# Market risks and oilfield ownership-Refining oil and gas disclosures

**Citation for published version:**
Hatherly, D, Kretzschmar, G & Misund, B 2007, 'Market risks and oilfield ownership-Refining oil and gas disclosures' Energy Policy, vol 35, pp. 5909-5917., 10.1016/j.enpol.2007.06.007

**Digital Object Identifier (DOI):**
10.1016/j.enpol.2007.06.007



**Published In:**
Energy Policy

# CENTRE FOR FINANCIAL MARKETS RESEARCH

# THE MANAGEMENT SCHOOL

**MARKET RISKS AND OILFIELD OWNERSHIP – REFINING SEC OIL AND GAS DISCLOSURES**

**Gavin L Kretzschmar**
**Bard Misund***
**David Hatherly**

**July 2006**
**Working Paper 06.02**

**ISBN: 1902850 890**

*We acknowledge the generous data provision and research sponsorship by energy research company – Wood Mackenzie. Comments by Richard Lines of the Wood Mackenzie Petroleum Economics team and University of Edinburgh reading group colleagues, particularly Paul Andre, are much appreciated. Any errors and omissions are the responsibility of the authors.

Data Availability: All data used in this research is commercially available from Wood Mackenzie Oil and Gas Research

## Abstract

Our paper uses an extensive sample of 292 oilfields to provide evidence that Securities and Exchange Commission (SEC) supplementary disclosures do not capture the price sensitivities of O&G disclosures implicit in the two main forms of oilfield ownership, concession and production sharing contracts (PSCs). SEC *present value disclosures* for both forms of ownership are shown to be significantly more responsive to oil prices than stock return sensitivities noted by Rajgopal (1999). Importantly, we show that unlike concessions, *reserve and production disclosures* vary in response to oil price movements for PSC regimes. Our results highlight the need to differentiate PSC disclosures from concession fields, and to fully reflect price risks implicit in oilfield ownership contracts. We extend findings by Rajgopal (1999) and propose refinements necessary to capture contractual price risk effects on SEC disclosures for assets in the O&G sector.

Key Words: SEC Disclosure, Oil and Gas, Reserves, Market Risk

# I. INTRODUCTION

Prior studies have shown oilfield disclosures to be value relevant in interpreting assets and earnings of companies in the oil and gas (O&G) industry (Boone, 2002). Reserve disclosures for companies in the energy sector provide important information needed to interpret the current and prospective performance of oil and gas exploration and production (see e.g. Quirin et al, 2000; Magnan and Cormier, 2002). Boone (2002) undertakes a survey of an extensive earlier debate as to SEC present value disclosures and confirms their value relevance. We contribute by providing evidence that current disclosures lack detailed asset data pertaining to ownership structures and their exposures to oil price volatility. The importance of oil price effects on reserve replacement and reporting is particularly relevant in the energy sector where reliance upon accounting return measures that ignore the economic value of capital invested in oil and gas (O&G) reserves have been shown to be potentially misleading (Antill and Arnott 2004; Osmundsen et al, 2006).

Rajgopal (1999) tested market risk effects in the O&G sector, acknowledging that 'while the SEC concludes that 'quantitative disclosures should help investors better understand specific market risk disclosures of different registrants' (SEC1997, 6048)……..market risk disclosures are unlikely to be reliable and plagued with measurement problems' (P 252). Pincus and Rajgopal (2002) also touch on the concept of reserve write downs, but in the context of sharp oil price declines that necessitate reserve revision. Despite findings by Clinch and Magliolio (1992) that reserves up to three years in the future are associated with ruling oil price sensitivities, it is not possible from current SEC O&G financial reporting to assess the potential effect of oil price variability on future SEC proven reserves and production entitlement. In other words the quantity of *underlying* PSC oil and gas assets for corporates are themselves a function of oil price levels and current disclosures provide no way of measuring this effect.

Our paper examines these price effects on disclosures, and the extent to which oil sector reserve ownership is affected by previously the unstudied effects of high oil prices driving down corporate reserve entitlement. The production sharing contracts (PSC) that cause this effect are shown in our study to have price varying effects similar to derivative contracts. The existence and price sensitivity of these contracts as they relate to underlying oilfields, are an alternative to concession ownership structures, and represent between 30 to 40 percent of emerging global reserve replacement opportunities. The nature of these contracts is not well understood and nor are details available from current SEC disclosures. As a result little academic work has been done on the effects of oil price on these alternative ownership structures.

PSC agreements vary widely but typically provide oil companies with a guarantee to cover a return on their capital costs and, in exchange, impose a reserve entitlement structure. The contract generally escalates participation sharing by the local government based on the price of oil and in some cases the volume of oil pumped.[1] Specifically and contractually linking asset entitlement to a range of oilfield returns generated primarily by commodity prices differentiates oilfields from other market sensitive corporate assets. Our paper focuses on this trait by interpreting government take as analogous to option claims against company reserves possessed by the field's local government - an interpretation that recognises the contractual nature of *possible* fiscal claims against oilfields (Lund 1992). This interpretation provides a framework for us to consider the disclosure requirements of underlying assets *and* financial instrument disclosures as identified by Rajgopal (1999) and to compare oil price effects on oilfield asset disclosures. The financial effects of production sharing contracts, driven by high oil prices, are becoming widespread in the O&G sector. Exxon's PSC production is expected to move from 18 to 38 percent by 2010, and BP from 8 to 20 percent over the same period and, with the exception of Shell, other oil majors are showing similar trends. [2]

Rajgopal (1999) notes that there are problems with price risk data, the disclosure of which provides inconsistent tabular information in his study. Rajgopal derives a O&G equity value beta as a constant at 0.247 percent per 1 percent change in the oil price (gas beta 0.072) and notes that beta ' is subject to measurement error because they are averages over the 1993-1996 period, whereas the theory……suggests that oil and gas price sensitivities depend on firm-specific and time period-specific stock of underlying reserves and the derivative strategy' sensitivities' (P 268). This observation by

[1] The contractual take by the local government can be interpreted as a form of taxation. In the Oil and Gas sector the term fiscal take is used for the (present) value of all forms of government taxation including any contractual take under the terms of a PSC.
[2] Shell is expected to reduce PSC production from nearly 50% to 30% - Anticipated PSC production is sourced from Deutsche Bank (2004)

Rajgopal allows the contribution of our empirical study; we use a study of extensive oilfield data to highlight the asymmetrical price sensitivities of O&G reserve entitlement (and thereby SEC disclosures) to price sensitivity.

We use our 292 oilfields to measure oilfield disclosures under varying price conditions and contribute to prior work on price risk disclosures. We find that O&G disclosures are significantly more variable than the oil price beta for equity value noted by Rajgopal (1999). Evidence is provided that disclosures respond to oil price movements in a variable manner; over the range US$22.5 – USD$ 33.75 the concession field present values (PV) in the Gulf of Mexico (GoM) sample increase by 1.306 percent per 1 percent change in oil price, with the increase falling to 1.21 percent per 1 percent change in the range USD$ 67.5- USD$ 90. The asymmetrical response for Angola PSC field PVs is more marked with a response rate of 1.587 and 0.332 per 1 percent change for the same oil price ranges as above. The most marked difference between concession ownership and production sharing disclosures is that reserves and production do not vary in response to oil price movements for concession fields, *while both production and reserves vary under PSC regimes*. To illustrate, for our GoM sample, reserve and production entitlement remains unchanged across the full price range USD$ 22.5 – USD$90. Angolan PSC reserves, by comparison, actually *decrease* by 0.451 percent per 1 percent oil price change in the range USD$ 22.5 – USD 33.75 and *decrease* by 0.388 percent in the range USD 67.5 - USD 90. Production entitlement, by comparison, also reduces in Angola, but by 0.291 percent and 0.181 percent respectively over the same price intervals.

Disclosure rules currently do not capture these price variant effects in financial statements, an insight that perhaps goes some way toward explaining the conflicting results in prior value relevance studies. Rules for supplementary information on underlying reserves, SEC (SEC, 1981) and FASB (FASB, 1982), are rooted in an era dominated by concessionary oilfield ownership structures. In contrast to concession ownership where reserves entitlement rests with the operator, PSC agreements provide government regimes an entitlement to share oilfield production with producers. The emergence of PSCs in the 1990s, means, however, that the nature and behavior of price sensitive government claims are not reflected in SEC disclosures; nor have their effects on disclosures been covered in previous research. We suggest that present SEC disclosures do not reflect the potential ownership effects of price volatility on 'bookable' reserves. Our paper bridges this gap and builds upon previous work that examines the importance of supplementary SEC disclosures in the context of concessionary arrangements (Berry et al 2004, Boone, 2002; Spear, 1994 and 1996; Alciatore, 1993). We specifically examine reserve entitlement structures, their response to price volatility, and the nature of variations in SEC disclosures, comparing concession agreements to PSC contracts.

Our results suggest that there should be separate PSC and concession reserve disclosures - based on our evidence that the two kinds of agreement behave significantly differently in response to oil and gas price changes. In line with Rajgopal (1999), we recommend that supplementary information should disclose the effects of oil and gas price changes on underlying reserve disclosures. Finally, given the variety of PSC terms in use between countries, and even from field to field within the same country (Bindeman, 1999), we propose that whenever PSC terms are unique, disclosures of claim terms should be separately displayed whenever they are specifically part of the oilfield contract.

In the next section we provide background in the form of the historical development of the SEC and FASB disclosure rules, the emergence of PSCs and a brief review of the literature that has tested these rules. In particular we emphasise the contingent and contractual nature of PSC terms and the importance of disclosing these separately from concession holdings. In sections III to IV we use our sample of oilfields across 6 oil producing countries to provide empirical evidence of the scale and effect of the reserve (claim) accounting problem facing accountants and analysts. Section III covers the research design, section IV the sample selection and data, and section V the empirical results. Section VI concludes with a discussion of these results and emphasises the need for responses from policy makers in relation to shortfalls in disclosure practice.

## II. BACKGROUND AND PRIOR RESEARCH

### Current SEC Disclosures 'presume' Concession Reserve Structures

SEC disclosures do not differentiate between oilfield ownership structures, notwithstanding the very different nature of their legal entitlement to underlying reserves. During the late 1970s and early 1980s, an era dominated by concession oilfield reserve ownership, the Financial Accounting Standards Board (FASB) and the Securities and Exchange Commission (SEC) issued a series of standards dealing with the accounting and disclosure of underlying oil and gas activities. First, the Statement of Financial Accounting Standards No. 19, (SFAS19: FASB, 1977), required oil and gas companies to account for their oil and gas activities at historical cost using successful efforts method (SE) instead of the full cost method (FC). Additionally, SFAS19 required the disclosure of (1) costs incurred in production activities, (2) capitalized costs relating to production activities, and (3) proved reserve quantities. However, the SEC unhappy that neither the SE nor the FC methods were appropriate for communicating oil and gas firms' underlying asset and reserve values, developed a new method of accounting for values of oil and gas reserves. As a result, the SEC issued Accounting Series Releases No. 253 (SEC, 1978) and No. 269 (SEC, 1979) through which it proposed Revenue Recognition Accounting (RRA) valuing the reserves directly from estimated cash flows rather than past incurred costs. Additionally, oil and gas firms were permitted to use either of the SE and FC methods, which in turn instigated the FASB to issue Statement of Financial Accounting Standards No. 25 (FASB, 1979), which effectively suspended the historical cost accounting method requirement in SFAS19. Furthermore, the RRA did not gain wide support and a few years later the SEC dropped the concept of pure cash flow estimation (SEC, 1981), handing over the issue to the FASB who were developing Statement of Financial Accounting Standards (SFAS) No. 69. This standard, issued in 1982, established the set of reserve disclosures which to this day determine the information content of SEC filings and financial reports. Specifically, neither contractually specified claims, nor the price risk exposures of physical reserves, have historically been subject to disclosure.

To overcome this SEC shortfall, our disclosure recommendations build on principles contained highlighted by Rajgopal (1999) and contained in SEC ruling of (1997). Justification for this approach is found in the SEC (1997, 6044) definition which specifically defines market risk as the risk of loss arising from adverse changes in market rates and prices, such as interest rates, foreign currency rates and similar market rate or price changes.

**The Relevance of Market Risk in Supplementary Oil and Gas Disclosures**

There is a body of literature that tests accounting measures and supplementary disclosure of reserves in the oil and gas industry. We suggest that the debate in these studies have been in part caused by the lack of data about the type of oilfield assets held by the companies under analysis. Early researchers, for instance, hampered by the lack of access to oilfield data and the applicable contractual terms cast doubt on the reliability of the value relevance of historic cost and even the 'present values' of oil and gas reserves (Magliolo, 1986; Harris and Ohlson, 1987; Shaw and Weir, 1993), and changes in reserves (Spear, 1993; 1996). Only recently have several researchers, using revised methodologies, provided evidence supporting the value relevance of present values (Berry et al, 2004; Bryant, 2003; Boone, 2002). None of these studies, however, covers the distinction between the present value of concession and PSC contracts, or the relative effects of market risk (oil price volatility) on reported reserves.

Likewise, there is little research support for the notion that contractual claims under PSCs might require contingency disclosure under Statement of Financial

Accounting Standards No. 5 (SFAS 5, FASB, 1975). Scope for PSC disclosure may also be offered by Statement of Financial Accounting Standards No. 133 (SFAS133, FASB 1997) and Financial Reporting Release No. 48 (SEC, 1997), which introduced a requirement for commodity price risk disclosures. No studies have until this point applied these statements to contingent claims against underlying oilfield assets, preferring to focus on their application to derivative disclosures which involve using one of three alternative formats: tabular disclosure, response analysis or value at risk.

Rajgopal (1999), for instance, studying the informativeness of commodity price risk financial instrument disclosures required by FR-48 (SEC, 1997), cast doubt on claims that the new market risk disclosures do not reflect firms' risk exposure in the oil and gas sector. The sensitivity analysis format of the FR-48 requires firms to report explicit estimates of fair value gains and losses on derivative positions due to changes in the underlying commodity. In addition, it encourages firms to voluntarily present fair value gains and losses on the underlying exposure to changes in prices. Rajgopal (1999) did find that proxies for the fair value response of the underlying exposure (oil and gas derivatives) were positively (negatively) associated with oil and gas betas. Moreover, the tabular and response formats each possessed incremental utility in explaining oil and gas betas. Currently in the O&G sector, estimates of the potential fair gains and losses on underlying oilfield contracts are not subject to similar reporting requirements.

Rajgopal is not alone in his price risk findings, Ahmed et al (2006), compared the valuation implications of derivative fair value information - in the banking sector. Importantly, their findings suggest that SFAS No. 133 has increased transparency of the nature of derivative financial instruments. Again, we anticipate that similar disclosure requirements for underlying O&G reserves would result in a transparency of the contingent nature of underlying PSC contracts.

To account for uncertainty surrounding future reserves it has been recommended (Arnott, 2004) that there should be a simple adjustment to SEC rules on reserves reporting to require companies to show reserves booked on a field by field basis. Whilst such finely grained tabular information might be regarded as confidential by companies we show that, at a minimum, disclosures should distinguish between PSC and concession reserve entitlement. Our paper adopts a position similar to that proposed for price risk by Rajgopal (1999), establishing the need for price response disclosures of underlying oilfield assets. Our proposal recognises the existence of price sensitive contractual conditions and emphasises the need for the commodity price responsiveness of present values, reserves and production sharing to be disclosed.

**Principal differences between PSC and Concession Market Risk Disclosures**

Traditional oilfield concession ownership is found in the Gulf of Mexico, Europe, and Australasia (amongst others). Under these royalty structures, if producers generate a profit from ongoing extraction, they pay corporation tax, sometimes supplemented with revenue, royalty or other taxes. In this instance, producers own the underlying reserves, with reported reserves being the recoverable reserves from the reservoir in total, and future physical reserve entitlement is unaffected by price volatility.

By contrast, early cost recovery production sharing contracts were signed in Indonesia in 1965 and now exist in many of the world's newer oil producing and non OECD regions including West Africa, Kazakhstan, Indonesia and Egypt. The proliferation of these agreements in the 1990s has been a direct result of government desire to reclaim control of natural resources once a fair return has been earned by the corporate producers. The PSC allows contractual contingent claims (often in forms of taxation or production sharing) to be made against producer reserves when an agreed threshold of return is met and costs have been covered.

At present the SEC requires a simple disclosure of price risk, measured by the response of profits to changes in oil/gas prices. We use our findings above to show that this approach focuses on the immediate 'income effect' without reference to effects on sustainable reserves, future production entitlement or NPV. For instance Exxon Mobil's 2006 SEC disclosures of total price risk state:

*'Crude oil, natural gas, petroleum product and chemical prices have fluctuated in response to changing market forces. The effect of these price fluctuations on earnings from Upstream, Downstream and Chemical operations have varied. In the Upstream, based on the 2005 worldwide production levels, a $1 per barrel change in the weighted-average realized price of oil would have approximately a $400 million annual after-tax effect on Upstream consolidated plus equity company earnings. ……. For any given*

*period, the extent of actual benefit or detriment will be dependent on the price movements of individual types of crude oil, taxes and other government take effects, price adjustment lags in long-term gas contracts, and crude and gas production volumes. Accordingly, changes in benchmark prices for crude oil and natural gas only provide a broad indicator of changes in earnings experienced in any particular period.'*

Conspicuously no price response is declared for disclosed SEC reserves in terms of either quantity of reserves or production entitlement or present value. The distinction in market risk on government take has a direct bearing on the two main components of supplementary SEC disclosure requirements of: (1) disclosures of proved oil and gas reserve quantities and annual changes therein, and (2) disclosures of proved oil and gas reserve values (using a standardised measure) and annual changes therein. Proved reserves of oil and gas[3], production[4] (an important element in the changes in proved reserves) and the expected net present value of the proved oil and gas reserves (the standardized measure[5]) have all been shown to be value relevant, we therefore focus on these three SEC measures in our analysis.

---

[3] FASB (1982) defines proved oil and gas reserves as *"Net quantities of an enterprise's interests in proved reserves and proved developed reserves of (a) crude oil (including condensate and natural gas liquids) and (b) natural gas shall be disclosed as of the beginning and the end of the year. "Net" quantities of reserves include those relating to the enterprise's operating and nonoperating interests in properties as defined in paragraph 11(a) of Statement 19. Quantities of reserves relating to royalty interests owned shall be included in "net" quantities if the necessary information is available to the enterprise; if reserves relating to royalty interests owned are not included because the information is unavailable, that fact and the enterprise's share of oil and gas produced for those royalty interests shall be disclosed for the year. "Net" quantities shall not include reserves relating to interests of others in properties owned by the enterprise."*

[4] FASB (1982) includes production of oil and gas in its definition of the changes in proved reserves: *"Changes in the net quantities of an enterprise's proved reserves of oil and of gas during the year shall be disclosed. Changes resulting from each of the following shall be shown separately with appropriate explanation of significant changes; (a) Revisions of previous estimates, (b) Improved recovery, (c) Purchases of minerals in place, (d) Extensions and discoveries, (e) Production and (f) Sales of minerals in place."*

[5] FASB (1982) defines the standardized measure as *"A standardized measure of discounted future net cash flows relating to an enterprise's interests in (a) proved oil and gas reserves (paragraph 10) and (b) oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the enterprise participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (paragraph 13) shall be disclosed as of the end of the year. The*

The primary research question in our study is whether disclosure requirements for price sensitive contractual claim terms should be differentiated from the SEC disclosures designed for concession entitlement. We find it instructive to isolate the price variable nature of oilfields by using our sample to examine both the *amount* and the *response* of SEC disclosures to oil price variations. Our expectations are clear, if SEC concession and PSC supplementary disclosure responses across our empirical sample prove to be differentially responsive to market risks, then as noted by Rajgopal (1999) there would be justification for their separate disclosure.

## III. RESEARCH DESIGN

We conduct an empirical study of how, when subject to commodity price variability, ownership disclosures differ across ownership regimes, and even within regimes. Our first test is for the significance of *response differences* between PSC and concession SEC disclosure requirements. A comparative empirical analysis of PSC and concession oil and gas price responses against GoM concession benchmarks allows us to achieve two insights; firstly, we conduct an analysis of concession oil price responses relative to the GoM – identifying regime differences between concessions and PSCs. Secondly, PSC fields were compared to GoM – identifying the extent of inter sample differences. This approach provides consistent and comparable country

---

*standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes. The following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraph 12; (a) Future cash inflows, (b) Future development and production costs, (c) Future income tax expenses, (d) Future net cash flows, (e) Discount and (f) Standardized measure of discounted future net cash flows."*

insights for all three SEC disclosures, testing whether Corporate SEC PSC and concession disclosures for *oil and gas reserves, production* and *NPV responses* differ by country - when compared to GoM concession disclosures.

Our second test lifts out the potential differences between PSC regimes by comparing PSCs against each other. This enables us to determine whether it is sufficient to disclose PSC as a homogenous group or whether the wide range of PSC terms illustrated in Appendix 3 make it necessary to disclose PSC terms individually.

## The Model - Demonstrating Differences in SEC Disclosures for PSC and Concession

Our taxation models are computationally intensive and differ (in line with tax terms) from regime to regime and indeed from field to field. The strength of our analysis is that field by field taxation computations are individually performed for the actual taxation terms applicable for each of the 292 oilfields for each of the five prices. Country tax protocols are programmed into GEM and used to underpin an empirical comparison of differential SEC disclosures as between actual PSC and concessionary ownership structures for oilfields in our sample.

To provide the reader with an understanding of the method and details of PSC oilfield calculations, an example of one actual field's calculations at a base case price of US$45 are shown in Appendices 1 and 2. Due to the practical difficulties of disclosing detailed PSC tax calculations on a field by field basis for all fields at all price decks, we do not show these separately, but provide an overview of the range of concession and PSC terms applicable to fields in our sample in Appendix 3.

We use an actual Angolan field (with the production profile altered to preserve confidentiality) to provide a simplified insight into the differences that the application of the $P_{45}$ price deck to different concession and PSC terms cause.[6] Firstly, we treat the field as if it is held under a domestic Angolan PSC agreement (Appendix 1) and then under GoM concession terms (Appendix 2). We use the specimen field to derive and calculate each figure in the $P_{45}$ columns of Table 1. This gives the PSC disclosures for reserves (408 mmboe), production (9000 boe/day) and NPV (US$3182 million) figures for an oil price scenario of US$45 in 2006, Appendix 1. Similarly, we calculate the 3 SEC measures for the same hypothetical field - identical to the specimen PSC field in every respect save that it is subject to concessionary terms. For purposes of the comparison, we have used the terms applicable to a GoM deepwater field. Appendix 2, Table B gives the SEC calculation of reserves (700 mmboe), production (9000 boe/day) and NPV (US$6545 million).

Our price response analysis of disclosures, as supported by taxation computations for each field, is presented over 5 price ranges. As our benchmark we set US$45 as the base case price deck, with the US$45 price deck analogous to the year end price used in current SEC disclosures. Our choice of price range is judgemental based on recent (2006) oil prices and their potential option implied volatility; we calculate SEC disclosures at

[6] The production profile has been changed to preserve confidentiality.

US$45, the base case price, two upside price decks US$67.5 and US$90, as well as two downside decks of US$33.75 and US$22.5 to demonstrate the price variable response of SEC disclosures.

Table 1 sets out an analysis of disclosure performances on either side of the $P_{45}$ price deck, and provides a summary of how our Angolan field disclosures look as at January 2006 under different price assumptions. The $P_{22.5}$ - $P_{90}$ comparison illustrates the effect that price variability can have upon ownership SEC disclosures, and serves to demonstrate the motivation for our study. The first point to note is that concession reserves remain constant at 700 mmboe while reserves vary from 240-659 mmboe under PSC terms. Table 1 shows that even at a low initial oil price, US$22.5, production sharing commences.

[TABLE 1 ABOUT HERE]

As the oil price increases, PSC contract terms result in reserves being recouped by government claims, *reducing corporate entitlement* to 240 mmboe at US$90, less than half the original entitlement. Production appears to remain constant under both regimes. This will be shown to be a short term effect; while concession production does in fact remain constant under differing price scenarios, PSC production terms would vary over time - see figure 1. A PSC phenomenon that would occur if higher prices were to persist and result in operators earning their contracted returns through price increases rather than production volumes.

[FIGURE 1 ABOUT HERE]

Finally, while the NPV of the specimen field does vary under both structures – concession fiscal take only increases as a result of price movement, while the PSC reserve claw back is dictated by fiscal terms in Appendix 3, where NPV is a composite of price and quantity of oil reserves, discounted at a rate of 10 percent, in line with SEC regulations.

## Empirical Tests of SEC Disclosure Responses

We present our test for differences as to how actual SEC disclosures respond to price changes across our oilfield sample in three parts; first we reflect the rate of change for the price intervals, then we reflect statistical tests of difference between PSCs and concessions as represented by GoM. Specifically, disclosure responses are calculated for each field within 5 specific prices (two on either side of US$45) to give an indication of the magnitude of change in the SEC disclosures per one percent change in the oil and gas price. For instance, we simulate the response of reserves, production and remaining PV when the oil prices fall from the $P_{45}$ to the $P_{33.75}$ scenario. Reserve entitlement responses between two price scenarios (referred to as P1 and P2) are calculated for each field in all six countries as follows[7]:

$$\text{Reserve Response } (P_1/P_2) = \frac{(R_{P1} - R_{p2}) / R_{P2}}{(P_{P1} - P_{P2}) / P_{P2}}, \qquad (1)$$

[7] Formulae are applied such that when P1<P45, the P1 is further from P2, and when P1 is greater than P45 then P1 >P2

where $R_{P1}$ and $R_{P2}$ refer to the entitled SEC reserves $R_{22.5}$, $R_{33.75}$, $R_{45}$, $R_{67.5}$ and $R_{90}$ (in mmboe) under P1 and P2, respectively, under each of the stylised five price scenarios. For instance, the reserve response between the $P_{45}$ (P2) and $P_{33.75}$ (P1) price decks would be calculated as $(R_{33.75} - R_{45})/R_{45}$ / $(P_{33.75} - P_{45})/P_{45}$.

Production entitlement responses are calculated as follows:

$$\text{Production response } (P_1/P_2) = \frac{(Q_{P1} - Q_{P2})/Q_{P2}}{(P_{P1} - P_{P2})/P_{P2}}, \qquad (2)$$

where $Q_{P1}$ and $Q_{P2}$ refer to the entitled SEC production $Q_{22.5}$, $Q_{33.75}$, $Q_{45}$, $Q_{67.5}$ and $Q_{90}$ (in mmboe) under P1 and P2, respectively, under each of the stylised five price scenarios.

PV responses are calculated as follows:

$$\text{PV response } (P_1/P_2) = \frac{(NPV_{P1} - NPV_{P2})/NPV_{P2}}{(P_{P1} - P_{P2})/P_{P2}}, \qquad (3)$$

where $NPV_{P1}$ and $NPV_{P2}$ refer to the remaining PVs: $NPV_{22.5}$, $NPV_{33.75}$, $NPV_{45}$, $NPV_{67.5}$ and $NPV_{90}$ (in mmboe) under P1 and P2, respectively, under each of the stylised five price scenarios.

The above allow us to analyse whether the commodity price responses of SEC disclosures in the concession regimes NCS and UKCS, and the PSC regimes

Angola, Egypt and Indonesia are statistically different from the equivalent responses in the concession countries US GoM, NCS and UKCS. The use of t-tests for difference are based on underlying field data. This approach introduces the principle that differential responses of SEC measures is based on ownership structures an demonstrate material variations in current disclosure between PSC and concession fields.

## IV. SAMPLE SELECTION AND DATA

Industry standard Oilfield data has been provided by the oil and gas consultancy Wood McKenzie. We made use of oilfield data from their commercially available Global Economic Model (GEM). This is compiled based on the analysis of direct technical information from operators and participants in the oilfields and all other public domain sources of information. Our sample was taken from their January 2006 database, each field has full life revenue, costs and taxation set our in panel data, distilled to pre and post tax present value calculations. Each field model contains data of the nature of that summarised in Appendix 1, Table 1A. From the total population we use stratified sampling to select a size varying sample of oilfields from each country (Cochrane 1946). We are guided in stratification by the findings of Kretzschmar & Moles (2006) who in their study of real option models found that fields displayed size varying characteristics. Fields with less than 6 million barrels of remaining oil and gas equivalent were therefore eliminated as abandonment expenses introduce idiosyncratic behaviour that would focus on the tax relief of abandonment costs rather than reserve disclosures for the predominantly producing fields in our study - Table 2.

Our sample represents oilfields containing between 80-90 percent of the total remaining oil and gas reserves in GoM, NCS, Angola, Egypt and Indonesia and approximately 50 percent of the reserves in UKCS. To our knowledge, no other academic study of oilfield ownership behaviour have analysed samples of a similar size. Each of the 6 regimes in our sample was selected for their fiscal homogeneity (Appendix 3).

[TABLE 2 ABOUT HERE]

## V. EMPIRICAL RESULTS

In this section we report the results of our tests for differences between field disclosure responses to price movements. GoM fields are used as a concession benchmark for differential responses of fields in the UKCS and NCS. Similarly Angola, Egypt and Indonesia responses are in turn tested against GoM in order to compare PSC SEC disclosure responses with concessions. We also test for differences between individual countries.

### SEC reserve disclosure responses to oil price variations - Comparisons to the GoM Benchmark

Concession reserve entitlement does not move in response to oil price changes (upper half of Table 3). The UK and Norway concession reserve responses are identical to GoM in showing no response to changing prices in Panel A. By contrast, the lower half of panel A provides insights into *the price response* of reserve entitlements for oil companies with reserves in PSC regimes. Our t tests reported in Table 3 panel B show that PSCs are (all) significantly different from GoM responses at the 0.1 percent level.

Our results layout allows readers to break reserve responses into price ranges and show that the PSC sample measured by Angolan, Egyptian and Indonesian fields are substantially influenced by changes in oil and gas prices. This reflects the intuition of Rajgopal (1999) that beta responses depend on the periodicity and price ruling for the measurement interval. Jin Jorion also mentioned the locality of oilfields as having an effect on prices obtained for resources, findings supported by out tabular analysis. For instance, when the oil price (and similarly the gas price per boe) decreases by 33.3% from $33.75 to $22.5, the reserve response as per our formula is -0.253 for Egypt, -0.324 for Indonesia, and -0.451 in the case of Angola - Table 3, Panel A. This means, for example, that the reserve entitlement for Egypt increases by 25.3% of 33.3%, an increase in actual physical reserves of 8.4%. Thus, over the price range, the impact on reserve entitlement is approximately a quarter the size of the price change. Similarly the impact for Indonesia is 32.4% of the price change and for Angola it is 45.1%. The negative signs of the reserve responses in Table 3 indicate that reserves move in the opposite direction to price. The movement encapsulates the response of disclosures to moves in oil prices - away from the year end levels of US$45 – that would be shown using SEC guidelines. There is for PSCs therefore an increase in reserve entitlement as price falls and vice versa. It is also noteworthy that, in the case of Egypt and Angola the reserve responses peak in the price range $45 to $33.75 whereas for Indonesia the most response is in the lower price range of $33.75 to $22.5. The pattern of reserve responses is a function of the terms of the

PSC with the older Indonesian agreements being crafted in an era of lower oil price expectations.

When the oil price increases by 33.3% from $67.5 to $90, Table 3 shows a response in reserve entitlement of 0.130 (of 33.3%) for Indonesia, 0.132 for Egypt and 0.388 in the case of Angola. These responses represent decreases in reserve entitlement as price rises. In all three cases the rate of decrease is moderated as prices rise (in the case of Angola from a response of 0.405 over the range from $45 to $67.5 to 0.388 over the range $67.5 to $90). Importantly, *rate of change* is dependent on PSC contract terms as they apply to the field and again varies by price range, depending on the contract terms.

[TABLE 3 ABOUT HERE]

**SEC reserve disclosure responses to oil price variations – Comparisons between PSC Regimes**

PSCs in turn demonstrate a wide range of responses between different PSC contracts in response to the same price change. Angola has the most aggressive production sharing terms, resulting in a 0.405 (of 50%) reserve decrease for the 50% increase in price from $45 to $67.5. (Egypt and Indonesia are both at 0.154). It is relevant to note that this effect is opposite on the downside, with reserves disclosed increasing for Angola by a rate of 0.684 of 33.3% in response to a 33.3% fall in price from US$45 to US$33.75.

The significant differences in reserve responses between Angola and both Egypt and Indonesia support our proposal that not only should there be separate reserve disclosures for PSCs in the first instance, but also separate disclosure by contract type.

### SEC production disclosures - responses to oil price variations - Comparisons to the GoM Benchmark

Production results deconstruct reserve entitlement into annualised production, providing evidence that production in concession regimes is unaffected by changes in oil and gas prices. The production volumes that oil companies are entitled to report remain constant at 100 percent, Table 4, Panel A.

### SEC production disclosure responses to oil price variations – Comparisons between PSC Regimes

On the other hand, production entitlement in Angola, Egypt and Indonesia are considerably affected. For example, a 33.3% decrease in oil and gas prices from $33.75 to $22.5 increases production entitlement by 0.205 (of 33.3%) for Egypt, by 0.291 for Angola and by 0.466 in the case of Indonesia. Likewise, a 33.3% increase in the commodity price from $67.5 to $90 will lead to reserve decreases of 0.064 (of 33.3%) for Indonesia, 0.106 for Egypt and 0.181 in the case of Angola. The negative signs assigned to reserve responses in Table 4 indicate that production entitlement moves in the opposite direction to price. The responses for Egypt and Angola are all significantly different from those in GoM at either the 1 percent or the 0.1 percent level.

[TABLE 4 ABOUT HERE]

Table 4 shows that the three PSC countries of Angola, Egypt and Indonesia are not significantly different from each other in terms of the 2006 production response to 2006 price change. However, figure 1 demonstrates that such a price change does differentially change the pattern of production entitlement for PSC countries in the longer term. It is this longer term differential impact on production that is picked up in the forthcoming paragraphs which examine PV responses to price change.

**SEC PV disclosure responses to oil price variations - Comparisons to the GoM Benchmark**

Table 5, Panel A reports responses in oilfield PV to changing oil and gas prices. As before, Panel B also reports the results of t tests to responses between each country and the GoM benchmark and between individual countries. The difficulty in interpreting causality behind changes in the PV measure stems from the fact that it is a composite of price and production, discounted at the SEC rate of 10 percent. Thus the effect of oil prices upon PV is somewhat more difficult to interpret, possibly contributing to the need for Boone (2002) to revisit previous value relevance studies. It can be seen from Table 5 that for all countries the PV response increases as prices fall with the largest responses being to a fall in price from $33.75 to $22.5. For example, in GoM such a 33.3% fall induces an even bigger percentage fall in PV being 1.306 times 33.3%. Nevertheless there are significant differences between the PV responses.

Table 5 shows that for price changes from $33.75 to $22.5, Indonesia, a PSC field and NCS, a concession field, have PV response that is significantly different (at the 1 percent level) from the GOM benchmark. However at higher prices ($P_{67.5}/P_{45}$ and above) it is Angola and Egypt that have the significantly higher PV price response compared to the GOM benchmark.

**SEC PV disclosure responses to oil price variations – Comparisons between PSC Regimes**

At high oil prices all oilfields experience an increase in PV if prices rise but those of Egypt, and in particular Angola, rise at a significantly lower rate. This is a reflection of the claw-back of reserves by the Angolan/Egyptian government under their PSC terms. Angola has the most aggressive claw-back. For example, a 50% increase in price from $45 to $67.5 results in a PV increase of only 0.33 0f 50%. Table 5 shows that Angola PV responses are significantly different from Egypt at all price ranges and from Indonesia at the higher price ranges, once again supporting the need for separate SEC disclosures for the individual PSC fields.

[TABLE 5 ABOUT HERE]

**Price and SEC Disclosures - Assessing Current Reserves, Production and NPV Reporting**

At present the SEC requires a simple disclosure of price risk, measured by the response of profits to changes in oil/gas prices. Conspicuously no price response is declared for the disclosed SEC reserves in terms of either quantity of reserves or production entitlement or present value. This omission could be rectified by an SEC/FASB requirement for straightforward tabular disclosure as illustrated in Tables 6 and 7, differentiating between Concessions and PSCs for both the quantity and present value of proven reserves over a range of prices.

[TABLE 6 ABOUT HERE]

The tabular disclosure encapsulates the asymmetrical relationship between price and PSC reserves, reflected in Table 6. Concession reserve entitlement does not change in response to price movements, with the response remaining firmly at 0 on the Y axis. Angola shows the most variance followed by Egypt and Indonesia. The price response of PSC reserves is also not linear across the range of prices, reflecting the differing contract terms from Appendix 3.

[TABLE 7 ABOUT HERE]

The same price asymmetry exists with PV except that the asymmetry is less given the compensatory effects of price increases. Figure 2a pulls the price response of reserves together with Figure 2b which shows the NPV response to price variations. The effect of the plus 50 and plus 100 percent price movement effects are most apparent in Angola, where aggressive production sharing causes reserves entitlement to fall 40 percent, while the corresponding growth in PSC NPV is 25 percent (relative to concession regime reserve loss of zero percent and NPV gain of 125 percent).

[FIGURE 2 ABOUT HERE]

## VI. DISCUSSION AND CONCLUSION

The SEC disclosure presumption that entitlements are consistent across ownership structures has been shown to be incorrect for all three SEC measures. We suggest that the practice of reporting year end reserves as a homogenous asset class conceals value relevant information that would enable analysts to determine companies with oil reserves most affected by price movements. Our arguments in support of the paper's recommendations are rehearsed in the following paragraphs.

In essence we question the very tenets of SEC resource disclosures. We base our enquiry on the existence of undisclosed claims in oilfield ownership contracts; noting that an oil and gas firm value can be decomposed into (1) the present value of future discretionary cash flows, (2) the present value of proven reserves (less contingencies) and (3) the present value of growth and development opportunities associated unproven reserves. Given declining reserve opportunities and the emergence of production sharing contracts (PSCs) an important corporate value determinant is the role that government contractual take (and hence residual corporate entitlement) plays in each of these three value elements. Each element is contractually dependent upon an assumed pattern of future oil prices, and as energy prices rise, fields producing through production sharing contracts are shown to have their 'bookable' barrels reduced due to participation by the local government.

PSCs are expected to increasingly affect the value of growth and development opportunities for oil companies as most of the regions of the world where opportunities exist, are adopting PSC arrangements. Since growth and development opportunities do not form part of the current supplementary disclosures, we do not examine this third effect, but we have examined the effect of PSC arrangements upon proven reserve quantities, their present values and upon production. Although SEC disclosures are made net of contingent claims (at year end prices), the size of potential contractual claims is not disclosed and hence the effect of the PSC terms at year end prices, let alone their potential effect at future prices, is not readily understood by users of financial information.

We have provided an overview of contract terms for a sample of countries through which we make a rigorous empirical investigation of the effect of PSCs upon the SEC reserve disclosures. We find that, in comparison to concessionary terms, the present value of reported reserves under PSCs, is significantly more sensitive to oil and gas prices. Moreover, PSC terms directly affect both reserve and production quantities also making these disclosures sensitive to oil and gas prices. Hence company entitlement is difficult to understand in a period of price change and volatility. This in turn makes the analyst's assessment of the annual replacement of reserves more difficult, and the isolation of sustainable discretionary cash flow problematic. Another effect is that on earnings disclosure - as the price of oil rises and a larger share of production comes from PSC regimes, oil companies will experience a larger effective tax take. This means that if the current relationship between concession and PSC tax rates hold, companies with larger PSC holdings are likely to experience greater increases in effective tax rates than those with concession holdings.

Our recommendations suggest that as a minimum there should be separate PSC and concession reserve disclosures. Secondly, we recommend that supplementary information should reflect the disclosure response, resulting from contractual obligations, of SEC reserve disclosures to oil and gas price changes. As a general rule we propose that there be separate reserve disclosures whenever differences in contract terms result in significantly different price response behaviours. Our recommendations are to a large extent an extension of emergent principles contained in the extension to SEC (1997) dated June 15 1998 which require corporates to disclose market risk exposures resultant from derivative and underlying non derivative items (or contractual positions) that affect a reader's understanding of the balance sheet. We conclude that contingencies associated with proven reserves are important data needed for the valuation of oil and gas companies.

# APPENDIX 1

## Detailed Calculations of oil and gas reserve entitlement, oil and gas production, and Remaining oilfield NPV under PSC tax terms

**Table 1A** below shows field data for a large Angolan oilfield.[8] Column (a) shows the production profile (in thousands of barrels of oil per day) for each year in the whole life of the oilfield, while column (b) depicts the corresponding price forecast.[8] In this specific example the oil produced is of Hungo quality (in contrast to West Texas Intermediate (WTI) and Brent blend), and this quality of oil is typically sold at a discount to WTI or Brent. Annual expected gross revenue (column c is calculated as the product of production (column a) and price (column b). Columns (d) and (e) describe the expected expenses incurred from operating the field (operating expenses, opex) and investments to prepare the field for production (capital expenditure, capex), respectively. Company cash flow (column l) is calculated as gross revenues less opex, capex and government take. Columns (f) – (k) relate to the calculation of government take and profit splits between the government and the contractor, and will be described in more detail in **Tables 1B and 1C**. **Table 1D** articulates how the SEC variables reserves, production and NPV are calculated.

---

[8] Oil production, field life, operating expenditures and capital expenditures have all been changed in order to ensure that no confidential information is revealed.

[8] The standardized SEC measure requires the use of the current year-end price of oil over the whole field life, we apply a slightly more conservative approach to incorporate findings from Bessembinder et al (1995) – for both concessions and PSC calculations. A $P_{45}$ oil price[7] scenario at time 0 consists of US$45/barrel for 2006, US$40/barrel for 2007, US$37/barrel for 2008, US$35.87/barrel for 2009 and US$36.77/barrel for 2010. From 2010 onwards, the oil price is increased by 2.5 percent a year. In addition, we develop 4 price scenarios where the prices in the $P_{45}$ scenario is scaled down up or down with a constant factor. For instance, we calculate a $P_{33.75}$ scenario where all the $P_{45}$ prices are multiplied by 75 percent, resulting in a oil price of US$33.75/barrel[2] at time 0. Similarly we calculate a $P_{22.5}$ scenario (50 percent of US$45, equivalent to US$22.5/barrel), a $P_{67.5}$ scenario (150 percent of US$45, equivalent to US$67.5/barrel) and a $P_{90}$ scenario (200 percent of US$45, equivalent to US$90/barrel). We tested this mean reversion against SEC tests and found that this is an accurate and more conservative approximation of the price effect on SEC PSC disclosures. Using static SEC year end prices actually increases the PSC price effect on reserves by enabling PSC claims to occur sooner, simply strengthening conclusions made in this paper.

## TABLE 1A

## Detailed calculation of cash flows for a typical Angolan oilfield under Angolan PSC tax terms

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Production Liquids 000 b/d | Liquid price Hungo US$/bbl | Gross Revenue US$M | Op Costs US$M | Capital Costs US$M | Cost Recovery US$M | Total Profit Share US$M | State Share (%) | Government Profit Share US$M | Contractor Profit Share US$M | Income Tax US$M | Company Cash Flow US$M |
| 2003 | 0 | | 0 | 0 | 105 | 0 | 0 | | 0 | 0 | 0 | -105 |
| 2004 | 0 | | 0 | 0 | 323 | 0 | 0 | | 0 | 0 | 0 | -323 |
| 2005 | 0 | | 0 | 0 | 552 | 0 | 0 | | 0 | 0 | 0 | -552 |
| 2006 | 10 | 41.9 | 153 | 29 | 679 | 76 | 76 | 25% | 19 | 57 | 29 | -603 |
| 2007 | 100 | 37.2 | 1358 | 126 | 232 | 679 | 679 | 25% | 170 | 509 | 255 | 576 |
| 2008 | 200 | 34.4 | 2512 | 198 | 238 | 1256 | 1256 | 25% | 314 | 942 | 471 | 1291 |
| 2009 | 200 | 33.4 | 2435 | 203 | 122 | 900 | 1535 | 25% | 384 | 1151 | 576 | 1151 |
| 2010 | 180 | 34.2 | 2246 | 194 | 62 | 289 | 1957 | 35% | 685 | 1272 | 636 | 669 |
| 2011 | 165 | 35.0 | 2111 | 187 | 64 | 273 | 1838 | 55% | 1011 | 827 | 414 | 435 |
| 2012 | 154 | 35.9 | 2023 | 184 | 66 | 258 | 1765 | 55% | 971 | 794 | 397 | 406 |
| 2013 | 144 | 36.8 | 1938 | 181 | 67 | 252 | 1686 | 75% | 1264 | 421 | 211 | 215 |
| 2014 | 135 | 37.7 | 1858 | 178 | 0 | 191 | 1667 | 75% | 1250 | 417 | 208 | 222 |
| 2015 | 126 | 38.7 | 1781 | 175 | 0 | 184 | 1597 | 75% | 1197 | 399 | 200 | 209 |
| 2016 | 118 | 39.7 | 1706 | 172 | 0 | 177 | 1530 | 75% | 1147 | 382 | 191 | 196 |
| 2017 | 110 | 40.6 | 1635 | 170 | 0 | 170 | 1465 | 75% | 1099 | 366 | 183 | 183 |
| 2018 | 103 | 41.7 | 1568 | 168 | 0 | 168 | 1400 | 75% | 1050 | 350 | 175 | 175 |
| 2019 | 96 | 42.7 | 1503 | 166 | 0 | 166 | 1337 | 75% | 1003 | 334 | 167 | 167 |
| 2020 | 90 | 43.8 | 1439 | 164 | 0 | 164 | 1275 | 75% | 957 | 319 | 159 | 159 |
| 2021 | 84 | 44.9 | 1380 | 163 | 0 | 163 | 1218 | 75% | 913 | 304 | 152 | 152 |
| 2022 | 79 | 46.0 | 1323 | 161 | 0 | 161 | 1161 | 75% | 871 | 290 | 145 | 145 |
| 2023 | 74 | 47.1 | 1268 | 160 | 0 | 160 | 1108 | 75% | 831 | 277 | 138 | 138 |
| 2024 | 24 | 48.3 | 423 | 78 | 0 | 78 | 346 | 75% | 259 | 86 | 43 | 43 |

(a) production profile
(b) Oil price assumption

(c) Gross revenues are calculated by multiplying oil production (annualised) by the oil price assumption, i.e.[(a) x (b) x 0.365]
(c) Opex profile
(e) Capex profile
(f) smallest of (e) x 50 percent and (c) [uplifted (40 percent) and depreciated (4 years)] + (d)
(g) (c) - (f)
(h) Profit oil splits (see Table 1B)
(i) (g) x (h)
(j) (g) x [1-(h)]
(k) (j) x 50 percent
(l) (c) – (d) – (e) – (i) – (k)

---

Two key features of PSCs are the concepts of cost recovery (termed 'cost oil') and profit sharing (termed 'profit oil'). While oil companies under concessionary fiscal terms are allowed to sell all of their production to market prices, under PSC fiscal terms they are only entitled to the production which covers the sum of 'cost oil' and 'profit oil'.

Cost recovery allows the contractor to recoup costs. Additionally, in some areas, such as the Angolan deepwater oil fields, contractors are also allowed capital costs uplifts, which allows the partner group to uplift all capital costs by at least 40 percent. In situations where large, high-cost, development projects are required (i.e. the majority of Angola's deepwater discoveries) the capital uplift means that for a project with capital expenditure of US$3 billion the recoverable costs are US$4.2 billion.

Production remaining after cost recovery is termed profit oil/gas and is divided between the contractor and the government. The basis on which this division is made varies between contracts with more recent contracts based on the contractor's rate of return (ROR) whereas in earlier contracts the split was based on cumulative production.

All offshore contracts awarded since 1991 fall under the ROR based model. During the application process bidders must specify the rate of return steps and the profit oil splits applicable to each tier. The contract allows for up to five different tiers of profit splits with rates varying from contract to contract. Typical rate of return based profit splits are given in Table 1B:

## TABLE 1B

**Profit splits for a typical Angolan oilfield under PSC tax terms**

| (a)<br>IRR | (b)<br>State share | (c)<br>Contractor share |
|---|---|---|
| <15% | 25% | 75% |
| 15% - 25% | 35% | 65% |
| 25% - 30% | 55% | 45% |
| 30% - 40% | 75% | 25% |
| >40% | 85% | 15% |

(a) IRR = internal rate of return
(b) State share of profit oil
(c) Contractor share of profit oil

The split is determined by the rate of return achieved in the previous period. The ROR calculation is based on the contractor's accumulated compounded post-tax cash flow. The contractor's cash flow is defined as in Table 1A (column (l)). Exploration expenditure is not included in the computation of contractor's net cash flow. Only expenditure after the date of commercial discovery is included.

The contractor's cash flow is compounded at each of the ROR rates specified in the contract and the profit oil split is taken relating to the highest ROR which yields a positive result (Table 1C). The compounded cash flow will by construct turn positive when the rate of return is achieved. For example, the 2003 company cash flow was minus US$105 million. The relevant Tier 1 cash flow for 2004 is calculated as -105 x 1.15 – 323 = -US$ 444 million, while the Tier 2 cash flow in the same year is calculated as -105 x 1.25 -323 = -US$ 454 million. This compounding is done for all the years in the field's life. In 2009, the Tier 1 compounded cash flow turns positive (US$622 million) signifying that the company has achieved at least 15 percent return on its investment. This results in a change in the profit split in favor of the government. Total profit oil for the following period is split 35 percent:65 percent (government percent : contractor percent).

In 2012 the company is expected to have achieved a 30 percent return on its investment, and will only be allowed 25 percent of the profit oil.

---

**TABLE 1C**

**Profit split tiers for a typical Angolan oilfield under PSC tax terms**

| Year | (a) Applicable Cash flow US$M | (b) 1st Tier US$M | (c) 2nd Tier US$M | (d) 3rd Tier US$M | (e) 4th Tier US$M | (f) State Share % |
|---|---|---|---|---|---|---|
| 2003 | -105 | -105 | -105 | -105 | -105 | 25% |
| 2004 | -323 | -444 | -454 | -460 | -470 | 25% |
| 2005 | -552 | -1062 | -1120 | -1150 | -1210 | 25% |
| 2006 | -603 | -1825 | -2003 | -2097 | -2297 | 25% |
| 2007 | 576 | -1523 | -1928 | -2151 | -2640 | 25% |
| 2008 | 1291 | -460 | -1119 | -1505 | -2406 | 25% |
| 2009 | 1151 | 622 | -248 | -806 | -2217 | 35% |
| 2010 | 669 | 1384 | 360 | -378 | -2434 | 55% |
| 2011 | 435 | 2027 | 885 | -56 | -2973 | 55% |
| 2012 | 406 | 2737 | 1512 | 333 | -3756 | 75% |
| 2013 | 215 | 3363 | 2105 | 648 | -5043 | 75% |
| 2014 | 222 | 4089 | 2854 | 1064 | -6839 | 75% |
| 2015 | 209 | 4912 | 3776 | 1592 | -9365 | 75% |
| 2016 | 196 | 5844 | 4916 | 2266 | -12915 | 75% |
| 2017 | 183 | 6904 | 6328 | 3129 | -17898 | 75% |
| 2018 | 175 | 8115 | 8085 | 4243 | -24883 | 75% |
| 2019 | 167 | 9499 | 10273 | 5683 | -34669 | 75% |
| 2020 | 159 | 11084 | 13000 | 7547 | -48377 | 75% |
| 2021 | 152 | 12898 | 16403 | 9963 | -67575 | 75% |
| 2022 | 145 | 14978 | 20649 | 13098 | -94460 | 75% |
| 2023 | 138 | 17363 | 25949 | 17165 | -132106 | 75% |
| 2024 | 43 | 20011 | 32480 | 22358 | -184905 | 75% |

(a) Using Table 1A column (l)
(b) Previous year's (b) x (100 percent + 15 percent) plus (a) where 15 percent is the assumed first tier rate of return threshold
(c) As (b) but using 25 percent
(d) As (b) but using 30 percent
(e) As (b) but using 40 percent
(f) Share determined by reference to Table 1B above. The split applicable in any one year is that determined by the rate of return achieved in the previous year (goes to column (h) in Table 1A (for following year)).

---

Since oil companies under PSC terms are only entitled to the production which covers cost oil and profit oil, their entitled production (Table 1D column (d)) will be different from total field production (Table 1D column (b)). In 2006 the field is expected to produce 10 million barrels of oil per year. Under concession terms, the oil companies would be entitled to the entire 10 million barrels/yr. However, under the PSC terms the production entitlement is less than this amount. In 2006 the contractors cost oil is US$76 million and its share of profit oil is US$57 million, a total of US$134 million. This is equivalent to a production of 3200 barrels per day, or 8.75 million barrels of oil a year (sum of cost oil and profit oil divided by market price of oil, i.e. 134/41.9).

Oil reserves are calculated as the sum of production over the whole field life (columns (a) and (c)). As Table 1D shows, the difference between total production and entitled production increases with government share of profit oil.

The expected net present value of the company cash flow is calculated using a discount rate of 10 percent, equivalent to SEC requirements (Table 1D column (e)).

[TABLE 1D ABOUT HERE]

---

**TABLE 1D**

**Calculation of reserves entitlement, production entitlement and Remaining NPV under Angola PSC tax terms**

| | (a) Remaining reserves mmboe | (b) Production 000boe/d | (c) Entitled reserves mmboe | (d) Entitled production 000boe/d | (e) Remaining NPV US$M |
|---|---|---|---|---|---|
| 2003 | 800 | 0 | 412 | 0 | 1614 |
| 2004 | 800 | 0 | 412 | 0 | 1880 |
| 2005 | 800 | 0 | 412 | 0 | 2391 |
| 2006 | 800 | 10 | 408 | 9 | 3182 |
| 2007 | 797 | 100 | 377 | 88 | 4103 |
| 2008 | 760 | 200 | 313 | 175 | 3938 |
| 2009 | 687 | 200 | 251 | 168 | 3041 |
| 2010 | 614 | 180 | 206 | 125 | 2194 |
| 2011 | 549 | 165 | 174 | 86 | 1744 |
| 2012 | 488 | 154 | 145 | 80 | 1483 |
| 2013 | 432 | 144 | 127 | 50 | 1226 |
| 2014 | 379 | 135 | 110 | 44 | 1133 |
| 2015 | 330 | 126 | 95 | 41 | 1024 |
| 2016 | 284 | 118 | 81 | 39 | 917 |
| 2017 | 241 | 110 | 68 | 36 | 813 |
| 2018 | 201 | 103 | 56 | 34 | 711 |
| 2019 | 163 | 96 | 44 | 32 | 608 |
| 2020 | 128 | 90 | 33 | 30 | 501 |
| 2021 | 95 | 84 | 22 | 29 | 392 |
| 2022 | 64 | 79 | 13 | 27 | 279 |
| 2023 | 36 | 74 | 3 | 25 | 162 |
| 2024 | 9 | 24 | 3 | 9 | 39 |

(a) Total field remaining reserves in million barrels of oil equivalent.
(b) Total field annual production in thousands of barrels of oil equivalent per day.
(c) Companies’ remaining reserves in million barrels of oil equivalent.
(d) Companies’ entitled annual production (net of royalty) in thousands of barrels of oil equivalent per day. Calculated as (b) less royalty (deepwater: 12.5%).
(e) Companies’ net present value of expected entitled cash flows.

# APPENDIX 2

## Detailed Calculations of oil and gas reserve entitlement, oil and gas production, and Remaining oilfield NPV under GoM concessionary tax terms

In **Table 2A and 2B** we describe the calculation of reserves, production and remaining NPV for the same field as in Tables 1A-1D, save that it is subject to US GoM deepwater taxation (see Appendix 3), and not Angolan PSC tax terms.

# TABLE 2A

## Detailed calculation of cash flows for a typical Angolan oilfield under GoM concession tax terms

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Production Liquids 000 b/d | Gas mmcfd | Gross Revenue $M | Op Costs $M | Capital Costs $M | Royalty $M | State Taxes $M | Federal Tax $M | Bonus $M | State Carry $M | State Equity Cash Flow $M | Company Cash Flow $M |
| 2003 | 0 | 0.0 | 0 | 0 | 105 | 0 | 0 | 0 | 0 | 0 | 0 | -105 |
| 2004 | 0 | 0.0 | 0 | 0 | 323 | 0 | 0 | 0 | 0 | 0 | 0 | -323 |
| 2005 | 0 | 0.0 | 0 | 0 | 552 | 0 | 0 | 0 | 0 | 0 | 0 | -552 |
| 2006 | 10 | 0.0 | 153 | 29 | 679 | 19 | 0 | 0 | 0 | 0 | 0 | -574 |
| 2007 | 100 | 0.0 | 1358 | 126 | 232 | 170 | 0 | 0 | 0 | 0 | 0 | 830 |
| 2008 | 200 | 0.0 | 2512 | 198 | 238 | 314 | 0 | 426 | 0 | 0 | 0 | 1336 |
| 2009 | 200 | 0.0 | 2435 | 203 | 122 | 304 | 0 | 620 | 0 | 0 | 0 | 1185 |
| 2010 | 180 | 0.0 | 2246 | 194 | 62 | 281 | 0 | 585 | 0 | 0 | 0 | 1125 |
| 2011 | 165 | 0.0 | 2111 | 187 | 64 | 264 | 0 | 547 | 0 | 0 | 0 | 1048 |
| 2012 | 154 | 0.0 | 2023 | 184 | 66 | 253 | 0 | 524 | 0 | 0 | 0 | 996 |
| 2013 | 144 | 0.0 | 1938 | 181 | 67 | 242 | 0 | 503 | 0 | 0 | 0 | 946 |
| 2014 | 135 | 0.0 | 1858 | 178 | 0 | 232 | 0 | 501 | 0 | 0 | 0 | 947 |
| 2015 | 126 | 0.0 | 1781 | 175 | 0 | 223 | 0 | 480 | 0 | 0 | 0 | 903 |
| 2016 | 118 | 0.0 | 1706 | 172 | 0 | 213 | 0 | 460 | 0 | 0 | 0 | 861 |
| 2017 | 110 | 0.0 | 1635 | 170 | 0 | 204 | 0 | 440 | 0 | 0 | 0 | 821 |
| 2018 | 103 | 0.0 | 1568 | 168 | 0 | 196 | 0 | 420 | 0 | 0 | 0 | 784 |
| 2019 | 96 | 0.0 | 1503 | 166 | 0 | 188 | 0 | 401 | 0 | 0 | 0 | 747 |
| 2020 | 90 | 0.0 | 1439 | 164 | 0 | 180 | 0 | 383 | 0 | 0 | 0 | 712 |
| 2021 | 84 | 0.0 | 1380 | 163 | 0 | 173 | 0 | 366 | 0 | 0 | 0 | 679 |
| 2022 | 79 | 0.0 | 1323 | 161 | 0 | 165 | 0 | 349 | 0 | 0 | 0 | 647 |
| 2023 | 74 | 0.0 | 1268 | 160 | 0 | 158 | 0 | 332 | 0 | 0 | 0 | 617 |
| 2024 | 24 | 0.0 | 423 | 78 | 0 | 53 | 0 | 102 | 0 | 0 | 0 | 190 |

(a) Oil production profile of a typical field. Yearly figures are shown as thousands of barrels of oil per day. Totals are in millions of barrels, calculated as $\sum(a) \times 0.365$ (conversion from thousands of barrels per day to millions of barrels per year).
(b) Gas production profile of a typical field. Yearly figures are shown as mmcf gas per day. Totals are in mmcf, calculated as $\sum(b) \times 0.365$.
(c) Cumulative production. Calculated as $[(a) + (b) \times cr] \times 0.365$, where cr is the conversion rate from gas (cf) into oil equivalent (bbl).

(d) Oil price assumption
(e) Gas price assumption
(f) Gross revenues are calculated by multiplying oil and gas (in oil equivalents) by their respective price assumptions, i.e.[(a) x (d) x 0.365] + [(b) x (e) x 0.176] x 0.365.
(g) Operating costs
(h) Capital expenditure excluding abandonment obligations
(i) Depreciation of capex; calculated under MACRS (7 years - double declining balance switching to straight line after 5 years)
(j) (f) x Royalty rate, where Royalty rate = 0 percent for (c) < 87.5 mmboe, or Royalty = 12.50 percent for (c) > 87.5 mmboe (for deep water oil fields)
(k) [(f) - (g) - (I) - (j)] x 35 percent
(l) (c) - (d) – (e) – (f) – (g) – (h) – (i) – (k).

---

Oil companies' entitlement to production and reserves in the specific oilfield is shown in Table 2B (shaded row shows the values which enter Table 1 in the main body of the paper).

---

**TABLE 2B**

**Calculation of reserves entitlement, production entitlement and Remaining NPV under GoM concession tax terms**

| | (a) | (b) | (c) | (d) | (e) |
|---|---|---|---|---|---|
| Year | Remaining reserves mmboe | Production 000boe/d | Entitled reserves mmboe | Entitled production 000boe/d | Remaining NPV US$M |
| 2003 | 800 | 0 | 700 | 0 | 4140 |
| 2004 | 800 | 0 | 700 | 0 | 4659 |
| 2005 | 800 | 0 | 700 | 0 | 5448 |
| 2006 | 800 | 10 | 700 | 9 | 6545 |
| 2007 | 797 | 100 | 697 | 88 | 7774 |
| 2008 | 760 | 200 | 665 | 175 | 7721 |
| 2009 | 687 | 200 | 601 | 175 | 7157 |
| 2010 | 614 | 180 | 538 | 158 | 6688 |
| 2011 | 549 | 165 | 480 | 144 | 6232 |
| 2012 | 488 | 154 | 427 | 135 | 5807 |
| 2013 | 432 | 144 | 378 | 126 | 5391 |
| 2014 | 379 | 135 | 332 | 118 | 4985 |
| 2015 | 330 | 126 | 289 | 110 | 4536 |
| 2016 | 284 | 118 | 249 | 103 | 4087 |
| 2017 | 241 | 110 | 211 | 96 | 3635 |
| 2018 | 201 | 103 | 176 | 90 | 3177 |
| 2019 | 163 | 96 | 143 | 84 | 2711 |
| 2020 | 128 | 90 | 112 | 79 | 2235 |
| 2021 | 95 | 84 | 83 | 74 | 1746 |
| 2022 | 64 | 79 | 56 | 69 | 1241 |
| 2023 | 36 | 74 | 31 | 64 | 718 |
| 2024 | 9 | 24 | 8 | 21 | 173 |

(a) Total remaining reserves in million barrels of oil equivalent. Calculated as the sum of column (b), multiplied by 0.365 (transforming thousands of barrels per day into millions of barrels per year).
(b) Total annual production in thousands of barrels of oil equivalent per day.
(c) Entitled remaining reserves in million barrels of oil equivalent. Calculated as the sum of column (d), multiplied by 0.365 (transforming thousands of barrels per day into millions of barrels per year).
(d) Entitled annual production, net of royalty (12.5% in US GoM Deepwater, See Appendix 3) in thousands of barrels of oil equivalent per day.
(e) Companies' (and total) net present value of expected entitled cash flows.

## APPENDIX 3:

### Overview of Fiscal terms under concession and PSC regimes

Due to the difficulty of disclosing detailed tax terms in concession or PSC countries on a field by field basis, we provide an overview of the range of concession and PSC terms applicable to all fields in our sample (Table 3A).

Concession terms are set out for each country in columns (a) – (e). In the case of US Gulf of Mexico, oil companies are subject to a royalty tax which is deducted from the well-head value of the oil, and a federal income tax which is taxed on net operating profit. In deepwater GoM, the royalty rate is 12.5 percent, while it is 16.7 percent in shallow water fields. Although, royalty tax is no longer applicable for UKCS and NCS oilfields, oil companies operating in these regimes are required to pay either a supplementary corporation tax (UKCS) or a supplementary petroleum tax (in UKCS and NCS).

By contrast, PSC tax terms are more complex. Some PSC contracts are based on the contractor's rate of return (based on the contractor's accumulated compounded post-tax cash flow, e.g. Angola IRR, column (f)), whereas in other contracts the split is based on cumulative production (e.g. Angola PROD, column (g)).

## TABLE 3A

## Overview of Concession and PSC fiscal terms in sample countries – Differentiation insights are made by referring to the concession or PSC Tax Base Terms[a] contained in columns (a)-(e) or (f) – (i) respectively

| | CONCESSION | | | | | PSC | | | |
|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| | UKCS | UKCS PRT | NCS | GoM SHALLOW WATER | GoM DEEP WATER | ANGOLA IRR | ANGOLA PROD | EGYPT | INDONESIA |
| R | | | | 16.7% | 12.5% | | | | |
| FTP | | | | | | | | | 10-20% |
| PRT | | 50% | | | | | | | |
| SCT | | | 50% | | | | | | |
| SCT | 10% | 10% | | | | | | | |
| CT | 40% | 40% | 28% | | | | | | |
| FIT | | | | 35% | 35% | | | | |
| CIT | | | | | | 50% | 50% | | |
| C&W | | | | | | | | | 44-56% |
| B | | | | | | S/P | S/P | S/P | S/P/C |
| PO | | | | | | 25-90%[1] | 40-90%[2] | 70-85%[3] | 65-85%[4] |
| PG | | | | | | 25-90%[1] | 40-90%[2] | 70-85%[3] | 55-70%[4] |
| PC | | | | | | | price cap[5] | DOM[6] | DOM[7] |

(a) Tax terms for non-PRT oilfields on the UK Continental Shelf (UKCS).
(b) Tax terms for PRT oilfields on the UK Continental Shelf (UKCS).
(c) Tax terms for oilfields on the Norwegian Continental Shelf (NCS)
(d) Tax terms for oilfields in shallow water Gulf of Mexico (GoM Shallow water)
(e) Tax terms for oilfields in deepwater Gulf of Mexico (GoM Deepwater)
(f) Tax terms for the oilfields in Angola which are subject to Rate of Return (IRR) based production sharing contracts.
(g) Tax terms for the oilfields in Angola which are subject to cumulative production (PROD) based production sharing contracts.
(h) Tax terms for the oilfields in Egypt which are subject to PSC contracts
(i) Tax terms for the oilfields in Indonesia which are subject to PSC contracts

[a] Variable definitions:

R = Royalty tax. Calculated on wellhead value of petroleum produced, where the well-head value is calculated as the sales value of production net of 'off-lease' costs relating to production and transport to point of sale

PRT = Petroleum Revenue Tax (UKCS). Calculated on pre-tax profits (revenues – operating costs – capital allowances)

SPT = Special Petroleum Tax (NCS). Calculated on total taxable profits

SCT = Supplementary Corporate Tax. Calculated on total taxable profits

FTP = First Tranche Petroleum. A percent of production is divided between the contractor and the government according to their pre-tax profit share entitlements.

CT = Corporation Tax (UKCS). Calculated on pre-tax profits (revenues – operating costs – capital allowances) less PRT

FIT = Federal Corporate income Tax (GoM). Calculated on operating profit net of allowable deductions
CIT = Corporate (petroleum) Income Tax (Angola). Calculated on the contractor's share of profit oil (gas), less price cap
C&W = Corporation and Withholding tax (Indonesia, effective rate). An effective tax rate integrating both standard income tax and dividend withholding tax, and is levied on the contractor's FTP, and the contractor's share of profit oil less allowable costs.
B = Bonus (S = Signature bonus, P = production bonus and C = Compensation bonus). Signature bonuses are payable for each contract, and the amount varies widely, but typically reflects the perceived prospectivity of the area. A production bonus is payable for each contract and the amount is typically a biddable item.
PO = Profit Oil. Under PSA tax terms a percent of production is available for the recovery of operation and capital costs. The remaining production after cost recovery is termed profit oil/gas and is divided between the contractor and the government. The basis on which this division is made varies between contracts. Some contracts are based on the contractor's rate of return (based on the contractor's accumulated compounded post-tax cash flow), whereas in other contracts the split is based on cumulative production. Within each contractor the split varies according to a sliding scale or is based on a constant basis. Profit oil/gas shares are negotiable and therefore oilfield specific.
PG = Profit gas.
PC = Price cap. A capping mechanism where the government receives an excess fee, calculated as the difference between the market price and the price cap, multiplied by the number of barrels in the contractor's share of profit oil.
DMO = Domestic Supply Obligation. A percent of the contractor's share of oil production must be supplied to the local market at a price considerably lower than prevailing market prices.
[1] Sliding scale IRR (terms are negotiable and field specific),
[2] Sliding scale production terms (terms are negotiable and field specific)
[3] Sliding scale production terms (terms are negotiable and field specific)
[4] Location and contract specific profit splits
[5] The price cap is calculated as the difference between the market price of oil and the negotiated cap.

## REFERENCES


Allayannis, G. and J. Weston, 2001. The Use of Foreign Currency Derivatives and Firm Market Value. *Review of Financial Studies* 14, 243-276.

Alciatore, M. 1993. New Evidence on SFAS No. 69 and the Components of the Change in Reserve Value. *The Accounting Review* 68(3): 639-656.

Ahmed, A.S., Kilic, E. and G.J. Lobo, 2006. Does Recognition versus Disclosure Matter? Evidence from Value-Relevance of Banks' Recognized and Disclosed Derivative Financial Instruments. *The Accounting Review* 81(3): 567-588.

Arnott, R. 2004. Oil and Gas Reserves: Communication with the Financial Sector. Oxford Institute for Energy Studies.

Berry, K.T., Wilcox, W. and C. Wright, 2004. The Relative Information Content of the Reserve Disclosures: Reserve Quantities vs. the Standardized Measure. *International Journal of Accounting, Auditing and Performance Evaluation* 1(3): 267-287.

Bessembinder, H., J. F. Coughenour, P. J. Seguin, and M. M. Smoller, 1995. Mean reversion in equilibrium asset prices: evidence from the futures term structure," *Journal of Finance*, 50(1): 361-375

Bindemann, K. 1999. Production-Sharing Agreements: An Economic Analysis. Oxford Institute for Energy Studies.

Boone, J.P. 2002. Revisiting the Reportedly Weak Value Relevance of Oil and Gas Asset Present Values: The Role of Measurement Error, Model Misspecification, and Time-Period Idiosyncrasy. *The Accounting Review* 77(1): 73-106.

Bryant, L. 2003. Relative Value - Relevance of the Successful Efforts and Full Cost Accounting Methods in the Oil and Gas Industry. *Review of Accounting Studies* 8: 5-28.

Clinch, G. and J. Magliolo 1992. Market Perceptions of Reserve Disclosures Under SFAS No.69. *The Accounting Review* 67(4): 843-861.

Cormier, D. and M. Magnan 2002. Performance Reporting by Oil and Gas Firms: Contractual and Value Implications. *Journal of International Accounting, Auditing & Taxation* 11: 131-153.

Deutsche Bank 2004. Oil & Gas Abacus. Taxes at High Oil Prices: Explained. Industry Update, Global Equity Research, Deutsche Bank.

Financial Accounting Standards Board, 1975. Statement of Financial Accounting Standards No.5: Accounting for Contingencies. Stanford, CT: FASB.

Financial Accounting Standards Board, 1977. Statement of Financial Accounting Standards No.19: Financial Accounting and Reporting by Oil and Gas Producing Companies. Stanford, CT: FASB.

Financial Accounting Standards Board, 1979. Statement of Financial Accounting Standards No.25: Suspension of Certain Accounting Requirements for Oil and Gas Producing Companies (an Amendment of FASB Statement No. 19). Stanford, CT: FASB.

Financial Accounting Standards Board 1982. Statement of Financial Accounting Standards No.69: Disclosures About Oil and Gas Producing Activities. Stanford, CT: FASB.

Financial Accounting Standards Board 1998. Statement of Financial Accounting Standards No. 133: Accounting for Derivative Instruments and Hedging Activities. Stanford, CT: FASB.

Harris, T. and J. Ohlson 1987. Accounting Disclosures and the Market's Valuation of Oil and Gas Properties. *The Accounting Review* 62(October): 651-670.

Haushalther, D, 2000. Financing Policy, Basis Risk, and Corporate Hedging: Evidence from Oil and Gas Producers. *The Journal of Finance* 55, 107-152.

Jin, Y. and P. Jorion, 2006. Firm Value and Hedging: Evidence from U.S. Oil and Gas Producers. *The Journal Finance* LXI(2): 893-919.

Kretzschmar, Gavin L. & Moles, Peter (2006). The Effect of "Private" and "Public" Risks on Oilfield Asset Pricing: Empirical Insights into the Georgetown Real Option Debate. *Journal of Applied Corporate Finance* 18 (2), 106-115.

Magliolo, J. 1986. Capital Market Analysis of Reserve Recognition Accounting. *Journal of Accounting Research* 24 (Supplement): 69-108.

Osmundsen, P., Asche, F., Misund, B. and K. Mohn (2006). Valuation of International Oil Companies. *Forthcoming* in Energy Journal.

Pincus, M and Rajgopal, S. 2002. The interaction between Accrual management and Hedging: Evidence from Oil and Gas Firms. *The Accounting Review* 77(1):127-160

Quirin, J.J., Berry, K.T. and D. O'Bryan 2000. A Fundamental Analysis Approach to Oil and Gas Firm Valuation. *Journal of Business Finance and Accounting* 27(7): 785-820.

Rajgopal, S. 1999. Early Evidence on the Informativeness of the SEC's Market Risk Disclosures: The Case of Commodity Price Risk Exposure of Oil and Gas Producers. *The Accounting Review* 74(3): 251-280.

U.S. Securities and Exchange Commission (SEC). 1978. Accounting Series Release NO. 269. Washington, D.C.: SEC.

U.S. Securities and Exchange Commission (SEC). 1979. Accounting Series Release No. 253. Washington, D.C.: SEC.

U.S. Securities and Exchange Commission (SEC). 1981. Accounting Series Release No. 289. Washington, D.C.: SEC.

U.S. Securities and Exchange Commission (SEC). 1997. Disclosure of Accounting Policies for Derivative Financial Instruments and Derivative Commodity Instruments and Disclosure of Qualitative and Quantitative Information about Market Risk Inherent in Derivative Financial Instruments, Other Financial Instruments, and Derivative Commodity Instruments. Release Nos. 33-7386; 34-38223; IC-22487; FR-48; International Series No. 1047; File No. S7-35-95. Washington, D.C.: SEC.

Shaw and Weir 1993. Organizational Form Choice and the Valuation of Oil and Gas Producers. *The Accounting Review* 68(3): 657-667.

Spear, N.A. 1994. The Market Reaction to the Reserve-Based Value Replacement Measures of Oil and Gas Producers. *Journal of Business Finance and Accounting* 23(17): 953-974.

Spear, N.A. 1994. The Stock Market Reaction to the Reserve Quantity Disclosures of U.S. Oil and Gas Producers. *Contemporary Accounting Research* 11(I-II): 381-404.

# TABLES

**TABLE 1**

**Angolan Field Oil and gas reserves, oil and gas production and net present value of reserves at January 2006 – Under Angolan domestic tax terms and Gulf of Mexico concession tax terms [a]**

| | Angolan field under domestic PSC tax terms | | | | | Angolan field under GoM concession tax terms | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | $P_{22.5}$ | $P_{33.75}$ | $P_{45}$ | $P_{67.5}$ | $P_{90}$ | $P_{22.5}$ | $P_{33.75}$ | $P_{45}$ | $P_{67.5}$ | $P_{90}$ |
| Reserves (mmboe) | 659 | 550 | 408 | 293 | 240 | 700 | 700 | 700 | 700 | 700 |
| Production ('000boe/d) | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Remaining NPV (US$ millions) | 1989 | 3053 | 3182 | 3842 | 4334 | 2659 | 4769 | 6545 | 11053 | 15227 |

[a] Abbreviations:

NPV = Net present value (in US$ millions).
mmboe = barrel-of-oil equivalent units (in millions). Calculated by summing the physical units of oil (measured in barrels) and gas (measured in thousands of cubic feet), where gas reserves volumes are converted into oil equivalents by dividing by six.
PSC = production sharing contract.
GoM = Gulf of Mexico.

**TABLE 2**

Descriptive Sample Statistics [a]

| | No. of fields in sample | No. of fields in population | Sample fields as % of population fields | Total remaining oil and gas reserves in sample fields (mmboe) | Total remaining oil and gas reserves in population (mmboe) | Sample reserves as % of population reserves |
|---|---|---|---|---|---|---|
| **CONCESSION** | | | | | | |
| GOM | 50 | 130 | 38.5% | 6063 | 7467 | 81.2% |
| NCS | 50 | 105 | 47.6% | 25851 | 27311 | 94.7% |
| UKCS | 67 | 380 | 17.6% | 5431 | 10127 | 53.6% |
| Total concession | 167 | 615 | 27.2% | 37345 | 44905 | 83.2% |
| | | | | | | |
| **PSA** | | | | | | |
| ANGOLA | 28 | 48 | 58.3% | 8636 | 10755 | 80.3% |
| EGYPT | 42 | 53 | 79.2% | 6123 | 6712 | 91.2% |
| INDONESIA | 55 | 71 | 77.5% | 10722 | 12426 | 86.3% |
| Total PSA | 125 | 172 | 72.7% | 25481 | 29893 | 85.2% |
| Total sample | 292 | 787 | 37.1% | 62826 | 74798 | 84.0% |

[a] Abbreviations:

GoM = Gulf of Mexico
NCS = Norwegian Continental Shelf
UKCS = UK Continental Shelf
Mmboe = barrel-of-oil equivalent (in millions)
PSC = Production sharing contracts

NOTE: PSC totals in Table 2 shows the country reserves pre-production sharing by the government and hence - do not tie in with values in Table 6 where the latter reflect government participation.

**TABLE 3**

**Responses of Reserve entitlement to oil and gas price change.**

| Panel A: Reserve response | | | | |
|---|---|---|---|---|
| | $P_{22.5}/P_{33.75}$ | $P_{33.75}/P_{45}$ | $P_{67.5}/P_{45}$ | $P_{90}/P_{67.5}$ |
| ***Concession*** | | | | |
| GoM | 0.000 | 0.000 | 0.000 | 0.000 |
| NCS | 0.000 | 0.000 | 0.000 | 0.000 |
| UKCS | 0.000 | 0.000 | 0.000 | 0.000 |
| | | | | |
| ***PSC*** | | | | |
| Angola | -0.451 | -0.684 | -0.405 | -0.388 |
| Egypt | -0.253 | -0.271 | -0.154 | -0.132 |
| Indonesia | -0.324 | -0.297 | -0.154 | -0.130 |

| Panel B: Statistical analysis (concession vs PSC) | | | | |
|---|---|---|---|---|
| | $P_{22.5}/P_{33.75}$ | $P_{33.75}/P_{45}$ | $P_{67.5}/P_{45}$ | $P_{90}/P_{67.5}$ |
| GoM vs Angola | *** | *** | *** | *** |
| GoM vs Egypt | *** | *** | *** | *** |
| GoM vs Indonesia | *** | *** | *** | *** |

| Panel C: Statistical analysis (intra-regime comparison) | | | | |
|---|---|---|---|---|
| | $P_{22.5}/P_{33.75}$ | $P_{33.75}/P_{45}$ | $P_{67.5}/P_{45}$ | $P_{90}/P_{67.5}$ |
| ***Concession*** | | | | |
| GoM vs NCS | - | - | - | - |
| GoM vs UKCS | - | - | - | - |
| NCS vs UKCS | - | - | - | - |
| | | | | |
| ***PSC*** | | | | |
| Angola vs Egypt | * | *** | *** | *** |
| Angola vs Indonesia | ns | *** | *** | *** |
| Egypt vs Indonesia | ns | ns | ns | ns |

*, **, *** denote significance at the 0.05, 0.01 and 0.001 levels respectively, in a two-tailed t-test. n.s. denotes non-significance. Panel A denotes reserves disclosure response in reaction to price movements. In Panel B, T-tests are carried out between GoM (benchmark) and UKCS, NCS, Angola, Egypt and Indonesia to test if responses of production SEC disclosures are significantly different from those of GoM oilfields. In Panel C – Tests for difference are also carried out between individual countries.

## TABLE 4

### Responses of production entitlement to oil and gas price change

| Panel A: Production response | | | | |
|---|---|---|---|---|
| | $P_{22.5}/P_{33.75}$ | $P_{33.75}/P_{45}$ | $P_{67.5}/P_{45}$ | $P_{90}/P_{67.5}$ |
| ***Concession*** | | | | |
| GoM | 0.000 | 0.000 | 0.000 | 0.000 |
| NCS | 0.000 | 0.000 | 0.000 | 0.000 |
| UKCS | 0.000 | 0.000 | 0.000 | 0.000 |
| | | | | |
| ***PSC*** | | | | |
| Angola | -0.291 | -0.348 | -0.162 | -0.181 |
| Egypt | -0.205 | -0.169 | -0.087 | -0.106 |
| Indonesia | -0.466 | -0.142 | -0.173 | 0.064 |

| Panel B: Statistical analysis (concession vs PSC) | | | | |
|---|---|---|---|---|
| | $P_{22.5}/P_{33.75}$ | $P_{33.75}/P_{45}$ | $P_{67.5}/P_{45}$ | $P_{90}/P_{67.5}$ |
| GoM vs Angola | *** | ** | *** | *** |
| GoM vs Egypt | *** | *** | ** | *** |
| GoM vs Indonesia | * | n.s. | *** | n.s. |

| Panel C: Statistical analysis (intra-regime comparison) | | | | |
|---|---|---|---|---|
| | $P_{22.5}/P_{33.75}$ | $P_{33.75}/P_{45}$ | $P_{67.5}/P_{45}$ | $P_{90}/P_{67.5}$ |
| ***Concession*** | | | | |
| GoM vs NCS | - | - | - | - |
| GoM vs UKCS | - | - | - | - |
| NCS vs UKCS | - | - | - | - |
| | | | | |
| ***PSC*** | | | | |
| Angola vs Egypt | ns | ns | ns | ns |
| Angola vs Indonesia | ns | ns | ns | ns |
| Egypt vs Indonesia | ns | ns | ns | ns |

*, **, *** denote significance at the 0.05, 0.01 and 0.001 levels respectively, in a two-tailed t-test. n.s. denotes non-significance. Panel A denotes production disclosure response in reaction to price movements. In Panel B, T-tests are carried out between GoM (benchmark) and UKCS, NCS, Angola, Egypt and Indonesia to test if responses of production SEC disclosures are significantly different from those of GoM oilfields. In Panel C – Tests for difference are also carried out between individual countries.

## TABLE 5

## Responses of remaining oilfield PV to oil and gas price change

| Panel A: NPV response | | | | |
|---|---|---|---|---|
| | $P_{22.5}/P_{33.75}$ | $P_{33.75}/P_{45}$ | $P_{67.5}/P_{45}$ | $P_{90}/P_{67.5}$ |
| ***Concession*** | | | | |
| GoM | 1.306 | 1.197 | 1.196 | 1.121 |
| NCS | 2.159 | 1.288 | 1.243 | 1.071 |
| UKCS | 1.603 | 1.401 | 1.352 | 1.240 |
| ***PSC*** | | | | |
| Angola | 1.587 | 0.713 | 0.330 | 0.332 |
| Egypt | 1.190 | 0.974 | 0.964 | 0.972 |
| Indonesia | 1.976 | 1.318 | 1.266 | 1.125 |

| Panel B: Statistical analysis (concession vs PSC) | | | | |
|---|---|---|---|---|
| | $P_{22.5}/P_{33.75}$ | $P_{33.75}/P_{45}$ | $P_{67.5}/P_{45}$ | $P_{90}/P_{67.5}$ |
| GoM vs Angola | n.s. | *** | *** | *** |
| GoM vs Egypt | n.s. | *** | *** | *** |
| GoM vs Indonesia | ** | * | n.s. | n.s. |

| Panel C: Statistical analysis (intra-regime comparison) | | | | |
|---|---|---|---|---|
| | $P_{22.5}/P_{33.75}$ | $P_{33.75}/P_{45}$ | $P_{67.5}/P_{45}$ | $P_{90}/P_{67.5}$ |
| ***Concession*** | | | | |
| GoM vs NCS | * | n.s. | n.s. | n.s. |
| GoM vs UKCS | n.s. | n.s. | n.s. | n.s. |
| NCS vs UKCS | n.s. | n.s. | n.s. | * |
| ***PSC*** | | | | |
| Angola vs Egypt | *** | *** | *** | *** |
| Angola vs Indonesia | ns | * | *** | *** |
| Egypt vs Indonesia | ns | *** | *** | *** |

*, **, *** denote significance at the 0.05, 0.01 and 0.001 levels respectively, in a two-tailed t-test. n.s. denotes non-significance. Panel A denotes PV disclosure response in reaction to price movements. In Panel B, T-tests are carried out between GoM (benchmark) and UKCS, NCS, Angola, Egypt and Indonesia to test if responses of production SEC disclosures are significantly different from those of GoM oilfields. In Panel C – Tests for difference are also carried out between individual countries.

**TABLE 6**

Reserves entitlement (mmboe) and changes in reserves (relative to base case, US$45)

| | | $P_{22.5}$ | $P_{33.75}$ | $P_{45}$ | $P_{67.5}$ | $P_{90}$ |
|---|---|---|---|---|---|---|
| Price Change relative to $P_{45}$ | | -50 % | -25 % | 0 % | 50 % | 100 % |
| ***Concession*** | | | | | | |
| GoM | Reserves entitlement | 6123 | 6123 | 6123 | 6123 | 6123 |
| | Response to oil price change relative to $P_{45}$ | *0 %* | *0 %* | *0 %* | *0 %* | *0 %* |
| NCS | Reserves entitlement | 25851 | 25851 | 25851 | 25851 | 25851 |
| | Response to oil price change relative to $P_{45}$ | *0 %* | *0 %* | *0 %* | *0 %* | *0 %* |
| UKCS | Reserves entitlement | 5431 | 5431 | 5431 | 5431 | 5431 |
| | Response to oil price change relative to $P_{45}$ | *0 %* | *0 %* | *0 %* | *0 %* | *0 %* |
| ***PSC*** | | | | | | |
| Angola | Reserves entitlement | 6845 | 5877 | 4969 | 3698 | 3110 |
| | Response to oil price change relative to $P_{45}$ | *38 %* | *18 %* | *0 %* | *-26 %* | *-37 %* |
| Egypt | Reserves entitlement | 3899 | 3664 | 3498 | 3327 | 3242 |
| | Response to oil price change relative to $P_{45}$ | *11 %* | *5 %* | *0 %* | *-5 %* | *-7 %* |
| Indonesia | Reserves entitlement | 12664 | 10786 | 10723 | 10027 | 9679 |
| | Response to oil price change relative to $P_{45}$ | *18 %* | *1 %* | *0 %* | *-6 %* | *-10 %* |

## Table 7

## NPV (US$M) and changes in NPV (relative to base case, US$45)

| | | $P_{22.5}$ | $P_{33.75}$ | $P_{45}$ | $P_{67.5}$ | $P_{90}$ |
|---|---|---|---|---|---|---|
| Price Change relative to $P_{45}$ | | -50 % | -25 % | 0 % | 50 % | 100 % |
| ***Concession*** | | | | | | |
| GoM | Remaining NPV (US$M) | 25475 | 45328 | 66174 | 106792 | 147400 |
| | Response to oil price change relative to $P_{45}$ | *38 %* | *68 %* | *100 %* | *161 %* | *223 %* |
| NCS | Remaining NPV (US$M) | 29015 | 56614 | 82110 | 132387 | 182483 |
| | Response to oil price change relative to $P_{45}$ | *35 %* | *69 %* | *100 %* | *161 %* | *222 %* |
| UKCS | Remaining NPV (US$M) | 20518 | 28594 | 41184 | 67050 | 92848 |
| | Response to oil price change relative to $P_{45}$ | *50 %* | *69 %* | *100 %* | *163 %* | *225 %* |
| ***PSC*** | | | | | | |
| Angola | Remaining NPV (US$M) | 19166 | 33092 | 41016 | 50576 | 58530 |
| | Response to oil price change relative to $P_{45}$ | *47 %* | *81 %* | *100 %* | *123 %* | *143 %* |
| Egypt | Remaining NPV (US$M) | 6720 | 14101 | 18851 | 27958 | 36966 |
| | Response to oil price change relative to $P_{45}$ | *36 %* | *75 %* | *100 %* | *148 %* | *196 %* |
| Indonesia | Remaining NPV (US$M) | 9334 | 20178 | 30238 | 49800 | 69296 |
| | Response to oil price change relative to $P_{45}$ | *31 %* | *67 %* | *100 %* | *165 %* | *229 %* |

# FIGURES

## FIGURE 1:

### Expected development of production entitlement over time for a hypothetical Angolan oil field under conditions of oil price volatility

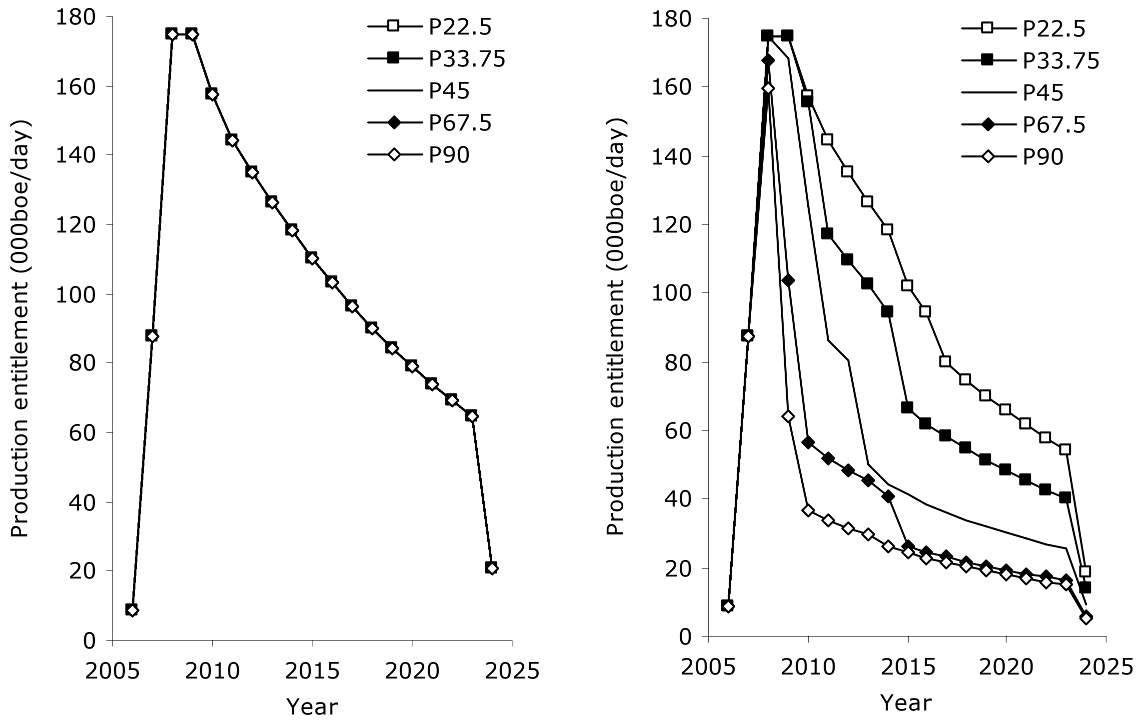

**FIGURE 2**

**The Oil Price *Relationship* between Reserves and NPV - Changes in aggregate reserves (a) and aggregate remaining NPV (b) when oil price changes from a base case of US$45/bbl**

**(a) Reserves** **(b) Remaining PV**