

Accounting for Depreciation, Depletion and Amortization in the Oil and Gas: Concepts, Issues and Challenges.

C.O. MGBAME

Department of Accounting
Faculty of Management Sciences,
University of Benin,
Benin City Nigeria
abbeyoyewole6464@gmail.com

P.A. DONWA

Department of Accounting
Faculty of Management Sciences,
University of Benin,
Benin City Nigeria

A.K. OYEWOLE

Department of Accounting
Faculty of Management Sciences,
University of Benin,
Benin City Nigeria

Abstract

The study examines the issues and challenges in depreciation, depletion and amortization that are significant for the oil and gas industry and whether DD&A is appropriately design to achieve benefits of the company's desires from its operations.

The study is essentially, a library research which based on empirical literature and methodology adopted was purely exploratory that was based on prior literature of other researchers and it does not involve data gathering and data analysis.

The study recommends that oil and natural gas properties, including related pipelines, should be depreciated using a unit – of – production method and the cost producing wells should be amortized over proved developed reserves.

Keywords: *Depreciation, Depletion & Amortization, Impairment, IFRS6, IAS16.*

Introduction

Tangible assets, from the moment they begin or should begin to be used, are depreciated systematically using a straight-line method over their useful life which is an estimate of the period over which the assets will be used by the company. When tangible assets are composed of more than one significant element with different useful lives, each component is depreciated separately (Antill & Arnott, 2002). The amount to be depreciated is represented by the book value reduced by the estimated net realizable value at the end of the useful life, if it is significant and can be reasonably determined. Replacement costs of identifiable components in complex assets are capitalized and depreciated over their useful life; the residual book value of the component that has been substituted is charged to the profit and

loss account. Expenditures for ordinary maintenance and repairs are expensed as incurred. Development costs are those costs incurred to obtain access to prove reserves and to provide facilities for extracting, gathering and storing oil and gas. They are then capitalized within property, plant and equipment and amortized generally on a unit of production basis, as their useful life is closely related to the availability of feasible reserves. This method provides for residual costs at the end of each quarter to be amortized at a rate representing the ratio between the volumes extracted during the quarter and the proved developed reserves existing at the end of the quarter, increased by the volumes extracted during the quarter. This method is applied with reference to the smallest aggregate representing a direct correlation between investments and proved developed reserves. Costs related to unsuccessful development wells or damaged wells are expensed immediately as losses on disposal (Chua & Woodward, 2004).

International accounting standard (IAS) 16 “property, plant and Equipment” is the standard under which property, plant and equipment and development or production assets (collectively, PP&E), and depletion, depreciation and amortization (collectively, DD&A) are governed. IAS 16 does not prescribe a single method of determining DD&A but does refer to straight line, diminishing balance and the unit of production methods. The cost of an item of PP&E is initially recognized as an entity’s balance sheet and in each subsequent period of the cost is amortised as an expense on the income statement. In a perfect world, at the end of the asset’s working life, the net cost remaining on the balance sheet should either equal the disposal proceeds or zero if there is no remain value (KPMG, 2011).

Statement of the Research Problem

Accounting for oil and gas activities presents many difficulties, such as significant upfront investment, uncertainty over prospects and long project lives have led to a variety of approaches being developed by companies, and a range of country-specific guidance for the sector. As countries around the world adopt IFRS, accounting approaches for affected companies may need to be reassessed. Many countries converted to IFRS in 2005 and conversions are imminent for other countries such as Canada and South Korea in 2011 and Mexico in 2012. Japan has permitted the early adoption of IFRS by listed companies from years ending on or after 31 March 2010 and is expected to announce a final decision on whether to mandate adoption in 2012. As countries adopt a single set of high quality, global accounting and financial reporting standards, there should be greater global consistency and transparency. However, it is recognised that extractive activities is an area in which there is little IFRS guidance. There is also variation in practice between companies applying IFRS, in treatment of depletion, depreciation and amortization in oil and gas accounting (KPMG, 2008).

Objectives of the Study

The objective of this paper was to examine the accounting issues and challenges of depreciation, depletion and amortisation that are significant for the oil and gas industry. The issues are addressed following the oil and gas value chain: exploration, development, production and sales of products; together with issues that are pervasive to a typical oil and gas entity.

Literature Review

Conceptual Framework

A method of accounting associated with the acquisition, exploration and development of new oil and natural gas reserves. Depreciation is a means of allocating the cost of material assets

over its useful life. Such as operating equipment. Depletion is used to allocate the cost of extracting natural resources from the earth, and is the actual physical depletion of a natural resource by a company. Amortization is the deduction of capital expenses over a specified time period (typically the life of an asset), which in case of oil and gas, refers to tangible non-drilling costs sustained while developing the reserves (Osmundsen, Asche & Mohn, 2004). Two accounting approaches are used by companies involved in exploration and development of oil and gas; the successful efforts (SE) methods and full cost (FC) method. Each method handles differently the treatment of specific operating expenses associated with the exploration of new oil and natural gas reserves. DD & A, production expenses and exploration costs are recorded on a company's income statement area determined by the "units – of – production" method (Cormier & Magnan, 2002).

Oil and gas exploration and production companies choose one of two acceptable accounting methods, successful efforts or full cost. The most significant difference between the two methods relates to the accounting treatment of drilling costs for unsuccessful exploration costs (Antill & Arnott, 2002). Under the successful efforts method, exploration costs and dry hole costs (the primary uncertainty affecting this method) are recognized as expenses when incurred and the costs of successful exploration wells are capitalized as oil and gas properties. Entities that follow the full costs including dry hole costs into one pool of total oil and gas property costs (Damodaran, 2002).

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 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 (KPMG, 2008).

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:

- The estimated fair value less costs to sell of the exploration prospect is positive; and
- 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. 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. 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 purpose and a policy of revaluation is applied to all assets in a class.

Depletion, depreciation and amortization (DD&A)

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.

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 their serve 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

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

According to Osmundse, Asch and Mohn (2004) Opined that 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.

Principles, Challenges and treatment of Depreciation, Depletion and Amortization in oil and gas Accounting

The following challenges and principles are derived from IAS 16:

- At the date of transition to IFRS, entities currently have three choices available for measuring assets:

(1) The cost model under which retrospective restatement is required to determine cost in accordance with IFRS 6, IAS 16 and IAS 38.

(2) The deemed cost election for individual assets, which requires fair value measurement with no retrospective treatment; or

(3) The revaluation model under which fair value less accumulated amortization is determined for each class of assets — see Section 9 for a discussion of the IASB’s proposed amendment to IFRS 1 that would remove the requirement for retrospective restatement of oil and gas assets by full cost entities in the event the amendment is approved by the IASB and the election is made by the entity

- Following transition to IFRS, subsequent asset acquisitions are initially recognized at cost and PP&E may be measured using the cost method or the revaluation method

- The cost of an item of PP&E includes:

— The purchase price plus duties and taxes, less discounts and rebates

— An apportionment from the cost of major or significant components of assets that will be subject to future expenditures expected to extend the asset’s useful life, such as major plant turnarounds, overhauls and replacement, i.e., those components that the entity considers will be replaced much sooner and separately from the rest of the asset

— Borrowing costs incurred to acquire qualifying assets

— Costs attributable to ready the asset for the service for which it is intended, excluding administration and general overhead costs, and

— An initial estimate of the costs of decommissioning, removal, restoration or abandonment resulting from utilization of the asset over time.

Each part of an item of PP&E with a cost that is significant in relation to the total cost of the item, including non-physical components such as labour, engineering and consulting fees and similar costs, must be depreciated separately

- Significant parts of an item that have the same life and depreciation method may be grouped for the purposes of calculating DD&A
- After separating significant parts of an item, an entity should separately depreciate the remainder, which would consist of the parts that are not individually significant (if an entity has varying expectations for these parts, approximation techniques may be necessary to depreciate the remainder in a manner that faithfully represents the consumption pattern and/or useful life)
- The amount subject to DD&A is determined as the cost of the asset less its residual value and should be allocated on a systematic basis over the useful life of the assets
- Useful life is defined in terms of use to the business (not economic life) as the period over which the asset is expected to be available for use or the number of production units expected to be obtained from the asset
- Useful life, residual value and the DD&A method used for all PP&E should reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity.
- DD&A should commence once the asset has achieved commercial viability, where commercial viability is generally recognized as occurring when the asset is in the location and condition necessary for it to be capable of operating in the manner intended by management
- DD&A should continue until the earlier of the date the item is classified as held for sale and the date the item is derecognized (an entity does not stop charging DD&A just because the asset is idle or has been removed from use; however, if the entity is recognizing DD&A on the basis of units of production, DD&A can temporarily cease in the event of an interruption of production)
- An entity is required to derecognize the carrying value of a part of an item of PP&E that is replaced, regardless of whether the part has been depreciated separately, if the entity has included the cost of the replacement item in the original carrying value of the PP&E
- The derecognized carrying value of a replaced part may be estimated, if necessary
- Gains or losses from DD&A recognition of an item of PP&E must be included in income, not revenue, in the period in which the item is derecognized, and
- All items of PP&E accounted for under IAS 16 are subject to the impairment requirements of IAS 36.

Review of Prior Empirical studies

A typical result from previous studies is that accounting information, such as earnings and capital employed, is insufficient in the assets valuation process for oil and gas exploration firms. Thus, there is a potential hazard in relying solely on accounting measures, such as ROA in asset valuation. indeed, some researchers have voiced their concern about the accuracy of historical cost accounting in conveying financial performance among oil and gas companies (Deakin & Deitrich 2002, Harris & Ohlson, 2007 Koester, 2010). Most of these studies emphasis the necessity of disclosing both financial and non-financial information.

McCormck and Vytheewaran (2008) pointed out particular problems in valuation of and companies, since the accounting information in the upstream sector does a distressingly poor job of conveying the true economic results” there are measurement errors in petroleum reserves, the responds to new information is asymmetric bad news is quickly reflected in the

reserve figures whereas good news take more time to be accounted for. Moreover, reserves may be exposed to measurement errors since they are noted in current oil price (and not the mid cycle price), and since they do not include the value of any implicit options. McCormack and Vytheewaran (2008) claim a bias in the reported figures, as the large and profitable oil companies are more conservative in their reserve estimates than most of the others. This may explain the importance that many analysts have put on company reputation, a factor that has been partially jeopardized by the recent reserve write-down in Royal Dutch/Shell as for depreciation, the successful – efforts method produces initial depreciation that are too high, the unit – of- production method also has the effect of depreciating assets too quickly. A possible implication is that an extra cost is added to new activity, whereas initial is rewarded, other measurement challenges specific to the oil business are cyclical investment pattern and long lead times, and these features can exacerbate the measurement errors. Similar effect may occur from the fact that discoveries are discontinuous and stochastic.

Antill and Arnott (2002) address the strategic dilemma between return on capital and production growth in the petroleum industry. The claim that 2002 ROACE figures of 15% were due to the fact the company possesses legacy assets that have cash flow, if market value of the capital employed were applied Antill and Arnott, estimate that ROACE would fall to approximately 8 to 9% which is more consistent with the cost raising capital. Antill and Arnott (2002) argued that the oil companies should accept investment projects with lower internal rate of return as the growth potential would add value to the companies.

Quirin, Berry and Bryan (2000) in their analysis of US oil and gas exploration firms 1993 – 1996 find that certain ratios such as reserve replacement ratios, reserve growth, production growth, and finding cost -to-depreciation ratio are perceived by analysts to have been instrumental during the equity valuations process of oil and gas firms. Their results indicate that these ratios provide incremental information accounting information, including book value of equity. Cormier, et al. (2003) found that cash flow changes in reserves provide incremental information over reported earnings for a data set of Canadian petroleum firms.

Chua and Woodward (2004) perform econometric valuation tests for the American oil industry 1990 – 2000. They test P/E – figures for integrated oil companies against dividend paid out net profit margin, asset turnover, financial leverage, interest rate, and beta, they fail to uncover robust relations in the data set the estimated interactions are weak, and some of them even have “wrong” signs. Chua and Woodward do not find support for the P/A – model, they therefore go on to test the stock price against cash flow from operations (following year and preceding year) dividend pay-out, net profit margin, total asset turnover, financial leverage, interest rate and proven reserves. Future cash flow and proven reserves are statistically significant explanatory factors, thus offering support for a fundamental approach to valuation. An increase in proven reserves of 10% produced an average increase in the stock price of 3.7%, in the model estimated by Chua and Woodward.

METHODOLOGY

This paper is qualitative in nature and was purely an exploratory one. It was based on prior literature of other researchers and secondary information from various journals, textbooks, newspapers and magazine articles. And does not involve data gathering, analysis and data interpretation.

Conclusion and Recommendations

Property, plant and equipment is stated at cost, less accumulated depreciation and accumulated impairment losses. 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, field development and future decommissioning costs are amortized over total proved reserves. The unit-of-production rate for the amortization of field development costs takes into account expenditures incurred to date, together with approved future development expenditure required to develop reserves. Other property, plant and equipment is depreciated on a straight-line basis over its expected useful life.

References

- Antill, N., & Arnott, R. (2002). Oil company crisis, management structure, *Profitability and Growth* SP15, Oxford institute for Energy studies.
- Canadian Institute of Chartered Accountants (CICA) — Adopting IFRS in Canada
- Chua, D., & Woodward, O. (2004). Financial performance of the U.S. Oil and gas industry; 1990-2000. *Financial Markets Institutions & Instruments*, 3 N, Blackwell.
- Cormier, D., & Margin, M.. (2002). Performance reporting by oil and gas firms: contractual and value implications. *Journal of International Accounting, Auditing & Taxation* 11,131-153.
- Deakin, E., & Deitrick, J. (2002). An evaluation of RRA and other supplemental oil and gas. Disclosures by financial Analysts. *Journal of Extractive Industries Accounting* 1, 63-70.
- Deloitte & Touche LLP., Ernst & Young LLP., KPMG LLP and Price water house Coopers LLP various *IFRS Publications and Seminar Materials*
- Demodaran, A. (2002). *Investment valuation* .Wiley Finance.
- Ernst &Young (2008). International GAAP. *Generally Accepted Accounting Practice Under International Financial Reporting Standards*
- International Accounting Standards (IAS) 16
- International Financial Reporting Standards (IFRS) 1 — 8
- International Financial Reporting Interpretations Committee Interpretations(IFRIC) 1 — 14
- KPMG. (2007). Assessing the Impact — Adoption of IFRS 6: *Exploration for and Evaluation of Mineral Resources* by Oil & Gas companies
- KPMG. (2008). Insights into IFRS
- Koester, R. (2010). Problems in analysing financial statements of oil and gas producing companies, *Oil and Gas tax quarterly* 38,789-800
- .McCormack, O., & Vytheewaran, T. (2008). How to use Eva in the oil and gas industry. *Journal of Applied Corporate Finance*, 11, 3 -10.
- Ohlson, W. (2002). Global integrated oil analyser. *Quarter assessment of the strategies and Valuation of the World's largest Integrated oil Companies*
- Osmundsen, P., Asche, F., & Mohn, J. (2004). IAEE Teharan.Valuation of oil companies. The use of financial Indicators, papers and proceedings, *Annual Conference. International Association for Energy economics (IAEE)*, Teheran, 25-27.
- Quirin, J. J., Berrog, K. T. & Bryan, D. O. (2001). A fundamental Analysis Approach to oil and gas. Gas firm valuation. *Journal of Business Financial and Accounting*.27 (7), 785-820.