Accounting in the Oil & Gas Industry
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Foreword

The nature of the oil and gas industry is such that accounting for its activities presents many difficulties. Oil & Gas projects require significant upfront investment, and there is uncertainty over prospects. The fact that project lives are long has led to a variety of approaches being developed by companies, and a range of country-specific guidance for the sector.

The need for a common financial reporting language that will enable users to have comparable information, and achieve greater global consistency and transparency is leading more countries around the world to adopt IFRSs.

Many countries converted into IFRS in 2005 and conversions are imminent for other countries such as Argentina and Mexico. The U.S. Securities and Exchange Commission has been studying the possibility of moving U.S. listed companies to IFRS, which shows that although there is a rough roadmap to be followed, there is common ground between the International Accounting Standards Board and the Financial Accounting Standards Board. Today over 100 countries either require or allow the application of IFRS- amongst them the EU countries (including Cyprus), Australia, Canada, Brazil, Japan, South Korea and Russia. Other countries that are considering to join in the future include India and China.

Even though the International Accounting Standards Board has issued IFRS 6 to address Exploration for and Evaluation of Mineral Resources, it is widely recognized that extractive activities is an area in which there is little IFRS guidance. This has led to variation in practice between companies applying IFRS.

Based on our experience, we outline the main sector-specific accounting issues that are significant to oil and gas companies. This publication considers currently effective standards and notes future developments that could impact accounting in the sector. This is not meant to be a comprehensive list; we have not considered in this publication material accounting topics of a generic nature (such as defined benefit pension scheme accounting, share-based payments, presentation of financial statements and business combinations).

This publication provides a helpful summary into the IFRS requirements for the oil and gas sector. Should the need arise, our International Financial Reporting Group (IFRG), and specifically Maria Karantoni, who is a Board member of both the IFRG and the Oil and Gas Service Line team, are ready, willing and able, to provide specific support for complicated circumstances requiring an in depth evaluation.

Michael M. Antoniades
Board Member
Exploration and evaluation (E&E) assets and Development assets

The two most common accounting approaches applied by IFRS companies are successful efforts and modified full cost accounting. There is no definition of these methods in IFRSs.

The costs involved in E&E and development activities are considerable, and often there are years between the start of exploration and the commencement of production. Even with today's advanced technology, exploration is a risky and complex activity. These factors create specific challenges in accounting for E&E expenditure.

There was no IFRS that specifically addressed E&E activities until IFRS 6 became effective in 2006. IFRS 6 was intended to be a temporary standard while the IASB undertook an in-depth project on extractive activities.

Traditionally, oil and gas companies have accounted for E&E costs using one of two broadly defined methods: the successful efforts method or the full cost method. However, as there is no single accepted definition of either method under IFRS, the application of these approaches can vary.

Capitalization of E&E expenditure

Asset recognition requirements for E&E expenditure

Prior to IFRS 6, expenditure would not be recognized as an asset unless it was probable that it would give rise to future economic benefits. This would mean that expenditure on an exploration activity likely would be expensed until the earlier of the time at which:

- it is determined that commercial reserves are present.

Applying this test, it would be rare for expenditure other than license acquisition costs to be capitalized prior to the determination of commercial reserves.

IFRS 6 relaxes this approach for E&E assets, allowing capitalization of E&E costs by expenditure class if the company elects that accounting policy.

Definition of E&E expenditure

Accounting standards to be applied depend on the stage of the project

IFRS 6 applies only to E&E expenditure. Outside of the scope of IFRS 6 the usual IFRS accounting requirements apply, including those in respect of impairment testing.

A non-exhaustive list of E&E expenditure that can be capitalized is provided by the standard. For example, the cost of geological and geophysical studies, the acquisition of rights to explore, exploratory drilling, trenching and sampling.

The stage of projects needs to be monitored to ensure that accounting policies are applied appropriately. IFRS 6 excludes pre-license expenditure from the scope of E&E costs, implying that E&E activities commence on acquisition of the legal rights to explore an area. Also, IFRS 6 does not apply to expenditure incurred after the technical feasibility and commercial viability of extracting the oil and gas are demonstrable. Determining when this is demonstrable, and the level of detail at which this assessment should be made, can involve considerable judgment and requires close communication between finance and technical specialists.

Classification, initial and subsequent measurement

Classification of expenditure forms the basis of presentation and subsequent measurement of assets

E&E assets are a separate class of asset that is measured initially at cost. E&E assets are classified as tangible or intangible assets depending on their nature. Tangible E&E assets may include the items of plant and equipment used for exploration activity, such as vehicles and drilling rigs. Intangible E&E assets may include costs of exploration permits and licenses as well as depreciation of tangible assets consumed in developing intangible assets such as exploratory wells.

The classification of E&E assets as tangible or intangible is the basis for accounting policy choices for both the subsequent measurement of the assets and for disclosure purposes. Subsequent to initial recognition, an entity applies either the cost model or the revaluation model, as appropriate, to each of its tangible and intangible E&E assets.

The cost model is applied to tangible assets used for E&E and intangible assets with a finite life used for E&E. They are depreciated or amortized respectively over their useful lives.

If an entity elects to apply the revaluation model, then the model applied is consistent with the classification of the assets as tangible or intangible. Tangible E&E assets are revalued using the property, plant and equipment model and intangible E&E assets using the intangible asset model. E&E assets are treated as a separate class of assets for disclosure purposes and a policy of revaluation is applied to all assets in a class.

Pre-Exploration expenditure

Entities are required to identify and account for pre-exploration expenditure separately from E&E expenditure

Pre-license costs are excluded from the scope of E&E costs. The recognition and measurement of pre-exploration expenditure is not addressed by IFRSs. In this respect an entity should choose an accounting policy to be
applied consistently. Pre-exploration expenditure typically includes the acquisition of speculative seismic data and expenditure on the subsequent geological and geophysical analysis of this data.

Development Expenditure

Entities identify and account for development expenditure separately from E&E expenditure

IFRS does not contain a definition of development activities or expenditure in the context of extractive activities including Oil and Gas. In the extractive industries, ‘development’ often refers to the phase in which the technical feasibility and commercial viability of extracting a mineral resource have been demonstrated and an identified mineral reserve is being prepared for production - e.g. construction of access to the mineral reserves.

A significant factor in determining technical feasibility and commercial viability is likely to be the existence of proven and probable reserves. During the commercial viability assessment an entity will also need to consider whether it has access to adequate resources to proceed with development activities.

Once the technical feasibility and commercial viability of extracting a mineral resource are demonstrable, expenditure related to the development of that mineral resource should not be recognized as E&E assets. IFRS does not prescribe the accounting for costs incurred on the development and extraction of resources. An entity should choose an accounting policy and apply it consistently.

Reclassifying exploration and evaluation assets

Per IFRS 6, when the technical feasibility and commercial viability of extracting a mineral resource are demonstrable, an entity:
• stops capitalizing E&E costs for that area;
• tests recognized E&E assets for impairment; and
• ceases classifying any unimpaired E&E assets (tangible and intangible) as E&E.

For E&E assets reclassified to development assets, an entity chooses an accounting policy, to be applied consistently, to classify such assets either as tangible or intangible development assets. Intangible E&E assets may be reclassified into tangible development assets or intangible development assets and vice versa.
Component accounting
Determining components requires judgment, and systems need to be capable of tracking components separately. The cost of an item of property, plant and equipment needs to be allocated into its significant parts (components). Each part is then depreciated separately using the appropriate depreciation method, rate and period. This process may involve significant judgment.

An item of property, plant and equipment should be separated into components when those parts are significant in relation to the total cost of the item.

Some oil and gas companies that have been applying full cost accounting under previous GAAP may have been calculating DD&A at a cost centre (typically a country) level. While there is no cost-pool concept under IFRS, the standard does allow companies to group and depreciate components within the same asset class together, provided they have the same useful life and depreciation method. However, it is unlikely that development or production oil and gas assets will be able to be grouped at a level greater than a field; this is because each field may be significant and the lives of the fields, and therefore depreciation rates, will vary.

Depreciation method
Companies need to choose the most appropriate depreciation method.

There is no preferable depreciation method under IFRS. Oil and gas companies have the option to use the straight-line method, the reducing balance method or the unit-of-production method, as long as it reflects the pattern in which the economic benefits associated with the asset are consumed. The unit-of-production method is most commonly used to deplete upstream oil and gas assets, using a ratio that reflects the annual production of a field in proportion to the estimate of reserves within that field.

IFRS provides no specific guidance on how the assumptions within the reserve estimates should be calculated or approximated. Consequently, practice varies as to which reserves base is used in the calculation of DD&A.

Commencement of depreciation/amortization
Available for use
Depreciation or amortization starts when an asset is available for use. For assets in the development stage there may be pilot testing phases prior to the start of full production. Whether incidental production arising during any such phase triggers depreciation depends on the assessment of whether the asset is available for use.

Some E&E assets (e.g. a drilling rig) may be available for use immediately and so could be depreciated/amortized during the E&E phase. Other assets will not be available for use until the whole field is ready to commence operations. In our view, there are two reasonable approaches to determining when depreciation/amortization of E&E assets should commence.

• Commence depreciation/amortization when the whole field is ready to commence operations, since, in effect, it is from this point that economic benefits will be realized.

• Commence depreciation/amortization during the E&E phase as the assets are available for use when considered on a stand-alone basis; however such depreciation/amortization is capitalized to the extent that the assets are used in the development of other assets.
Impairment of non-financial assets

Annual impairment testing for intangible assets that are not yet available for use is relaxed for E&E assets

Exemptions from certain impairment testing requirements for E&E assets

IFRS 6 requires E&E assets to be assessed for impairment only when facts and circumstances suggest that the carrying amount of an E&E asset may exceed its recoverable amount and, on the transfer of E&E assets to development assets. Unlike for other intangible assets, there is no requirement to assess whether an indication for impairment exists at the end of each reporting period until an entity has sufficient information to make a conclusion about the technical feasibility and commercial viability of extraction.

The standard includes industry-specific examples of ‘trigger events’ that indicate that an E&E asset should be tested for impairment:

- right to explore in the specific area has expired or will expire in the near future and is not expected to be renewed;
- substantive expenditure on further exploration for and evaluation of mineral resources in the specific area is neither budgeted nor planned;
- commercially viable reserves have not been discovered and the company plans to discontinue activities in the specific area; and
- data exists to show that while development activity will proceed, the carrying amount of the E&E asset will not be recovered in full through such activity.

Impairment testing calculations are performed in line with general impairment requirements and take into account the time value of money.

Development and production assets

Reporting date consideration of impairment indicators

For non-current assets (other than goodwill and E&E assets) IAS 36 Impairment of Assets requires companies to assess at the end of each reporting period whether there is an indication of possible impairment. If there is such an indication, then impairment testing is required.

An impairment loss is recognized to the extent that the carrying amount of an asset or cash generating unit exceeds its recoverable amount. If recoverable
amount cannot be determined for the individual asset, because the asset does not generate independent cash inflows separate from those of other assets, then the impairment loss is recognized and measured based on the cash-generating unit to which the asset belongs.

Cash-generating units (CGUs)
Identification of appropriate CGUs can be complex
A CGU is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows from other assets or group of assets of the oil and gas company.

In our experience, many companies in the oil and gas sector base the identification of CGUs on license, field or core areas. For some companies that operate a number of areas or fields that have shared infrastructure and E&E assets, the identification of CGUs can be more complex.

An accounting policy is also needed for allocating E&E assets to CGUs when an impairment test is to be performed. For assets during the E&E phase, CGUs can be aggregated to form a group of units for impairment testing purposes. Allocation of assets to CGUs and impairment groups requires judgment and the interaction with indicators of impairment will require consideration.

Indicators of impairment
Some examples of indicators of impairment are outlined below.

- **Market value has declined significantly or the company has operating or cash losses.** For example, a significant downward movement in the oil price may result in operating cash losses and represent a trigger for impairment.
- **Technological obsolescence.**
- **Competition.**
- **Market capitalization.** For example, the carrying amount of the oil and gas company’s net assets exceeds its market capitalization. This may be a particular risk for companies with large E&E assets.

  - **Significant regulatory changes.** For example, increased regulation of environmental rehabilitation processes.
  - **Physical damage to the asset.** For example, damage to a drilling rig caused by an explosion.
  - **Significant adverse effect on the company that will change the way in which the asset is used/expected to be used.** For example, the re-nationalization requirements of some governments may lead to some projects being diluted to accommodate a government interest.

Goodwill
Impairment testing at least annually
Under IFRS, oil and gas companies are required to test goodwill (and intangible assets with indefinite useful lives) for impairment at least annually, irrespective of whether indicators of impairment exist. Additional testing at interim reporting dates is required if impairment indicators are present. Goodwill by itself does not generate cash inflows independently of other assets or group of assets and therefore is not tested for impairment separately. Instead, it should be allocated to the acquirer’s CGUs that are expected to benefit from the synergies of the related business combination.

Goodwill is allocated to a CGU that represents the lowest level within the company at which the goodwill is monitored for internal management purposes. The CGU cannot be larger than an operating segment as defined in IFRS 8 Operating Segments, before aggregation. An impairment loss is recognized and measured at the amount by which the CGU’s carrying amount, including goodwill, exceeds its recoverable amount.

Impairment reversals
Reversal of impairment losses restricted
Impairment losses related to goodwill cannot be reversed. However, for other assets companies assess whether there is an indication that a previously recognized impairment loss has reversed. If there is such an indication, then impairment losses are reversed if the recoverable amount has increased, subject to certain restrictions.
Decommissioning and environmental provisions

Oil and gas companies often incur an obligation to meet the costs of site restoration, decommissioning and dismantling assets as a result of E&E activities. These costs are likely to be a significant item of expenditure for most oil and gas companies.

Timing of recognition

A present obligation that is more likely than not

Decommissioning and environmental provisions are covered by IAS 37 Provisions, Contingent Liabilities and Contingent Assets. A provision is recognized when there is a present obligation (legal or constructive), an outflow of resources is probable and a reliable estimate of the amount of the obligation can be made. Probable is defined as more likely than not.

A present obligation can be legal or constructive in nature. For oil and gas companies a legal obligation for decommissioning and remediation often is contained in the license agreement and related contracts, or in legislation. However, in some countries environmental legislation may be less developed and it may be difficult to determine the extent of the obligation. A constructive obligation may arise from a company’s published policies about environmental clean-up or from past practices.

An obligation to make good damage or dismantle equipment is provided for in full when the damage is caused or the asset installed.

When the provision arises on initial recognition of an asset, the corresponding debit is treated as part of the cost of the related asset and is not recognized immediately in profit or loss. In addition, the effect of any changes to the estimate of a decommissioning liability is generally added to, or deducted from, the cost of the asset.

Measurement

Judgment is required to measure provisions

The provision is measured at the best estimate of costs to be incurred. This takes the time value of money into account, if material. The best estimate may be based on the single most likely cost of decommissioning and takes uncertainties into account in either the cash flows or discount rate used in measuring the provision. The discount rate should reflect the risks specific to the liability and adjusting the discount rate for risk often is complex and involves a high degree of judgment.

Many complexities exist in calculating an estimate of expenditure to be incurred. Technological advances may reduce the ultimate cost of decommissioning and may also affect the timing by extending the expected recoveries from reservoirs. The estimate is updated at each reporting date.

For midstream and downstream assets with indefinite useful lives, the timing of decommissioning may be so distant that the present value of liabilities may not be material in early years. When there is uncertainty about the useful life of the asset, this uncertainty needs to be taken into account in the measurement of the provision. In such cases, it may be that the provision is not significant until the expected date at which the facilities will be decommissioned is less distant. Significant judgment may be required in measuring the provision.
Joint arrangements

The term joint venture is a widely used operational term, although not all such arrangements are joint ventures for accounting purposes. A recently issued standard (IFRS 11 “Investments in joint arrangements”) could significantly impact the accounting.

Determining whether an arrangement is a joint arrangement

Companies need to review their arrangements to determine whether they should be accounted for as a joint arrangement. Joint arrangements are a common way for oil and gas companies to share the risks and costs of exploration and production activities, and come in a variety of forms. Within the sector, the term joint venture is used widely as an all-encompassing operational expression to describe shared working arrangements. However, under IFRS there are strict criteria that must be met in order for joint arrangement accounting to be applied. A joint arrangement is an arrangement over which two or more parties have joint control being the contractually agreed sharing of control. Joint control is not determined by economic interest. Control is based on the contractual arrangements and exists when decisions about the relevant activities require the unanimous consent of more than one party to the arrangement. Companies must review their arrangements to determine whether joint control exists. When the company does not have joint control, the arrangement likely will be accounted for as an investment, subsidiary or associate.

Accounting for joint ventures prior to adoption of IFRS 11

Accounting is based on whether there is a separate legal entity. An accounting policy choice is available for jointly controlled entities. IAS 31 Interests in Joint Ventures is applicable before IFRS 11 becomes effective on 1 January 2013. There are three classifications of joint venture under IAS 31: jointly controlled entity, jointly controlled asset and jointly controlled operation.

Jointly controlled entities

A jointly controlled entity is a joint arrangement that is carried out through a separate legal entity. An accounting policy choice is available when accounting for jointly controlled entities. A venturer accounts for its interest using either proportionate consolidation or the equity method. In KPMG’s 2008 survey The Application of IFRS: Oil and Gas there was an almost even split between companies applying the equity method and those using proportionate consolidation.

Jointly controlled assets and jointly controlled operations

Jointly controlled assets and jointly controlled operations are joint ventures that are not separate legal entities. Venturers in jointly controlled assets and jointly controlled operations recognize the assets and liabilities, or share of assets and liabilities, that they control, as well as the costs incurred and income received in relation to that arrangement.

Accounting for joint arrangements from 2013

Significant impact on accounting for joint arrangements as a result of IFRS 11 adoption

The IASB issued IFRS 11 in May 2011. The standard is effective for periods beginning on or after 1 January 2013, with early adoption permitted subject to some conditions. There are two classifications of joint arrangements under IFRS 11: joint ventures and joint operations. The classification of arrangements under IFRS 11 requires judgment and the terms of arrangements and the nature of any related agreements must be considered to determine the classification of the arrangement for accounting purposes.

Joint venture

A joint venture is a joint arrangement whereby the jointly controlling parties, known as joint venturers, have rights to the net assets of the arrangement. Joint ventures include only arrangements that are structured through a separate vehicle (such as a separate company). However, not all joint arrangements that are companies will necessarily be joint ventures. Classification will be determined based on the nature and terms of arrangements. The legal form is only one factor to be considered. When the contractual arrangements and other facts and circumstances indicate that the joint venturers have rights to assets and obligations for liabilities of the arrangement, the arrangement will be a joint operation. One circumstance that could indicate that an arrangement is a joint operation is if the arrangement is designed so that the jointly controlled company cannot undertake its own trade, and can only trade with the parties to the joint arrangement. Related agreements and other facts and circumstances also need to be considered.

A joint venturer will account for its involvement in the joint venture using the equity method in accordance with IAS 28 (2011) Investments in Associates and Joint Ventures.

Joint operation

A joint operation is a joint arrangement whereby the jointly controlling parties, known as joint operators, have rights to assets and obligations for liabilities relating to the arrangement. An arrangement that is not structured through a separate vehicle will be a joint operation; however, other arrangements may also fall into this classification depending on the rights and obligations of the parties to the arrangement.

A joint operator recognizes its own assets, liabilities and transactions, including its share of those incurred jointly.
Revenue recognition

Oil and gas companies reporting under IFRS need to assess whether the risks and rewards of ownership have been transferred in order to determine when to recognize revenue. The determination of when this occurs can present challenges for oil and gas companies. The individual facts and circumstances will need careful consideration as they may vary between contracts.

Timing of revenue recognition

There is no industry standard as to the timing of the transfer of ownership in oil and gas transactions. The revenue arising from each transaction is recognized based on the terms of the underlying sales agreement. For most transactions involving the sale of physical oil and gas, the contractual terms for the transfer of ownership will be based on the delivery or lifting of production. For example, for crude oil sales generally there are two points at which title could pass from seller to buyer: when the crude oil is lifted from the site of production; or when the crude oil is delivered to the refinery/storage depot. For petroleum products sold to retail distribution networks, generally revenue is recognized on delivery to service stations.

Physical exchange of products

The physical exchange of products is common within the oil and gas industry. For example, under crude oil buy/sell arrangements a company agrees to buy a specified quantity and grade of oil to be delivered at a specified location, while simultaneously agreeing to sell a specified quantity and grade of oil at a different location with the same counterparty, generally to facilitate operational requirements. In accordance with IAS 18 Revenue, the exchange of goods or services that are of a similar nature and value is a transaction that does not generate revenue. The nature of the exchange will determine if it is a like-for-like exchange accounted for at book value, or an exchange of dissimilar goods within the scope of IAS 18.

Overlift and underlift

In many joint arrangements the timing of revenue recognition will coincide with a fixed schedule of lifting, which stipulates when each participant lifts its share of crude oil or gas from the production facility. The practicalities of loading an oil tanker mean that any single lifting can be more or less than a company’s entitlement, resulting in an overlift (a lifting in excess of the company’s contractual allocation of production) or an underlift (a lifting less than the company’s contractual allocation of production). Oil and gas companies need to consider how they account for any overlift or underlift balances, including what measurement base to apply to any resulting asset or liability.
Reserves reporting

There is no specific IFRS reporting requirement on reserves. However, in view of the fact that oil and gas reserve estimates constitute critical information for evaluating oil and gas companies, many oil and gas companies include an accounting policy for reserves or a commentary in the critical estimates and judgments note, or in the management discussion and analysis section of the annual report.

The purpose of reserves reporting is to make available information about the oil and gas reserves controlled by companies in the sector. This is essential in assessing their current performance and future prospects.

Disclosures

In the absence of specific guidance, oil and gas companies tend to refer to other requirements, such as those in the US, Canada, Australia and the UK. The nature of reserves estimates is such that, even if all companies provided disclosure based on a single classification, meaningful comparison between companies would be difficult without in-depth analysis of the many assumptions inherent in the core disclosures.

**Impact of reserve estimates on financial statement balances**

While the reporting of reserves data is important in its own right, reserves measures are also used in deriving a number of accounting estimates.

- **DD&A calculations.** In our experience these calculations are based on the unit-of-production method and the volume of reserves used in the calculation affects the calculation of the associated DD&A charge.
- **Decommissioning and environmental rehabilitation provisions.** Reserves estimates are a key factor in determining the economic life of an oil field and therefore impact on the calculation of the respective provisions.
- **Impairment.** Downward revisions in reserve estimates often represent an indicator of impairment and assumptions for reserves are used in impairment calculations.
- **Reserves** are a key input to fair value calculations in accounting for a business combination.
- **Deferred tax assets.** Assumptions about future profit potential based on reserves estimates may be the basis for the recognition of deferred tax assets arising from unused tax losses.

Because of the impact of reserves information in the financial statements, oil and gas companies typically include some information about reserves in the critical estimates and judgments note to the financial statements.
Financial instruments

Oil and gas companies generally have financial instrument accounting issues owing to the significant commodity price risk that they face and the structures in place to manage this and other exposures such as currency fluctuations.

Accounting and disclosure requirements

Contracts to buy and sell oil and gas and other non-financial items may be included in the scope of the financial instruments standards. There is an exemption for contracts that are held for physical delivery or receipt for the company’s expected purchase, sale or usage requirements (the ‘own use exemption’). However, specific conditions must be met to apply this exemption, and its applicability should be reviewed carefully.

Specific types of oil and gas contracts also commonly contain embedded derivatives that may need to be accounted for separately. For example, gas contracts that are not derivatives themselves may contain embedded derivatives as a result of a pricing mechanism linked to an index other than a gas pricing index.

As it currently stands, IAS 39 Financial Instruments: Recognition and Measurement requires financial assets to be classified into one of four categories: at fair value through profit or loss; loans and receivables; held to maturity; and available for sale. Financial liabilities are categorized as either financial liabilities at fair value through profit or loss or ‘other’ liabilities.

Financial assets and financial liabilities are measured initially at fair value. After initial recognition, loans and receivables and held-to-maturity investments are measured at amortized cost. All derivative instruments are measured at fair value with gains and losses recognized in profit or loss except when they qualify as hedging instruments in a cash flow or net investment hedge.

A financial asset is derecognized only when the contractual rights to cash flows from that particular asset expire or when substantially all risks and rewards of ownership of the asset are transferred. A financial liability is derecognized when it is extinguished or when the terms are modified substantially.
Future developments

New standard on revenue recognition

The IASB and the FASB are working on a joint project to develop a single principles-based standard for revenue recognition, which would replace IAS 11, IAS 18 and a number of interpretations, including IFRIC 13 and IFRIC 18. In June 2010, the IASB published its proposals in the Exposure Draft ED/2010/6 Revenue from Contracts with Customers. These proposals were redeliberated in response to comments received, and the IASB subsequently published a revised Exposure Draft ED/2011/6 in November 2011. The Boards plan to redeliberate the proposals in the second half of 2012 with a view to publishing a final standard in 2013. Some aspects of the project may affect entities in the extractive industries.

Discussion Paper DP/2010/1 Extractive Activities

In April 2010, the IASB published Discussion Paper (DP) DP/2010/1 Extractive Activities, which was based on the work of a group of national standard setters. The DP focused on upstream activities for minerals, oil and natural gas. In November 2010, the IASB amended its work plan and deferred work on a number of projects that were active at the time. The future of this project is subject to the IASB’s agenda consultation, which was launched in July 2011.
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