological and geophysical costs, including seismic surveys for exploration purposes are expensed as incurred. Mineral interests are capitalized as intangible assets when acquired. These acquired interests are tested for impairment on a regular basis, property-by-property, based on the results of the exploratory activity and the management's evaluation.

Extract from Annual Report and Accounts 2010, Total S.A., see p. 9 for full details

1.3 Initial recognition and reclassification out of E&E

BP Plc

Exploration and appraisal expenditure

Geological and geophysical exploration costs are charged against income as incurred. Costs directly associated with an exploration well are initially 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 and payments made to contractors. If potentially commercial quantities of hydrocarbons are not found, the exploration well is written off as a dry hole. If hydrocarbons are found and, subject to further appraisal activity, are likely to be capable of commercial development, the costs continue to be carried as an asset.

Costs directly associated with appraisal activity, undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons, including the costs of appraisal wells where hydrocarbons were not found, are initially capitalized as an intangible 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 approved by management, the relevant expenditure is transferred to property, plant and equipment.

Extract from Annual Report and Accounts 2010, see BP Plc, p. 152 for full details

BG Group Plc

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 commercial reserves have been discovered.

When proved reserves are determined, the relevant expenditure, including licence acquisition costs, is transferred to property, plant and equipment. Relevant exploration expenditure associated with unconventional activities, including coal seam and shale gas, is transferred to property, plant and equipment on the determination of proved plus probable reserves. Exploration expenditure transferred to property, plant and equipment is subsequently depreciated on a unit of production basis. Expenditure deemed to be unsuccessful is written-off to the income statement.

Extract from Annual Report and Accounts 2010, BG Group Plc, see p. 80 for full details

1.4 Impairment considerations for exploration assets

Total S.A.

Exploratory wells are tested for impairment on a well-by-well basis and accounted for as follows:

- Costs of exploratory wells which result in proved reserves are capitalized and then depreciated using the unit-of production method based on proved developed reserves;
- Costs of dry exploratory wells and wells that have not found proved reserves are charged to expense;
- Costs of exploratory wells are temporarily capitalized until a determination is made as to whether the well has found proved reserves if both of the following conditions are met:

- The well has found a sufficient quantity of reserves to justify its completion as a producing well, if appropriate, assuming that the required capital expenditures are made;
- The Group is making sufficient progress assessing the reserves and the economic and operating viability of the project. This progress is evaluated on the basis of indicators such as whether additional exploratory works are under way or firmly planned (wells, seismic or significant studies), whether costs are being incurred for development studies and whether the Group is waiting for governmental or other third-party authorization of a proposed project, or availability of capacity on an existing transport or processing facility.

Extract from Annual Report and Accounts 2010, Total S.A., see p. 9 for full details

1.5 Dry holes

Statoil ASA

Statoil uses the 'successful efforts' method of accounting for oil and gas exploration costs. Expenditures to acquire mineral interests in oil and gas properties and to drill and equip exploratory wells are capitalised as exploration and evaluation expenditure within intangible assets until the well is complete and the results have been evaluated. If, following evaluation, the exploratory wells has not found proved reserves, the previous capitalised costs are evaluated for de-recognition or tested for impairment.

Extract from Annual Report and Accounts 2010, Statoil ASA, see p. 12 for full details

Petrochina Company Limited

Exploratory wells in areas not requiring major capital expenditures are evaluated for economic viability within one year of completion of drilling. The related well costs are expensed as dry holes if it is determined that such economic viability is not attained. Otherwise, the related well costs are reclassified to oil and gas properties and are subject to impairment review (Note 3(f)). For exploratory wells that are found to have economically viable reserves in areas where major capital expenditure will be required before production can commence, the related well costs remain capitalised only if additional drilling is underway or firmly planned. Otherwise the related well costs are expensed as dry holes. The Group does not have any significant costs of unproved properties capitalised in oil and gas properties.

Extract from Annual Report and Accounts 2010, Petrochina Company Limited, see p. 175–176 for full details

2 Depreciation, Depletion and Amortisation

2.1 Depletion, Depreciation and amortisation

BP Plc

Oil and natural gas properties, including related pipelines, are depreciated using a unit-of-production method. The cost of producing wells is amortized over proved developed reserves. Licence acquisition, common facilities and future decommissioning costs are amortized over total proved reserves. The unit-of-production rate for the amortization of common facilities costs takes into account expenditures incurred to date, together with the future capital expenditure expected to be incurred in relation to these common facilities and excluding future drilling costs.

Extract from Annual Report and Accounts 2010, BP Plc, see p. 152 for full details

OAO Gazprom

Depletion of acquired production licenses is calculated using the units-of-production method for each field based upon proved reserves. Oil and gas reserves for this purpose are determined in accordance with the guidelines set by Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers, the World Petroleum Congress, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers, and were estimated by independent reservoir engineers.

Depreciation of assets (other than production licenses) is calculated using the straight-line method over their estimated remaining useful lives.

Extract from Annual Report and Accounts 2010, OAO Gazprom, see p. 13 for full details

2.2 DD&A – Unconventional activities

BG Group Plc

Exploration and production assets associated with unconventional activities, including coal seam and shale gas, are depreciated from commencement of commercial production in the fields concerned, using the unit of production method based on proved plus probable reserves, together with the estimated future development expenditure required to develop those reserves.

Extract from Annual Report and Accounts 2010, BG Group Plc, see p. 80 for full details

3 Estimation of reserves

3.1 Estimation of reserves

Royal Dutch Shell Plc

Unit-of-production depreciation, depletion and amortisation charges are principally measured based on Shell's estimates of proved developed oil and gas reserves. Estimates of proved reserves are also used in the determination of impairment charges and reversals. Also, exploration drilling costs are capitalised pending the results of further exploration or appraisal activity, which may take several years to complete and before any related proved reserves can be booked.

Proved reserves are estimated by reference to available geological and engineering data and only include volumes for which access to market is assured with reasonable certainty. Estimates of oil and gas reserves are inherently imprecise, require the application of judgement and are subject to regular revision, either upward or downward, based on new information such as from the drilling of additional wells, observation of long-term reservoir performance under producing conditions and changes in economic factors, including product prices, contract terms or development plans.

Changes to Shell's estimates of proved developed reserves affect prospectively the amounts of depreciation, depletion and amortisation charged and, consequently, the carrying amounts of oil and gas properties. It is expected, however, that in the normal course of business the diversity of the Shell portfolio will limit the effect of such revisions. The outcome of, or assessment of plans for, exploration or appraisal activity may result in the related capitalised exploration drilling costs being recorded in income in that period.

Information about the carrying amounts of oil and gas properties and the amounts charged to income, including depreciation, depletion and amortisation, is presented in Note 9.

Extract from Annual Report and Accounts 2010, Royal Dutch Shell Plc, see p. 107 for full details

3.2 Disclosure of use of SEC definitions

BG Group Plc

On 20 December 2007, BG Group ceased to be a United States Securities and Exchange Commission (SEC) registered company and the Group's SEC reporting obligations also ceased with effect from that date. BG Group continues voluntarily to use the SEC definition of proved reserves to report proved gas and oil reserves and disclose certain unaudited supplementary information detailed on pages 132 to 138. BG Group also now uses SEC definitions (introduced by the SEC in 2009) for probable reserves.

BG Group's strategy aims to connect competitively priced gas to high-value markets. Hydrocarbon reserves, and gas in particular, are developed in relation to the markets that they are intended to supply. Information in this section is therefore grouped as shown below to reflect the nature of the markets supplied by BG Group.

- UK
- Atlantic Basin – Canada, Egypt, Nigeria, Trinidad and Tobago and the USA
- Asia and the Middle East – Areas of Palestinian Authority, Australia, China, India, Kazakhstan, Oman and Thailand
- Rest of the World – Algeria, Bolivia, Brazil, Italy, Libya, Madagascar, Norway, Poland, Tanzania and Tunisia

Gas and oil reserves cannot be measured exactly since estimation of reserves involves subjective judgement. Therefore, all estimates are subject to revision. Changes in gas and oil prices in fields subject to Production Sharing Contracts (PSCs) may result in changes to entitlements and therefore proved reserves.

Proved reserves

BG Group utilises the SEC definition of proved reserves. Proved reserves are those quantities of oil and gas, that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations.

Proved developed reserves are those reserves that can be expected to be recovered through existing wells and with existing equipment and operating methods. Proved undeveloped reserves comprise total proved reserves less total proved developed reserves.

Probable reserves

BG Group adopted the SEC definition of probable reserves in 2009. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

Probable developed reserves are those reserves that can be expected to be recovered through existing wells and with existing equipment and operating methods. Probable undeveloped reserves comprise total probable reserves less total probable developed reserves.

Discovered resources
Discovered resources are defined by BG Group as the best estimate of recoverable hydrocarbons where commercial and/or technical maturity is such that project sanction is not expected within the next three years.

Risked exploration
Risked exploration resources are defined by BG Group as the best estimate (mean value) of recoverable hydrocarbons in a prospect multiplied by the 'chance of success'.

Total resources
Total resources are defined by BG Group as the aggregate of proved and probable reserves plus discovered resources and risked exploration. Total resources may also be referred to as total reserves and resources.
Extract from Annual Report and Accounts 2010, BG Group Plc, see p. 132 for full details

Statoil ASA
Proved oil and gas reserves have been estimated by internal experts on the basis of industry standards and governed by criteria established by regulations of the SEC. The SEC revised Rule 4-10 of Regulation S-X and changed a number of oil and gas reserve estimation requirements effective for the year ending 31 December 2009. The revised rule requires, on a prospective basis, the use of a price based on a 12 month average for reserve estimation instead of a single end-of-year price and allows for non-traditional sources such as bitumen extracted from oil sands to be included as reserves. The Financial Accounting Standards Board (FASB) aligned the requirements for supplemental oil and gas disclosures contemporaneously with the changes made by the SEC.
Extract from Annual Report and Accounts 2010, Statoil ASA, see p. 18 for full details

4 Impairment

Royal Dutch Shell Plc
Other than properties with no proved reserves (where the basis for carrying costs in the Consolidated Balance Sheet is explained under "Exploration costs"), the carrying amounts of goodwill are tested for impairment annually, while all assets are tested for impairment whenever events or changes in circumstances indicate that the carrying amounts for those assets may not be recoverable. If assets are determined to be impaired, the carrying amounts of those assets are written down to their recoverable amount, which is the higher of fair value less costs to sell and value-in-use.

Value-in-use is determined as the amount of estimated risk-adjusted discounted future cash flows. For this purpose, assets are grouped into cash generating units based on separately identifiable and largely independent cash inflows. Estimates of future cash flows used in the evaluation of impairment of assets are made using management's forecasts of commodity prices, market supply and demand, product margins and, in the case of oil and gas properties, expected production volumes. The latter takes into account assessments of field and reservoir performance and includes expectations about proved and unproved volumes, which are risk-weighted utilising geological, production, recovery and economic projections. Cash flow estimates are risk-adjusted to reflect local conditions as appropriate and discounted at a rate based on Shell's marginal cost of debt.
Extract from Annual Report and Accounts 2010, Royal Dutch Shell Plc, see p. 103 for full details

5 Decommissioning Obligation

5.1 Initial recognition

BG Group Plc
Where a legal or constructive obligation has been incurred, provision is made for the net present value of the estimated cost of decommissioning at the end of the producing lives of assets. When this provision gives access to future economic benefits, an asset is recognised and then subsequently depreciated in line with the life of the underlying producing asset, otherwise the costs are charged to the income statement. The unwinding of the discount on the provision is included in the income statement within finance costs. Any changes to estimated costs or discount rates are dealt with prospectively.
Extract from Annual Report and Accounts 2010, BG Group Plc, see p. 80 for full details

OMV Aktiengesellschaft
Provisions are set up for all present third parties obligations to where it is probable that the obligation will be settled and the amount of the obligation can be estimated reliably. Provisions for individual obligations are based on the best estimate of the amount necessary to settle the obligation.

Decommissioning and restoration obligations: The Group's core activities regularly lead to obligations related to dismantling and removal, asset retirement and soil remediation activities. These decommissioning and restoration obligations are principally of material importance in the E&P segment (oil and gas wells,

surface facilities), and in connection with filling stations on third-party property. At the time the obligation arises, it is provided for in full by recognizing the present value of future decommissioning and restoration expenses as a liability. An equivalent amount is capitalized as part of the carrying amount of long-lived assets. Any such obligation is calculated on the basis of best estimates. The capitalized asset is depreciated on a straight-line basis in R&M and using the unit- of production method in E&P. The unwinding of discounting leads to interest expense and accordingly to increased obligations at each balance sheet date until decommissioning or restoration. For present obligations relating to other environmental risks and measures, provisions are recognized in case where it is likely that such obligations will arise and the amount of the obligation can be estimated reliably.
Extract from Annual Report and Accounts 2010, OMV Aktiengesellschaft, see p. 82 for full details

5.2 Changes in estimates

Royal Dutch Shell Plc

Provisions for decommissioning and restoration costs, which are primarily in respect of hydrocarbon production facilities, are measured on the basis of current requirements, technology and price levels; the present value is calculated using amounts discounted over the useful economic life of the assets. The liability is recognised (together with a corresponding amount as part of the related property, plant and equipment) once an obligation crystallises in the period when a reasonable estimate can be made. The effects of changes resulting from revisions to the timing or the amount of the original estimate of the provision are reflected on a prospective basis, generally by adjustment to the carrying amount of the related property, plant and equipment.
Extract from Annual Report and Accounts 2010, Royal Dutch Shell Plc, see p. 106 for full details

Petrochina Company Limited

Provision for future decommissioning and restoration is recognised in full on the installation of oil and gas properties. The amount recognised is the present value of the estimated future expenditure determined in accordance with local conditions and requirements. A corresponding addition to the related oil and gas properties of an amount equivalent to the provision is also created. This is subsequently depreciated as part of the costs of the oil and gas properties. Any change in the present value of the estimated expenditure other than due to passage of time which is regarded as interest expense, is reflected as an adjustment to the provision and oil and gas properties.
Extract from Annual Report and Accounts 2010, Petrochina Company Limited, see p. 179 for full details

6 Financial Instruments and Derivatives

6.1 Scope of IAS 39

BG Group Plc

Within the ordinary course of business BG 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. Certain long-term gas sales contracts operating in the UK gas market have terms within the contract that constitute written options, and accordingly they fall within the scope of IAS 39. In addition, commodity instruments are used to manage certain price exposures in respect of optimising the timing and location of physical gas and LNG commitments. These contracts are recognised on the balance sheet at fair value with movements in fair value recognised in the income statement.

The Group uses various commodity based derivative instruments to manage some of the risks arising from fluctuations in commodity prices. Such contracts include physical and net-settled forwards, futures, swaps and options. Where these derivatives have been designated as cash flow hedges of underlying commodity price exposures, certain gains and losses attributable to these instruments are deferred in other comprehensive income and recognised in the income statement when the underlying hedged transaction crystallises or is no longer expected to occur. All other commodity contracts within the scope of IAS 39 are measured at fair value with gains and losses taken to the income statement. Gas contracts and related derivative instruments associated with the physical purchase and re-sale of third-party gas are presented on a net basis within other operating income.
Extract from Annual Report and Accounts 2010, BG Group Plc, see p. 81 for full details

6.2 Forward contracts and derivatives

OAO Gazprom

As part of trading activities the Group is also party to derivative financial instruments including forward and options contracts in foreign exchange, commodities, and securities. The Group's policy is to measure these instruments at fair value, with resultant gains or losses being reported within the profit and losses of the consolidated statement of comprehensive income. The fair value of derivative financial instruments is determined using actual market data information and valuation techniques based on prevailing market interest rate for similar instruments as appropriate. The Group has no material derivatives accounted for as hedges.

The Group routinely enters into sale and purchase transactions for the purchase and sales of gas, oil, oil products and other goods. The majority of these transactions are entered to meet supply requirements to fulfill contract obligations and for own consumption and are not within the scope of IAS 39 "Financial instruments: recognition and measurement".

Sale and purchase transactions of gas, oil, oil products and other goods and which are not physically settled or can be net settled and are not entered into for the purpose of receipt or delivery of non-financial item in accordance with the Group's expected purchase, sale or usage requirement are accounted for as derivative financial instruments in accordance with IAS 39 "Financial instruments: recognition and measurement". These instruments are considered as held for trading and related gains or losses are recorded within the profit and loss section of the consolidated statement of comprehensive income.

Derivative contracts embedded into sales-purchase contracts are separated from the host contracts and accounted for separately. Derivatives are carried at fair value with gains and losses arising from changes in the fair values of derivatives included within the profit and loss section of the consolidated statement of comprehensive income in the period in which they arise.
Extract from Annual Report and Accounts 2010, OAO Gazprom, see p. 10 for full details

6.3 Embedded derivatives

Centrica Plc

Derivatives embedded in other financial instruments or other host contracts are treated as separate derivatives when their risks and characteristics are not closely related to those of the host contracts and the host contracts are not carried at fair value, with gains or losses reported in the Income Statement. The closely-related nature of embedded derivatives is reassessed when there is a change in the terms of the contract which significantly modifies the future cash flows under the contract. Where a contract contains one or more embedded derivatives, and providing that the embedded derivative significantly modifies the cash flows under the contract, the option to fair value the entire contract may be taken and the contract will be recognised at fair value with changes in fair value recognised in the Income Statement.
Extract from Annual Report and Accounts 2010, Centrica Plc, see p. 79 for full details

Statoil ASA

Derivatives embedded in other financial instruments or in non-financial host contracts are recognised as separate derivatives when their risks and economic characteristics are not closely related to those of the host contracts, and the host contracts are not carried at fair value. When there is an active market for a commodity or other non-financial item subject of a purchase or sale contract, a pricing formula will, for instance, be considered to be closely related to the host purchase or sales contract if the price formula is based o the active market in question. A price formula with indexation to other markets or products will however result in recognition of a separate derivative. When there is no active market for the commodity or other non-financial item in question, Statoil assesses the characteristics of such a price related embedded derivative to be closely related to the host contract if the price formula is based on relevant indexations commonly used by other market participants. This applies to a number of Statoil's long term natural gas sales agreements. Contracts are assessed for embedded derivatives when Statoil becomes a party to them, including at the date of a business combination. Such embedded derivatives are measured at fair value at each period end, and the changes in fair value are recognised in profit or loss for the period.
Extract from Annual Report and Accounts 2010, Statoil ASA, see p. 16 for full details

6.4 Hedge Accounting

Centrica Plc

For the purposes of hedge accounting, hedges are classified either as fair value hedges, cash flow hedges or hedges of net investments in foreign operations.
Fair value hedges: A derivative is classified as a fair value hedge when it hedges the exposure to changes in the fair value of a recognised asset or liability. Any gain or loss from re-measuring the hedging instrument to fair value is recognised immediately in the Income Statement. Any gain or loss on the hedged item attributable to the hedged risk is adjusted against the carrying amount of the hedged item and recognised in the Income Statement. The Group discontinues fair value hedge accounting if the hedging instrument expires or is sold, terminated or exercised, the hedge no longer qualifies for hedge accounting or the Group

revokes the designation. Any adjustment to the carrying amount of a hedged financial instrument for which the effective interest method is used is amortised to the Income Statement. Amortisation may begin as soon as an adjustment exists and shall begin no later than when the hedged item ceases to be adjusted for changes in its fair value attributable to the risk being hedged.
Extract from Annual Report and Accounts 2010, Centrica Plc, see p. 79 for full details

OMV Aktiengesellschaft

Derivative instruments are used to hedge risks resulting from changes in interest rates, currency exchange rates and commodity prices. Derivative instruments are recognized at fair value, which reflects the estimated amounts that OMV would pay or receive if the positions were closed at balance sheet date. Quotations from banks or appropriate pricing models have been used to estimate the fair value of financial instruments at balance sheet date. Price calculation in these models is based on forward prices of the underlying, foreign exchange rates as well as volatility indicators as of balance sheet date. As a general rule unrealized gains and losses are recognized as income or expense, except where hedge accounting is applied. In the case of fair value hedges, changes in the fair value resulting from the risk being hedged for both the underlying and the hedging instrument are recognized as income or expense. For cash flow hedges, the effective part of the changes in fair value is recognized directly in equity, while the ineffective part is recognized immediately in the income statement. Where the hedging of cash flows results in an asset or liability, the amounts that are provided under equity are recognized in the income statement in the period in which the hedged position affects earnings.
Extract from Annual Report and Accounts 2010, OMV Aktiengesellschaft, see p. 81-82 for full details

7 Revenue Recognition

7.1 Revenue

Royal Dutch Shell Plc

Revenue from sales of oil, natural gas, chemicals and all other products is recognised at the fair value of consideration received or receivable, after deducting sales taxes, excise duties and similar levies, when the significant risks and rewards of ownership have been transferred, which is when title passes to the customer. For sales by Upstream operations, this generally occurs when product is physically transferred into a vessel, pipe or other delivery mechanism. For sales by refining operations, it is either when product is placed onboard a vessel or offloaded from the vessel, depending on the contractually agreed terms. For wholesale sales of oil products and chemicals it is either at the point of delivery or the point of receipt, depending on contractual conditions.
Extract from Annual Report and Accounts 2010, Royal Dutch Shell Plc, see p. 102-103 for full details

Petrochina Company Limited

Sales are recognised upon delivery of products and customer acceptance or performance of services, net of sales taxes and discounts. Revenues are recognised only when the Group has transferred to the buyer the significant risks and rewards of ownership of the goods in the ordinary course of the Group's activities, and when the amount of revenue and the costs incurred or to be incurred in respect of the transaction can be measured reliably and collectability of the related receivables is reasonably assured.

The Group markets a portion of its natural gas under take-or-pay contracts. Customers under the take-or-pay contracts are required to take or pay for the minimum natural gas deliveries specified in the contract clauses. Revenue recognition for natural gas sales and transmission tariff under the take-or-pay contracts follows the accounting policies described in this note. Payments received from customers for natural gas not yet taken are recorded as deferred revenues until actual deliveries take place.
Extract from Annual Report and Accounts 2010, Petrochina Company Limited, see p. 179 for full details

7.2 Revenue–Underlift

Royal Dutch Shell Plc

Revenue resulting from the production of oil and natural gas from properties in which Shell has an interest with other producers is recognised on the basis of Shell's working interest (entitlement method). Gains and losses on derivative contracts and the revenue and costs associated with other contracts that are classified as held for trading purposes are reported on a net basis in the Consolidated Statement of Income. Purchases and sales of hydrocarbons under exchange contracts that are necessary to obtain or reposition feedstock for Shell's refinery operations are presented net in the Consolidated Statement of Income.
Extract from Annual Report and Accounts 2010, Royal Dutch Shell Plc, see p. 103 for full details

7.3 Revenue – Exchanges and acting as agents

BP Plc

Revenues associated with the sale of oil, natural gas, natural gas liquids, liquefied natural gas, petroleum and petrochemicals products and all other items are recognized when the title passes to the customer. Physical exchanges are reported net, as are sales and purchases made with a common counterparty, as part of an arrangement similar to a physical exchange. Similarly, where the group acts as agent on behalf of a third party to procure or market energy commodities, any associated fee income is recognized but no purchase or sale is recorded.

Extract from Annual Report and Accounts 2010, BP Plc, see p. 157 for full details

7.4 Revenue–Trading activity

BP Plc

Additionally, where forward sale and purchase contracts for oil, natural gas or power have been determined to be for trading purposes, the associated sales and purchases are reported net within sales and other operating revenues whether or not physical delivery has occurred.

Extract from Annual Report and Accounts 2010, BP Plc, see p. 157 for full details

OAO Gazprom

Contracts to buy or sell non-financial items entered into for trading purposes and which do not meet the expected 'own use' requirements, such as contracts to sell or purchase commodities that can be net settled in cash or settled by entering into another contract, are recognized at fair value and associated gains or losses are recorded as Net gain from trading activity. These contracts are derivatives in the scope of IAS 39 for both measurement and disclosure. Revenues generated by trading activities are reported as a net figure, reflecting realized gross margins.

Extract from Annual Report and Accounts 2010, OAO Gazprom, see p. 15 for full details

8 Royalty and taxes

8.1 Petroleum taxes

Centrica Plc

The definition of an income tax in IAS 12, Income Taxes, has led management to judge that PRT should be treated consistently with other income taxes. The charge for the year is presented within taxation on profit from continuing operations in the Income Statement. Deferred amounts are included within deferred tax assets and liabilities in the Balance Sheet.

Extract from Annual Report and Accounts 2010, Centrica Plc, see p. 81 for full details

8.2 Production taxes

OAO Gazprom

Natural resources production tax on hydrocarbons, including natural gas and crude oil, is due on the basis of quantities of natural resources extracted. In particular NRPT for natural gas is defined as an amount of volume produced per fixed tax rate (RR 147 per mcm). NRPT for crude oil is defined as an amount of volume produced per fixed tax rate (RR 419 per ton) adjusted depending on the monthly average market prices of the Urals blend and the RR/USD exchange rate for the preceding month. Ultimate amount of the NRPT on crude oil depends also on the depletion and geographic location of the oil field. NRPT on gas condensate is defined as a fixed percentage from the value of the extracted mineral resource. Natural resources production tax is accrued as a tax on production and recorded within operating expenses.

Extract from Annual Report and Accounts 2010, OAO Gazprom, see p.12 for full details

9 Emission Trading Schemes

Total S.A.

In the absence of a current IFRS standard or interpretation on accounting for emission rights of carbon dioxide, the following principles have been applied:

- emission rights granted free of charge are accounted for at zero carrying amount;
- liabilities resulting from potential differences between available quotas and quotas to be delivered at the end of the compliance period are accounted for as liabilities and measured at fair market value;
- spot market transactions are recognized in income at cost; and
- forward transactions are recognized at their fair market value on the face of the balance sheet. Changes in the fair value of such forward transactions are recognized in income.

Extract from Annual Report and Accounts 2010, Total S.A., see p. 15 for full details

Centrica Plc

Carbon Emissions Reduction Target programme (CERT) UK-licensed energy suppliers are set a carbon

emission reduction target by the Government which is proportional to the size of their customer base. The current CERT programme runs from April 2008 to March 2011. The target is subject to an annual adjustment throughout the programme period to take account of changes to a UK-licensed energy supplier's customer base. Energy suppliers can meet the target through expenditure on qualifying projects which give rise to carbon savings. The carbon savings can be transferred between energy suppliers. The Group charges the costs of the programme to cost of sales and capitalises costs incurred in deriving carbon savings in excess of the annual target as inventory, which is valued at the lower of cost and net realisable value and which may be used to meet the carbon emissions reduction target in subsequent periods or sold to third parties. The inventory is carried on a first-in, first-out basis. The carbon emission reduction target for the programme period is allocated to reporting periods on a straight-line basis as adjusted by the annual determination process.
Extract from Annual Report and Accounts 2010, Centrica Plc, see p. 74 for full details

OMV Aktiengesellschaft

Emission allowances received free of cost from governmental authorities (EU Emissions Trading Scheme for greenhouse gas emissions allowances) reduce financial obligations related to CO2 emissions; provisions are recognized only for shortfalls.
Extract from Annual Report and Accounts 2010, OMV Aktiengesellschaft, see p. 83 for full details

10 Joint ventures

10.1 Accounting for joint ventures

BP Plc

A joint venture is a contractual arrangement whereby two or more parties (venturers) undertake an economic activity that is subject to joint control. Joint control exists only when the strategic financial and operating decisions relating to the activity require the unanimous consent of the venturers. A jointly controlled entity is a joint venture that involves the establishment of a company, partnership or other entity to engage in economic activity that the group jointly controls with its fellow venturers.

The results, assets and liabilities of a jointly controlled entity are incorporated in these financial statements using the equity method of accounting. Under the equity method, the investment in a jointly controlled entity is carried in the balance sheet at cost, plus post-acquisition changes in the group's share of net assets of the jointly controlled entity, less distributions received and less any impairment in value of the investment. Loans advanced to jointly controlled entities that have the characteristics of equity financing are also included in the investment on the group balance sheet. The group income statement reflects the group's share of the results after tax of the jointly controlled entity.

Financial statements of jointly controlled entities are prepared for the same reporting year as the group. Where necessary, adjustments are made to those financial statements to bring the accounting policies used into line with those of the group.

Unrealized gains on transactions between the group and its jointly controlled entities are eliminated to the extent of the group's interest in the jointly controlled entities. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred.

The group assesses investments in jointly controlled entities for impairment whenever events or changes in circumstances indicate that the carrying value may not be recoverable. If any such indication of impairment exists, the carrying amount of the investment is compared with its recoverable amount, being the higher of its fair value less costs to sell and value in use. Where the carrying amount exceeds the recoverable amount, the investment is written down to its recoverable amount.

The group ceases to use the equity method of accounting on the date from which it no longer has joint control or significant influence over the joint venture or associate respectively, or when the interest becomes held for sale.

Certain of the group's activities, particularly in the Exploration and Production segment, are conducted through joint ventures where the venturers have a direct ownership interest in, and jointly control, the assets of the venture. BP recognizes, on a line-by-line basis in the consolidated financial statements, its share of the assets, liabilities and expenses of these jointly controlled assets incurred jointly with the other partners, along with the group's income from the sale of its share of the output and any liabilities and expenses that the group has incurred in relation to the venture.
Extract from Annual Report and Accounts 2010, BP Plc, see p. 150 for full details

10.2 Accounting for jointly controlled operations

BG Group Plc

Most of BG Group's exploration and production activity is conducted through jointly controlled operations. The Group accounts for its own share of the assets, liabilities and cash flows associated with these jointly controlled operations using the proportional consolidation method. The results of undertakings acquired or disposed of are consolidated from or to the date when control passes to or from the Company.
Extract from Annual Report and Accounts 2010, BG Group Plc, see p. 79 for full details

Total S.A.

Investments in jointly-controlled entities are consolidated under the equity method. The Group accounts for jointly controlled operations and jointly-controlled assets by recognising its share of assets, liabilities, income and expenses.
Extract from Annual Report and Accounts 2010, Total S.A., see p. 7 for full details

10.3 Equity accounting and investments with less than joint control

Petrochina Company Limited

Associates are entities over which the Group has significant influence but not control, generally accompanying a shareholding of between 20% and 50% of the voting rights. Investments in associates are accounted for by the equity method of accounting in the consolidated financial statements of the Group and are initially recognised at cost.

Under this method of accounting the Group's share of the post-acquisition profits or losses of associates is recognised in the consolidated profit or loss and its share of post-acquisition movements in other comprehensive income is recognised in other comprehensive income. The cumulative post-acquisition movements are adjusted against the carrying amounts of the investments. When the Group's share of losses in an associate equals or exceeds its interest in the associate, including any other unsecured receivables, the Group does not recognise further losses, unless it has incurred obligations or made payments on behalf of the associate.

Unrealised gains on transactions between the Group and its associates are eliminated to the extent of the Group's interest in the associates; unrealised losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred. The Group's investment in associates includes goodwill identified on acquisition, net of any accumulated loss and is tested for impairment as part of the overall balance. Goodwill represents the excess of the cost of an acquisition over the fair value of the Group's share of the net identifiable assets of the acquired associate at the date of acquisition. Accounting policies of associates have been changed where necessary to ensure consistency with the policies adopted by the Group.
Extract from Annual Report and Accounts 2010, Petrochina Company Limited, see p. 172–173 for full details

10.4 Farm Outs

Statoil ASA

For exploration and evaluation asset acquisitions (farm in arrangements) in which Statoil has made arrangements to fund a portion of the selling partners' (farmor's) exploration and/or future development expenditures, these expenditures are reflected in the financial statements as and when the exploration and development work progresses. Exploration and evaluation asset dispositions (farm out arrangements) are accounted for on a historical cost basis with no gain or loss recognition.

Exchanges (swaps) of exploration and evaluation assets are accounted for at the carrying amounts of the assets given up with no gain or loss recognition.
Extract from Annual Report and Accounts 2010, Statoil ASA, see p. 12 for full details

10.5 Production Sharing Agreements

OMV Aktiengesellschaft

Exploration and production sharing agreements (EPSAs) are contracts for oil and gas licenses in which production is shared between one or more oil companies and the host country/national oil company in defined proportions. Under certain EPSA contracts the host country's/national oil company's profit share represents imposed income taxes and is treated as such for purposes of the income statement presentation.
Extract from Annual Report and Accounts 2010, OMV Aktiengesellschaft, see p. 79 for full details

Total S.A.

Development costs incurred for the drilling of development wells and for the construction of production facilities are capitalized, together with borrowing costs incurred during the period of construction and the present value of estimated future costs of asset retirement obligations. The depletion rate is usually equal to the ratio of oil and gas production for the period to proved developed reserves (unit-of-production method).

With respect to production sharing contracts, this computation is based on the portion of production and reserves assigned to the Group taking into account estimates based on the contractual clauses regarding the reimbursement of exploration, development and production costs (cost oil) as well as the sharing of hydrocarbon rights (profit oil).
Extract from Annual Report and Accounts 2010, Total S.A., see p. 9 for full details

11 Business Combinations and Goodwill

11.1 Allocation of purchase price to assets and liabilities acquired

BP Plc

Business combinations are accounted for using the acquisition method. The identifiable assets acquired and liabilities assumed are measured at their fair values at the acquisition date. The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at acquisition-date fair value, and the amount of any minority interest in the acquiree. Minority interests are stated either at fair value or at the proportionate share of the recognized amounts of the acquiree's identifiable net assets. Acquisition costs incurred are expensed and included in distribution and administration expenses.

Goodwill is measured as being the excess of the aggregate of the consideration transferred, the amount recognized for any minority interest and the acquisition-date fair values of any previously held interest in the acquiree over the fair value of the identifiable assets acquired and liabilities assumed at the acquisition date.

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.

Following initial recognition, goodwill is measured at cost less any accumulated impairment losses. Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate that the carrying value may be impaired. Impairment is determined by assessing the recoverable amount of the cash-generating unit to which the goodwill relates. Where the recoverable amount of the cash-generating unit is less than the carrying amount, an impairment loss is recognized. An impairment loss recognized for goodwill is not reversed in a subsequent period.
Extract from Annual Report and Accounts 2010, BP Plc, see p. 151 for full details

11.2 Common control transactions

Petrochina Company Limited

An acquisition of a business which is a business combination under common control is accounted for in a manner similar to a uniting of interests whereby the assets and liabilities acquired are accounted for at carryover predecessor values to the other party to the business combination with all periods presented as if the operations of the Group and the business acquired have always been combined. The difference between the consideration paid by the Group and the net assets or liabilities of the business acquired is adjusted against equity.
Extract from Annual Report and Accounts 2010, Petrochina Company Limited, see p. 172 for full details

11.3 Goodwill and Bargain Purchases

OAO Gazprom

The excess of the consideration transferred, the amount of any non-controlling interest in the acquiree and the acquisition-date fair value of any previous equity interest in the acquiree over the fair value of the group's share of the identifiable net assets acquired is recorded as goodwill. If this is less than the fair value of the net assets of the subsidiary acquired in the case of a bargain purchase, the difference is recognized directly in the statement of comprehensive income. Goodwill is tested annually for impairment as well as when there are indications of impairment. For the purpose of impairment testing goodwill is allocated to the cash generating units that are expected to benefit from synergies from the combination.
Extract from Annual Report and Accounts 2010, OAO Gazprom, see p. 9 for full details

11.4 Asset vs. Business

Statoil ASA

An acquisition of a business, (an integrated set of activities and assets that is capable of being conducted and managed for the purpose of providing a return directly to investors), is a business combination. Determining whether the acquisition meets the definition of a business combination requires judgement to be applied on a case to case basis. Acquisitions are assessed under the relevant criteria to establish whether the transaction represents a business combination or an asset purchase. Depending on the specific facts, acquisitions of exploration and evaluation licences for which a development decision has not yet been made, have largely been concluded to represent asset purchases.
Extract from Annual Report and Accounts 2010, Statoil ASA, see p. 11 for full details

12 Functional Currency

BP Plc

Functional currency is the currency of the primary economic environment in which an entity operates and is normally the currency in which the entity primarily generates and expends cash.

In individual companies, transactions in foreign currencies are initially recorded in the functional currency by applying the rate of exchange ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated into the functional currency at the rate of exchange ruling at the balance sheet date. Any resulting exchange differences are included in the income statement. Non-monetary assets and liabilities, other than those measured at fair value, are not retranslated subsequent to initial recognition.

In the consolidated financial statements, the assets and liabilities of non-US dollar functional currency subsidiaries, jointly controlled entities and associates, including related goodwill, are translated into US dollars at the rate of exchange ruling at the balance sheet date. The results and cash flows of non-US dollar functional currency subsidiaries, jointly controlled entities and associates are translated into US dollars using average rates of exchange. Exchange adjustments arising when the opening net assets and the profits for the year retained by non-US dollar functional currency subsidiaries, jointly controlled entities and associates are translated into US dollars are taken to a separate component of equity and reported in the statement of comprehensive income. Exchange gains and losses arising on long-term intragroup foreign currency borrowings used to finance the group's non-US dollar investments are also taken to equity. On disposal of a non-US dollar functional currency subsidiary, jointly controlled entity or associate, the deferred cumulative amount of exchange gains and losses recognized in equity relating to that particular non-US dollar operation is reclassified to the income statement.
Extract from Annual Report and Accounts 2010, BP Plc, see p. 151 for full details

Petrochina Company Limited

Items included in the financial statements of each entity in the Group are measured using the currency of the primary economic environment in which the entity operates ("the functional currency"). Most assets and operations of the Group are located in the PRC (Note 38), and the functional currency of the Company and most of the consolidated subsidiaries is the Renminbi ("RMB"). The consolidated financial statements are presented in the presentation currency of RMB.

Foreign currency transactions of the Group are accounted for at the exchange rates prevailing at the respective dates of the transactions; monetary assets and liabilities denominated in foreign currencies are translated at exchange rates at the date of the statement of financial position; gains and losses resulting from the settlement of such transactions and from the translation of monetary assets and liabilities are recognised in the consolidated profit or loss.

For the Group entities that have a functional currency different from the Group's presentation currency, assets and liabilities for each statement of financial position presented are translated at the closing rate at the date of the statement of financial position. Income and expenses for each statement of comprehensive income presented are translated at the average exchange rates for each period and the resulting exchange differences are recognised in other comprehensive income.
Extract from Annual Report and Accounts 2010, Petrochina Company Limited, see p. 173–174 for full details

Appendix B – IFRS/US GAAP differences

There are a number of differences between IFRS and US GAAP. This section provides a summary description of those IFRS/US GAAP differences that are particularly relevant to oil and gas entities. These differences relate to: exploration and evaluation, reserves and resources, depreciation, inventory valuation, impairment, disclosure of resources, decommissioning obligations, financial instruments, revenue recognition, joint ventures and business combinations.

1. Exploration and evaluation

Issue	IFRS	US GAAP
Capitalisation in the exploration and evaluation phase	No formal capitalisation models prescribed. IFRS 6 permits continuation of previous accounting policy for E&E assets but only until evaluation is complete. Wide range of policies possible from capitalisation of all E&E expenditures after licence acquisition to the expense of all such expenditures. However, changes to capitalisation polices are restricted to those which move the policy closer to compliance with the IFRS Framework.	Two formal models – successful efforts and full cost, in accordance with FAS 19 and Regulation S-X Rule 4-10. Types of expenditure that may be capitalised are defined.
Impairment of E&E assets	IFRS 6 provides specific relief for E&E assets. Cash-generating units (CGUs) may be combined up to the level of an operating segment for E&E assets. Impairment testing is required immediately before assets are reclassified from E&E to development. IFRS 6 also provides guidance in relation to identifying trigger events for an impairment review. Impairment charges against E&E assets are reversed if recoverable amount subsequently increases. An exploratory well in progress at period end which is determined to be unsuccessful subsequent to the balance sheet date based on substantive evidence obtained during the drilling process in that subsequent period suggests a non-adjusting event. These conditions should be carefully evaluated based on the facts and circumstances.	No similar relief for E&E assets. This is unlikely to result in a GAAP difference when the company uses successful efforts under US GAAP. A company applying full cost will probably be able to shelter unsuccessful exploration costs in pools with excess net present value until these are depleted through production. No reversal of impairment charges is permitted. If an exploratory well is in progress at the end of a period and after the balance sheet date (but before the financial statements for that period are issued) the well is determined not to have found reserves, the exploration costs incurred through the end of the period should be recorded as expense for that period. (ASC 855).

2. Reserves and Resources

Issue	IFRS	US GAAP
Definitions	No system of reserve classification prescribed. No restriction on the categories used for financial reporting purposes.	Entities must use the definitions of reserves and resources approved by the SEC (see section 2.8). Only proved reserves can be disclosed for financial reporting purposes. Proved and proved developed are used for depletion depending on the nature of the costs.

3. Depreciation of production and downstream assets

Issue	IFRS	US GAAP
Depletion of production assets	The reserve and resource classifications used for the depletion calculation are not specified. An entity should develop an appropriate accounting policy for depletion and apply the policy consistently, e.g., unit of production method. Commonly used categories of reserves include proved, proved developed, or proved and probable.	The definitions of reserves used are those adopted by the SEC. Proved reserves are used for depletion of acquisition costs and proved developed reserves are used for depletion of development costs.
Components of property, plant and equipment	Significant parts (components) of an item of PPE are depreciated separately if they have different useful lives. Pool-wide depletion of production assets not permitted.	Cost categories follow major types of assets as required by FAS 19 – individual items are not separated. Production assets held in a full cost pool depleted on a pool-wide basis.

4. Inventory valuation issues

Issue	IFRS	US GAAP
Impact of changes in market prices after balance sheet date Inventories	Inventories measured at the lower of cost and net realisable value. Net realisable value does not reflect changes in the market price of the inventory after the balance sheet date if this reflects events and conditions that arose after the balance sheet date.	Inventories measured at the lower of cost and market value. When market value is lower than cost at the balance sheet date, a recovery of market value after the balance sheet date but before the issuance of the financial statements is recognised as a type I (adjusting) post balance sheet event.

5. Impairment of production and downstream assets

Issue	IFRS	US GAAP
Impairment test triggers	Assets or groups of assets (cash generating units) are tested for impairment when indicators of impairment are present.	Long-lived assets, including proved properties, are tested for impairment whenever events or changes in circumstances indicate that the carrying amount of the asset or asset group may not be recoverable. Unproved properties are assessed periodically for impairment based on results of drilling activity, firm plans, etc. Full cost entities test impairment each period by performing a ceiling test.
Level at which impairment tested	Assets tested for impairment at the cash generating unit (CGU) level. CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. Production assets typically tested for impairment at the field level. A pool-wide impairment test is not permitted.	Similar to IFRS except that the grouping of assets is based on largely independent cash flows (in and out) rather than just cash inflows. Production assets accounted for under the full cost method are tested for impairment on a pool-wide basis.
Measurement of impairment	Impairment is measured as the excess of the asset's carrying amount over its recoverable amount. The recoverable amount is the higher of its value in use and fair value less costs to sell.	Impairment of proved properties is measured as the excess of the asset's carrying amount over its fair value. Impairment of unproved properties is based on results of activities. For full cost companies generally impairment equals the excess of net unamortised cost for each pool over the full cost ceiling as defined.
Reversal of impairment charge	Impairment losses, other than those relating to goodwill, are reversed when there has been a change in the economic conditions or in the expected use of the asset.	Impairment losses are never reversed.

6. Disclosure of resources

Issue	IFRS	US GAAP
Disclosure requirements	Disclosure requirements in respect of entities in exploration and evaluation stage (E&E stage) have been laid out in IFRS 6. Determination of commercial reserves is usually after the E&E stage and is accordingly outside the scope of IFRS 6. There are no specific requirements to disclose reserves and resources; however, IAS 1 includes general requirement to disclose additional information necessary for a fair presentation.	Detailed disclosures required by ASC 932 and SEC "Final Rule" (see section 2.8).

7. Decommissioning obligations

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

8. Financial instruments and embedded derivatives

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

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

As explained in section 7, the IASB have a number of ongoing projects relating to Financial Instruments and these should remove some of the differences. Differences between IFRS and US GAAP in the following table are based on IAS 39. Where transition to IFRS 9 or major IASB projects are ongoing, this has been noted.

Issue	IFRS	US GAAP
Definition of a derivative	A derivative is a financial instrument: • whose value changes in response to a specified variable or underlying rate (for example, interest rate); • that requires no or little net investment; and • that is settled at a future date. An option contract between an acquirer and a seller to buy or sell stock of an acquire at a future date that results in a business combination would be considered a derivative under IAS 39 for the acquirer; however, the option may be classified as equity from the seller's perspective.	Sets out similar requirements, except that the terms of the derivative contract should: • require or permit net settlement; and • identify a notional amount. There are therefore some derivatives that may fall within the IFRS definition, but not the US GAAP definition.

Issue	IFRS	US GAAP
Separation of embedded derivatives	Derivatives embedded in hybrid contracts are separated when: • the economic characteristics and risks of the embedded derivatives are not closely related to the economic characteristics and risks of the host contract; • a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative; and • the hybrid instrument is not measured at fair value through profit or loss. Under IFRS, reassessment of whether an embedded derivative needs to be separated is permitted only when there is a change in the terms of the contract that significantly modifies the cash flows that would otherwise be required under the contract. A host contract from which an embedded derivative has been separated, qualifies for the 'own use' exemption if the 'own use' criteria are met. Under IFRS 9, embedded derivatives are no longer bifurcated from financial assets; however, they will continue to require bifurcation from financial liabilities. See section 7.3 for further details.	Similar to IFRS except that there are some detailed differences of what is meant by 'closely related'. Under US GAAP, if a hybrid instrument contains an embedded derivative that is not clearly and closely related to the host contract at inception, but is not required to be bifurcated, the embedded derivative is continuously reassessed for bifurcation. The normal purchases and normal sales exemption cannot be claimed for a contract that contains a separable embedded derivative – even if the host contract would otherwise qualify for the exemption.
'Own use' exemption	Contracts to buy or sell a nonfinancial item that can be settled net in cash or another financial instrument are accounted for as financial instruments unless the contract was entered into and continues to be held for the purpose of the physical receipt or delivery of the non- financial item in accordance with the entity's expected purchase, sale or usage requirements. Application of the 'own use' exemption is a requirement – not an election.	Similar to IFRS, contracts that qualify to be classified as for normal purchases and normal sales do not need to be accounted for as financial instruments. The conditions under which the normal purchase and normal sales exemption is available is similar to IFRS but detailed differences exist. Application of the normal purchases and normal sales exemption is an election.

Issue	IFRS	US GAAP
Calls and put in debt instruments	Calls, puts and prepayment options embedded in a hybrid instrument are closely related to the debt host instrument if either: a) the exercise price approximates the amortised cost on each exercise date or b) the exercise price of a prepayment option reimburses the lender for an amount up to the approximate present value of the lost interest for the remaining term of the host contract. Once determined to be closely related as outlined above, these items do not require bifurcation. Under IFRS 9, calls and put options are never bifurcated for financial assets. See section 7.3 for further details.	Multiple tests are required to evaluate whether an embedded call or put is clearly and closely related to the debt host. The failure of one or both the below outlined tests is common and typically results in the need for bifurcation. Test 1 – If debt instrument is issued at a substantial premium or discount and a contingent call or put can accelerate repayment of principal, then the call or put is not clearly and closely related. Test 2 – If not, then it must be assessed whether the debt instrument can be settled in such a way that the holder would not recover substantially all of its recorded investments or embedded derivative would at least double the holder's initial return. However, this rule is subject to certain exceptions.
Day one gains or losses	The ability to recognise day one gains and losses is different under both frameworks with gains/losses more common under US GAAP. Day one gains and losses are recognised only when the fair value is evidenced by comparison with other observable current market transactions in the same instrument or is based on a valuation technique whose variables include only data on observable markets.	In some circumstances where the transaction price is not equal to the fair value, entities must recognise day one gains and losses even if some inputs to the measurement model are not observable.

Issue	IFRS	US GAAP
Assessing hedge effectiveness	IFRS requires that hedge be tested for effectiveness on an ongoing basis and that effectiveness be measured, at a minimum, at the time an entity prepares its annual or interim financial reports. Therefore if an entity is required to produce only annual financial statements, IFRS requires that effectiveness be tested only once in a year. However, the entity may choose to test effectiveness more frequently. **Shortcut method** IFRS does not allow a shortcut method by which an entity may assume no ineffectiveness. There is an IASB project on hedge accounting which will make it easier for hedges to qualify as effective.	US GAAP requires that hedge effectiveness be assessed whenever financial statements or earnings are reported and at least every three months (regardless of how often the financial statements are prepared). **Shortcut method** US GAAP provides for a shortcut method that allows an entity to assume no effectiveness for certain fair value or cash flow hedges of interest rate risk using interest rate swaps.
Credit risk and hypothetical derivatives	A hypothetical derivative perfectly matches the hedged risk of the hedged item. Because the hedged item would not contain the derivative counter party's (or an entity's own) credit risk, the hypothetical derivative would not reflect that credit risk. The actual derivative, however, would reflect credit risk. The resulting mismatch between changes in the fair value of the hypothetical derivative and the hedging instrument would result in ineffectiveness.	A hypothetical derivative will reflect an adjustment for the counter party's (or an entity's own) credit risk. This adjustment will be based upon the credit risk in the actual derivative. As such, no ineffectiveness will arise due to credit risk, as the same risk is reflected in both the actual and the hypothetical derivative.

Issue	IFRS	US GAAP
Cash flow hedges with purchased options	When hedging one-sided risk via a purchased option in a cash flow hedge of a forecasted transaction, only the intrinsic value of the option is deemed to be reflective of the one-sided risk of the hedged item. Therefore, in order to achieve hedge accounting with purchased options, an entity will be required to separate the intrinsic value and time value of the purchased option and designate as the hedging instrument only the changes in the intrinsic value of the option. As a result, for hedge relationships where the critical terms of the purchased option match the hedged risk, generally, the change in intrinsic value will be deferred in equity while the change in time value will be recorded in the income statement. In the proposed hedge accounting amendments, the change in time value will be either deferred in OCI or amortised over the option life – it is not recorded in the income statement.	US GAAP permits an entity to assess effectiveness based on total changes in the purchased option's cash flows (that is, the assessment will include the hedging instrument's entire change in fair value). As a result, the entire change in the option's fair value (including time value) may be deferred in equity based on the level of effectiveness. Alternatively, the hedge relationship can exclude time value from the hedging instrument such that effectiveness is assessed based on intrinsic value.
Foreign currency risk and location of hedging instruments	IFRS allows a parent company with a functional currency different from that of a subsidiary to hedge the subsidiary's transactional foreign currency exposure. It is not required that the entity with the hedging instrument to have the same functional currency as the entity with the hedged item. At the same time, IFRS does not require that the operating unit exposed to the risk being hedged with the consolidated accounts be a party to the hedging instrument.	Under the guidance, either the operating unit that has the foreign currency exposure is a party to the hedging instrument or another member of the consolidated group that has the same functional currency as that operating unit is a party to the hedging instrument. However, for another member of the consolidated group to enter into the hedging instrument, there may be no intervening subsidiary with a different functional currency.

Issue	IFRS	US GAAP
Hedging more than one risk	IFRS permits designation of a single hedging instrument to hedge more than one risk in two or more hedged items. For this, the risks hedged have to be identified clearly, effectiveness of the hedge should be demonstrated and it should be possible to ensure that there is specific designation of the hedging instrument and different risk positions. In the application of this guidance, a single swap may be separated by inserting an additional (hypothetical) leg, provided that each portion of the contract is designated as a hedging instrument in a qualifying and effective hedge relationship.	US GAAP does not allow a single hedging instrument to hedge more than one risk in two or more hedged items. US GAAP does not permit creation of a hypothetical component in a hedging relationship to demonstrate hedge effectiveness in the hedging of more than one risk with a single hedging instrument.
Cash flow hedges and basis adjustments on acquisition of non financial items	Under IFRS, basis adjustment commonly refers to an adjustment of the initial carrying value of a nonfinancial asset or nonfinancial liability that resulted from a forecasted transaction subject to a cash flow hedge. That is, the initial carrying amount of the nonfinancial item recognised on the balance sheet (i.e., the basis of the hedged item) is adjusted by the cumulative amount of the hedging instrument's fair value changes that were recorded in equity. IFRS gives entities an accounting policy choice to either basis adjust the hedged item (if it is a nonfinancial item) or release amounts to profit or loss as the hedged item affects earnings. The current hedging ED proposes to remove this policy choice, and it will be mandatory to basis adjust the hedged item.	In the context of a cash flow hedge, US GAAP does not permit basis adjustments. That is, under US GAAP, an entity is not permitted to adjust the initial carrying amount of the hedged item by the cumulative amount of the hedging instruments' fair value changes that were recorded in equity. US GAAP does refer to 'basis adjustments' in a different context wherein the term is used to refer to the method by which, in a fair value hedge, the hedged item is adjusted for changes in its fair value attributable to the hedged risk.

9. Revenue Recognition

Issue	IFRS	US GAAP
Overlift/underlift	Revenue is recognised in overlift/underlift situations on a modified entitlements basis. Note that the joint revenue project between IASB and FASB may remove difference in approach.	US GAAP permits a choice of the sales/liftings method or the entitlements method for revenue recognition.

10. Joint ventures

Issue	IFRS	US GAAP
Definition	A joint venture is a contractual agreement that requires all significant decisions to be taken unanimously by all parties sharing control.	A corporate joint venture is a corporation owned and operated by a small group of businesses as a separate and specific business or project for the mutual benefit of the members of the group.
Types of joint venture	IFRS distinguishes between three types of joint venture: • jointly controlled entities – the arrangement is carried on through a separate entity (company or partnership); • jointly controlled operations – each venturer uses its own assets for a specific project; and • jointly controlled assets – a project carried on with assets that are jointly owned. Note that when IFRS 11 is adopted, there will only be two types of joint arrangement – joint operation and joint venture. See section 6.1 for more details. Jointly controlled entities may fall into either category, depending on rights and obligations.	Refers only to jointly controlled entities, where the arrangement is carried on through a separate corporate entity.

Issue	IFRS	US GAAP
Jointly controlled entities	Either the proportionate consolidation method or the equity method is allowed. Proportionate consolidation requires the venturer's share of the assets, liabilities, income and expenses to be either combined on a line-by-line basis with similar items in the venturer's financial statements, or reported as separate line items in the venturer's financial statements. Note that when IFRS 11 is adopted, proportionate consolidation will not be allowed for joint ventures. See section 6.1 for more details.	Prior to determining the accounting model, an entity first assesses whether the joint venture is a Variable Interest Entity (VIE). If the joint venture is a VIE, the primary beneficiary should consolidate. If the joint venture is not a VIE, venturers assess the accounting using the voting interest model. If control does not exist then typically the arrangement will meet the criteria to apply the equity method to measure the investment in the jointly controlled entity. Proportionate consolidation is generally not permitted except for unincorporated entities operating in certain industries, such as the oil & gas industry.
Contributions to a jointly controlled entity	A venturer that contributes nonmonetary assets, such as shares or non-current assets, to a jointly controlled entity in exchange for an equity interest in the jointly controlled entity recognises in its consolidated income statement the portion of the gain or loss attributable to the equity interests of the other venturers, except when: • the significant risks and rewards of the contributed assets have not been transferred to the jointly controlled entity; • the gain or loss on the assets contributed cannot be measured reliably; or • the contribution transaction lacks commercial substance.	Common practice is for an investor (venturer) to record contributions to a joint venture at cost (i.e., the amount of cash contributed and the book value of other non-monetary assets contributed). However, sometimes, appreciated non-cash assets are contributed to a newly formed joint venture in exchange for an equity interest when others have invested cash or other financial-type assets with a ready market value. Practice and existing literature in this area vary. Arguments have been put forth that assert that the investor contributing appreciated non-cash assets has effectively realised part of the appreciation as a result of its interest in the venture to which others have contributed cash. Immediate gain recognition can be appropriate. The specific facts and circumstances will affect gain recognition, and require careful analysis.

11. Business Combinations

IFRS and US GAAP have largely converged in this area. The revised business combinations standards which were recently issued eliminated many historical differences, although certain important differences remain, the details of which are included in the following table:

Issue	IFRS	US GAAP
Cost of acquisitions – Contingent Consideration	Contingent consideration classified as an asset or liability will likely be a financial instrument measured at fair value, with any gains or losses recognised in profit or loss (or OCI as appropriate). Contingent consideration classified as an asset or liability that is not a financial instrument is subsequently accounted for in accordance with the provisions standard or other IFRSs as appropriate.	Contingent consideration classified as an asset or liability is remeasured to fair value at each reporting date until the contingency is resolved. The changes in fair value are recognised in earnings unless the arrangement is a hedging instrument for which ASC 815, as amended by new business combination guidance (included in ASC 805), requires the changes to be initially recognised in other comprehensive income.
Recognition of contingent liabilities and contingent assets	The acquiree's contingent liabilities are recognised separately at the acquisition date provided their fair values can be measured reliably. The contingent liability is measured subsequently at the higher of the amount initially recognised or the best estimate or the best estimate of the amount required to settle (under the provisions guidance). Contingent assets are not recognised.	Acquired liabilities and assets subject to contingencies are recognised at fair value if fair value can be determined during the measurement period. If fair value cannot be determined, companies should typically account for the acquired contingencies using existing guidance. An acquirer shall develop a systematic and rational basis for subsequently measuring and accounting for assets and liabilities arising from contingencies depending on their nature.
Contingent consideration – Seller accounting	Under IFRS, a contract to receive contingent consideration that gives the seller the right to receive cash or other financial assets when the contingency is resolved meets the definition of a financial asset. When a contract for contingent consideration meets the definition of a financial asset, it is measured using one of the measurement categories specified in IAS 39.	Under US GAAP, the seller should determine whether the arrangement meets the definition of a derivative. If the arrangement meets the definition of derivative, the arrangement should be recorded at fair value. If the arrangement does not meet the definition of derivative, the seller should make an accounting policy election to record the arrangement at either fair value at inception or at the settlement amount at the earlier of when consideration is realised or is realisable.

Issue	IFRS	US GAAP
Non controlling interests	Entities have an option, on a transaction-by-transaction basis, to measure non controlling interests at their proportion of the fair value of the identifiable net assets or at full fair value. This option applies only to instruments that represent present ownership interests and entitle their holders to a proportionate share of the net assets in the event of liquidation. All other components of non controlling interest are measured at fair value unless another measurement basis is required by IFRS. The use of the full fair value option results in full goodwill being recorded on both the controlling and non controlling interest. In addition non gains or losses will be recognised in earnings for transactions between the parent company and the non-controlling interests, unless control is lost.	Non controlling interests are measured at fair value. In addition, no gains or losses are recognised in earnings for transactions between the parent company and the non controlling interests, unless control is lost.
Combinations involving entities under common control	IFRS does not specifically address such transactions. Entities develop and consistently apply an accounting policy; Management can elect to apply purchase accounting or the predecessor value method to a business combination involving entities under common control. The accounting policy can be changed only when criteria for a change in an accounting policy are met in the applicable guidance.	Combinations of entities under common control are generally recorded at predecessor cost, reflecting the transferor's carrying amount of the assets and liabilities transferred.

12. Goodwill

Issue	IFRS	US GAAP
Impairment of goodwill	Goodwill impairment testing is performed under a one-step approach: Recoverable amount (higher of its fair value less costs to sell and its value in use) is compared with its carrying amount. Impairment loss recognised in operating results as the excess of the carrying amount over the recoverable amount. Impairment loss is allocated first to goodwill and then on a pro rata basis to the other assets of the CGU or group of CGU's to the extent that impairment loss exceeds the book value of goodwill.	Goodwill impairment testing is performed under a two-step approach: 1) Fair value and carrying amount of the reporting unit, including goodwill, are compared. If the fair value of the reporting unit is less than the carrying amount, Step 2 is completed to determine the amount of the goodwill impairment loss, if any. 2) Goodwill impairment is measured as the excess of the carrying amount of goodwill over its implied fair value. The implied fair value of goodwill calculated in the same manner that goodwill is determined in a business combination – is the difference between the fair value of the reporting unit and the fair value of the various assets and liabilities included in the reporting unit. Any loss recognised is not permitted to exceed the carrying amount of goodwill. The impairment charge is included in operating income.

13. *Fair value of assets and liabilities*

Issue	IFRS	US GAAP
Definition of fair value	Fair value is the amount for which the asset could be exchanged or a liability be settled between knowledgeable, willing parties in an arm's length transaction. IFRS does not specifically refer to either an entry or exit price. IFRS does not contain guidance about which market should be used as a basis of measuring fair value when more than one market exists. The fair value definition of a liability uses a settlement concept.	Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The exchange price represents an exit price. Fair value measurements include the concept of 'highest and best use' which refers to how the market participants would use an asset to maximise the value of asset or group of assets. The fair value definition of a liability is based on a transfer concept and reflects non-performance risk, which generally considers the entity's own credit risk.

Under both IFRS and US GAAP, observable markets typically do not exist for many assets acquired in a business combination. As a result for many non financial assets, the principal or most advantageous market will be represented by a hypothetical market, which likely will be the same under both frame works.

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