Petroleum Taxation: A Critical Evaluation with Special Application to the UK Continental Shelf

by

Carole Nakhle

Thesis submitted for the degree of Doctorate of Philosophy

Department of Economics
School of Human Sciences
University of Surrey

July 2004

ABSTRACT

This thesis provides a framework of economic analysis which both Governments and the petroleum industry can draw upon in their negotiation of fiscal terms that offer a fair and just basis of wealth allocation. Its principal objectives are to critically evaluate the petroleum fiscal regime in the UK North Sea since 1975, and identify a fiscal regime that is acceptable to Government and oil industry alike.

Government and oil companies are the key decision-makers in the upstream sector of petroleum industry. However, their individual focus is one of competing rather than complementary objectives. Governments of oil producing countries face important challenges when designing a tax system that meets the two fundamental objectives of ensuring a fair share of revenues for themselves whilst simultaneously providing sufficient incentives to encourage investment. Besides, petroleum resource has special features that can impose further difficulties in the design and implementation of an appropriate tax system aimed at achieving a balance between both Government and industry interests'.

Over the years, achieving this balance has given rise to significant controversy in the UK. The structure of the current fiscal regime was formally legislated through the Oil Taxation Act of 1975. However, the regime has been frequently reviewed and amended. Its current structure is significantly different from its original version. The various amendments to the regime have led researchers and specialists to either criticising or supporting Government actions.

This thesis conducts an in depth analysis on the principal fiscal packages that have applied to the UKCS and analyses their effect on the balance between the Government and oil companies' objectives. The research is carried out in the light of an essential and timely feature, the current maturity of the UK oil province. The thesis demonstrates that, in practice, it is very difficult to develop an ideal fiscal package. Several complications are associated with petroleum taxation, resulting mainly from the difficulty in determining a suitable tax base as well as the inevitable compromises to the criteria that are required to categorise an optimal tax. Consequently, it is not surprising to find that none of the tax instruments proposed in previous studies or those applied in the UK represents an optimal tax.

The UK petroleum fiscal regime suffered from several limitations. However, currently, the UK fiscal regime is one of the most attractive regimes in the world, from an investor's standpoint. Government take is lower than the pre-1993 fiscal structures, but any future concerns about UKCS taxation must take into account the current maturity of the petroleum reserve base. A high level of Government take is not recommended in cases of high-risk exploration, high-cost development, or for those provinces with modest petroleum potential, as is the case in the UK North Sea.

ACKNOWLEDGEMENTS

My experiences during the conduct of this thesis have provided the most stimulating moments in my academic endeavours. I have studied to distinguish between contrasting research findings, each side being backed by compelling analysis. I have experienced various research methods, quantitative analytical techniques and presentation styles. I have developed a deep understanding of the petroleum industry operations, a sector that was completely new for me at the very beginning of my research. Despite the various challenges I went through over the last four years, I look at my thesis now and a sense of pride and happiness grow inside my heart.

For the accomplishment of this work, I would like to express my sincere thanks to my supervisors Mr. Hawdon and Professor Hunt who offered me timely and valuable advice, guiding me to think harder about my topic and assisting me to improve the quality of my work. Likewise, I would like to acknowledge the worthwhile and continuous support of my dear friends and tax specialists Mr. Shevlin and Mr. Wastell. I also would like to thank all the respondents for the valuable time they gave to participate in the survey, as well as WoodMackenzie for providing me with GEM.

Last but not least, I would like to thank my family and friends, in particular my father, my mother, Paul, Chafic, and Sania, for giving me endless support, encouragement and sacrifice.

CAROLE NAKHLE

CHAPTER ONE

INTRODUCTION

1.1. PREAMBLE

Petroleum exploration and exploitation, like other primary industries, creates wealth from the earth's natural resources. However, the location of petroleum production is entirely dictated by geology and geography. Few, if any, other industries are as site specific and few natural resources have at the time of their production a value out of all proportion with their production costs, as is the case with petroleum.

As these words are being written in 2004, there is once again growing concern regarding the security of supply of crude oil to the developed and developing economies of the world. In particular, the issue of continuing access to crude oil resources on reasonable terms, not simply to meet the needs of economic growth but also to ensure security of supply, is once again to the foreground of economic debate. Central to that debate now and in the future will be the issue of the allocation of the wealth created by the development of petroleum in both traditional as well as in new producing provinces of the world. This wealth allocation process will of necessity need to take account of the interest of all stakeholders and in particular local Governments as well as various sectors of the international petroleum industry.

In today's world no major industry can exist in a vacuum. The international petroleum industry is today much affected by changing political, sociological and economic trends.

It is against this background that this thesis has been prepared with the overarching objective of providing a framework of economic analysis which both Governments and the petroleum industry can draw upon in their negotiation of fiscal terms that offer a fair and just basis of wealth allocation.

1.2. PETROLEUM TAXATION IN THE UK

Petroleum taxation has received considerable attention since the discovery of oil in the 1960s in the UK sector of the North Sea. The structure of the current fiscal regime was first set out in a 1974 White Paper and was formally legislated through the Oil Taxation Act of 1975. The regime consisted of three main instruments, Royalty, Petroleum Revenue Tax (PRT) and Corporation Tax (CT). At the outset the Government had two key objectives. These were to secure a fairer share of profits for the nation and ensure a suitable return for oil companies on their capital investment (Inland Revenue, 2003a).

Although the fiscal regime for the UK Continental Shelf (UKCS) was established in 1975, virtually from the commencement of oil production it has been frequently reviewed and amended. Rowland & Hann (1987) argue that no other sector in the UK economy has been subject to such fiscal instability.

The level of marginal Government take gradually declined from approximately 87 per cent in the 1980s to just 30 per cent in the mid-1990's. In April 2002, however, the Government increased its take for the first time since 1983 through the imposition of a 10 per cent Supplementary Charge on CT based income.

The various amendments to the regime have generated much controversy, with researchers and specialists either criticizing or defending the changes. On occasions even extreme views have been expressed. For example, Bland (1988) argues that the UKCS fiscal regime is "a patchwork of separate taxes, each amended and adjusted in response to changing circumstances and forming a less than cohesive whole" (p.1). In concurring with Bland, Rutledge and Wright (1998) describe the fiscal regime in the UK as the "weakest in the world" (p.801). Opposing such views, Martin (1997) argues that Government action in particular that in 1983 and 1993 was responsible for the two production peaks in the pattern of the UKCS oil production. Johnston (2003) also maintains that although Government actions since 1983 appeared "crazy and irresponsible they were simply ordinary measures that led to hyperactivity in the UKCS and made its offshore the most active offshore province in the world" (p.6).

More recently, as a result of the 2002 changes, the debate was further intensified. While the current Chancellor believes that the new changes will encourage long term investment, the UK Offshore Operators Association argues that taxes are being increased at the wrong time in the North Sea's life (UKOOA, 2002).

1.3. THESIS OBJECTIVES

In the light of such controversy, the two overriding objectives of this thesis are to:

1. critically analyse the petroleum fiscal regime in the UK North Sea since 1975 and,
2. ascertain a fiscal regime that is efficient, effective and also acceptable to both the Government and the oil industry.

This thesis conducts an in depth analysis on the principal fiscal packages that have applied to the UKCS, taking into account the sustainability and unfolding international competitiveness of this oil province. It critically evaluates the possible outcomes of previous fiscal rates and structures, had they still applied today. It also researches the way in which the UK Government, through the design of its petroleum fiscal regime and the subsequent amendments, has affected the trade off between themselves and oil companies. Taking into consideration the UK experience, the thesis questions whether an ideal fiscal regime can be created in various petroleum provinces.

The controversy surrounding the UK petroleum fiscal regime and its various amendments arises from the need to balance the two chief but competing objectives of taxation. These are to capture a large share of economic rent while stimulating private investment in the sector (Bond, Devereux & Saunders, 1987).

Further, since there is no objective yardstick for sharing economic wealth between the various interests involved in the petroleum activity, controversy will always prevail. A trade off will always exist, since both Government and oil companies want to maximise their own rewards. Mercier (1999) argues that tax rates that are set too low leave the Government, the owner of the resource, a small and inequitable portion. Yet, if tax rates are too high, investment will be discouraged, not only in new projects, but in sustaining the capital investment required to maximise future value added from existing operations (Crowson, 2004).

However, the exploration and exploitation of oil requires significant financial resources that can exceed the capability of most of oil producing countries. Further the high risk involved, as a result of geology and oil price volatility, renders a purely national approach to the exploitation of petroleum difficult (Blinn et al, 1986). "It follows that exploration and exploitation activities present delicate legal, technical, financial and political problems and any solution requires a balancing act between the respective interests of the producing countries and the oil companies" (Blinn et al, 1986, p.15).

Consequently, despite the competing objectives of both Government and oil companies, a balance can still be reached. But, the right choice of fiscal regime can improve the trade off between each party's interest. "A small sacrifice from one side may be a big gain for the other" (Sunley, Baunsgaard & Simard, 2002, p.1).

National tax policies can greatly influence the petroleum industry long-term global sustainability. This research is carried out in the light of an essential and timely feature, the current maturity of the UK North Sea province. The larger fields (such as Forties, Brent and Ninian) were discovered in the early phases of exploration and brought into production between 1975-1979. Fields found during subsequent periods have become progressively smaller. This fact emphasises further the significance of taxation in impacting on the trade off between the opposing viewpoints of the Government and companies. As Colbert reportedly remarked "the art of taxation consists in so plucking the goose as to obtain the largest amount of feathers with the least possible amount of hissing[1]". Crowson (2004) adds "it is also important not to frighten away the geese so that they no lay any eggs, golden or otherwise, let alone present themselves for plucking" (p.12).

Another important aspect of this thesis, and which instinctively follows from the analysis of the fiscal impact, concerns the effectiveness of the evaluation techniques that are being used or recommended to measure the effects of taxation on profitability and revenue. The choice of financial evaluation technique is of particular significance to both oil companies and Government. An inappropriate technique can generate a misleading figure for profitability and taxable capacity leading, in turn, to incorrect decision making and an inappropriate assessment of a particular fiscal structure or instrument. In addition, major controversy still surrounds the choice of an appropriate evaluation technique.

[1] As referred to in Crossman (2004), p.12.

Accordingly, three evaluation techniques are used to calculate the effects of taxation in this thesis: traditional Discounted Cash Flow (DCF) and more recent techniques, Modern Asset Pricing (MAP) and Real Options Theory (ROT). The DCF method has been the one mostly applied in previous studies and is currently used by oil companies (Siew, 2001). Over the last few years, however, there has been an increasing interest in the use of other methods. MAP and ROT have been developed to overcome some of the weaknesses of the DCF approach. In fact, they can be considered as an evolved version of the traditional technique. The thesis compares the three techniques and critically analyses any significant difference in their results in order to determine if any method produces more useful results, particularly when evaluating a fiscal regime.

1.4. THE IMPORTANCE OF THE RESEARCH

The research undertaken in this thesis is timely and of particular relevance for several reasons.

Firstly, the present maturity of the UK sector of the North Sea imposes a significant challenge on Government fiscal policy, which is of critical importance in maintaining the attractiveness of the oil province from an investor's standpoint. UK oil production peaked in 1999 at 2.8 mmbbl a day and is forecast to decline by about 60 per cent over the next ten years. Today, around 47 per cent of the UK proven reserve base of 63 bnbbloe combined oil and gas reserves have been produced (Ruairidh, 2003).

From the UK's estimated total endowment of oil, about two-thirds have been already produced and only about one-third remains for future production (Zittel, 2001). Furthermore, the UKCS currently ranks 19th globally in terms of average commercial discovery size (Scottish Council for Development and Industry, 2002). Given the larger and more commercially attractive opportunities in other parts of the world and the higher Exploration and Development costs in the hostile and technically challenging UKCS environment, it is going to be harder for the UK Government to continue to attract investment (Morgan, 2000).

Secondly, oil is a strategic commodity and is likely to remain as such for some time. In this regard, it has special characteristics relating to its price volatility and the fact it is an exhaustible resource with an uncertain level of reserves, particularly at the Exploration stage. It is also an important end-use commodity and an important factor of production, which affects the price of other goods. These characteristics are likely to complicate the design of a tax system.

Thirdly, the UK is ranked the tenth largest oil producer, making it an important region for the industry (Deloitte & Touche, 2003). The oil industry contributes significantly to the UK economy. The first full year of production from the UKCS was in 1976 and by the early 1980s the UK had become self-sufficient in oil, with crude oil exports reaching a value of £5 bn. a year. This had a substantial impact on the UK’s hitherto precarious balance of payments position. In 2001, oil and gas production reached 4.3 mmboe. per day, representing some 85 per cent of the UK's total primary energy production.

Since Exploration and Production (E&P) activity began in the mid-1960s, oil companies have invested almost £200 bn. in the UK offshore sector. It is also estimated that over 380,000 people are employed directly and indirectly in over 6,000 businesses by the oil industry (UKOOA, 2001). Additionally, since the beginning of oil production, more than £106 bn. in taxes has flowed to the UK Treasury, contributing to healthcare, education and all the other services funded by the Government. In the year 2002, the Government collected £5.4 bn. from upstream taxes (DTI, 2003).

Clearly, the oil industry is and has been a vital component of the UK economy. As such, it is not surprising that any UK Government involvement in setting the level of tax tries to ensure that UK's oil province is an attractive area for investment.

1.5. THE CONTRIBUTION OF THE STUDY

This thesis evaluates the UK petroleum fiscal regime. Its major contribution to particularly this field and petroleum taxation more generally lies mainly in the novel approach adopted to study the issue, by attempting to bring together the interests of both the Government and the oil industry. Empirical analysis is carried out at two levels: firstly, in qualitative terms by undertaking a survey of opinions, and secondly, in quantitative terms by combining the different financial evaluation techniques then expanding the analysis to incorporate other internationally representative regimes. To date, no such a detailed analysis has been published on the UKCS several other provinces such as Iraq.

The survey is a unique undertaking in this field of economic research. It analyses the issues from the perspective of both the main constituents: the Government and the petroleum industry. Given their competing interests, these two bodies have different perspectives on petroleum taxation. As such, the survey provides significant information from specialists and benefits from their expertise. More importantly, this kind of analysis is unlikely to be found in the literature associated with this important topic.

The succeeding quantitative analysis is undertaken at four separate stages.

Firstly, a transparent detailed model of the UKCS fiscal regime is derived. The regime is often described as complex and this is probably the reason why few attempts have been made to fully establish a tax model for the UKCS. Nevertheless, developing a cash flow model is essential as it allows a clear understanding of the computation of each tax instrument and the interaction between the various instruments.

Secondly, the evaluation of the profitability of 25 oil fields and the revenues generated from their operations is made under nine fiscal scenarios using two evaluation techniques, DCF and MAP. Such a quantitative comparison has been lacking in the literature of petroleum taxation, particularly for the UKCS. On one hand, the analysis covers a wider range of tax scenarios than previous studies. In fact, it is rather a time line analysis extending over a period of 27 years. On the other hand, to date the application of MAP for the evaluation of the UK petroleum regime is very limited.

DCF is a relatively straightforward technique, whereas MAP requires an understanding of wider financial theories such as Contingent Claim Analysis and the Derivative Asset Pricing Approach, in addition to incorporating more dynamic oil price models. MAP can allow a more appropriate valuation of risk by adjusting revenues for oil price risk, while discounting the net cash flow at the risk free rate. In the simple and common application of DCF, the effect of uncertainty is determined by including a risk premium in the discount rate, which is applied irrespective of the risk profile of the different components of the cash flow[2].

Thirdly, the analysis is expanded to evaluate the possible effects of taxation on the timing of investment. This characteristic is of particular significance nowadays, given the maturity of the UKCS and the need to develop the discovered fields to maintain production and sustain self-sufficiency. In order to incorporate investment flexibility, ROT is implemented and it is further compared with DCF, which is based on the static investment concept of now-or-never. The application of ROT has been also limited in the field of petroleum taxation especially for petroleum activity in the UKCS.

Finally, the research is further expanded to compare the UK petroleum fiscal regime with five internationally representative regimes; Australia, Norway, Indonesia, China and Iraq. The research evaluates the evolution of the international competitiveness of the UKCS since 1975 relative to the five selected countries.

[2] See, for example, Kemp & Rose (1983), Martin (1997) and Kemp & Stephens (1997).

The major contribution of this study lies in the time-line analysis of the international attractiveness of the fiscal terms in the UK. Another important aspect is the derivation of fiscal models for the other countries selected, principally Iraq, for which information is not easily accessible.

An additional important feature of this quantitative analysis is that, unlike many of previous studies, it is based on real operating oil fields rather than hypothetical ones. Smith & Mccardle (1998) argue that the use of model fields and their consequences can greatly oversimplify the study. This is particularly relevant in the analysis of UK oil taxation, as no two fields are alike in the UK North Sea province.

The uniqueness of oil taxation when compared to other commodities is a consequence of the oil industry's characteristics; the significant contribution it makes to the national economy, the high operating and development costs, high uncertainty in exploration activities, volatility of oil prices, and the maturity of the UK oil province. These all add challenges to both the Government and the industry. Consequently, the field of oil taxation requires specific knowledge by any regulator and a study such as this can yield new insights into the investment decision process with regards to the impact of the different fiscal packages and regimes on the oil industry. The results of this work can also aid a decision for changing or creating a new fiscal regime, in particular in Iraq, where future change seems inevitable.

1.6. STRUCTURE

Following this Introduction chapter, which highlights the main research question, the study of the theoretical background of taxation in general and petroleum taxation in particular is covered in Chapter 2. The chapter analyses the set of criteria that can be used to assess petroleum related tax instruments and evaluates the various instruments proposed in previous studies. As such, it establishes the basis for evaluating the UK petroleum fiscal regime and sets the framework for the empirical analysis.

In Chapter 3, a detailed study of the evolution of the UK North Sea tax system from its beginnings in 1975 through to the Budget changes introduced in 2002 is conducted. The study examines the principal amendments introduced, which generated substantial changes to the fiscal structure and provoked significant controversies. Such an examination provides the background knowledge for the analysis of oil taxation in the UK. It also helps to understand the different arguments used in the debate.

Chapter 4 initiates the empirical analysis of this thesis and presents the survey of opinions of the main players involved in the UKCS, with regard to the effects of the major fiscal packages. The findings are synthesized in an attempt to find ways in which the existing regime might be improved or how an alternative regime more acceptable to Government and industry might be created.

Chapter 5 starts the quantitative analysis of the UKCS fiscal regime. The chapter derives a cash flow model, clearly explaining the computation of the fiscal instruments and their interaction. This is a prerequisite to proceeding with the quantitative analysis. In any one year or in any one field the amount that the Government will take in the form of taxes cannot be simply evaluated or anticipated without an appropriate model (UKOG, 1983). The chapter further sets out the principal assumptions adopted in subsequent chapters.

After the model is developed, the quantitative evaluation of taxation is conducted.

In Chapter 6, oil field profitability and Government revenue are analysed under nine tax scenarios using two techniques DCF and the MAP. A detailed review of the basic concepts underlying each method is set out, in order to build a deeper understanding of the differences between the two methods and hence a more useful interpretation of any difference in their results.

Chapter 7 continues the quantitative evaluation but incorporates an additional feature to decision making in investment, which is flexibility. The chapter investigates whether the tax structure and level of government take have any effect on the timing of the decision to develop a field, as such identifying investment distortions and addressing the neutrality of the regime. Several authors argue that ignoring flexibility can significantly undervalue a project. To undertake the research ROT is used and compared with DCF.

Chapter 8 completes the empirical analysis by comparing the UK fiscal regime with the Australian, Norwegian, Indonesian, Chinese and Iraqi regimes. A detailed study of the fiscal regimes is undertaken, and then a qualitative and quantitative analysis is carried out. Studying other regimes may reveal a benchmark fiscal regime with features that have not been revealed in the previous chapters' analysis.

A discussion of the results and the conclusions drawn from this research are set out in Chapter 9.

CHAPTER TWO

THE TAXATION OF OIL: THEORETICAL BACKGROUND

2.1. INTRODUCTION

Chapter one introduced the objectives of the thesis, mainly to evaluate the level and structure of taxation associated with petroleum extraction activity in the UKCS. The purpose of this chapter is to analyze the set of criteria with which to evaluate petroleum related tax instruments, to study the nature of economic rent resulting from such activity and to assess the various instruments proposed in previous studies to capture the rent. Consequently, this chapter establishes the basis for evaluating the UK petroleum fiscal regime and sets the framework for the empirical analysis undertaken in the later chapters.

Furthermore, the chapter provides an understanding of the components of a suitable tax system taking into consideration the special features of the petroleum resource and the industry. These include *inter alia* exhaustibility of the resource, the economic rent generated, the uncertainties such as those associated with petroleum geology as well as volatile prices, the specific characteristics of individual oil fields and the possibility of re-investment. Such characteristics impose numerous difficulties in the design and implementation of an appropriate tax system aimed at achieving a balance between both Government and industry objectives.

Taxation in essence is the mechanism whereby Governments generate revenues on behalf of the society[3], affect the overall investment climate and, as appropriate, intervene in certain industries. However, Governments of oil producing countries face important challenges when designing a tax system that meets two fundamental objectives: namely to ensure a fair share of revenues for themselves whilst simultaneously providing sufficient incentives to encourage investment. These two objectives are competing rather than complementary (Stauffer & Gault, 1985). Over the last 25 years oil revenues have played a vital role in both financing the UK Government's current expenditure and influencing its medium term economic strategy. However, in doing so a considerable slice of the producer's profits has been removed by taxation.

"In the absence of a healthy and financially successful oil industry, the Government cannot realize the full benefit of resource extraction. Notwithstanding, a Government that agrees to terms that do not capture fair value for the resource betrays the trust of its citizens" (Watkins, 2001, p1). That said, such a trade off might be improved if an appropriate tax system is adopted. The UK Government, for instance, has set its objective from taxing oil activity in the North Sea, as being one of obtaining a fair share of revenues while keeping the UK North Sea an attractive province for investments (Inland Revenue, 2003a).

[3] The Government is considered as an agent of the rest of the society. Government failure can exist: however, this issue goes beyond the subject of the thesis.

Tax rates that are set too high will eliminate field value and create investment disincentives, hence both the producer and the Government are left with nothing. Conversely, too low a tax rate will increase the producer's share of field value leaving the Government a small and inequitable portion (Mercier, 1999). Therefore, an appropriate fiscal regime can generate a positive rather than a zero-sum outcome. In the former, both the Government and investors benefit respectively from a fair share of revenues and appropriate profitability whereas, in the latter, the return to Government cannot be increased without reducing the incentive to private firms (Stauffer & Gault, 1985).

This chapter is organized in six sections. Following this introduction, Section 2.2 addresses the main functions of taxation with reference to petroleum industry activity. Section 2.3 studies the key features of an appropriate tax system, particularly as applied to an exhaustible resource such as oil. Section 2.4 includes a discussion of the concept of economic rent and examines the different types of rents recognizing that each has different tax policy implications. Section 2.5 analyses the main tax instruments applied in the upstream petroleum sector. Section 2.6 discusses the concepts highlighted in this chapter commenting on the practical applicability of a favorable tax instrument and qualitatively assesses the tax instruments proposed in the literature of petroleum taxation. Closing remarks on the main lessons of petroleum taxation are made in Section 2.7.

2.2. THE FUNCTIONS OF TAX

Raja (1999) describes taxation as "being simply a transfer payment by the private sector to the State since there is no direct productive activity on its own part in generating tax revenue" (p.1). However, taxation, in general, and taxation of petroleum in particular, goes well beyond the simple process of providing revenue to Government. The main functions of oil taxation are presented as follows:

i. Financing Government expenditures: Taxes are the principal source of revenue that Governments use to finance public expenditures. Energy taxation, in particular, provides substantial revenue to virtually every advanced economy (Boskin & Robinson, 1985). The UK is no exception. Since the beginning of oil production, more than £106 bn. has flowed to the Inland Revenue thereby contributing to healthcare, education and various other services funded by Government (DTI, 2003).

ii. Rent extraction: Taxation is used to capture a large share of the economic rent accruing from the production of a scarce resource, such as oil[4]. The concept of economic rent is discussed in Section 2.4.

[4] Taxation is one of the mechanisms by which the Government attempts to capture economic rent from petroleum activity. Other mechanisms, such as competitive bidding, also known as auction licensing, can be used. "Competitive bidding in the absence of collusion should lead to the state's receiving a large part of any economic rent accruing from oil and gas production" (Robinson & Morgan, 1978, p.193). However, the concept of auction licensing goes beyond the scope of the thesis.

iii. Distribution of benefits: "The distribution of benefits from natural resources is at the heart of many resource taxation policies. Many tax instruments have been adopted almost entirely on distributional grounds" (Heaps & Helliwell, 1985, p.426). A key distribution of benefit is between Government and the producer, especially as the natural resource is deemed to be owned by the State who is entitled to a fair share of the value of the exhaustible resource.

Taxation also has other important objectives such as:

iv. Impact on the economic environment: By increasing or decreasing the amount of income it collects, a Government can encourage, or discourage, different economic activity (Committee on Energy Taxation, 1980). Taxation can be used to mitigate certain economic problems such as the "Dutch Disease", where the petroleum industry adversely impacts upon the international competitiveness of the non-oil sector. It can also be used to moderate the pace of exploration and exploitation of petroleum and at the same time reduce the depletion rate. In other cases where, for instance, there is chronic balance of payments problem, the Government can use taxation to accelerate the development of export oriented natural resources, as occurred in the UK in the late 1970s. However, petroleum taxation is not a tool for macroeconomic policy, since it forms only one part of public sector funding (Watkins, 2001).

v. Demand management: For energy-producing countries, if the cost of domestic production of an energy source is very low compared to that in the international market then prices in the local market will be low. In this case, taxation can be applied to reduce the differential, hence discourage wasteful energy use as well as counteracting the distortion in the investment choice (Committee on Energy Taxation, 1980). The demand management function is of particular importance when the price of the commodity is determined in domestic markets. Nevertheless, it is of less importance in the case of oil, whose price is determined in the international market.

vi. Control of pollution emissions from energy: Many proposals have been made for the use of taxes to control pollution from energy. "Green" taxes such as on CO_2 emissions are designed to mitigate or prevent pollution and other adverse effects on the environment.

2.3. EFFECTIVE TAX CRITERIA

Six important criteria characterize an effective tax system. These are the attributes of an optimal tax [5] and they affect the design of a tax regime as follows:

[5] The theory of optimal taxation concentrates primarily on personal income taxes and focuses on the effects of taxation on households rather than producers, which is not the objective of this thesis. A detailed discussion of optimal taxation theory can be found in Ramsey (1927), Diamond & Mirrlees (1971a,b), Dasgupta & Stiglitz (1971), Samuelson (1986), and Heady (1993). Altay presents a detailed summary of the different studies on optimal tax theory.

i. Efficiency: This criterion is satisfied when resources in the economy are allocated in accordance with the tastes and preferences of individuals. This is defined as the social optimal position (Swan, 1984). Altay (2000) argues that the allocative efficiency concept has been the main point of departure for the economic theory of optimal taxation. Raja (1999), however, refers to the difficulties in distinguishing between the social and private optimal levels of efficiency. Efficiency is often combined with the neutrality criterion, explained below.

ii. Neutrality: Garnaut & Clunies Ross (1983) define a neutral tax as one that "would reduce disposable income but not affect decisions on consumption, trade or production" (p.26). Raja (1999) refers to neutrality in terms of Government revenues, where a neutral tax will generate revenues when a company earns profits and nothing when it makes losses. As such, the focus of the neutrality criterion is on whether the tax system interferes with investment and operational decisions in such a way as to cause them to deviate from what is the social optimum (Amundsen, Andersen & Sannarnes, 1993). A neutral tax does not distort investment decisions while a distortionary tax affects the decision making process, such that individuals make inferior choices to those that would have been made in the absence of the tax and, consequently, resources are not allocated efficiently (Kemp & Rose (1982), Dickson (1999)). In the petroleum sector, for instance, a non-neutral tax can adversely affect decisions relating to the development of marginal fields.

Watkins (2001) argues that taxation should neither deter exploitation of a full range of field sizes, nor interfere with project rankings: if project A is more attractive than project B before tax, it should remain so after tax.

iii. Equity: This is a broad criterion that can be considered from different perspectives.

Firstly, firms in the same economic circumstances or oil fields with the same characteristics, including similar cost structures, can be taxed in the same way. This is referred to as "horizontal equity" (Dickson, 1999, p.3). Vertical equity refers to the equivalent treatment of companies or resources with different characteristics. A progressive tax is more likely to satisfy this criterion. Firms that exploit more valuable resources have a greater ability to pay and so their tax liabilities can be greater. Similarly, fields with high profitability can be taxed more heavily than those with low profitability. Stauffer & Gault (1985) emphasize the equity issue and argue that one way of improving a tax system is to reduce taxes on marginal fields and equalize each participant's after tax return across all fields.

Secondly, extracting and consuming natural resources now will reduce the stock available for future generations. Dickson (1999) argues that a tax system, which satisfies the intergenerational equity criterion, is one that discourages rapid depletion of resources when prices are low at the expense of future generations.

In this sense, an equitable tax will ensure that future generations get a fair share of the resources or compensation for those that are depleted.

Finally, since the State owns the natural resources, it should receive a fair payment especially when it transfers exploitation and/or ownership rights to private companies (Mommer, 2001).

iv. Risk sharing: Risk can be defined as the variation in the investor's expected returns (Stauffer & Gault (1985), Mercier (1999)). When the investor evaluates the profitability of a project, the required rate of return combines both a risk free rate and a risk premium[6]. The lower the premium the lower the required rate of return and vice-versa. There are several sources of risk in oil activity. Exploration activity is dominated by risks related to the geological and geophysical attributes of a project, in this case the probability associated with finding substantial and economic deposits when drilling (Raja, 1999). However, the risk is not only limited to the Exploration phase, "only when the deposit is exhausted do you know precisely what the reserve was" (Andrews-Speed, 1998, p.14). The volatility of oil prices is also an important source of risk, affecting all projects in the same direction.

[6] The concept of risk is discussed in more detail in Chapter 6

Kemp & Rose (1982) argue that the attitude of the investor depends not only on the level of tax, but also on the extent to which the Government shares the project's risks. Mitchell (1982), however, has a different opinion. The author maintains that whilst oil companies have the means to diversify risks through a worldwide portfolio, the Government cannot accommodate oil business risks at a lower social cost than that achievable by the companies[7]. Other studies, such as those by Stauffer & Gault (1985) and Rodriguez-Padilla (1991) raised the issue of risk but in the context of fiscal risk. Such studies conclude that taxation can increase the risk of a project since it increases the political risk by means of additional fiscal risk (Rodriguez-Padilla, 1991). The latter issue is considered in the context of the criterion of stability, explained further below.

v. Stability: Devereux & Morris (1983) argue that if a tax system changes frequently and *prima facie* in an unpredictable manner, it may seriously affect future development projects. In accordance with such a view, Kemp & Rose (1982) maintain that a tax system subject to continuous tinkering will tend to increase political risk and reduce the value placed by investors on future income streams. Further, Boskin & Robinson (1985) argue that temporary taxes are likely to be inferior to permanent ones.

[7] Mitchell's (1982) finding is of some relevance particularly in circumstances where the investor has a portfolio of projects. Although diversification is acknowledged to be an important element in risk reduction, this is considered to be at a corporate level and outside the scope of this empirical study, which deals with projects rather than company risk.

The stability of the fiscal regime is an important criterion as it affects the confidence of investors in Government policy, particularly in the case of petroleum extraction activity, which is characterized by long-term projects. Stability can be also considered in the context of Government revenue. Dickson (1999) argues that stable Government revenue will assist with expenditure forecasting and budgeting, while Devereux & Morris (1983) maintain that tax revenue should be as stable as possible and should not fluctuate wildly as a result of such exogenous factors as the crude oil price.

vi. Clarity and simplicity: These criteria relate to the administration and monitoring of the tax system, where an ideal tax is simple to understand and inexpensive to administer. Devereux & Morris (1983) argue that a simple tax regime makes it easier for the taxpayer to judge the tax consequences of their actions. Dickson (1999) uses the term administrative efficiency in the context of clarity and simplicity. The author adds that an ideal tax is one which is levied on a well-defined tax base that is simple and easy to collect. Watkins (2001) refers to the importance of transparency, arguing that "the more transparent the means by which the Government obtains revenues, the better informed the investors and the less the scope for manipulation and administrative discretion-behavior that increases industry's perception of risk" (p.17).

These are the principal criteria of an optimal petroleum tax as argued in previous studies. However, the weight given to each of these criteria differs in the literature and many studies have limited their analysis to only some of those criteria.

According to Heady (1993), the equity concept has absorbed the main interest of economists; it has been widely discussed and is still a major part of the evaluation of any tax policy proposal. Kemp & Rose (1983) emphasize the importance of efficiency and risk sharing attributes, whereas Dickson (1999) ignores the concept of risk sharing and focuses on efficiency/neutrality and equity. Raja (1999) concentrates on the concept of neutrality and Watkins (2001), whilst including the majority of the criteria, emphasizes the concept of risk sharing.

Despite such divergence in interests, the majority (if not all) of the work undertaken in the area of optimal taxation in the petroleum and wider energy sector follows a common theme, that of economic rent. In general, the studies contend that a tax based on economic rent is likely to be an ideal tax. To assist in understanding the validity of such views the concept of economic rent is defined and discussed in the next section.

2.4. ECONOMIC RENT

This section introduces and explains the concept of economic rent and its measurement, as used in other studies particularly in the case of petroleum resources.

It commences with the definition of economic rent in order to understand the reasons why previous studies consider it the most suitable base for an ideal tax. The section further emphasises the different types of economic rent and discusses their implications on taxation policy.

2.4.1. DEFINITION

Dickson (1999) defines economic rent as "the true value of the natural resource, the difference between the revenues generated from resource extraction and the costs of extraction. These costs include the costs of employing factors of production and their opportunity costs" (p.1). Similarly, Banfi, Filippini & Mueller (2003) define economic rent as "the surplus return above the value of the capital, labour and other factors of production employed to exploit the resource. It is the surplus revenue of the resource after accounting for the costs of capital and labour inputs" (p.2). In addition to the capital and labour inputs referred to, further inputs in respect of entrepreneurial reward and risk taking need to be incorporated.

Consequently, economic rent can best be considered as "a bonus, a financial return not required to motivate desired economic behavior" (Raja, 1999, p.2). In this sense, previous studies presume a tax based on economic rent is optimal since it satisfies the tax criteria (Dickson, 1999). Since the magnitude of such profits is not relevant to economic decisions, they constitute a justifiable base for taxation (Rowland & Hann, 1987).

Garnaut & Ross (1979) also argue that if taxes are only levied on economic rent, there will be no effect on the incentive of firms to undertake any activity since rent is not required by the firm to continue or initiate operations. Additionally, because the true value of the resource will be collected, the consumption of future generations will not be sacrificed cheaply (Dickson, 1999).

Further, if the tax seeks to capture economic rent, then the tax-take falls when economic rent decreases and rises when it increases. As such, the tax base responds in the appropriate direction to variations in costs and crude oil prices (Kemp, Stephen & Masson, 1997). Kemp & Rose (1982) argue that a stable system increases the possibility of substantial economic rent. Rowland & Hann (1986) maintain that a fair progressive tax, aimed at absorbing economic rent, is neutral and stable. Swan (1984) argues that a tax system, which collects as much economic rent as possible, is fair to the community. More recently, Rutledge & Wright (1998) argue that a neutral tax should fall on economic rent and which, at the same time, will allow for risk sharing between Government and investor.

The exploitation of exhaustible natural resources can generate significant economic rent. Oil, in particular, is not only an exhaustible resource but also a strategic commodity with no perfect substitute. This implies that the extraction of oil can earn substantial amounts of economic rent.

In their definition of economic rent generated from petroleum extraction activity in the UK North Sea, Rowland & Hann (1987) provide a more practical measure of that rent. "The economic worth of a license to produce oil from a tract of the UKCS may be measured by the present value of the flow of the future revenues from that tract's production less the present value of associated future costs, where the costs include monetary items such as equipment as well as non-monetary items such as exposure to risks. The difference between these two amounts, the net present value, (NPV) is the economic rent of that tract. It may be positive, negative or zero. If it is positive, it implies that the licensee is enjoying profits in excess of those necessary to induce the production of petroleum (pure profits)" (p.4). Similarly, Raja (1999) argue that taxes should be aimed at taxing positive NPV because the NPV method discounts all future cash flows and incorporates all the relevant rewards to factors of production. In certain of the literature, it is argued that a positive NPV could be considered as economic rent representing the surplus over and above that which is necessary to induce investment. This is considered by the author to be a simplistic representation of economic rent. The concept of NPV is developed in Chapters 6 and 7.

2.4.2. TYPES OF RENT

There are several types of rent. These need to be highlighted before further explaining the suitability of economic rent as a tax base, since such differences can be of particular significance to taxation policy. The three main types of economic rent are as follows.

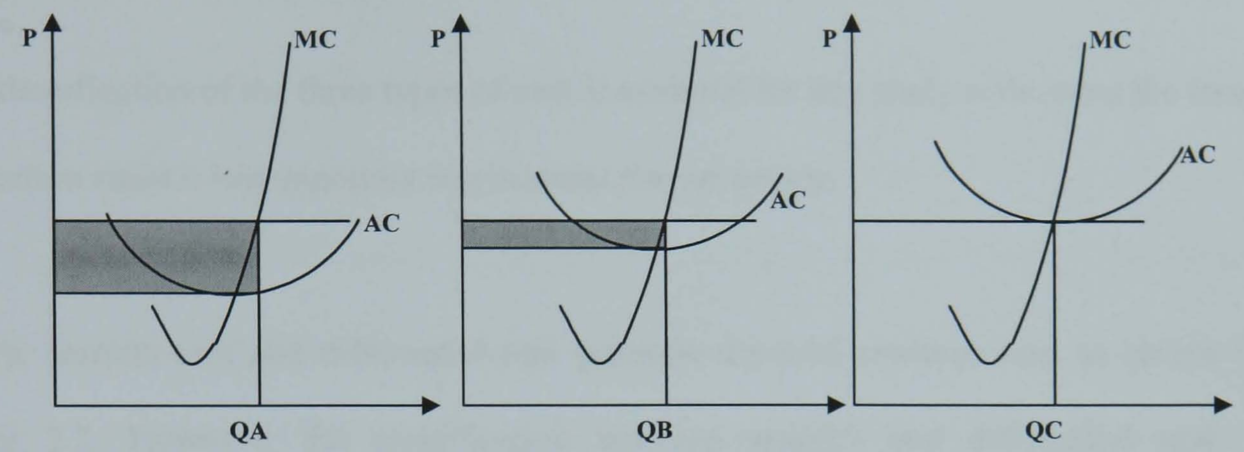
i. Scarcity rent: This type of rent results from the natural scarcity of the resource, which limits the output available. It represents the "foregone future profits as a result of extraction today" (Dickson, 1999, p.2). It can be expressed as "the difference between marginal revenue and marginal production cost that can only come about as a result of the natural or policy induced scarcity of the resource" (Kooten & Bulte, 2001, p.65).

ii. Differential or Ricardian rent[8]: Ricardo compared the rent from three tracts of arable land where increasingly greater levels of rent accrue to land of increasing productivity, with land at the margin receiving no rent (Kooten & Bulte, 2001). This is analogous to the returns accruing to oilfields.

Figure 2.1 illustrates the concept of Ricardian rent, where AC and MC respectively represent the average costs and marginal cost of grain production. Fields A and B earn rent, but the marginal field C does not since its AC is too great and is equal to the unit price. The rent accruing to A and B are determined in comparison to C, as they benefit from greater productivity or better soil quality as compared with C. That is why such rent is referred to as differential rent or quality rent.

[8] As referred to by Kooten & Bulte (2001)

Figure 2.1 Ricardian Rent[9]



Banfi, Filippini & Mueller (2003) refer to differential rent in the context of hydropower plants, where the difference between the cost of the most expensive plant (equivalent to field C in Figure 2.1) and the production costs of cheaper schemes (equivalent to fields A and B in Figure 2.1) determine the additional quality rent. Further, Dickson (1999) argues that differential rent arises because extraction costs depend on differences in the quality of the resource and location.

iii. Quasi rent: The third type of rent represents the returns that accrue to firms from past investment and innovative practice or as a result of changes in the market. Such rents only occur in the short-run before they are competed away (Raja, 1999). They are "earnings over and above that required to maintain a firm in business in the short run" (Kooten & Bulte, 2001, p.65). The existence of sunk costs, representing past expenditure, are a necessary but not sufficient condition to generate quasi rents.

---

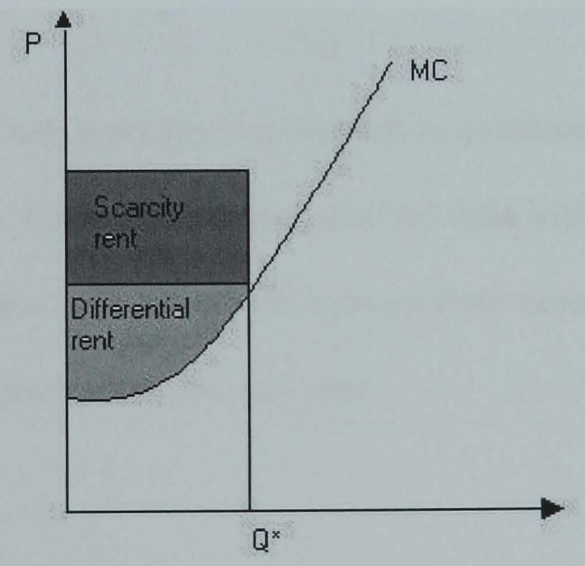
9 Adapted from Kooten & Bulte (2001), p.60

2.4.3. IMPLICATIONS

The identification of the three types of rent is essential for any study addressing the issue of taxation since it has important implications for tax policy.

Firstly, scarcity rent and differential rent generate the total resource rent, as shown in Figure 2.2. However, the classification between scarcity and differential rent is somewhat artificial, since any rent could be understood to be generated by either scarcity or differential effects alone (Banfi, Filippini & Mueller, 2003).

Figure 2.2 Differential & Scarcity Rent [10]



Further, according to Raja (1999), in a normal competitive market when pure profits are earned new entrants are attracted into the industry. In the long run this reduces profits to

[10] Adapted from Kooten & Bulte (2001). It should be noted that the quantity of oil that can be produced is restricted to the amount Q* by physical limits on the availability of oil.

normal levels. However, because oil is a scarce non-renewable resource, pure profits are not eliminated by competition.

Secondly, the resource rent (i.e. scarcity rent and differential rent) is an appropriate tax base since taxation of this rent does not affect the behaviour of the firm. This is not the case with quasi rent. Although quasi rent is part of economic rent, it only occurs in the short run. The capture of quasi rent can alter the long run efficiency behaviour of firms, often causing them to reduce investment and therefore the social optimum level of output. According to Banfi, Filippini & Mueller (2003), the firm should keep the quasi rent generated by its more efficient behaviour in comparison to other firms. It will be competed away in the long run since competitors will learn from the firm generating quasi rent.

Although such distinctions are not generally highlighted in previous studies, they do have two important implications. Firstly, in the case of an oil field with P > AC (fields A & B in Figure 2.1) there is resource rent, which consequently constitute a tax base. Secondly, quasi rent is not to be included in the tax base.

2.5. TAX INSTRUMENTS

Oil taxation can take several forms. Various tax instruments have been proposed in previous studies on energy taxation in order to capture the economic rent from oil activity. This section defines these instruments and analyses their main characteristics.

Four tax instruments are selected, namely Government Royalty, Brown Tax, Resource Rent Tax (RRT) and Income Tax. Royalty is an output-based tax because it is levied on the unit or the value of production, whereas the other three instruments are profit-based taxes or cash-flow taxes, because they are imposed on net profit or operating income after capital investment. A description of each of these instruments follows.

i. Government Royalty: "A Royalty is a payment made for the right to use another's property for purposes of gain. It is a payment for the use of a wasting asset" (Stiegeler, 1985, p.376). Mommer (2001) argues that a country is entitled to earn a Royalty on the extraction of its natural resources. Raja (1999) compares this mechanism to a piece of land, being taken away hence compensation is necessary. The Royalty can be a per-unit tax, which is a uniform fixed charge levied on a specified level of output or an ad-valorem tax, which is a fixed charge levied on the value of the output.

ii. Brown Tax[11]: This tax is levied as a fixed proportion of a project's net cash flow in each period. When the net cash flow is positive firms have to pay the tax but when the net cash flow is negative firms receive a rebate. In other words, the Brown Tax involves the payment of a proportional subsidy or tax credits on annual cash losses and an equivalent tax on annual cash profits. Consequently, it is a tax on net cash flow with full contribution by the Government.

[11] After its proposer Brown (1948), as referred to in Watkins (2001)

iii. Resource Rent Tax (RRT): The RRT was introduced by Garnaut & Ross (1975) and was developed primarily for application in less developed countries particularly those that rely on external sources of capital investment. It is a modified version of the Brown Tax but instead of paying tax credits in years with negative cash flows, the Government allows such negative amount to be carried forward and deducted from positive cash flows in later periods. However, the negative net cash flows are uplifted by a minimum rate of return requirement (the threshold rate) and added to the next year's net cash flow. The accumulation process is continued until a positive net cash flow is generated. No tax is payable until the firm has recovered its costs inclusive of a threshold rate of return which is compounded from year to year. As such, the RRT involves carrying forward losses, whereas the Brown Tax provides a rebate for losses (Garnaut & Ross, 1975).

iv. Income Tax: Unlike the previous two types of cash flow taxes, Income Tax applies to a company's profits. The tax is levied at a corporate rather than oil field level, as such it is generally known as Corporation Tax or company expenditure tax. Income Tax in most countries allows current expenses, interest expense and historic cost depreciation to be deducted. In fact, all forms of income tax allow relief for capital expenditure, but extra reliefs are sometimes given to provide incentives to develop high cost "marginal" projects and are called uplift allowances on capital expenditure.

In general, a country's oil taxation system can take the form of any of these tax instruments, possibly with some adjustments and often using a combination of two or more of these instruments[12].

2.6. ANALYSIS

This section analyses the principal concepts highlighted in Sections 2.3 and 2.4, taking into consideration the findings of previous studies. It is divided into four sub-sections. The first studies the concept of economic rent. The second analyses the practicability of the optimal tax criteria. The third relates to the tax instruments described in the previous section. These are evaluated with regard to the extent that they satisfy the criteria of an ideal tax. Finally, the fourth section analyses the interaction of the different tax instruments.

2.6.1. ECONOMIC RENT

It was stated in Section 2.3 that economic rent can be an important source of Government revenue and its appropriation, in theory, can take place without destroying economic incentives.

---

[12] The UK petroleum fiscal regime is a typical example as it included a Royalty, Petroleum Revenue Tax (similar to RRT) and Corporation Tax (Income Tax), which are described in detail in Chapter 3.

Yet, many complications arise when estimating the quantum of economic rent and such difficulties have been highlighted in previous studies, as in those of Kemp & Stephens (1997) and Raja (1999). The complications include distinguishing between resource rent and quasi rent. This distinction is important because resource rent can be taxed away whereas attempts to capture quasi-rent usually result in inefficient behavior by the investing firms. However, in reality Governments find it difficult to distinguish between the two types of rent.

A second complication is the difficulty Governments have in determining acceptable rates of return for all companies, especially oil companies, as they do not normally reveal directly their required rate of return on investment.

Thirdly, measuring economic rent requires knowledge of the differing costs of the individual factors of production as well as their opportunity costs. The difficulty in measuring each of these components is what makes the determination of economic rent and its capture difficult and controversial (Banfi, Filippini & Mueller, 2003).

Further, as Kemp & Rose (1982) argue, because the size of a given discovery and its related exploitation costs can vary substantially, economic rent will vary from field to field. Although this problem can be partly overcome by a progressive tax system, it is difficult to make conventional fiscal systems sufficiently flexible and focused on resource rent.

Given the problems outlined above, it is difficult to estimate economic rent and this makes it complex to design and impose a tax that captures it exactly. Nevertheless, the impact of such problems can be reduced through the use of proper evaluation techniques to measure a project's profitability, incorporating both an appropriate level of risk and making use of actual revenues and cost data[13].

2.6.2. SATISFACTION OF TAX CRITERIA

As in most areas of taxation there is often an inevitable compromise in satisfying the evaluation criteria. Some of these conflicts are analysed below.

- Neutrality and Simplicity: Several studies have questioned the suitability of neutrality as a major characteristic of tax systems[14]. A major disadvantage with neutral taxes is their complicated administration, especially in the case of petroleum extraction, recognising the individual characteristics of oil fields (size, location, quality, etc). In this case, to maintain neutrality, the Government is required to calculate different levels of rent, discount rates and expected yields in order to value each individual field properly, subsequently imposing what would be called a fully differentiated tax. Such a task is impractical since it can be significantly complicated to administer.

[13] This is explained in more detail in Chapter 6

[14] Detailed study is done by Raja (1999), also refer to Smith (1999) and Bond, Devereux & Saunders (1987).

- Neutrality and revenue generation: Heaps and Helliwell (1985) argue that there is a conflict between revenue collection and neutrality. A neutral tax system provides incentives for companies to exploit marginal fields. However, because marginal fields do not generate resource rent, they do not generate revenues for the Government. Further, as Mommer (1996) debate, under a neutral tax regime the company can exploit the resource without paying any tax. This is an important issue because, as was discussed in Section 2.4, although marginal fields do not generate differential rent they can benefit from scarcity rent.

- Equity, simplicity and efficiency: Governments often try to incorporate tax allowances and reliefs to reduce the tax burden on marginal fields as a means of ensuring equity. Such allocations, however, can impose additional administrative costs, thereby making the tax system complicated. Also, as Bittker (1980) argues, these allowances can generate misallocation of resources, thereby creating inefficiencies.

- Stability and fiscal risk: Although stability of the tax regime is often advocated, in reality it cannot be fully achieved. Boskin & Robinson (1985) refer to this difficulty in the sense that Governments face the problem of maintaining a consistent regime over time. "A stable regime is not one which is cast in stone" (Andrews-Speed, 1998, p.17). In fact, flexibility can be allowed to permit the regime to evolve as a result of major changes in the external environment.

- Risk-sharing: The criteria of risk sharing can be argued in terms of the extent to which the risk can be shared between the Government and investors. However, it is worthy of note that companies have a portfolio of activities and are able to diversify certain forms of risk.

It can be concluded that a compromise prevails between the various criteria of an optimal tax when trying to design and implement a practical tax system. Compromise is also inevitable because of the competing objectives of Government and the private investor. The Government usually seeks to achieve high revenues and receive a portion of the fiscal take relatively early in the life of a petroleum project, while at the same time accept an appropriate amount of project risk. The private investor tends to accept the need for a reasonable overall level of tax take especially in fiscal systems that adopt a risk sharing attitude and provide the capacity to recover project costs at an early stage (Kemp & Rose, 1982).

Given all the compromise between criteria and trade off between objectives, it is not surprising to find that the principal tax instruments suggested in previous studies do not satisfy all the main criteria of optimal taxation. This is further analysed in the following section.

2.6.3. QUALITATIVE ASSESSMENT OF PROPOSED INSTRUMENTS

The previous two sections highlighted the difficulty in determining the appropriate tax base and meeting all the criteria of an optimal tax. This section assesses qualitatively the main tax instruments, addressing their advantages and limitations. The evaluation is derived from the arguments raised in previous studies.

2.6.3.1. ASSESSMENT OF GOVERNMENT ROYALTY

Royalty is a simple tax. Its computation is straightforward since it is imposed on the amount or the value of the output. It also ensures a share of revenue for the Government as soon as production commences. This is in contrast to profit-based taxes where the Government obtains its first tranche of revenues only when the net cash flow begins to turn positive. In this sense, Royalty ensures that some of value of the resource, concurrent with extraction, flows to the State.

However, since Royalty is imposed on gross revenues (or the amount of output), it completely ignores costs and profits associated with the project. Royalty is not targeted on economic rent and because it is not neutral it is likely to affect investors' behavior and create distortions for several reasons.

Firstly, Royalty has an up-front effect because it is imposed concurrent with the commencement of production.

Secondly, because it is imposed irrespective of the size of the field, the marginal cost curve will rise as a field is being depleted. This may cause operating income to become negative even when gross revenues exceed extraction costs and consequently can lead to a premature abandonment of the field.

Thirdly, just as with any tax, which is based on production, Royalty pushes more of the commercial risk onto the investor with little protection arising from cost increases or reduced oil prices.

Previous studies have commented on the regressive aspect of Royalty, which can render profitable projects unattractive on a post-tax basis. Raja (1999) describes Royalty as "a classic example of a non-neutral tax" (p.3). Hotelling (1931) argues that the imposition of a revenue tax is equivalent to an increase in the resource extraction cost, affecting the depletion decision of the investor. Kemp & Rose (1982) made similar observations arguing that a high tax rate on production is more likely to cause distortions and disincentives to continuous production than a profits-tax at the same rate.

To reduce the distortions caused by the imposition of Royalty, Mercier (1999) contends the application of a sliding scale Royalty. This Royalty is based on charging different rates of tax depending on the level of production or oil prices. In this case, the Royalty rate will be low when production or oil price is low and vice versa, thereby decreasing the possibility of negative cash flows when production or oil prices are low.

Such a tax incorporates the benefit of normal Royalty, which is the generation of early revenues and also combines a progressive aspect in contrast to the impact of a fixed rate. As such, the sliding scale Royalty can extend economic field life with both Government and the investor sharing the overall gains (Mercier, 1999). However, an additional burden is added, and which is the administrative complexity of the sliding scale tax[15].

2.6.3.2. ASSESSMENT OF THE BROWN TAX

The Brown Tax is a cash-flow tax and consequently incorporates the different costs an investor incurs in each period. It is based on economic rent and satisfies principally the criteria of neutrality and risk sharing. According to Rowland & Hann (1987), the Brown Tax is the oldest type of neutral tax imposed on extraction industries. Garnaut & Ross (1983) argue that this tax is financially equivalent to the Government having contributed equity in an oil field.

Despite such advantages the Brown Tax is unlikely to be applied in reality, mainly because it imposes an unacceptable level of risk on the Government. Further, since companies are aware that in the case of unsuccessful exploration the Government will subsidize their investment, they have less incentive to reduce costs and increase efficiency.

---

[15] See Chapter 8, China Sliding Scale Royalty

2.6.3.3. ANALYSIS OF RESOURCE RENT TAX

RRT is a modified form of the Brown Tax, designed to capture economic rent and therefore considered a neutral tax. Furthermore, it is a progressive tax that responds automatically to a variety of outcomes. It is based on actual profitability hence avoids the problems of cost and price forecasting.

As with any tax based on profits, RRT tends to share risk with the Government; if costs rise or oil prices fall taxable profits change in sympathy, as does the tax burden. Further, as the company only pays tax when a profit is made the payback period of the investment will be shorter than if a Royalty is applied. Authors like Garnaut & Ross (1975), Devereux & Morris (1983) and Kemp & Stephens (1997) argue that RRT is an appropriate tax instrument to collect economic rent without distorting investment decisions. Consequently, it may be appropriate to apply RRT at significantly higher rates to capture a bigger share of rent given it has less distorting effects at the margin than alternative forms of taxation (Garnaut & Ross, 1979). Fraser & Kingwell (1997) maintain that if a Government switches from Royalty to RRT, its tax revenue can be increased without affecting the optimal level of investment.

Notwithstanding, RRT has some weaknesses. It is thought to give rise on occasion to over-investment, hence affecting the rate of resource depletion. Since it is targeted on economic rent it is difficult to raise large amounts of revenue and preserve neutrality, especially in view of the difficulty of determining economic rent (Smith, 1999).

In fact, problems result from the determination of the threshold at which RRT should be levied. The threshold represents the rate of return that investors require to undertake a project. In other words it represents the level of normal profit. However, this raises the issue of whether companies are motivated by the prospect of normal profit, since businesses usually seek to maximize profits. Furthermore, since the threshold reflects the investor's required rate of return, this can vary from one project to another.

As regards the generation of early revenues, if the Government applies RRT it is unlikely to receive revenues until several years after first production. This is principally because the threshold rate has to be achieved before RRT becomes payable. Consequently, authors like Palmer (1980) argue that RRT is politically unacceptable since it may delay tax payments and can only be imposed in conjunction with corporation tax.

2.6.3.4. ANALYSIS OF INCOME TAX

Since Income Tax is a profit-based tax, it is also assumed to be neutral. Raja (1999), for instance, argues that Income Tax is typical examples of a neutral tax because when profits are zero Income Tax revenues are zero. This is unlike Royalty where if profits are zeros the tax revenue will be positive.

Samuelson (1986) argues that a proportional Income Tax left undistorted the choice among projects of different economic lives and time-line profiles. Similarly, Musgrave

(1982) maintains that, with full and immediate loss offsets, an Income Tax is neutral in its impact on different projects. Although, Dasgputa and Stiglitz (1971) argue that no differential taxes should be used, (otherwise they will affect the allocative efficiency of resources), the authors advise the use of differential taxes (e.g. special petroleum taxes) if economic rent exists. If differential taxes are not feasible, high rates of corporate taxes can be applied to the energy sector to tax rent indirectly (Boskin & Robinson, 1985). Garnaut & Ross (1975) recommended an adjusted version of Income Tax, known as The Higher Rates of Proportional Income Tax (HRIT), which is more targeted on economic rent than on profits and requires payment of normal corporate Income Tax but at a higher rate than would be applicable to non-resource income.

In contradiction, Devereux & Morris (1983) and, more recently, Kemp, Stephens & Masson (1997) argue that Income Tax is neither directly targeted at economic rent, nor is it progressive. Consequently, it is can distort investment decisions. Further, if tax reliefs are very large, a gold-plating effect may be induced whereby the investment in capital equipment may result in tax relief exceeding the original investment.

The main debate surrounding the Income Tax is more likely to be focused on the immediate deductibility of costs. In practice, Income Tax allows for deduction of capital costs but over a period of time using depreciation, which can apply over the life of the project. In contrast to the Brown Tax and RRT, with Income Tax, investors usually do not recover their costs immediately, and this can result in early payments of revenues to the Government.

To conclude this section, it can be argued that each tax has some benefits and some limitations, as summarized in Table 2.1. As such, it is not surprising that several oil producing countries have in practice adopted a combination of two or more tax instruments in an attempt to capture the economic rent and minimize distortions in the investment decision.

Table 2.1. Tax Instruments Summary

Tax Instruments	Advantages	Limitations
Royalty	- Simple - Early source of revenue	- Regressive - Non neutral - Not targeted on economic rent - Less risk sharing
Brown Tax	- Neutral - Risk sharing - Targeted on economic rent - Progressive	- High risk on Government - Late source of revenue - Over-investment - Complicated
Resource Rent Tax	- Neutral - Progressive - Risk sharing - Targeted on economic rent	- Complicated - Requires knowledge of threshold rate - Late source of revenue - Over investment
Income Tax	- Simple - Neutral - Progressive - Risk sharing at the corporate level - Homogeneous treatment among industries	- Late source of revenue - Gold plating - Not project related - Often no immediate 100% relief for Capital Expenditures

2.6.4 INTERACTION OF TAX INSTRUMENTS

Although a tax instrument can create distortions, it cannot be ruled out solely for this reason. The most appropriate tax instrument is one which creates the least distortion, and the more a tax is targeted towards economic rent, the less the distortion created. Often, the combination of several taxes is advisable in fact it is usually applied in oil producing countries, such as the UK and Australia.

Boskin & Robinson (1985), for instance, argue that two taxes with opposite effects can be used to counterbalance each other. Kemp & Rose (1983) maintain that the Government has to choose a combination of fiscal arrangements, but it should be careful in determining the relative weights given to different elements in the structure of the system. Garnaut & Ross (1979) argue in favor of a combination of RRT and Income Tax where the company pays in each period the higher of either RRT or Income Tax. In this situation, the company will pay the Income Tax even in early years, since with RRT the payments are delayed. At the same time, when RRT applies, both Government and companies will benefit from the advantages of this tax. More recently, Lund (2002) maintains that it is optimal to combine a tax on gross revenue, such as Royalty, with a tax on economic rent.

Stauffer & Gault (1985) argue that an ideal tax substantially reduces perceived risk without any loss of revenue to the company. In this sense, the authors compared the ideal tax to the following four fiscal packages: a Corporate Income Tax with a deductible Royalty, a Production-Sharing Contract[16], a carried interest system superimposed on a Corporate Income Tax and Royalty, and a rent skimming surtax superimposed on a Corporate Income Tax. The authors argue that while Royalty and Income Tax package is the highest risk scheme, the rent skimming is the lowest (i.e. it allows a high risk sharing). Carried interest systems are second while the Production-Sharing Contract is third.

[16] Explained in detail in Chapter 8

However, despite its superiority to other tax systems, the rent skimming system is far from ideal as it allows larger returns to the larger or more profitable discoveries (Stauffer & Gault, 1985).

2.7. SUMMARY & CONCLUSION

The first step towards achieving the objectives of this thesis is to analyze the theoretical background for petroleum taxation. This is accomplished in this chapter, which consequently sets out the basis for an in-depth analysis of the UK fiscal regime.

The analysis carried out in this chapter highlights the main functions and effects of petroleum taxation. The principal criteria of an ideal tax against which all tax instruments relating to petroleum extraction activity are normally assessed are also developed. Six criteria are analyzed, namely efficiency, neutrality, equity, risk sharing, stability and simplicity - all of which are desirable when designing a tax system. A tax targeted on economic rent is often recommended, as it is believed to meet the optimum criteria. Subsequently, both the concept and type of economic rent are addressed since these have important implications for taxation policy. Additionally, an analysis of the main tax instruments proposed in previous studies is undertaken.

In this regard, several complications are identified. In fact, designing an optimal tax system that meets different considerations, some of which are contradictory, vary between countries and evolve over time is a complicated task (Bhattacharyya, 1998).

This is particularly true in the case of petroleum taxation, which is a complex issue in its own right, both in terms of economic theory and political economy (Miller, 2000). Natural resources, such as petroleum, have special characteristics that complicate the design of an optimal tax system. Oil is an exhaustible resource, with an uncertain level of reserves before any investment takes place. It is both a raw material input as well as a final product with few substitutes.

More importantly, as this chapter shows, the main source of complication lies in the difficulty of determining economic rent and the distinction between the various types of rents, namely resource rent and quasi rent. Another source of complication is the inevitable compromise between the various criteria of an optimal tax. Such difficulties make it complex to design and impose a tax that captures the resource rent exactly.

None of the tax instruments proposed in previous studies represents an optimal tax. The main tax instruments often suggested are Royalty, Brown Tax, RRT and Income Tax. Each tax has both advantages and limitations. But, although a tax instrument can create distortions, it cannot be ruled out solely for this reason. The most appropriate tax instrument is one which creates the least distortion, and the more a tax is targeted towards economic rent, the less the distortion created.

This leads the author to agree with the findings of Stauffer & Gault (1985), who maintain that the concept of an ideal tax is useful primarily as a paradigm against which to test actual or proposed fiscal systems.

Nevertheless, it can be argued that although compromise seems to be inevitable and an ideal tax not practical, the trade off can be improved and a balance can be reached in terms of generating a fair share of revenue for the Government while keeping the country attractive for investment.

The examination of the various tax criteria as well as the major petroleum tax instruments leads the author to focus on the tax instruments used in the development of the UK fiscal regime that applies to oil activity in the North Sea. The analysis and qualitative evaluation of these instruments is the subject of the next two chapters. A quantitative assessment is then introduced and developed in Chapters 5-8. The evaluation is carried out in the light of the five chief criteria of an ideal tax, as discussed in this chapter[17].

---

[17] In the remainder of this thesis, the efficiency criterion is combined with neutrality.

CHAPTER THREE

EVOLUTION OF THE UK PETROLEUM FISCAL REGIME

3.1. INTRODUCTION

The previous chapter established the background against which the taxation of oil on the Exploration and Production (E&P) activity in the UKCS can be studied and evaluated. In order to carry out the evaluation, the following step is to study the establishment of the regime in 1975 and its evolution from its beginnings through to the Budget changes introduced in 2002/03. This is the principal objective of this chapter, which analyses the basic structure of the UK petroleum fiscal regime and subsequent amendments thereto. The chapter also studies the reasons for such amendments and highlights the resulting controversies. Such a study is essential to providing the fundamental framework for understanding the drivers behind the current tax system. Further, from the analysis of the differing arguments used in the debate, and which has followed from the various changes, conclusions can be derived as to the nature and characteristics of the fiscal system.

Oil is one of the UK's most important natural resources and the oil industry is of particular significance to the UK economy. The discovery of oil brought something new and rich to the British economy (Nelsen, 1991). As discussed in Chapter 1 (p.8), the oil industry is and has been a vital component of the UK economy, mainly in terms of significant investments, job creation and generation of revenue.

The role of the Government has been to set the framework within which the private sector can pursue the development of the UK's petroleum resources and to ensure that an appropriate share of the associated wealth is secured for the nation. The UKCS fiscal regime is one of the principal mechanisms used to capture the economic benefits of the UKCS for the nation. Since the commencement of production, more than £106bn in taxes has flowed to the UK Treasury (DTI, 2003).

The structure of the current fiscal regime was first set out in a 1974 White Paper, and was formally legislated through the Oil Taxation Act (OTA) of 1975. The system consisted of three main instruments, namely Royalty, Petroleum Revenue Tax (PRT) and Corporation Tax (CT). At the outset, the Government had two key objectives. These were to secure a fairer share of profits for the nation and to maximise the gain to the balance of payments while ensuring a suitable return for oil companies on their investment (Inland Revenue, 2003a). In fact, the 1960s were marked by minimal Government intervention in the offshore petroleum industry. However, the discovery of significant quantities of oil on the UKCS, the worldwide trend toward greater national control of petroleum resources and higher crude oil prices all contributed to a dramatic transformation of the petroleum policies established during the 1960s (Nelsen, 1991).

Although the OTA of 1975 established the petroleum fiscal regime for the UKCS, it has been frequently reviewed and amended. This was caused by a combination of factors such as the volatility of oil prices, the international competitiveness of the UK as an oil producing province and latterly the maturity of the UKCS.

The UK Government enjoyed its greatest intake of revenue from oil companies during the early 1980s, but it was under oil companies pressure to ease the tax burden even at this point in time (Nelsen, 1991). This pressure continued until 2002, with the level of Government take gradually falling from approximately 87 per cent in the 1980s to just 30 per cent in the mid 1990's. In April 2002, however, the Government increased its take for the first time since 1983 through the imposition of a 10 per cent Supplementary Charge on the Corporation Tax based income.

The major changes highlighted above are analysed in detail in this chapter. Section 3.2 studies the development of the fiscal regime between 1975 and 2002, including a brief description of the characteristics of the main tax instruments[18]. Section 3.3 focuses on the debate arising from the principal amendments, it further analyses the advantages and disadvantages of each of the tax instruments, taking into consideration the arguments raised in previous studies undertaken in this area. Section 3.4 discusses the major findings arising from this analysis and conclusions are derived. Section 3.5 includes the final remarks.

3.2. EVOLUTION OF THE UK NORTH SEA TAX SYSTEM

This section charts the evolution of the UK oil taxation since 1975. It proceeds by describing the four main evolutionary phases, starting with the originating legislation enacted in 1975, and the following amendments undertaken in 1983, 1993 and 2002.

The section describes the principal tax instruments[19] and highlights the main factors leading to the four major changes that affected the level of tax take and the structure of the system itself.

3.2.1. FOUNDATION OF THE CURRENT REGIME

In July 1974, the Government published a White Paper[20], setting out two principal objectives with respect to the taxation of E&P activities on the UKCS. These were firstly to secure a fairer share of profits for the nation and secondly to assert greater public control (Nelsen, 1991). In this White paper, the basic structure of the current oil taxation system was established. This was subsequently legislated for in the Oil Taxation Act in 1975[21]. The system was based on three elements, namely Royalty, PRT and CT.

3.2.1.1. ROYALTY

In extractive industries, Royalty is a payment to a landowner, the Crown, for the right, granted under the license, to extract oil and gas[22] (Inland Revenue, 2003b).

---

[18] A detailed numeric computation of the tax instruments is carried out in Chapter 5.

[19] A detailed computation is provided in Chapter 5.

[20] Entitled "United Kingdom Offshore Oil & Gas Policy" (Inland Revenue, 2003)

[21] Before 1975, there were two elements of the UK North Sea fiscal regime: Royalty charged at 12.5% and Corporation Tax charged at 50%. The Oil Taxation Act (1975) established the Petroleum Revenue Tax and the main regulations governing the administration of the tax (National Audit Office, 2000).

[22] Royalty is not charged on a field but on the license. In general, there is no difference between the field and the license but there are several cases where a license covers more than one field or where a field extends into the area covered by more than one license (Inland Revenue, 2003). For reasons of simplicity, it will be assumed that there is no difference between the field and the license.

In the UK, the Royalty rate was fixed at 12.5 per cent on the gross revenues of each field with a deduction for Conveying and Treating (C&T) costs. These costs represent the cost of bringing the petroleum ashore and its initial treatment. Royalty is based on a six-month period and is administered by the Department of Trade and Industry (DTI) rather than the Inland Revenue who have responsibility for the other tax instruments.

3.2.1.2. PETROLEUM REVENUE TAX

PRT is a special petroleum profits tax. It is assessed on a field basis, hence a company with taxable losses in one field cannot offset them against profits in another field. This is because each field is treated separately under a "ring fence" arrangement. As a result, all fields are treated equally irrespective of ownership. PRT is charged on a half-yearly basis, initially at a rate of 45 per cent, on the value of oil and gas produced. This broadly equates to receipts less the expenditure incurred in developing and operating the field. PRT was introduced to capture economic rent from the more profitable fields. Less profitable projects are shielded from the tax as a result of various allowances and reliefs (Inland Revenue, 2003b). Three main reliefs are identified:

i. Uplift, which is an additional allowance of 75 per cent to Capital Expenditures (CAPEX), so companies will not start paying PRT until they have at least recovered 175 per cent of their CAPEX.

ii. Oil Allowance, which allows one million tonnes (Mt) of oil per annum to be exempt from PRT up to a cumulative maximum of ten Mt. As a result, PRT is unlikely to be payable on fields with reserves of less than 100 mmbbls. The Oil Allowance was introduced to help the development of marginal fields (Inland Revenue, 2003b).

iii. Safeguard, which limits the PRT liability in any chargeable period to 80 per cent of the amount by which gross profit exceeds 15 per cent of cumulative expenditure. Safeguard was introduced to ensure that, while it applies, PRT-calculated after taking account of all other reliefs- does not reduce a participator's return on capital in any chargeable period to 15 per cent or less. As such, the Safeguard limits PRT liability for a part of the field's life and allows fields to achieve a certain level of return on investment before they incur any PRT liability (Inland Revenue, 2003b).

PRT is similar to the Resource Rent Tax (analysed in Chapter 2). However, the two taxes differ in their respective treatment of expenditure carried forward for offset against future profits. RRT allows such expenditure to be carried forward in real terms, together with an interest mark up, while PRT compensates for the absence of this relief by allowing Uplift to apply to most development expenditures[23] (Bond, Devereux & Saunders, 1987).

---

[23] This difference is explained in more detail in Chapter 8, where Australia PRRT is compared with the UK PRT.

3.2.1.3. CORPORATION TAX

CT was initially set at 52 per cent on company gross profits. Exploration costs were deemed fully deductible, while development costs were made subject to various tax depreciation allowances. CT is the standard company tax on profits that applies to all companies operating in the UK. However, in normal CT applications a company can offset losses generated by one activity against income generated by its other activities. In the case of UKCS E&P activity, there is a ring fence that prohibits the use of losses from other activities to reduce the profits originating from within the UKCS ring fence. Conversely, losses and capital allowances inside the ring fence may be set against income arising outside the ring fence.

3.2.1.4. TIGHTENING OF THE SYSTEM (1978-1982)

Following the increase in oil price in the mid 1970s, the Government implemented measures to increase the level of total tax take on UKCS activities. In 1978, it increased the PRT rate to 60 per cent, reduced the uplift allowance to 35 per cent and reduced the oil allowance from one Mt. to 500,000 Mt. per year, with a maximum allowance of 5 Mt. In 1980, the PRT rate was raised to 70 per cent, thereby increasing the combined marginal rate to some 87 per cent. Further, a new tax, Supplementary Petroleum Duty (SPD), was introduced.

Like Royalty, SPD was charged on a field by field basis by reference to 20 per cent of gross revenues less an oil allowance of one Mt. per annum. SPD was applied in the early producing life of field and was payable on monthly basis.

3.2.2. ABOLITION OF ROYALTY (1983)

In 1981/1982, the reduction in both oil prices and declining levels of development activity, combined with continuing industry pressure, led the Government to consider some adjustments to the fiscal regime. In 1983, for the first time relaxations in the system were introduced, chiefly to encourage exploration and appraisal activity and to encourage the development of new fields (Inland Revenue, 2003a).

In 1983, SPD was abolished and replaced by Advance Petroleum Revenue Tax (APRT). Like SPD, APRT was imposed on gross revenues less an allowance of one Mt per year. The rate applied was 20 per cent and payments were to be made on monthly basis. However, unlike SPD, APRT was not a new tax but rather an instrument for accelerating the payment of PRT. It consisted of an advance payment of PRT that would be offset against the actual PRT payments due later in the life of a field. Additionally, the PRT rate was increased to 75 per cent.

In the same year (1983), the Government further amended the regime by abolishing Royalty on fields receiving development consent after April 1982.

The Oil Allowance against PRT was restored to one Mt. per year for a maximum of ten years. In addition, a cross-field allowance was introduced with respect to PRT, permitting up to ten per cent of the development costs of a new field to be offset against the PRT liabilities of another field. By the end of 1986, APRT was abolished and CT reduced to 35 per cent.

3.2.3. ABOLITION OF PETROLEUM REVENUE TAX (1993)

In 1993, the Chancellor of the Exchequer announced in his budget speech that "as the North Sea has developed, the PRT regime has begun to look increasingly anachronistic... As profits in many existing fields attract a marginal tax rate of over 83 per cent, there is little incentive for companies to keep costs under control or for additional investment in existing fields" (OGJ, 1993c). Consequently, PRT was reduced to 50 per cent on existing fields receiving development approval before April 1993 and abolished on all fields receiving development consent after that date.

3.2.4. IMPOSITION OF SUPPLEMENTARY CHARGE (2002)

In 1998, following the increase in oil prices in 1996/7, the Government proposed two alternative fiscal reforms. One was the application of a supplementary corporation tax on upstream activity profits. The other was the re-introduction of PRT on fields receiving development consents after March 1993.

In the former case, a single tax would be applied for the majority of fields and the overall corporation tax would be 35-40 per cent, the highest since 1986. Under either option, the Government intended to abolish the 12.5 per cent Royalty on production (Rutledge & Wright, 2000). Following a sharp fall in oil prices in 1998, these proposals were dropped. However, after 1998 circumstances changed when oil prices exceeded $30 a barrel and North Sea production reached record levels. The discovery of the Buzzard oil field, which was the UK's biggest new oil find in almost a decade (*circa* 300 mmbbls), brought a positive outlook as regards the North Sea oil reserves (DTI, 2002).

In 2002, the Government introduced new changes to oil taxation in the UKCS. The changes were very close to one of the reform packages proposed in 1998. A 10 per cent Supplementary Charge on profits subject to CT was applied in addition to the normal 30 per cent rate, as a revenue raising measure (Hendersen, 2004). The charge is calculated on the same basis as normal CT, but there is no deduction for financing costs against the Supplementary Charge (DTI, 2003). Additionally, a 100 per cent capital investment allowance was introduced against both general Corporation Tax and the Supplementary Charge, instead of the 25 per cent allowance previously available. Furthermore, the Royalty was abolished on older fields that had received development consent before 1983, in an attempt to encourage fuller exploitation of reserves from those fields[24].

[24] The 2002 changes are not the last changes applied to the UK petroleum fiscal regime. Other amendments were made or proposed but they go beyond the scope of this study. In 2003, the Government abolished PRT on tariffs receipts. In fact, a field, which is liable to PRT and provides services in relation to another field, has to be pay PRT on the tariffs received from the new field. However, with the 2003 changes, such payments are abolished on new business (Inland Revenue, 2003). Since a major assumption in this thesis is the use of one field (See Chapter 5, Section 5.3.1), such a change is not incorporated in the analysis. Further and very recently, the Government proposed to enhance tax relief on exploration costs for new entrants to the North Sea (Petroleum Review, 2004).

3.3. CONTROVERSY SURROUNDING UK OIL TAXATION

Chapter 2 concludes that it is difficult to design an ideal tax system and that each tax instrument when applied to oil activity has both advantages and disadvantages. Consequently, it is not surprising to find considerable debate surrounding the principal amendments to UK oil taxation policy. The remainder of this section summarizes the controversies relating to the structure of the fiscal regime in the UK. It studies the arguments for and against the main tax instruments, as discussed in previous studies.

3.3.1. ROYALTY AND THE 1983 CHANGES

The abolition of Royalty on fields that received development consent after 1982 generated two opposing views, although the majority welcomed the changes.

Several authors like Moose (1982), Devereux & Morris (1983), Bond, Devereux & Saunders (1987), Kemp (1990), Nelsen (1991), Kemp & Stephens (1997) and Martin (1997) argue the inappropriateness of imposing Royalty and, in particular, its negative effect on the development of marginal fields. According to Moose (1982), the 1975 fiscal system imposed such a high burden on marginal fields that if they were to be developed either crude oil prices would have to rise or the UK tax system would have to be modified to reduce the fiscal burden.

Devereux & Morris (1983) emphasize the inappropriate revenue base of Royalty, making it an unsuitable method for taxing mineral exploitation. This was implicitly recognized by the Government when new fields were exempted from Royalty in 1983 (Bond, Devereux & Saunders, 1987). Kemp (1990) describes the 1975 fiscal package as regressive in relation to economic rent, mainly because Royalty is regressive as regards profits. However, the post 1983 package is described as wholly profit related and "constitutes a major structural improvement, which has improved the investment environment in the UK" (Kemp, 1990, p. 621). Nelsen (1991) further emphasizes the non-neutral aspect of Royalty. The author argues that the abolition of Royalty is an important step towards achieving neutrality of the regime. "The application of only PRT and CT represented an entirely new approach by Government to the taxation of oil profits. It signaled that taxation would be used to secure a full share for the Exchequer of the substantial economic rent expected from UKCS oil production (Nelsen, 1991, p.143). Kemp & Stephens (1997) maintain that Royalty generates a high fiscal risk since it is not fully profit-related and impacts more severely on less profitable fields, principally because costs are not allowed as deductions. Martin (1997) argues that the abolition of Royalty is the main reason that led to the peak in oil production in 1984/1985.

The abolition of Royalty was particularly welcomed by the oil industry. In 1991, Texaco's president argued that the changes would provide a substantial encouragement to Exploration and Development activities and create incentives for long-term investments (Bijur, 1991).

Despite such statements, the abolition of Royalty met with some criticisms. Rowland & Hann (1986) argue that the abolition of Royalty, while maintaining PRT and CT, does not alter the fundamental deficiencies of the UKCS tax system. Mabro (1994) compares not charging a Royalty on oil to a situation where the Government handed out buildings rent free to businesses and simply charged them corporate tax on their profits[25]. In a more general discussion, Raja (1999) describes not imposing Royalty "as senseless" because "a resource being extracted from a country without a charge" (p5).

Mommer (2001) argues that Royalty is the only instrument that can make the UK fiscal regime a more proprietorial regime[26], providing more control for the Government over oil activity. Recently, Wright (2003) maintains that "sticking with upstream taxes which guarantee at least some income whatever the oil price, as Royalties do, is a sensible strategy. In this way, the tax may be transformed into an accepted cost of production which ensures that the resource owner is unambiguously compensated for the depletion of an exhaustible resource" (p.22).

3.3.2. PETROLEUM REVENUE TAX AND THE 1993 CHANGES

As with the abolition of Royalty, the abolition of PRT on fields that received development consent after 1992 generated controversy. However, the divergence in views was more pronounced.

[25] As referred to in Miller (2000)
[26] This point is further explained in chapter 6.

Many authors favoured PRT as an instrument to capture economic rent on oil related activity and strongly criticized its abolition, unlike others who emphasized the limitations of PRT.

Among the first group, Zhang (1995) emphasizes the neutrality of PRT and argues that if the Government maintained its 1987 share of UKCS profits, revenues would have been almost three times their actual levels. Accordingly, the author concludes that the abolition of PRT in 1993 resulted from either a weakness in Government planning or because of unseen distortions. Kemp & Stephens (1997) maintain that PRT was almost neutral and efficient despite the high marginal rates of tax on oil revenues when all allowances were exhausted. The authors further argue that PRT was progressive in relation to variations in the oil price and development costs. Similarly, Kemp, Stephens & Masson (1997) argue that "PRT could collect a share of economic rents from fields without necessarily endangering the viability of a development project…it is progressive on its impact on profits" (p.117).

In agreement with such a view, Mommer (1999) also argues that PRT is the main excess profit collecting device in the UK, and its several reliefs "ensure that PRT cannot, even accidentally, cut into the normal profits to which the companies are entitled" (p.15). More recently, Miller et al (2000) propose that the Government should re-impose PRT on the exempt oil fields at the 50 per cent rate.

From an industry perspective, UKOOA (1993) argues that the abolition of PRT reliefs can slow UKCS exploration and discourage investment. The association debates that such a change will, in particular, affect small companies as a consequence of the removal of cross-field allowance. According to UKOOA, this will also affect Government revenues, since in the long term, reserves will shrink and there will be fewer developments and less construction, hence the Government will be the big loser (OGJ, 1993b).

Taylor (1993), of Esso UK Plc, argues that two opposing effects resulted from the changes in PRT. On one hand, the reduction in PRT to 50 per cent on fields that received development consent before 1993 has a positive impact. On the other hand, the reduction of exploration expenditures and the loss of cross-field allowance lead to a reduction in the development of new and small fields. Nevertheless, Taylor concludes that the overall impact is beneficial to the industry (OGJ, 1993a).

Among the group that highlight the limitations of PRT, two views can be distinguished. The first emphasizes the problems of PRT but suggests an improvement, whereas the second advocates its complete removal.

Authors such as Devereux & Morris (1983), Bond, Devereux & Saunders (1987), Kemp (1990) and Kemp & Stevens (1997) relate the main weakness of PRT to its imposition alongside Royalties and CT, both of which are distortionary instruments. Bond, Devereux & Saunders (1987) describe this characteristic as a "serious deficiency" of PRT (p.49).

A second major weakness is attributed to the complicated structure of PRT, although in its original state it was a fairly simple tax (Devereux & Morris, 1983). Rowland (1983) criticizes the way the progressive aspect is applied to PRT. The author argues that progressivity is attempted not by means of a suitable rate structure but by means of arbitrary allowances, which does not insolate the returns for those fields needing most protection. "The allowances do not protect the returns on the fields most needing protection and the North Sea tax structure burdened the less profitable finds while giving relatively favourable tax treatment to the richer oilfields" (Rowland, 1983, p.235).

Rowland & Hann (1986) conclude that PRT has a regressive aspect in that its base does not grow in line with profits. The authors argue that progressivity should be automatic without changes being made especially structural changes to the allowances. Bond, Devereux & Morris (1987) maintain that the PRT allowances are intended to be of disproportionate assistance to relatively unprofitable fields but in practice this is not always the case. Robinson & Morgan (1978) and Robinson & Rowland (1978) conclude that PRT is in many ways a poor form of taxation. "It is a complicated device and could be abandoned" (Robinson & Morgan, 1978, p.201). Robinson & Morgan (1978) argue that PRT is a poor source of revenues, mainly as a result of the Safeguard[27].

[27] See definition on p.58. The computation of the Safeguard is explained in detail in Chapter 5.

In fact, according to the Inland Revenue (2000), some oil companies gained an unfair tax advantage by delaying their claims for operating expenditure relief while benefiting from the Safeguard provision. By deferring expenditure claims to a subsequent period, when Safeguard no longer applied, the deferred claim had a direct effect in reducing the PRT payable. This is contrary to the intent of Safeguard relief (Inland Revenue, 2000).

Rutledge & Wright (2000) argue that the three main PRT reliefs- Uplift, Oil Allowance and Safeguard are "equally important weaknesses" (p.5). The authors maintain that the Uplift postpones PRT payment and the Oil Allowance is based on the assumption that small oil fields are necessarily less profitable. The Safeguard is considered as the "strangest provision", since it is based on the presumption that the amount of tax paid should not exceed 80 per cent of the excess of gross profits over the 15 per cent return on capital (p.6).

Also, the Government expressed its view regarding the abolition of PRT. According to the then Chancellor of the Exchequer, PRT is an expensive tax that cost the Exchequer an estimated £200M in 1991 and 1992. In addition, by allowing companies a larger share of the profits generated, the proposed reforms are intended to reduce the apparent disincentives to cost cutting and future investment in existing fields (Inland Revenue, 2000).

Kemp (1990) had previously raised the issue that the uplift provision encouraged more capital-intensive exploitation methods than would a neutral scheme. The author argues that the interaction of this allowance with the Safeguard provision meant that gold-plating incentives can occur. Martin (1997) maintains that the abolition of PRT is the main reason behind the 1995 peak in oil production of 2.49 mmbbl/d. This result underlines the non-neutral aspect of PRT. Finally, Watkins (2001) argues that the number of modifications to which PRT has been subjected are "a testimony to its clumsiness" (p.13).

3.3.3. CORPORATION TAX, SUPPLEMENTARY TAX AND THE 2002 AMENDMENTS

CT has both advantages and disadvantages, as highlighted in Chapter 2, and consequently there is also a divergence of opinions concerning its imposition. This section studies the debate surrounding the application of both CT on oil activity in the UKCS and the imposition of the 10 per cent Supplementary Tax (ST) in April 2002, since the ST is computed on a similar base to CT.

Among the authors who argue in favour of CT, Robinson & Morgan (1978) maintain that a tax applied on total company profits from UKCS activities is an appropriate instrument. The authors argue that companies can adjust their operations so as to improve the after-tax returns on high-cost projects, rather than dealing with single fields as is the case with PRT. Raja (1999) emphasizes the neutral aspect of CT and describes the UK regime based solely on CT as an example of a highly neutral tax regime.

Also, Beckman (1998) argues that CT is simple to administer, in fact it is the simplest way for the Government to raise revenues from E&P companies.

From the Government perspective, imposing an Income Tax, such as CT combined with the ST, is intended to encourage long-term investment without providing better tax reliefs than those available to other industries and, as such, prevent unwelcome repercussion effects (Inland Revenue, 2003a).

Opposing such arguments authors like Devereux & Morris (1983), Kemp (1990), Kemp & Stephens (1997), Rutledge & Wright (1998) argue that CT has an inappropriate tax base, which does not capture economic rent. Devereux & Morris (1983) contend that the severity of the tax burden for a field depends on which companies are involved because capital allowances from one field can be used to offset tax liabilities on another. Kemp (1990) argues that CT is not directly related to economic rent, as it does not allow a normal return on investment as a cost. Concurring with such a finding, Kemp & Stephens (1997) maintain that CT is non-neutral and can create distortions because it fails to distinguish between normal profit (i.e. the required return on capital invested) and pure profit or economic rent. Rowland & Hann (1986) underline the non-progressive aspect of CT. The authors argue that CT collects proportionately more from each field when prices are lower and that unprofitable fields receive a greater CT burden on unit profits than do their more profitable counterparts. However, it is important to stress that the authors assert that the regressive nature of CT is accentuated because PRT, a non-progressive tax, is itself a deduction against CT.

Rutledge & Wright (1998) emphasize the inability of CT to capture economic rent. Consequently, the authors argue that imposing only CT on E&P activity does not generate a fair share of revenues for the Government and that it makes the UK fiscal regime the weakest in the world. Supporting such findings, Miller (2000) argues that oil companies are not paying their fair share of taxes. According to Miller (2000), before April 2002, Government revenues were far below the levels of the 1980s. In 1984/85, Government revenues reached a peak of £12.2bn. Tax receipts subsequently declined with the fall in oil prices to a low of £1bn. in 1991/92. Although the tax receipts recovered to £3.3bn. in 1997/98, they dropped again to £1.6bn. in 1998/99. Further, when companies' profits reached a peak of over £18bn. in the mid-1980s, the Government take was about £12bn. almost 60 per cent. When in 1996/97, companies' profits reached another peak of about £16bn. Government revenue was less than £4bn. with companies paying only quarter of their gross profits in tax (Miller, 2000).

The industry response to the 2002 fiscal package was divided. Some companies, such as Talisman, welcomed the new changes and argued that the increase in the tax rate was more than offset by the current year decrease in taxable income, as a result of the 100 per cent capital allowance write-down (PR Newswire, 2002). In contrast, other companies, such as BP and ExxonMobil, maintain that the changes to capital allowances and the abolition of Royalties are not expected to come close to offsetting the ST (Macalister, 2002). Leith (2002) argues that with hostile environments like that of the North Sea, the 2002 fiscal changes left companies feeling betrayed and raised concerns about when fiscal stability will be achieved.

Industry representatives, such as UKOOA, argue that there is no room for additional taxes. According to UKOOA (2002), prices of between \$14 to \$18 a barrel are needed in the UKCS to make a return. This is because the majority of the large oil fields are now discovered and only small fields remain, which are more expensive to develop on a unit cost basis hence less profitable. UKOOA (2002) maintains that the April 2002 changes can adversely affect smaller companies, jobs and investments, as well as generating an unstable environment in which companies must operate.

3.4. THE UK CONTINENTAL SHELF FISCAL REGIME

This section is divided into two parts. The first part analyses the principal findings derived from the arguments raised in previous studies, regarding the UK oil regime. The second part discusses the current mature state of the UKCS province, as it challenges the development of the fiscal policy.

3.4.1. ANALYSIS

The findings of this chapter are not different from those of Chapter 2, with respect to the individual components of the UK fiscal regime, namely Royalty, PRT and CT. In fact, in their original context, these taxes have the characteristics of a Royalty, Resource Rent Tax and an Income Tax, respectively.

Consequently, from the balance of arguments raised in previous studies and from Chapter 2 findings, the main conclusions regarding the individual taxes are presented as follows.

- Royalty is a simple instrument to administer and it generates early revenues for the Government. However, it is regressive, non-neutral and not targeted on economic rent.

- PRT is a special petroleum tax, targeted on economic rent. It allows a certain return before any tax is paid. The nature of its allowances and deductions ensure that it is progressive. Nevertheless, it is a complicated tax and tends to delay fiscal receipts.

- CT is simple and applies without exception to all industries in the UK. However, it is levied on a company basis and, similar to PRT, it tends to delay fiscal revenues.

Conclusions can further be derived regarding the overall fiscal package that applies to the UKCS. As the previous section demonstrated, significant controversy surround the regime and its main changes. On balance, when the UK fiscal regime is assessed against the criteria of an ideal system as discussed in Chapter 2, the following arguments are applicable.

Firstly, the UK fiscal regime lacks stability, as it has been subjected to frequent changes.

This criticism has often been made in previous studies, as no other sector in the UK economy has been subject to such instability (Rowland & Hann, 1987). Since 1975, "more changes have been recorded due to tax legislation than price changes" (UKOG, 1984, p.1). Robinson & Rowland (1978) argue that the Government introduced several changes before the practical operation of the system can be observed. Such a weakness questions the effectiveness of the regime and its ability to cope effectively with different economic conditions, such as changing oil prices. Further, even though the regime was more risk sharing in its initial structure, its various amendments increased political risk and reduced investor confidence.

According to Inland Revenue (2003a), the many adjustments made to the regime reflected the changes that were taking place on the UKCS, such as a decreasing field size distribution and quite sharp changes in the price of oil. In fact, when oil prices began to increase from 1973 to 1981, PRT was increased from 45 per cent to 60 per cent, and later to 70 per cent in 1980. When the oil price reached a peak in 1981, SPD was introduced. A relaxation of the system came about after the decline in oil price starting in 1983.

From the balance of arguments, it can be concluded that some degree of flexibility is appropriate to the regime so that it has the capability to adjust to changes in the external environment.

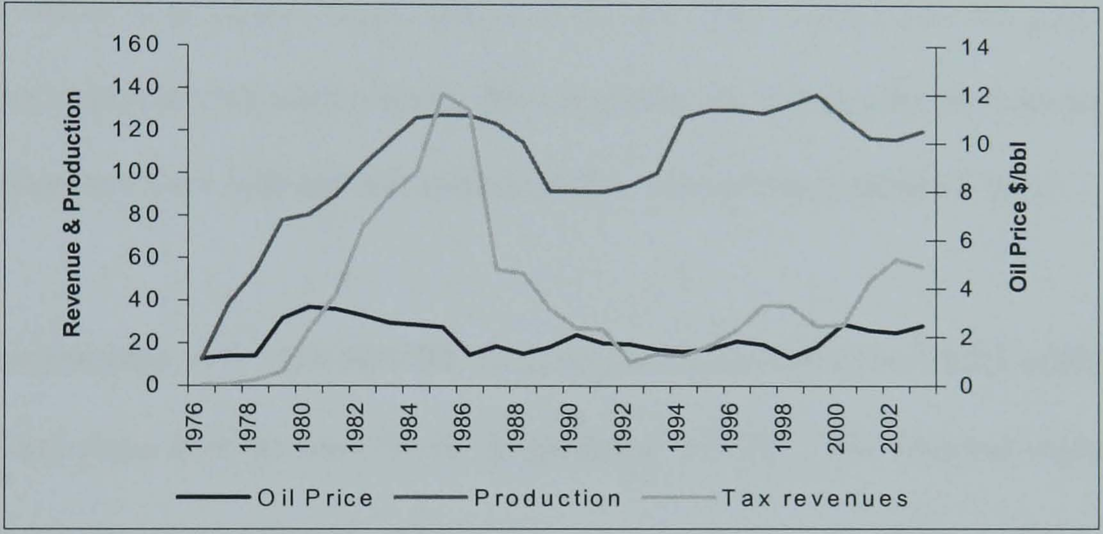
However, it is also argued that regime modifications should not be undertaken on a frequent basis, be of a major or structural nature nor undertaken without advanced warning. Oil prices are volatile and consequently it is almost impossible to track every change. This explains why several authors have criticized the UK Government for changing the regime in response to upward movements in crude oil prices. For instance, Rowland (1983) describes such measures as "an ill-conceived move based on a myopic view of how the oil industry operates, of the factors affecting the oil industry and of the burdens imposed by the cumbersome North Sea tax structure" (p.202). Noreng (1980) argues that the UKCS fiscal regime is not sensitive to changes in oil prices while Nelsen (1991) maintains that while it appears that both the UK and Norway imposed a tax system in response to oil price changes, it seems that this was true only for Norway. In the UK, however, the objective was often to increase the Treasury's take from the UKCS.

The second important conclusion that can be derived from the analysis of previous studies' arguments is that the UK fiscal regime is complicated and several authors consider such complications unnecessary. This is particularly true for PRT and the complex nature of the differing reliefs and allowances available.

Thirdly, the regime is argued to lack neutrality, as it can affect decisions like the development of marginal fields, early abandonment or reduction in exploration activity. Royalty, in particular, is argued as being a typical non-neutral tax.

In fact, after its abolition in 1983, exploration and appraisal expenditures rose from £816M. in 1987 to £1,955M. in 1991, and between 1989 and 1993 the UK had the largest number of new field wildcat wells drilled (516) in the world (UKOOA, 2001). This increase in activity was accompanied by an increase in Government revenues, as Figure 3.1 shows.

Figure 3.1. Oil Price, Production & Tax Revenue[28]



The abolition of PRT in 1993 also had a similar positive effect on both the levels of activity and tax revenues. Nevertheless, it is important to stress that PRT generates the largest share of revenues for the Government compared with Royalty and CT. It has produced almost £42bn. for the Exchequer since it was introduced in 1975, compared with £23.2bn. from CT and £20.2bn. from Royalty (NAO, 2000).

The generation of revenues for the Government leads to the fourth conclusion, also derived from the arguments raised in previous studies.

It can be seen from Figure 3.1 that tax revenues reached a peak in 1985/6 at about £11.5bn. but are currently much lower. In the early 1990s Government receipts from UKCS activity fell to their lowest levels. Production on the other hand initially peaked in 1985 at 127.6bnt, but by 1995 it had risen to 129.9bnt and finally, in 1999, it peaked at 137bnt.

This raises the issue of whether the Government is receiving an appropriate share of revenues. Miller et al. (2000) argue that even the pre-1983 regime was not generating a fair share of revenues, the reason being that companies do not pay for licenses to extract oil: these licenses were and still are "allocated free after a beauty contest" (p.1).

From these findings, it is clear that the fiscal regime applying to the UKCS suffers from several limitations that go back to its beginnings in 1975. The original regime was weakened by the many changes introduced in a relatively short space of time, adding further to the administrative burden.

The Select Committee on Energy (1982) highlights such limitations and argues that "the tax system, at its current level of complexity and frequency of change, has now passed the point at which its impact can be said to be broadly neutral and a substantial risk exists that development is being discouraged."[29]

---

[28] Data Source: Inland Revenue (2003) & DTI (2003).

[29] As referred to in Rowland (1983), p.1.

3.4.1. A CHALLENGING SITUATION

Since 1975, the UKCS has undergone major change, which has had important consequences mainly on the Government fiscal policy. One fact that clearly emerges is the maturity of the UKCS. "North Sea oil, the precious resource that has contributed hundreds of billions of pounds to the UK economy, is now slipping into history" (Reuters, 2004, p.1).

Over the last few years, the UKCS has experienced an increase in the number of producing fields, which have increased three-fold since 1985. In 2001, 21 new field development projects were approved by the DTI, more than double the number approved in 2000 (UKOOA, 2001). As might be expected, however, since oil was first discovered on the UKCS the average size of discoveries has fallen greatly.

The larger fields (such as Forties, Brent and Ninian), with an average size above 200mmboe, were discovered in the early phases of exploration and were brought into production between 1975-1979. The fields found during subsequent periods have become progressively smaller, with an average discovery size of 25 to 30mmboe and an average commercial discovery size of 64mmboe. By 1996, well over half the fields in the UKCS were in the small category[30] (Sem & Ellerman, 1997).

[30] Appendix A illustrates the general trend reflecting the general decrease in the size of fields brought into production in the UKCS over the period 1975-2000.

The production from the 13 original large fields has fallen substantially, although they still contribute more than 15 per cent of total UKCS production. By comparison, the 69 fields that were discovered between 1995-1999, produce in total less than half of the oil coming from the first fields (Zittel, 2001). UK oil production peaked in 1999 at 2.8mmbbl/d and is forecast to decline by about 60 per cent over the next ten years. Today, around 47 per cent of the UK's 63bnbbloe combined oil and gas reserves have been produced (Ruairidh, 2003). From the UK's estimated total endowment of oil (20bnbbls), about two thirds has been already consumed and about one third (11bnbbl) remains for future production (Zittel, 2001).

Another peculiarity of the UKCS that can act as a constraint to Government fiscal policy is the relative international competitiveness of the province. It currently ranks 19th globally in terms of the average commercial discovery size (Scottish Council for Development and Industry, 2002). According to the Scottish Council for Development and Industry (2002), since 1998, the scale of discoveries in other parts of the world, notably Kazakhstan, Angola, Brazil and Nigeria, have been an order of magnitude higher than the average discovery size in the UKCS. Additionally, the exploration and development costs in these regions are typically much lower than in the hostile and technically challenging UKCS environment. Morgan (2000) argues that with \$10 a barrel operating costs in the UK North Sea compared with \$5 in Angola and \$6 in Gulf of Mexico, it is going to be harder to continue to attract investment in competition with the larger and more commercially attractive opportunities available elsewhere in the world.

3.5. SUMMARY & CONCLUSION

In order to meet the objectives of this thesis and carry out the evaluation of the UK petroleum fiscal regime, the first step is to analyse the establishment of the regime in 1975 and its evolution from its roots through to the Budget changes introduced in 2002. This chapter covers such analysis. It studies the basic structure of the fiscal regime, which was designed to secure an appropriate share of profits for the nation while offering stable, attractive and economically sound investment conditions to the oil industry (Inland Revenue, 2002). The 1975 package was based on Royalty, PRT and CT, which together generated a marginal tax rate of approximately 77 per cent. The regime has, however, changed over time with frequent alterations made to the level of Government take and to structure of the regime. Currently, marginal tax rates are between 70 per cent and 40 per cent depending on the age of the field in question. The various changes have generated considerable controversy, which have not been resolved. Divergence in the reaction to those changes has frequently been noted.

From the analysis of the evolution of the regime and the subsequent controversies, the chapter derived certain conclusions regarding the UK fiscal regime. At this stage of analysis, it can be said that the regime suffered from several limitations, including the lack of neutrality, simplicity, stability, the high degree of uncertainty imposed on investors as a consequence of the regime instability, and the low generation of tax revenues.

An additional issue, the current maturity of the UKCS reserve base, is also addressed as it is of particular significance for taxation policy and is often referred to in previous studies. Given the size of the remaining fields, the decrease in the production from mature fields and the increasing range of alternative global investment opportunities for oil companies, taxation will be of much greater significance than in the past.

Although times have changed, the UKCS can still provide opportunities of which the discovery of the Buzzard field is an example. Similarly, advances in technology can significantly help in reducing exploration and development costs. Finally, many of the new emerging regions competing with the attractiveness of the UKCS suffer from political instability. "Maturity brings with it all kinds of advantages- in particular the existing of infrastructure and great body of knowledge concerning the geological nature of the area" (Rutledge & Wright, 2000, p.9). The Government, through the design and implementation of an appropriate fiscal regime that improves the trade off between fiscal revenues and companies' interests (as discussed in Chapter 2), plays an important role in ensuring the longevity of the UKCS and sustaining a high level of investment.

The findings of this chapter are essential in understanding firstly the reasons that led to the establishment of the current system and secondly the arguments used in the debate created by the different changes. This analysis leads to the empirical evaluation of the fiscal regime, which will be carried out both qualitatively and quantitatively. The next chapter discusses the qualitative aspect of the UKCS fiscal regime.

CHAPTER FOUR

SURVEY OF OPINIONS RELATING TO THE UK NORTH SEA PETROLEUM FISCAL REGIME

4.1. INTRODUCTION

The previous chapter analyzed the principal controversies surrounding the UK petroleum fiscal regime based on the findings of previous studies. In order to proceed with the assessment of the regime, a more rigorous and substantial evaluation is required. This chapter initiates the empirical analysis of this thesis and carries out a qualitative assessment of the regime. In particular, it describes and analyses the "Survey of Opinions" solicited from key players in the UK oil sector, with respect to the fiscal regime and the chief changes thereto over the last 27 years. The findings are then synthesized in an attempt to find ways in which the existing regime might be improved or how an alternative regime, which is more acceptable to Government and industry at present, might be created.

The survey was conducted between March 2001 until August 2002. A questionnaire was designed to cover the key aspects of this thesis, chiefly the effects of the major changes in the UK oil tax structure. It also addresses the attractiveness of the UK North Sea province identifying in turn a set of alternatives, which may be preferable to existing policies.

The questionnaire was sent to tax specialists in selected oil companies operating in the UKCS, as well Government institutions, and leading consultancy companies. In addition, face-to-face interviews were carried out.

A survey of this type has a major contribution to make to the body of research and is valuable for four main reasons.

Firstly, it is a unique undertaking in this field of economic research. It analyses the issues from the perspective of the two main constituents namely; the Government and the petroleum industry/oil companies with respect to petroleum taxation. These two bodies generally have competing objectives and consequently their perspectives on petroleum taxation, as discussed in Chapter 2, can be quite different. These perspectives are clearly addressed in the survey, based upon a specific set of questions focused on soliciting the views of both sectors.

Secondly, the survey incorporates the most recent views of tax specialists from within both the Government and the oil companies. As such, it provides significant information coming directly from those specialists and benefits from their expertise, especially of those dealing with taxation over a considerable period of time and under changing circumstances. More importantly, this kind of analysis is unlikely to be found in the literature associated with this important topic, nor to be fully captured in the quantitative assessment of the regime.

Thirdly, the survey allows a more detailed evaluation of the fiscal regime and an in depth understanding of the effects of the different amendments in the tax structure, particularly from both the Government and industry standpoints. Further, it more appropriately reflects the complex commercial and technical realities of the UKCS, which appear to be absent in several previous studies, which also tend to reflect a more partisan approach to the issues.

In fact, since efficient petroleum taxation raises complex problems, as discussed in the previous two chapters, "it requires considerable insight into the oil industry" (Blinn et al, 1986, p.233). "If we could obtain from the companies their forecasts about how profitable they expected their operations to be under the current fiscal regime, compare their expectations about the profitability of one oil province with their expectations about the profitability of another province and to plot these changing expectations over time, then we would certainly be acquiring useful information that cannot be provided by an outside model" (Rutledge & Wright, 1998b, p.8).

Finally, the survey provides significant guidance for the quantitative analysis in the following chapters, chiefly in that it identifies the most common methods and techniques adopted by the respondents when evaluating the effects of taxation.

The design of the survey, its process and results are covered in this Chapter. Section 4.2 describes the design of the survey and its methodology. Section 4.3 summarises the findings and Section 4.4 discusses those findings. Concluding remarks are provided in

Section 4.5. The cover letter, questionnaire, and respondents' replies are all presented in Appendix B.

4.2. SURVEY DESIGN

This section explains the manner in which the survey was designed and carried out. Firstly, it discusses the design of the questionnaire, then proceeds with the selection of the sample surveyed including the identification of any source of bias. This is followed by a description of the techniques used to carry out the survey and, finally, a review of the quality of responses.

4.2.1. QUESTIONNAIRE DESIGN

The analysis performed in Chapters 2 and 3 led to the establishment of particular criteria and study of the principal issues that are essential to evaluating oil taxation policy in the UK. As such, that analysis provided guidance for setting the survey questions. In turn, these questions are designed to specifically capture the perceptions of different respondents on four key areas, namely:

i. Evaluation of the main fiscal packages that were introduced for oil extraction activity in the UK, and in particular the basic 1975 package and the principal amendments thereto in 1983, including the abolition of Royalty[31], in 1993 the abolition of PRT[32] and in 2002 with the imposition of the Supplementary Charge. This work is fundamental to the research hence it is covered in most of the questions but is directly addressed in the first four questions.

ii. Risk-sharing and financial evaluation techniques. The issue of risk sharing was discussed in detail in Chapter 2, and is of particular importance to the research for two reasons. Firstly, it identifies the extent to which the fiscal regime shares risk with investors as well as its impact on investors' confidence. Secondly, it leads to identifying the techniques used to incorporate risk in the evaluation of a project's profitability. For consistency, the most popular techniques will be adopted in the quantitative analysis section of this thesis. This subject is addressed in Question 5.

iii. International competitiveness of the UK oil fiscal regime. This issue is essential for a complete analysis of the topic, especially given the global nature of the industry, with oil companies operating in many different countries with a variety of fiscal terms. Consequently, the fiscal terms offered by the various petroleum producing countries play an important role in attracting and encouraging oil exploration and production.

---

[31] On fields that received development consent after 1983.
[32] On fields that received development consent after 1993.

The question of the international competitiveness of the UK oil fiscal regime is addressed in the survey in the light of the criticism that it is the "weakest in the world", as described by Rutledge & Wright (1998a, p.801). It is covered in Question 6 and its three supplementary questions.

iv. The future of the UK North Sea. As discussed in Chapter 3, the changing commercial environment of the UK North Sea province has a major impact on the Government fiscal policy[33]. Consequently, understanding the future of the province provides guidance as to the appropriateness of the regime in place. This is addressed in the final question of the questionnaire. This question further investigates how the different players view the future of UKCS and attempts to identify any divergence in the perception of the oil companies and the Government.

In total, the questionnaire consists of seven questions designed to solicit information from the principal stakeholders in the UK North Sea on these four issues. However, because some questions include sub-sections the actual total number of questions amounts to 15. The questions are presented in open-ended manner so as to solicit a more detailed expression of opinion[34].

It is important to stress that two modifications were made to the original questionnaire in the course of undertaking the survey. This was done for two reasons.

---

[33] See Chapter 3, Section 3.4.2.

The first reason is to incorporate the tax changes in April 2002. This alteration, however, does not generate a dramatic difference because in the original version Question 4 addresses the 1998 tax proposals[35], which incorporated the possibility of imposing an additional charge. This option was implemented in the 2002 changes. The second reason is to adapt some questions to the role of the respondent and the institutions represented. As such, questions addressed to Government institutions are formulated differently than those addressed to the oil companies. Nevertheless, consistency of meaning is maintained throughout. A detailed explanation of the modifications introduced is given in Appendix B.

4.2.2. SAMPLE SELECTION

In this survey, the sample is not a simple random one. It is rather purposive, as is the norm in qualitative research of this type. A purposive sample involves selecting "small numbers of people with specific characteristics, behaviour or experience… to facilitate broad comparisons between certain groups that the researcher thinks likely to be important" (Walker, 1988, p.30). Consequently, in this survey, the size of the sample is not as critical as the expertise and knowledge of the respondents both with respect to UK oil taxation, as well as familiarity with the subsequent amendments to the regime and the computational complexities involved.

---

[34] The questionnaire is presented in Appendix B.
[35] See Chapter 3, Section 3.2.4

As such, the target population in this survey is the tax experts, mainly at the head of tax level, working either within Government or the oil companies. Tax experts working with major consultancy companies are also included within the target population, because of their experience in working with oil companies.

The first step in the selection process is to establish a list of the different Government institutions, oil companies and consultancies, from which the sample is to be selected. The selection of Government institutions is a straightforward task, since there are only a limited number of relevant institutions. The task is somewhat more complicated with respect to the selection of oil companies, given the number of companies of varying sizes operating in the UK North Sea.

A complete list of oil companies is obtained from the Institute of Petroleum directory, which also includes their addresses. Details of each company are checked by visiting their respective websites and an indication of the relative size of their operations is provided by reference to the General Economic Model (GEM) from WoodMackenzie[36].

Companies are then divided into two groups: small and large companies referred to respectively as "independents" and "majors". The majors constitute the main target population in this survey because of their long-term involvement in the UK North Sea, effectively since oil exploration activity began in the late 1960s and early 1970's.

---

[36] This model provides the database on both oil companies and oil and gas fields in the UK North Sea. It is explained in detail in Chapter 6.

Furthermore, such companies hold a portfolio of fields including many mature fields subject to Royalty, PRT and CT. As such, the tax experts in these companies can provide detailed information regarding the development of oil taxation since 1975, and the effects of the past amendments on the company's activity.

However, the majority of independents started operating relatively recently- some in early 1990's but many others in the late 1990's. Further, the activities of these companies are mainly focused on the smaller oil fields. As such, tax experts in these smaller companies may not always be able to provide substantial background perspective on development of the fiscal regime over the last 27 years as it effects these smaller companies. Nevertheless, their contribution is valuable especially with respect to the impact of the current regime, and the fact that the smaller sized companies are currently the new wave of operators on the UKCS.

Finally, a list of the major consultancy companies based in the UK is prepared. Such companies are well established in the UK and provide advisory services on a variety of problems for various types of businesses, including oil companies. They also publish special reports, chiefly on oil activity in the UK. Consequently, tax experts working for such companies can provide considerable information regarding the impact of taxation from a range of perspectives.

As soon as the lists are prepared, the next step is to select the sample of the tax specialists. The heads of tax involved directly with taxation in the UKCS from Government institutions are selected and contacted. Their contact details are provided on the institutions' website. A group of 7 consultancies and 10 oil companies is randomly selected, including 6 majors and 4 independents. Details of some of the tax specialists are available online, whilst contact with others has come as a result of the 25th IAEE Annual Conference, 2001, in Aberdeen. For the remaining respondents, the companies are directly contacted and details of their head of taxes are requested. In total, the panel of respondents consists of 19 tax specialists.

4.2.3. SOURCE OF BIAS

It is important to take in consideration certain potential sources of bias, mainly resulting from the selection of respondents as well as the lack of randomness. In order to carry out the survey, tax specialists in Government and companies are selected, however, these specialists can have interest in more complex tax regimes. The lack of randomness can be reflected firstly in the high proportion of experts from oil companies and consultancy companies, compared with representatives from the Government. Secondly, it is replicated in the higher proportion of respondents from large oil companies relative to the proportion of respondents from small companies.

Nevertheless, these possible sources of bias do not weaken the validity of the survey, for the following reasons.

Firstly, given the complicated aspect of the UK petroleum fiscal regime resulting mainly from the interaction of the various taxes and their reliefs, tax specialists are considered to be the most suitable source of information particularly with respect to the details of the regime.

Secondly, the sample selected can be described as a stratified sample, because it involves "taking random samples but within subsets of the population so determined that the sample will definitely be representative of the population" (Sapsford, 2001, p.8). In fact, adopting complete randomness in the selection process is unlikely to produce either a representative sample or valid results. In this case for instance, there are only two major Government institutions, involved with UKCS oil taxation. Consequently, if the sample is randomly selected, it is unlikely that the Government institutions are included.

Thirdly, because there is a wider panel of oil and consultancy companies compared with Government institutions, it is not surprising to find such a high representation of the industry within the sample. In essence, the sampling process is aiming to produce as good a representation as possible of the population.

Finally, because the survey investigates the effects of the main amendments of the regime since 1975 on companies' performance so as to ensure validity, the sample by definition needs to include companies with significant experience within the UKCS. These are likely to be the large companies that hold a large portfolio of assets in the UKCS in contrast to the smaller companies.

This chiefly justifies the higher proportion of larger companies relatively to smaller ones. Nevertheless, the inclusion of consultancy companies partially overcomes this weakness, because these companies deal with different companies, regardless their size or experience in the UKCS.

4.2.4. SURVEY TECHNIQUE

The principal survey technique is an interview based on the seven key questions presented in Appendix B. This data collection method is the most commonly used survey technique, in particular for qualitative data collection (Fink & Kosecoff, 1985). The benefit of applying the interview technique consists mainly in the personal contact between the interviewer and the interviewee. This allows questions to be expanded to allow for wider discussions that generate in depth information and provide the opportunity to ask follow-up questions.

The selected specialists were contacted by e-mail or/and phone and were invited to participate in the survey. In order to encourage participation, respondents were promised confidentiality. The author requested a meeting at which to conduct an interview. Ahead of the meeting the author sent a copy of the questionnaire, so that the respondent could become familiar with the questions prior to the interview taking place. The interviews were performed at the interviewee's place of work and lasted about one hour, on average. During the interview, data was recorded by note taking.

In five cases, it was difficult to arrange a meeting for interview because of time and distance involved. In these cases, some were sent the questionnaire and they replied by e-mail.

4.2.5. QUALITY OF RESPONSE

In total 19 questionnaires were sent, 10 interviews were carried out and 5 questionnaires were replied by e-mail and 4 were not returned. Consequently, the response rate was approximately 80 per cent.

Among the non-returned questionnaires, three are from oil companies and one from a consultancy company. Two respondents apologized for not being able to provide the necessary information. Of these the first, an oil company, argued that the information required was confidential, whereas, the other respondent, a consultancy company, mentioned that the questions required detailed information that only an oil company, not a consultancy company, could provide. The third respondent sent an e-mail to the author to clarify one question and promised to reply soon. However, the author did not hear from the respondent again, although the author tried to re-contact the respondent. The fourth specialist from an oil company did not respond despite three attempts to contact the individual.

4.3. FINDINGS

This section summarizes the main findings of the survey[37]. These findings are organised in four sub-sections, each sub section illustrating one of the four main topics of this survey. As respondents were promised confidentiality, different notations are used. These are presented in Table 4.1.

Table 4.1. Respondents Notation

Notation	Institution	Total Respondents
Respondent Gn	Government	2 (Respondents G1 and G2)
Respondent On	Oil Company	7 (Respondents O1, O2, O3, O4, O5, O6 and O7)
Respondent Cn	Consultancy company	6 (Respondents C1, C2, C3, C4, C5 and C6)

4.3.1. ASSESSMENT OF THE PRINCIPAL FISCAL PACKAGES

Questions 1 to 4 address the impact of the principal fiscal packages that have been imposed on oil activity in the UK namely the 1975 package, the abolition of Royalty in 1983, the abolition of PRT in 1993 and the imposition of the Supplementary Charge in 2002.

[37] The detailed answers are provided in Appendix B.

4.3.1.1. 1975 FISCAL PACKAGE

From a Government perspective (Respondents G1 and G2), the 1975 fiscal package is justified as follows. The Royalty element gives oil companies the right to exploit the oil resource, which is owned by the Government. As such, the Government receives a specified part of the production as a compensation for the depletion of its assets. The PRT element applies as a super-profits tax, aimed at capturing "a share of the economic rent from oil activity" in the UKCS (Respondent G1). The CT element is imposed because all companies in the UK pay this income tax and oil companies are no exception.

Respondents C1 and C2 made additional comments. Respondent C1 argues that since oil was a new experience for the UK, the country had broadly to follow what other countries were doing relative to their oil extraction activity. Royalty was a common instrument applied in other countries to oil production, albeit mainly to onshore fields. However, Royalty allowed only partial deductions of individual field's costs although their location differed one from another. PRT "unlike Royalty, provided for the deduction of all direct costs... Had Royalty applied to a more homogeneous cost base, the Government wouldn't have needed the PRT" (Respondent C1).

Respondent C2 argues that the reason for imposing PRT was that in the wake of the high oil prices in the 1970s a windfall tax was required on top of Royalty and CT. However, the respondent adds that the regime was not sensitive enough to changes in oil prices.

All respondents from the oil industry[38] agree that the 1975 package was unsatisfactory, mainly as the result of the imposition of Royalty and the high marginal tax take.

"Investments within an existing PRT field ring fence are adversely impacted by the 69 per cent Royalty/PRT/CT regime" (Respondent O1).

"The regime acts as a disincentive to investment... Activities had dried up due to the very high marginal tax rates then in place" (Respondent O3).

Respondent C1 adds that the main limitation of the 1975 package is its complication, which imposed an additional administrative burden.

4.3.1.2. ABOLITION OF ROYALTY

From a Government perspective, Respondent G2 argues that as Royalty does not allow the deduction of all costs, it can distort the investment decision particularly with respect to marginal activities. The respondent further adds that the abolition of Royalty in 1983 did not generate a loss in revenue for the Government.

"Had the tax still applied "the development of many fields would have been stopped and the Government wouldn't have generated more revenues" (Respondent G2).

[38] Except two respondents, since the companies they work for were not involved in the UKCS before 1993.

Agreeing with such a statement, Respondent C2 maintains that Royalty was abolished because it was not a significant source of revenue for the Government.

All respondents from oil companies that were subject to Royalty payments (O1, O2, O3, O5 and O7) and respondents from consultancy companies (C1-C6) comment on the negative aspect of Royalty, in that it is imposed on gross revenues rather than profits. For instance, Respondent C3 describes Royalty as a tax that "hits in a more aggressive way".

However, in terms of the effects of Royalty on early abandonment and marginal fields a divergence in views is noted.

Firstly, 31 per cent of respondents agree that Royalty leads to early abandonment.

"The point of abandonment is where marginal cost equates to marginal revenue. This means that Royalty is a more important determinant of abandonment than either PRT or CT since it is a fixed cost of production" (Respondent C5).

Opposing such views, both Respondents G1 and G2 from Government institutions argue that Royalty does not have a significant impact on early abandonment given the possibility of Royalty remission.

"If Royalty results in the shortening of the field life, then companies can apply for Royalty remission" (Respondent G1).

"There is a discretionary provision to repay Royalty to oil producers if they consider that it will maintain the development of petroleum resources of the UK. This mechanism would encourage incremental production from older, Royalty-paying fields" (Respondent G2).

Secondly, concerning the effects of the abolition of Royalty on decision making on the development of marginal fields particularly, a divergence within the industry opinions is noted. Among 11 respondents, seven argue that the abolition of Royalty encouraged the development of marginal fields.

"The improvements in the fiscal regime made in 1983 led to a material increase in development activity that lasted through the 1980's despite the rapid real decline in the oil price" (Respondent O3).

"At the time it was particularly important for some new developments to proceed" (Respondent C6).

Among the other respondents, three respondents maintain that the abolition of Royalty, if it had any impact, it was "minor".

"The abolition of Royalty had a modest impact but nonetheless positive because it is an allowable deduction for PRT and CT. But the net impact is relatively small" (Respondent C4).

"The abolition of Royalty is not a material factor in determining investment decisions. It only affects the end of field life and any incremental expenditure to extend the field life" (Respondent C5).

"Fiscal terms alone will not influence marginal developments or the timing of abandonment" (Respondent O2).

Respondent O3, however, agues that it was the reduction in the overall tax burden, as a consequence of abolishing Royalty, which led to an increase in activity.

"Prior to the fiscal changes in 1983 development activities had dried up due to the very high marginal tax rates then in place" (Respondent O3).

Finally, Respondent C2 highlights a different limitation of the 1983 fiscal changes, which, because they came as a surprise, helped to create an impression of instability.

4.3.1.3. ABOLITION OF PETROLEUM REVENUE TAX

Both Respondents G1 and G2 argue that PRT was the main source of revenue in early years of its imposition. However, by the early 1990s PRT was not generating sufficient revenues and that is why it was abandoned.

"PRT was expensive to the Government. There was a lot of exploration but the fields discovered did not yield sufficient revenue for the Government, given the different reliefs" (Respondent G2).

Among those reliefs, Respondent G1 argues that the oil allowance was the most expensive to the Government. The respondent further maintains that after abolishing PRT on new fields in 1993, more revenues were generated, mainly as a result of abolishing offsetting exploration costs.

21 per cent of respondents from the industry argues that the abolition of PRT was beneficial for the industry.

"This directly encouraged the development of Andrew, ETAP and the first production West of Shetland. The Schiehallion field is now the largest producing oil field in the UKCS" (Respondent O3).

The respondents further referred to the inefficiency and complexity of PRT.

"The pre-1993 fiscal regime subsidized exploration activity, which led to an inefficient allocation of capital" (Respondent O3).

"The structure of PRT could lead to counter investment decisions or gold-plating" (Respondent C2).

However, 57 per cent of respondents argue that the abolition of PRT was beneficial but it also led to the loss of the different "generous" reliefs, particularly the oil allowance that protected marginal fields from paying the tax.

"The retention of oil allowance is considered to be of prime importance to the more marginal fields" (Respondent O2).

"The oil allowance is must be the most valuable relief" (Respondent C6).

On the other hand, 22 per cent of respondents maintain that the abolition of PRT was damaging. Two respondents (C6 and O1) relate this effect to the loss of PRT reliefs.

"There has been a marked decline in exploration activity since Exploration and Appraisal Relief (E&A) was abolished and PRT for new fields ... the oil allowance must be the most valuable relief" (Respondent C6).

"Prior to 1993 all PRT allowances had a significant beneficial impact in encouraging activity" (Respondent O1).

Respondent C2 relates the detrimental effect to the resulting instability.

"The Government abolishment of PRT was unexpected. This created a lot of uncertainties" (Respondent C2).

4.3.1.4. THE SUPPLEMENTARY CHARGE AND THE 2002 CHANGES

Five respondents (G1, O2, C4, C5 and C6) were interviewed after the 2002 changes. Respondent C6 argues that the abolition of Royalty and the Writing Down Allowance as the main benefit of the changes.

"Abolition of Royalty is... important not least in terms of allowing the Government to retain its creditability... The First Year Allowance is the only thing that compensates for the new 10 per cent SCT " (Respondent C6).

Opposing such a view, Respondent C4 maintains that commented "increasing the CT is not appropriate currently". Similarly, Respondent C5 argues that "although the Government has changed the headline rate of CT, it made fundamental changes to CT: the Supplementary 10 per cent does not allow the deduction of interests. This can affect companies' decisions in the manner in which they finance their investments. As a consequence small companies will use more imaginative and more risky routes to raise capital".

As for the destabilizing effects, Respondent G1 argues that dropping the proposed changes after a decline in oil prices (in 1998) did not mean that it would never be considered. In agreement with such statement, Respondent O2 maintains that "the latest changes, although unacceptable to the industry, primarily because of their destabilizing affect, were in fact not totally unexpected".

The other respondents addressed the 1998 proposals, which compare an application of a Supplementary Charge with a re-introduction of PRT. The industry does not normally favor any increase in tax, however when faced with either an increase in the CT rate or an application of PRT, 93 per cent of respondents *prefer* the former option.

"The Government could equalize the tax effect on fields by abolishing all upstream taxes and replacing this with a supplementary rate of CT, which delivers the same overall yield. This would remove the unnecessary complexity of the current system and remove disincentives to invest in mature fields" (Respondent O5).

"It is essential that any tax regime is focused on profit and not revenue. The CT Writing Down Allowance (WDA) ensures this condition is met. The relative fast depreciation provided by the WDA ensures that the after tax return is not significantly less than the before tax return, and consequently the CT regime does not inhibit activity" (Respondent O1).

"This best suits the nature of geological risk in the UK" (Respondent O4).

On the other hand, Respondent O4 rejects both alternatives, while Respondent O7 agrees that the abolition of Royalty can be a beneficial step but,

"If this has to be paid for by robbing Peter, then the status quo is better overall" (Respondent O7)

4.3.1.5. ALTERNATIVE REGIME

All respondents from the industry argue that the Government needs to maintain the stability of the regime.

"Companies require a stable fiscal regime if they are to invest in long timeframe high-risk projects" (Respondent O1).

"The recent change has made the UK again an unstable tax regime and there will be companies who will not invest in marginal projects with a long payback period for fear they will get hit again later" (Respondent C6).

Furthermore, 93 per cent of respondents are against the application of any special tax, whether PRT or Royalty.

"The least worst option is to change CT rather than applying PRT. CT is a corporate tax thus it takes into account the company's overall portfolio, not simply a single project" (Respondent C5).

"The most appropriate fiscal system is...namely CT only. This ensures that the upstream industry is treated in the same way as any other industry in the UK. Since the returns in the oil sector in recent years have been below those that can be earned elsewhere in the economy, the intellectual case for additional taxation on oil and gas activities is not sustainable" (Respondent O3).

Respondent C4 argues that PRT should not be applied because "it is a complicated tax as it stands, plus it is likely to create greater uncertainty, thus affecting investment decisions...Changing CT is simpler, more direct and unlikely to cause significant distortions and create greater uncertainty".

Respondents C2 and C3 are against the re-application of PRT because it does not suit the current reality of the UK oil industry.

"The oil industry is a competitive industry, thus over the long-term there are no super profits" (Respondent C2).

"PRT is a super profit tax, so to charge a super profit tax, companies should be making super profits in each field... this is not the case anymore" (Respondent C3).

Two respondents (G2 and C6), however, pointed out their preference to PRT. Respondent G2 argues that "technically, nothing is wrong with the PRT". Respondent C6 argues that "the original PRT was...a fair system which guaranteed to the company a full return of costs and an annual return on investment before any special levy applied". But the respondent further debates that re-introducing PRT "after nearly ten years would be very difficult". Additional alternatives are suggested namely;

"Link CT changes to the behavior of oil prices" (Respondent C4),

"The recent changes need to be supplemented by additional incentives to explore (say, a 25 per cent supplement on Exploration costs)" (Respondent C6),

"Apply RRT similar to Australia" (Respondent G2),

and,

"Apply a flat CT, but fields, such as Don, need subsidy" (Respondent C4).

4.3.2. RISK-SHARING AND EVALUATION TECHNIQUES

The second subject in this survey is the extent to which the UK oil fiscal regime is risk sharing and/or imposes a fiscal risk, and additionally the evaluation techniques that companies adopt so as to incorporate risk in their investment decision analysis. On the first issue there was a wide variety of opinions.

Four respondents (C1, C2, C4 and C5) argue that the system in its early stages was more risk absorbing, since according to these respondents, a high tax take was needed to compensate for the risk the Government was willing to share the oil industry.

"High tax rates work perfectly as risk sharing" (Respondent C1).

Three respondents (G1, O1, and C1) argue that since PRT is a cash flow tax it is more risk absorbing then Royalty, as the latter is paid as soon as production commences.

"A cash flow tax is when the Government takes an equity share, which equals a percentage tax take from the cash flow (CF). In this case, the Government is facing a risk-sharing situation. Both the Government and companies will have the same CF (e.g. negative tax at the early stage of investment)... PRT works well as a CF " (Respondent G1).

"To the extent fiscal regime is profit based, an equitable sharing of risk between Government and industry occurs. Royalty does not result in an equitable risk sharing since it is not profit based" (Respondent O1).

Four respondents (O4, O5, C3 and C6) refer to the instability of the tax regime in creating an uncertain fiscal environment for investors who "dislike uncertainty". When evaluating a project, investors base their evaluation on an average life of over 20 years and as such include in their analysis a stable fiscal outlook. Consequently, these respondents argue that the stability of the fiscal regime is crucial for creating a healthy investment environment and maintaining the competitiveness of the country.

"The company would be unlikely to consider investments in countries where the fiscal system is not properly defined or is known to be unstable" (Respondent O4).

"The real threat of an adverse tax change as proposed in March 1998 caused investment decisions to be deferred until the fiscal uncertainty was resolved. Maintaining fiscal stability is a key element of delivering investor confidence and UKCS competitiveness"

(Respondent O5)

Two respondents (O3 and C2) comment on the partnership between the Government and the industry as reducing investors' risk.

"The fiscal risk will never go away but with meaningful discussions between the industry and Government at such forums as PILOT we believe that the Government is committed to ensuring that the UKCS remains competitive" (Respondent O3).

On the other hand, three respondents from oil companies (O2, O3 and O4) argue that oil companies developed their own strategies to find ways to adapt and learn to live with risk.

"Since 1984, the company policy has been to expand overseas and diversify away from the UK tax changes" (Respondent O4).

"Fiscal changes do not especially alarm us because risk and uncertainty are inherent in the business and the UK is no more risky than anywhere else" (Respondent O2).

"The company has been a key player in the development of the UKCS for over 30 years and has learnt to live with the fiscal risk" (Respondent O3).

Such comments agree with the Mitchell (1982) concept of risk diversification, referred to in Chapter 2[39].

Concerning the evaluation techniques that companies use to evaluate their projects and incorporate risk, the survey results indicate that several methods are used. The most common evaluation method indicated by 87 per cent of respondents is identified as the Net Present Value (NPV) method. Risk, namely oil price and geological risk, is incorporated mainly through sensitivity analysis (O3, O5, O6, O7, G2, and C1) and the use of higher discount rates (O4, O5, C4, and C5).

However, Respondent O6 argues that "no one will invest with just a positive NPV for 10 per cent discount rate", while Respondent G2 refers to the importance of understanding the companies' decision making criteria so as to gain an understanding as to whether a project is acceptable or not. However, this is a time consuming process.

[39] See Section 2.3 on Risk Sharing

Other techniques are also identified but at a lesser extent, namely separate cash flow discounting (Respondent C5) and Modern Asset Pricing Model (Respondent C4). Two respondents (O7 and C2) refer to the Real Options Theory. However, Respondent O7 argues that "the theory is currently on-fashion but it is too complicated to be applied in the daily operations of the company" and Respondent C2 adds that the theory is “less likely to work in the long term".

On the other hand, Respondent O4 argues that "the uncertainties of the regime are not generally factored into risk analysis".

4.3.3. INTERNATIONAL COMPETITIVENESS

As it might be expected, all respondents rejected Rutledge & Wright (1998) argument that the regime is the "weakest in the world" (p.801). In fact, all respondents agree that there are several factors, such as costs, geology, and exploration risk that are essential to include when looking at the international competitiveness of a fiscal regime.

"The fiscal regime cannot be seen in isolation from the prospectivity. Whilst in headline terms the fiscal regime for new developments in the UKCS is more attractive than, for instance, Norway, the fields size are smaller and unit costs higher in the UKCS than for typical new fields in Norway. At the Exploration level Norway offers the potential for large discoveries while the UKCS does not" (Respondent O2).

Consequently, four respondents (O7, C1, C2 and C3) argue the difficulty in comparing the UK oil fiscal regime to other regimes.

"The question is impossible to answer, as each country is appropriate to its own geological facts and circumstances" (Respondent O7).

"The weaknesses or the strengths of the system cannot be measured by the marginal tax rate on fields" (Respondent C2).

The dominant opinion is that the current fiscal regime is "fit-to-purpose" (Respondent G2) and" well-attuned to the economic realities of the UK North Sea" (Respondent O1), where newly discovered fields cannot stand a "harsher" system.

"The current UK fiscal regime largely reflects the maturity of the UKCS and the marginality of likely future developments" (Respondent O3).

"The regime is also geared to maximise UKCS resources" (Respondent C4).

Other respondents (O5 and O6) argue that the regime is required to maintain the competitiveness of the mature oil province. Respondent G1 further maintains that other countries are "more generous, more favourable to oil companies".

4.3.4. THE FUTURE OF THE UK NORTH SEA

All respondents agree that the future level of activity in the UK North Sea is towards a decline. As Respondent C6 points out, "most companies are pessimistic!"

"Recent discoveries are quite small and unlikely to offset the decline from the older fields" (Respondent O5).

"There is a serious decline in the size of new discoveries in the mature shallow water area of the UK North Sea" (Respondent O3).

"There will be little real prospectivity to encourage further investment in the UKCS and activity level will inevitably fall" (Respondent O2).

Two respondents argue that the UK North Sea is unattractive particularly for large companies.

"On an international level, the competition over capital will be more significant over the next few months, many opportunities elsewhere for the big companies, and the UK is not on the list" (Respondent C5).

"The remaining UKCS opportunities are of insufficient scale to attract further investment... Major operators are now attracted to deepwater areas where major fields are still to be found" (Respondent O3).

One respondent (C2) further added that the Government should now worry about the "security of supply rather than...revenues".

Nevertheless, 40 per cent of respondents agree that despite such expectations this does not mean that the UK North Sea era has ended. These respondents argue that it is the Exploration activity, which is in decline not necessarily development and production.

"A lot of discoveries are waiting to be developed" (Respondent G1).

"The North Sea has a brilliant future" (Respondent C5).

Five respondents (O1, O2, O6, and C3) maintain that the oil price is a significant factor in determining both the levels of activity and profitability in the UK oil province.

"The level of activity has probably only been sustained by the recent and continued high oil price" (Respondent O2).

"The behavior of oil and gas prices is a major determinant of the profitability of the region. Activity level will be determined by the development of newly discovered fields" (Respondent C3)

Other respondents (O5, O6, O7, C1, C3, C4 and C5) argue that technology, industry structure, infrastructure, and taxation, are principal determinants of future levels of activity and profitability.

"Very few companies are spending money on Exploration; they are more likely to be spending money on development of existing fields, such as new drilling techniques, new seismic, etc... to recover more oil from these fields " (Respondent C1).

"The small Independents will play a role in the UKCS to develop the remaining resource base"

(Respondent C3)

"There is also a need to ensure that old fields are not abandoned prematurely since there will then be no infrastructure in place from which to produce/transport the new finds"

(Respondent C6).

"The Government... by adopting favourable fiscal policies ...can play an important role in extending the life of the UK North Sea province " (Respondent O5).

4.4. ANALYSIS OF FINDINGS

In this section, the findings of the survey are synthesised in an attempt to ascertain and discuss the distinctive views of the respondents. From these views, conclusions are derived with respect to the characteristics of UK oil taxation relative to the major criteria of an ideal tax, as defined in Chapter 2, and to the arguments of previous studies, as discussed in Chapter 3.

4.4.1. NEUTRALITY

From the different opinions provided on the effects of the major fiscal changes in oil taxation in the UKCS, the UK oil fiscal regime is unlikely to be described as neutral, particularly the 1975 fiscal package and especially Royalty. For instance, Respondent O3 argues "that the key fiscal changes of 1983 and 1993 both led to significant increases in investment activity by the company", as Martin (1997) and Johnston (2003) maintain.

Not surprisingly, all respondents agree that the abolition of Royalty encouraged activity, with 64 per cent referring to the detrimental impact of Royalty on the development of marginal fields. Consequently, it can be concluded that Royalty inhibited oil activity hence it is not a neutral fiscal component.

However, a certain divergence in opinions exists as regards the effect of Royalty on early abandonment, particularly between respondents from the Government and those from the industry. The former argue that Royalty remission overcomes such a problem and only 31 per cent of respondents from the industry argue that Royalty can lead to early abandonment. Consequently, the effect of Royalty on mature fields does not seem to be dramatic hence its abolition in 2002 raises several questions.

Firstly, it seems that by 2002, the Government was convinced that it should abolish Royalty if the production from mature fields was to be extended. However, as Respondent G2 argues, the effect of Royalty as a distortionary tax is difficult to prove in practice because of the volatility of oil prices. Such an opinion is further emphasized with the fact that by 2001 only two cases were presented to the Government for Royalty remission. Secondly, as both respondents from Government institutions argue, Royalty provides the ownership right to oil for private companies. In this case, with the abolition of Royalty, companies are using a nationally owned resource without paying for it. This agrees with the arguments of Mabro (1998), Miller et al (1999), Mommer (2001), and Wright (2001), as highlighted in Chapter 3.

As such, the principal reason for the abolition of Royalty seems to be that this instrument is no longer a major source of income for the Government, as the production of oil in mature fields is in decline. This suggests that Royalty was originally applied to guarantee early revenues for the Government, especially that its abolition came at the time when the Government introduced an increase in the Income Tax, which appears to be a better source of revenue.

As for PRT, a divergence in opinions is noted with respect to the effects on oil activity, and consequently it is difficult to conclude on its neutrality. In fact, only 21 per cent argue that the abolition of PRT enhanced oil activity. This can be particularly true in the case of large fields. However, in the case of marginal fields, PRT does not have any effect according to approximately 79 per cent of respondents, given the different reliefs, especially the oil allowance. As such, PRT can be described as neutral in its impact on marginal fields. A profit related tax, such as PRT, is likely to offer tax reliefs and allowances, so as to take into account the special risks that the oil industry face and to capture only a share of economic rent. As Respondent G1 argues, PRT captures only a share of the excess profit and not all of it, otherwise it can make the activity unattractive to investors.

Nevertheless, as has been discussed in Chapter 2, the neutrality concept is often combined with the efficiency concept. In this survey, 21 per cent of respondents refer to inefficiency in capital expenditures allocations, as a result of the PRT reliefs.

For instance, Respondent G2 argues that "PRT does not cause you to think about incurring certain expenditure because such expenditure is deducted". Similarly, Respondent O3 debates that the "the pre-1993 fiscal regime subsidized exploration activity, which led to an inefficient allocation of capital". Consequently, the neutrality and efficiency of PRT are put in question.

No comments are made on the CT and the ST as obstructing the development of oil fields. In contrast, Respondent O1 for instance argues that "CT regime does not inhibit activity". Similarly Respondent O5 points out that "CT removes disincentives to invest in mature fields". From such opinions, it can be derived that CT is considered neutral from the industry perspective.

Additionally, the CT allowances seem to largely contribute to the neutrality of the tax. For example, Respondent C3 argues that "CT allowances are the most important and broadly neutral". In fact, the accelerated depreciation lowers significantly the taxable income during the payback period, which is of particular importance in the capital-intensive oil industry.

Moreover, 87 per cent of respondents from the industry prefer Income Tax relatively to any other special petroleum taxes. This further emphasizes the neutrality of the tax. Nevertheless, it is worthy of note to refer to a distinctive view expressed by Respondent C2, who argues that the CT is neutral "and has almost no effect because of its low rate".

To conclude, there is a general agreement that taxation can play a principal role in affecting the investment environment and the international competitiveness of a province. However, two respondents emphasized that taxation alone is not the only factor affecting decision-making. Respondent O2 argues that "fiscal terms alone will not influence marginal developments or the timing of abandonment". Consequently, there are other factors that should be taken in consideration, namely oil price and prospectivity.

4.4.2. EQUITY

The survey put forward the idea that by imposing CT only the oil industry is treated similarly to other industries. This proposes that taxation based on CT is an equitable system because, according to 47 per cent of respondents, the tax applies to all industries in the UK and the oil industry, particularly, is achieving similar profitability as other industries. Respondent O3 indeed argues that other industries are even more profitable. As such, special petroleum taxes, like PRT, that treat the oil industry differently from other industries in the UK are not desirable. In fact, despite its "generous" reliefs, PRT is rejected by 87 per cent of respondents when compared with the imposition of the Corporation Tax. This again raises the question of the efficiency of such reliefs, which were originally introduced to allow progressivity in the PRT system.

On the other hand, some respondents argue that the profitability of the oil industry largely depends on oil prices. Respondent C5, for instance, points out that "companies will make normal profits at modest production and modest prices but no super profits". This raises the issue of the effects of an increase in oil price, which, in this case, allow companies to achieve abnormal profits unlike other industries. As such, a super-profits tax, like PRT, may be required.

Three additional points are worthy of note as regards achieving equity. Firstly, profitability is required to develop new technology and sustain the activity in older fields, as well as developing marginal fields in order to extend the life of the UK North Sea province.

Secondly, the Government needs to take into consideration the impact of taxation on small independent companies, who are the new players in the North Sea. Such companies do not have a large international portfolio of investments like the majors. Respondent C1 refers to the damaging effects that PRT have on small players because unlike CT, it does not offer any interest reliefs. Nevertheless, there are no interest reliefs on the 10 Supplementary Charge neither and this is a criticism that Respondent C2 makes as regards the 2002 fiscal changes.

Finally, as Respondent G1 argues, the changes to taxation in the UK were made because "companies should pay a fair share of their profit in tax". Consequently, it can be concluded that neither Royalty nor PRT were generating a fair share of revenue for the Government, and as a consequence they were abolished.

4.4.3. RISK SHARING

The findings of the survey reveal that, according to 27 per cent of respondents, high tax takes can compensate for the high risk sharing. That is why these respondents argue that the UK tax system was more risk absorbing in its early stages. However, taxes based on profits, or cash flow, such as PRT, are risk sharing unlike Royalty, which is revenue based. In fact, PRT is indirectly described as the most risk-absorbing component of the 1975 fiscal package given the Exploration reliefs that it provides.

Furthermore, risk sharing is not necessarily reflected in the fiscal terms. Some 20 per cent of respondents refer to the importance of partnership between the Government and the industry to reduce risk as perceived by the industry, namely geological and fiscal risk. Such a partnership between the UK Government and the industry has been achieved (and is still in existence) as a consequence of initiatives like the PILOT program.

4.4.4. STABILITY

20 per cent of respondents argue that the stability of the regime is the most significant factor in affecting investment climate. These respondents debate that any attempt to destabilize the regime can largely affects investors' confidence and reduces the international competitiveness of the country.

On this matter, Respondent C5 makes expresses a distinctive opinion, as the respondent argues that although the abolition of Royalty enhances activity, such a change will create instability and negatively affect the province prospects. Opposing such views, one respondent acknowledged the difficulty of achieving stability in the regime, given the volatility of oil price; "it is difficult for one size to fit all circumstances" (Respondent C4).

It is also important to note that although the 2002 changes were proposed in 1998, they came as a surprise despite the disapproval of Respondents G1 and O2. In fact, during the interview one month prior to the April 2002 changes, Respondent G2 denied any possible changes to the tax regime in the near future.

Two respondents argue that oil companies have developed their own strategies to cope with risk and that is why the changes to the regime did not affect their decision-making. In fact, Respondent O4 points out that "the uncertainties of a fiscal regime are not generally factored into risk analysis".

It can be concluded that, rather than establishing a regime that is risk absorbing, the Government might prefer to compensate for this by maintaining and improving its partnership with industry and also sustaining the stability of the regime. Both partnership and stability can be crucial to promoting the international competitiveness of a mature oil province.

4.4.5. SIMPLICITY

The findings of the survey with respect to the simplicity criterion are not different from the findings of the two previous chapters. All respondents who referred to the simplicity of the regime argue that PRT is a complicated tax, unlike CT. For example, Respondent O2 argues that the 2002 changes "represented the simplest method for the Government to achieve the revenue that they required". Additionally, Respondent C1 refers to the interaction of the three instruments in the 1975 fiscal package that generated complications and imposed an additional administrative burden.

4.4.6. PROPOSED ADJUSTMENTS

The main objective of the survey is to identify the principal weaknesses in the regime and to find ways to ameliorate it or an alternative system that might be acceptable to Government and industry alike. From the discussion in the previous sections and the arguments made in the survey, several suggestions are highlighted as possible attempts to improve the fiscal regime, which is in place currently.

Nevertheless, before proceeding, it is important to stress on the contradiction in perspectives between industry and the Government regarding taxation, given their competing objectives. Mommer (2001) argues that "whatever the levy, a case is constructed where the existing levy is actually a disincentive, deters a potential investment or even worse, creates perverse incentives" (p.2).

Such an argument seems to indirectly agree with that of Rutledge & Wright's (1998) view that the UK has the "weakest regime in the world" (p.801). In fact, although in this survey all respondents reject the Rutledge & Wright criticism, none of the respondents suggest a further decrease in the tax rates. This suggests that the industry is convinced that in the UK the tax rate is very competitive. Respondent O5 argues indeed that "a regime based upon a CT rate greater than 30 per cent might be appropriate in the event of the abolition of Royalties". As such, it can be derived that no reduction in the tax rates is advisable.

As discussed in both Chapters 2 and 3, a tax targeted on economic rent is likely to meet the criteria of an ideal tax. However, no respondent in this survey suggests applying a tax that captures economic rent. Although three respondents (G1, G2 and C3) argue that PRT was intended to capture such rent, the tax is described as having several deficiencies. The explanation can be partly the inability of failing to clearly define economic rent. In fact, according to Respondent G1, the Government does not have a clear definition of economic rent. This raises the issue on the Government's ability in practice to impose a tax that targets economic rent.

However, other possible adjustments suggested in the survey can be considered. These are discussed as follows.

Firstly, the current system, based solely on Income Tax is described as neutral and simple.

Nevertheless, compared with PRT, CT and ST are argued to lack incentives to explore, although they are preferred to PRT. The abolition of PRT is met with criticism on one specific point, the abolition of the Exploration reliefs, which are described as essential by the industry. This raises the possibility of introducing some Exploration reliefs to the current system. Respondent C6, for instance, argues that "the recent changes need to be supplemented by additional incentives to explore (say, a 25 per cent supplement on Exploration costs)". However, according to Respondent G1, such a measure is difficult to implement. "The Government is not currently giving too many reliefs because it realized that the past era will not be alive again" (Respondent G1). In fact, the general perspective of the industry is that the Exploration activity has been and will continue to be in decline but it is the development of existing fields, which will determine the future of the UK oil province.

Secondly, another possibility can be to subsidize certain fields, like Don, where "there is lot of oil still to come but given a technology barrier, it has been abandoned" (Respondent C2). However, subsidizing activity makes the tax more like a Brown Tax hence imposes high risk on the Government[40]. Further, subsidies can lead to inefficient use of capital. For instance, Respondent O3 argues that "the pre-1993 fiscal regime subsidized Exploration activity, which led to an inefficient allocation of capital".

[40] Discussed in Chapter 2, Section 2.6.3.2

A third possible adjustment is to allow the deduction of financial costs against the 10 per cent Supplementary Charge, similarly to CT, as Respondent C5 argues. Such an alternative can be simple to implement.

These propositions involve altering the existing tax structure. However, a fourth possibility suggests a complete change in the fiscal regime. Instead of PRT, the UK Government can impose a Resource Rent Tax similar to that used in Australia. The comparison between UK PRT and Australia RRT is studied in detail in Chapter 8.

4.5. SUMMARY & CONCLUSION

This chapter conducts a qualitative evaluation of the UK oil fiscal regime. It describes the different stages of the survey carried out among the main players in the UK North Sea. The chapter further summarizes and analyses the survey findings to evaluate the UK fiscal regime since its establishment in 1975, and to find ways in which the existing regime might be improved from both the Government and industry standpoint. In the light of the competing objectives of these two players, and of the controversy surrounding the UK petroleum fiscal regime, the analysis done in this chapter is of particular contribution to the progress of this thesis as well as the body of research.

The survey solicits opinions on four main issues, which are firstly, the impact of the chief tax instruments and the consequences of the principal amendments on both the Government and the industry.

Secondly, the risk sharing attribute of the fiscal regime and the evaluation techniques that companies adopt to evaluate their projects and incorporate risk. Thirdly, the rating of the UK oil province on an international scaling and finally, the future of the UK North Sea, but more importantly the role of taxation in determining those two concerns.

With a response rate of approximately 80 per cent, the main findings of the survey are summarized as follows. Taxation in the UK is argued as a major determinant of activity levels and trends. Tax instruments like Royalty and PRT are considered as non-neutral, as their abolition in 1983 and 1993 respectively, affected to a certain extent the activity in the UK North Sea. Royalty is outlined as a regressive tax and the least desirable, hence its abolition is considered as essential.

Nevertheless, the abolition of PRT raises different opinions. On one hand, the several PRT reliefs are considered as expensive to the Government and can lead an inefficient allocation of Expenditures. Further, the abolition of PRT seems to favor the large fields, as small fields are protected from the payment of the tax given the different reliefs. Further, compared with CT, PRT is less preferred, as there is a general argument that the oil industry should not be treated differently from other industries. But, on the other hand, the abolition of PRT led to the abolition of the Exploration and Appraisal reliefs, as well as a reduction in the perceived level of risk sharing with Government, and which was a previous and important attribute of the regime.

The "least worst option" as an alternative regime or actually what can be an improvement in the regime is to combine an increased in the Corporation Tax with the abolition of all upstream taxes. Yet, the stability of the regime is argued as of particular significance in maintaining investors' confidence. Maintaining and improving Government partnership with industry is also considered equally important.

Another general agreement is with respect to the description of the UK regime as the weakest in the world. Not surprisingly, all respondents reject this statement, which is rather described as extreme because the regime is "well attuned" to the economic realities of a mature oil province. In fact, all respondents argue that the level of activity in the UK North Sea, particularly Exploration, is declining but both oil price and taxation can play an important role in determining both activity and profitability of the industry.

The survey attempts to identify alternatives to the existing regime that might be acceptable to both the Government and industry alike. Five main propositions are made, namely the imposition of an income tax with the abolition of all special petroleum taxes, as suggested by majority of respondents, the application of RRT, the introduction of Exploration reliefs as well as subsidies, and finally the deduction of finance costs from ST. The first two propositions are quantitatively assessed in the following chapters. However, since the research is undertaken at the development stage of a field life cycle, Exploration reliefs are not going to be evaluated[41].

[41] See Section 5.2.1 in Chapter 5, p.133 and Section 9.4 in Chapter 9, p.306

Furthermore, introducing such a relief depends on Government and industry future outlook for activity in the North Sea, which seems to be pessimistic. The main concern is to encourage the development of discovered fields and extends the life of existing fields. With regards to subsidies, such an alternative seems very difficult to apply as it transfers too much of the risk onto the Government. Additionally, the thesis does not take into consideration finance costs, as such the deduction of these costs is not assessed any further.

The findings of the research done in this chapter provide material insights into the effects of the past changes as well as the desirability and feasibility of changes to the current tax regime. The next chapter commences with a more detailed quantitative analysis of the impact of such changes on the economics of North Sea operations.

CHAPTER FIVE

THE UK NORTH SEA TAX MODEL, METHODOLOGY AND ASSUMPTIONS

5.1. INTRODUCTION

Chapter 3 analyzed the tax instruments that have applied to oil E&P activity on the UKCS since 1975, while Chapter 4 surveyed the principal views of key decision makers regarding the influence of taxation on oil field profitability and, consequently, its effects on decision making. However, the principal findings and opinions expressed need to be quantitatively tested for a more complete evaluation of the UK petroleum fiscal regime and ascertaining a regime that can be acceptable to both Government and industry alike. Such an evaluation requires a comprehensive understanding of the rules of taxation. Consequently, at this stage, a model of the UKCS oil fiscal regime needs to be derived in order to understand how the principal tax instruments and their different reliefs work, interact and impact on both oil field profitability and Government revenues.

The objective of this chapter is to establish the analytical framework for the quantitative evaluation of the fiscal regime. From the principles of petroleum taxation as applied in the UK, the chapter derives a cash flow model that clearly shows how the tax take is calculated and impacting on both profitability and revenues. Further, the chapter highlights the principal assumptions and methodology adopted in the quantitative evaluation performed in subsequent chapters.

As the previous two chapters demonstrated, the UK oil fiscal regime is based on very complex rules. "Tax systems are rarely simple but the legislation covering the taxation of UK North Sea oil (the Oil Taxation Act, 1975) is quite extraordinarily complex" (Robinson & Morgan, 1978, p.93). In the absence of complexity, the calculation of fiscal take is a more straightforward task. Firstly revenues less costs are calculated so as to produce the pre-tax cash flow. Secondly, a tax rate is applied to determine the total tax take, which is then deducted from the pre-tax cash flow in order to arrive at the post tax profitability in a given period. This chapter demonstrates that in the case of the UKCS, the analysis is less straightforward and requires an in-depth understanding of the different tax rules.

The complexity of the regime is probably the reason why limited attempts have been made to fully establish a tax model of the UKCS, which clearly demonstrates the effects of taxation on profitability. Among these few attempts, the early work of Devereux & Morris (1983) is distinguished. Other authors such as Favero (1992) and Zhang (1997) have used small-scale economic models and in other cases, such as Kemp & Rose (1983) and Kemp & Stephens (1997), the models are not fully described. As such, the treatment of UK oil taxation in the academic literature remains very limited. Yet, establishing a comprehensive tax model is essential to providing appropriate guidance in understanding the workings of the UK regime, where "there are rules not simple formulas to calculate the tax liability"[42].

[42] Earp (Head, North Sea Tax Policy, DTI) in a personal e-mail to the author (2002).

For instance, it is difficult and probably inaccurate to comment on the effect of a particular tax relief if no clear computation is established. As will be shown later, this is especially the case when loss carry forwards are involved at the early stages of an oil field's life.

In this chapter the principles of oil taxation are taken from the principal sources of such information which are the Inland Revenue (2003a,b) and the DTI (2003). A fully transparent cash flow model for the UKCS is then derived, for the purpose of this thesis. Since the principal objective of the thesis is to evaluate the impact of taxation on profitability and Government revenue, the availability of this model is a prerequisite for the quantitative analysis. Such a model produces an appropriate framework where the various interdependencies of tax instruments become more manageable and transparent (Creedy, 1999).

The chapter is divided into four main sections. Section 5.2 incorporates the derivation of the cash flow model. The section is further divided into four subsections mainly concerned with the computation of the three principal components of fiscal take. To assist understanding of the tax computation, a detailed example of a selected oil field is presented in Appendix C. Section 5.3 sets out the principal assumptions underlying the quantitative analysis. It also incorporates a brief review of the WoodMackenzie Global Economic Model as well as the sample of fields selected. Section 5.4 covers the concluding remarks.

5.2. THE DERIVATION OF THE CASH FLOW MODEL

This section studies the computational sequence of the three main tax instruments that have applied to E&P activity on the UKCS namely, Royalty, PRT and CT. However, it is important to stress that these taxes have several reliefs and were the subject of many changes that have almost prohibited their capture in the model. Notwithstanding, the principal reliefs and changes are fully evaluated.

The section commences with a brief description of the different stages of an oil field's life cycle, because "a full understanding of the taxation problems of oil and gas cannot be achieved without at least a basic appreciation of the physical nature of oil operations" (Hayllar & Pleasance, 1977, p.5). The section then proceeds with listing the variables used in the development of the model. This is followed by a separate computation of each fiscal component so as to derive a complete model of the UK oil fiscal regime.

5.2.1. FIELD LIFE CYCLE

There are six phases in the life of an offshore oil field. These are presented as follows:

i. The acquisition of a license or concession: The search for oil begins when the Government announces its intention to offer oil companies the right to prospect in a part of its territorial waters (UKOOA, 2003).

ii. Exploration: This phase starts with the decision to drill a well. Seismic surveys are undertaken to identify the prospect. Once technical data is obtained and analyzed, the decision is taken whether to proceed further. If the conditions are right to continue with the project, the next stage is to drill an exploration well. If the well proves dry the exploration costs of the dry hole are written-off, whereas if oil is found the company proceeds to the testing phase. In the UKCS, the success rate of exploration wells is estimated to be approximately 21 per cent (UKOOA, 2001).

iii. Appraisal: Following a discovery, it is necessary to appraise the reservoir and ascertain its characteristics (size, structure and quality), thereby reducing technical uncertainty. Once data has been obtained and interpreted, the decision to develop the discovery must be taken. This decision depends on numerous factors, including an estimate of the future oil price at the time the project would be expected to come on stream (UKOOA, 2003).

iv. Development: If the field is commercially viable, the next stage is the development phase. A decision is taken as regards the development technology to be employed in exploiting the reserves of the field. A detailed development plan has to be submitted to the DTI for approval before construction proceeds.

According to Inland Revenue (2003b), the aforementioned stages are incorporated into one single stage, the Exploration Stage, which "covers broadly the period from the obtaining of the license to the time when a decision is made to develop, or not to develop a field"[43].

v. Production: Once the first production wells are drilled the production phase begins and the project comes 'on stream'. A number of production wells are drilled to access as high a proportion of the field reserves as possible. The natural pressure within the reservoirs forces the oil up the wellbore, allowing it to be delivered to an offshore production facility on the sea surface or to a production facility onshore. It is only when production starts that both operating revenues and operating costs occur. The costs occurring before the production stage are generally regarded as capital expenditures.

vi. Abandonment phase: This is the final stage in the cycle, where the field is no longer profitable and is decommissioned.

In the UK, an oil field life cycle tends to be longer than in most other areas of the world both because of the nature of the environment and the scale of the risks and costs involved. The Exploration and Appraisal stages, in particular, can last many years. Exploration and development activities have often taken ten years or more and even then it may take another twenty or thirty years to produce all recoverable reserves (Inland Revenue, 2003). Accordingly, there may be substantial delays before oil companies begin to obtain a return from their investments (UKOOA, 2003).

---

[43] Inland Revenue (2003) Oil Taxation Manual- Overview of the main types of costs incurred in oil exploration and production.

5.2.2. LIST OF VARIABLES

The following are the variables used to develop the UK North Sea Tax Model.

- NCF_t Net Cash Flow in period t
- R_t Oil Revenue in period t
- C_t Total Cost in period t
- T_t Total Tax Take in period t
- CE_t Capital Expenditures (CAPEX) in period t
- OE_t Operating Costs (OPEX) in period t
- Q_t Oil production in period t
- P_t Oil price in period t
- ROY_r Royalty in period t
- t_r Royalty rate
- up_t Uplift rate on capital expenditure in period t
- K Payback Period
- $Loss_{t-1}$ Loss carried forward from Period t-1, for PRT purpose
- OA_t Oil Allowance in period t
- n Number of years over which profitability is calculated
- π_a Adjusted profit
- π_{pt} PRT assessable profit
- PRT_r Mainstream Petroleum Revenue Tax in period t
- t_p PRT rate
- S Safeguard period
- π_{ct} CT assessable profit
- CT_t Corporation tax in period t
- t_c Corporation tax rate
- WDA_t Writing Down Allowance in period t
- FYA_t First Year Allowance in period t
- $Lossc_{t-1}$ Loss Carried forward from period t-1, for CT purpose
- ST_t Supplementary Charge in period t
- t_s Supplementary Charge rate in period t

5.2.3. NET CASH FLOW OF AN OIL FIELD

At a given period t, the profitability of an oil field is given by its Net Cash Flow, as in the following:

$$NCF_t = R_t - C_t - T_t \qquad (5.1)$$

Where the total cost, C_t, incorporates two principal costs namely; the Capital Expenditures, CAPEX, and the Operating Expenditures, OPEX. The tax comprises three main elements: Royalty, PRT and CT. These are described separately in the following sections.

5.2.3.1. ROYALTY

In April 2002, the Government decided to abolish Royalty on all fields (see Budget Release, 2002). This decision was made effective in December 2002. Prior to that year, Royalty applied on fields that received development approval before April 1982, at a rate of 12.5 per cent and charged on half yearly periods. The rate is imposed on the gross revenue with deductions for Conveying and Treating costs (C&T). These costs include the cost of getting the oil from the wellhead to the point of sale but exclude the exploration and drilling costs.

According to WoodMackenzie (2000), the C&T costs comprise:

- 70 per cent of the capital costs of the platform depreciated (on a straight-line basis) over eight years (or 16 chargeable periods) or the life of the field, whichever is the shorter.
- Approximately 60 per cent of total platform operating costs.
- 100 per cent of the costs of transportation.

Given the C&T costs, the effective Royalty rate is likely to be between 9 and 12 per cent of gross revenues[44]. The Royalty take is given as:

$$ROY_t = t_r R_t \tag{5.2}$$

Where:

$$R_t = P_t Q_t \tag{5.3}$$

The post-Royalty revenue becomes:

$$P_t Q_t - t_r (P_t Q_t) = (1 - t_r) P_t Q_t \tag{5.4}$$

Royalty is an allowable cost for both PRT and CT in the case of a field paying all three.

[44] Devereux & Morris (1983) assume that the C&T costs represent 37.6% of Capital Expenditure depreciated over 8 years (i.e. 4.7% of CAPEX per year) and 4.5% of Operating Costs. As such, the authors represent the Royalty take in a given period *t* as in the following:

$$ROY_t = \left(R_t - \left(0.047 * \sum CE_t\right) - \left(0.045 * OE_t\right)\right) * 0.125$$

5.2.3.2. PETROLEUM REVENUE TAX- PRT

PRT is assessed on a six-month period at a rate of 50 per cent on 'assessable profit' for fields that gained development approval before 16 March 1993. This rate has changed five times since 1975, as Table 5.1 shows:

Table 5.1. Evolution of PRT Rate

Period	PRT Rate
1975-1978	45%
1979	60%
1980-1982	70%
1983-1993	75%
1993 Onwards	50%

Under the PRT rules, a ring fence exists around the field where only expenditure incurred on the oil field can be set against the income from the field and not against the profits from another field[45]. The assessable or taxable profit is the gross revenue less a series of deductions principally Royalty, Opex and Capex, Uplift, Losses Brought Forward and Oil Allowance. Although Safeguard relief applies, it is not given as a deduction but is calculated separately.

Opex and Capex are fully deductible in the year in which the expenditure is incurred. Certain types of costs, principally financial costs, are excluded.

[45] However, the introduction of the Cross Field Allowance (CFA) in 1987, enabling 10 per cent of the development costs on a new field to be offset against PRT liabilities on another field operated by the same company, was one of the exceptions to the general principle that PRT is a field-based tax (Inland Revenue, 2003).

Capex benefits from an additional relief known as Uplift or Supplement, at a rate of 35 per cent[46]. As such, 135 per cent of Capex is deductible from gross revenue, reducing the assessable profit by the following amount:

$$CE_t + up_t CE_t = CE_t(1 + up_t) \tag{5.5}$$

No PRT is paid until the accumulated Capex and Uplift has been written off. However, Uplift on Capex is granted only up to payback period, *K*, which is defined as the first period in which cumulative cash flow becomes positive. In other words, the payback period is "the point where the cumulative incomings exceed cumulative outgoings, (outgoings being defined as including not only Capital Expenditure but also the uplift)" (WoodMackenzie, 2000, p.74). As such, the payback period, *K*, can be found as the minimum value of *K* for which the following relationship is satisfied:

$$\sum_{t=1}^{K}(R_t - ROY_t - OE_t) > \sum_{t=1}^{K} CE_t(1 + up_t) \tag{5.6}$$

After the Payback period, no Uplift is granted and Capex in subsequent periods although not qualifying for Uplift continues to be allowed as a deduction.

Losses are carried forward and set against profits in future chargeable periods. However, when the production has ceased, losses (such as abandonment costs) can be carried back against earlier period's profits, working backward until the loss is exhausted (Inland Revenue, 2003).

---

[46] The rate was initially 75 per cent but it was reduced to 35 per cent in 1979.

Where there is still a profit, after the deduction of expenditures and losses, Oil allowance is given. This relief exempts a fixed amount of production from each field from PRT until such time as the total Oil Allowance for the field is fully utilized.

Oil Allowance is a deduction from profits equal to the value of 250,000 tonnes of oil for each six-month period up to a cumulative maximum of 5 Mt[47], multiplied by the relevant price of each period. If production does not reach 250,000 tonnes in a chargeable period, that part of the Oil Allowance is not lost but is available in later chargeable periods but always with the limitation of 250,000 tonnes per chargeable period and 5 Mt overall (Hayllar & Pleasance, 1977).

Any profit remaining for the period after the deduction of expenditures, losses and Oil Allowance is liable to PRT. Consequently, the assessable profit for PRT, to which the PRT rate will apply, is given by:

$$\pi_{pt} = R_t - ROY_t - OE_t - CE_t(1 + up_t) - Loss_{t-1} - OA_t \tag{5.7}$$

As such, the mainstream PRT take is defined as:

$$PRT_t = t_p \pi_{pt} = t_p \{R_t - ROY_t - OE_t - CE_t(1 + up_t) - Loss_{t-1} - OA_t\} \tag{5.8}$$

At this stage, the Safeguard relief rules are applied.

---

[47] Before 1979, 500,000 tonnes of oil were allowed for each period with a maximum cumulative allowance of 10 million tonnes.

This is a form of tapering relief, i.e. an upper limit, under which an oil field will never pay more than the Safeguard liability. As such, in certain cases, Safeguard can further reduce the amount of PRT chargeable, thereby allowing a field to achieve a minimum level of return on investment before it incurs any PRT liability. The Safeguard applies as follows.

Firstly, an "adjusted profit", π_a is calculated and which is the gross revenue less Royalty and operating costs.

$$\pi_a = R_t - ROY_t - OE_t \tag{5.9}$$

Secondly, this profit is compared to the accumulated CAPEX (without the Uplift), $\sum_{n=1}^{t} CE$, called the Safeguard Base.

Then,

- If $\pi_a < 15\%$ of $\sum_{n=1}^{t} CE$, no PRT is paid.
- If $\pi_a \geq 15\%$ of $\sum_{n=1}^{t} CE$, PRT is compared to the Safeguard limit, which is 80% of (π_a-15% of $\sum_{n=1}^{t} CE$), and the company pays whichever is the smaller amount. As such, when the Safeguard limit is lower than the PRT liability, the Safeguard reduces the amount of PRT chargeable.

Safeguard applies over only a limited period of time, which is the number of chargeable periods up until the field has reached payback plus half of that number of periods. Therefore, S, the period in which the Safeguard provision ends, is given by:

$$S = 1.5K \tag{5.10}$$

5.2.3.2. CORPORATION TAX

Unlike PRT, CT applies on a company rather than a field basis. An oil company is subject to the standard CT rules that apply to all companies operating in the UK but, in addition, is subject to the ring fence rules. UK E&P activities are treated as distinct from all other activities carried out by the company and profits from these activities are referred to as 'ring fence' profits. In order to prevent tax leakage, only losses incurred within the ring fence are allowed as a deduction from ring fence profits. The main CT rate is currently 30 per cent, "one of the lowest company tax rates in the world" (DTI, 2001, p.1)[48]. This rate has changed several times, since 1975 as Table 5.2 shows.

Table 5.2. Evolution of CT Rate

Period	CT Rate
1975 - 1983	52%
1983-1984	50%
1984-1985	45%
1985-1986	40%
1986-1990	35%
1990-1991	34%
1991-1997	33%
1997-1998	31%
1999- Onwards	30%

[48] See Appendix D comparing the fiscal take in a sample of countries

The assessable profit for CT is calculated after deduction of Royalty, Opex, Capital Allowances (depreciation), together with any losses brought forward from previous years, interest costs[49], as well as any PRT payable.

The principal capital allowances are the First Year Allowance (FYA) and the Writing Down Allowance (WDA) which cannot both be claimed in the same year. The FYA represents an immediate relief, its rate has varied over time:

- Prior to 14 March 1984, FYA rate 100 per cent
- 14 March 1984-31 March 1985, FYA rate 75 per cent
- 1 April 1985-31 March 1986, FYA rate 50 per cent
- After that date, FYA ceased to apply.

If FYA is claimed, the expenditure remaining, the Residual Balance, will qualify for a WDA in the following period. If a 100 per cent FYA is due, the residual value is zero. Prior to April 2002, WDA applied at a rate of 25 per cent on the undepreciated pool of expenditure brought forward from the previous years. However, after April 2002, a 100 per cent Capital Allowance was applied instead of the 25 per cent rate, and is also adopted in the quantitative analysis in the following chapters.

Any losses, which are inevitable in an activity involving a long lead-time between development and the generation of positive cashflows are carried forward and set against future profits in other chargeable periods.

[49] Finance costs have not been incorporated in the calculation of CT in this thesis. As such it is assumed that the company is self-financed.

When the production has ceased, a claim is made to carry back the loss (Abandonment costs) against earlier profits, working backward until it is exhausted.

The assessable profit for CT is defined as:

$$\pi_{ct} = R_t - ROY_t - OE_t - PRT_t - CA_t - Lossc_{t-1} \qquad (5.11)$$

And the CT take will be:

$$CT_t = t_c \pi_{ct} \qquad (5.12)$$

In the 2002 Budget, the Government imposed the Supplementary Tax at a rate of 10 per cent. This tax is applied to the same tax base as CT, the only difference being that there was no deduction for financing costs[50]. Nevertheless, since finance costs are not incorporated in the calculation of CT in this thesis, the ST and CT will be calculated on the same tax base. As such, it can be assumed that given a ST rate of 10 per cent the applicable CT rate will be 40 per cent.

The assessable profit for ST is as follows:

$$\pi_{st} = R_t - ROY_t - OE_t - PRT_t - CA_t - Lossc_{t-1} \qquad (5.13)$$

[50] "This was aimed at preventing companies manipulating their levels of borrowing between ring fence and non-ring fence activities to minimize the impact of the supplementary charge" (Inland Revenue, 2003).

And the ST take is:

$$ST_t = t_s \pi_{st} \tag{5.14}$$

5.2.4. CASH FLOW MODEL

The previous sections studied in detail the computation of the tax base for Royalty, PRT and CT. Consequently, the post-tax profitability of an oil field, where Royalty, PRT and CT apply in a particular period, *t*, can be expressed as follows:

$$NCF_t = R_t - ROY_t - OE_t - CE_t - PRT_t - CT_t \tag{5.15}$$

Where:

- The post-Royalty revenue is given by:

$$(1 - t_r)R_t \tag{5.16}$$

- The post-PRT profit is given by:

$$(1 - t_r)R_t - OE_t - CE_t - t_p\{R_t - ROY_t - OE_t - CE_t(1 + up_t) - Loss_{t-1} - OA_t\} \tag{5.17}$$

- The post-CT profit (including the ST) or the net post-tax cash flow is given by:

$$\begin{aligned}&(1 - t_r)R_t - OE_t - CE_t - t_p\{R_t - ROY_t - OE_t - CE_t(1 + up_t) - Loss_{t-1} - OA_t\}\\&- t_c\{R_t - ROY_t - OE_t - PRT_t - CA_t - Lossc_{t-1}\}\end{aligned} \tag{5.18}$$

The above Net Cash Flow model raises an important point of interest.

As the NCF equation shows, the oil price, size of the field, Opex and Capex as well as taxation and related reliefs are the key variables directly affecting profitability and, as such, the investment decisions and the international competitiveness of the UK's petroleum fiscal regime. The size and costs of the field are related to geological, geographic and environmental circumstances.

In a survey undertaken by Mohiuddin & Ash-Kuri (1998)[51] on 30 companies, 83 per cent of these argue that prospectivity is the most important factor while fiscal terms come second with 80 per cent of respondents and political stability third. Since exploration activity is high risk and expensive to undertake, firms are anxious to ensure, that wherever they drill or explore, there will be a reasonable probability of success (Ritchie, 1992).

This can explain why countries with very tough fiscal regimes still attract substantial investments. For example, although the UK is believed to have one of the most attractive fiscal regimes in the world while Indonesia has relatively tough fiscal terms, Indonesia comes second to the UK in terms of the number of wells drilled. This indicates the favorable prospectivity in the region. As long as companies are confident of finding a resource, they are able to deal with all the other factors in such a way as to earn an acceptable rate of return (Raja, 1999).

---

[51] As referred to by Raja (1999)

Nevertheless, Chapter 4 demonstrates that in mature areas such as the UK North Sea, taxation now plays one the most significant role in determining the future of the province.

Martin, in 1997, argues that the changes made to the UK petroleum fiscal regime are the most important factor that led to the 1985 and 1995 peaks in oil production. Technological progress, leading to cost reduction, is the second most important factor. Nevertheless, according to Martin (1997), technological progress is significant only when combined with high oil price. The author further argues that the oil price, although it is the third most important factor that leads to production peaks if, considered alone, is not a sufficient variable to explain the change in production.

Deriving the cash flow model allowed a better understanding of the functioning and interaction of the different tax instruments of the UK petroleum fiscal regime. As such, a clearer picture is provided to assist in understanding the debate surrounding the different tax instruments and their reliefs as applied in the UKCS.

5.3. ASSUMPTIONS

The cash flow model derived in the previous section sets out the basis for the quantitative analysis. This section highlights the major assumptions underlying the analysis.

5.3.1. COMPANIES & FIELDS

In order to avoid unnecessary complications, this thesis takes as its basic operating premise a single company which operates and owns a single oil field. If there are several companies investing in an oil field, each will own a percentage and the tax base will apply on the individual company's, not the overall profitability of the field. This particularly applies in the case of CT.

Following Devereux & Morris (1983), it is assumed that a company's profit in a particular field is equal to its interest in that field multiplied by the profit generated (after deductions of both Royalty and PRT). A company's assessable profit for CT is the sum of different profits from each of the fields it holds an interest.

The analysis carried out in this thesis concentrates on the effects of taxation on individual oil fields. In fact, "the outside observer cannot know in detail the tax position of the companies" (Robinson & Morgan, 1978, p.113). This partly explains the reason why several of the studies[52] done in the field of UK petroleum taxation assume no difference between the effects of tax on individual oil fields and on the company. Although such assumptions may not reflect the exact impact of tax, particularly CT, they are unlikely to generate any contradictory findings. The profitability of an oil field, which is greatly influenced by taxation, is a key determinant of the attractiveness of an oil province.

[52] Among others Robinson & Morgan (1978), Kemp & Rose (1983), Rowland (1983), Kemp, Stephens & Masson (1997), Kemp & Stephens (1997), Laughton (1998).

5.3.2. TAX SCENARIOS

Chapter 3 critically analyzed the evolution of the petroleum fiscal regime in the UK and the various amendments made as a consequence of changes in field size, infrastructure, oil prices and international competitiveness.

Using the Cash Flow Model, different tax scenarios are introduced in order to assess and compare the outcome of the principal changes made to the regime between 1975 and 2002, both as regards field profitability and Government revenues.

Consequently, in this thesis nine tax scenarios are adopted which, except for Scenario 1- the Base Case Scenario- calculate profitability and Government revenue under the differing combinations of tax instruments and tax rates that generated the major controversies when they were implemented.

Scenarios 2 to 5 evaluate the effects of the historic tax rates, while Scenarios 6 evaluates the 2002 regime, and also assessing one of the proposed adjustments as identified in Chapter 4.

Since the main PRT reliefs have generated significant controversies, Scenario 7 isolates and evaluates the effects of those reliefs on both field profitability and Government revenue under the current regime through three sub-scenarios.

All the scenarios are summarized in Table 5.3.

Table 5.3. Tax Scenarios[53]

▪ Scenario 1 (Base)	Under this scenario, no tax applies.
▪ Scenario 2	This scenario evaluates the pre-1983 structure with 12.5% Royalty, 70% PRT and 52% CT.
▪ Scenario 3	This scenario assesses the post-1983 but pre-1993 structure, where fields are subject to 75% PRT and 33% CT.
▪ Scenario 4	This scenario computes the post-tax profitability of fields that received development consent after 1983 but before 1993, but following the changes in 1993, the PRT rate was reduced to 50% and CT applies at 30%.
▪ Scenario 5	This scenario evaluates the tax structure that applies to fields that received development consent after 1993 but before the 2002 changes. In this case, fields are subject to 30% CT.
▪ Scenario 6	This scenario assesses the 2002 changes, where the 10% Supplementary charge was introduced on fields that are subject only to CT.
▪ Scenario 7	This scenario also evaluates the 2002 changes, but applies ST on fields that are in a 50% PRT and 30% CT-paying position.
- Scenario 7.a	No Uplift applies
- Scenario 7.b	No Oil Allowance applies
- Scenario 7.c.	No Safeguard applies

5.3.3. GLOBAL ECONOMIC MODEL

The Global Economic Model (GEM) (2002 version) is an Excel spreadsheet economic evaluation tool developed by WoodMackenzie, a well-established consultancy company in the E&P sector of the petroleum industry, who kindly agreed to supply a copy of their model to assist the author in the research.

[53] Where PRT applies, it is assumed that the Uplift rate is 35 per cent and the Oil Allowance is a maximum of 5 Mt.

In general, the model serves two main purposes. Firstly, it provides a cost and production database covering all oil and gas fields in the UK, including past and prospective information. Secondly, it is an economic modeling tool that can be used to evaluate individual field or company developments in the UK (WoodMackenzie, 2000). A field's profitability is calculated under a specific set of assumptions principally oil price, inflation and tax, which can be varied.

However, for the purpose of this thesis, GEM is mainly used as the basic source of production, historic oil price and cost data. In fact, because GEM is based on spreadsheet formulas that calculate a field's profitability under specific tax scenarios that cannot be amended and only use the Discounted Cash Flow evaluation method, additional spreadsheet based models are developed to overcome these limitations. These spreadsheets utilize the tax formulas set out in this chapter to calculate field profitability and Government revenue under the different tax scenarios detailed in the previous section[54].

Additionally, in those spreadsheets, field profitability is calculated using different financial evaluation techniques, namely Discounted Cash Flow (DCF) and Modern Asset Pricing (MAP), which are described in detail in the following chapter.

Furthermore, GEM calculates profitability under fiscal terms that are specific to the UK. In order to complete the international comparison (see Chapter 8), additional spreadsheets are developed to include the fiscal terms of five other oil producing countries.

---

[54] See Appendix C, for an example

5.3.4. SAMPLE OF FIELDS

Different sizes of fields generate different levels of profitability. In relative terms small and medium fields do not generate same levels of economic rent as large fields. Consequently, different tax instruments have a varying impact on field profitability in so far as "one size does not fit all".

To illustrate this variable impact, a sample of oil fields is selected and classified according to the size of their recoverable reserves[55] into very small, small, medium, large and very large categories, as in the following:

- A very small field is deemed to have less than 100 mmbbl of recoverable reserves.
- A small field has less than 200 mmbbl of recoverable reserves.
- A medium field has recoverable reserves between 200 and 400 mmbbl.
- A large field has recoverable reserves of more than 400-500 mmbbl.
- Any field with recoverable reserves of more than 500 mmbbl is described as very large. Nevertheless, no very large fields are incorporated in the analysis because there has not been any UK discovery of this size for the last 20 years. Further, the very large fields that are in production are currently in their final stages of decline.

[55] Recoverable reserves are "that proportion of the oil and gas in the reservoir that can be removed using currently available techniques" (DTI, Oil & Gas Glossary, 2003)

This classification is the result of a comparison of size division from major sources:

Table 5.4. Division of Fields by Size

Study By	Very Small	Small	Medium	Large
Robinson & Morgan (1978)		100-250	250-350	>350
Kemp & Macdonald (1995)	<100	100-250	250-500	>500
Sem & Ellerman (1998)		<100	100-400	>400
Simmons & Co (2003)	<100	100-200	200-400	>400

The Brown Book (DTI, 2001) provides information on 143 oil fields operating in the UK North Sea and GEM provides data on their production and costs. The distribution of these fields relative to the four size groups provided the following proportions of the total number of fields:

Table 5.5. Distribution of Fields

Field Size	Proportion of total field base
Very Small	56%
Small	26%
Medium	10%
Large	8%

A sample of 25 oil fields is randomly selected for investigation on the basis of their providing a representative coverage of post 1993 (pre 2002) operating oil fields in the North Sea. As such, with respect to the distribution of UK oil fields, the data set selected includes 10 very small, 9 small, 4 medium and 2 large field[56]. Production and cost data for these fields is provided in Appendix E[57].

[56] A minor alteration is made to the proportion of fields selected to allow a better comparison, as such 10 very small fields are selected instead of 14, 9 small instead of 7, and 4 medium instead of 3.
[57] For reasons of consistency, the cash flows of the various fields selected are assumed to start in 2002.

The use of real data affords the study a more authoritative status especially when individual characteristics such as water depth, size, costs and life, which are specific to each field, are incorporated into the models. Smith & Mccardle (1998) argue that the use of a model field greatly oversimplify the problems analysed, because in reality there are many complications such as uncertain production rates, development costs and construction lags.

5.3.5. ADDITIONAL ASSUMPTIONS

In addition to the principal assumptions highlighted in the previous sections, the following assumptions are made:

- A base Brent oil price of \$19.50/bbl in 2002 is used for evaluation purposes. This rate remains constant in real terms, with 2002 as base year.

- All figures are expressed in real terms and in £M.

- The analysis is done on nominal terms then deflated. k_t is the inflation factor, where $k_t = k_{t-1}\exp(k)$, with $k_0 = 1$ and k the constant annual inflation rate of 2.5 per cent from 2002, as assumed in GEM

- A constant exchange rate of US\$1.50 = £1 STG, as assumed in GEM.

5.4. CONCLUSION

This chapter has derived a tax model that applies to oil activity in the UK North Sea, from the legal terms of oil taxation, as provided by the Inland Revenue and the DTI. The transparent cash flow model derived allows a clear understanding and quantitative evaluation of the effects of different tax instruments and their reliefs on oil field profitability and Government revenue.

The chapter then proceeds with the review of the principal assumptions that are adopted in the cash flow model in the following chapters, particularly the assumptions regarding the tax scenarios and sample of fields. Seven tax scenarios are assumed in order to evaluate and compare the outcome of the principal changes made to the regime between 1975 and 2002, both as regards field profitability and Government revenues. Furthermore, 25 oil fields, currently operating in the UK oil province, are selected to carry out the research.

The analysis undertaken in this chapter demonstrates the significant complexity of the UK fiscal regime and is reflected in the underlined tax equations. "In any one year or in any one field the amount that the Government will take in the forms of taxes cannot be simply evaluated or anticipated without an appropriate computer model; there is no such thing as an adequate "back of the envelope" calculation in the North Sea" (United Kingdom Oil & Gas Taxation and Accounting, 1984, p.14). The level and combination of taxes vary with the date a particular field received development consent.

Where more than one tax applies, the tax instruments interact with each other. Royalty is allowable as a deduction against PRT and CT, while PRT is only allowed as a deduction in calculating CT. Additionally, the different items of expenditure have different degrees of allowability for each type of tax. PRT in particular was described as a complicated device in the previous two chapters.

This chapter sets the analytical framework for the quantitative evaluation of the UK oil fiscal regime. Up to this stage, the profitability of an oil field is modelled for a single specific period. Nevertheless, in computing the profitability of a project based on expected future cash flows, both time and risk need to be taken in consideration in the calculation. This is often incorporated through the use of an appropriate discount rate although it can be done using other techniques. These are explained in detail in the following chapters, which cover the quantitative evaluation of the UK oil fiscal regime.

CHAPTER SIX

IMPACT OF DIFFERENT TAX SCENARIOS ON OIL FIELD PROFITABILITY AND GOVERNMENTREVENUE

6.1. INTRODUCTION

The previous chapter derived the tax model and outlined the main assumptions that are adopted in the quantitative evaluation of the UK petroleum fiscal regime. This chapter proceeds with the assessment of the regime taking into consideration both the industry and Government interests, hence evaluating the effect of taxation on oil field profitability and Government revenue from the UKCS. An important aspect of the study is the appraisal technique used to calculate the after tax profitability and, consequently, capture more appropriately the effect of taxation.

The choice of the financial evaluation technique is of particular significance for both companies and Government. To assess the taxation impact, an appropriate evaluation technique must be adopted. An inappropriate technique can result in a misleading figure both as regards profitability and taxable capacity.

In Chapter 5, an after tax Net Cash Flow (NCF) equation was derived. This NCF is calculated for a given period of time. However, to value their projects, oil companies estimate the after tax present value of their total expected net cash flows discounted for both time and risk.

Bjerkedal (2000) argues that under some evaluation techniques, "a tax system can appear less attractive, even though it is not... in this case very severe conclusions can be drawn and companies can make wrong statements, based on incorrect computation methods in evaluating project economics" (p.4). Emhjellen & Alaouze (2001) maintain that changing the valuation method may affect an oil company's investment decision on new projects because the ranking of projects will vary under different valuation methods. In an attempt to explain the reason that led to the decline in the value of oil companies over the last 15 years, Siew (2001) argues that oil companies have made incorrect investment decisions based on faulty project appraisal methods.

For several decades in the energy industry, the most common form of project evaluation has been the Discounted Cash Flow (DCF) technique (Laughton, Sagi & Samis, 2000). However, over the last few years, there has been an increasing interest in the use of more useful and more modern evaluation techniques, such as the Modern Asset Pricing model (MAP) developed by Jacoby & Laughton (1991) and Real Options Theory (ROT)[58]. These techniques were developed to overcome some of the weaknesses of DCF, and can be considered as evolved versions of the traditional technique. They can allow a more efficient valuation of risk, hence an improved investment decision making by oil companies compared with the commonly applied DCF[59].

[58] This chapter focuses on MAP, while the following chapter incorporates ROT because an additional assumption in decision-making is taken in consideration, and which is flexibility.

[59] The DCF technique can be more sophisticated, but in this thesis a more simplistic version of the technique is followed, as adopted in majority of previous studies, among others Kemp & Rose (1983) and Kemp & Stephens (1997).

The DCF method is currently used by oil companies (Emhjellen & Alaouze, 2001) and a recent study done by Siew (2001) found that 99 per cent of oil companies use this technique. Furthermore, the majority of previous studies[60] utilized this traditional technique to evaluate the profitability of an oil field. The number of applications of the newer methods in the evaluation of the UK oil fiscal regime is however substantially less. Jacoby & Laughton[61] (1991) were pioneers in the application of the MAP technique to evaluate the oil fiscal regime in the UKCS. However, they limited their analysis to the 1975 fiscal structure.

Evaluating after tax profitability of an oil field under both the traditional and modern techniques can therefore be beneficial. It is useful to see if the more modern techniques give significant difference from the traditional method and whether they should be recommended as a replacement to the traditional technique. Furthermore, comparing two competing techniques not only gives new insights regarding the efficiency of these methods, but also increases the reliability of the conclusions of this thesis.

The remainder of this chapter is organized as follows. Section 6.2 analyses and compares the concepts of the traditional DCF and MAP, the more modern technique. Section 6.3 expands the comparison of the two methods in terms of discounting expected future cash flows. The results are presented and discussed in Section 6.4. Section 6.5 summarizes and concludes the chapter.

---

[60] Among others, Robinson & Morgan (1978), Rowland (1983), Rowland & Hann (1987), Kemp & Rose (1982), Kemp & Stephens (1997), and Martin (1997).

[61] Because of the limited published work in the field of MAP, the author benefited from discussion with Dr. Laughton.

6.2. DCF VERSUS MAP: CONCEPTS & COMPUTATIONAL STEPS

This section compares the concepts and computational steps of DCF and MAP. It addresses the limitations of DCF and the manner in which MAP overcomes these limitations.

6.2.1. DCF COMPUTATIONAL STEPS & LIMITATIONS

The Discounted Cash Flow (DCF) technique has been (and still is) the most commonly used method in evaluating expected future cash flow. Under this technique, the project[62] evaluation is usually done in three steps:

Firstly, the analyst estimates the project net cash flows that will occur at each time period in a particular scenario.

Secondly, the project cash flows are discounted using a certain discount rate, incorporating a risk premium[63].

Finally, the discounted cash flows are added to form the project value, also called the Net Present Value (NPV)[64].

---

[62] The term "project" in this thesis refers to an oil field.
[63] See Section 6.3 for further explanation of DCF discounting.
[64] In some cases, a probability distribution for different scenarios is constructed. In this case, the Expected Net Present Value, ENPV, is used as a measure of the overall profitability of the project.

Siew (2001) argues that there are two main advantages to using DCF method[65]. Firstly, it is a cash flow based technique, which takes into account the time value of money[66]. Secondly, it is quick and relatively easy to understand and calculate.

However, according to Jacoby & Laughton (1992), there are several problems in following the DCF method, mainly:

i. The use of uniform discounting in the DCF method is based on the "false" premises that the risks inherent within different components of the project cash flow are of the same magnitude. This is of particular significance when using the assumption that the only uncertainty results from oil price, as is the case in this thesis. As such, "the discounting in the DCF is only vaguely related to the uncertainty in the cash flows" (Jacoby & Laughton, 1992, p.9).

ii. Under DCF, the discount rate is constant and therefore it does not take into consideration the resolution of uncertainty over time. As such, under DCF, the future cash flows are discounted excessively and this can lead to a tendency to throw capital at any project alternative that will accelerate the receipt of revenues. Consequently, DCF introduces bias against long-term decision-making.

iii. DCF analysis depends critically on the choice of a project discount rate. However, many organizations do not understand the very complex issues that lie behind the

---

[65] NPV is one of the applications of DCF technique. Other profitability indicators can be the Internal Rate of Return (IRR) and finding the required price for given rate of return. However, authors like Bierman & Smidt (1988) argue that NPV method is simpler, easier and more direct.

[66] This point is further discussed in Section 6.2.2.

chosen rate. DCF method treats risk in an *ad hoc* matter through some combination of subjective choices of discount rates.

iv. The focus of the DCF analysis is on a "now or never" investment decision. It does not allow future management flexibility, which can add value to an investment. Consequently, DCF can undervalue projects (Watkins, 2002)[67].

6.2.2. MAP CONCEPT

In 1991, Jacoby & Laughton introduced an alternative to DCF for the evaluation of petroleum projects. They called the new technique Modern Asset Pricing (MAP), which is based on the Derivative Asset Pricing theory (explained in Section 6.3.2). The Derivative Asset Pricing theory has been developed over the last three decades and as such it is not a new approach. However the theory is applied in the pricing of complex financial instruments, whereas MAP expands the model for the evaluation of petroleum projects, where the technique is still in its "infancy" (Laughton, 1998c).

MAP is based on the following two major ideas:

i. Firstly, a project can be valued by considering the cash that it consumes and generates. Cash flow is a commodity and can be valued according to the two characteristics that are important to people who trade in it. These characteristics are time and risk.

---

[67] The concept of flexibility is discussed in detail in Chapter 7.

The DCF method recognizes this idea in the use of discount rates that combine a risk free rate (valuation for time) and a risk premium (valuation of risk) (Laughton, 1998a).

People prefer to receive cash sooner rather than later. "A dollar received now is more valuable than a dollar received five years from now because of the investment possibilities that are available for today's dollar" (Bierman & Smidt, 1984, p.47). Therefore, there is a time discount in the valuation of the claim to a cash flow. The longer the time to the receipt of the cash that an asset provides, the lower the value of the asset (Salahor, 1998).

For a risk free cash flow there is no discount for risk since there is no risk involved. As such there is only discounting for time. The time discount rate is derived from the risk free cash value, which in turn can be expressed in terms of the risk-free interest rate. However, when cash flows are uncertain there needs to be a discount for risk in addition to discount for time. "Most people have an aversion to uncertainty in their level of welfare. Therefore, if they have a choice, most people would prefer to reduce uncertainty in their lives by investing their current wealth in assets that would provide extra cash in future situations where they would otherwise be poor rather in situations where they would otherwise be rich" (Salahor, 1998, p.15). In the former case, assets will be more valued than those in the latter, as there will be a markup for risk of the expected payoff.

When the existence of uncertainty directly influences financial market prices it is called "priced risk"[68] and requires non-zero risk discounting but when it does not have any direct influence it is called "unpriced risk"[69], which does not require risk discounting. An oil project faces uncertainty as regards the price of oil, which is normally a priced risk, as well as project-specific technical and geological determinants as regards the volume of oil to be produced, which is normally a non-priced risk (Salahor, 1998).

ii. The second idea is the "principle of value consistency" or the "no-arbitrage principle", which states that if two assets have the same cash flow consequences they have the same price (Coelen, 2002). The special form of this principle is the "principle of value additivity", which allows to break the cash flows of a project into parts with different risk characteristics for evaluation and then add the value of the parts to get the value of the whole project (Salahor, 1998).

Under the MAP technique, the analyst performs the equivalent of the first two steps in the DCF evaluation process (Section 6.2.1) but in the reverse order, as described below:

Firstly, the analyst discounts the uncertain project cash flow determinants using appropriate discounting structures for each determinant.

---

68 Also called "non-diverisfiable", "systemic", "market" or "macroeoconomic" risks, because it is correlated with the overall economy and cannot be completely removed by diversification strategy.

69 Also called "diversifiable", "non-systemic", "local", "private" or "project-specific" risks, because it is not correlated with the overall economy and can be removed almost completely by diversification strategy.

Secondly, the input valuations are filtered through the project structure to find the cash flow values.

Finally, these values are added to form the total project value.

6.2.3. MAP: OVERCOMING DCF LIMITATIONS

MAP overcomes the limitations of DCF outlined in Section 6.2.1 in the following ways:

i. The DCF technique recognizes the first idea behind MAP regarding the use of a discount rate that combines both a risk-free rate (valuation of time) and a risk premium (valuation of risk). However, with DCF, the effect of uncertainty is determined by the risk premium in the discount rate and which is the same for the different components of the cash flow. With MAP, however, the risk adjustment only applies on the risky components of the cash flow. So, instead of applying a uniform project discount rate, under MAP, discounting is done at the level of the cash flow components. As such, MAP provides a company with a "framework for determining the differentiated effects on asset values of the diverse combinations of uncertainties to which its different assets are exposed" (Laughton, 2002, p.12). According to Laughton (1998a), discounting individual projects determinants, as MAP does, involves fewer considerations than directly discounting project cash flow. Discounting the price of a barrel of oil to be received 10 years from now is much simpler than discounting the set of cash flows for a producing field.

In principle, MAP can give a more appropriate value estimates than DCF because it discounts revenues and costs using discount rate that reflects the riskiness of each of the cash flow components (Emhjellen & Alaouze, 2001). The following simple example demonstrates the difference in profitability between using DCF and MAP to evaluate a project.

Table 6.1. DCF versus MAP- Example

Project	Expected CF Year1	DCF NCF discounted @10%	MAP		
Cost	-100		Discounted @ 6%	A	-£94.34
Revenue	400		Discounted @ 12%	B	£357.14
NCF	300				
Profitability		£272.73	Total (A+B)		£262.80

Although the difference in the profitability of the project under the two methods is small, for oil companies, however, with billion dollar mutli-period projects, the possible valuation and decision errors may be substantial (Emhjellen, 1999).

ii. The discounting of value for risk is determined by how uncertainty is resolved over time. Unlike DCF where discounting is done at a constant rate, under MAP uncertainty is resolved as new information arrives over the course of time. Furthermore, the use of a constant discount rate throughout the life of a project is based on the assumption that oil price grows at a constant rate over time (Siew, 2001). MAP, however, can more readily exploit a sophisticated dynamic model of oil prices as compared with the DCF technique[70] (Baker, Mayfield & Parsons, 1998).

[70] See Section 6.3.2.3.

iii. Choosing an appropriate discount rate is very complex under DCF. With MAP, the discount rate is not given as a direct input into the evaluation as is the case with DCF, but is allowed to arise jointly from the discounting of the project's determinants and from the project structure.

iv. MAP incorporates flexibility in decision making, allowing the company to change the timing of its investment. However, when flexibility is taken into consideration, MAP is referred to as Real Options Theory (ROT). This concept is discussed in detail in the following chapter.

6.3. DCF VERSUC MAP: DISCOUNTING

In this section, the discounting techniques and the determination of the discounting factors are examined under DCF and MAP

6.3.1. DCF DISCOUNTING

DCF estimates the profitability of a project by calculating the Net Present Value, *NPV*[71], which is expressed in the following:

[71] The NPV is adopted to measure profitability at the Development and Production phases of a field's life cycle. However, this measure is modified when applied at the Exploration and Appraisal phases, which go beyond the scope of this thesis. In this case, profitability is measured by the Expected Monetary Value (EMV), which is expressed as in the following (Kemp, Stephens & Mason, 1997):

$$EMV = p_s NPV - EC$$

Where:

- p_s is the probability of success. According to UKOOA (2001), the chance of discovery is currently approximately 21 per cent in the UKCS.
- EC the exploration costs.

$$NPV = \sum_{t=1}^{n} NCF_t \times DF \qquad (6.1)$$

The discrete discount factor, *DF*, is given by the following expression:

$$DF = \frac{1}{(1+r)^t} \qquad (6.2)$$

While continuous discounting is given by the following:

$$DF = \lim_{t \to \infty} \frac{1}{(1+r)^t} = e^{-rt} \qquad (6.3)$$

Where *r* is the discount rate:

- If there is no uncertainty, cash flows are discounted for time only, and the discount rate would be the risk-free interest rate.

- If there is uncertainty, cash flows are discounted for both time and risk, and the discount rate is the interest rate plus a risk premium.

There is likely to be a range of discount rates employed by investors in the North Sea depending on the overall cost of capital and the risk premium relating to specific projects (Kemp, Stephens & Mason, 1997).

6.3.2. MAP DISCOUNTING

This section analyses the concepts on which MAP is based. It further demonstrates how its discounting is derived and the extent to which it differs from DCF discounting.

6.3.2.1. DERIVATIVE ASSET PRICING

MAP is based on the Derivative Asset Pricing theory that is at the core of most financial analysis in the options, futures and securities markets. "Derivatives are financial instruments that derive their values from the prices of other assets...Their principal function is to serve as tools for managing exposure to the risks associated with the underlying asset" (Bodie & Merton, 2000, p.36). When the magnitude of the cash flow associated with an asset (the derivative asset) is determined by the value of other assets, called the underlying asset, then the value of the derivative asset can be calculated from the values of the underlying assets. This is accomplished by creating a trading strategy in portfolios of the underlying assets designed to replicate the cash flows hence the value of the derivative asset (Jacoby & Laughton, 1992).

The no-arbitrage principle makes such a valuation possible as different assets with the same cash flow consequences have the same price. If the relationship between the future traded price of a risky asset and the future cash flow from a risky project is known, then a portfolio with the same expected payoff as the project can be created by investing in the traded risky asset and in the risk free asset (Emhjellen, 1999).

6.3.2.2. VALUATION OF RISKY ASSETS

A project can be thought of as a portfolio of claims to individual cash flows. In this case, one can focus first on the single cash flows and value each individually. Then, once each individual cash flow is valued, the project can be valued by summing the individual cash flow values (Jacoby & Laughton, 1992).

Jacoby & Laughton (1992) provide a practical method for the evaluation of oil projects based on derivative asset pricing. The authors assume that oil price is the only uncertain variable, hence uncertainty of the project cash flow is determined only by reference to the uncertainty of the price of a barrel of oil. Therefore, the only uncertainty in value may be modelled through modelling uncertain future oil prices.

Oil price can be modelled through the use of forward contracts, which are one of the most common types of derivatives. A forward contract "obliges one party in the contract to buy, and the other party to sell, some asset at a specified price on some specified date (maturity date). It permits buyers and sellers of the asset to eliminate the uncertainty about the future price at which the asset will be exchanged" (Bodie & Merton, 2000, p.36). The fixed amount that is paid to obtain the forward contract is called the Forward Price or the Certainty Equivalent of the uncertain amount (Laughton, 2002).

Each future oil price, P_t, can be formulated as the terminal value of the forward contract. In other words, each oil forward contract is a claim to a single cash flow at maturity, where the cash flow amount is P_t.

Hence, to get the certain P_t, investors pay today the forward price, which reflects both time and risk preferences. As such, the underlying value of the derivative asset valuation depends on the current expectation of the output price claims, here oil price (Emhjellen, 1999).

Let $V_0(P_t)$ be the current value of the claim to be received at time t and $E_0(P_t)$ the current expectation of the oil price evaluated at time zero. $V_0(P_t)$ is then given by:

$$V_0(P_t) = E_0(P_t)e^{-\mu t} \tag{6.4}$$

The future expected rate of return, μ, on the underlying risky asset is the sum of two terms, the risk free rate and a risk premium. The risk free rate is the return for time and it is assumed to be constant. The risk premium is taken to be proportional to the amount of volatility of the oil price expectations at time *t*. This proportionality constant also termed the price of risk is assumed positive and constant overtime so that there is risk discounting in the valuation of the output price claim. Jacoby & Laughton (1992) identify the price of risk as the risk due to oil market uncertainty. The future expected rate of return is then expressed as in the following:

$$\mu = i + \phi\sigma \tag{6.5}$$

Where:

- ϕ is the price of risk.
- σ is the volatility of oil price expectations.

The current value of the claim becomes:

$$V_0(P_t) = E_0(P_t)e^{(-\phi\sigma t)}e^{(-it)} \tag{6.6}$$

The first discount factor $e^{-\phi\sigma t}$ is the discount factor for risk[72]. It is referred to in the remainder of the analysis as the Risk Discount Factor, RDF. This risk adjustment converts the forward price of oil into a certainty equivalent price of oil (Emhjellen, 1999). The second factor e^{-it} is the discount factor for time and it is referred to hereafter as the Time Discount Factor, TDF, where i is the nominal risk-free rate.

6.3.2.3. MODELING OIL PRICE VOLATILITY

Determining oil price volatility is an important aspect of MAP since it has a significant impact on computing the RDF. Further, it constitutes a major difference between MAP and DCF, with respect to the assumption regarding the evolution of future oil price. The constant discounting in DCF is based on the assumption that oil price uncertainty grows at a constant rate over time, whereas with MAP, uncertainty is assumed to be resolved over time (Siew, 2001). MAP uses a stochastic process, more precisely a Mean Reversion Model, to illustrate the behaviour of future oil price.

A stochastic process is defined as "a variable that evolves over time in a way that is at least in part random" (Dixit & Pindyck, 1994, p.60). So, a stochastic process involves time and randomness (Dias, 2001).

[72] See Section 6.3.2.3 for further discussion

The most common stochastic processes used in modelling uncertainty related to oil projects are the Geometric Brownian Motion (GBM) with drift and the Mean Reverting Processes (MRM)[73] (Dixit & Pindyck, 1994).

i. Geometric Brownian Motion with Drift (GBM): This popular and simple model is the most often used stochastic process in financial economics theory. It is also known as the random walk model (Baker, Mayfield & Parsons, 1998). The GBM presumes that the forecasted uncertainty is constant therefore shocks to the market have permanent effects. That is why the model is also called the permanent shock price model (Bradley, 1998).

For an oil price that follows a GBM, the stochastic equation for its variation with the time t is given by:

$$dP_t = \alpha P_t dt + \sigma P_t dz \tag{6.7}$$

Or:

$$\frac{dP_t}{P_t} = \alpha dt + \sigma dz \tag{6.8}$$

Where:

- dz is the increment of Wiener process; E[dz] = 0. Var [dz] = dt
- α is the constant drift variable or the expected growth.

[73] For further detail see Appendix F.

- σ is the annual standard deviation of $\frac{dP}{P_t}$. It illustrates the volatility of price, the random variation term or the deviation from the expected rate, hence the term of uncertainty.

ii. Mean Reversion Model (MRM): This model presumes that the forecasted uncertainty declines over time so that the effects of shocks decay because of long term equilibrating forces. Prices in this model tend to revert to a prior trend after being shocked (Bradley, 1998). As applied to the petroleum industry the idea is that if the price is too far (above or below) a certain long-run equilibrium level P' market forces will act to reduce (if P >> P') or increase (if P << P') the oil production or exploration activity. This creates a reverting force that is similar to a spring, as strong as P is far from the equilibrium level P' (Dias, 2001).

If oil prices follow a mean reversion process, they have the following characteristics:

$$dP / P = \lambda(P' - P)dt + \sigma dz \qquad (6.9)$$

Where:

- λ is the speed of reversion or the mean reversion factor of oil prices, associated with a half life, HL. It is given by:

$$\lambda = \frac{\log 2}{HL} \tag{6.10}$$

When λ tends to zero, P_t becomes a simple Brownian motion and variance tends to $\sigma^2 t$ (Dixit & Pindyck, 1994, p.75).

- P' is the normal level or long run equilibrium level of P. Hence, P' is the long-run mean price to which the price will tend to revert

For the GBM model, every change in the oil price is a permanent change in the long-run price drift. As such, the amount of uncertainty and its associated risk discounting continues to grow at a constant rate with respect to time. In contrast, mean-reversion assumes the opposite. Every price oscillation is simply a temporary deviation from the predictable long-run equilibrium level. Consequently, the reversion force effect does not permit, even in the distant future, extreme values for P. Hence, in the reverting model, there is uncertainty only in the very short term and the forecasted uncertainty is halved for each year that is added to the term of the forecast and the total amount of oil price uncertainty "saturates" in the long term. Salahor (1998) argues that under conditions of oil price mean reversion, as forecast uncertainty reduces over time, the systematic risk discount should also decrease to reflect this.

Baker, Mayfield & Parsons (1998) present evidence of mean reversion. Pindyck (2001) argued that the mean-reversion model was better for oil prices after studying the long run evolution of the oil prices using 127 years of data. According to Dias (2001), the mean-reversion model is more consistent with the futures market, with econometric tests and even microeconomic theory.

As one of the concepts behind MAP is that uncertainty is resolved over time, MAP is based on the assumption that oil prices follow a mean reversion process (Emhjellen, 1999). In fact, Siew (2001) argues that one of the main advantages of MAP over DCF is the fact that MAP considers the effects of mean reversion in oil prices.

6.3.2.4. MAP NET PRESENT VALUE

The net present value calculated under MAP is called Certainty Equivalent to distinguish it from the NPV calculated under DCF. The after-tax project Certainty Equivalent, NPV_e, is given by:

$$NPV_e = \sum R_{et} - \sum C_{et} - \sum T_{et} \qquad (6.11)$$

Where $\sum R_{et}$ is the sum of the present values of the expected revenue cashflow, $\sum C_{et}$ is the sum of the present values of the expected cost cashflow and $\sum T_{et}$ is the sum of the present values of the expected tax cashflow.

R_{et} is the present value of the expected revenue cash flows at time t, hence the Revenue Certainty Equivalent. It is given by:

$$R_e = Q_t \times V_0(P_t) \tag{6.12}$$

Replacing $V_0(P_t)$ by its value derived from equation 24, Revenue Certainty Equivalent becomes:

$$R_e = Q_t \times E(P_t) \times RDF_t \times TDF_t \tag{6.13}$$

Where:

$$TDF_t = \exp(-it) \tag{6.14}$$

and,

$$\mathrm{RDF_t} = \exp(-\varphi\sigma(1 - \exp(-\lambda t))/\lambda) \text{ [74]} \tag{6.15}$$

C_{et} is the Certainty Equivalent of the expected total costs cashflow at time t, and it is given by:

$$C_e = C_t \times TDF_t \tag{6.16}$$

[74] Under the assumption of Mean Reversion Model for oil prices, the variance is given by:

$$v(P_t - P') = \frac{\sigma^2}{2\lambda}(1 - e^{-2\lambda t}) \tag{6.17}$$

In a spreadsheet model developed by Laughton at the Norwegian Petroleum Directorate Workshop on Modern Asset Pricing and Project Evaluation (Stavanger, Norway, May 1997), to calculate project values, Laughton considered a simple version of variance and deducted the RDF formula. Laughton RDF formula is applied in this thesis. The spreadsheet model was kindly supplied by Emhjellen and adapted to UK conditions by the author.

$(R_{et} - C_{et})$ is the value of the pre-tax cashflow at time *t*.

T_e is the present value of the total tax cashflow at time *t*. It is derived from the application of the tax model provided in Chapter 5, but taking into consideration both the Revenue Certainty Equivalent and the Cost Certainty Equivalent.

6.4. RESULTS & DISCUSSION

This section highlights the assumptions used to complete the analysis presented in this chapter, in addition to those set out in Chapter 5. It further summarizes the main results of the analysis. The discussion focuses firstly on comparing the net present values of the oil fields obtained using the DCF and MAP techniques under the Base Scenario. Secondly, it examines the impact of the different tax scenarios on different field sizes.

6.4.1. ADDITIONAL ASSUMPTIONS

Using the cash flow model derived in Chapter 5, this section assesses and compares the outcome of the principal changes made to the UK petroleum regime between 1975 and 2002, both as regards field profitability and Government revenue. This evaluation is undertaken using the nine tax scenarios developed in Chapter 5, which, except for Scenario 1 (Base case Scenario), calculate profitability and Government revenue under the differing combination of tax instruments and tax rates, which were subsequently to prove controversial when implemented.

The analysis is carried out using the major assumptions highlighted in Chapter 5. The 25 oil fields used for evaluation purposes are analysed under the nine tax scenarios. The profitability of the fields is calculated firstly under the DCF method and then using the MAP technique. Due to the individual characteristics of each oil field, an Excel spreadsheet particular to each oil field was developed so as to proceed with the analysis. The study is done in nominal terms and the results are subsequently deflated. By way of example, a detailed analysis of Alba field is provided in Appendix G.

Additional assumptions used include:

- i, the nominal risk-free rate, is assumed to be 4.5 per cent, as this approximates the average nominal risk free rate in 2002 as given by the UK Debt Management Office (2003).

- r, the discount rate, is assumed to be 10 per cent in real terms, as was applied in the majority of published studies[75], to mirror the industry's discount rate.

- σ , the annual volatility of oil price was reported in the literature as typically in the range of 15 and 25 per cent per annum[76]. In this Chapter, it is assumed equal to 20 per cent.

- λ, the speed of reversion of oil prices, is associated with a half life, HL, of 5 years (hence λ = 0.139). A half-life of five yeas for the mean reversion of oil

[75] See Kemp & Rose (1983), Rowland (1983), Kemp & Stephens (1997), Martin (1997) and Bradley (1998).

prices was assumed by Laughton & Jacoby (1992) and Emhjellen & Alaouze (2001) and is the value estimated by Pindyck (1997, p.7).

- ϕ, the price of risk, is considered 0.3503 in annual terms as assumed by Jacoby & Laughton (1992), Laughton (1997) and Emhjellen (1999).

6.4.2. FINDINGS

The results of the analysis are displayed in Tables 6.2-6.11, with all figures presented in £M. Oil fields are grouped by size because the main factor determining the variable effects of the differing tax packages is oil field size (Kemp & Crichton, 1979). This partly explains why the Government reduced its take from approximately 87 per cent in the early 1980s to 40 per cent in 2002, as the number of small fields increased relative to the larger accumulations[77]. However, other factors come into play namely oil field profitability and productive life expectancy.

6.4.2.1. DCF VERSUS MAP: COMPARISON OF RESULTS

The profitability of oil fields under DCF and MAP techniques is compared with a Base zero tax scenario in order to evaluate the performance of the two methods. Results from the techniques are then used to investigate whether a clear preference exists as to differing tax regimes.

---

[76] See Paddock et al (1988), Pindyck (1988), Dixit & Pindyck (1994) and Lund (2001).
[77] See Chapter 3, Section 3.4.1

Table 6.2 displays the profitability of the 25 selected oil fields under the Base scenario using both techniques. The main finding is that the two discounting methods produce different project NPVs.

The difference is particularly significant for larger, long-term projects, like Tern, Alba and Schiehallion. In fact, as the fields become larger, with relatively longer productive life duration, the difference between the two methods becomes more pronounced. Under DCF, because the discounting is constant, long term projects are under-valued compared with MAP, where given the Mean Reversion Model, the risk discount rate declines from a short-term rate toward zero in the long term. As such, revenues are highly discounted in the long term with DCF compared with MAP resulting in lower values.

Therefore, the quantitative differences in the two methods are mainly due to the decline in revenue discounting over the project duration under MAP. This reverse decline supports the criticism that Jacoby & Laughton (1992) make of the DCF method, highlighting in particular the inherent bias of the method against long term projects[78].

The length of the field's productive life is not, however, the only factor affecting the difference in results between DCF and MAP. Both the distribution of revenues and costs play an important role. For instance, in the case of Montrose a small field, but with a 40 years life, the difference between MAP and DCF is only £15.2MM (or 5.9 per cent). This is a consequence of the fact that annual revenues from this field are very modest, unlike Auk field where the difference is larger (36.3 per cent).

[78] See Section 6.2.1.

Table 6.2. Oil Field Profitability- Base Scenario

Base Scenario Fields	DCF (£M) (1)	MAP (£M) (2)	Difference (£M) (2-1)	Difference %	Life (from production start-up)
Very Small					
Argyll	292.3	318.1	25.9	8.1%	17
Arkwright	81.4	92.2	10.8	11.7%	18
Birch	57.5	55.8	-1.7	3.0%	19
Blake	276.0	280.1	4.1	1.4%	12
Kappa	171.4	137.6	-33.8	24.5%	10
Highlander	350.2	370.9	20.8	5.6%	27
Janice	182.4	170.6	-11.8	6.9%	11
Tiffani	-208.1	-301.0	-93.0	30.8%	16
Thelma	224.1	252.8	28.8	11.3%	11
Toni	182.6	234.1	51.5	22.0%	16
Small					
Arbroath	503.1	651.3	148.2	22.7%	24
Auk	385.4	604.4	219.1	36.2%	36
Balmoral	161.4	199.9	38.5	19.2%	21
Beatrice	165.4	143.8	-21.6	15.0%	24
Heather	170.9	208.1	37.2	17.8%	32
Leadon	571.4	677.2	105.9	15.6%	14
Montrose	257.1	272.2	15.2	5.5%	40
Osprey	277.8	329.2	51.4	15.6%	19
Scapa	399.2	511.5	112.4	21.9%	35
Medium					
Captain	541.4	643.8	102.5	15.9%	33
Clair	418.3	758.7	340.5	44.8%	28
Maureen	495.2	455.0	-40.2	8.8%	16
Tern	719.5	1097.1	377.7	34.4%	25
Large					
Alba	1040.1	1501.3	461.2	30.7%	24
Schiehallion	1481.2	2092.8	611.7	29.2%	25

In terms of the impact of the distribution of costs, with MAP, costs are discounted at a lower rate than DCF. Therefore, in the case of high cost fields, particularly those with substantial CAPEX, NPVs calculated using MAP are likely to be lower compared with those using the DCF method. Furthermore, the longer the period in which CAPEX occurs the lower the MAP NPV is likely to be. This is the case of the Beatrice oilfield where CAPEX are relatively significant and extend over 10 years of the field's life. As such, Beatrice NPV under MAP is lower than its equivalent under DCF. However, in the case of most oil projects, a large part of the CAPEX typically occurs at the early stage of the project.

Consequently, it can be said that the shorter (longer) the life of a field, and the smaller (lager) the field is, the narrower (the wider) the NPVs calculated under the DCF method versus those derived under MAP. This partly explains the relatively smaller difference in the findings of Emhjellen & Alouze (1999, 2001) and Laughton (1997) when comparing the two techniques, since the authors considered shorter fields' life, where the longest duration being 20 years. However, it is difficult to generalize, as other factors such as the distribution of both revenues and costs over time need to be considered.

6.4.2.2. IMPACT OF DIFFERENT TAX SCENARIOS[79]

The following section presents the results of oil fields profitability and Government revenue under different tax scenarios. The principal emphasis of the discussion is on comparing the effects of different tax packages on different field sizes, while continuing the comparison between DCF and MAP techniques.

Table 6.3 displays the results of the profitability of 25 oil fields profitability under both Scenarios 2 and 3. Under Scenario 2, Royalty applies alongside PRT and CT, whereas in Scenario 3, only PRT and CT apply. Under Scenario 2, there is a significant reduction in profitability for all fields, particularly very small and small fields (see Kappa for instance). Such a low level of profitability can discourage field development and may lead to early abandonment, as some Respondents argued in Chapter 4 in the context of Government Royalty.

---

[79] For various Scenarios, see Table 5.3, p.150.

Two fields Janice, a very small field, and Beatrice, a small field, have a negative profitability. However, these fields have higher profitability under Scenario 3, despite the higher rate of PRT. This difference in profitability is principally due to the impact of Royalty, as very small and small fields do not pay PRT as a result of the availability of oil allowance. This is consistent with the view of Respondent G2 in Chapter 4, who argued that the effect of the abolition of Royalty depends on whether oil field profits are subject to PRT and CT.

Table 6.3. Oil Field Profitability- Scenarios 2 & 3.

Scenario2	12.5% Royalty, 70% PRT, 52%CT			Scenario3	75% PRT, 50%CT		
Fields	DCF (£M)	MAP (£M)	Difference %	Fields	DCF (£M)	MAP (£M)	Difference %
Very Small				Very Small			
Argyll	108.1	116.7	7.4%	Argyll	162.7	195.5	16.8%
Arkwright	27.7	31.4	11.8%	Arkwright	51.9	59.3	12.5%
Birch	13.7	12.8	7.0%	Birch	31.9	33.6	5.1%
Blake	85.2	92.3	7.7%	Blake	144.2	151.9	5.1%
Kappa	-0.7	-58.5	98.8%	Kappa	71.0	32.6	117.8%
Highlander	97.5	104.8	7.0%	Highlander	173.3	194.1	10.7%
Janice	-171.8	-231.7	25.9%	Janice	-26.9	-66.2	59.4%
Tiffani	-237.8	-321.9	26.1%	Tiffani	-218.4	-301.0	27.4%
Thelma	68.5	80.4	14.8%	Thelma	120.1	147.1	18.4%
Toni	47.3	64.5	26.7%	Toni	89.5	132.8	32.6%
Small				Small			
Arbroath	132.9	178.0	25.3%	Arbroath	186.5	305.8	39.0%
Auk	105.9	143.9	26.4%	Auk	160.6	225.1	28.7%
Balmoral	-4.3	-25.9	83.4%	Balmoral	58.6	79.4	26.2%
Beatrice	-11.1	-18.9	41.3%	Beatrice	53.7	65.0	17.4%
Heather	25.2	45.1	44.1%	Heather	78.2	124.9	37.4%
Leadon	113.9	181.4	37.2%	Leadon	215.1	355.7	39.5%
Montrose	77.5	85.5	9.4%	Montrose	129.4	154.4	16.2%
Osprey	74.7	114.6	34.8%	Osprey	131.1	197.5	33.6%
Scapa	130.6	177.1	26.3%	Scapa	202.9	265.2	23.5%
Medium				Medium			
Captain	77.8	161.9	51.9%	Captain	164.4	346.9	52.6%
Clair	59.8	218.1	72.6%	Clair	115.7	342.4	66.2%
Maureen	57.2	34.3	66.8%	Maureen	133.7	216.3	38.2%
Tern	92.4	227.8	59.4%	Tern	148.7	355.7	58.2%
Large				Large			
Alba	116.4	285.0	59.2%	Alba	228.1	505.3	54.9%
Schiehallion	223.7	563.0	60.3%	Schiehallion	436.9	699.7	37.6%

For the medium to large fields (and some of the small fields that are in a PRT-paying position), both Scenarios 2 and 3 lead to a significant reduction in profitability. Furthermore, the abolition of Royalty increased the PRT take because Royalty is allowed for deduction from the PRT taxable income.

As to the difference in profitability as measured by the DCF and MAP techniques, in principal the results are consistent with the findings of the Base Scenario. However, the tax take is lower with MAP evaluation because taxation applies on the discounted revenues and costs. This further affects the timing of some reliefs, such as the oil allowance, since its value depends on annual production and revenue. In fact, with MAP evaluation, the impact of taxation is less severe as compared with those under DCF technique. This concurs with the findings of Bjerkedal (2000), who argues that the taxes can be overestimated in any project where a discounting rate above the risk free rate is used.

However, in the case of fields rendered loss making particularly under Scenario 2 (e.g. Kappa and Balmoral), MAP indicates an even lower value than DCF. This is mainly due to the effect of Royalty imposed on Gross Revenues, which are discounted at a higher rate than costs.

The effective tax rate derived from each field under Scenarios 2 and 3 respectively are shown in Tables 6.4 and 6.5, together with the total tax take from each field as well as the Government revenues generated from each of the tax instruments.

Table 6.4. Government Take- Scenario2

Scenario2	Effective rate(%)	Total (£M)	Roy (£M)	PRT (£M)	CT (£M)
Argyll	60.9	475.0	109.1	32.1	333.8
Arkwright	59.0	156.0	38.2	0	117.1
Birch	59.3	164.0	38.1	0	125.9
Blake	63.9	376.2	93.2	52.5	230.6
Kappa	80.4	320.7	61.4	0	258.6
Highlander	65.4	534.0	118.0	68.3	347.7
Janice	119.2	555.4	85.2	0	487.2
Tiffani	103.3	65.0	40.9	0	24.2
Thelma	62.3	343.6	85.2	33.2	225.1
Toni	61.8	386.3	87.9	34.1	261.9
Very Small	Total	3376.2			
Arbroath	67.0	1394.0	262.9	397.8	733.3
Auk	79.6	2139.8	329.6	1196.3	613.8
Balmoral	58.4	515.4	112.2	0	403.2
Beatrice	60.0	780.6	174.3	0	606.3
Heather	66.1	886.6	191.3	191.0	504.3
Leadon	68.1	973.6	209.3	266.5	497.8
Montrose	66.5	710.2	145.9	151.6	412.7
Osprey	62.4	635.7	147.4	80.4	413.9
Scapa	64.2	938.4	190.1	181.8	566.6
Small	Total	8974.3			
Captain	75.4	2303.3	446.7	1004.4	852.2
Clair	77.4	2638.4	488.1	1290.9	859.4
Maureen	64.4	1455.0	313.3	258.1	883.6
Tern	77.7	2990.1	513.3	1525.1	951.8
Medium	Total	9386.8			
Alba	80.7	4209.7	693.4	2422.2	1094.1
Schiehallion	78.3	4622.8	821.1	2469.1	1358.7
Large	Total	8832.5			

As noted from the results under Scenario 2, the effective tax take resulting from the combinations of 12.5 per cent Royalty, 70 per cent PRT and 52 per cent CT does not exceed 81 per cent on the selected fields given the application of the different reliefs. The only exceptions are Janice and Tiffani, which have been rendered loss making through the combined effects of Royalty and CT.

It is also important to stress that some of the very small and small fields do not pay PRT. Royalty impacts as soon as production commences and as such is due earlier than the other taxes.

For instance, in the case of Scapa, Royalty occurs 3 years before CT and 6 years before PRT while in the case of Heather Royalty is due 2 years before CT but 8 years before PRT.

Table 6.5. Government Take- Scenario3

Scenario3	Effective rate(%)	Total (£M)	Roy (£M)	PRT (£M)	CT (£M)
Argyll	43.8	341.6	0	124.0	217.5
Arkwright	33.0	86.9	0	0	86.9
Birch	33.9	93.7	0	2.7	91.0
Blake	43.1	253.7	0	88.5	165.2
Kappa	46.3	184.3	0	3.8	180.4
Highlander	44.6	364.1	0	132.8	231.4
Janice	69.6	324.8	0	0.4	324.4
Tiffani	34.6	21.8	0	0	21.8
Thelma	41.1	226.9	0	67.5	160.2
Toni	41.0	256.1	0	74.2	181.9
Very Small	Total	2153.9			
Arbroath	65.0	1353.5	0	999.1	354.3
Auk	71.5	1922.2	0	1537.2	385.0
Balmoral	35.8	315.9	0	34.3	281.6
Beatrice	41.9	544.6	0	149.9	394.7
Heather	50.9	683.5	0	354.8	328.7
Leadon	53.7	767.6	0	439.9	327.8
Montrose	51.9	556.1	0	295.0	261.1
Osprey	47.7	486.4	0	224.1	260.8
Scapa	48.1	703.8	0	329.6	374.2
Small	Total	7333.6			
Captain	63.9	1951.4	0	1394.8	556.5
Clair	67.6	2302.7	0	1746.6	556.1
Maureen	55.8	1261.5	0	764.5	497.1
Tern	72.0	2770.4	0	2229.0	541.4
Medium	Total	8286.0			
Alba	73.6	3837.6	0	3157.9	679.7
Schiehallion	69.1	4079.4	0	3181.1	898.3
Large	Total	7917.0			

Under Scenario 3, with 75 per cent PRT and 33 per cent CT, Arkwright, Tiffani and Janice are still protected against the impact of PRT. Birch, Beatrice and Balmoral however start paying, because their taxable income subject to PRT is now higher as Royalty is no longer deductible.

Also, it is important to stress that there is no significant difference in Government take from the large fields, as the major source of income is from PRT, unlike the very small fields, where the major source is CT.

Table 6.6 displays the results of profitability under both Scenarios 4 and 5.

Table 6.6. Oil Field Profitability- Scenarios 4 & 5

Scenario4	50% PRT, 30% CT			Scenario5	30% CT		
Fields	DCF (£M)	MAP (£M)	Difference %	Fields	DCF (£M)	MAP (£M)	Difference %
Very Small				Very Small			
Argyll	187.7	208.9	10.1%	Argyll	203.4	221.6	8.2%
Arkwright	54.6	62.3	12.4%	Arkwright	54.6	62.3	12.4%
Birch	34.6	35.6	2.8%	Birch	35.8	35.6	0.6%
Blake	163.9	172.5	5.0%	Blake	189.1	193.1	2.1%
Kappa	80.3	41.4	94.0%	Kappa	82.5	36.3	127.3%
Highlander	201.4	220.4	8.6%	Highlander	257.2	254.3	1.1%
Janice	-8.5	-44.6	80.9%	Janice	-3.4	-44.6	92.4%
Tiffani	-217.4	-301.0	27.8%	Tiffani	-217.4	-301.0	27.8%
Thelma	134.7	159.8	15.7%	Thelma	151.3	174.1	13.1%
Toni	102.7	149.1	31.1%	Toni	118.2	156.9	24.7%
Small				Small			
Arbroath	263.0	353.0	25.5%	Arbroath	345.0	447.9	23.0%
Auk	201.1	296.1	32.1%	Auk	266.9	415.8	35.8%
Balmoral	70.2	90.4	22.3%	Balmoral	77.6	90.4	14.2%
Beatrice	67.2	42.0	60.0%	Beatrice	79.3	72.2	9.8%
Heather	89.1	206.8	56.9%	Heather	99.9	133.3	25.1%
Leadon	259.7	370.1	29.8%	Leadon	373.6	462.8	19.3%
Montrose	148.8	169.0	12.0%	Montrose	174.1	181.7	4.2%
Osprey	153.7	213.4	28.0%	Osprey	184.3	224.7	18.0%
Scapa	233.7	303.1	22.9%	Scapa	276.2	355.9	22.4%
Medium				Medium			
Captain	215.7	384.3	43.9%	Captain	350.9	422.1	16.9%
Clair	162.0	400.8	59.6%	Clair	275.6	515.1	46.5%
Maureen	180.7	258.5	30.1%	Maureen	296.7	279.4	6.2%
Tern	252.2	471.2	46.5%	Tern	467.9	747.3	37.4%
Large				Large			
Alba	377.1	683.2	44.8%	Alba	683.7	1007.1	32.1%
Schiehallion	610.2	921.9	33.8%	Schiehallion	994.9	1443.2	31.1%

The abolition of PRT did not generate a significant difference on the very small and even small fields, unlike the larger fields. The difference is reduced between DCF and MAP in Scenario 5 relatively to Scenarios 2-4, as PRT reliefs do not apply anymore and their timing does not affect the distribution of the fiscal take.

Government revenues are displayed in Table 6.7 for both Scenarios 4 and 5.

Table 6.7. Government Take- Scenarios 4 & 5

Scenario4	Effective rate(%)	Total (£M)	PRT (£M)	CT (£M)	Scenario5	Effective rate(%)	Total (£M)	PRT (£M)	CT (£M)
Argyll	36.3	283.4	69.2	214.2	Argyll	30.0	235.0	0	235.0
Arkwright	30.0	79.0	0	79.0	Arkwright	30.0	79.0	0	79.0
Birch	30.7	84.8	1.8	83.0	Birch	30.0	83.6	0	84.0
Blake	37.0	218.0	59.0	159.0	Blake	30.0	176.7	0	177.0
Kappa	42.3	168.7	5.1	163.7	Kappa	41.0	165.2	0	165.0
Highlander	38.3	313.0	88.5	224.5	Highlander	27.0	217.6	0	218.0
Janice	64.0	297.9	4.7	293.2	Janice	63.0	294.6	0	295.0
Tiffani	31.4	19.8	0	19.8	Tiffani	31.0	19.8	0	19.8
Thelma	35.7	196.7	45.0	152.4	Thelma	30.0	165.4	0	165.0
Toni	35.5	223.2	49.5	172.8	Toni	30.0	187.7	0	188.0
Very Small	Total	1884.5			Very Small	Total	1624.6		
Arbroath	43.3	901.4	403.6	497.8	Arbroath	30.0	613.0	0	613.0
Auk	56.9	1528.5	1024.8	503.7	Auk	30.0	811.0	0	811.1
Balmoral	32.0	282.3	22.9	259.4	Balmoral	30.0	266.0	0	266.3
Beatrice	36.9	480.4	109.4	371.0	Beatrice	31.0	404.0	0	403.8
Heather	41.0	570.8	238.9	331.9	Heather	30.0	400.0	0	400.2
Leadon	46.5	664.7	335.3	329.3	Leadon	30.0	430.0	0	429.9
Montrose	40.3	410.4	149.6	260.8	Montrose	30.0	305.7	0	305.7
Osprey	36.4	371.2	93.6	277.6	Osprey	30.0	306.0	0	305.7
Scapa	40.6	592.9	133.2	459.7	Scapa	30.0	439.0	0	438.9
Small	Total	5802.6			Small	Total	3974.7		
Captain	53.7	1639.8	1022.0	617.8	Captain	30	924.0	0	924.0
Clair	55.9	1903.2	1248.2	655.0	Clair	30	1029.0	0	1029.0
Maureen	48.0	1084.3	575.9	508.4	Maureen	30	681.0	0	681.0
Tern	58.0	2229.9	1527.1	702.7	Tern	30	1161.0	0	1161.0
Medium	Total	6857.2			Medium	Total	3795.0		
Alba	58.6	3057.4	2155.1	508.4	Alba	30	1565.3	0	1565.0
Schiehallion	56.3	3325.0	2220.1	1104.9	Schiehallion	30	1770.9	0	1770.9
Large	Total	6382.4			Large	Total	3336.2		

In Scenario 5, it is important to stress that the abolition of PRT did not generate significant reduction in Government revenues in the case of very small fields, particularly. However, in the case of medium and large fields, the revenues are almost halved.

Table 6.8 shows the profitability of oil fields under Scenarios 6 and 7a.

Table 6.8. Oil Fields Profitability- Scenarios 6 & 7a

Scenario6	30% CT, 10% ST			Scenario7a	50% PRT (no Uplift), 10%ST, 30%CT		
Fields	DCF (£M)	MAP (£M)	Difference %	Fields	DCF (£M)	MAP (£M)	Difference %
Very Small				Very Small			
Argyll	192.1	202.5	5.1%	Argyll	153.4	175.8	12.7%
Arkwright	45.6	52.3	12.8%	Arkwright	45.6	53.7	15.1%
Birch	28.6	28.9	1.0%	Birch	26.2	19.2	36.5%
Blake	160.1	164.1	2.4%	Blake	129.0	138.6	6.9%
Kappa	52.8	11.4	363.2%	Kappa	50.3	10.1	398.0%
Highlander	226.2	215.4	5.0%	Highlander	164.8	182.8	9.8%
Janice	-65.4	-116.4	43.8%	Janice	-79.1	-105.6	25.1%
Tiffani	-220.5	-301.0	26.7%	Tiffani	-220.5	-301.0	26.7%
Thelma	127.1	147.9	14.1%	Thelma	132.2	138.7	4.7%
Toni	96.8	131.2	26.2%	Toni	80.0	115.1	30.5%
Small				Small			
Arbroath	292.4	380.1	23.1%	Arbroath	214.2	286.3	25.2%
Auk	227.3	352.9	35.6%	Auk	166.9	246.0	32.2%
Balmoral	49.7	53.9	7.8%	Balmoral	38.4	48.1	20.2%
Beatrice	50.6	48.3	4.8%	Beatrice	23.5	48.3	51.3%
Heather	76.2	108.3	29.6%	Heather	54.1	104.4	48.2%
Leadon	307.7	391.3	21.4%	Leadon	184.1	314.4	41.4%
Montrose	146.5	151.5	3.3%	Montrose	121.3	136.6	11.2%
Osprey	153.2	189.9	19.3%	Osprey	116.8	169.0	30.9%
Scapa	235.2	304.0	22.6%	Scapa	183.8	253.7	27.6%
Medium				Medium			
Captain	287.3	348.2	17.5%	Captain	142.1	282.1	49.6%
Clair	228.1	433.9	47.4%	Clair	118.3	289.2	59.1%
Maureen	230.5	220.9	4.3%	Maureen	95.5	161.7	40.9%
Tern	384.1	630.7	39.1%	Tern	181.1	362.2	50.0%
Large				Large			
Alba	564.9	842.4	32.9%	Alba	264.4	461.3	42.7%
Schiehallion	832.8	1226.7	32.1%	Schiehallion	463.8	736.6	37.0%

Scenario 6 illustrates the effect of the imposition of the extra 10 per cent charge on fields that previously were only paying CT. Scenario 7a represents the effects of the imposition of PRT along with 30 per cent CT and 10 per cent ST, but where no Uplift applies. To better estimate the significance of PRT reliefs, it is helpful to compare the results under Scenario 7a with those under Scenarios 7b and 7c. This is the situation where no oil allowance or Safeguard applies.

Government take under both Scenarios 6 and 7a is summarized in Table 6.9.

Table 6.9. Government Take- Scenarios 6 & 7a

Scenario6	Effective rate(%)	Total (£M)	CT+ST (£M)	Scenario7a	Effective rate(%)	Total (£M)	PRT (£M)	CT+ST (£M)
Argyll	36.5	284.4	284.4	Argyll	47.1	367.4	90.2	277.2
Arkwright	40.0	105.3	105.3	Arkwright	40.0	105.3	0	105.3
Birch	40.3	111.4	111.4	Birch	42.2	116.6	8.6	108.0
Blake	40.0	235.6	235.6	Blake	48.4	284.9	82.0	202.8
Kappa	55.3	220.3	220.3	Kappa	56.0	223.3	5.0	218.3
Highlander	35.5	290.1	290.1	Highlander	48.7	398.1	105.5	292.6
Janice	84.3	392.8	392.8	Janice	79.7	371.1	5.1	366.0
Tiffani	41.9	26.4	26.4	Tiffani	41.9	26.4	0	26.4
Thelma	40.0	220.6	220.6	Thelma	37.2	205.1	31.1	174.6
Toni	40.0	250.2	250.2	Toni	45.9	286.8	61.1	225.6
Very Small	Total	2137.0		Very Small	Total	2384.9		
Arbroath	39.2	817.3	817.3	Arbroath	52.5	1086.6	435.7	650.9
Auk	40.3	1081.5	1081.5	Auk	63.4	1703.2	1036.2	667.1
Balmoral	40.2	355.0	355.0	Balmoral	42.8	377.9	38.1	339.8
Beatrice	41.4	538.4	538.4	Beatrice	52.4	680.8	237.3	443.5
Heather	39.8	533.6	533.6	Heather	55.1	738.8	334.5	404.3
Leadon	40.0	573.2	573.2	Leadon	57.6	822.9	416.0	406.8
Montrose	40.0	434.5	434.5	Montrose	53.2	569.5	225.1	344.4
Osprey	40.0	407.6	407.6	Osprey	51.5	525.2	196.1	329.1
Scapa	40.1	585.2	585.2	Scapa	56.1	819.9	390.7	429.2
Small	Total	5326.3		Small	Total	7278.0		
Captain	40.4	1232.5	1232.5	Captain	64.1	1956.9	1207.4	749.5
Clair	40.0	1372.7	1372.7	Clair	64.1	2185.6	1354.9	830.7
Maureen	40.0	908.3	908.3	Maureen	60.1	1357.7	749.0	608.7
Tern	40.0	1547.8	1547.8	Tern	65.3	2512.6	1607.9	904.7
Medium	Total	5061.3		Medium	Total	8012.8		
Alba	40.0	2087.0	2087.0	Alba	66.4	3464.6	2296.0	1168.7
Schiehallion	40.0	2361.3	2361.3	Schiehallion	64.2	3789.3	2380.0	1409.3
Large	Total	4458.6		Large	Total	7271.1		

The effect of the abolition of the oil allowance and Safeguard on oil field profitability and Government revenue are displayed in Tables 6.10 and 6.11 respectively.

Table 6.10. Oil Field Profitability- Scenarios 7b & 7c

Scenario7b	No oil allowance			Scenario7c	No Safeguard		
Fields	DCF (£M)	MAP (£M)	Difference %	Fields	DCF (£M)	MAP (£M)	Difference %
Very Small				Very Small			
Argyll	87.6	96.1	8.8%	Argyll	154.8	178.5	13.3%
Arkwright	27.5	35.7	23.0%	Arkwright	45.6	52.3	12.8%
Birch	13.1	9.9	32.3%	Birch	27.3	28.9	5.5%
Blake	84.0	100.1	16.1%	Blake	138.5	138.4	0.1%
Kappa	4.1	-37.1	111.1%	Kappa	50.8	10.1	403.0%
Highlander	102.7	108.7	5.5%	Highlander	147.7	161.2	8.4%
Janice	-86.9	-125.9	31.0%	Janice	-75.4	-121.1	37.7%
Tiffani	-224.3	-301.0	25.5%	Tiffani	-224.3	-301.0	25.5%
Thelma	67.6	95.2	29.0%	Thelma	107.1	130.7	18.1%
Toni	44.7	81.8	45.4%	Toni	83.5	120.9	30.9%
Small				Small			
Arbroath	147.5	199.8	26.2%	Arbroath	207.1	296.8	30.2%
Auk	119.4	172.5	30.8%	Auk	170.6	249.9	31.7%
Balmoral	14.2	16.5	13.9%	Balmoral	49.7	53.9	7.8%
Beatrice	16.8	41.7	59.7%	Beatrice	25.0	48.3	48.2%
Heather	37.4	82.1	54.4%	Heather	61.3	108.3	43.4%
Leadon	160.5	265.6	39.6%	Leadon	208.1	301.0	30.9%
Montrose	76.6	72.5	5.7%	Montrose	124.7	140.6	11.3%
Osprey	80.9	123.9	34.7%	Osprey	126.9	173.7	26.9%
Scapa	130.4	174.9	25.4%	Scapa	198.8	258.8	23.2%
Medium				Medium			
Captain	148.8	281.6	47.2%	Captain	164.0	246.4	33.4%
Clair	105.8	291.9	63.8%	Clair	130.1	290.0	55.1%
Maureen	97.7	170.1	42.6%	Maureen	111.2	144.2	22.9%
Tern	152.8	338.1	54.8%	Tern	199.2	391.1	49.1%
Large				Large			
Alba	253.9	524.3	51.6%	Alba	301.6	587.4	48.7%
Schiehallion	463.3	714.9	35.2%	Schiehallion	445.0	721.1	38.3%

The oil allowance is found to be the most important PRT relief for the very small and small fields. In fact, the abolition of the oil allowance has had the most significant impact on those fields. While the abolition of the Uplift and Safeguard had relatively minor effects on the profitability, the effects were reversed with the abolition of the oil allowance.

Highlander field, for instance, paid an effective tax rate of 70.4 per cent under Scenario 7b where the oil allowance was abolished compared with 48.7 and 49.4 per cent under respectively the Scenarios 7a with no Uplift, and 7c with no Safeguard. Also, the Arkwright field was protected against the payment of PRT in all scenarios except Scenario 7b, although it utilised only 12mmbbl instead of 37.5mmbbl of the total oil allowance available[80]. In fact, many of the very small and small fields do not claim all the allowance available, due to their very low annual production. Furthermore, as oil allowance applies only when the Uplift has been fully utilised, the abolition of Uplift resulted in fields being able to claim a larger share of the allowance. As such, the abolition of the Uplift has been attenuated by the acceleration in the use of the oil allowance.

As for the other PRT reliefs, namely the Uplift and Safeguard, the effects were more pronounced in the case of medium and large fields. In fact, the effects of these two reliefs depend mainly on the value of the CAPEX as well as the payback period[81]. As the larger fields tend to have a longer payback period and larger CAPEX spend than the smaller ones, the Uplift and Safeguard relied are of greater significance. Nevertheless, the oil allowance is also important for the larger fields, which have the capacity to maximise all of the available allowance because of their high levels production. The equal importance of the three PRT reliefs to the medium and large fields can be seen from the close similarities between the effective tax rates under Scenarios 7a, 7b and 7c. In the case of Schiehallion field, for example, the effective tax rates are 64, 65.2 and 65.2 per cent for Scenarios 7a, 7b and 7c respectively.

[80] 37.5mmbbl is equivalent to the 5 Mt of total oil allowance allowed per field.
[81] See Chapter 5.

These findings are consistent under both DCF and MAP techniques.

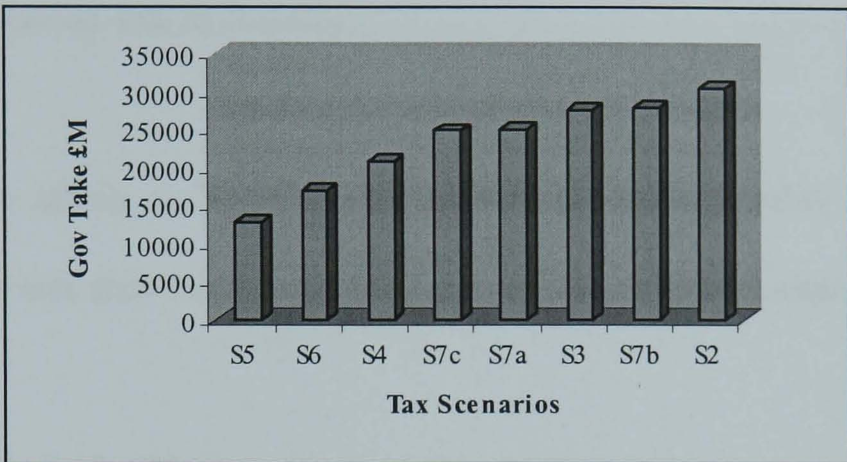
Table 6.11. Government Take- Scenarios 7b & 7c

Scenario7b	Effective rate(%)	Total (£M)	PRT (£M)	CT+ST (£M)	Scenario7c	Effective rate(%)	Total (£M)	PRT (£M)	CT+ST (£M)
Argyll	69.8	544.5	385.4	159.1	Argyll	46.6	363.1	83.0	280.1
Arkwright	64.2	169.2	106.4	62.8	Arkwright	40.0	105.3	0	105.3
Birch	63.7	176.1	107.9	68.2	Birch	41.8	115.5	6.8	108.7
Blake	67.3	396.5	268.1	128.4	Blake	46.0	271.0	59.0	212.0
Kappa	83.2	331.9	186.0	145.9	Kappa	56.1	223.5	5.2	218.3
Highlander	70.4	575.1	400.5	174.6	Highlander	49.4	404.0	115.4	288.6
Janice	95.8	446.3	89.0	357.2	Janice	87.5	407.7	24.7	383.0
Tiffani	54.5	34.3	0	34.3	Tiffani	54.5	34.3	0	34.3
Thelma	65.8	363.0	238.2	125.9	Thelma	46.8	258.1	63.0	196.0
Toni	65.9	412.4	270.3	142.1	Toni	44.8	279.9	49.5	230.4
Very Small	Total	3449.3			Very Small	Total	2462.3		
Arbroath	68.4	1424.7	999.1	425.6	Arbroath	58.8	1224.8	666.1	558.8
Auk	69.8	1875.2	1322.9	552.4	Auk	63.2	1697.0	1025.8	671.2
Balmoral	57.4	507.1	253.4	253.6	Balmoral	40.2	355.0	0	355.0
Beatrice	59.0	767.7	382.2	385.5	Beatrice	50.7	659.4	201.6	457.7
Heather	63.2	847.8	516.3	331.6	Heather	52.3	701.3	272.0	429.3
Leadon	64.7	925.0	586.2	338.8	Leadon	54.3	776.5	338.8	437.7
Montrose	68.8	735.7	502.0	233.6	Montrose	51.6	552.4	196.6	355.8
Osprey	65.8	670.9	438.9	232.0	Osprey	48.8	497.4	149.6	347.7
Scapa	68.1	995.2	682.9	312.3	Scapa	49.1	717.3	219.7	497.6
Small	Total	8753.1			Small	Total	7115.6		
Captain	65.3	1992.8	1267.1	725.7	Captain	61.3	1872.9	143.5	1729.4
Clair	68.1	2318.7	1576.8	742.0	Clair	62.3	2121.8	1248.6	873.2
Maureen	62.6	1415.9	846.0	569.9	Maureen	58.0	1311.5	672.0	639.5
Tern	69.1	2659.8	1853.3	806.5	Tern	64.0	2464.1	1527.1	937.0
Medium	Total	8387.2			Medium	Total	7770.3		
Alba	68.1	3556.0	2448.2	1107.8	Alba	65.0	3373.8	2144.6	1229.6
Schiehallion	65.2	3849.5	2480.0	1368.0	Schiehallion	65.2	3850.5	2493.0	1374.4
Large	Total	7423.5			Large	Total	7241.2		

Figure 6.1 compares the total Government take from all fields under the different tax scenarios. It indicates that Scenario 2, which reflects the pre-1983 fiscal package in the UK, generates the highest revenues. This is followed by Scenario 7b, where PRT applies at 50 per cent but without the oil allowance, alongside 30 per cent CT and 10 per cent ST.

Scenario 3 (75 per cent PRT and 33 per cent CT) generates the third highest take, followed by Scenario 7c (no Safeguard), which generates a very similar amount of Government revenues as Scenario 3.

Figure 6.1. Total Government Take under Different Scenarios



Scenario 4 (50 per cent PRT and 30 per cent CT) generates the fifth highest amount of revenue followed by a close figure from Scenario 7a (no Uplift). The least amount of fiscal take derived from the nine scenarios is Scenario 5 with only 30 per cent CT. The April 2002 changes that are supposed to generate a higher share of revenues as compared with the application of CT only appear to have achieved its objectives. However, the combination of CT and ST gives less revenue compared with the pre-1993 tax structure where both PRT and CT applied, despite the fact that PRT is not paid by all fields and provides several reliefs. Consequently, one could question the effectiveness of the abolition of PRT in 1993. Although the PRT generates a relatively higher share of Government revenues than other instruments, its share is mainly derived from the medium and large fields. As such, given the current state of the UKCS, where the majority of fields are very small, the PRT share is most probably going to be very small, as those fields do not pay PRT due to the oil allowance hence leaving the Government with almost nothing.

Another point that can be raised is the complication of PRT, associated mainly with the computation of its reliefs, which further can lead to inefficiency as discussed in the previous chapters. In this case, one can question the possibility of the application of simpler instruments that could generate similar amount of revenues. This point is further addressed in Chapter 8, where the UK PRT is compared with the Resource Rent Tax in Australia and the Special Tax in Norway.

The following two tables, 6.12 and 6.13 summarise the profitability of the selected fields under the various scenarios, using DCF and MAP techniques respectively.

Table 6.12. Oil Field Profitability under DCF- Summary

Scenarios / Fields	Base (£M)	UK2 (£M)	UK3 (£M)	UK4 (£M)	UK5 (£M)	UK6 (£M)	UK7a (£M)	UK7b (£M)	UK7c (£M)
Argyll	292.3	108.1	162.7	187.7	203.4	192.1	153.4	87.6	154.8
Arkwright	81.4	27.7	51.9	54.6	54.6	45.6	45.6	27.5	45.6
Birch	57.5	13.7	31.9	34.6	35.8	28.6	26.2	13.1	27.3
Blake	276.0	85.2	144.2	163.9	189.1	160.1	129.0	84.0	138.5
Kappa	171.4	-0.7	71.0	80.3	82.5	52.8	50.3	4.1	50.8
Highlander	350.2	97.5	173.3	201.4	257.2	226.2	164.8	102.7	147.7
Janice	182.4	-171.8	-26.9	-8.5	-3.4	-65.4	-79.1	-86.9	-75.4
Tiffani	-208.1	-237.8	-218.4	-217.4	-217.4	-220.5	-220.5	-224.3	-224.3
Thelma	224.1	68.5	120.1	134.7	151.3	127.1	132.2	67.6	107.1
Toni	182.6	47.3	89.5	102.7	118.2	96.8	80.0	44.7	83.5
Arbroath	503.1	132.9	186.5	263.0	345.0	292.4	214.2	147.5	207.1
Auk	385.4	105.9	160.6	201.1	266.9	227.3	166.9	119.4	170.6
Balmoral	161.4	-4.3	58.6	70.2	77.6	49.7	38.4	14.2	49.7
Beatrice	165.4	-11.1	53.7	67.2	79.3	50.6	23.5	16.8	25.0
Heather	170.9	25.2	78.2	89.1	99.9	76.2	54.1	37.4	61.3
Leadon	571.4	113.9	215.1	259.7	373.6	307.7	184.1	160.5	208.1
Montrose	257.1	77.5	129.4	148.8	174.1	146.5	121.3	76.6	124.7
Osprey	277.8	74.7	131.1	153.7	184.3	153.2	116.8	80.9	126.9
Scapa	399.2	130.6	202.9	233.7	276.2	235.2	183.8	130.4	198.8
Captain	541.4	77.8	164.4	215.7	350.9	287.3	142.1	148.8	164.0
Clair	418.3	59.8	115.7	162.0	275.6	228.1	118.3	105.8	130.1
Maureen	495.2	57.2	133.7	180.7	296.7	230.5	95.5	97.7	111.2
Tern	719.5	92.4	148.7	252.2	467.9	384.1	181.1	152.8	199.2
Alba	1040.1	116.4	228.1	377.1	683.7	564.9	264.4	253.9	301.6
Schiehallion	1481.2	223.7	436.9	610.2	994.9	832.8	463.8	463.3	445.0

Table 6.13. Oil Field Profitability under MAP- Summary

Scenarios / Fields	Base (£M)	UK2 (£M)	UK3 (£M)	UK4 (£M)	UK5 (£M)	UK6 (£M)	UK7a (£M)	UK7b (£M)	UK7c (£M)
Argyll	318.1	116.7	195.5	208.9	221.6	202.5	175.8	96.1	178.5
Arkwright	92.2	31.4	59.3	62.3	62.3	52.3	53.7	35.7	52.3
Birch	55.8	12.8	33.6	35.6	35.6	28.9	19.2	9.9	28.9
Blake	280.1	92.3	151.9	172.5	193.1	164.1	138.6	100.1	138.4
Kappa	137.6	-58.5	32.6	41.4	36.3	11.4	10.1	-37.1	10.1
Highlander	370.9	104.8	194.1	220.4	254.3	215.4	182.8	108.7	161.2
Janice	170.6	-231.7	-66.2	-44.6	-44.6	-116.4	-105.6	-125.9	-121.1
Tiffani	-301.0	-321.9	-301.0	-301.0	-301.0	-301.0	-301.0	-301.0	-301.0
Thelma	252.8	80.4	147.1	159.8	174.1	147.9	138.7	95.2	130.7
Toni	234.1	64.5	132.8	149.1	156.9	131.2	115.1	81.8	120.9
Arbroath	651.3	178.0	305.8	353.0	447.9	380.1	286.3	199.8	296.8
Auk	604.4	143.9	225.1	296.1	415.8	352.9	246.0	172.5	249.9
Balmoral	199.9	-25.9	79.4	90.4	90.4	53.9	48.1	16.5	53.9
Beatrice	143.8	-18.9	65.0	42.0	72.2	48.3	48.3	41.7	48.3
Heather	208.1	45.1	124.9	206.8	133.3	108.3	104.4	82.1	108.3
Leadon	677.2	181.4	355.7	370.1	462.8	391.3	314.4	265.6	301.0
Montrose	272.2	85.5	154.4	169.0	181.7	151.5	136.6	72.5	140.6
Osprey	329.2	114.6	197.5	213.4	224.7	189.9	169.0	123.9	173.7
Scapa	511.5	177.1	265.2	303.1	355.9	304.0	253.7	174.9	258.8
Captain	643.8	161.9	346.9	384.3	422.1	348.2	282.1	281.6	246.4
Clair	758.7	218.1	342.4	400.8	515.1	433.9	289.2	291.9	290.0
Maureen	455.0	34.3	216.3	258.5	279.4	220.9	161.7	170.1	144.2
Tern	1097.1	227.8	355.7	471.2	747.3	630.7	362.2	338.1	391.1
Alba	1501.3	285.0	505.3	683.2	1007.1	842.4	461.3	524.3	587.4
Schiehallion	2092.8	563.0	699.7	921.9	1443.2	1226.7	736.6	714.9	721.1

6.5. CONCLUSION

This chapter has proceeded with the evaluation of the UK petroleum fiscal regime, taking into consideration both the industry and Government interests, in an attempt to identify whether a fiscal package that is preferable for those two main players exists. The chapter has evaluated the effects of different tax scenarios on a sample of oil fields' profitability and Government revenue in the UKCS, in the light of the debate surrounding this subject, as the previous chapters demonstrated.

The evaluation was carried out using two evaluation techniques, the traditional DCF method and the more modern approach using MAP. Such a comparison permits to discern if the more new technique gives significant difference than the traditional method and whether it should be recommended as a replacement to the traditional technique. Further, it allows investigating the consistency in results.

The most severe fiscal package in terms of Government take on profitability is the one that applied to oil activity before 1983, based on the combination of Royalty, PRT and CT (Scenario2). This is the only Scenario that rendered several fields unprofitable. Scenario 7b, where the application of PRT alongside CT and ST but without the oil allowance, generated a similar reduction in profitability particularly for the smaller fields, although less severe. In fact, the oil allowance is found to be the most important relief for smaller fields, while all of the three PRT reliefs are of equal importance for larger fields. For instance, despite the high PRT rates the very small and small fields, especially those which were rendered loss making under Scenario 2, were nonetheless, profitable under Scenario 3.

Some of the very small and small fields are protected against the payment of PRT due mainly to oil allowance relief. For larger fields, all PRT reliefs are equally important. Furthermore, for fields in PRT paying position, the reliefs are also important as they delay payment of the tax. For instance, in the case of Heather field, under Scenario 2, Royalty hits 2 years before CT but 8 years before PRT.

In terms of Government revenue generated under the different tax scenarios, Scenario 2 generated the highest fiscal take, followed by a similar finding under Scenario 7b.

Scenario 3 (75 per cent PRT and 33 per cent CT) generated the third highest level of Government take. In the scenarios where PRT applies, the major source of Government take is from the larger fields. Scenario 7c (no Safeguard) produced almost the same amount of Government revenues as in Scenario 3. Scenario 4 (50 per cent PRT and 30 per cent CT) generated the fifth highest amount of revenues followed by a close figure from Scenario 7a (no Uplift).

The lowest fiscal take is generated under Scenario5, where CT of 30 per cent applies. The imposition of the 10 per cent ST in 2002 has produced a higher Government take compared with Scenario 5. Notwithstanding, the 2002 structure still generates the second lowest take relatively to other scenarios. This is particularly true when compared with the results arising from the application of PRT and CT, despite the fact that PRT is not paid by all fields and affords several reliefs. For instance, although the abolition of PRT does not induce significant reduction in Government revenue in the case of very small fields, in the case of medium and large fields the revenues are almost halved.

Consequently, one can question the effectiveness of the abolition of PRT in 1993, on fields that received development consent after that date. However, with the majority of fields currently developed in the UK North Sea being small, PRT is likely to be a poor source of revenues for the Government, given its generous reliefs. Further, abolishing any one of those reliefs would have a discriminating effect with respect to fields' size. Also, PRT has high administrative costs as compared with the other instruments, namely Royalty and CT.

As such, from the analysis done in this chapter, it can be concluded that maintaining the pre-1983 structure would have resulted in many fields abandoned or undeveloped. Maintaining the post-1983/pre-1993 structure would have resulted in low fiscal revenues generated. The changes made to the UK petroleum fiscal regime in 2002 may not have increased dramatically the fiscal receipts as compared with imposing 30 per cent CT. Nevertheless, the post-2002 structure based on Income Tax only makes the regime more neutral, easier to administer and better attuned to the current mature state of the UK oil province.

Regarding the evaluation techniques used DCF and MAP produced different project NPV. The difference is particularly significant for larger, long-term projects. This is mainly due to the DCF method's use of a high constant discount rate, which tends to undervalue long term projects. Whereas in the case of MAP, given the Mean Reversion Model, the risk discounting tends to decline over time. As such, DCF undervalues profitability while at the same time over-estimates the impact of taxation. Therefore, MAP can provide a more useful evaluation than its DCF counterpart.

In principle, the MAP method is preferable than DCF because it discounts revenues and costs using discount rates which reflect the risks inherent in each of these components. MAP discounts revenue using a discount factor that includes components such as oil price volatility, financial risk, mean reversion of oil prices and time (Emhjellen & Alaouze, 2001). Additionally, MAP can more readily exploit a sophisticated dynamic model of oil prices as compared with the DCF technique.

Nevertheless, the main findings regarding the impact of taxation on oil field's profitability are consistent between MAP and DCF, although with MAP evaluation, the impact of taxation is less severe compared with DCF. This supports the findings of Bjerkedal (2000) who argues that the taxes are overestimated in any project where taxes are discounted at a rate above the risk free rate. However, in terms of projects ranking, the results are not very consistent. This can be of particular significance in the case where a company is selecting between projects, but this goes beyond the scope of this thesis.

This chapter presents a particular approach to evaluate the fiscal regime that applies to oil activity in the UKCS. The study done in this chapter is a time-line analysis, evaluating the principal fiscal packages that applied to oil activity since 1975, using and contrasting two evaluation techniques, the traditional commonly used DCF and the more modern technique, MAP, which can also be considered as an evolved version of DCF. The study further sets the basic concepts for the evaluation techniques hence it is complemented with the analysis done in the following chapter. The same tax scenarios and fields are considered for evaluation but an additional assumption is taken in consideration. This is the flexibility in decision making, requiring the use of the Real Options Theory, which can be considered to be an expansion of MAP.

CHAPTER SEVEN

THE IMPACT OF TAXATION ON THE TIMING OF FIELD DEVELOPMENT

7.1. INTRODUCTION

The previous chapter evaluated the effects of the principal fiscal packages in the UK on both oil field profitability and Government revenue, comparing the findings using two evaluation techniques DCF and MAP. This chapter proceeds with the evaluation of the regime and expands the empirical analysis undertaken in Chapter 6, taking into consideration another important dimension namely the effect of taxation on the timing of an oil field development. The chapter investigates whether the tax structure and rates have any effect on the delaying of the decision to develop a field, thereby identifying any related investment distortions and addressing the neutrality of the regime[82].

When economic conditions are not favourable, companies are able to delay their investment decisions to a more profitable period and, when faced with an uncertain situation, companies can also choose to wait for more information to reduce the uncertainty and then proceed with the investment. The change in investment timing in turn affects the timing of fiscal receipts. Kemp & Rose (1982) argue that the Government normally aims to collect a part of the fiscal take at the early stage of an oil field life. If the development of an oil field is delayed, the fiscal receipts from that project are delayed as well. Accordingly, both oil companies and Government interests' can be affected by a change in the development timing.

[82] See Chapter 2, Section 2.3

In the UK, several fields were discovered and explored in the 1970s and early 1980s, but were developed only in the 1990s[83]. Kemp, Rose & Dandie (1992) ague that a very large number of fields have been discovered in the UKCS but have not yet been developed. This is due to several factors including taxation, technology and oil price. Martin (1997) maintains that fiscal terms are the main factors affecting the timing of the decision to develop an oil field in the UKCS, where the 1983 and 1993 fiscal changes[84] led to peaks in production in the years 1985 and 1995. Technology is the next important factor, followed by the oil price (Martin 1997).

This chapter concentrates on analysing the possible effects of different fiscal instruments and packages on the timing of oil field development in the UKCS. This is of particular significance nowadays given the maturity of the UK North Sea and the need to develop discovered fields so as to maintain production and sustain self-sufficiency.

The ability to affect the timing of investment introduces a new aspect to the research, which is flexibility in decision-making. "Flexibility is the degree to which a project is able to adjust to changes in different parameters" (Emhjellen, 1999, p.59). Dixit & Pindyck (1994) argue that such flexibility can add value to a project, hence the need for an evaluation technique that captures it and allows a useful evaluation of field profitability as well as the appropriate impact of taxation on that profitability. An inappropriate technique can result in an incorrect measure of the taxation impact.

[83] For example, Tiffani was discovered 1979 and Toni in 1977, but they were developed in 1990.

Laughton (1998b) argues that one of the main limitations of DCF technique is that it does not consider the timing of investment or production, as applied in its simplistic form. As such, DCF is unable to capture flexibility in decision-making since it is a static approach based on a "now or never" decision (Laughton, 1998b). Because DCF does not make provision for flexibility, it can undervalue oil projects (Laughton, Sagi & Samis (2000), Watkins, (2002)).

The use of a more useful technique, more precisely, the Real Options Theory (ROT), for the valuation of petroleum projects is gaining interest in the academic literature[85] (Zettl, 2001). Laughton, Sagi & Samis (2000) argue that over the past years, an increasing number of organizations in the upstream petroleum industry have been experimenting with the use of the Real Options technique, which is becoming the focus of almost all of the attention and writing in the energy industry. Laughton (1998b) maintains that ROT is one technique that avoids some of the limitations of the DCF methodology.

ROT was originally developed for the appraisal of financial derivatives. The most common types of derivatives are forward contracts and financial options. An analogy exists between financial options and real investments, such as petroleum projects. It was this similarity that led to the adoption of ROT for the valuation of such projects[86]. Because ROT is based on the concept of "wait and see" in decision-making, it provides management with certain degree of flexibility, which in turn produces an option value.

---

[84] See Chapter 3.

[85] Among others, Dixit & Pindyck (1994), Laughton (1998), Laughton et al (2000), Zettl (2001), and Dias (2002)

[86] This analogy is developed in Section 7.3.2.

"The option value is the value of making a future decision after the outcome of an uncertain variable is known and therefore avoiding the risk of a poor outcome (Emhjellen, 1999, p. 59). Dixit & Pindyck (1995) argue that ignoring the option value can lead to a significant underestimation of a project's value, in this case an oil reserve. By treating an undeveloped oil reserve as an option, its value can be determined correctly. Additionally, ROT can be considered as an expansion to MAP but applied in situations where the management of future flexibility is analysed concurrently[87] (Laughton, Sagi & Samis, 2000). As such, ROT also benefits from the major advantages of the MAP approach namely separate discounting of the individual Cash Flow components and the incorporation of a more rigorous oil price model.

Although a number of studies have addressed the subject of investment timing in the oil industry and the application of ROT to evaluate petroleum projects, only limited attempts have been made to evaluate the effects of taxation on timing. Among those attempts, Zhang (1997) applied ROT to evaluate the neutrality of PRT, but his analysis was limited to PRT without considering other combinations of tax instruments. Besides, Zhang's (1997) study was based on hypothetical fields, which is the case with most of the published studies on the application of ROT. Such a simplification may not reflect the real complications resulting from uncertain production rates or development costs. Furthermore, while other studies focused on the effect of some parameters, such as the time to expiration and the amount of oil price uncertainty on the value of flexibility, this chapter focuses on the effect of taxation on investment timing.

[87] This point is further developed in Section 7.4.3

The chapter investigates whether taxation enhances or deters a real option value and hence flexibility. Accordingly, it brings a new perspective with respect to evaluating the effect of taxation on real options value and as such on investment and development incentives, particularly in the UKCS.

The remainder of this chapter is organized as follows. Section 7.2 develops the basic concepts of Real Option Theory, highlighting the limitations of DCF with respect to the value of waiting. The section further reviews the concepts of financial options and their analogy to real options. Section 7.3 proceeds with the evaluation of different fiscal scenarios using ROT. Section 7.4 presents and discusses the results. Section 7.5 summarises and concludes the chapter.

7.2. DCF "NOW OR NEVER" CONCEPT

This section develops a simple two-period example to illustrate the "now or never" concept using the simplistic form of DCF technique. The example highlights the limitations of DCF in considering any increase in the project value, in the case where the investor chooses to wait for new information to arrive and for better economic conditions before undertaking his investment.

Assuming an oil project with an instant investment $I = \$160$, producing 10 barrels of oil per period, with zero operating cost.

The current price of a barrel of oil is $P_0 = \$20$, but in year 1, there is q=0.5 probability that the price will be \$25, and *(1-q)* probability that it will be \$15. After that, the price will stay at the new level. Using discrete DCF discounting, with a 10 per cent discount rate, the NPV of this project is equal to:

$$\text{NPV} = -160 + 200/(1.1) = \$21.8$$

Under the DCF approach, since the project NPV is positive, one should invest now. However, such a conclusion is not necessarily correct because it ignores the opportunity cost of investing now instead of waiting and keeping open the possibility of not investing should the price fall. For instance, if instead of investing now investors decide to wait and invest next year, the NPV in each price scenario is given as in the following:

- NPV_h (High Price Scenario): $NPV_h = (-160/1.1) + (250/1.1) = \$81.8$
- NPV_l (Low Price Scenario): $NPV_l = (-160/1.1) + (150/1.1) = -\$9$

And the expected NPV in year 1, *ENPV*, is given by:

$$ENPV = 0.5\,NPV_h + 0.5\,NPV_l = \$36.4$$

This result indicates that it would be correct to delay the investment by one year. Since companies have the option to delay their investments, it is assumed that they will go ahead only if prices are high, as such earning NPV_h of \$81.8 on their investment.

In this case, delaying the investment to year 1 allowed the company to earn extra $60 (81.8-21.8) on its project. This difference between the profitability from investing in year 1 and the profitability of investing today can be regarded as the value of waiting. However, this value is not incorporated in the DCF technique, which assumes an inability to initiate actions to take advantage of changes in prices. In this case, companies are faced with a strict choice: either to invest now or to abandon the project.

The lack of flexibility in DCF is one of the major limitations of this technique. Dentskevich (1991) argues that DCF tends to miss value investments. This is particularly true in situations of high uncertainty where management can respond flexibly to new information (Copeland & Keenan, 1998). In the DCF technique, a high level of risk is normally reflected in a high discount rate, which in turn reduces the value of a project. However, "that would grossly underestimate the value of the project, as it completely ignores the flexibility that a company has regarding when to develop the project" (Dixit & Pindyck, 1995, p.113).

Lund (2001) argues that flexibility can increase the value of a project by almost 95 per cent, while Pike & Neale (1996) maintain that the "true" NPV from a project should be expressed as the sum of the NPV of the basic project and the NPV of waiting (p.336). The authors further add that this partly explains the reason for which companies frequently defer wealth creating projects or accept uneconomic projects. Ekern (1998) maintains that a traditionally calculated positive NPV is neither a necessary nor a sufficient condition for a project to be profitable.

7.3. REAL OPTIONS THEORY: BASIC CONCEPTS

ROT was developed to overcome the limitation of DCF in terms of incorporating flexibility in project evaluation. The options evaluation technique was originally applied in the pricing of complex financial instruments, but the origin of the term "real options" can be attributed to Myers (1977) who first identified the similarity between real assets and financial options. This analogy led to the development of options technique for the valuation of real projects.

This section reviews the basic concepts of ROT and analyses financial options, addressing their similarity with real investments and more precisely with the development of an oil field.

7.3.1. IRREVERSIBILITY AND TIMING

Dixit & Pindyck (1995) argue that the DCF technique is based on questionable assumptions. Firstly, DCF assumes that investments are reversible (i.e. they can be undone and expenditures recovered should market conditions turn unfavourable). Secondly, if investments are irreversible they are a now-or-never proposition that is, if the firm does not undertake the investment now it will lose the opportunity forever (Dixit & Pindyck, 1995). Although it is possible that some types of projects can fall into these categories, several do not. These assumptions undermine the robustness of the DCF approach (Siew, 2001).

When a firm makes an irreversible investment it gives up the possibility of waiting for new information that might affect the desirability or timing of the expenditure. This lost value is an opportunity cost that must be included as part of the cost of the investment and investment rules that ignore this can be significantly in error (Dixit & Pindyck, 1994).

In order to incorporate the opportunity cost into the evaluation of a project, both irreversibility and timing are required. Irreversibility refers to the fact that once investment is taken, some costs cannot be recovered if the investor changes his mind. Timing refers to the ability to delay investment as an alternative to investing today, until new information arrives.

While the DCF rule compares investing today with never investing, a more useful comparison can be to examine a range of possibilities: investing today, or waiting longer and perhaps investing next year, or waiting longer and perhaps investing in two years and so on (Dixit & Pindyck, 1995). Dias (2001) argues that this ability to delay an irreversible investment can profoundly affect the decision to invest.

Irreversibility and timing constitute the key assumptions in ROT. They provide a company with the opportunity or option to invest. Because this option can be valuable, as Section 7.2 demonstrated, it can be inappropriate to ignore it from the evaluation of projects' profitability, particularly when analysing the effect of taxation on that profitability.

The opportunity to invest is similar to holding a financial call option. Therefore, to understand the way flexibility is incorporated into the evaluation, the next section develops the concept of financial call options and expands the analysis to real projects, such as to the development of oil fields in the UK North Sea.

7.3.2. FINANCIAL OPTIONS

Options in real investments originate from the idea of financial options. Like a forward oil contract, financial options are the most common derivatives and are used to manage exposure to the risks associated with the underlying asset[88]. A financial option is "a contractual arrangement giving the owner the right, but not the obligation to buy (call option) or sell (put option) the underlying asset, at a given price, at some time in the future" (Pike & Neale, 1996, p.319). The fixed price specified in an option contract is called the Exercise or strike Price, E, and the date after which an option can no longer be exercised is called the Expiration or Maturity date, T_M.

Financial options are widely used in the financial community, where it is possible to buy options on all kinds of assets such as shares, bonds, foreign currency and commodities. The rest of this section focuses on options over shares. Furthermore, there are two types of options: An American type, which can be exercised at any time up to and including the expiration date and a European option, which can only be exercised on the expiration date (Bodie & Merton, 2000).

[88] See Chapter 6, Section 6.3

This chapter considers the American call option, because in the upstream oil industry, several real options are of American nature. For example, purchasing an oil lease normally gives the E&P company the right but not the obligation to develop the field should commercial oil be discovered. It is most likely that such an option can be exercised at any time during the life of the lease (Siew, 2001).

For illustrative purpose, assume an American call option that expires in 3 months time. Its underlying price, which is the closing price on the current date, is 120. The strike price is 115 and the last price at which the option was traded was 7. The hypothetical value of an option if it were to expire immediately is called its intrinsic value (Bodie & Merton, 2000, p.385). Therefore, if the American option considered in this example is expiring immediately, it would be worth the difference between its underlying price (120) and its striking price (115), as such if exercised immediately the intrinsic value of the call is 5. However, the option price is 7, therefore exceeding its intrinsic value by 2. This difference is called the option's time value[89], also called the option premium (Dias, 2001).

Let F be the option value, which is the sum of its intrinsic value (Stock price, S_T, less the Exercise price, E) and its time value. As the expiration date of the option approaches, the time value decreases but at expiration the option is worth its intrinsic value (Zettle, 2002). Figure 7.1 illustrates the call option payoff that depicts the relation between the value of the option (measured on the vertical axis) and the price of the underlying asset (on the horizontal axis). It is this payoff that affects investment-timing, in the following way:

- If the exercise price, E, is higher than the stock price, S_T, the option is *out-of-the money* or worthless ($F = 0$), and investors would not take the option, so as not lose money since exercising the option today would yield a negative net payoff. In this case, the intrinsic value of the option is zero, since it cannot be negative (Dias, 2001).

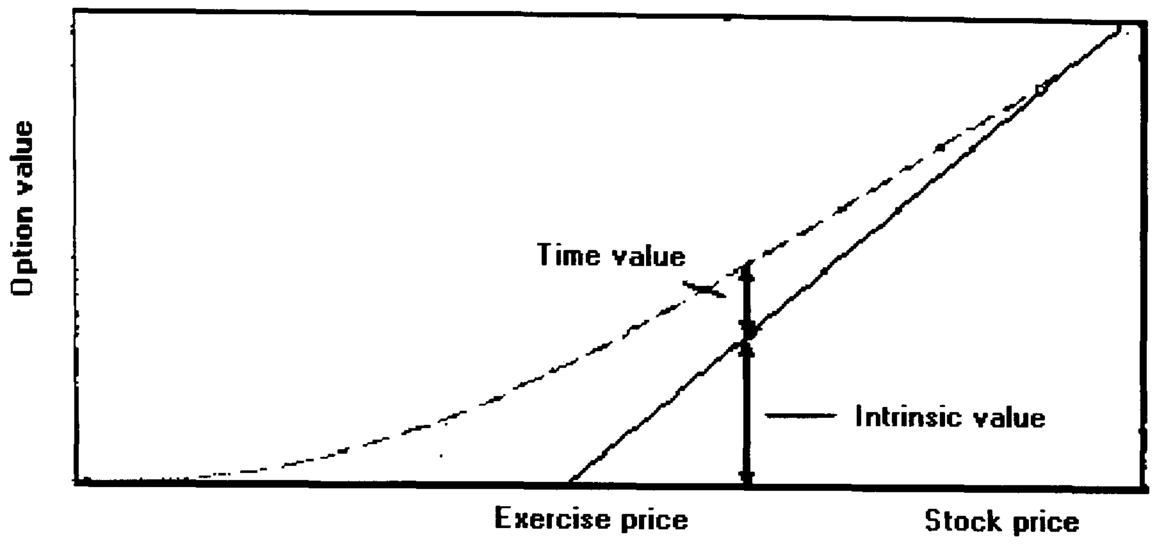
- If E is equal to S_T, the option is *at-the-money* and exercising the option today would yield a zero payoff ($F = 0$).

- If E is lower than S_T, the option is *in-the-money* and exercising the option today would yield a positive net payoff ($F = (S_T - I) + TimeValue$). However, the fact that the option is in-the-money does not necessarily mean that investors should exercise the option (Dixit & Pindyck, 1994). Dias (2001) argues that investors should wait until the option is *deep-in-the-money* to invest, where there is no value for waiting, or the value of waiting is too low compared with the intrinsic value ($F = S_T - I$).

In Figure 7.1, the dotted line represents the actual option value as a function of the stock price, while the lower limit shows that the value of the option equals the payoff if exercised immediately. It also shows that the option value never falls below this payoff, hence at expiration, the value of the call can be expressed as max (S_T-E, 0).

[89] This example is adapted from Bodie & Merton (2000).

Figure 7.1.Call Option Payoff Diagram[90]



7.3.3. ANALOGY BETWEEN FINANCIAL OPTIONS AND OIL PROJECTS

The analogy between financial and real options is the basis for using ROT in the valuation of corporate investments. The common element for using this theory in the evaluation of real projects is that the future is uncertain, and in an uncertain environment having the flexibility to decide what to do after some of that uncertainty is resolved definitely has value. Options pricing theory provides the means for assessing that value (Bodie & Merton, 2000). Investment opportunities are "options- rights but not obligation to take some action in the future" (Dixit & Pindyck, 1995, p.105). As such, an irreversible investment opportunity can be compared to a financial call option. The holder of the call option has the right, for a specified period, to pay the Exercise price and to receive, in return, the asset, for example a share that has some value.

[90] Adapted from Zettl (2002)

Similarly, a company with an investment opportunity has the option to spend money now or in the future (the Exercise price) in return of an asset of some value (the entitlement to the stream of profits from the project). Siew (2001) argues that this flexibility may have value and should be reflected in the appraisal of a project.

The earlier applications of ROT are in evaluating exhaustible resources, namely petroleum projects, which require long term planning horizons. "Nowhere is the idea of investments as options better illustrated than in the context of decisions to exploit deposits of natural resources" (Dixit & Pindyck, 1995, p.113). Given the technical and economic uncertainties in oil projects, the application of ROT for the evaluation of such projects can be of particular significance (Dias, 2001).

The classical model of Paddock, Siegel & Smith (1988) is one of the earliest and most popular models to evaluate oil reserves using option-pricing techniques (Dias, 2001). An undeveloped reserve is an option; it gives the owner the right to invest in development of the reserve, immediately or later, depending on market conditions. By valuing this option, the value of the reserve can be determined as well as the optimum point cut which it should be developed (Dixit & Pindyck, 1994). "Developing the oil reserve is like exercising a call option", (Dixit & Pindyck, 1995, p.113), and the exercise price is the cost of development. Oil activity is rich in real options, which if managed optimally enhance the value of the portfolio of projects and real assets in general for the oil company (Dias, 2001). An oil company has various options, such as the option to explore, to appraise, to develop, to produce and to abandon[91].

[91] For a field life cycle, See Chapter 5, Section 5.2.1.

In the Exploration phase, the firm has the option to drill the well or to wait. If it decides to explore and in situation of discovering an oil reserve, the firm has the option to invest in the Appraisal phase to ascertain the geological characteristics of the field. If the appraisal is undertaken, then, the company has the option of committing a large investment in development of the reserve or to wait. If the field is developed, then the company has the option to produce or to wait. If it produces and economic conditions turn unprofitable, the company has the option to abandon.

The focus of the analysis in this chapter is on the Development option, where flexibility is of particular importance[92]. The Development strategy has a significant impact on the profitability of an oil project. It requires large investment costs, and is made early in the project's lifetime where information concerning future oil prices is uncertain. Hence, the selection of the development strategy is a challenging task for the decision-maker (Lund, 2001).

7.3.4. VALUING REAL OPTIONS

The most familiar model for the pricing of options is the Black-Scholes model, developed in the early 1970s. Under the Black-Scholes formula, there are five variables that need to be estimated in order to calculate the option value[93].

---

[92] When development plans are made, Exploration and Appraisal costs are sunk costs and are normally disregarded (Lund, 1987). At the Production stage, operators may choose to wait (i.e. temporarily stop production) if, for instance, oil prices decline. In this case, although there are no direct costs associated with the decision to wait, the operator is still faced with the fixed operating costs, hence making postponing production less attractive (Lund, 2001). Furthermore, Lund (1987) argues that the economic significance of flexibility at the abandonment stage is small.

These are:

1. The current price of the underlying stock, S_T.
2. The Exercise price, E.
3. Annual volatility of stock price, σ (a measure of the amount by which the stock price could change during the time to maturity of the option).
4. Risk free interest rate, i
5. Time to expiration, T.

In addition to these factors, Merton (1973) generalised the Black-Scholes model to allow the incorporation of a sixth parameter, dividend yield, *d*, which is the dividend per share divided by the market price at time of purchase[94].

The development of an oil field is analogous to a financial option. To acquire an offshore oil field, the company must first bid for an exploration license for exclusive rights to explore a particular offshore block. In general, the exploration license lasts five years during which the oil company has to make a decision on whether to proceed with the development or to return the block to the host government (Siew, 2001). Table 7.1 summarizes the analogies between financial options, real options and extends the comparison to a petroleum development project.

---

[93] See Appendix H for a review of the Black Scholes model.
[94] As referred to by Boddie & Merton (2000), p.400.

Using the financial options analogy, the current estimate of the expected value of the undeveloped reserve on which the oil company has an option to invest in (current asset value) can be viewed as the current stock price.

The Exercise price for the undeveloped reserve would refer to development cost (investment) incurred should the project be carried out. The annual volatility of the option refers to the measure of the amount by which the current asset estimate can change during the length of the option. Since the current value of the undeveloped reserve is assumed to be only a function of the oil price, the annual volatility is that of oil price.

Table 7.1. Analogy between Financial and Real options[95]

Option Terminology	Financial Options	Real Options	Petroleum Project
Value of underlying asset	Stock price	Gross project value (Present Value of expected Cash Flow)	Present Value of the developed Reserve
Exercise price	Exercise price	Present Value of investment Expenditure	Present Value of capital costs
Maturity Time	Time to expiration	Time span during which The investment can be undertaken	Negotiated development Period (Relinquishment Requirement)
Volatility	Volatility of stock price	Volatility of gross Project value	Volatility of oil price
Risk free interest rate	Risk free interest rate	Risk free interest rate	Risk free interest rate
Dividend	Dividend	Net convenience yield	Net convenience yield

The risk free rate of interest used to calculated financial options is the same for real options.

[95] Adapted from Dias (2001) and Zettl (2002).

The time to expiration is related to the maximum time that the investment decision can be postponed. The length of the exploration license or the relinquishment date[96] can be viewed as the time to maturity of the option. At expiration, if the option was not exercised before, the firm either presents the development investment plan (commit to start the investment immediately) or returns the concession to the Government (Dias, 2002). Finally, the dividend of the oil project is the net production revenue less the rate of depletion, also called the cash flow rate (net cash flow as a percentage of the project value) or the net convenience yield (Dias, 2001).

Let V_{et} be the present value of the expected cash flows from the project, in other words, V_{et} is the present value of the operating revenues less operating costs and tax.

$$V_{et} = R_{et} - OE_{et} - T_{et} \tag{7.1}$$

Where:

- R_{et} is the present values of the expected revenue cashflow in period t.
- OE_{et} is the present values of the expected cost cashflow in period t.
- T_{et} is the present values of the expected tax cashflow in period t.

Let I'_{et} be the present value of the investment expenditure net of fiscal benefits.

96 "When the lease must be given back to the Government because the development of the project has not been undertaken" (Emhjellen, 1999, p.69).

$$I'_{et} = I_{et} - FB_{et} \qquad (7.2)$$

Where:

- I_{et} is the present value of capital expenditures in period t.
- FB_{et} is the present value of investment fiscal benefits in period t.

The project cash flows can be obtained when the company decides to develop the field. In this case, the company exercises its option by paying the exercise price, I_{et}, net of fiscal benefits[97]. Therefore, the immediate exercise of the option generates a net payoff, or the net value of the project, which is the NPV_{et}, where:

$$NPV_{et} = V_{et} - I'_{et} \qquad (7.3)$$

Let F_r be the value of the real option, in this case the undeveloped oil field. This value is determined from the partial differential equation based on the Black-Scholes model, as follows[98]:

$$\frac{1}{2}\sigma_V^2 V_{et}^2 F''(V) + (i-\delta)V_{et}VF'(V) - iF = 0 \qquad (7.4)$$

This equation is solved subject to the following boundary conditions[99]:

[97] I'_{et} is equivalent to the Exercise Price, E, in the case of a financial option, as assumed on p. 208.

[98] For a derivation of this equation see Appendix H.

[99] For an explanation, see Appendix H.

$$
\begin{aligned}
&F(0,t) = 0 \\
&F(V,t) = \max(V_t - I, 0) \\
&F(V^*,t) = V^* - I \\
&F'(V^*,t) = 1
\end{aligned}
\qquad (7.5)
$$

Where:

- δ is the dividend yield
- F' is the first derivative of F
- F'' is the second derivative of F
- V^* is the threshold, which is the critical value of V where the real option is *deep-in-the-money* and the value of waiting is zero (Cappuccio & Morettor, 2001).

The decision to exercise the option and develop of the field is taken in the light of the option value, as explained below and further illustrated in Figure 7.2.

- If $V_{et} > I'_{et}$, $NPV_{et} > 0$ and the option is *in-the-money*. However, the company should consider exercising its option when it is deep in the money, where $V > V^*$, the option premium is zero and the option value, F_r, is equal to its intrinsic value, NPV_{et}.

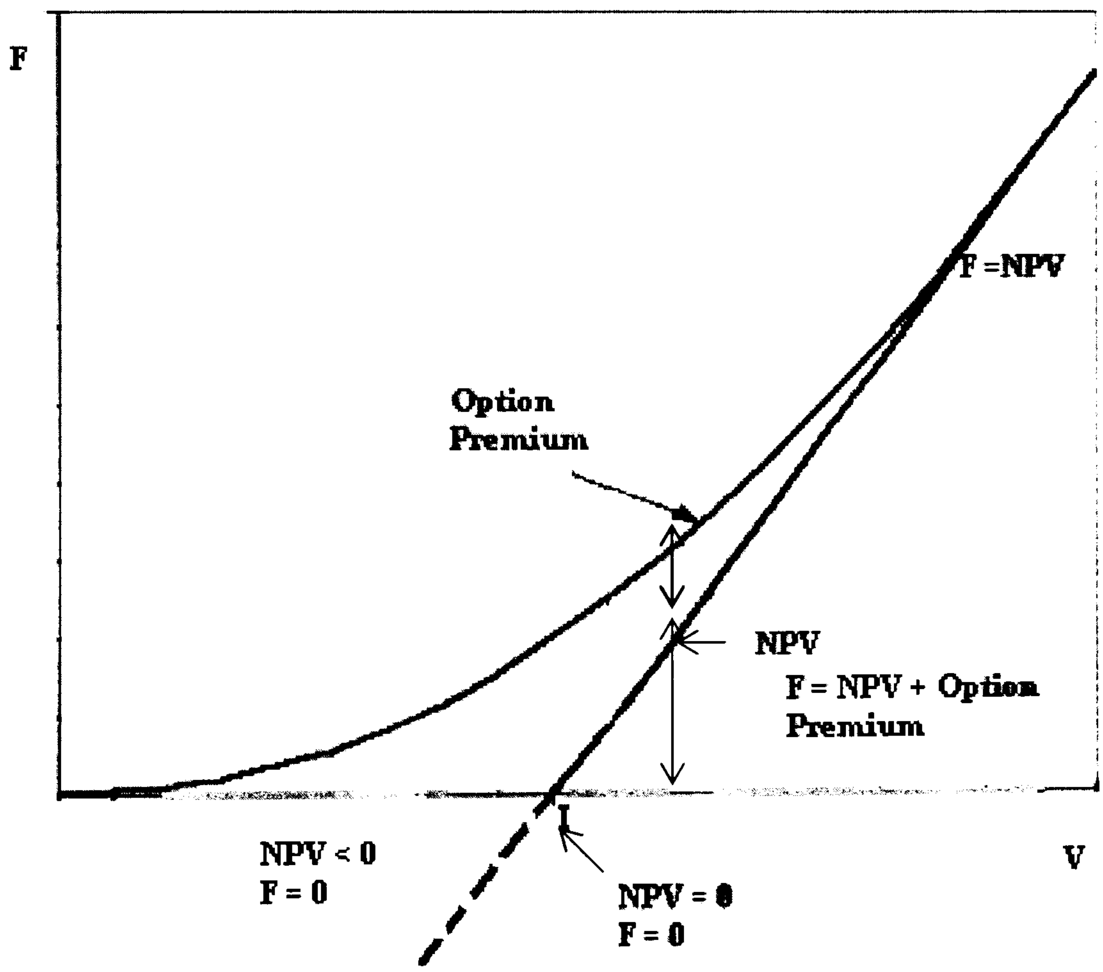
- If $V_{et} = I'_{et}$, $NPV_{et} = 0$ and the option is *at-the-money*. In this case, $F_r = 0$.

- If $V_{et} < I'_{et}$, $NPV_{et} < 0$ and the option is *out-of-the-money*. Also, in this case, $F_r = 0$, because the option value cannot be negative[100].

Subsequently, because the option value cannot be negative, it can be said that the payoff from a real option is equal to:

- $V_{et} - I'_{et}$, if $V_{et} > I'_{et}$
- 0, if $V_{et} < I'_{et}$

Figure 7.2. Investment Decisions & Real Options[101]



[100] See Section 7.3.2.
[101] Adapted from Dias (2002)

Through its double effect on the net payoff, firstly on the project value and secondly on the investment expenditure, taxation is likely to affect the decision to exercise the option or the timing of the investment.

The following section covers the empirical analysis used to evaluate the effect of taxation on investment timing through its effect on project value as well as the post-tax cost of investment.

7.4. METHODOLOGY & ASSUMPTIONS

This section details the methodology adopted to evaluate the UK fiscal regime with respect to its effect on investment timing. The section also presents the main assumptions that are needed to complete the analysis, in addition to those presented in Chapters 5 and 6. Furthermore, since the study performed in this chapter is an extension of the empirical analysis undertaken in Chapter 6, the relation between ROT and MAP is explained.

7.4.1. METHODOLOGY

The analysis performed in this chapter is based on the 25 oil fields selected in the previous chapter. The profitability of these fields as well as Government revenues are evaluated under the nine tax scenarios presented in Chapter 5, using the ROT technique. The findings are then compared with the DCF values calculated in the previous chapter.

To compute the real option value, as well as the value of waiting, the Timing Software[102] developed by Dias (2002) is used. This software comprises Excel spreadsheets that use a simple model analogy of real options with American call option.

For the purpose of this chapter, the software is used to calculate the real option value. However, the software requires inputs, namely the discounted values of the expected cash flow, V_{et}, and of the investment expenditures, I'_{et}, the time to expiration, the dividend yield and the nominal risk free interest rate. As such, separate spreadsheets are developed for each field and for each tax scenario in order to determine the values of both V_{et} and I'_{et}.

Further, in order to isolate the fiscal effects on investment expenditures, the following steps are adopted:

Firstly, the total field's profitability, NPV_{et}, is calculated as follows:

$$NPV_{et} = R_{et} - OE_{et} - CE_{et} - T_{et} \tag{7.6}$$

Secondly, the field's profitability, V_{et}, is calculated in the same way as NPV but this time assuming Capital Expenditures, CE_{et}, equal to zero.

[102] The software is available for download from the following website: http://www.puc-rio.br/marco.ind/main.html

Finally, the difference between NPV_{et} and V_{et} gives the value of investment expenditures net of fiscal benefits, I'_{et}.

Once calculated, the values are inserted into the Timing Software in order to determine the option value.

7.4.2. ASSUMPTIONS

The analysis in this chapter uses the same economic assumptions and tax scenarios as presented in both Chapters 5 and 6. However, certain additional assumptions are used in this chapter namely:

- The time to expiration, *T*, is assumed to be 5 years. In the UK, the Production license covers the most important stages of exploration and development as well as actual production. Under the first four licensing rounds the rights under a production license last for an initial period of six years, under the fifth licensing round, licenses are granted for a period of four years (Hayllar & Pleasance, 1977). Also, Emhjellen (1999), Dias (2001) and Siew (2001) assume an expiration period of 5 years, as a typical time for relinquishment.

- The dividend yield, δ, is assumed to be 2 per cent in annual terms, similarly to the real risk-free rate. Pickles & Smith (1993) and Dias (2001) argue that the risk free interest rate is a good practical value for the dividend yield.

- λ, the speed of reversion of oil prices, is assumed to tend to zero, hence, oil prices are assumed to follow a Geometric Brownian Motion, rather than a Mean Reversion as done in Chapter 6. This assumption is adopted for the following reasons. Firstly, early models of Black & Scholes (1973), and Paddock, Siegel & Smith (1988) assume a Geometric Brownian Motion (GBM), which is much simpler to use than the Mean Reversion Model.

The same assumption is also implemented in several recent studies, such as those of Zhang (1997) and Lund (2001). Laughton (1998) considers the GBM assumption when taking into consideration investment flexibility. "There may be problems with the use of this particular class of models of price reversion in the consideration of projects with timing flexibility" (Laughton, 1998, p.93). Pindyck (2001) argues that the GBM assumption is unlikely to lead to large errors in the optimal investment rule, as the speed of reversion is relatively very slow. Secondly, the Timing software uses the same assumption and as such the chapter adopts the same assumption for reasons of consistency.

Since uncertainty is modelled differently in GBM and Mean Reversion Model[103], the two models have different implications for the term structure of the risk discount factor (Bradley, 1998). Under the Mean Reversion assumption, the risk discount rate declines from a short-term rate toward zero in the long term, whereas the risk discount rate is constant under GBM. Consequently, higher values are likely to result under the Mean Reversion assumption. According to Bradley (1998),

[103] See Chapter 6, Section 6.3.2.3.

although there are quantitative differences in the two oil price models, the qualitative features of the two models are the same.

Under GBM, the risk discount factor used to adjust oil revenues for risk, is assumed as follows:

$$\mathrm{RDF}_t = \exp(-\phi\sigma t) \tag{7.7}$$

With ϕ, the price of risk[104].

- The discounted values are obtained by applying the time discount factor, TDF, where:

$$TDF_t = \exp(-it) \tag{7.8}$$

The evaluation is carried out firstly in nominal terms then the results are deflated, and given in £M.

7.4.3. REAL OPTIONS THEORY AND MAP

ROT is based on the same concepts as MAP, namely Derivative Asset Pricing and Contingent Claims Analysis. To value an asset, the cash flows occurring at each period are split into different components, then valued separately depending on the risk inherent to each component.

[104] As defined in Chapter 6, Section 6.3.2.2.

As oil price is assumed to be the only source of uncertainty, revenues are adjusted for risk while the other components, mainly costs, are discounted at the risk free rate. Once the individual components of the cash flow are valued, the project value is determined by adding up the individual components' values. Hence, because ROT is based on the same concepts applied in MAP, it also benefits from the major advantages of the MAP approach, namely this separate discounting of the Cash Flow components and the incorporation of a rigorous oil price model.

However, while MAP assumes a forward contract to model oil price uncertainty, ROT considers financial options. Both forward contracts and financial options are the most common financial derivatives used, but they differ in the following way. While a forward contract[105] *obliges* the holder of the contract to exercise its right at a specified price and day, the option "gives its owner the *right* (not the obligation) to buy or sell some asset at a specified price" (Bodie & Merton, 2000, p.384). As such, the option gives more flexibility than the forward contract.

Consequently, the application of ROT to value real projects, which are analogous to financial options, allows the incorporation of management flexibility in decision-making. Furthermore, when MAP is extended to incorporate flexibility, the model is referred to as Real Options technique (Laughton, Sagi & Samis, 2000).

[105] See Chapter 6, Section 6.3.2.2.

7.5. RESULTS AND ANALYSIS

This section summarises the main results of the evaluation of oil field profitability and Government revenue under nine tax scenarios (as defined in Chapter 5, p.150), using the Real Options technique. The section further compares those findings with the results of the DCF technique, as calculated in Chapter 6 (Section 6.4.2.2). Results from the models are then used to investigate whether a clearly preferable tax regime can be found. Each of the tax scenarios 2-7c is evaluated against the Base Scenario, in which taxes are set to zero. This enables a more explicit comparison between DCF and ROT. It also permits to identify whether the imposition of a particular fiscal package affects the value of waiting and as such the timing of development of a particular field.

7.5.1. DCF VERSUS ROT

Table 7.2 displays the profitability of the 25 selected oil fields evaluated using both techniques under the Base scenario. The main finding is that the two discounting methods produce different projects NPV. The ROT values are always lower than DCF, most probably as a result of the discrete discounting of the cash flow components under ROT. The difference is particularly significant for the fields with positive NPV under DCF, but with a negative NPV as calculated with ROT. This is the case of Birch, Beatrice, Heather, and Captain. The difference between the two methods is sometimes more pronounced relatively to the difference between MAP and DCF, as discussed in the previous chapter[106]. Such a variance relates mainly to the underlying models.

[106] See Chapter 6, Table 6.2

Table 7.2. Oil Field Profitability- Base Scenario

Base Scenario	DCF	ROT	Difference	Option Value	Value of Waiting
	£M	£M	%	£M	£M
Very Small					
Argyll	292.3	202.4	30.8%	202.4	0.0
Arkwright	81.4	49.2	39.6%	49.2	0.0
Birch	57.5	-7.1	87.7%	14.0	21.1
Blake	276	212.8	22.9%	212.8	0.0
Kappa	171.4	79.5	53.6%	79.5	0.0
Highlander	350.2	268.2	23.4%	268.2	0.0
Janice	182.4	108.7	40.4%	125.9	17.2
Tiffani	-208.1	-412.1	98.0%	3.5	415.6
Thelma	224.1	193.5	13.7%	193.5	0.0
Toni	182.6	147.1	19.4%	147.1	0.0
Small					
Arbroath	503.1	289.2	42.5%	289.2	0.0
Auk	385.4	177.3	54.0%	177.3	0.0
Balmoral	161.4	38.2	76.3%	95.6	57.4
Beatrice	165.4	-200.8	221.4%	19.6	220.4
Heather	170.9	-97.2	156.9%	19.3	116.5
Leadon	571.4	531.4	7.0%	531.4	0.0
Montrose	257.1	79.2	69.2%	84.0	4.8
Osprey	277.8	164.1	40.9%	167.7	3.6
Scapa	399.2	288	27.9%	288.0	0.0
Medium					
Captain	541.4	-28.8	105.3%	102.5	131.3
Clair	418.3	326.3	22.0%	326.3	0.0
Maureen	495.2	271.5	45.2%	303.4	31.9
Tern	719.5	414.7	42.4%	414.7	0.0
Large					
Alba	1040.1	594.6	42.8%	600.1	5.5
Schiehallion	1481.2	1202.8	18.8%	1202.8	0.0

Firstly, with MAP the use of Mean Reversion model for oil price reduces the long-term discounting for revenues. With ROT, however, revenues' discounting grows over time, due to the Geometric Brownian Motion assumption. Secondly, while revenues are adjusted for risk, costs are discounted at the risk free rate under ROT, similarly to MAP. With DCF, however, both revenues and costs are discounted at the risk-adjusted rate. Consequently, the difference between DCF and ROT is more significant for low revenue and high cost fields, like Beatrice, Heather and Captain.

For instance, in the case of Captain, the discounted costs' value is higher than the discounted revenue value, because CAPEX, alone, constitute about 50 per cent of revenues on an undiscounted basis. However, for fields, like Leadon and Schiehallion, with high revenues and low costs, the difference between the two techniques is small. For Schiehallion, for example, the total costs constitute only 25 per cent of the total revenues, on an undiscounted basis.

Furthermore, under DCF, all fields have a positive NPV, except Tiffani field. Following the concept of "now or never", the development of all of the 24 oil fields can be carried out. With ROT, however, 11 fields have a value of waiting, significant in the case of 6 fields. As such, under the ROT concept of "wait and see", the development of such fields can be delayed instead of being carried out today. This can explain why authors, like Ekern (1998), argued that the option analysis may yield results partly conflicting with the recommendations of the traditional DCF.

In fact, if a field has a negative NPV under DCF, it is probably that its development would never be undertaken. But ROT leads to a more flexible outcome, where the development would be delayed and undertaken under more favourable conditions. For instance, the development of Tiffani field can be delayed instead of defected. However, because the value of waiting for this field is substantial, it is unlikely that the development of the field will be undertaken. When the value of waiting is small or zero, both ROT and DCF lead to the same conclusion with regard to the development decision. This applies to 19 fields from the selected sample.

7.5.2. EFFECT OF TAX ON INVESTMENT TIMING

The following section presents the results of oil field profitability and Government revenue under different tax scenarios. The analysis concentrates on the effects different tax packages have on the value of waiting and the option value of different fields. As discussed in Section 7.3, taxation can affect the option value through its effect on V, the present value of the expected cash flows and I, the present value of Capital Expenditures. While an increase in taxation is likely to reduce the value of V, higher tax reliefs have the opposite effect on I. The total effect depends on the amount of the tax and its capital expenditure relief.

Consequently, tax instruments, like Royalty, are expected to increase the value of waiting, since they are imposed on revenues and may offer limited reliefs for development costs. However, profits-related tax instruments, like PRT and CT, are expected to encourage early development, as they offer several capital expenditure reliefs, particularly PRT. Table 7.3 displays the results of the 25 oil fields under both Scenarios 2 and 3, where under Scenario 2 Royalty applies alongside PRT and CT, but in Scenario 3, only PRT and CT apply.

Under Scenario 2, there is a significant reduction in the profitability of all fields, regardless their size (e.g. Janice, Leadon, Tern and Schiehallion). Four fields, two very small (Kappa and Janice), and two small (Balmoral and Beatrice[107]) even have a negative profitability compared with the Base Scenario.

[107] As calculated under DCF

Under Scenario 3, there is a reduction in profitability but it is less pronounced compared with Scenario 2. In fact, compared with the Base Scenario, the profitability of only one very small field, Janice, becomes negative.

Table 7.3. Oil Field Profitability- Scenarios 2 & 3

Scenario2	12.5% Royalty, 70% PRT, 52%CT				Scenario3	75% PRT, 50%CT			
	DCF £M	ROT £M	Option Value £M	Value of Waiting £M		DCF £M	ROT £M	Option Value £M	Value of Waiting £M
Very Small					Very Small				
Argyll	108.1	60.2	60.2	0.0	Argyll	162.7	117.1	117.1	0.0
Arkwright	27.7	11.0	12.3	1.3	Arkwright	51.9	30.1	30.1	0.0
Birch	13.7	-19.1	2.1	21.2	Birch	31.9	-9.1	6.9	16.0
Blake	85.2	60.5	60.5	0.0	Blake	144.2	116.2	116.2	0.0
Kappa	-0.7	-92.4	0.0	92.3	Kappa	71.0	-17.9	7.1	25.0
Highlander	97.5	61.3	61.3	0.0	Highlander	173.3	129.1	129.1	0.0
Janice	-171.8	-268.8	0.1	268.9	Janice	-26.9	63.8	65.6	1.8
Tiffani	-237.8	-429.1	0.0	412.0	Tiffani	-218.4	-412.1	0.0	412.1
Thelma	68.5	66.8	66.8	0.0	Thelma	120.1	120.6	120.6	0.0
Toni	47.3	43.0	43.0	0.0	Toni	89.5	91.6	91.6	0.0
Small					Small				
Arbroath	132.9	29.8	31.6	1.8	Arbroath	186.5	147.7	147.7	0.0
Auk	105.9	-24.6	5.9	30.5	Auk	160.6	33.3	39.4	6.1
Balmoral	-4.3	-70.5	1.4	71.9	Balmoral	58.6	-28.8	15.0	43.8
Beatrice	-11.1	-255.7	0.0	255.7	Beatrice	53.7	-200.8	0.8	201.6
Heather	25.2	-140.5	0.0	140.5	Heather	78.2	-105.8	2.0	107.8
Leadon	113.9	167.3	167.3	0.0	Leadon	215.1	274.4	274.4	0.0
Montrose	77.5	-19.4	7.6	27.0	Montrose	129.4	31.8	36.6	4.8
Osprey	74.7	38.9	44.4	5.5	Osprey	131.1	101.8	101.8	0.0
Scapa	130.6	93.2	93.2	0.0	Scapa	202.9	155.6	155.6	0.0
Medium					Medium				
Captain	77.8	-140.1	1.0	141.1	Captain	164.4	-80.0	11.9	91.9
Clair	59.8	200.5	200.5	0.0	Clair	115.7	200.5	200.5	0.0
Maureen	57.2	-23.9	40.8	64.7	Maureen	133.7	-23.9	53.4	77.3
Tern	92.4	89.1	89.1	0.0	Tern	148.7	197.1	197.1	0.0
Large					Large				
Alba	112.2	126.0	126.0	0.0	Alba	223.7	271.1	271.1	0.0
Schiehallion	223.7	322.4	322.4	0.0	Schiehallion	436.9	495.0	495.0	0.0

Furthermore, the imposition of the pre-1983 and post-1983 packages does generate a value of waiting for certain fields, although those fields have a zero value of waiting under the Base Scenario. Under Scenario 2, the ROT results indicate that 14 oil fields have a value of waiting, significant in the case of 11 fields.

Such a result is not surprising. Since Royalty is imposed on revenues, and when combined with costs discounted at the risk free rate under ROT, the result is a significantly lower NPV value, and as such consequently a higher value of waiting.

Under Scenario 3, 10 fields have a value of waiting, significant for 8 fields. Janice and Montrose have a notable higher value of waiting under Scenario 2 than Scenario 3. This indicates that both the pre-1983 and post-1983 packages impact the development timing and can lead to postponing development activity, but the effect of pre-1983 structure is more substantial.

Nevertheless, for certain fields, namely Captain and Alba, there is a reduction in the value of waiting, particularly under Scenario 3. This is possibly due to investment expenditures fiscal benefits, which are significant for fields with large capital expenditures, like Captain. This point is further discussed in the analysis of Scenarios 7a, 7b and 7c, where no Uplift, oil allowance nor Safeguard applies respectively.

Table 7.4 displays the results of profitability under both Scenarios 4 and 5.

Scenarios 4 and 5 generate close profitability, particularly for the very small and small fields, such as Arkwright, Birch and Kappa. Such fields are in a PRT paying-position but are normally protected by the available reliefs. Four fields (Osprey, Tern, Alba, and Schiehallion) do not have any waiting value under Scenario 4 but under Scenario 5 those fields have a waiting value, even though small. This can be explained by the PRT fiscal benefits for Capital Expenditures from which those fields benefited under Scenario 4 and which do not apply when PRT is not imposed.

Table 7.4. Oil Field Profitability- Scenarios 4 & 5

Scenario4	50% PRT, 30% CT				Scenario5	30% CT			
	DCF £M	ROT £M	Option Value £M	Value of Waiting £M		DCF £M	ROT £M	Option Value £M	Value of Waiting £M
Very Small					Very Small				
Argyll	187.7	126.9	126.9	0.0	Argyll	203.4	137.2	137.2	0.0
Arkwright	54.6	31.8	31.8	0.0	Arkwright	54.6	31.8	31.8	0.0
Birch	34.6	-8.9	7.9	16.8	Birch	35.8	-8.9	8.6	17.5
Blake	163.9	128.4	128.4	0.0	Blake	189.1	143.6	143.6	0.0
Kappa	80.3	-9.1	10.8	19.9	Kappa	82.5	-9.1	11.4	20.5
Highlander	201.4	150.8	150.8	0.0	Highlander	257.2	180.8	180.8	0.0
Janice	-8.5	67.9	73.3	5.4	Janice	-3.4	67.9	96.8	28.9
Tiffani	-217.4	-412.1	1.5	413.6	Tiffani	-217.4	-412.1	0.7	412.8
Thelma	134.7	126.8	126.8	0.0	Thelma	151.3	132.5	132.5	0.0
Toni	102.7	96.2	96.2	0.0	Toni	118.2	97.8	97.8	0.0
Small					Small				
Arbroath	263.0	164.9	164.9	0.0	Arbroath	345.0	193.4	193.4	0.0
Auk	201.1	60.2	90.0	29.8	Auk	266.9	98.8	98.8	0.0
Balmoral	70.2	-22.7	25.7	48.4	Balmoral	77.6	-22.7	40.8	63.5
Beatrice	67.2	-200.8	2.3	203.1	Beatrice	79.3	-200.8	7.0	207.8
Heather	89.1	-139.2	2.1	160.2	Heather	99.9	-105.0	6.7	111.7
Leadon	259.7	305.7	305.7	0.0	Leadon	373.6	360.4	360.4	0.0
Montrose	148.8	36.1	41.9	5.8	Montrose	174.1	36.1	45.3	9.2
Osprey	153.7	107.5	107.5	0.0	Osprey	184.3	107.5	111.8	4.3
Scapa	233.7	172.2	172.2	0.0	Scapa	276.2	192.7	192.7	0.0
Medium					Medium				
Captain	215.7	-69.2	27.4	96.6	Captain	350.9	-69.2	25.5	94.7
Clair	162.0	279.9	279.9	0.0	Clair	275.6	279.9	279.9	0.0
Maureen	180.7	-23.9	106.8	103.7	Maureen	296.7	-23.9	120.3	144.2
Tern	252.2	223.6	223.6	0.0	Tern	467.9	269.1	272.9	3.8
Large					Large				
Alba	377.1	321.1	321.1	0.0	Alba	683.7	387.8	397.1	9.3
Schiehallion	610.8	612.0	612.0	0.0	Schiehallion	994.9	809.9	815.0	5.1

In order to evaluate the effect of the imposition of the 10 per cent Supplementary charge in 2002 changes, Scenario 6 is compared with Scenario 5, where only CT applies.

Table 7.5 presents the profitability of oil fields under Scenarios 6 and 7a. In general, the additional ST does not generate a critical difference in the profitability of fields, nor in the value of waiting.

Table 7.5. Oil Field Profitability- Scenarios 6 & 7a

Scenario6	30% CT, 10% ST			
	DCF £M	ROT £M	Option Value £M	Value of Waiting £M
Very Small				
Argyll	192.1	124.0	124.0	0.0
Arkwright	45.6	26.0	26.0	0.0
Birch	28.6	-9.5	6.8	16.3
Blake	160.1	120.5	120.5	0.0
Kappa	52.8	-38.6	2.7	41.3
Highlander	226.2	151.7	151.6	0.0
Janice	-65.4	54.3	68.3	14.0
Tiffani	-220.5	-412.1	0.3	412.4
Thelma	127.1	112.2	112.2	0.0
Toni	96.8	81.4	81.4	0.0
Small				
Arbroath	292.4	161.5	161.5	0.0
Auk	227.3	72.7	74.3	1.6
Balmoral	49.7	-43.1	26.3	69.4
Beatrice	50.6	-200.8	4.4	205.2
Heather	76.2	-107.6	3.7	111.3
Leadon	307.7	303.4	303.4	0.0
Montrose	146.5	21.8	33.1	11.3
Osprey	153.2	88.6	93.1	4.5
Scapa	235.2	160.9	160.9	0.0
Medium				
Captain	287.3	-82.6	6.0	88.6
Clair	228.1	264.4	264.4	0.0
Maureen	230.5	-23.9	104.1	128.0
Tern	384.1	220.5	225.8	5.3
Large				
Alba	564.9	318.9	329.8	10.9
Schiehallion	832.8	679.0	679.0	0.0

Scenario7a	50% PRT (no uplift), 10%ST, 30%CT.			
	DCF £M	ROT £M	Option Value £M	Value of Waiting £M
Very Small				
Argyll	153.4	103.7	103.7	0.0
Arkwright	45.6	26.0	26.0	0.0
Birch	26.2	-9.5	8.0	17.5
Blake	129.0	99.5	99.5	0.0
Kappa	50.3	-38.6	2.4	41.0
Highlander	164.8	122.8	122.8	0.0
Janice	-58.7	54.3	60.4	6.1
Tiffani	-220.5	-412.1	0.0	412.1
Thelma	132.2	107.2	107.3	0.0
Toni	80.0	74.4	74.3	0.0
Small				
Arbroath	212.0	120.7	120.7	0.0
Auk	166.9	38.1	43.7	5.6
Balmoral	38.4	-44.8	13.8	58.6
Beatrice	23.5	-200.8	1.1	201.9
Heather	54.1	-108.0	1.8	109.8
Leadon	184.1	247.4	247.4	0.0
Montrose	121.3	24.6	31.6	7.0
Osprey	120.8	82.8	83.8	0.0
Scapa	183.8	134.4	134.4	0.0
Medium				
Captain	142.1	-82.6	17.9	100.5
Clair	118.3	264.4	264.4	0.0
Maureen	95.5	-23.9	90.0	113.9
Tern	181.1	147.9	148.9	0.0
Large				
Alba	264.4	191.2	196.6	5.4
Schiehallion	459.7	438.1	438.1	0.0

In order to evaluate the possible effects of PRT reliefs on the value of waiting, Scenarios 7a, 7b and 7c are compared consecutively.

Table 7.6 presents the results under Scenarios 7b and 7c, where CT and ST apply with PRT but without the oil allowance nor Safeguard respectively.

Table 7.6. Oil Field Profitability- Scenarios 7b & 7c

Scenario7b	No oil allowance				Scenario7c	No Safeguard			
	DCF £M	ROT £M	Option Value £M	Value of Waiting £M		DCF £M	ROT £M	Option Value £M	Value of Waiting £M
Very Small					Very Small				
Argyll	87.6	53.5	53.5	0.0	Argyll	154.8	106.7	106.7	0.0
Arkwright	27.5	18.5	18.5	0.0	Arkwright	45.6	26.0	26.0	0.0
Birch	13.1	-9.5	2.4	11.9	Birch	27.3	-9.5	6.2	15.7
Blake	84.0	71.6	71.6	0.0	Blake	138.5	107.5	107.5	0.0
Kappa	4.1	-71.3	0.0	71.3	Kappa	50.8	-38.6	2.4	41.0
Highlander	102.7	74.3	74.3	0.0	Highlander	147.7	99.4	99.4	0.0
Janice	-86.9	54.3	54.3	0.0	Janice	-75.4	56.1	61.3	5.2
Tiffani	-224.3	-412.1	0.0	412.1	Tiffani	-224.3	-412.1	0.0	412.1
Thelma	67.6	78.3	78.3	0.0	Thelma	107.1	103.7	103.7	0.0
Toni	44.7	58.7	58.7	0.0	Toni	83.5	77.4	77.4	0.0
Small					Small				
Arbroath	145.3	99.6	99.6	0.0	Arbroath	204.9	131.7	131.7	0.0
Auk	119.4	-0.7	14.6	15.3	Auk	170.6	39.0	44.4	5.4
Balmoral	14.2	-60.0	2.1	62.1	Balmoral	49.7	-43.1	14.1	57.2
Beatrice	16.8	-190.6	0.1	190.7	Beatrice	25.0	-200.8	1.1	201.9
Heather	37.4	-108.0	0.0	108.0	Heather	61.3	-108.0	1.8	109.8
Leadon	160.5	210.4	210.4	0.0	Leadon	208.1	231.0	231.0	0.0
Montrose	70.3	-8.0	7.5	15.5	Montrose	125.4	21.8	23.0	1.2
Osprey	84.7	72.4	72.4	0.0	Osprey	129.6	84.4	84.6	0.2
Scapa	130.4	94.3	94.3	0.0	Scapa	198.8	143.3	143.3	0.0
Medium					Medium				
Captain	148.8	-82.6	9.2	91.8	Captain	164.0	-74.5	19.4	93.9
Clair	105.8	264.4	264.4	0.0	Clair	130.1	242.2	242.2	0.0
Maureen	97.7	-23.9	39.6	63.5	Maureen	111.2	-23.9	50.8	74.7
Tern	152.8	142.6	142.6	0.0	Tern	199.2	154.9	162.1	7.2
Large					Large				
Alba	253.9	233.4	233.4	0.0	Alba	134.1	242.2	242.2	0.0
Schiehallion	459.0	461.7	461.7	0.0	Schiehallion	441.1	405.2	405.2	0.0

Uplift is an important relief on capital expenditures. Hence, the abolition of this relief is likely to generate an increase in the value of waiting particularly for fields, which have significant CAPEX. Maureen field, for example, has a value of waiting of £113.9M under Scenario 7a compared with £63.5M under Scenario 7b. However, the difference is not critical because when Uplift does not apply, the payback period is shorter, speeding up both the Oil Allowance and the Safeguard.

Although the oil allowance is the most important PRT relief for the very small and small fields, as discussed in the previous chapters, the three reliefs have similar impact on the value of waiting of the selected fields. Balmoral field, for example, has a value of waiting of £58.6M under Scenario 7a where the Uplift is abolished, £62.7M under Scenario 7b where the oil allowance does not apply and £57.2M in the absence of the Safeguard under Scenario 7c. Such a finding highlights that the three PRT reliefs are inter-related and are equally important. If the oil allowance is abolished the development of 10 oil field might be delayed, in the case of the abolition of both the Uplift and Safeguard, the development of a total of 8 fields might be postponed, under the ROT concept.

Under the nine tax scenarios evaluated, the development timing of approximately 14 fields is not affected. Those fields (Argyll, Arkwright, Blake, Highlander, Thelma, Toni, Arbroath, Leadon, Osprey, Scapa, Clair, Tern, Alba and Schiehallion) have either a zero or insignificant value of waiting under the various scenarios considered.

On average, Scenarios 3-7a and Scenario 7c generate a value of waiting for 8 fields and as such probably affecting their development timing. However, Scenario 2 impacts the value of waiting of 11 fields, while Scenario 7b affects 10 fields. Such a finding is consistent with the previous chapter's findings, where the imposition of Royalty with PRT and CT and the abolition of the oil allowance lead to close results. As a consequence of the flexibility option, the oil fields with a significant value of waiting are not going to be developed today, but instead their development is postponed. This in turn can affect the timing of fiscal receipts, as analysed in the following section.

7.5.3. EFFECT OF INVESTMENT TIMING ON FISCAL REVENUE

Table 7.7 presents the total Government take from each field, under different tax scenarios, if all fields are developed. The results in this table are consistent with those of Chapter 6 (p.196), and therefore the same interpretation applies.

In brief, Scenario 2 generates the highest revenue, followed by Scenario 7b, Scenario 3, Scenario 7c, Scenario 4, Scenario 7a, then Scenario 6 while the lowest fiscal take is generated under Scenario 5.

Nevertheless, using the ROT concept, where the development of fields with a significant value of waiting can be postponed, the effect of various tax scenarios on Government revenues can vary.

Table 7.8 illustrates the total Government take from the fields that do not have a value of waiting (or the value is insignificant) under different tax scenarios and as such are developed today. The table indicates that a suspension of development of certain fields results in a reduction in Government revenue, under all scenarios.

Scenario 2, illustrating the pre-1983 fiscal package, has the most significant impact. If this scenario is imposed on the 25 oil fields selected, it can generate a reduction in Government revenue by almost a half (47.9 per cent). This results from the fact that the development of 11 oil fields, particularly small fields, is not profitable today and as such it is suspended.

Table 7.7 Total Government Revenue from Individual Fields

	Scenario2	Scenario3	Scenario4	Scenario5	Scenario6	Scenario7a	Scenario7b	Scenario7c
Very Small								
Argyll	475.0	341.6	283.4	235.0	284.4	367.4	544.5	363.1
Arkwright	156.0	86.9	79.0	79.0	105.3	105.3	169.2	105.3
Birch	164.0	93.7	84.8	83.6	111.4	116.6	176.2	115.5
Blake	376.2	253.7	218.0	176.7	235.6	284.9	396.5	271.0
Kappa	320.7	184.3	168.7	165.2	220.3	223.3	331.9	223.5
Highlander	534.0	364.1	313.0	217.6	290.1	398.1	575.1	404.0
Janice	555.4	324.8	297.9	294.6	392.8	371.1	446.3	407.7
Tiffani	65.0	21.8	19.8	19.8	26.4	26.4	34.3	34.3
Thelma	343.6	226.9	196.7	165.4	220.6	205.1	363.0	258.1
Toni	386.3	256.1	223.2	187.7	250.2	286.8	412.4	279.9
Total (£M)	3376.2	2153.9	1884.5	1624.5	2137.1	2384.9	3449.4	2462.5
Small								
Arbroath	1394.0	1353.5	901.4	613.0	817.3	1086.6	1424.7	1224.8
Auk	2139.8	1922.2	1528.5	811.0	1081.5	1703.2	1875.2	1697.0
Balmoral	515.4	315.9	282.3	266.0	355.0	377.9	507.1	355.0
Beatrice	780.6	544.6	480.4	404.0	538.4	680.8	767.7	659.4
Heather	886.6	683.5	570.8	400.0	533.6	738.8	847.8	701.3
Leadon	973.6	767.6	664.7	430.0	573.2	822.9	925.0	776.5
Montrose	710.2	556.1	410.4	305.7	434.5	569.5	735.7	552.4
Osprey	635.7	486.4	371.2	306.0	407.6	525.2	670.9	497.4
Scapa	938.4	703.8	592.9	439.0	585.2	819.9	995.2	717.3
Total (£M)	8974.3	7333.6	5802.6	3974.7	5326.3	7324.8	8749.3	7181.1
Medium								
Captain	2303.3	1951.4	1639.8	924.0	1232.5	1956.9	1992.8	1872.9
Clair	2638.4	2302.7	1903.2	1029.0	1372.7	2185.6	2318.7	2121.8
Maureen	1455.0	1261.5	1084.3	681.0	908.3	1357.7	1415.9	1311.5
Tern	2990.1	2770.4	2229.9	1161.0	1547.8	2512.6	2659.8	2464.1
Total (£M)	9386.8	8286.0	6857.2	3796.0	5061.3	8012.8	8387.2	7770.3
Large								
Alba	4209.7	3837.6	3057.4	1565.3	2087.0	3464.6	3556.0	3373.8
Schiehallion	4622.8	4079.4	3057.4	1778.7	2371.6	3789.3	3849.5	3850.5
Total (£M)	8832.5	7917.0	6114.8	3344.0	4458.6	7253.9	7405.5	7224.3
Total Revenue (£M)	30569.8	25690.5	20659.1	12739.2	16983.3	24976.4	27991.4	24638.2

Table 7.8. Government Revenue under ROT Concept

	Scenario2	Scenario3	Scenario4	Scenario5	Scenario6	Scenario7a	Scenario7b	Scenario7c
Very Small								
Total(£M)	2271.1	1854.1	1611.2	1356.0	1779.0	2018.7	2907.0	2089.1
Reduction in Revenue	**48.7%**	**16.2%**	**17.0%**	**19.8%**	**20.1%**	**18.1%**	**18.7%**	**17.9%**
Small								
Total (£M)	3941.7	5789.6	4469.1	2904.7	3899.3	5527.3	4015.8	5465.4
Reduction in Revenue	**127.7%**	**26.7%**	**29.8%**	**36.8%**	**36.6%**	**32.5%**	**117.9%**	**31.4%**
Medium								
Total (£M)	5628.5	5073.1	4133.1	2190.0	2920.5	4698.2	4978.5	4585.9
Reduction in Revenue	**66.8%**	**63.3%**	**65.9%**	**73.3%**	**73.3%**	**70.6%**	**68.5%**	**69.4%**
Large								
Total (£M)	8832.5	7917.0	6114.8	3344.0	4458.6	7253.9	7405.5	7224.3
Reduction in Revenue	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
Total								
Total Revenue (£M)	20673.8	20633.8	16328.2	9794.7	13057.4	19498.1	19306.8	19364.7
Reduction in Revenue	**47.9%**	**24.5%**	**26.5%**	**30.1%**	**30.1%**	**28.1%**	**45.0%**	**27.2%**

The abolition of the oil allowance results in 45 per cent reduction in Government revenue, the second most significant impact. This is mainly produced by a reduction of 117.9 per cent of revenue from small fields, and which further emphasises the importance of the oil allowance for such fields. The other scenarios generate less critical effects, with a reduction of 28 per cent, on average, in fiscal receipt, particularly from the medium fields.

In fact, compared with Scenarios 2 and 7b, the impact of the other fiscal packages is less pronounced, as both PRT and CT provide significant fiscal reliefs encouraging by this early development

7.5. SUMMARY & CONCLUSION

This chapter has expanded the empirical analysis of Chapter 6, evaluating the effects of different tax scenarios on the timing of oil field development and the available Government revenue generated in the UKCS, as such taking into consideration both the industry and Government interests. The chapter examines whether different tax structures and rates can delay the development activity, as such identifying any related investment distortions and addressing the neutrality of the regime.

Flexibility in decision making permits companies to postpone the development of an oil field, until economic conditions become more favourable or uncertainty is reduced, for example. The petroleum industry has a significant managerial flexibility due to the long life nature of oil projects. Previous studies argued that such flexibility can add value to projects and neglecting it in oil ventures can lead to an under-valuation of assets and a consequential miss-allocation of resources in the economy. Consequently, a growing body of empirical work suggests that because the DCF technique, in its simplistic form, is based on the static concept of "now or never", it does not account for the existence of flexibility in investment decisions and as such it can undervalue a project. The Real Options Technique is suggested as a more useful technique than DCF, because it allows the incorporation of flexibility in the valuation of projects. Although ROT was originally developed for the appraisal of financial derivatives, the analogy between petroleum projects and financial options allows the application of ROT to value oil projects. Accordingly, in this chapter, the analysis is carried out using ROT in order to evaluate oil field profitability under various tax scenarios.

The main finding is that taxation can affect the development timing of an oil field. On the one hand, taxes can reduce the value of expected cash flows, and consequently they can increase the value of waiting and the possibility of delaying investment. But on the other hand, fiscal benefits can reduce the investment expenditure value, leading to an opposite effect on the value of waiting. The chapter demonstrates that tax instruments, such as Royalty with limited Capital Expenditure reliefs, can lead to a significant increase in the value of waiting thereby encouraging investment delay and leading to delay and probably loss of fiscal revenue, unlike PRT and CT.

Furthermore, the analysis identifies that, in the UK, none of the tax structures evaluated can be described as entirely neutral. In particular, the pre-1983 fiscal package results in the suspension of the development of 44 per cent of oil fields, leading to halving the total fiscal take, the most significant reduction as compared with other scenarios. The abolition of the oil allowance (Scenario 7b) generates a similar result, due to the importance of this relief particularly for the small fields.

The impact is less pronounced with the other tax scenarios, which affect the development timing of on average result 32 per cent. In fact, imposing income tax solely (Scenarios 5 and 6) generates a similar outcome to the imposition of PRT alongside CT and ST, despite the PRT higher tax rate. This is mainly due to the fact that PRT offers various reliefs that can reduce the value of waiting and thereby encourage early development.

In mature provinces, such as the UKCS, developing existing fields is likely to be the most important concern (as discussed in Chapter 4), in order to sustain production as well as maintain the interest of oil companies in the province. Further, any delay in the development of certain fields is not an outcome preferred by the Government, who generally aims to receive receipts as early as possible. As such, it can be concluded that the major changes to the fiscal regime, particularly that of 1983, have maintained investment and Government revenue in response to the changing nature of the North Sea province. However, the abolition of PRT in 1993 had a less significant impact in terms of investment timing, due to the fact that small fields are protected against the payment of this tax.

As regards the evaluation techniques, for certain fields, the DCF technique leads to different conclusion as compared with ROT. This is particularly true for fields with a significant value of waiting, as evaluated under ROT. In this case, under ROT, delaying development would be more profitable than investing today, whereas under DCF, companies should carry out their development activity. Nevertheless, when the value of waiting is insignificant, the two techniques lead to the same conclusion.

Up to this stage, the evaluation of the UK petroleum fiscal regime is undertaken by comparing the effects of the principal fiscal packages that applied since 1975 on the UKCS on both the industry and Government interests. In the following chapter, the evaluation of the regime is completed as it is carried out on an international level. The UK fiscal regime is compared with five other international representative regimes in order to assess the international competitiveness of the regime.

CHAPTER EIGHT

UKCS FISCAL REGIME: A COMPARISON WITH FIVE REPRESENTATIVE INTERNATIONAL REGIMES

8.1. INTRODUCTION

Chapters 6 and 7 evaluated the impact of the major fiscal packages that applied to UK oil activity between 1975 and 2002, on oil field profitability and Government revenue. This chapter expands and completes the study in this thesis by assessing the UKCS tax regime international competitiveness and comparing it with five other international regimes. Studying other regimes may reveal a benchmark fiscal regime with features that have not been revealed in previous chapters' analysis.

This analysis is of particular significance to mature provinces like the UK North Sea. Oil companies have international activities and often compare their available investment options in various countries (Rowland & Hann, 1987). Each country offering investment opportunities has a different profile with regard to key investment parameters, such as field size, costs and fiscal terms, and investors weigh these together to decide which areas to target for acquiring new business (WoodMackenzie, 2002). As the previous chapters demonstrated, taxation substantially affects the profitability of oil fields as well as the development timing, and thereby the attractiveness of the province. Consequently, in countries where oil production has started to decline, fiscal regimes can be tuned to compensate for the decline in production by encouraging existing and new companies to sustain production and develop the remaining less profitable fields.

For instance, in Norway, in an attempt to relax the fiscal regime, Royalty was tapered off for the fields that are still liable to Royalty payments (Bjerkedal, 2000). Similarly, Middle Eastern oil producing countries, like Iraq[108], have been actively searching for mechanisms to facilitate foreign investment in their upstream oil sector for various economic and political reasons (International Petroleum Enterprises, 2001). In contrast to such measures, the UK tightened its regime by imposing the Supplementary Tax in 2002, although the country is the most-mature province in the North Sea.

Furthermore, there is a notable controversy surrounding the international competitiveness of the UK petroleum fiscal regime, as Chapter 3 demonstrated. Authors like Quinlan (1998) argue that the regime in the UK is the most attractive of any established producing country worldwide. Similarly, Kemp & Stephens (1997) maintain that although the level of take is certainly low by international standards, the system is very attractive and there is no other major producing province that offers only one simple fiscal instrument at a modest rate. Furthermore, the survey results in Chapter 4 imply that all respondents consider that the regime is well attuned to the reality of the North Sea. At the other extreme, authors like Rutledge & Wright (1998) and Miller et al (2000) argue that in the UK oil companies do not pay their fair share of taxes and the petroleum fiscal regime is weak by international standards.

The previous chapters, particularly Chapter 2, discussed the difficulty in determining a single impartial yardstick that balances the two competing objectives of Government and oil companies. This partly explains the wide range of fiscal regimes in the world, as countries try to improve the trade-off between those two main players' interests.

[108] The Iraqi regime is analysed on a pre-2003 basis.

Johnston (1998) argues that "there are more petroleum fiscal systems in the world than there are countries" (p.5). Furthermore, each country has its own political and economic environment, which can affect the design of its fiscal regime. But despite the diversity of petroleum fiscal regimes, these can be grouped into two broad types namely, Concessionary and Contractual regimes, which are discussed in more detail in Section2.

In this chapter, the UK petroleum fiscal regime is compared with five international regimes, the Norwegian, Australian, Indonesian, Chinese and Iraqi regimes, in order to critically evaluate how these countries attempt to ensure an appropriate share of revenue for the Government whilst safeguarding oil companies' interests. These countries are selected for the following reasons.

The UK, Norwegian and Australian regimes follow a concessionary regime, whereas the three other countries follow a contractual system.

The Norwegian regime has often been compared with the UK oil tax regime[109]. A divergence in Government policies was often noticed (Nelsen, 1991). Andersen (1993) argues that in the UK, the 1980s were characterised by a reduction of Government participation, unlike Norway where the period up to 1986 was one of continuous tightening and increased Government intervention. However, in 1998, while the UK was thinking about tightening its regime, the Norwegian Government was seeking relaxing its system (Quinlan, 1998).

[109] Robinson & Morgan (1978), Robinson & Rowland (1978), Brent (1991), Quinlan (1998)

In Australia, the Government tries to recoup economic rent by the application of a special petroleum tax, the Resource Rent Tax, which is often claimed to be the most efficient and neutral tax instrument[110]. Indonesia has adopted a Production Sharing Contract (PSC)[111] type of contractual regime. The Indonesian model "is the standard of comparison for all production sharing contracts" (Johnston, 1998, p.22). China also adopts a contractual regime but combines some features of a concessionary regime, namely Royalty and Income tax (Johnston, 2002). Iraq uses a Service contract, which is the other common type of contractual regime[112]. In Iraq, the large size of oil reserves, the low exploration cost and the high political risk make the petroleum fiscal regime in this country worthy of note.

The chapter contributes to the academic literature in the following three main ways. Firstly, the chapter compares the principal fiscal packages that applied to UK oil activity from 1975 to 2002 with five international fiscal packages. As such, it covers a time line analysis instead of focusing on one specific package and to date no similar work has been published. Secondly, the chapter evaluates the most recent fiscal changes that were implemented in the countries considered for analysis, and as such, the study is up-to-date. Finally, the chapter derives fully transparent cash flow models for each of the country selected, including Iraq for which information is not easily accessible. In fact, the analysis of the Iraqi regime is very limited in the academic literature. In this chapter, the Iraqi cash flow model was developed after intensive consultation with specialists in international petroleum regimes.

[110] See Chapter 2, Section 2.5
[111] See Section 8.2.2.1
[112] See Section 8.2.2.2

The remainder of this chapter proceeds as follows. Section two compares the characteristics of the two main fiscal regimes, which are the concessionary and contractual systems. The section also compares qualitatively the fiscal packages in the six countries selected. Section 3 covers the methodology and assumptions used to complete the analysis. Section 4 presents and discusses the principal findings. Section 5 covers the concluding remarks. Appendix I presents an example of the calculation of field profitability and Government take under the various regimes selected.

8.2. WORLD FISCAL REGIMES

Johnston (1998) argues that world petroleum fiscal regimes can be divided into two broad categories, which are:

1. The concessionary systems that allow private ownership of mineral resources. Oil companies take title to produced oil at the wellhead and then pay the appropriate royalties and taxes.

2. The contractual based systems, where the Government retains ownership of minerals. Oil companies receive a fee for exploration, development and production operation services. If this fee is a share of production, the system is called a "Production Sharing Contract" (PSC), and in this case the oil company takes title to its share of petroleum extracted. If the fee is in cash, the system is known as a "Service Contract", and the company does not take title to any petroleum extracted (Johnston, 1998).

Mommer (2001) describes the two categories of fiscal regimes as the liberal and proprietorial regimes respectively. The author argues that in liberal regimes, oil companies are in a much stronger position compared with the proprietorial systems, where the Government exercises a stronger control over the exploitation and production of the natural resource.

The concessionary system originated with the very beginning of the petroleum industry (mid 1800), while the contractual system emerged a century later (mid-1950) (Blinn et al, 1986). In the following section, the characteristics of each system are analysed and compared in more detail.

8.2.1. CONCESSIONARY SYSTEMS

This section analyses the general features of concessionary systems, focusing on their most relevant characteristics to this thesis, namely the tax instruments imposed and their principal deductions. The theoretical background of the principal tax instruments applied in concessionary systems was discussed in detail in Chapter 2. The analysis done in this section attempts to identify the general trends as well as divergence in the application of those instruments in countries following a concessionary regime. The section further derives the cash flow model specific to each regime and compares the fiscal structures in three countries adopting a concessionary regime, the UK, Australia and Norway.

8.2.1.1. GENERAL FEATURES

A concession is defined as "an agreement between a Government and a company, that grants the company the right to explore for, develop, produce, transport and market hydrocarbons or minerals within a fixed area for a specific amount of time" (Johnston, 1998, p.296). There are 55 countries applying a concessionary system to petroleum activity (Johnston, 2001). A common way of taxing oil companies in a concessionary regime involves a combination of Income Tax, Special Petroleum Tax and Royalty. That is why concessionary regimes are commonly known as "Royalty/Tax Systems".

Royalties are typically either specific levies (based on the volume of oil and gas extracted) or ad valorem (based on the value of oil and gas extracted). Some countries have introduced a profit element in Royalties by having them depend on the level of production (Sunley, Baunsgaard & Simard, 2002). This is known as a sliding scale Royalty.

Income tax is generally the most common instrument used in oil producing countries of the world (Sarma & Naresh, 2001). Commonly, the Income Tax comprises a basic rate structure i.e. a single rate, provisions for deduction of certain items from the tax base, supplementary levies and tax incentives. Currently, the overall corporate Income Tax rate in several countries lies in the range 30 to 35 per cent (Sarma & Naresh, 2001). Various countries provide an incentive for Exploration and Development by allowing Exploration costs to be recovered immediately and allowing accelerated recovery of Development costs (tax depreciation), for example, over five years.

Accelerated cost recovery brings forward payback for the investor (Sunley, Baunsgaard & Simard, 2002). In addition to tax deductions, losses carried forward and/or back are commonly allowed tax incentives (Sarma & Naresh, 2001).

In addition to Income tax, oil-producing countries impose a special petroleum tax, such as Resource Rent Tax (RRT), in order to capture a larger share of economic rent from oil production. The special tax is normally based on cash flow but is imposed only when cumulative cash flow is positive. In countries where the special petroleum tax exists, the tax is usually imposed as a supplement to the general corporate Income Tax. Sarma & Naresh (2001) argue that an issue arises as to whether the special tax should be imposed before or after the Income Tax. If imposed before, then it can be treated as a deductible cost (like in the UK), but if imposed after, the payment of Income Tax can be treated as a cash outflow in calculating the special tax's income base.

Sunley, Baunsgaard & Simard (2002) argue that some countries ring-fence their oil and gas activities whilst others ring-fence individual projects. Ring fencing imposes a limitation on deductions for tax purposes across different activities or projects undertaken by the same taxpayer. The authors argue that such rules matter for two main reasons. Firstly, the absence of ring fencing can postpone Government tax receipts because a company that undertakes a series of projects is able to deduct Exploration and Development costs from each new project against the income of projects that are already generating taxable income. Secondly, as an oil and gas area matures, the absence of ring fencing may discriminate against new entrants that have no income against which to deduct Exploration or Development expenditures.

8.2.1.2. CASH FLOW MODEL

This section derives a representative cash flow model that can apply to any concessionary regime. The analysis done in this chapter is largely based on that of Chapter 5, where the cash flow model for the UK was determined. In a concessionary system, the Net Cash Flow after tax at period t, NCF_t, can be illustrated by the following:

$$NCF_t = R_t - ROY_t - OE_t - CE_t - T_t \tag{8.1}$$

Where:

- R is the gross revenue
- ROY is the Royalty take
- OE is the operating cost
- CE is the capital expenditure
- T is the total tax take, which is usually the sum of the Income Tax and the special petroleum tax.
- t is the time period.

8.2.1.3. UK CONCESSIONARY SYSTEM

The UK fiscal regime is fully explained in Chapter 5. The post-tax Net Cash Flow that applies to fields that received development approval after 1993 is expressed as:

$$NCF_t = R_t - OE_t - CE_t - CT_t \tag{8.2}$$

where CT is assumed to incorporate the Supplementary Tax imposed in 2002.

The post-tax *NCF* of fields that received development before 1993, is expressed as:

$$NCF_t = R_t - OE_t - CE_t - PRT_t - CT_t \tag{8.3}$$

Prior to the abolishing of Royalty in 2002 for all fields, the post-tax *NCF* of oil fields that received development approval before 1983 is expressed as:

$$NCF_t = R_t - ROY_t - OE_t - CE_t - PRT_t - CT_t \tag{8.4}$$

8.2.1.4. AUSTRALIA CONCESSIONARY SYSTEM

The Australian tax regime that applies to offshore activities has the following features.

Royalty used to apply at a rate of 10 per cent but was abolished in 1990. The Corporate Income Tax (CIT) is currently charged at 30 per cent, and it is the same income tax that applies to all companies operating in Australia. Capital expenditures are depreciated on a straight-line basis over field life. In addition to Income Tax, petroleum projects are subject to a special taxation, the Petroleum Resource Rent Tax (PRRT), which is deductible for CIT purposes.

PRRT applies at 40 per cent on net cash flow, but only when net cumulative receipts turn positive. Hence it is levied after the company has recouped all Exploration and Development costs. Undeducted Capital Expenditures are compounded forward at an Uplift rate, which is a specified return on capital that supposedly will yield a fair return on investment (Barrows, 2000). For Exploration costs the Uplift rate is approximately 23 per cent, while for Development costs, it is equivalent to 15 per cent. As such, compounded Capital Expenditures are carried forward and deducted from positive cash flows in later periods. The accumulation process is continued until a positive net cash flow is generated. No tax is payable until the firm has recovered its costs inclusive of the Uplift rate.

For Income Tax, deductible expenses are offset against income from any source. For PRRT, however, there is a ring fence around all offshore activities for Exploration expenses and around the field for development expenses (Barrows, 2000). Furthermore, the Australian regime does not provide Abandonment costs reliefs.

The post-tax Net Cash Flow at period t, NCF_t, can be expressed in the following equation:

$$NCF_t = R_t - OE_t - CE_t - PRRT_t - CIT_t \tag{8.5}$$

where:

$$PRRT_t = t_{ap}\{R_t - OE_t - (CE_t + up_{at})\} \tag{8.6}$$

and,

$$CIT_t = t_{ac}(R_t - OE_t - D_{at} - PRRT_t) \tag{8.7}$$

With:

- t_{ap} the PRRT rate
- up_{at} the uplift rate
- t_{ac} the CIT rate
- D_{ac} the depreciation

8.2.1.5. NORWAY CONCESSIONARY SYSTEM

The Norwegian petroleum fiscal regime is based mainly on the Corporate Income Tax (CIT) and Special Petroleum Tax (SPT). Prior to 1986, Royalty (also called the production fee) used to apply. Before 1972 Royalty was applied at a 10 per cent flat rate. After 1972, Royalty was applied on a sliding scale, ranging from 8 to 16 per cent, depending on production. However, in 1986 Royalty was abolished for all fields receiving development approval from 1 January 1986 (Barrows, 2000).

The Corporate income tax (CIT) currently applies at a rate of 28 per cent. It was reduced from 50.8 per cent in 1992. This is the general Income tax that applies to all companies operating in Norway. The Special Petroleum Tax (SPT) applies to offshore production income at 50 per cent. Unlike PRT in the UK, and PRRT in Australia, the SPT is not deductible for CIT purposes.

For both CIT and SPT purposes, depreciation for Capital Expenditures is allowed on 6-year straight-line basis. Hence, for SPT deductions and depreciation are the same as for CIT, except that for SPT an additional Uplift applies. For all fields approved before 1986, the SPT uplift is an extra 100 per cent on expenditures incurred for each asset used in production and pipeline transportation. For fields whose development plan was accepted after 1 January 1986 the uplift applies at a rate of 5 per cent over 6 years (Samuelsen, 2002).

For SPT purposes, there is a ring fence around the field. For CIT purposes, losses from operations on the Continental Shelf may be offset against profits from producing fields. Only 50 per cent of losses from other activities may be offset against profits from Continental Shelf activities (Barrows, 2000).

SPT and CIT allow losses to be carried forward, hence no tax is paid unless all losses have been absorbed. Abandonment costs are not fully deductible like in the UK, but a grant exists, and which allows the deduction of abandonment costs at a rate equal to the effective tax rate.

The Norwegian cash flow model can be illustrated in the following equation:

$$NCF_t = R_t - OE_t - CE_t - SPT_t - CIT_{nt} \tag{8.8}$$

where:

$$SPT_t = t_{as}(R_t - OE_t - D_{nt} - up_{nt}) \qquad (8.9)$$

and,

$$CIT_{nt} = t_{nci}(R_t - OE_t - D_{nt}) \qquad (8.10)$$

with:

- t_{ns} the SPT rate
- up_{nt} the 5 per cent uplift for 6 years
- t_{nc} the CIT rate
- D_{ns} the depreciation

8.2.1.6. CONCESSIONARY SYSTEMS: QUALITATIVE COMPARISON

Table 8.1 summarises the main characteristics of the concessionary systems as they apply in the UK, Australia and Norway. It can be seen that a certain harmonisation exists between the concessionary regimes applied in the three selected countries. Firstly, none of the UK, Australian and Norwegian regimes currently apply Royalty. Secondly, the Income tax rate is around 30 per cent. However with the additional 10 per cent Supplementary charge imposed in April 2002, the UK has the highest rate at 40 per cent.

Table 8.1. Concessionary Systems: Summary

Country		Royalty	Income Tax	Special Petroleum Tax	Tax Reliefs
Australia	Post 1990	-	30%	PRRT 40%	Uplift (15-23%)
	Pre-1990	10%		Deductible from CIT taxable base	Abandonment cost not deductible
Norway	Post 1986	-	28%	SPT 50%	Uplift 5%
	Pre 1986	8-16%		Not Deductible from CIT Taxable Base	Abandon Relief (<100%)
UK	Post 2002	-	40%	PRT 50%	Uplift 35% Allowance Safeguard
	Post 1993	-	30%	PRT 50%	Uplift 35% Allowance Safeguard
	1983-93	-	33%	PRT 75%	Uplift 35% Allowance Safeguard
	Pre 1983	12.50%	52%	PRT 70%	Uplift 35% Allowance Safeguard
				Deductible from CT taxable base	Abandonment cost deductible (100%)

Thirdly, this Income Tax is the general tax that applies to all companies operating in the three countries respectively. Hence, oil companies are treated on the same basis as any other company in the country. Fourthly, given the special characteristics of the oil sector (availability of economic rent, high risks, long time lags involved in prospecting and extraction and high capital intensity), there is a special treatment of the oil sector. That is why the three countries have incorporated a special resource tax, which is between 40 and 50 per cent. Additionally, the three countries provide tax incentives and extra expenditure reliefs, such as Uplift and the ability to carry losses forward. In fact, the UK, Australia and Norway regimes allow losses to be carried forward and taxes to be paid only when Net Cash Flow turns positive.

However in terms of expenditure reliefs, the UK offers the most generous reliefs compared with Australia and Norway. For instance, the UK PRT offers three significant reliefs namely Uplift (35 per cent), Oil Allowance and Safeguard, compared with Uplift of 15 and 5 per cent in Australia and Norway respectively.

Furthermore, the UK offers 100 per cent relief for Abandonment costs unlike Norway, where only a certain percentage, normally equal to the effective fiscal take (i.e. on average 76 per cent) is allowed for deductions, while in Australia there are no Abandonment costs reliefs. Consequently, Norway seems to impose the strictest terms, especially in that it does not allow the Special Petroleum Tax to be deducted for Income Tax purposes, unlike the UK and Australian regimes.

The comparison is further expanded in the quantitative part of the analysis, covered in Section 8.4. The following section evaluates the other common type of fiscal regimes in oil producing countries, where divergence is more noticeable compared with the UK regime.

8.2.2. CONTRACTUAL BASED SYSTEMS

Sunley, Baunsgaard & Simard (2002) argue that the contractual regime is an alternative to concessionary regime. This section analyses the main features of contractual regimes and studies those applied in Indonesia, China and Iraq in order to compare them with the UK fiscal regime.

8.2.2.1. GENERAL FEATURES

As the name indicates, the contractual regime is based on a contract between the Government and the oil company, also called the Contractor. The Government enters into a contract with the operator for a given area (Johnston, 1998).

An essential characteristic of this system is that the Government retains ownership of the resource, hence all production belongs to the Government and the oil company is appointed as a contractor to assist the Government in developing the resource. The parties agree that the contractor will meet the Exploration and Development costs in return for a share of production or a fee for this service, if production is successful.

If the contractor receives a share of production after the deduction of Government share, the system is known as a Production Sharing Contract (PSC). If the contractor is paid a fee (often subject to taxes) for conducting successful Exploration and Production operations, the system is known as a Service Contract, also called Risk-Service Agreement. The latter is called so because in a Risk-Service Contract, the host Government (or its national oil company) hires the services of an international oil company and in case of commercial production out of the contractual area, the oil company is paid in cash for its services (Blinn et al, 1986).

There are 64 countries adopting a PSC system to their petroleum activities and typical examples are Indonesia and China while there are only 12 countries following a service contract, a typical example of which is Iraq (Johnston, 2001).

In contractual regimes, the contractor bears all the costs and risks of Exploration and Development. The contractor has no right to be paid in the event that discovery and development does not occur. However, if there is a discovery the contractor is allowed to recover the costs it has incurred, and this is known as Cost Recovery or Cost Oil.

Cost Recovery is similar to cost deductions under the concessionary systems. It includes mainly unrecovered costs carried over from previous years, Operating Expenditures, Capital Expenditures, Abandonment Costs and some investment incentives. Interest expense is generally not a recoverable cost. However, in general there is a limit for cost recovery that on average ranges from 30-60 per cent of Gross Revenue, in other words, for any given period the maximum level of costs recovered is 60 per cent of Revenue. This is further analysed in Section 8.2.2.3.

Contractual systems normally offer certain investment incentives. For instance, unrecovered costs in any year can be carried forward to subsequent years. Also, some contracts allow these costs to be uplifted by an interest factor to compensate for the delay in cost recovery. Investment credits can also be provided to allow the contractor to recover an additional percentage of Capital Costs through cost recovery. There is usually a ring fence on petroleum activities, hence all costs associated with a particular block or licence must be recovered from revenues generated within that block.

The principle of Cost Recovery applies to both a Production Sharing Contract and in Risk-Service Agreement. However, the basis of the contractor's remuneration after it has recovered its cost differs in type.

In a PSC, the remaining oil after cost recovery is termed "Profit Oil" and is divided between the Government and the contractor according to some formula set out in the contract (Sunley, Baunsgaard & Simard, 2002). Hence, in this case, the remuneration of the contractor is a share of the production.

In a Service Agreement, the Government allows the contractor to recover its costs. Additionally, the Government pays the contractor a fee based on a percentage of the remaining revenue. Because the remuneration of the contractor is in cash in a Service Contract, the system has met some resistance on the part of some oil companies who would prefer a PSC as it provides them with a ready access to all parts of the production process (Blinn et al, 1986). Since the contractor does not receive a share of production, terms such as production sharing and Profit Oil are not appropriate even though the arithmetic will often carve out a share of revenue in the same fashion that a PSC shares production (Johnston, 1994).

Additionally, in a PSC, the share of Profit Oil can be subject to Income Tax, while in a Service Contract the fixed fee remuneration of the contractor can be subject to tax.

Royalty is not a common instrument in contractual regimes (Johnston, 2001), however countries like China still apply it. In this case, Royalty is paid to the Government before the remaining production is split. Nevertheless, an alternative to Royalty is to have the limit on Cost Oil, to ensure that there is Profit Oil as soon as production commences. Sunley, Baunsgaard & Simard (2002) argue that such a limit on cost recovery has similar economic impact as a Royalty, with the Government receiving revenue- its share of Profit Oil- as soon as production commences.

In some countries, the Government has the option to purchase a certain portion of the contractor's share of production at a price lower than the market price. This is called Domestic Market Obligation (DMO) (Johnston, 2001).

Also, there can be an additional Government take in form of Bonus Payments, which can be on Exploration, in this case called "Signature Bonus" or Production, hence called "Production Bonus". In the latter case, Bonuses are normally on a sliding scale of production, therefore if daily production reaches a certain level the Government takes a fixed sum, which increases if daily production reaches higher levels.

8.2.2.2. CASH FLOW MODEL

Determining the Net Cash Flow under contractual systems is not as straightforward as under concessionary systems. Several stages must be determined; these are presented in the following.

Firstly, Net Revenue is determined. This is the Gross Revenue less Royalty, if applicable.

Secondly, Cost Oil is determined. This includes broadly the Operating Expenditures, Depreciation of Capital Expenditures and any Investment Credit and Uplift. Investment Credit applies only to facilities such as platforms, pipelines and processing equipment, while Uplift applies to all Capital Costs.

Thirdly, the costs available for recovery are then compared to the limit imposed on Revenue, in order to determine the level of costs allowed for deduction at a particular period. For instance, if the cost recovery limit is 80 per cent, in a given period the maximum costs that can be deducted is 80 per cent of Revenue.

If costs exceed that limit, the difference between the actual value of costs and the allowed value is carried forward to a future period.

The following stage differs between a PSC and a Service contract.

In a PSC, the difference between Net Revenue and Cost Oil determines the Profit Oil that will be shared between the contractor and the Government, depending on the split rate. As such, the contractor's share can be expressed as in the following:

$$\text{Contractor Profit Oil} = \text{Net Revenue} - \text{Cost Recovery} - \text{Government Share} \tag{8.11}$$

Finally, the contractor Profit Oil can be subject to Income Tax. In this case, the contractor Profit Oil can be considered as the taxable income under a concessionary system. In general, Investment credits and Uplifts are cost recoverable but not deductible for calculation of Income Tax. The opposite is true for Bonuses, which are not cost recoverable by they are tax deductible (Johnston, 1998).

Consequently, the contractor entitlement can be calculated as follows:

Contractor Entitlement =		Cost Recovery
	plus	Investment Credits
	plus	Contractor share of Profit Oil
	less	DMO
	less	Government Tax
	less	Royalty (if applicable)

(8.12)

Government total share can be expressed as the sum of:

- Royalty (if applicable)
- Share of Profit Oil
- Bonus
- DMO
- Tax

In a Service Contract, the contractor entitlement includes its cost recovery (normally plus interest) and an agreed rate of return, as the remuneration fee. This sum covering Cost Recovery, interest and the rate of return is paid over a certain number of months in equal instalments. Once the contractor receives all its payment, that period is known as the "Handover date", at which the foreign contractor hands over facilities to the Government (or the national company) and as such it is no longer involved in the project (Sarkis, 2003). Consequently, up to the Handover date, the contractor entitlement can be expressed as in the following:

Contractor Entitlement =		Cost Recovery
	plus	Investment Credits
	plus	Remuneration Fee
	less	DMO
	less	Government Tax
	less	Royalty (if applicable)

(8.13)

The Government share in this case is any remaining profitability of the oil field, once the contractor received the remuneration for its service.

8.2.2.3. INDONESIA PRODUCTION SHARING CONTRACT

Indonesia is one of the most active countries in the Southeast Asia. The country is a "pioneer" of the PSC, with the first contracts signed in the early to 1960s.

It has been famous for the 85/15 per cent split in favour of the Government. Several changes have altered the Indonesian regime, among others the reduction in the split rate to 64/36 per cent in favour of the Government. Additionally, the current system (based on the 1990 PSC model) has the following characteristics.

The Indonesian system does not charge a Royalty. Instead, it imposes what is known as the First Tranche Petroleum (FTP) contract, which requires that 20 per cent of the production be shared at 64/36 per cent in favour of the Government before cost recovery. The FTP acts like a Royalty since it is imposed on Gross Revenue and guarantees the Government a minimum income just as production commences. The Government FTP share will be added to the total Government take, while the contractor FTP will be added to his taxable income, and is subject to Income Tax (Barrows, 2000).

An interesting peculiarity of the Indonesian regime is that there is no limit for cost recovery. But in reality, the 20 per cent FTP acts as a cap since it reduces the available Gross Revenue for cost recovery to 80 per cent. In other words, the FTP is similar to 80 per cent cost recovery limit.

The Indonesian PSC offers 15.5 per cent Investment Credit, which is cost recoverable but not tax deductible. Depreciation on oil Capital Expenditures is at 25 per cent per year using the Declining Balance method with the undepreciated amount written off in year five.

Income Tax applies at a rate of 44 per cent. It was reduced from 48 per cent in 1994. Furthermore, there is a ring fence for each licence.

Production Bonuses apply as follows (Sunley, Baunsgaard & Simard, 2002):

- If daily production reaches 50,000 barrel per day (bbl/d) the contractor pays the Government £10M.
- If daily production exceeds 50,000 bbl/d but less than 100,000 bbl/d, the contractor pays the Government an additional £10M.
- If daily production exceeds 250,000 bbl/d, the contractor pays the Government an additional £25M.

The Indonesian DMO requires the contractor to sell 25 per cent of its share of oil to the national oil company Pertamina. After 60 months of production from a given field, the price the contractor receives for the DMO crude is 25 per cent of the market price (Barrows, 2000).

8.2.2.4. CHINA PRODUCTION SHARING CONTRACT

China adopts a PSC for its petroleum activity, but also combines with this system Royalty and Income tax. Such combination makes the system an interesting case to study as Royalty is not common in PSCs (Johnston, 2002). Furthermore, the Royalty applies on a sliding scale where it varies with the level of production, unlike the fixed rate on Gross Revenue in the UK (prior to 2002). Table 8.2 summarises the Royalty rates as they apply since in 1989. The maximum rate is 12.5 per cent, while a lower Royalty can be negotiated for medium sized fields if commercially marginal.

Table 8.2. China Sliding Scale Royalty[113]

Field size Barrels of oil per day	Royalty rate %
Up to 20,000	0
20,001-30,000	4
30,001-40,000	6
40,001-60,000	8
60,001-80,000	10
>80,000	12.5

Another important feature of the Chinese PSC (based on the 1996 model) is that profit oil is split at a negotiable rate, depending on the annual level of production and as such the rate varies from one field to another. A factor "X" is determined for each field in accordance with the successive incremental tiers on the basis of the annual gross production of crude oil from an oil field during that calendar year, as presented in Table 8.3. To determine the single "X" factor for each field, firstly the annual production (Q_n) is multiplied by the corresponding "X" factor (X_n), secondly the total amount ($Q_n * X_n$) is divided by the total production of the field and multiplied by 100. The resulting figure is the rate at which the profit oil is divided between the Government and the contractor for a particular field.

Table 8.3. China "X" Factor

Production (Thousands Barrel per day) (Q_n)	Factors (X) Applicable to Each Production Tier (X_n)
Up to 9,999 b/d	X1 = 4%
10,000 b/d-19,999 b/d	X2 = 8%
20,000 b/d-39,999 b/d	X3 = 15%
40,000 b/d-59,999 b/d	X4 = 20%
60,000 b/d-99,999 b/d	X5 = 28%
100,000 b/d-149,999 b/d	X6 = 45%
150,000 b/d-199,999 b/d	X7 = 55%
Over 200,000b/d	X8 = 70%

[113] Source: Barrows (2000)

Cost recovery is 62.5 per cent of annual gross revenue. Operating Costs incurred are recovered first, then Capital Costs are fully recovered, any unrecovered balance is carried forward to the following period and is compounded at a 9 per cent interest rate.

A Value Added Tax (VAT) of 5 per cent applies on Gross Revenue and Corporate Income tax applies at a rate of 33 per cent. A ring fence exists around the contract area for cost recovery only but not for Income Tax.

8.2.2.5. IRAQ SERVICE CONTRACT

In Iraq, the fiscal arrangement that applies to petroleum activity is a Risk-Service Agreement. This is also known as a BuyBack contract, and is similar to the system adopted by other countries, such as Iran. In these countries, the arrangements with foreign companies "shall in no way entitle the companies to any claims on the crude oil" (Barrows, 2000, p.105).

Under the Iraq Service Agreement (based on the 2000 model), the oil company undertakes all development work at its own cost and receives a sum that reimburses it for its costs plus interest and agreed remuneration. Cost recovery is allowed at 50 per cent of gross revenue, and a Remuneration Index is introduced in order to enable the contractor to make return on its cumulative investment. The Remuneration Index is also called "R Factor", which is typical in Service Contracts (Johnston, 1994).

The R factor can be determined as in the following (Wells, 2002):

$$R = \frac{\text{Cumulative Contractor's Cost Recovery Payments} + \text{Cumulative Contractor's Profit Payment}}{\text{Cumulative Contractor's Cost Recovery Payments}} \qquad (8.14)$$

where Cumulative Contractor's Profit Payment is the cumulative 10 per cent of gross revenue. On average, a 1.5 is assumed as a Remuneration Index.

As soon as the contractor recovers 1.5 times his cumulative investments, the Handover Date is reached and if at that date there are any unrecovered costs, the sum is paid by equal instalments over 8 quarters or 2 years after the Handover date. After that, the Iraqi State is entitled to all the future net incomes (Barrows, 2000). As such, the Iraqi Government take can be on average between 85-90 per cent. Johnston (2001) argues that a Government take of 95-97 per cent is considered typical under a Risk Service arrangement.

The contractor is exempt from any Income Tax. There are typically negotiable Production Bonus payments payable if production reaches 50,000 bbl/d, 100,000 bbl/d and 200,000 bbl/d.

8.2.2.6. CONTRACTUAL SYSTEMS: QUALITATIVE COMPARISON

Table 8.4 summarises the characteristics of the contractual systems as they apply in Indonesia, China and Iraq. Several similarities exist in the way the systems work but the process of sharing revenue is different.

The three basic economic and fiscal elements of a PSC are Cost Recovery, the Profit Oil Split between the contractor and the Government and the Income Tax. The four basic economic and fiscal elements of a Service Contract are Cost Recovery, the Remuneration Fee, the Handover date and the Income tax.

Table 8.4. Contractual Systems: Summary

Country	Royalty	Income Tax	Cost Recovery	Investment Credit	Bonus	DMO	Profit Split
Indonesia	FTP 20%	44%	-	15.5%	Yes	Yes	64%/36%
China	Sliding scale 0-12.5%	33%	62.5%	9%	-	-	X Factor
Iraq	-	-	50%	1.5 Remuneration Index	Yes	-	-

In concessionary regimes, the international oil company usually owns the oil reserves. In contractual regimes, the Government maintains ownership of the resource, however it maximises its control under a Risk Service Agreement (Wells, 2002). Blinn et al (1986) argue that the Service system emphasises the principles of Government sovereignty and for that reason it is hardly surprising that this type of agreement is mostly in use in Latin American countries "where the nationalist sentiment concerning hydrocarbons is the strongest" (p.97). Wells (2002) also argues that concessionary systems are not a suitable form of contract for the Middle East oil producers. These countries are influenced by Islamic law, the Shari'ah, which forbids foreign ownership of national resources (Blinn et al, 1986). Furthermore, because fiscal terms are fixed upon signature of the contract between the Government and contractor, contractual systems offer a more stable environment than the concessionary systems.

The main difference between the PSC and a Service Agreement lies in the mechanism used to remunerate the oil company. In a Concessionary system, the oil company receives the net income after costs, tax and Royalty. Under a PSC, the company gets cost recovery and a share of the remaining profit, while under a Service Contract, it receives the cost recovery and a profit fee or remuneration until Handover date.

Although the principles are the same under PSC and Service Contract, such a difference in remuneration generates further distinction in terms of duration of contract, cost-reduction incentives and impact of changes in oil price and reservoir characteristics.

PSCs can be long term in nature (25 years) but in Service Agreements the contractor involvement depends on the Handover date, which in turn is affected mainly by the Capital Expenditure and oil revenue (Jankowski, 2000). Generally speaking, Service Agreements are short-term, normally lasting for 9 years, compared with up to 30 years under a PSC (Wells, 2002). As such, under PSC, the contractor receives profit throughout the life of the contract, which is normally the life of the field, whereas under a Service Agreement the contractor cost recovery and profit remuneration end at the Handover date.

As a consequence of the limit on Cost recovery, contractors are normally encouraged to reduce their Capital Cost. However, in the Service Contract, the contractor has no incentive to reduce the long-term costs, since the field is likely to be under the control of the Government.

Sarkis (2003) argues that this is a major limitation of the Service Contract, while Wells (2002) maintains that a long-term partnership with a contractor may result in better overall field performance and much more value for the state than in the short-term approach. The author further adds that Service Agreements are suited to low-risk, short-term projects, but not to marginal oil fields.

Furthermore, in both types of contractual agreements, the contractor is largely exposed to reservoir and oil price risks. In case of unsuccessful Exploration, the contractor does not receive any compensation. Similarly, if the oil price declines then the share of revenue allowed for cost recovery decreases as well. However, under the Service Contract, unlike the PSC, the contractor does not benefit from any upside in reservoir or oil price, since it receives a pre-determined remuneration fee (Sarkis, 2003).

Given such analysis, it is expected to identify that the toughest fiscal terms from a company standpoint are likely to be found under contractual regimes while more lenient terms are expected under concessionary regimes. This is investigated in the following section.

8.3. METHODOLOGY & ASSUMPTIONS

The empirical analysis is conducted under the same economic assumptions of the previous three chapters, namely a constant real oil price of $19.5 a barrel, with 2002 as a base year, a constant annual inflation rate of 2.5 per cent and a constant exchange rate of 1.5$/£.

Additionally, four fields are selected randomly from the sample of 25 oil fields, which were used to complete the analysis in Chapters 6 and 7. The four fields selected are:

- Argyll, a very small field
- Arbroath, a small field
- Tern, a medium field
- Schiehallion, a large field.

The nine UK tax scenarios, which were developed in Chapter 5, are compared with the fiscal packages under the Australian, Norwegian, Indonesian, Chinese and Iraqi regimes. The analysis mainly compares the impact of the selected fiscal regimes on different field size, cost structure, and Government revenue. In other words, the study focuses on determining the ways those countries attempt to achieve the balance between maintaining the attractiveness of their oil province to international investors while generating a satisfactory share of revenue for the country. Furthermore, the analysis focuses on the change in the international competitiveness of the UK fiscal regime from an investor standpoint from 1975 until 2002.

A spreadsheet is developed to illustrate the petroleum fiscal package for each country[114]. The different economic and fiscal assumptions for each country are those that apply effectively in those countries and which were summarised in Tables 8.1 and 8.4. Under each scenario, the fields' profitability is calculated, and both the contractor's and Government shares are derived. All results are calculated firstly in nominal terms than deflated.

[114] See Appendix I.

For simplification, the profitability is calculated using the Discounted Cash Flow technique, with a real discount rate of 10 per cent. This also allows a more explicit comparison of the effects of the different fiscal structures on that profitability. Furthermore, as Chapter 6 demonstrated, in general there was a consistency between the effects of taxation under both DCF and MAP, except that under DCF the effects were more significant. A Real Options analysis is not performed. In fact, for the four fields selected, both ROT and DCF generate the same outcome. Further, oil companies may not have a significant flexibility to defer their investment timing under contractual systems, since they do not own the mineral resource and they have to respect the fixed terms in the contract.

8.4. FINDINGS & ANALYSIS

This section presents and discusses the tax performance of the UK compared with the other five selected countries. One criterion to assess that performance is through the effects of the different fiscal packages on the profitability of the four selected oil fields. The second criterion is Government revenue generated and the effective tax rates.

8.4.1. FIELD PROFITABILITY UNDER VARIOUS FISCAL PACKAGES

Table 8.5 illustrates fields' profitability (NPV) under the nine UK fiscal regimes and under the five other international regimes.

The table further shows the profitability ranking on a range from 1, the highest, to 13, the lowest, for each field then for the total profitability of the four fields. The second column in the table, called "Pre-tax", refers to the Base Scenario, where fields' NPVs are calculated on a pre-tax basis[115].

Table 8.5. Oil Fields Profitability under Different Tax Scenarios

Scenario / Field	Pre-tax £M	UK2 £M	UK3 £M	UK4 £M	UK5 £M	UK6 £M	UK7 £M	UK8 £M	UK9 £M	Australia £M	Norway £M	Indonesia £M	China £M	Iraq £M
Argyll	293	108	163	188	203	192	153	88	155	173	53	44	165	35
Ranking		*9*	*6*	*3*	*1*	*2*	*8*	*10*	*7*	*4*	*11*	*12*	*5*	*13*
Arboath	503	131	184	261	343	290	214	145	205	177	92	59	237	75
Ranking		*10*	*7*	*3*	*1*	*2*	*5*	*9*	*6*	*8*	*11*	*13*	*4*	*12*
Tern	724	92.4	149	252	468	384	181	153	199	224	79	35	227	81
Ranking		*10*	*9*	*3*	*1*	*2*	*7*	*8*	*6*	*5*	*11*	*13*	*4*	*12*
Schiehallion	1487	218	439	607	999	837	466	465	447	495	240	167	430	262
Ranking		*12*	*8*	*3*	*1*	*2*	*5*	*6*	*7*	*4*	*11*	*13*	*9*	*10*
Total	3007	550	935	1307	2013	1703	1012	851	1006	1069	464	305	1058	453
Ranking		*10*	*8*	*3*	*1*	*2*	*6*	*9*	*7*	*4*	*11*	*13*	*5*	*12*

The current fiscal structure that applies to UK oil activity (Scenario UK6) provides the second highest profitability, after Scenario UK5, which illustrates the imposition of the 30 per cent CT alone. This is followed by UK Scenario3 where 50 per cent PRT applies alongside 30 per cent CT. These results are consistent for all fields.

The fourth highest level of total profitability is noted under the Australian regime. This applies to the very small field, Argyll, and the largest field, Schiehallion. However, for the small and medium fields, China generates the fourth highest level of profitability. But in fact, there is a small difference between the profitability values determined under

[115] In the tables, the UK tax scenarios are referred to as UK2-UK7c, instead of Scenario 2-Scenario 7c. See Chapter 5, p.150.

the Australian and Chinese regimes, for the medium field, Tern. The overall ranking puts China in the fifth position. Such a ranking can largely be due to China Sliding Scale Royalty and X factor, as both depend on annual production from the field. This can explain the fact that under the Chinese regime, smaller fields have relatively high profitability. The results are reversed for the larger field, with significant annual production. In fact, for Schiehallion field, China has a ranking of nine.

The order in ranking is less consistent for levels 6-9, but on average, the UK tax scenarios namely, UK7a, UK7c, UK3 and UK7b generate the sixth, seventh, eighth and ninth highest profitability. The order differs from one field to another given the relative importance of PRT reliefs for each field, and which depend on the production and costs profiles, as discussed in Chapters 6 and 7. For instance, Scenario UK3, with 75 per cent PRT and 33 per cent CT results in the sixth highest profitability for Argyll field, a very close NPV to China Scenario. However, the abolition of the oil allowance results in the tenth level of profitability for this field, a lower level than Scenario UK2, where Royalty applies with PRT and CT. This emphasises the importance of the oil allowance to the smaller fields. The abolition of Uplift (Scenario UK7a) then Safeguard (Scenario UK7c) have a limited effect on Arbroath field, probably due to the field shorter payback period.

For the larger fields, particularly Tern and Schiehallion, Scenario UK3 generates lower profitability (ranking 9), most probably resulting from the 70 per cent rate of PRT. In fact, imposing 50 per cent PRT under Scenario 4 results in one the highest profitability levels.

For all the fields, the pre-1983 UK structure (Scenario UK2) generates one of the lowest profitability, compared with the other eight UK tax scenarios as well as Australian and Chinese fiscal packages. Although the Chinese tax scenario and UK2 scenario include Royalty, the taxable base for Royalty differs. Whilst it is a fixed rate of Gross Revenue 12.5 per cent in the UK, it is on a sliding scale of production in China, varying with the annual production and further exempting the first tranche of production of 20,000 bbl/d from the payment of the tax. This makes the Chinese Royalty more progressive than the UK Royalty.

However, the UK Scenario 2 is still more favourable relatively to the Norwegian, Indonesian, and Iraqi regime, for all fields, except Schiehallion. For this large field, the pre-1983 structure is "tougher" then both the Norwegian and Iraqi regimes, with respect to its level of profitability.

In general, the following lowest levels of profitability are noticed in Norway (ranking 11), Iraq (ranking 12) and Indonesia (ranking 13). The results with regard the Norwegian petroleum fiscal regime are consistent among the various fields. Indonesia is the least favourable regime for the small, medium and large fields, while for the very small field, Iraq generates the lowest profitability. The Iraqi regime is not as tough as the field size increases (ranking 12 for the small and medium fields, and ranking 10 for the large field). As such, the Iraqi regime can be described as regressive, with respect to fields' size.

The total profitability ranking results concur with those of the qualitative comparison done in earlier sections, particularly for concessionary regimes. The results are also consistent to with those of a study done by Van Meurs Associates (1999), with respect to the UK and Australia petroleum fiscal regimes. In fact, the study compares the extent to which a regime is favourable relative to other regimes from an investor standpoint. According to that study, the UK profitability ranking is 10, which means that there are nine other countries that have petroleum regimes more favourable to the international investor (Barrows, 2000). Australia has a ranking of 113.

The ranking of the other regimes is less consistent particularly if the different field sizes are taken in consideration. For example, according to the Van Meurs study, China has a ranking of 158 compared with 142 for Indonesia, but this does not conform with the findings of this chapter. Furthermore, according to Van Meurs study Norway has a ranking of 221, making the country less attractive to investors compared with the other countries selected, particularly Indonesia. Given the lack of information provided to explain Van Meurs' ranking, it can be concluded that this ranking for Norway may have included the participation of the national oil company, Statoil, whose share could have been assumed to form a part of the total Government take.

The Van Meurs study also gives Iraq a ranking of 312, indicating that the regime is the least favourable for investors. However, the study does not refer to the differing effects on various fields' size. Furthermore, it is likely that that study takes into consideration other factors such as the unstable political environment of Iraq, which is beyond the scope of this thesis.

8.4.2. GOVERNMENT REVENUE UNDER DIFFERENT FISCAL PACKAGES

Table 8.6 represents the total Government take from each field under the different fiscal packages. The ranking shows the lowest Government revenue generated (ranking 1) to the highest take (ranking 13).

Table 8.6. Fiscal Revenue under Different Tax Scenarios

Scenario / Field	UK2 £M	UK3 £M	UK4 £M	UK5 £M	UK6 £M	UK7 £M	UK8 £M	UK9 £M	Australia £M	Norway £M	Indonesia £M	China £M	Iraq £M
Argyll	475.0	342	283	235	284	367	545	363	456.9	608.1	663.6	333.4	709.2
Ranking	*9*	*5*	*2*	*1*	*3*	*7*	*10*	*6*	*8*	*11*	*12*	*4*	*13*
Arboath	1394	1353	901	613	817	1087	1425	1225	1217.4	1596	1772.1	964.1	1783
Ranking	*9*	*8*	*3*	*1*	*2*	*5*	*10*	*6*	*7*	*11*	*12*	*4*	*13*
Tern	2990	2770	2230	1161	1548	2513	2660	2464	2216.6	2957	3247.3	2043.7	3173
Ranking	*11*	*9*	*5*	*1*	*2*	*7*	*8*	*6*	*4*	*10*	*13*	*3*	*12*
Schiehallion	4644	4079	3325	1779	2361	3789	3850	3849	3403.8	4498	4885.2	3462.5	4541
Ranking	*10*	*9*	*3*	*1*	*2*	*6*	*8*	*7*	*4*	*11*	*13*	*5*	*12*
Total	9503	8536	6740	3788	5009	7756	8480	7901	7295	9659	10568	6803.7	10206
Ranking	*10*	*9*	*3*	*1*	*2*	*6*	*8*	*7*	*5*	*11*	*13*	*4*	*12*

Imposing only a 30 per cent CT (Scenario UK5) in the UK from 1993 to 2002 generates the lowest Government revenue from all fields. It is followed by the imposition of the Supplementary charge in 2002 (Scenario UK6), then the combination of 50 per cent PRT with 30 per cent CT (Scenario UK4). The revenues generated under these scenarios are lower than the post-1983/pre-1993 fiscal package (Scenario UK4). In fact, the results regarding the fiscal revenue generated under the various UK tax scenarios are consistent with those of the previous chapters.

The Chinese fiscal regime results in the fourth level of Government take, followed by the Australian regime. In fact, China produces a close figure of fiscal receipt as compared with Scenario UK3.

Australia with its 30 per cent CIT and 40 per cent PRRT generates a close fiscal take from the very small as compared with Scenario UK2 with Royalty, PRT and CT. However, for the small field, Arbroath, the revenues generated are closer to those under Scenario UK3, while for the larger fields, the figure is similar to that of Scenario UK4. Despite the higher rate of PRT, this tax offers relatively generous reliefs namely Uplift, oil allowance and Safeguard, compared with Uplift only for PRRT in Australia. Furthermore, the Abandonment costs are allowed for deduction in the UK fiscal regime unlike the Australian system. The difference is widened for the smaller fields, where PRT reliefs can be of critical significance. The importance of the PRT reliefs in reducing the overall Government take can be noted in the higher share of revenue generated under UK Scenarios 7a, 7b and 7c relatively to the revenue generated under the Australian regime.

The pre-1983 fiscal package in the UK generates the highest level of revenue as compared with the other UK tax scenarios.

In Norway, the Government adopted some measures to relax the regime, among others the abolition of Royalty. Despite the fact that this tax does not apply anymore, the Norwegian fiscal regime still generates the highest share of revenue compared with the other two concessionary regimes.

This can be due to the fact that the Special Petroleum tax is not allowed as a deduction for Corporation Income Tax, unlike both the UK and Australia.

Table 8.7 permits a clearer comparison of the different fiscal components of these three concessionary systems. For instance, ST generates higher revenue from Schiehallion field, as compared with all the other scenarios, except for Scenario UK3, with 75 per cent PRT.

Table 8.7. Government Revenue under UK, Australian and Norwegian Regimes

Scenario / Field	UK2 £M				UK3 £M			UK4 £M			UK5 £M	UK7 £M		
	Total	Roy	PRT	CT	Total	PRT	CT	Total	PRT	CT	Total (CT)	Total	PRT	CT
Argyll	475	109	32.1	334	342	124	218	283	69.2	214	235	367	90.2	277
Arboath	1394	263	398	733	1353	999	354	901	403	498	613	1087	436	650
Tern	2990	513	1525	952	2770	2229	541	2230	1527	703	1161	2513	1608	905
Schiehallion	4644	824	2469	1359	4079	3181	898	3325	2220	1105	1779	3789	2380	1409

Scenario / Field	UK6 £M	UK8 £M			UK9 £M			Australia £M			Norway £M		
	Total (CT+ST)	Total	PRT	CT	Total	PRT	CT	Total	PRRT	CIT	Total	ST	CIT
Argyll	284	545	385	159	363	83	280	457	314	143	608	391	223
Arboath	817	1425	999	426	1225	666	559	1217	829	388	1596	1032	595
Tern	1548	2660	1853	807	2464	1527	937	2217	1456	760	2957	1919	1111
Schiehallion	2361	3850	2480	1368	3867	2493	1374	3404	2272	1132	4498	2876	1682

The Indonesian and Iraqi regimes produce the highest share of revenue. The Iraqi regime take is higher for the smaller field, whilst the result is reversed for the Indonesian regime. In fact, in Indonesia different fiscal elements apply to ensure the Government receives a significant share of revenue, particularly from the larger fields. For instance, although no Royalty or cost recovery limit applies, the 20 per cent FTP acts like a Royalty. Additionally, Bonus and DMO apply and they are linked to the annual production.

8.4.3. EFFECTIVE RATES UNDER DIFFERENT FISCAL PACKAGES

Government take can also be analysed by considering the effective average tax rate under each tax scenario. These are presented in Table 8.8, where the last row summarises the average effective rate of each scenario and country.

Table 8.8 Effective Tax Rates

Scenario Field	UK2 %	UK3 %	UK4 %	UK5 %	UK6 %	UK7 %	UK8 %	UK9 %	Australia %	Norway %	Indonesia %	China %	Iraq %
Argyll	60.9	43.8	36.3	30.0	36.5	47.1	69.8	46.6	58.3	77.6	84.7	42.6	91.0
Arboath	66.8	64.9	43.3	29.0	39.2	52.2	68.4	58.8	58.4	76.6	85.1	46.3	85.6
Tern	77.7	72.0	57.9	30.0	40.0	65.3	69.1	64.0	57.3	76.4	83.9	52.8	82.0
Schiehallion	78.7	69.1	56.6	30.0	40.0	64.2	65.2	65.2	57.4	75.9	82.4	58.4	76.6
Average	71.0	62.5	48.5	29.8	39.0	57.2	68.1	58.7	57.9	76.6	84.0	50.0	84.0

A proportional regime indicates that the same percentage tax take occurs in fields of quite different profitability (Kemp & Rose, 1982). As such, UK5, UK6, Norway, Australia and to a lesser extent Indonesia, can be described as proportional. When the percentage take increases with the field size and profitability, the system can be described as progressive. Consequently, all the other UK scenarios, those incorporating PRT, in addition to China tax scenario can be described as progressive. Iraq, however, can be considered as a regressive system, with the effective tax rate declining with the field size.

The pre-1983 effective tax rate in the UK is closer to the current Norwegian, Indonesian, and Iraqi regimes than it is to the recent UK fiscal structures, which are in fact the lowest.

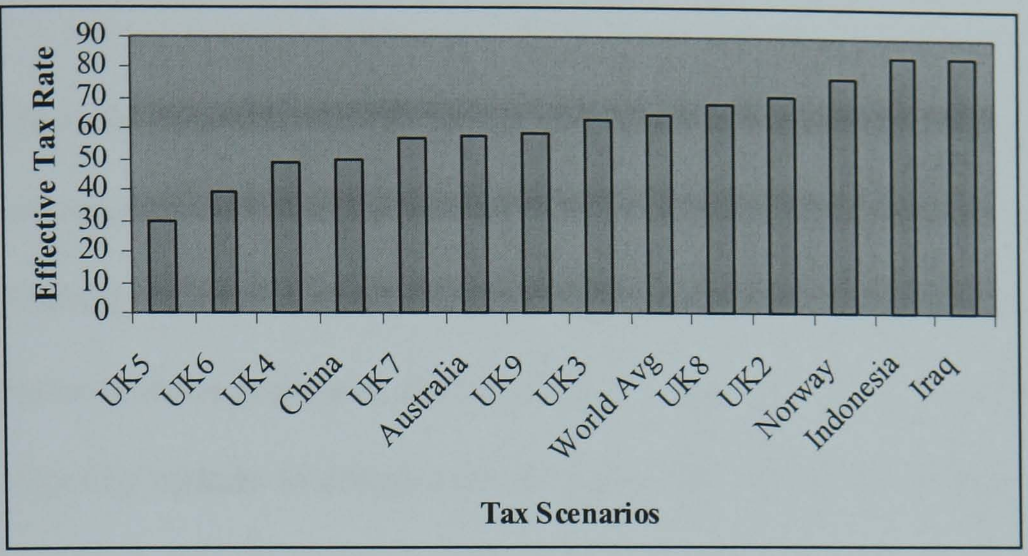
Although tough fiscal terms are expected to be found under contractual regime, the analysis indicates that concessionary systems like the Norwegian, can be even tougher, while some PSC, like in China, can lead to similar conclusions as other concessionary regimes.

Furthermore, Service Agreements are expected to offer the toughest terms among the contractual arrangement. In fact, the Iraqi regime does impose the highest rate on the smaller fields, reaching 90 per cent. This can explain the arguments of, for example, Wells (2002) and Sarkis (2003) who maintain that Service Contracts are not suited for small fields. The high level of Government take is particularly discernible if the total field life is considered. However during the period of the contracts' duration (i.e. up to the Handover date) the Government take is less significant. The analysis has also shown that, on average, both the Indonesian and Iraqi regimes provide a similar outcome (84 per cent effective rate).

Johnston (2002) determined a world average rate of 65 per cent on a study covering 133 regimes. Figure 8.1 compares the countries selected effective rates with this average rate.

Indonesia, Iraq, Norway, the 1975-UK regime, and the application of PRT without the Oil Allowance all fall above the world average Government take, while the other scenarios, including China and Australia fall below.

Figure 8.1. Effective Fiscal Rates & World Average Rate



The 2002 changes to the UK fiscal regime did increase the effective tax rate but the regime still offers the lowest total fiscal rate, particularly as it applies on fields that received development consent after 1993. Nevertheless, it would be inadequate to describe the UK fiscal regime as the weakest in the world. Currently, maintaining the level of activity is a serious concern for the UK Government, as the UKCS is considered to be a mature province where significant discoveries are unlikely to be made.

One would expect that in a competitive world, areas with the least favourable geology, highest development and operating costs and lowest wellhead prices would offer lenient terms (Harbinson & Westwood, 2002). The findings of Chapter 4 strongly confirm such argument[116]. Furthermore, with the decline in production in the foreseeable future, countries like Norway have started considering reforms to their petroleum sector (Lund, 2002).

---

[116] For instance, Respondent O4 argues that "whilst in headline terms the fiscal regime for new developments in the UKCS is more attractive than, for instance, Norway, the fields size are smaller and unit costs higher in the UKCS than for typical new fields in Norway. At the exploration level Norway offers the potential for large discoveries the UKCS does not".

8.5. SUMMARY & CONCLUSION

In this chapter, the fundamental UK petroleum fiscal packages are compared with five international regimes. The analysis focused on the effects of different packages firstly on the profitability of four selected oil fields of different size, and secondly on the level of Government revenue generated. A broad range of fiscal instruments and structures is available to policy makers to design a fiscal regime for the petroleum sector in order to attract investment and secure a reasonable share of economic rent for the Government (Sunley, Baunsgraad & Simard, 2002). The study undertaken in this chapter investigates the way the Government in the six countries attempt to maintain a balance between these two conflicting objectives. In fact, each of the countries analysed in this chapter has developed its own fiscal package, where several fiscal elements interact in different ways.

There are two broad categories of fiscal regimes namely, Concessionary and Contractual, where the main difference between the two systems is of a legal nature, i.e. the holding of the mining rights and the title to production. Under a concessionary regime, the oil company takes ownership of the resource and often pays a Royalty combined with a special resource tax and an Income tax. Under a contractual system, the Government maintains ownership of the resource and the oil company is appointed as a contractor to assist the Government in exploiting the resource. In this case, the oil company receives compensation for its service. If the compensation is a share of production, the system is known as a Production Sharing Contract (PSC). If the compensation is in cash, the system is known as a Service Contract.

The UK, Australia and Norway adopt a Concessionary regime and the three countries imposed Royalty, an Income Tax and a special petroleum tax- a Petroleum Revenue Tax (PRT) in the UK, a Petroleum Resource Rent Tax (PRRT) in Australia and a Special Petroleum Tax (SPT) in Norway. Indonesia, China and Iraq follow the contractual system. More precisely, Indonesia and China adopt a PSC, while a Risk-Service Contract is found in Iraq. In PSCs, the main *fiscal* elements are Cost Recovery, sharing of profit oil and, often, an Income tax. In Service Agreement, the elements are the Cost Recovery, Remuneration Fee and the Handover date.

The analysis shows that in terms of oil field profitability, the current fiscal regime in the UK is the most favourable compared with all the other countries as well as past structures that applied since 1975. The other UK scenarios, except for the pre-1983 structure and the abolition of the oil allowance, also offer the most lenient terms, similarly to China and Australia.

In fact, compared with the Australia and Norway, the UK offers the most generous reliefs, particularly with respect to PRT, the treatment of Abandonment costs and the deduction of PRT from the CT taxable base. Australia implements a similar structure to the post-1983/pre-1993 UK regime, but it limits its reliefs to Uplift, while Abandonment costs are not allowed for deduction. Norway has relatively limited reliefs, like Australia, but although the country allows a certain deduction of Abandonment cost, the Special Tax is not deductible from the Income Tax base, rendering the total tax take more significant compared with the other two countries. In fact, Norway has fiscal takes very close to the countries under contractual regimes.

However, the Norwegian regime is significantly simpler than the other two concessionary systems, while in the UK, the computation of the fiscal take is the most complicated.

China offers the most lenient terms among the contractual arrangements, particularly in the case of the smaller fields, given the progressive aspect of both its sliding scale Royalty and the negotiable profit split. In contrast, both Indonesia and Iraq generate the lowest profitability and the highest fiscal take and the lowest oil profitability. Iraq can also be a regressive regime with its highest effective tax take on the smallest field, compared with a lower take from the larger fields. Apart from Iraq, the PSCs in Indonesia and China and the concessions in Norway, Australia and the UK based on Income tax are found proportional to the field size. The UK scenarios including PRT are found rather progressive.

In terms of Government revenue, the introduction of the 10 per cent supplementary charge in 2002 increased the Government take, compared with precedent structure but still the system generates the lowest take compared to the other scenarios. This could partly explain some criticisms such as oil companies are not paying their fair share of taxes (Miller et al (2000), Rutledge & Wright (1998)).

There is no doubt that the UK offers significant opportunities for investors, mainly as a result of its political stability. Furthermore, the industry benefits from an intensive continuous partnership between the Government and the companies.

Nevertheless, as Raja (1999) argues, although political stability is an important criterion affecting the direction of investment, the size of the reserves and the exploration risk play a significant role in attracting investments. The UK being a mature area chose relaxing its regime and offering low fiscal rates in order to sustain the oil production and maintain the international competitiveness of the province from an investor standpoint. Johnston (2002) argues that, although the average Government take worldwide is around 65 per cent, this rate is very high for "average" geological potential. "For countries with better-than-average potential the Government take is closer to 80 per cent. However, better-than-average geological potential is rarely sufficient to sustain such a high Government take" (Johnston, 2002, p.25).

In fact, the April 2002 changes may not have increased dramatically the fiscal take, but since the Supplementary charge does not include a deduction for financial expenses, it can place a burden particularly on smaller UKCS E&P companies who are the new generation of investors. Furthermore, although the UK offers a stable political environment, its petroleum fiscal regime witnessed frequent amendments[117], which can affect adversely investor confidence, even though not all those changes can be described as substantial. Any attempt to further strengthening the regime must allow for the fact that the UK is a mature province, with remaining small marginal fields to be developed (Nakhle & Hawdon, 2003).

The analysis carried out in this chapter further shows that each fiscal system has its advantages and disadvantages.

---

[117] See Chapter 3

In brief, in PSC and Service Agreements tax rates are held constant during the contract while in concessionary regimes amendments are possible at anytime (Barrows, 2000). On the other hand, PSC and Service Agreements with a high fixed profit/production split rate in favour of the Government do not seem suitable for the development of small marginal fields, given the limit on cost recovery. Furthermore, Exploration is conducted at the contractor's own risk, with no reimbursement in case of unsuccessful Exploration. Service Contracts can be more rigid than PSCs given their short duration and the fixed remuneration fee. Varzi (2002) argues that this may be of advantage for the oil company especially at times of low prices but not in periods of high prices.

Accordingly, it is impossible to categorise fiscal regimes as "good" or "bad", because each regime is applied under specific circumstances. For instance, while contractual arrangements are imposed to ensure a higher Government control, such structures are unlikely to be applied in liberal economic environments such as the UK. Further, it can be very restrictive to judge about the performance of the regime simply by looking at its type of arrangement or at its tax rates. The analysis performed in this chapter shows that several factors, such as fiscal reliefs and the process of calculating the tax base, can lead to significant differences among fiscal packages, while same targets can be achieved with different structures and regimes.

The chapter likewise emphasises the argument raised in Chapter 2 that clearly there is no one ideal fiscal regime suitable for all petroleum projects in all countries. Varzi (2002) argues that no two PSCs are the same, Sarma & Naresh (2001) maintain that harmonisation of mineral levies across the countries is a distant possibility.

Similarly, Johnston (2001) argues that there are more fiscal regimes than there are countries while Helliwell (1982) maintains that generalisation about anything as complex as taxation can be dangerous.

This chapter completes the empirical analysis in this thesis. The following chapter summarises and concludes the research undertaken in this thesis.

CHAPTER NINE

SUMMARY & CONCLUSION

9.1. THESIS SUMMARY

The principal objectives of this thesis are to critically evaluate the petroleum fiscal regime in the UK North Sea since 1975, and to identify a fiscal regime that is acceptable to Government and oil industry alike.

Government and oil companies are the principal players in the upstream sector of petroleum industry. However, their individual focus is one of competing rather than complementary objectives. For example, Governments seek to generate high levels of take from oil related activity. Since Governments in oil producing countries are considered to be the natural resource owner, "it has been widely argued... that the lion's share of economic rent should accrue to host governments" (Crowson, 2004, p.10). Additionally, Governments prefer to receive a part of the fiscal take comparatively early in the life of an oil field. On the other hand, the principal objective of oil companies is to ensure an acceptable and sufficient level of profitability in its operations (Blinn et al, 1986). Since taxation removes a considerable slice of the producer's profits, oil companies prefer fiscal systems that result in a low overall tax level thereby allowing high post-tax returns. In addition, their preferred systems are those geared to facilitating a risk sharing position together with the rapid recovery of development costs.

Consequently, if tax rates are set too high, investment is discouraged. Alternatively, if they are set too low Governments will be left with an inequitable share of economic rent. Given the existence of these competing objectives, a trade off will always be necessary. Over the years achieving this balance has given rise to significant controversy in the UK.

Nevertheless, because of the significant financial resources required in the exploration and exploitation of oil, the high inherent risk, as well as the contribution that the oil industry makes to economic development, a balance between the various parties' interests is required. The design of an appropriate regime can improve the trade off and a balance can be reached between Government and oil companies.

This thesis seeks to ascertain the type of fiscal package that can be acceptable to both the Government and the industry alike, based upon a time-line analysis covering the evolution of the UKCS petroleum fiscal regime, since its passage into legislation in the 1975 Oil Taxation Act. Accordingly, the thesis considers two principal criteria for assessing that regime namely, the impact of petroleum taxation on oil field profitability and its corresponding effect on Government revenue. Other criteria, such as stability and simplicity of the regime, are also considered but these are generally of a qualitative nature.

The first stage of the analytical process has been to establish the basis for evaluating the regime. This is undertaken in Chapter 2, where criteria with which to evaluate tax instruments are examined so as to identify the key features of an ideal tax system.

The mostly frequently identified criteria in the literature are efficiency, neutrality, equity, risk sharing, stability, clarity and simplicity. Further, the chapter analyses the concept and nature of economic rent associated with petroleum exploitation activity. This is important since the majority of previous studies contend that a tax based on economic rent is likely to be an ideal tax. The chapter proceeds with an analysis of the various instruments proposed in previous studies and used to capture economic rent.

The next chapter examines the establishment of the regime in 1975 and its subsequent evolution through to the Budget changes introduced in 2002. This analysis focuses on the four main evolutionary phases, starting with the originating legislation and the subsequent amendments introduced in 1983, 1993 and 2002, each of which generated significant controversy.

In the subsequent stages, a qualitative and quantitative evaluation of the regime is undertaken using an approach, which differs from those adopted in previous studies.

Chapter 4 carries out a qualitative assessment of the regime. The chapter discusses the "Survey of Opinions" solicited from key players in the UK oil sector, with respect to the fiscal regime. This analysis complements later chapters, in so far as a comprehensive evaluation of the regime requires both a qualitative and quantitative assessment, recognising that not all features can be fully captured quantitatively.

In Chapter 5, a cash flow model is developed that clearly demonstrates how the tax take is calculated and its impact on both profitability and Government revenue.

Details of the principal assumptions and the methodology adopted in the analysis set out in subsequent chapters are also included. In total, nine tax scenarios are assumed in order to evaluate and compare the outcome of the principal changes made to the UK regime over the last 27 years. Further, some 25 oil fields currently in production in the UKCS are selected for analysis.

Chapter 6 evaluates the effects of different tax scenarios on selected oil field profitability and Government revenues. The evaluation is carried out using two evaluation techniques, the traditional and commonly used DCF method and the more modern approach using MAP. In order to assess the impact of taxation, an appropriate evaluation technique is crucial. This is of particular importance when measuring economic rent. MAP was developed to facilitate a more efficient evaluation of risk and profitability.

Chapter 7 complements the analysis undertaken in Chapter 6. The same tax scenarios and fields are considered for evaluation but an additional concept based upon the notion of flexibility in decision making is introduced. In essence, the capacity to postpone development decisions to more favourable periods is examined as well as the consequential effect of taxation on the field development timing. Such an analysis is of particular importance for several reasons. Firstly, any change in investment timing can affect the timing of fiscal receipts. Secondly, in a mature province such as the UKCS, any delay in oil field development is not desirable due to the need to maintain oil production and thereby sustaining self-sufficiency. In order to incorporate flexibility in the analysis, the Real Options Theory is used.

Finally, Chapter 8 completes the quantitative evaluation of the UKCS regime by assessing its international competitiveness and comparing it with those of oil producing countries such as Australia, Norway, Indonesia, China and Iraq. As part of this comparison the principal types of international petroleum arrangements are introduced namely the Concessionary and Contractual systems, including Taxes and Royalties Arrangements, Production Sharing Contracts and Risk-Service Agreements.

9.2. PRINCIPAL FINDINGS

Chapter 2 identifies several complications associated with petroleum taxation. The principal sources of complication are associated with determining economic rent and the distinctions to be drawn between the various types of rents. A further source of complication is the inevitable compromises to the criteria that are required to categorize an optimal tax. As an example, a neutral and progressive tax is complex to administer and typically delays revenue generation. Although regime stability is advisable, flexibility needs to be built in so that the regime can adjust to and evolve with major changes in the external environment. Consequently, it is not surprising to find that none of the tax instruments proposed in previous studies represents an optimal tax. The thesis finds that RRT and Income Tax are superior instruments as compared with Royalty and Brown Tax insofar as they create the least distortion between Government and oil company interests.

Arising from the analysis in Chapter 3, Royalty is found to be a simple instrument to administer while at the same time generating early revenues for the Government.

However, since it is regressive, non-neutral and not targeted on economic rent, it is less desirable as compared with PRT and/or CT. PRT allows companies to achieve a minimum return before any tax is paid and the nature of its reliefs ensures that it is progressive. Nevertheless, its complex structure and its tendency to delay fiscal receipts tend to count against it. Finally, CT is a simple tax that applies without exception to all UK industries. However, the fact that it is levied on a company basis, delays fiscal revenues and is set at a relatively low rate means that it is not an optimal tax instrument.

As a consequence of the advantages and disadvantages of each tax, controversy surrounded the major changes made to the regime. However, on the balance of arguments, this thesis concludes that the regime suffered from several limitations, including the lack of neutrality, simplicity, and stability, resulting in a high degree of uncertainty for investors and a relatively low level of tax revenues.

The various amendments in the UK petroleum tax system since 1975 further emphasise the difficulty of designing an ideal tax system. Moreover, any future concerns about UKCS taxation must take into account the current maturity of the petroleum reserve base, where opportunities still exist and taxation will play a critical role. The Government, through the implementation of an appropriate fiscal policy that improves the trade off between revenues and companies' interests, can ensure both the longevity of the UKCS and a continuing high level of investment in the sector. The life of the UKCS can be considerably extended if players are encouraged to squeeze out reserves previously seen as uneconomic (Reuters, 2004).

In Chapter 4 tax instruments such as Royalty and PRT are found to be non-neutral. This is confirmed by their respective abolition in 1983 and 1993 having been seen as affecting the level of activity on the UKCS. Royalty is perceived to be a regressive tax and its abolition is considered essential. In contrast, the abolition of PRT has given rise to a number of differing opinions. The principal controversy surrounding PRT is that it can lead to an inefficient allocation of expenditures as a result of its various reliefs and can actually give rise to investment disincentives in larger fields. PRT is also found to be neutral on small and marginal fields, but also a poor source of revenue. CT generates the least controversy, insofar as it is a simple tax applying to all industries (with the exception of the ring fence pertaining to petroleum exploration and extraction activities).

This thesis concludes that the existing regime can be improved by the abolition of all upstream taxes, combined with an increase in the CT rate. Notwithstanding, the current regime is well attuned to the economic realities of a mature petroleum province. Although it is less risk sharing than the pre-1993 package, particularly as a result of the abolition of PRT reliefs, improving Government partnership with industry can compensate for this. In this regard the stability of the regime is considered equally important to maintaining investors' confidence.

Chapter 5 demonstrates the significant complexity of the UK fiscal regime as reflected in the derivation of the tax model and particularly with regard to PRT and its various reliefs. It is important to stress that the level and combination of taxes vary significantly with the date on which a particular field received development consent.

Chapter 6 finds that the most severe fiscal package in terms of government take on field profitability is the combination of Royalty, PRT and CT. This is the only scenario that rendered several fields unprofitable. The application of PRT alongside CT and ST, but without the oil allowance, generates a similar though less severe reduction in profitability particularly as regards the smaller fields. The highest profitability is generated under the application of CT at 30 per cent. In the scenarios where PRT applies, the major source of government take is from the larger fields. The lowest take resulted from the application of CT only. The oil allowance is found to be the most important relief for smaller fields, protecting some of them from the payment of the tax, while each of the three PRT reliefs are of equal importance for larger fields. Furthermore, for fields in a PRT paying position, the reliefs are also important in that they delay payment of the tax.

Regarding the evaluation techniques applied, it is noted that DCF and MAP produce different project NPV results, which is particularly significant in the case of larger, long life projects. This is principally due to the DCF method's use of a constant discount rate, which tends to undervalue long life projects. Whereas in the case of MAP, given the use of an oil price forecast based upon the Mean Reversion Model, the risk discount rate tends to decline over time.

MAP can provide a more appropriate evaluation than its DCF counterpart because it discounts revenues and costs using rates which reflect the risks inherent in each of these components. Further, the use of this technique can more readily exploit a sophisticated dynamic model of oil prices as compared with the more static DCF technique.

Chapter 7 demonstrates that the upstream petroleum industry has both the opportunity and the requirement to utilise managerial flexibility particularly in the case of long life projects. It is shown that the existence of flexibility can add significant value to projects, which might otherwise be under-valued, and, as a consequence, result in a miss-allocation of resources. Critics insist that DCF analysis does not account for the existence of flexibility in investment decisions because of the static nature of "the now or never" decision process, hence the need to use a technique that takes into account flexibility, namely the Real Options Theory.

Tax has two opposite effects on project evaluation. On the one hand, taxes reduce the value of expected cash flows, thereby increasing the possibility of delayed investment. On the other hand tax allowances have the opposite effect. As a result, the higher (lower) these deductions, the lower (higher) the option premium and the less (more) noticeable are the effects of taxation on investment timing. The thesis finds that tax instruments, like Royalty, with limited expenditure reliefs, can encourage investment delay leading to deferral and/or loss in fiscal revenues. This is unlikely to be desirable in a mature province such as the UKCS where there is a need to sustain development and future production while maintaining the interest of oil companies in a high cost province. Consequently, it can be concluded that if the Government had maintained the 1975 fiscal structure, many fields would have not been developed. For less profitable fields, the DCF valuation technique can contradict the findings using ROT. While DCF provides a positive NPV and hence encourages development, ROT provides a negative NPV encouraging investors to wait for more appropriate conditions before development takes place. For marginal fields, DCF provides a negative NPV, which in turn may lead to a decision to abandon the project for good, while ROT recommends waiting.

Chapter 8 demonstrates that, in terms of oil field profitability, the current UKCS fiscal regime is the most attractive compared with the five other countries selected. This is also the case when compared with UK petroleum fiscal regimes applying since 1975. More generally, except for the pre-1983 regime, the various fiscal levels in the UK are found to be more attractive than those applied in the other countries, due mainly to the generous reliefs applying to UKCS activity. In order of ranking the UKCS was followed by Australia and China, while in Norway the fiscal take is very close to that of countries operating under Contractual regimes. Hence, the thesis finds that it is possible to arrive at a similar tax take irrespective of the type of agreement.

Among the contractual regimes, China offers the most lenient terms due to the progressive nature of both its Sliding-Scale Royalty and the negotiable profit split. Of the six countries compared Indonesia and Iraq are found to be the toughest regimes, representing the highest fiscal take and on a corresponding basis the lowest profitability.

In terms of Government revenue, the UK current petroleum regime generates the lowest take compared to the other previous regimes. Nevertheless, given the maturity of the province, such a low take can be necessary to sustain oil production and maintain the international competitiveness from an investor standpoint. Also, as analysis in previous chapters has demonstrated, the regime has suffered from several limitations, not captured directly in the quantitative analysis. These relate mainly to the instability of the regime arising principally from frequent amendments, many of which appear to be less than essential.

Chapter 8 further demonstrates that each system has its own advantages and disadvantages, resulting from the need to balance the competing objectives of Government and the oil companies. Each regime is applied under specific circumstances and there is no one ideal fiscal regime suitable for all petroleum projects in all countries. Due to the significant differences in geological prospect and economic environment between various countries, a fiscal package that is appropriate for one country may prove to be inappropriate for another.

The overriding objectives of this thesis are to evaluate the various fiscal packages that applied to the UKCS since 1975, and to identify a fiscal regime that is acceptable to Government and oil industry alike. The main conclusion of this thesis is that, although the UK fiscal regime was unstable, complicated, and non-neutral particularly when formally legislated in 1975, it is now simple and relatively neutral by international standards. Maintaining the 1975/pre-1983 structure would have resulted in many fields abandoned or undeveloped. Maintaining the post-1983/pre-1993 structure would have resulted in low fiscal revenues generated, in addition to the high administrative costs and wasteful investment in Exploration. Imposing 40 per cent Income Tax is currently acceptable to the Government and most favourable to oil companies, especially in the light of the current mature state of the UK oil province.

Another important conclusion is that it is difficult to formulate one ideal regime that suits various provinces with different geology and cost structures. It is important to tailor the fiscal terms in such a way as to be attractive for both for large as well as small discoveries while safeguarding the economic long-term interests of the oil companies.

9.3. RECOMMENDATIONS

Limiting the evaluation of a fiscal regime to the level of tax rates can be very restrictive.

A high level of Government take is not recommended in cases of high-risk exploration, high-cost development, or for those provinces with modest petroleum potential, as is the case in the UK North Sea. The ideal regime would improve the profitability of marginal fields in order to persuade oil companies to develop these discoveries.

This thesis argues that profit related taxes are superior to revenue or production based ones. However, in the case of the larger more profitable discoveries, an accurate evaluation of the field's profitability is recommended, so that government's targets the resource rent rather than the quasi rent. Otherwise activity is likely to be discouraged.

If future changes to the UK regime are to be introduced the Government would on balance appear to favor the use of fiscal reliefs as a means of encouraging the development of the remaining high-cost fields. As Condray (2002) argues, maximizing the economic recovery of reserves in the North Sea is surely in everyone's interest - the companies, the nation, employment, for export of know how and enhancing security of supply. Nevertheless, such changes, if introduced, should be undertaken in consultation with the industry and not in an *ad hoc* manner, otherwise they will adversely affect the stability of the regime as well as investor confidence.

As for the evaluation techniques, MAP is still in its infancy and both MAP and ROT require detailed knowledge of advanced financial and statistical theories.

In contrast DCF is relatively simple, easy to understand and has been applied over a long period of time. Due to the complexity of the petroleum industry with its high risk operating environment, the use of simple but accurate techniques is imperative. Whilst MAP and ROT are more evolved than DCF it is unlikely that they will replace traditional DCF methods in the short term especially when, as Chapter 4 demonstrated, such techniques are unfamiliar to 99 per cent of the respondents. Consequently, this thesis recommends that these new techniques can be used as a complement to rather than an alternative for existing DCF techniques.

9.4. FURTHER RESEARCH

A number of theoretical implications follow from this research, suggesting a number of areas that merit further research.

One key area that merits further research is to extend the fiscal analysis to include full cycle exploration economics rather than only the appraisal and development phases, which because of data limitations, formed the basis of the analytical work contained in this thesis. This would have the benefit of introducing the concept of exploration risk, which is a fundamental investment driver in the upstream petroleum sector.

A basis premise of the analysis contained in this thesis is the assumption of one company operating one field. Further research could be undertaken by relaxing this assumption and considering a company with a portfolio of fields.

As such the effect of the various tax instruments on oil company profitability could be examined in a more dynamic manner. Furthermore, a more precise evaluation of PRT cross-fields allowances could be captured as well as the tax shelter impacts on a company's CT liabilities following from sequential field development.

Further research should also be undertaken as regards evaluation techniques, particularly MAP and ROT. Complementary to this research further work is required to produce more sophisticated oil price models such as mean reversion with jumps, as developed by Dias (2001). Also, ROT could usefully be expanded to include other phases of the project life cycle such as the Exploration and Abandonment phases.

Another possible expansion to this research could be in the area of international comparison taking into consideration a greater number of countries, particularly those considering reform or designing a new petroleum fiscal regime. Other work related to this thesis would be to take into account the macroeconomic effects of particular fiscal packages in various countries.

REFERENCES

Aaron H. & M. Boskin (1980) "The Economics of Taxation", Studies of Government Finance, The Brookings Institution, Washington DC.

Altay A. (2000) "The Theory of Optimal Taxation and New Approaches: A Survey", Dokuz Eylül Üniversitesi http://www.sbe.deu.edu.tr/SBEWEB/dergi/dergi05/altay.htm (last visited: 12/02)

Alexander's Gas & Oil Connections (1998) "Shell Expro Warns UK Government on Tax Issue", vol. 3, (June 15).

Ambler S. (1999) "Les Modeles a Agent Representatif et la Politique de Taxation Optimale", CREFE- Universite de Quebec a Montreal.

Amimer D. (2001) "Economic Evaluation and Optimisation of Assets in Petroleum Industry", Unpublished Thesis, University of Dundee.

Amundsen E., C. Andersen & J.G. Sannarnes (1993) "Rent Taxes on Hydropower Generation", The Energy Journal, vol.13, pp.97-116.

Andersen S. (1993) "The Struggle Over North Sea Oil and Gas: Government Strategies in Denmark, Britain and Norway", Oxford University Press, USA.

Andrews-Speed P. (1998) "Fiscal Systems for Mining- The Case of Brazil", Journal of Mineral Policy, Business and Environment, vol. 13, pp. 13-21.

Arthur Andersen (2000) "Guide to Upstream Oil and Gas Taxation in the UK", Tax Services.

Atkinson A. & J. Stiglitz (1980) "Lectures in Public Economics", McGraw-Hill Book Company UK Ltd.

Auerbach A. (1985) "The Theory of Excess Burden and Optimal Taxation", in "Handbook of Public Economics", vol.1 (edited by A. Auberbach & M. Feldstein) p.61-127, Elsevier Science Publishers.

Baker M., S. Mayfield & J. Parsons (1998) "Alternative Models of Uncertain Commodity Prices for Use with Modern Asset Pricing Methods", The Energy Journal, vol. 19, pp. 115-148.

Banfi S, M. Filippini & A. Mueller (2003) "Rent of Hydropower Generation in Switzerland in a Liberalised Market", Centre for Energy Policy and Economics (CEPE), Federal Institute of Technology, Zurich.

Bank of England (2002) "Interest and Exchange Rate Data" http://www.bankofengland.co.uk (Oct. 02)

Barrows G. (2000) "World Petroleum Arrangements", The Barrows Company Inc.

Beckman J. (1998) "Industry Confounded by UK Tax Hiatus", Offshore Journal, Offshore Europe Section, May.

Bhattacharyya S. (1998) "Energy Taxation and Environmental Externalities: a Critical Analysis", The Journal of Energy and Development, vol.22, pp.199-220.

Bierman H. & S. Smidt (1984) "The Capital Budgeting Decision", Mcmillan Publishing Company, Seventh Edition.

Bijur P. (1991) "Comment: Here's how to Assure Adequate Investment Levels in North Sea", Oil & Gas Journal, vol.89, issue 29, July 22.

Bittker B. (1980) "Equity, Efficiency, and Income Tax Theory: Do Misallocations Drive out Inequities?" Yale University Law School.

Bjerkedal N. (2000) "The Report from the Norwegian Tax Expert Commission", The 11th International Petroleum Tax Conference, Odlo, Norway, November 9-10.

Black F. & M. Scholes (1973) "The Pricing of Options and Corporate Liabilities", Journal of Political Economy, vol.81, pp.637-659.

Bland D. (1988) "UK Oil Taxation", Arthur Young, 2nd edition.

Blinn et al (1986) "International Petroleum Exploration & Exploitation Agreements-Legal, Economic and Policy Aspects", Barrows Company Inc.

Bond S. & M. Devereux (1995) "On the Design of a Neutral Business Tax under Uncertainty", Journal of Public Economics, vol. 58, pp. 57-71.

Bond S., M. Devereux & M. Sunders (1987) "North Sea Taxation for the 1990's", The Institute for Fiscal Studies.

Bodie Z. & R. Merton (2000) "Finance", Prentice Hall, Inc.

Boskin M. & M. Robinson (1985) "Energy Taxes and Optimal Tax Theory", The Energy Journal, vol. 6, Special Tax Issue, pp.1-15.

Bradley P. (1998) "On the Use of Modern Asset Pricing for Comparing Alternative Royalty Systems for Petroleum Development Projects", The Energy Journal, vol. 19, pp. 47-81.

Brealey R. & S. Myers (1991) "Principles of Corporate Finance", Fourth Edition, McGraw-Hill, NY.

Brennan M. & E. Schwartz (1985) "A New Approach to Evaluating Natural Resource Investments", Midland Journal of Applied Corporate Finance, vol.3, pp.37-47.

Brennan M. & E. Schwartz (1985) "Evaluating Natural Resource Investments", Journal of Business, vol. 58, pp.135-157.

Brown E. (1948) "Business Income Taxation and Investment Incentives", In "Employment and Public Policy, Essays in Honour of A.H. Hansen, New York, as referred to in Watkins (2001).

Burns J, I. Lewis & G. Sick (1992) "Valuing Petroleum Investments Using Discrete Option Pricing Theory", Society of Petroleum Engineers, Paper 24475.

Cappuccio N. & M. Morettor (2001) "Comments on the Investment-Uncertainty Relationship in a Real Option Model", University Di Padova, Department of Economics, Italy.

Coelen N. (2002) "Black-Scholes Option Pricing Model", Paper Posted at Trinity Education Webpage, http://www.trinity.edu/departments/mathematics/studpapers/s11pdf (12/2003)

Committee on Energy Taxation (1980) "Energy Taxation: an Analysis of Selected Taxes", National Academy of Science, Washington DC.

Condray A. (2002) "North Sea Investment & Strategy- a Global Context", Speech Presented at the "Future for Investment in the North Sea Conference", London, May.

Copeland T. & V. Antikarov (2001) "Real Options- A Practitioner's Guide", Texere LLC Publishing, pp.372.

Copeland T. & P. Keenan (1998) "How Much is Flexibility Worth?" The McKinsey Quarterly, vol2, pp.38-49.

Cox J., S. Ross & M. Rubenstein (1979) "Option Pricing: A Simplified Approach", Journal of Financial Economics, vol.7, pp.229-263.

Creedy J. (1999) "Tax Models and Their Uses", The University of Melbourne.

Crowson P. (2004) "Astride Mining: Issues & Policies for the Minerals Industry", Mining Journal Books Ltd.

Crum Fry R. (1985) "Capital Tax Distortions in the Petroleum Industry", The Energy Journal, vol.6, Special Tax Issue, pp.155-169.

Dasgputa P. & G Heal (1979) "Economic Theory and Exhaustible Resources", Cambridge University Press, Oxford.

Dasgputa P. & J. Stiglitz (1971) "Differential Taxation, Public Production and Economic Efficiency", Review of Economic Studies, vol.38, pp.151-174.

Davis G. (1998) "Estimating Volatility and Dividend Yield when Valuing Real Options to Invest or Abandon", Quarterly Review of Economics and Finance, vol. 38, Special Issue, pp. 715-754.

Deacon R. (1992) "Taxation, Depletion and Welfare: A Simulation Study of the U.S. Petroleum Resource", Journal of Environmental Economics and Management, vol.24, pp.159-187.

Deloitte & Touche (2003) "Perspectives on UK Oil & Gas Taxation", Deloitte & Touche LLP.

Dentskevich P. (1991) "The Applications of Option Valuation Techniques to the Valuation of Physical Investment Opportunities", PhD Thesis, Imperial College of Science Technology & Medicine, Management School.

Department of Trade & Industry (2003) "Oil & Gas Directorate" http://ww.og.dti.gov.uk/upstream/taxation/index.htm (Dec. 2003)

Department of Trade & Industry (2002) "Abolition of North Sea Royalty-Consultation on Appropriate Timing", DTI, http://www.og.dti.gov.uk/consultations/roycon.pdf (11/2002)

Department of Trade & Industry (2001) "Industry Activity Survey, 2001", Notes kindly provided by Mr. Earp, DTI.

Department of Trade and Industry -DTI (2000) "Development of the Oil and Gas Resources of the UK- Brown Book", http://www.dbd-data.co.uk/bbonline/index.htm (Feb. 2001)

Devereux M., Griffith R. & A. Klemm (2004) "Why Has the UK Corporation Tax Raised so Much Revenue?" The Institute For Fiscal Studies IFS Working Papers.

Devereux M & C. Morris (1983) "North Sea Oil Tax Revenue: a Disaggregated Model", The Institute For Fiscal Studies IFS, Working Paper no. 40.

Diamond P. & J. Mirrlees (1971a) "Optimal Taxation and Public Production I: Production efficiency", American Economic Review, vol.61, pp.8-27.

Diamond P. & J. Mirrlees (1971b) "Optimal Taxation and Public Production II: Tax Rules", American Economic Review, vol. 41, pp.277-296.

Dias M. (2001) "Real Options in Upstream Petroleum: Overview of Models and Applications", http://www.puc-rio.br/marco.ind/overview.html (Dec. 2003)

Dias M. (1999) "A Note on Bibliographical Evolution of Real Options", in Lenos Trigeorgis, Edition, Real Options and Business Strategy- Applications to Decision Making, pp.357-362.

Dias M. (1997) "The Timing of Investment in E&P: Uncertainty, Irreversibility, Learning and Strategic Consideration", Paper presented at 1997 SPE Hydrocarbon Economics and Evaluation Symposium, Dallas, Proceedings pp.135-148.

Dias M. & K. Rocha (1998) "Petroleum Concessions with Extendible Options Using Mean Reversion with Jumps to Model Oil Prices", Paper presented at the 3rd Annual International Conference on Real Options, June, Netherlands.

Dickson T. (1999) "Taxing Our Resources for the Future", Paper Posted at Economic Research and Analysis (ERA), http://www.eraweb.net (Mar. 2000)

Dixit A. & R. Pindyck (1995) "The Options Approach to Capital Investment", Harvard Business Review, May-June, pp. 105-115.

Dixit A. & R. Pindyck (1994) "Investment Under Uncertainty", Library of Congress Cataloguing in Publication Data.

Eckbo P. L. (1987) "Worldwide Petroleum Taxation: the Pressure for Revision", MA Massachusetts Institute of Technology press.

Ekern S. (1988) "An Option Pricing Approach to Evaluating Petroleum Projects", Energy Economics, vol.10, pp.91-99.

Emhjellen M. (1999) "Valuation of Oil Projects Using the Discounted Cashflow Method", Unpublished PhD Thesis, School of Economics, The University of New South Wales, April.

Emhjellen M. & C. Alaouze (2001) "The Discounted Net Cashflow Method and a Modern Asset Pricing Method- Implications for Project Selection and Government Policy", The University of New South Wales.

Emhjellen M. & C. Alaouze (1999) "A Comparison of Oil Project NPV's in the North Sea Obtained using the Weighted Average Cost of Capital Discounting Method and a Modern Asset Pricing Method", The University of New South Wales.

Energy Committee (1987) "The Effect of Oil and Gas Prices on Activity in the North Sea", House of Commons, Third report from the Energy Committee.

Fane G. (1987) "Neutral Taxation Under Uncertainty", Journal of Public Economics, vol.33, pp.95-105.

Favero C. (1992) "Taxation and the Optimisation of Oil Exploration and Production: the UK Continental Shelf", Oxford Economic Papers, vol.44, pp. 187-208.

Financial Secretary (1994) "Speech to Petroleum Economist Conference".

Fink A. & J. Kosecoff (1985) "How to Conduct Survey- A Step by Step Guide", SAGE Publication, Inc.

Fowler F. (1995) "Improving Survey Questions- Design and Evaluation", SAGE Publications, Inc.

Fraser R. & R. Kingwell (1997) "Can Expected Tax Revenue be Increased by an Investment Preserving Switch from Ad Valorem Royalties to a Resource Rent Tax?" Resource Policy, vol.23, pp.103-108.

Fullerton D. & V. Henderson (1983) "Differential taxation, Public Production and Economic Efficiency", Urban Institute, Washington DC.

Garnaut R. & A. Clunies Ross (1979) "The Neutrality of the Resource Rent Tax", The Economic Record, vol.55, pp.193-201.

Garnaut R. & A. Clunies Ross (1975) "Uncertainty, Risk Aversion and the Taxing of Natural Resource Projects", Economic Journal, vol.85, pp.272-287.

Garnaut R. & A. Clunies Ross (1983) "Taxation of Mineral Rents", Oxford University Press, NY.

Ghouri S. (1996) "Pakistan's New Petroleum Policy", Energy Policy, vol.24, pp. 477-488.

Gibson R. (2003) "Real Options Theory as an Investment Decision-Making Tool", Zurich University, Switzerland.

Gilbert R. (1976) "Optimal Depletion of an Uncertain Stock", Technical Report no. 207, Stanford University, May.

Gray L.C. (1914) "Rent Under the Assumption of Exhaustibility", Quarterly Journal of Economics, 28.

Hawdon D. (1991) "Future Oil and Coal Prices: a Survey Approach" in Pearson, PJG Edition, Prospects for British Coal, Macmillan, pp.171-189.

Hawdon D. (1984) "Survey of Oil Price Expectations", in Hawdon D. Edition, The Changing Structure of the World Oil, Croom Helm, pp.107-111.

Harberger A. (1961) "The Tax Treatment of Oil Exploration", The Proceedings of the Second Energy Institute, Washington DC, The American University, pp.259-269.

Harberger A. (1980) "Tax Neutrality in Investment Incentives", University of Chicago.

HarrisonLovegrove Co. (2003) "The UK Continental Shelf-Still an Attractive Place", http://www.hargrove.co.uk (July 2003)

Harvie C. (1994) "Fool's Gold: The Story of North Sea Oil", London: Hamish Hamilton.

Hayllar R. & R. Pleasance (1977) "UK Taxation of Offshore Oil and Gas", Butterworth & Co. Ltd.

Heady C. (1993) "Optimal Taxation as a Guide to Tax Policy: A Survey", Fiscal Studies, vol.14, pp.15-41.

Heaps T. & J. Helliwell (1985) "The Taxation of Natural Resources" Handbook of Public Economics, vol. 1, Elsevier Science Publishers

Helliwell J. (1982) "Taxation of Oil and Gas Revenues of Four Countries: Canada", The Energy Journal, vol. 3, pp.20-30.

Henderson D. (2004) "North Sea Industry Experiences Renewed Interest", Alexander's Gas & Oil Connections, vol. 9, April 7.

Hotelling H. (1931) "The Economics of Exhaustible Resources", Journal of Political Economy, vol.39, pp.111-119.

Horngren C, G. Sundem & J. Elliott (1993) "Introduction to Financial Accounting", Third Edition, Prentice Hall.

Ilersic A. et al (1969) "Taxation Economics" Macmillan and Co. Ltd.

Inland Revenue (2003a) "International- The North Sea Fiscal Regime a Guide to UK and UK Continental Shelf", http://www.inlandrevenue.gov.uk/international/ns-fiscal3.htm#b (Nov. 2003)

Inland Revenue (2003b) "Oil Taxation Manual" http://www.inlandrevenue.gov.uk/manuals/otmanual/contents.htm (Nov. 2003)

Inland Revenue (2003c) "Petroleum Revenue Tax: Exemption for New Tariffing Business", Budget 2003, 9 April.

Inland Revenue (2000) "PRT: Misuse of Safeguard Relief", Inland Revenue Press, 21 March 2000.

Institute of Fiscal Studies Committee (1981) "The Taxation of North Sea Oil", The Institute For Fiscal Studies IFS.

The Institute of Petroleum (2001) "Industry Information: Leading Oil Companies in the UK", London.

International Petroleum Enterprises (2001) "Reopening of Upstream Oil & Natural Gas to Foreign Interests: Views and Actions of Iran, Iraq, Kuwait & Saudi Arabia", Report Published by IPE.

Jacoby H. & D. Laughton (1992) "Project Evaluation: A Practical Asset Pricing Model", Energy Journal, vol.13, pp.19-47.

Jacoby H. & D. Laughton (1991) "Project Evaluation: A Practical Asset Pricing Approach", Institute for Financial Research, University of Alberta, Working Paper no. 1-91.

Jankowski E. (2000) "Nature of the Iranian BuyBack Contracts", Paper Presented at the IBC's Production Sharing Agreements/Host Government Contracts Conference- 11th April, London.

Johnson C. (1979) "The Improvement of the North Sea", Journal of Institute of Fiscal Studies, vol.1, pp.39-51.

Johnston D. (2003) "Petroleum Contract Analysis and Design. State-of-the-Art-State-of-the-Industry", Daniel Johnston & Co., Inc.

Johnston D. (2002) "International Petroleum Fiscal System Analysis", Daniel Johnston & Co., Inc.

Johnston D. (2001) "International Production Sharing Contract Cash Flow Model", Daniel Johnston & Co., Inc.

Johnston D. (1998) "International Petroleum Fiscal Systems and Production Sharing Contracts", PennWell Books.

Johnston J. & A. Reynolds (1985) "A Natural Resource Theory of Unitary Taxation", The Energy Journal, vol.6, Special Tax Issue, pp.309-323.

Jorgenson D. & D. Slesnick (1985) "Efficiency versus Equity in Petroleum Taxation", The Energy Journal, vol.6, Special Tax Issue, pp.171-187.

Kellas G. (1993) "Tax Reforms Raise Questions for Oil Industry in the UK", Oil&Gas Journal, vol. 91, Issue 35.

Kemp A. (1990) "An Assessment of UK North Sea Oil and Gas Policies", Energy Policy, (September), pp.599-623.

Kemp A. & Stephens L. (1997) "The UK Petroleum Fiscal System in Retrospect", University of Aberdeen.

Kemp A., L. Stephens L. & K. Masson (1997) "A Reassessment of Petroleum Taxation in the UKCS", University of Aberdeen.

Kemp A. & et al. (1993) "The impact of the UK 1993 budget proposals on oil and gas in the UKCS", University of Aberdeen-North Sea Study Occasional Paper, no. 41.

Kemp A., D. Rose & R. Dandie (1992) "Development and Production Prospects for UK Oil and Gas Post-Gulf Crisis- A financial Simulation", Energy Policy, vol.20, pp. 20-29.

Kemp A. & D. Rose (1982) "The Effects of Taxation on Petroleum Exploitation: a Comparative Study", University of Aberdeen.

Kemp A. & D. Crichton (1979) "Effects of Changes in UK North Sea Oil Taxation", Energy Economics, October 79, pp.224-240.

Kemp A. & D. Crichton (1978) "A Review of the Proposed Changes in North Sea Oil Taxation", North Sea study occasional papers- University of Aberdeen.

Kooten C. & E. Bulte (2001) "The Economics of Nature- Managing Biological Assets", Blackwell Publishers.

Laine J. (1993) "Option Valuation of Field Development Projects", Society of Petroleum Engineers, Paper 37965.

Laughton D. (2002) "A Brief Primer on the Use of Modern Asset Pricing for Project Evaluation in the Upstream Petroleum Industry", Notes provided by Laughton to the author.

Laughton D. (1998a) "The Potential for Use of Modern Asset Pricing Methods for Upstream Petroleum Project Evaluation: Introductory Remarks", The Energy Journal, vol.19, pp. 1-11.

Laughton D. (1998b) "The Management of Flexibility in the Upstream Petroleum Industry", The Energy Journal, vol.19, pp. 83-114.

Laughton D. (1998c) "The Potential for Use of Modern Asset Pricing Methods for Upstream Petroleum Project Evaluation: Concluding Remarks", The Energy Journal, vol.19, pp.149-153.

Laughton D. (1997) Spreadsheet presented at the Norwegian Petroleum Directorate Workshop on Modern Asset Pricing and Project Evaluation, Stavanger, Norway, May.

Laughton D., J. Sagi & M. Samis (2000) "Modern Asset Pricing and Project Evaluation in the Energy Industry" Western Centre for Economic Research, University of Alberta, Bulletin 56, September.

Leith D. (2002) "Death and Taxes not Necessarily", Ernst & Young LLP, Aberdeen, Scotland.

Loury G. (1976) "The Optimum Exploitation of an Unknown Reserve", Unpublished paper, University of California, February.

Lund D. (2002) "Petroleum Tax Reform Proposals in Norway and Denmark", Energy Journal, vol.23, pp. 37-56.

Lund D. (2001) "Rent Taxation when Cost Monitoring is Imperfect", Resource and Energy Economics, vol.24, pp.211-228.

Lund D. (1992) "Petroleum Taxation Under Uncertainty: Contingent Claims Analysis with an Application to Norway", Energy Economics, vol.14, pp.23-31.

Lund D. (1987) "Investment, Taxes and Uncertainty with Applications to the Norwegian Petroleum Sector", PhD Dissertation, Massachusetts Institute of Technology.

Lund M. (2001) "Real Options in Offshore Oil Field Development Projects", Paper Given at the 3rd Annual International Conference on Real Options, 6-8 June, Netherlands.

Lund M. (2000) "Valuing Flexibility in Offshore Petroleum Projects", Annals of Operation Research, p.325-350.

Macalister T. (2002) "Oil Tax Threat to 50,000 jobs", The Guardian (May 24).

Martin S. (1997) "Tax or Technology? The Revival of UK North Sea Production", Oxford Institute for Energy Studies.

McDonald R. & D. Siegel (1986) "The Value of Waiting to Invest", Quarterly Journal of Economics, November 1986, pp.707-727

Mercier D. (1999) "Royalty that Slides with Oil Prices Can Add Value to Producing Fields", Oil & Gas Journal, vol.97, pp. 92-95.

Merton R. (1973) "The Theory of Rational Option Pricing", Bell Journal of Economic Management Science, vol.4, pp.141-183.

Miller M. (2000) "Why We Must Make More of Black Gold", The Observer-Business section, October 8.

Miller M. et al (1999) "Collecting Economic Rents on North Sea Oil and Gas: A Proposal", Research Report Submitted to ESCR, University of Warwick.

Mirrlees J. (1976) "Optimal Tax Theory: a Synthesis", Journal of Public Economics, vol. 6, pp.327-358.

Mitchell (1982) "Taxation of Oil and Gas Revenues of Four Countries: The United Kingdom", The Energy Journal, vol.3, pp.39-50.

Mohiuddin A. & S. Ash-Kuri (1998) "Measures to Promote Exploration and Production Investment in Pakistan", Oil and Gas Law and Taxation Review, no. 7, p. 263-269.

Mommer B. (2001) "Fiscal Regimes and Oil Revenues in the UK, Alaska and Venezuela", Oxford Institute for Energy Studies.

Mommer B. (1999) "Oil Prices and Fiscal Regimes", Oxford Institute for Energy Studies.

Mommer B. (1996) "Bernard Mommer Defends Petroleum Royalty as an Efficient Rent-Collecting Device", Oxford Energy Forum, May.

Moose J. (1982) "British and American Tax Treatment of UK North Sea Oil Fields", Energy Journal, vol.3, Special Issue, pp.55-63.

Morgan O. (2000) "Can Gordon Soak the Oil Man?" The Observer- Business section, October 8.

Muttitt G. & J. Marriott (2000) "Pump and Circumstances", The Guardian, October4

Musgrave R. (1982) "A Brief History of Fiscal Doctrine", in "Handbook of Public Economics", vol.1 (edited by Auberbach A. & M. Feldstein), Elsevier Science Publishers, pp.1-59.

Myers S. (1977) "Determinants of Capital Borrowing", Journal of Financial Economics, vol.5, pp.147-175.

Nakhle C. & D. Hawdon (2003) "The Impact of Oil Taxation on Fields' Profitability in the UK North Sea- A Comparison with Five International Representative Regimes", Paper Presented at the 26th Annual IAEE Conference, June, Prague.

Nakhle C. & D. Hawdon (2002) "The Impact of Oil Taxation on Field's Development in the UK North Sea", Paper Presented at the 25th Annual IAEE Conference, Aberdeen.

National Audit Office (2000) "Petroleum Revenue Tax", Report by the Comptroller and Auditor General HC 5, Session 2000-2001 (December, 14)

Nelsen B. (1991) "The State Offshore: Petroleum, Politics, and State Intervention on the British and Norwegian Continental Shelves", Praeger Publishers, NY.

Nelson Y. & D. Nix (1997) "Results of the Delphi IX Survey of Oil Price Forecasts", California Energy Commission.

Newbery D. & N. Stern (1987) "The Theory of Taxation for Developing Countries" A World Bank Research Publication, Oxford University Press.

Noreng O. (1980) "The Oil Industry and Government Strategy in the North Sea", British Library Cataloguing in Publication data.

OGJ (1993a) "UK Job Loss Seen in PRT Changes", Oil & Gas Journal, vol. 91, (April 19).

OGJ (1993b) "UK Operators React to PRT Changes", Oil & Gas Journal, vol. 91, (March 29).

OGJ (1993c) "UK Plans Big Changes in Taxes on Oil and Gas", Oil & Gas Journal, vol. 91, (March 22)

Oswald A. (2000) "Oil and the Real Economy: an Interview with Andrew Oswald", (March, 17), University of Warwick.

Paddock J., D. Siegel & J. Smith (1988) "Option Valuation of Claims on Real Assets: the Case of Offshore Petroleum Leases", Quarterly Journal of Economics, vol. 103, pp.479-508.

Palmer K. (1980) "Mineral Taxation Policies in Developing Countries: An Application of Resource Rent Tax", International Monetary Fund: Staff Papers, vol.61, pp.65-73.

Pechman J. (1980) "What Should be Taxed: Income or Expenditure?" Studies of Government Finance, The Brookings Institute, Washington DC.

Petroleum Review (2004) "Enhanced UK Tax Relief for New North Sea Entrants", February Issue, vol. 58, pp.3.

Perman R., J. Ma & J. McGilvray (1998) "Natural Resources and Environmental Economics", Longman Singapore Publishers Ltd.

Pickles E & J. Smith (1993) "Petroleum Property Evaluation: A Binomial Lattice Implementation of Option Pricing Theory", Energy Journal, vol.14, pp.1-26.

Pike R. & B. Neale (1996) "Corporate Finance & Investment- Decisions & Strategies", Second Edition, Prentice Hall Europe.

Pindyck R. (2002) "Lectures on Real Options", Sloan School of Management, Massachusetts Institute of Technology.

Pindyck R. (2001) "The Long-Run Evolution of Energy Prices", Energy Journal, vol.20, pp.1-27.

Pindyck R. (1993) "Investments of Uncertain Cost", Journal of Financial Economics, vol. 34, pp. 53-76.

Quinlan M. (1998) "North Sea Oil and Gas Province", Petroleum Economist, August 98, http://wuda.hypermart.net/characters/cjhuang.html (Feb. 2001)

Raja A. (1999) "Should Neutrality be the Major Objective in the Decision-Making Process of the Government and the Firm" www.dundee.ac.uk/cepmlp/main/html/car_article2.htm (Dec. 2000)

Ramsey F. (1927) "A Contribution to the Theory of Taxation", Economic Journal, vol.37, pp.47-61

Ray R. (1997) "Issues in the Design and Reform of Commodity Taxes: Analytical Results and Empirical Evidence" Journal of Economic Surveys, vol.11, No.4.

Reuters (2004) "Analysis- UK Faces Future without North Sea Oil", Reuters News Service (January 14).

Ricardo D. (1951) "The Principles of Economy & Taxation", vol.1 of "Works & Correspondence", Edited by Sraffa & Dobb, Cambridge University Press (as referred to by Watkins, 2001).

Ritchie D. (1992) "Mineral Sector Investment Criteria - An Industry Perspective", United Nations Seminar, December.

Robinson C. & C. Rowland (1978) "Marginal Effect of PRT Changes", Petroleum Economist, vol. 18, pp.501-503.

Robinson C. & J. Morgan (1978) "North Sea Oil in the Future", Macmillan Press Ltd.

Robinson C. & J. Morgan (1976) "World Oil Prices and the Profitability of North Sea Oil", Petroleum Review, April, pp.197-206

Robinson C. & Rowland (1976) "A Comparison of Tax Systems", Petroleum Economist, May, pp.170-171.

Rodriguez-Padilla (1991) "Fiscalite Petroliere et Risque", The Energy Journal, vol.13, pp.91-113.

Rowland C. (1983) "The Economics of North Sea Oil Taxation", University of Surrey, Unpublished PhD Thesis.

Rowland C. (1980) "Changing North Sea Profits Taxation and the Gains from Offshore Oil", Surrey Energy Economics, University of Surrey, Discussion Paper no.3.

Rowland C. & D. Hann (1987) "The Economics of North Sea Oil Taxation", Macmillan Press.

Rowland C. & D. Hann (1986) "UK Oil Taxation: Failings and Reform", Surrey Energy Economics Centre, University of Surrey, Discussion Paper no.32.

Ruairidh S. (2003) "The UK North Sea: 2003 a Year of Transition?" Simmons & Company International, Energy Industry Research, February 7.

Rutledge I. & Wright P. (2001) "Taxing Petroleum: Don't Forget about the Upstream", Financial Times Energy Economist (Energy Economist Briefing), (October), pp.2-12.

Rutledge I. & Wright P. (1998a) "Profitability and Taxation in the UKCS Oil and Gas Industry: Analysing the Distribution of Rewards Between Company and Country", Energy Policy, vol.26, pp.795-812.

Rutledge I. & Wright P. (1998b) "North Sea Oil Taxation: Principles, Methods and Evidence", Centre for Energy, Petroleum and Mineral Law and Policy, University of Dundee.

Rutledge I. & Wright P. (1997) "Profitability and Taxation in the North Sea Oil and Gas Industry", University of Sheffield, Energy Studies Paper.

Salahor G. (1998) "Implications of Output Price Risk and Operating Leverage for the Evaluation of Petroleum Development Projects", The Energy Journal, vol.19, pp.13-46.

Samuelsen J. (2002) "The Norwegian Petroleum Tax System", PriceWaterhouseCoopers.

Samuelson P. (1986) "Theory of Optimal Taxation", Journal of Public Economics, vol. 30, pp.137-143.

Sapsford R. (2001) "Survey Research", SAGE Publications Ltd.

Sarkis N. (2003) "Iran-South Pars Production above target Rate with Only 15 of the 20 Planned Drills", Arab Oil & Gas, vol. 32, pp. 5-14.

Sarma J. & G. Naresh (2001) "Mineral Taxation around the World: Trends an Issues", Asia-Pacific Tax Bulletin, pp.2-10.

Select Committee on Energy, Press Statement: North Sea oil depletion policy, HMSO, London, 18

Sem T. & D. Ellerman (1997) "North Sea Reserve Appreciation, Production and Depletion", Massachusetts Institute of Technology.

Siegel D., J. Smith & J. Paddock (1986) "Valuing Offshore Oil with Option Pricing Models", Midland Corporate Finance Journal, vol. 5, pp.22-30.

Smith J. & K. Mccadle (1999) "Options in the Real World: Lessons Learned in Evaluating Oil and Gas Investments", Operations Research, vol.47, pp.1-15.

Scottish Council for Development and Industry (2002) "The Implications of Recent Changes to the North Sea Fiscal Regime", Policy Paper.

Scully G. (1994) "Tax Rates, Tax Revenues and Economic Growth", National Centre for Policy Analysis.

Siew W. (2001) "Financial Evaluation Techniques Used to Evaluate Risk and Appraise Projects in the Oil Industry", Unpublished Thesis, University of Dundee.

Smith B. (1999) "The Impossibility of a Neutral Resource Rent Tax", Faculty of Economics and Commerce, Australian National University, Working Paper no.380.

Stauffer T. & Gault J. (1985) "Exploration Risks and Mineral Taxation: How Fiscal Regimes Affect Exploration Incentives", The Energy Journal, vol.6, Special Tax Issue, pp.125-135.

Stiegeler S. (1985) "Dictionary of Economics & Business", Gower Publishing Company Limited.

Stiglitz J. (1975) "The Efficiency of Market Prices in the Long Run Allocations in the Oil Industry", In Brannon (1975)

Stiglitz J. (1972) "Taxation, Risk Taking & the Allocation of Investment in a Competitive Economy", Studies in the Theory of Capital Markets, pp. 295-361.

Swan (1984) "Resource Rent Tax", Economic Papers, vol.3, pp.1-11.

Sunley E, T. Baunsgaard & D. Simard (2002) "Revenue from the Oil and Gas Sector: Issues and Country Experience", IMF Conference Proceedings on Fiscal Policy Formulation and Implementation in Oil Producing Countries, June 5-6, 2002.

Trigeorgis L. (1990) "A Real Options Application in Natural Resource Investments" Advances in Futures and Options Resources, vol.4, pp.153-164.

Trigeorgis L. (1996) "Real Options: Managerial Flexibility and Strategy in Resource Allocation", Massachusetts Institute of Technology Press, Cambridge, MA, pp.308.

UK Debt Management Office (2003) "Quarterly Review- January-March 2003" http://www.dmo.gov.uk (Nov. 2003)

UKOOA (2003) "Exploration on the West Coast of Britain- West Britain the Search for oil an explanation", http://www.ukooa.co.uk/issues/exploration/v001321.htm (Dec. 2003)

UKOOA (2002) "Survey Reveals Extent of Tax Hit on North Sea Exploration", http://www.ukooa.co.uk (Oct. 2002)

UKOOA (2001) "Harnessing Talent & Technology- Economic Report", UKOOA Publications.

UKOG (1984) "United Kingdom Oil and Gas Taxation and Accounting– Supplement 1", UK Oil & Gas.

Van Meurs P. (1997) "World Fiscal Systems for Oil", Van Meurs Associates, vol.2, pp.509.

Varzi M. (2002) "Mobilising Iran's Natural Gas Resources- The Role of Foreign Private Capital", Oil & Gas Research, Dresdner Kleinwort Benson- UK.

Verleger P. (1980) "An Assessment of the Effects of the Windfall Profits Tax on Crude Oil Supply", The Energy Journal, vol.1, pp.41-58.

Walker R. (1988) "Applied Qualitative Research", Gower Publishing Limited.

Watkins C. (2001) "Atlantic Petroleum Royalties: Fair Deal or Raw Deal", The AIMS Oil and Gas Papers, Atlantic Institute for Market Studies, Halifax, Nova Scotia.

Watkins T. (2002) "Real Options Theory", San Jose State University, Economics Department, http://www.sjsu.edu/faculty/watkins/realoptions.htm (10/02)

Wells P. (2002) "Buy-Back & Production Sharing Arrangements. What is the Difference?" Paper Presented at the IIES Conference 9-10th December- Tehran.

Wright P. (2003) "Liberalising Upstream Oil and Gas: The UK Experience and Its Implications", OPEC Bulletin, vol.34, pp.16-22.

WoodMackenzie (2000) "Global Economic Model- User Guide".

WoodMackenzie (2000) "UK Fields Onstream & Under Development".

WoodMackenzie (2000) "UK Upstream Service- Country Overview", WoodMackenzie, November.

Zettl M. (2002) "Valuing Exploration and Production Projects by Means of Option Pricing Theory", International Journal of Production Economics, vol. 78, pp.109-116.

Zhang L. (1997) "Neutrality and Efficiency of Petroleum Revenue Tax: A Theoretical Assessment", The Economic Journal, vol.107, pp.1106-1120.

Zhang L. (1995) "Taxing Economic Rents in Oil Production: Assessment of UK PRT", Department of Economics, University of Warwick.

Zittel W. (2001) "Analysis of the UK Oil Production", A Contribution to ASPO (Association for the Study of Peak Oil), http://www.energykrise.de (Mar. 2003)

GLOSSARY[118]

Abandon: To cease work on a well, which is non-productive. Also used in the context of field abandonment.

Abandonment Allowance: A 100 per cent allowance for expenditure incurred in respect of abandoning a field.

Appraisal Expenditure: Costs incurred in survey, exploitation and appraisal of licence areas not yet under development or in production.

Appraisal Well: A well drilled as part of an appraisal drilling programme which is carried out to determine the physical extent, reserves and likely production rate of a field.

Barrel: A unit of volume measurement used for petroleum and its products

7.5 barrels = 1 ton

Barrel of Oil Equivalent (boe): A term used to express the gas volume in terms of its energy equivalent in barrels of oil. 6 thousand cubic feet of gas equals 1 bbl of crude oil.

bbl: Abbreviation of one barrel of oil.

b/d: Abbreviation of Barrel per day

bn: Abbreviation of Billion.

bnbbl: Abbreviation of Billion of Barrels

bnbbloe: Abbreviation of Billion Barrels of oil equivalent.

bnt: Abbreviation of Billion Tonnes

[118] The definitions are taken from various sources, namely DTI (2003) and Johnston (1994).

BT: Abbreviation of Brown Tax.

CAPEX: Abbreviation of Capital Expenditure.

Commercial Discovery: The term applies to any discovery that would be economically feasible to develop under a given fiscal system. A field that satisfied these conditions would then be granted commercial status, and the contractor would then have the right to develop the field.

Commercial field: Field judged to be capable of producing sufficient net income to be worth developing.

Concession: An agreement between a Government and a company that grants the company the right to explore for, develop, produce, transport, and market hydrocarbons or minerals within a fixed area for a specific amount of time. The concession and production and sale of hydrocarbons from the concession is then subject to rentals, royalties, bonuses, and taxes. Under a concessionary agreement the company would hold title to the resources that are produced.

Contractor: An oil company operating in a country under a production sharing contract or a service contract on behalf of the host government for which it receives either a share of production or a fee.

Contractor take: The total contractor after-tax share of profits.

Cost of Capital: The minimum rate of return on capital required to compensate debt holders and equity investors for bearing risk. Cost of capital is computed by weighting the after-tax cost of debt and equity according to their relative proportions in the corporate capital structure.

Cost Oil: A term most commonly applied to production sharing contracts which refers to the oil (or revenues) used to reimburse the contractor for exploration costs, development capital costs, and operating costs.

Cross Field Allowance (CFA): An element (up to 10 per cent) of immediate relief qualifying field development costs where a participator on a new taxable development has, or expects to have, PRT profits in another taxable field.

CT: Abbreviation of Corporation Tax

DCF: Abbreviation of Discount Cash Flow Technique.

Decommissioning: Term used for the re-use, recycling and disposal of redundant oil and gas facilities.

Development expenditure: All costs including financing costs, E&A expenditures incurred in bringing a field to commercial production and is defined as tangible assets.

Development Phase: The phase in which a proven oil or gas field is brought into production by drilling production (development) wells.

Discovery: An Exploration well which has encountered hydrocarbons.

DTI: Abbreviation of Department of Trade & Industry

E&A: Abbreviation of Exploration and Appraisal.

E&P: Abbreviation of Exploration and Production.

Enhanced Oil Recovery: A process whereby oil is recovered other than by natural pressure in a reservoir.

Exploration drilling: Drilling carried out to determine whether hydrocarbons are present in a particular area or structure.

Entitlements: The shares of production to which the operating company and the government or government agencies are authorized to lift. Generally, legal entitlement equals Profit Oil plus Cost Oil in a PSC.

Exploration expenditure: All costs, including premium payments, associated with acquisition of new acreage, drilling of exploratory wells and other costs incurred in evaluating commercial viability of geological entities.

Exploration phase: The phase of operations which covers the search for oil or gas by carrying out detailed geological and geophysical surveys followed up where appropriate by exploratory drilling.

Exploration well: A well in an unproven area or prospect, may also be known as a "wildcat well".

Field: A geographical area under which an oil or gas reservoir lies.

Fiscal System: Technically, the legislated taxation structure for a country including royalty payments. The term includes all aspects of contractual and fiscal elements that make up a given government-foreign oil company relationship.

Gold Plating: When a company or contractor makes unreasonably large expenditures due to lack of cost-cutting incentives. This kind of behaviour could be encouraged where a contractor's compensation is based in part on the level of capital and operating expenditure.

Government Take: The total government share of profit oil or revenues not associated with cost recovery. Same as government after-tax equity split and government marginal take.

Incentives: Fiscal or contractual elements emplaced by host governments that make petroleum exploration or development more economically attractive. Includes such things as tax credits, lower Government take, uplift, and investment credit.

Investment Credit: A fiscal incentive where the government allows a company to recover an additional percentage of tangible capital expenditure.

M: Abbreviation of Million.

MAP: Abbreviation of Modem Asset Pricing Technique.

mmbbl: Abbreviation of Million Barrels

mmbbl/d: Abbreviation of Million Barrels per day

mmboe: Abbreviation of Million Barrels Oil Equivalent.

Mt: Abbreviation of Million Tonnes.

Marginal Field: A field that may not produce enough net income to make it worth developing at a given time; should technical or economic conditions change, such a field may become commercial.

Oil Allowance: A gross production relief that reduces effective PRT rate, but cannot be used to create a loss.

Oil Equivalent: Used when adding together volumes of oil, gas and NGL. It is defined as the energy obtained from burning the various types of petroleum. One tonne of oil equivalent = one tonne of oil = 100 cubic meters of natural gas.

Operator: The company that has legal authority to drill wells and undertake production of hydrocarbons are found.

Operating Profit (or Loss): The difference between business revenues and the associated costs and expenses exclusive of interest or other financing expenses, and extraordinary items, or ancillary activities. Synonymous with net operating profit (or loss), operating income (or loss), and net operating income (or loss).

OPEX: Abbreviation for Operating Expenditure.

Oil Taxation Act (OTA): Came into force in 1975, introducing PRT.

Petroleum: A generic name for hydrocarbons, including crude oil, natural gas liquids, natural gas and their products.

Petroleum Revenue Tax (PRT): Applies to UK oil production and associated profits of licensees. Applies only to fields which received consent before 18 March 1993.

Possible Reserves: Those reserves which at present cannot be regarded as 'probable' but are estimated to have a significant but less than 50 per cent chance of being technically and economically producible.

Probable Reserves: Those reserves which are not yet proven but which are estimated to have a better than 50 per cent chance of being technically and economically producible.

Production Sharing Agreement: This (PSA) is the same as a Production Sharing Contract (PSC). While at one time this term was quite common, it is used less frequently now, and the term *Production Sharing Contract* is becoming more common.

Production Sharing Contract: A contractual agreement between a contractor and a host government whereby the contractor bears all exploration costs and risks and development and production costs in return for a stipulated share of the production resulting from this effort.

Progressive Taxation: Where tax rates increase as the basis to which the tax increases. Or where tax rates decrease as the basis decreases. The opposite of regressive taxation.

Proven Field: An oil and/or gas field whose physical extent and estimated reserves have been determined.

Proven Reserves: Those reserves that on the available evidence are virtually certain to be technically and economically producible (i.e. having a better than 90 per cent chance of being produced).

Recoverable Reserves: That proportion of the oil and/gas in a reservoir that can be removed using currently available techniques.

Resource Rent Tax (RRT): Some economists refer to additional profits taxes as a resource rent tax. Normally the RRT is levied after the contractor or oil company has recouped all capital costs plus a specified return on capital that supposedly will yield a fair return on investment.

Ring-fencing: A cost centre based fiscal device that forces contractors or concessionaries to restrict all cost recovery and or deductions associated with a given license (or sometimes a given field) to that particular cost centre. The cost centres may be individual licenses or on a field-by-field basis. For example, exploration expenses in one non-producing block could not be deducted against income for tax calculations in another block. Under PSC, ring-fencing acts in the same way: cost incurred in one ring fenced block cannot be recovered from another block outside the ring fence.

Royalty payments: As part of some early UKCS licence round conditions there was an obligation to pay a royalty on "value of the petroleum" which is deductible in computing PRT and CT.

ROT: Abbreviation of Real Options Theory.

Significant Discovery: A DTI definition of a well which flow tested, or would have flowed, at a rate of 1000 barrels of oil a day or 15 million cubic feet of gas a day.

Sliding Scales: A mechanism in a fiscal system that increases effective taxes and/or royalties based upon profitability or some proxy for profitability, such as increased levels of oil or gas production.

UKCS: Abbreviation of United Kingdom Continental Shelf

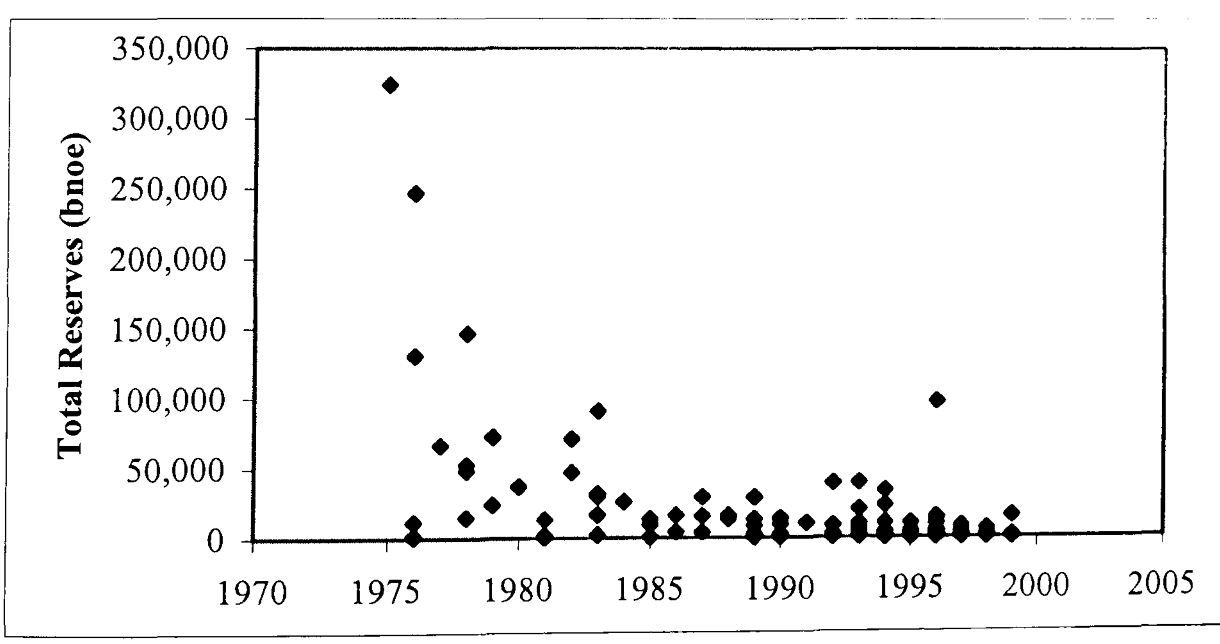
UKOOA: Abbreviation of United Kingdom Oil Offshore Association

Uplift: Common terminology for a fiscal incentive whereby the government allows the contractor to recover some additional percentage of tangible capital expenditure.

APPENDIX A

FIELDS DISTRIBUTION BY SIZE

The following graph shows the distribution of fields by size from 1975 to 2000. The graph shows that more fields were developed in the 1990s compared to previous periods. However, the graph indicates that the first fields that were brought to production in the mid-1970s are much larger than the fields brought to production in subsequent years, particularly in the 1990s.



APPENDIX B

B.1. COVER LETTER

A cover letter accompanying the questionnaire was sent to all respondents.

Dear *Sir/Madam*[1],

I am doing PhD in Energy Economics at the University of Surrey. My research project is concerned with the impact of taxation on oil exploration and production activity in the UK Continental Shelf.

To understand the real nature of oil operations in the UK North Sea and the impact of taxes on these operations, I am conducting a survey among oil companies operating in the North Sea, Government institutions and major consulting companies.

I kindly request you to take part of the survey. I enclosed the questionnaire with this letter and I would like you to fill in the questions that apply to your company/institution. All information provided will be treated with strict confidentiality and will be used for the purpose of my research only.

I would very much appreciate your assistance in this regard and trust that I will hear from you soon.

My contact address is:
Economics Department
University of Surrey
Guildford, Surrey
GU2 7XH
E-mail: c.nakhle@surrey.ac.uk
Telephone: 07867954320

Thank you in anticipation.

Yours sincerely,

Miss Carol Nakhle

[1] The letter was individually addressed.

B.2. QUESTIONNAIRE

This section includes firstly the final version of the questionnaire, and secondly the questions adjusted from the original version.

B.2.1. Final Version

Name of the company:

Name of the person in charge of the questionnaire:

The Impact of The UK Petroleum Fiscal Regime On Oil Company Performance on The UKCS.

Q1) How has the company's willingness to invest been affected by the following changes to the tax system:

a- Abolition of Royalty in 1983
b- Abolition of PRT in 1993

Q2) If we consider the 1975 oil taxation structure, how does the company evaluate the impacts of the key components of the UKCS fiscal regime namely Royalty, PRT and CT in terms of:

a- The development of marginal fields
b- Early abandonment

Q3) Which of the following allowances does the company find essential to reduce the burden of tax and encourage the activities within the North Sea:

a- PRT allowances: - Uplift
- Safeguard

- Oil allowance

b- CT allowances

Q4) To generate extra revenue from the North Sea activity, the Government has been thinking of changing the structure of the tax system in 1998. Two options were discussed; either an increase in the CT rate, or a reintroduction of the PRT. In its latest 2002 Budget release, the Government opted for a 10% supplementary CT.

a- How does the company perceive the latest changes?

b- Would a reintroduction of PRT be preferred?

c- Is there a third alternative that you would like to suggest?

Q5) There are different evaluation methods to incorporate the risk related to oil projects, such as the Net Present Value and the Modern Asset Pricing model, etc.

a- How does the company incorporate risk in the evaluation of project attractiveness?

b- To what extent does the fiscal regime affect this risk?

Q6) After 1983, oil companies were required to pay only CT on UKCS oil and gas profits for those fields that received development consent after that date. This led some observers to describe the British regime as the weakest in the world.

a- How would you evaluate the current UKCS fiscal regime?

b- Do you agree or disagree with the previous statement and why How do you evaluate the current regime?

c- On an international scaling, how would you evaluate the UK petroleum fiscal regime?

Q7) What are the company's current expectations regarding the level of activity and profitability of the UK North Sea oil industry?

B.2.2. QUESTIONS ALTERED

Two main adjustments were made to the original version of the questionnaire for two reasons. The first reason was to reflect the 2002 fiscal changes that took place during the course of the survey. More precisely, the original formulation of Question 4 was as such:

"To generate extra revenue from the UK North Sea, the Government has been considering certain changes to the structure of the tax system effective as of 1998. Two options were discussed; either an increase in the CT rate, or a reintroduction of the PRT.

a. Which of these options does the company find more appropriate?
b. Are there alternative that the company would like to suggest?"

Further, as a consequence of the 2002 changes, which led to the abolition of Royalty, Question 5 in the original version was omitted from the final version of the questionnaire since it was not relevant anymore. Question 5 was formulated as follows:

Q5) Lately the issue of the tax burden on mature oil and gas fields has been the subject to considerable discussions. On one hand these fields are now well into their decline phase of production but are still under the burden of three components of Government take, namely Royalty, PRT and CT. On the other hand, they do not face any residual major capital costs, other than abandonment costs. Hence is it fair for the UK Government to continue extract rent from these fields? In your opinion, should there be a special treatment for such fields, i.e. a relief in the level of Government take? If yes, which measures should be taken?

The second reason for adjustment was made to adapt Question 1 to respondents working with Government institutions and three tax specialists from consulting companies but with previous experience with the Government. As such, instead of asking respondents about the impact of different tax changes on company's willingness to invest, the experts where asked the following:

Q1. What are the economic justifications for applying each of Royalty, PRT and CT?
Q2. What are the reasons that led to the abolition of both Royalty and PRT reciprocally in 1983 and 1993?

B.2.3. REPLIES

B.2.3.1. NOTATIONS

For reasons of confidentiality, respondents' identity is not revealed. Instead, the following notations are adopted:

- "Respondent Gn" if the respondent works for Government Institution n. In total there are 2 respondents from Government institutions- Respondents G1 and G2.

- "Respondent On" if the respondent works for an oil company n. In total, there are 7 respondents from oil companies- Respondents O1, O2, O3, O4, O5, O6 and O7.

- "Respondent Cn" if the respondent works for a consulting company. In total, there are 6 respondents from consulting companies- Respondents C1, C2, C3, C4, C5 and C6.

B.2.3.2. ANSWERS

In the following, are presented the original answers to all questions, including the adjusted questions. That's why there are a total of 10 questions instead of 7.

1. (Altered)

What are the economic justifications behind imposing each of Royalty, PRT and CT?

Respondent G1

- Royalty is a payment that companies make to get the license or right of extracting and exploiting the resources owned by the Government.
- PRT was applied to extract a share of the excess profit/economic rent from oil and gas activities. It was developed after a consultation between the Government and the industry so both sides agreed its application. The Government doesn't have an explicit definition for economic rents. Several factors are taken in consideration when determining the rents of a particular field, such as for example the size of the field (the larger the field is, the more likely the higher the rent is) or the Internal Rate of Return (usually higher that 10%)... Also, with the oil allowance, half of the profit is not being taxed, in this case this profit (less than the half) is considered normal while the second half is considered the rent, and on which PRT should apply. In theory, because PRT is an excess profit tax (so after tax, the field should still be profitable), marginal fields do not pay PRT.
- CT was applied because all companies operating in the UK pay this tax.

Respondent G2

- Royalty is usually applied as a compensation for the Government because its owned assets are being used and depleted.
- There is always the question of achieving a balance between generating resources to the nation and keeping companies motivated. PRT was able to realize such a balance (start up costs, full deduction, no PRT until positive CF...). PRT is imposed to capture the excess of profits. In fact, under PRT a company gets profits earlier because costs are amortized over years, and as such, it can create value for shareholders earlier since reporting profits will impact share price and ability to pay dividends. PRT does not cause you to think about incurring certain expenditure, because the expenditure is deducted. It is however an expensive tax, but if you invest more in another field, you get more deduction
- CT is imposed on all companies operating in the UK

Respondent C1

- Royalty: oil was a new experience to the UK. The Government followed what was applied elsewhere in its fiscal policy, and Royalty is a common fiscal instrument.
- CT: this tax applied to all companies operating in the UK, so, in structural terms, it was very difficult to exclude it. From technical terms, companies operating in the North Sea also have other businesses, such as in other companies so they incur costs that are not related to the North Sea. It is a blanket tax on companies' profits on a global basis.

- PRT: With Royalty and CT there was no need for PRT. A possible alternative would have been to apply a higher Royalty rate. This is possible if all fields were onshore. However, this was not feasible because of the cost problem in North Sea. This problem is rather substantial than quantifiable given the different characteristics (thus different profitability) of each field. Since Royalty does not allow different costs to be deducted, PRT was created. This tax was like a Royalty but unlike Royalty, it allowed the deduction of direct costs. Had Royalty applied to a homogeneous cost base, the Government wouldn't have needed the complicated PRT. Further, the PRT takes a layer down from CF. It applies after the oil is brought onshore and after minimum cleaning out process. In this case, the company can sell the oil, make some profit and then pay the tax. This encourages in particular the development of marginal fields and keeps companies motivated.

Respondent C2 - In the 1970s, oil prices increased sharply, and this necessitated a windfall tax in addition to Royalty, which was imposed on the top of barrel. The CT is the normal income tax that applies to all companies in the UK.

2. (Altered)

Why Royalty was abolished on fields given development consent after 1983 and PRT abolished on fields given development consent after 1993?

Respondent G1 - PRT was the main source of revenue for the Government in early years of its imposition. But in 1992, Government revenues were negative and almost zero in 1993. This was due to offsets of companies for their appraisal expenditures (quite a generous relief, with the oil allowance being the most expensive to the Government) and exploration expenditures (cross-fields allowances: a part of the profit is used to invest elsewhere...). After abolishing PRT on new fields in 1993, more revenues are generated, mainly as a result of abolishing offsetting exploration costs.

- The Government is not currently giving too many reliefs because it realized that the past era will not be alive again

Respondent G2 - Royalty does not allow deduction of all costs. Consequently, it can distort marginal activity especially that big developments have been achieved. The Government wants Royalty to be abolished because it does distort investment in marginal fields. But this is difficult to prove in practice, because of the volatility of oil prices. Since Royalty is allowable against PRT and CT, its impact would be greater if fields are reliable for PRT but do not pay PRT. When Royalty was abolished in 1983, the Government did not lose revenue because if Royalty still applied, the development of many fields would have been stopped and the Government wouldn't have generated more revenues.

- PRT is expensive to the Government. There were lot of explorations but the fields discovered did not bring money for the Government, given the different reliefs. Its abolition stimulated the activity but did not generate a big effect on marginal fields, which did not pay PRT as they were protected by the different allowances.

Respondent C1

- The combination of 12.5% Royalty, 50% PRT. and a 52% CT was upsetting the oil industry. The taxes themselves are not complicated but it is the working down sequence, which is complicated. Such complication results from detailed rules, for instance, to deal with CAPEX under PRT and under CT. As such, to calculate the tax base, we need different information, a different gathering system, and extra administration burden.
- Royalty was abolished because it creams off something from the top. This can be very discouraging especially when you don't know if you will make returns.
- PRT: Big and medium size fields are already in production. They are all in a position of tax paying because there are no more capital expenditure, except abandonment costs, to be deducted. In addition to these big tax bills that companies are paying on older fields, there is too much to be spent on newly developed marginal fields. Further, the impact of these marginal fields on companies' profit is marginal. Thus, if after tax profits are small, no shareholder value is created. In fact, with a higher risk resulting from the uncertainty surrounding the field and the volatile oil price, let alone environmental pressures, oil companies require higher after tax returns. As a result, rather than bothering in undertaking the investment, the company can use the money for a different type of expenditure, where it is more likely to get a better payback return and more importantly it avoids all those problems of abandonment, leaking, environmental pressures...

Respondent C2

- The 1975 system combined the best features of Royalty and PRT, but also their worst features. The Government needed to combine something more sensitive to prices, and lot of work has been done.
- In 1983, there was a strong lobby for relaxation of the regime. In fact, there was a partnership between practitioners in the oil industry and the Government. They wanted to find what could be done to encourage investments and to bring marginal fields to development. The problem was that the industry couldn't come with good examples to convince the Government that fields are small (prior to 1983). But in 1983, the lobby was stronger. And since Royalty was not a huge source of revenue to the Government, the latter took measures that were unexpected by the industry: abolishing Royalty. They were unexpected because the industry was rather worrying about changing the structure of PRT.
- In 1993, similarly to 1983, the Government abolishment of PRT was unexpected. This created lot of uncertainties

Respondent C3

- PRT is a super profit tax, so to charge a super profit tax, companies should be making super profits in each field (since PRT is on a field by field basis); this is not the case anymore.
- Royalty hits in more aggressive way (front-end). The Government recognized this in the 1998 proposals, where it suggested abolishing Royalty, in addition to other fiscal measures.

1) Final version

How does the company evaluate the impact of key components of the 1975 UKCS fiscal regime (Royalty, PRT and CT) mainly on:

a. **The development of marginal fields**

b. **Early abandonment of existing fields**

Respondent O1
- Investments within an existing PRT field ring fence are adversely impacted by the 69% Royalty/PRT/CT regime.
- No impact on decision

Respondent O2
- All valuations are run using existing fiscal terms and there is no presumption that terms will change. The group does not currently hold and has not previously held any assets that were liable to UK PRT or Royalty and therefore, from the group perspective, there is a view that fiscal terms alone will not influence marginal developments or the timing of abandonment

Respondent O3
- The industry remains concerned that the tax regime for older fields (pre 1993) levies a marginal tax rate of up to 69% which acts as disincentive to investment in these fields.
- The pre-1993 fiscal regime subsidized exploration activity which led to an inefficient allocation of capital

Respondent O4
- The pre-1983 fiscal package imposed a high burden particularly on marginal fields. The abolition of Royalty in 1983 reduced the fiscal burden and encouraged the development of marginal fields.
- The abolition of PRT and its different reliefs resulted in a reduction in drilling activity but in the main PRT does not alter the development of marginal fields nor cause premature abandonment.

Respondent O5
- See answer above.

Respondent O6
- No impact on decision because the company does not operate any field subject to Royalty.
- No impact of PRT on marginal fields that do not pay the tax mainly because of the oil allowance.

Respondent O7
- Royalty can adversely impact particularly older fields and possibly lead to premature abandonment.
- PRT does not have any impact on the development of marginal fields nor premature abandonment. And despite the large reductions in the fiscal burden on new fields, effective tax rates on mature fields are still substantial.

Respondent C1
- PRT is a remarkable tax as designed. For fields of less than 60MMBBL no PRT is paid. Additionally, the safeguard ensures that companies have recovered their costs before they pay PRT. Incentive exists for marginal fields, especially with the cross fields allowance, and loss carry back.

Respondent C3 - Royalty is a regressive tax and the Government has been convinced of this aspect of Royalty.
- PRT is complex concerning abandonment. All the carry back rules...end up with; no effective economic relief. The system as it is, creates no incentives; no interest relief (no relief for financial costs, whereas this relief exists in CT).

Respondent C4 - Royalty has a minor effect on marginal fields. As for PRT, the impact depends on the size of the field; marginal fields don't pay PRT. Regarding CT, there is an important effect but it will vary from company to company- how much allowance they have, loss carried forward, etc.
- Royalty plays an important part particularly with regard to relief (possibility of using a part of abandonment costs against Royalty relief). For PRT, very much dependent on the field, such as under Oil Taxation Act the carry back of abandonment costs doesn't trigger relief immediately; it will first displace oil allowances and whatever is left of taxable income, then get PRT relief for abandonment. The Argyll field is an example of ineffective relief for abandonment; this field was the fist to start production and the first to be abandoned. It is like gambling; if oil price increases then you win, but if oil price decreases then you lose. Finally, as for CT, the effect will depend on the company

Respondent C5 - Neither Royalty nor CT is a major component. PRT has no major impact provided that you have the oil allowances out of PRT net.
- The point of abandonment is where marginal revenues equate to marginal costs. This means that Royalty is a more important determinant of abandonment than either PRT or CT since it is a fixed cost of production

Respondent C6 - I do not think I can help with this

2) How has the company's willingness to invest been affected by the following changes in the tax system:

a. Abolition of Royalty in 1983

b. Abolition of PRT in 1993

Respondent O1 - The abolition of Royalty, together with enhancements to the PRT regime (doubling oil allowance) made a substantial difference to both my company & industries willingness to invest.
- The abolition of PRT for fields developed after 1993 had a marginally positive impact on investments' attitudes. Prior 1993 few fields were large enough & profitable enough to pay PRT, so the impact of PRT abolition was not dramatic

Respondent O2 - The group was not involved in UK activities until 1998 and therefore the changes were irrelevant
- See a

Respondent O3 - The fiscal system has a direct impact on company investment decisions and the attractiveness of the UKCS as a place to invest. The key fiscal changes of 1983 and 1993 both led to significant increases in investment activity by the company. In particular, the fiscal changes of 1993, which removed PRT for new fields directly encouraged the development of Andrew, ETAP and the first production West of Shetland. The Schiehallion field is now the largest producing oil field in the UKCS. Immediately prior to the fiscal changes in 1983 development activities had dried up due to the very high marginal tax rates then in place (up to 90%). The improvements in the fiscal regime made in 1983 led to a material increase in the development activity that lasted through the 1980's despite the rapid real decline in the oil price

Respondent O4 - Since 1984, the company policy has been to expand overseas and diversify away from the UK tax changes have influenced this- eg. The abolition of PRT relief for exploration wells resulted in less UK drilling but in the main it has not altered the main strategy.

Respondent O5
- Royalty hits revenues before any profit is made. Its abolition had significantly improved the position of marginal fields.
- The abolition of PRT stimulated the development and production activities, but it did not have a big effect on marginal fields.

Respondent O6
- The company was not involved in the UKCS before 1991 so the abolition of Royalty did not have any effect on the company performance
- The abolition of PRT meant a reduction in the tax burden so it did stimulate the activity. But in the other hand, PRT was a generous tax offering different reliefs. Overall the effect was positive.

Respondent O7
- The abolition of Royalty had a positive effect because of the front-end aspect of this tax.
- The reduction of PRT to zero has helped but it is not as simple to say there is no tax. There are of course some benefits because mainly less tax encourages the activity. However because the sharing in risk has been reduced, the effectiveness in exploration has been reduced as well.

Respondent C3
- The recent conditions in the UK North Sea are as follows:
- Small companies are the new entrants, applying for licenses. That's in fact where we need to look at the impact of tax
- Large companies are interested in large projects such as the Caspian Sea (where approximately we can find 30bbl recoverable). These companies are happy with the projects they already took in the past but not attracted for remaining projects.
- Therefore, reducing tax has reduced the problem of tax on small players. Nevertheless, a low level of tax means less sharing of risk

Respondent C4
- The abolition of Royalty had a modest impact but nonetheless positive because Royalty is deducted for PRT and CT, so the net impact is very small.
- The abolition of PRT had a significant effect but that has been mitigated by E&A expenditures adjustments. In terms of large companies, the benefit was positive but not necessarily of major considerations. But the main beneficiaries are small companies given their smaller portfolio of projects

Respondent C5 - The abolition of Royalty is not a material factor in determining investment decisions. It only affects the end of field life and any incremental expenditure to extend the field life.

- The abolition of PRT had an impact in terms of cross-field allowances and Exploration and Appraisal (E&A) relief, which had an adverse effect on exploration activity. Also, the size and type of companies are important to differentiate. Smaller companies will effectively use the Government to fund their exploration activity through E&A. So, when this relief was removed the number of exploration wells decreased; small companies don't have the same access to capital as large companies, who can fund all exploration costs themselves.

Respondent C6 - At the time it was particularly important for some new developments to proceed.

- There has been a marked decline in exploration activity since Exploration and Appraisal (E&A) was abolished and PRT for new fields. There have, however, been a number of marginal fields developed, which probably would not have happened if PRT had applied

3) Which of the following allowances does the company find essential in reducing the burden of Government take and at the same time encouraging activity in the UKCS:

a. PRT allowances:- Uplift

- **Safeguard**
- **Oil allowance**

b. CT allowances

Respondent O1 - These allowances only apply to fields approved for development before 1993, and therefore have little impact on current development activity. Prior to 1993 all 3 allowances had a significant beneficial impact in encouraging activity.

- It is essential that any tax regime taxes profit and not revenue. The CT 25% writing down allowance (WDA) ensures this condition is met. The relative fast depreciation provided by WDA ensures that the after tax return is not significantly less than the before tax return, and consequently the CT regime does not inhibit activity.

Respondent O2 - Although PRT is not currently an issue for the group, the retention of oil allowance is considered to be or prime importance to the more marginal fields

- The recently introduced 100% capital allowances are likely to encourage new capital expenditure and to assist in the rationalization of North Sea interest by way of the sale and purchase of assets.

Respondent C2 - CT has almost no effect because of the low rate.

- Under the CT, abandonment losses are carried back for 3 years. But is the CT relief economical? Is it going to be applied in practice?

Respondent C3 - PRT reliefs go simultaneously. Oil allowances are significant to some fields. Uplift was important because no interest deduction in PRT
- CT: scientific allowances, plant and machinery, extraction relief. CT allowances are the most important and broadly neutral. But the UK gives reliefs for all businesses.

Respondent C4 - Uplift & Safeguard: more important for larger fields
- Oil allowances: more important for small fields
- Most new developments will be under CT rate, so anything done under CT must be seen as generating a positive aspect to return

Respondent C5 - All depend on the size of the fields:
- Uplift & Safeguard: the more the larger fields, the more these reliefs are important.
- Oil allowances: most important for smaller fields because the uplift & safeguard period is small.
- Relatively insensitive to investment decisions for the following reasons:
  1. It is only a timing effect (we get the relief at a certain stage)
  2. In the early days of field life, it is likely that profits are smaller and there are other expenditures that reduce the taxable income.
- A more important relief is the relief against interests, which is a crucial deduction.

Respondent C6 - In terms of fields within the scope of PRT I would have thought the oil allowance must be the most valuable relief.
- CT allowances: The 100% Scientific Research Allowance pre the Finance Act 2002 but now the First Year Allowance for virtually all capital costs. It is the only thing that compensates for the new 10% SCT.

[The following two questions (i.e. 6a & 6b) addresses the same issue, but Q.6b is a developed version of Q.6b to incorporate the 2002 changes.]

4) Original Version

To generate extra revenue from the UK North Sea, the Government has been considering certain changes to the structure of the tax system effective as of 1998. Two options were discussed; either an increase in the CT rate, or a reintroduction of the PRT.

a. **Which of these options does the company find more appropriate?**
b. **Are there alternatives that you would like to suggest?**

Respondent G1 - The Government listened to academics in 1998, when the proposed changes were developed after consultations. Dropping the proposed changes after a decline in oil prices doesn't mean that it would never be considered.
- There are two arguments that the Government consider:

1. Companies should pay a fair share of their profit in tax, but

2. The Government doesn't want to affect negatively the attractiveness of the North Sea in the long-term

Respondent G2 - Technically, nothing is wrong with the PRT. But re-introducing PRT would be messy for fields, and the problem is that PRT is a field by field basis. A better way to raise money may be to apply RRT similar to Australia or increasing CT on oil companies, but CT is inefficient.

- However, there isn't a technical issue but rather a confidence issue. For instance, the 1993 changes were unsustainable; companies believed that the Government will re-apply PRT. The need for a bigger share of profits will affect incremental activity especially that exploration is already very low. There is a trade off between short-term revenues and long term activity; the industry argues stability of the regime.

Respondent O1 - Neither option is appropriate. Companies require a stable fiscal regime if they are to invest in long timeframe high-risk projects

Respondent O3 - The most appropriate fiscal system is the one in place today for new developments, namely CT only. This ensures that the upstream industry is treated in the same way as any other industry in the UK. Since the returns in the oil sector in recent years have been below those that can be earned elsewhere in the economy, the intellectual case for additional taxation on oil and gas activities is not sustainable. Capital cannot be attracted into the oil and gas industry unless shareholders can be offered comparable returns to those on offer in other sectors, e.g. information technology, telecommunications, pharmaceuticals

Respondent O4 - The CT only regime applying to post 93 fields. Looking at it from today's viewpoint it provides a fully consolidated system with early deductions for capital expenditure. This best suits the nature of geological risk in the UK.

Respondent O5 - Applying only CT for all fields with the abolition of Royalties and a higher CT rate than the current 30%.

- The Government could level the fields by abolishing all upstream taxes and replace this with a supplementary rate of CT, which delivers the same overall yield. This would remove the unnecessary complexity of the current system and remove disincentives to invest in mature fields

Respondent O6 - The company is supportive of the current fiscal regime (CT only). By establishing such an attractive tax regime the Government ensures that the UK is a competitive place for E&P activities.

Respondent O7 - The abolition of Royalty as a non-profit based levy is the most obvious measure. However if this has to "paid for" by robbing Peter, then the status quo is overall better

- A tightening of the fiscal regime would damage activity, investment and jobs.

Respondent C1 - Tax in the UK is a complex regime but leave it alone for the issue of stability. If changes occur, there will be winners and losers, but PRT creates Big winners and Big losers. If Government tries to take more (when the North Sea activity is already on a downward track), small companies (who are willing to take over fields at the end of their life) are heavily dependent on banks. Are the banks going to accept to take this risk?

- Compared with CT, PRT is more focused but again the big losers are small companies since there are no interest reliefs. Dilemma: the Government wants to increase tax and increase activity. But losers are small companies, who will revitalize the North Sea.

Respondent C2

- There are some fundamental problems with hybrid taxes.
  1. Re-introducing PRT? PRT structure could lead to counter investment decisions, or gold-plating (the more you invest, the higher the return, which is non sense). Safeguard can give more than 100% of the relief.
  2. An alternative would be to apply a flat CT. But fields, such as Don, need subsidy. Lot of oil still to come but given technology barrier, it has been abandoned.
- The oil industry is a competitive industry, thus over the long-term no super profits, and it will be unfair to chase profitability over the oil price track. Even when prices were high, introducing a windfall tax will deter future investments over the long term. An important issue for the Government: security of supply rather than Government revenues.

Respondent C3

- Companies when analyzing a project, they consider an average over 20 years of life, they include in their analysis a stable tax, given the variations in price. Oil contracts may be tougher but at least they offer 1) a stable take and 2) allow the contribution of companies. Thus, the main issue is the issue of stability. In 1998, the Government created uncertainty, its proposal of applying some changes to tax gave some pausal thoughts for oil companies.

4. Final Version

To generate extra revenue from the North Sea activity, the Government has been thinking of changing the structure of the tax system in 1998. Two options were discussed; either an increase in the CT rate, or a reintroduction of the PRT. In its latest 2002 Budget release, the Government opted for a 10% supplementary CT.

a. **How does the company perceive the latest changes?**

b. **Would a reintroduction of PRT be preferred?**

c. **Is there a third alternative that the company would like to suggest?**

Respondent O2

- The latest changes, although unaccepted to industry, primarily because of their destabilizing affect, were in fact not totally unexpected and probably represented the simplest method for the Government to achieve the revenue that they required.
- Reintroduction of PRT is likely to produce a less equitable incremental result given many companies already hold PRT paying assets.

- We have no real third alternative to suggest.

Respondent C4 - No PRT because it is a complicated tax as it stands, plus it is likely to create greater uncertainty, thus affecting investment decisions, while changing CT is simpler, more direct and unlikely to cause significant distortions and create greater uncertainty.
- A third alternative would be to possibly link CT changes to the behavior of oil prices. But increasing the CT is not appropriate currently, so better to leave it alone

Respondent C5 - At least worse option is to change CT rather than applying PRT. CT is a corporate tax thus it takes into account the company's overall portfolio, not a single project. Although the Government has changed the headline rate of CT, it made fundamental changes to CT: the supplementary 10% does not allow the deduction of interests. This can affect companies' decisions in the manner in which they finance their investments. As a consequence, small companies will use more imaginative and more risky routes to raise capital. Another consequence of the latest changes is the law of non-intended consequences, particularly the adverse effects on foreign companies in particular American and French who are major investors

Respondent C6 - The original PRT was, I believe, a fair system which guaranteed to the company a full return of costs and an annual return on investment before any special levy applied. However, reintroduction after nearly ten years would be very difficult. The recent changes need to be supplemented at the very least by additional incentives to explore (say, a 25% supplement on exploration costs). Early abolition of Royalty is also important not least of all to let the Government retain its creditability

[The following question was removed from the questionnaire after the 2002 changes].

5. Original Version

Lately the issue of the tax burden on mature oil and gas fields has been the subject to considerable discussions. On one hand these fields are now well into their decline phase of production but are still under the burden of three components of Government take, namely Royalty, PRT and CT. On the other hand, they do not face any residual major capital costs, other than abandonment costs. Hence is it fair for the UK Government to continue extract rent from these fields? In your opinion, should there be a special treatment for such fields, i.e. a relief in the level of Government take? If yes, which measures should be taken?

Respondent G1 - If Royalty can be shortening the field life, then companies can apply for Royalty remission (concession), which is presented to DTI who, jointly with the Treasury give the remission approval. This year (2001) there have been couple of fields that received this relief. It is a real, not theoretical option.

- Thus, Royalty is a burden but when it affects the investment decision companies can ask for concession, this is to avoid undesirable effects. This is rather a remission procedure not abolishing

Respondent G2 - There is a discretionary provision to repay Royalty to particular oil producers if they consider that it will facilitate or maintain the development of petroleum resources of the UK. This mechanism would encourage incremental production from older, Royalty-paying fields.

Respondent C1 - For fields coming to an end, it is not a reason to have a blanket against PRT, but yes for Royalty abolishing

Respondent C4 - The regime needs to be kept under review of mature fields, such as abolishing Royalty and reducing PRT. But it is difficult for one size to fit all circumstances

Respondent C5 - The bigger factor in investment decisions is certainty. Although you might think about this (i.e. abolishing Royalty) positively, you think that the Government will act in other way negatively. So better no changes.

5. Final version

There are different evaluation methods to incorporate the risk related to oil projects, such as the Net Present Value and the Modern Asset Pricing model, etc.

a. How does the company incorporate risk in the evaluation of project attractiveness?

b. To what extent does the fiscal regime affect this risk?

Respondent O1 - By considering all potential risks, quantifying them and conducting economic sensitivities.

- To the extent fiscal regime is profit based, an equitable sharing of risk between Government and industry occurs. Royalty does not result in an equitable risk sharing since it is not profit based.

Respondent O2 - It does not especially alarm us. Risk and uncertainty are inherent in the business and the UK is no more risky than anywhere else

Respondent O3 - The company has been a key player in the development of the UKCS for over 30 years and has learnt to live with the fiscal risk. The fiscal risk will never go away but with a meaningful discussions between the industry and Government at such forms as PILOT we believe that the Government is committed to ensuring that the UKCS remains competitive. The fiscal regime is responsive and appropriate to the competitive circumstances of the UKCS i.e. high costs, small fields and hostile marine environment

Respondent O4 - Exploration and other reservoir risks are initially factored into the calculations of future expected cash flows. These cash flows are then further discounted to reflect the required group minimum rates of return.
- The uncertainties of a fiscal regime are not generally factored into risk analysis. The only related risking would be in respect of political rather than fiscal risk. The group would be unlikely to consider investments in countries where the fiscal system is not properly defined or is known to be unstable

Respondent O5 - Normal evaluation of after-tax Cash flows. Risk is normally incorporated through sensitivity analysis or higher discount rates.
- Investors dislike uncertainty; the real threat of an adverse tax change as proposed in March 1998 caused investment decisions to be deferred until the fiscal uncertainty was resolved. Maintaining fiscal stability is a key element of delivering investor confidence and UKCS competitiveness.

Respondent O6 - No one will invest with just a positive NPV for 10% discount rate. So we cannot consider the negative or positive NPV as a criteria because of the high risk. Sensitivity analysis to handle risk.

Respondent O7 - Different scenarios for oil price and costs, probability of a successful well, etc… The main technique is to discount the future cash flow. The Real Options Theory is currently on fashion but it is too complicated to be applied in the daily operations of the company.

Respondent G1 - A cash flow tax is when the Government takes an equity share, which equals a percentage tax take from the cash flow. In this case, the Government is facing a risk-sharing situation. Both the Government and companies will have the same CF (e.g. negative tax at the early stage of investment), and NPV of the project should be halved (shared equally) between the Government and the companies.
- PRT works well as a CF tax but losses are carried forward instead of result in a tax refund straight away. But if we look at late field development (plus abandonment costs), PRT works exactly like a CF tax.

Respondent G2 - One needs to understand companies' decision criteria or project evaluation, but this is time consuming. Look at NPV under range of scenarios, spider curve with range of positive and negative outcomes…

Respondent C1 - To incorporate risk, companies can take different scenarios of e.g. prices and costs, with different probabilities, and change the discount rate, or assessing probabilities of certain account, i.e. applying market risk-rate. The different values of NPV should be considered under different scenarios. But how do we include the risk coming from Government political action?
- Usually tax is seen as a cost, but it also has some characteristics such as risk sharing, since it is not based on gross amount. High tax rates work perfectly as risk sharing, especially when the state acts to create certain behavior pattern, such as increasing activity. PRT is an enormous tax but high risk-sharing with Government means if a field is not successful expenditure reliefs will still apply. That's why it encouraged marginal fields.

Respondent C2 - The NPV is the most commonly used evaluation technique, with different scenarios. The Real Options theory is less likely to work in the long term

Respondent C3 - Expected Net Present Value methodology; allowing probabilities for the chances of success and failure… Using different factors: political risk, exploration risk.
- The question is not only the impact of higher tax burden but also the risk sharing. In Norway for example, although the Government take is high, the Government takes exploration risk (approximately 78% of CAPEX) in addition no ring fence. In the UK, lower tax thus less/no sharing of economic rents but also no sharing of exploration risk

Respondent C4 - Higher discount rates, applying risk (MAP).
- The regime in its early stages was risk absorbing, this doesn't apply for new investments

Respondent C5 - Higher threshold of discount rate. Applying probabilities. Individual component of project should be treated separately.
- We need to look at post-Government take if higher marginal tax rate can distort investment decisions, because the Government is paying for higher share for taking exploration risk

Respondent C6 - Again, better addressed by companies but the recent change has made the UK again an unstable tax regime and there will be companies who will not invest in marginal projects with a long payback period for fear they will get hit again later. It's easy to increase SCT!

6) After 1983, oil companies were required to pay only CT on UKCS oil and gas profits for those fields that received development consent after that date. This led some observers to describe the British regime as the weakest in the world.

a. **How would you evaluate the current UKCS fiscal regime?**
b. **Do you agree or disagree with the previous statement and why?**
c. **On an international scaling, how would you evaluate the UK petroleum fiscal regime?**

Respondent O1 - I disagree. The regime is well attuned to the economic realities of the UK North Sea.

Respondent O2 - Judging the weakness of the regime is not a simple question. The fiscal regime cannot be seen in isolation from the prospectivity. Whilst in headline terms the fiscal regime for new developments in the UKCS is more attractive than, for instance, Norway, the fields size are smaller and unit costs higher in the UKCS than for typical new fields in Norway. At the exploration level Norway offers the potential for large discoveries the UKCS does not. For mature fields the UKCS applies marginal tax levels of up to 69% including Royalty, which acts in a regressive manner.

Norway recently abolished Royalty and can offer more attractive economics for investment in mature fields

Respondent O3 - The current UK fiscal regime largely reflects the maturity of the UKCS and the marginality of likely future developments. It is in fact comparable to many other regimes in the taxation of marginal developments. It is important to avoid the comparison between current UK rates and the highest marginal rates in other countries. Many of these other countries provide benefits for marginal developments and many of the players in those countries would not expect to pay any of the higher special taxes.

Respondent O4 - Statement is not factually correct. Fields approved for development after 1993 are not required to pay PRT. I do not agree with statement "UKCS is weakest regime in world". Regime needs to be considered in context of costs & geological environment in which it has to operate. I refer you to a UKOOA publication p. 21-23 (mailed separately) which puts UKCS into context

Respondent O5 - In Alaska, there is bad weather but large fields. The Caspian Sea is also better than the UK North Sea from a geological view (of course there is a different risk profile- political but not geological). So companies now have a choice and they are looking for the best payback return. Taxation can play an important role in this case. That's why the Government in the UK should offer attractive fiscal terms to maintain activity in the North Sea.

Respondent O6 - The North Sea oil fields are one of the most difficult and costly offshore areas to develop. There is no denial that the regime is attractive, but this should be the case in a mature area. Under such circumstance, the Government needs to offer attractive fiscal terms if it wants to maintain international competitiveness of the county. Describing the regime as the weakest in the world is an extreme view.

Respondent O7 - The question is impossible to answer, as each country is appropriate to its own geological facts and circumstances. That is Norway, for example, still has large fields with economic rents. Over time Norway will have to reduce its tax rates if it wishes to maintain investment. As a matter of principle we think fully consolidated regimes are preferable and would obviously like tax rates to be minimized

Respondent G1 - Other countries are more generous, more favourable to oil companies

Respondent G2 - Better to fit to purpose rather than weak; high costs, small fields, exploration success is pretty low.

Respondent C1 - There are two important things to consider:

1. The risk profile of the sector, if the Government got it right
2. The high risk environment

- We need to look at what the regime is trying to achieve; so for example, there are lot of differences between what you are trying to achieve in fiscal in Russia, UK, USA, Saudi... Certain forms of behavior are independent of the economic situation. Thus, we should be comparing "like with like".

- Further, how do you define weak and strong, worse risk/reward ratio?!

Respondent C2 - The weaknesses of a regime can be an underestimation of expected production peak and time length. Thus, the weaknesses or the strengths of the system cannot be measured by the marginal tax rate on fields. For instance, we would rather look at the partnership, or benefits to balance of payment, self-sufficiency.... Thanks to tax, the Government has achieved the desired objectives, which is maximise the production of oil and gas. Further, the changes in tax have reflected a successful partnership between the Government and oil companies

Respondent C3 - In Ireland, the tax is very low; the effective Government take per barrel is on average 50%. The tax that is appropriate for on one hand large fields, and on the other hand, marginal fields, cannot be compared.

- Further, in 1998, UKOOA compared different industries in the UK and found that the pharmaceuticals have higher returns than the North Sea. The North Sea has moderate returns and moderate drilling levels plus high risk. When looking at profits of large companies, a small portion comes from the North Sea. For example, 80% of BP profits come from other activities in other areas
- International comparison is not appropriate, several things should be taken in consideration: geological risk, political risk, size of discoveries, tax regimes (UK has 7 regimes within the North Sea for different prospects)

Respondent C4 - Don't agree. The regime is competitive relatively to the international oil and gas industry worldwide. It is also geared to maximise UKCS resources

- It is the best relatively to the maturity of oil province.

Respondent C5 - The regime is appropriate to current state of development of UKCS, which is currently generating minimum amount of economic rent. The size and nature of current fields developed could not stand a harsher fiscal regime

- Low overall of Government take, which is appropriate to the UKCS maturity and it fits its circumstances. Under the existing regime, the oil industry is treated similarly to other industries so no discrimination.

Respondent C6 - The problem is that the recent Buzzard discovery might never be repeated. Future fields are expected to be small and will depend on existing infrastructure to get developed. A normal CT system probably suits that kind of new project. However, there is also a need to ensure that old fields are not abandoned early since there will then be no infrastructure in place from which to produce/transport the new finds. Taxes like the SCT will make old fields uneconomic earlier particularly if the Government does not abolish Royalty

7) What are the company's current expectations regarding the level of activity and profitability of the North Sea UK oil industry?

Respondent G1 - Check the survey by DTI and UKOOA (2001)

Respondent G2 - Lot of discoveries are waiting to be developed
- The Government believes that new smaller companies are the key to extending the life of the North Sea production. I refer you to the experience of the Gulf of Mexico.

Respondent O1 - Both are highly dependent on oil price trends, however a gradual decline in activity as the UKCS matures must be expected

Respondent O2 - The level of activity has probably only been sustained by the recent and continued high oil price. As the UKCS matures further, and particularly if oil price fall appreciably from current levels, there will be little real prospectivity to encourage further investment in the UKCS and activity level will inevitably fall

Respondent O3 - There is a serious decline in the size of new discoveries in the mature shallow water area of the UK North Sea. Major operators are now attracted to deepwater areas where major fields are still to be found. The remaining UKCS opportunities are of insufficient scale to attract further investment.

Respondent O4 - UK activity will decline over time with wide price related variations over the short term. Total profitability will follow this decline but again short run oil price variations will cause wide variations. Internationally oil and gas production will continue to expand.

Respondent O5 - UK oil production peaked in 1999. Exploration activity has significantly declined over the last 10 years, and is expected to further decline. Recent discoveries are quite small and inefficient to offset the decline from the older fields.
- The Government, however, can play an important role in extending the life of the UK North Sea province. By adopting favourable fiscal policies, the Government can largely contribute to increased industry efficiency.

Respondent O6 - The UKCS is already suffering from a maturing production base, which is negatively affecting its international competitiveness. Any reduction in profitability will alter the country's investment outlook. The key of course is the price of oil and gas, but taxation also plays a significant role.

Respondent O7 - The remaining fields to be exploited in the UK are small and technically challenging. Both a favourable fiscal policy and advance in technology are required to extend the life of the oil province.

Respondent C1 - Very few companies are spending money on exploration, they are more likely spending money on development of existing fields, such as new drilling techniques, new seismic, etc... to recover more oil from these fields. Thus, in the future, the level of development activities will increase in addition to some recoveries as the big companies are being replaced by small companies. As a result two big changes: new technology plus changes in ownership

Respondent C2 - No forecast, but could say that the tax changes will have adverse effects because they will reduce the amount of capital companies have access to both internal and external funds. Capital markets are unlikely to be impressed by changes in the perceived stable regime

Respondent C3 - The behavior of oil and gas prices is a major determinant of the profitability of the region.
- Activity level will be determined by the development of newly discovered fields. The small independent will play a role in the UKCS to develop the remaining resource base.

Respondent C4 - Pre-1983, an oil company declared that there is more oil to come from well-established fields such as Forties, as there is from new investments. The cost structure in 1983 was very high compared to now. Even a 75-150mmb was seen as marginal. The race now is more towards increase the use of new technology, in addition the structure is already there (the platforms).

Respondent C5 - The North Sea has a brilliant future, unless Government interferes, companies will make normal profits at modest production and modest prices but no super profits. Thus, the future of UK North Sea depends on Government measures: take more and activity decreases; the Government would be damaging in particular what they depend on to revitalize the industry i.e. the small companies.
- On an international level, the competition over capital will be more significant over the next few months, many places for hunting for big companies, UK is not on the list

Respondent C6 - Most companies are pessimistic!

APPENDIX C

EXAMPLE OF TAX TAKE COMPUTATION IN THE UKCS

Table 1: Pre-tax & Post-tax Net Cash Flow

Year	Production 000b/d	Oil Price £/bbl	Revenues £M	Total OPEX £M	Total CAPEX £M	Pre-tax NCF £M	Total Gov Take £M	Post-Tax NCF £M	Real NCF £M
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2002	0	13	0	0	110	-110	0	-110	-110
2003	0	13.3	0	0	235	-235	0	-235	-229.2
2004	0	13.7	0	0	220	-220	0	-220	-209.3
2005	44	14	224.8	54	50	120.8	2.5	118.3	109.7
2006	69.5	14.4	364	58.7	25	280.3	25.7	254.6	230.4
2007	70	14.7	375.8	58.8	58	259	49.6	209.4	184.8
2008	92	15.1	506.3	66.8	73	366.5	231.9	134.5	115.8
2009	81	15.5	456.9	68.4	121	267.4	202.1	65.4	54.9
2010	73.4	15.9	424.3	69.3	37	318	217	100.9	82.6
2011	77.6	16.3	460.1	65.7	11	383.4	314.2	69.3	55.3
2012	78.2	16.7	474.7	63.9	70	340.8	277.3	63.5	49.5
2013	74	17.1	460.7	64.1	50.9	345.7	281.1	64.6	49
2014	86	17.5	548.8	72.4	10.4	466	385	81	60
2015	74	18	484	68.8	5.4	409.8	335.4	74.4	53.8
2016	60	18.4	402.3	63.1	0	339.2	273.1	66.1	46.6
2017	48	18.9	329.9	57.4	0	272.5	214.4	58.1	39.9
2018	42	19.4	295.8	49.4	0	246.5	203.3	43.2	29
2019	34	19.9	245.5	48.5	0	197	172.2	24.8	16.2
2020	29	20.4	214.6	46.8	0	167.8	146.7	21.1	13.5
2021	25	20.9	189.6	47.3	0	142.4	124.5	17.9	11.1
2022	23.5	21.4	182.7	41.9	0	140.8	123.2	17.7	10.7
2023	22	22	175.3	34.9	0	140.5	122.8	17.6	10.4
2024	0	22.5	0	0	110	-110	-94.2	-15.8	-7.9
2025	0	23.1	0	0	0	0	0	0	0
Totals:	1103.2		6816.2	1100.1	1186.7	4529.4	3607.8	921.6	666.9

(A) Daily oil production in 000bbl, as given in GEM (2000)

(B) Base Brent oil price of \$19.5/bbl, constant exchange rate of US \$1.5=£1STG and constant inflation rate of 2.5%.

(C) Annual oil revenue in £M, where: (C) = (A) × (B) ×365/1000

(D) Operating expenditures in £M, as given in GEM (2000)

(E) Capital expenditures in £M, as given in GEM (2000)

(F) Pre-tax NCF = (C) - (D) - (E)

(G) Total Government take = Royalty + PRT + CT (See tables 2-6)

(H) Post-tax NCF = (F)-(G)

(I) Real post-tax NCF = (H)/Inflation factor

Table 2: PRT Calculation (Part1)

Year	Period	Revenues £M	Royalty £M	Total OPEX £M	Total CAPEX £M	Uplift 35% £M	Net Profit 1 £M	Cumulative Losses £M	Loss c/f Set-Off £M	Net Profit 2 £M
		(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
2002	1	0	0	0	25	8.8	-33.8	-33.8	0	0
2002	2	0	0	0	85	29.8	-114.8	-148.5	0	0
2003	1	0	0	0	125	43.8	-168.8	-317.3	0	0
2003	2	0	0	0	110	38.5	-148.5	-465.8	0	0
2004	1	0	0	0	115	40.3	-155.3	-621	0	0
2004	2	0	0	0	105	36.8	-141.8	-762.8	0	0
2005	1	71.6	0	25.6	35	12.3	-1.2	-764	0	0
2005	2	153.4	2.5	28.5	15	5.3	102.2	-661.7	102.2	0
2006	1	178.3	12.4	29.2	15	5.3	116.4	-545.3	116.4	0
2006	2	186.2	13.3	29.5	10	3.5	129.9	-415.5	129.9	0
2007	1	190.9	15.3	29.5	27.5	9.6	109	-306.5	109	0
2007	2	185.5	15.5	29.3	30.5	10.7	99.6	-206.9	99.6	0
2008	1	259.1	22.5	33.6	33	11.6	158.4	-48.5	158.4	0
2008	2	248.1	20.5	33.2	40	14	140.4	0	48.5	91.9
2009	1	248.7	15.9	34.2	72.5	0	126.1	0	0	126.1
2009	2	209.1	9	34.2	48.5	0	117.5	0	0	117.5
2010	1	212.9	11.1	34.7	21	0	146.1	0	0	146.1
2010	2	212.4	17.1	34.7	16	0	144.6	0	0	144.6
2011	1	247	23.4	32.8	6	0	184.8	0	0	184.8
2011	2	214.3	20.8	32.8	5	0	155.7	0	0	155.7
2012	1	232.4	22.3	31.9	32.5	0	145.8	0	0	145.8
2012	2	243.7	23	31.9	37.5	0	151.3	0	0	151.3
2013	1	231.1	23.4	31.9	27.8	0	148	0	0	148
2013	2	231.1	23.4	32.3	23.1	0	152.4	0	0	152.4
2014	1	275.4	28.4	36	5.2	0	205.8	0	0	205.8
2014	2	275.4	28.4	36.4	5.3	0	205.4	0	0	205.4
2015	1	243	24.9	34.2	2.7	0	181.2	0	0	181.2
2015	2	243	25	34.6	2.7	0	180.7	0	0	180.7
2016	1	202	20.4	31.3	0	0	150.2	0	0	150.2
2016	2	202	20.5	31.7	0	0	149.8	0	0	149.8
2017	1	165.7	16.8	28.5	0	0	120.3	0	0	120.3
2017	2	165.7	17.1	28.9	0	0	119.7	0	0	119.7
2018	1	148.7	15.5	24.5	0	0	108.6	0	0	108.6
2018	2	148.7	15.5	24.8	0	0	108.3	0	0	108.3
2019	1	127	12.9	24.1	0	0	90	0	0	90
2019	2	119.8	12	24.4	0	0	83.4	0	0	83.4
2020	1	111.6	11.2	23.3	0	0	77.2	0	0	77.2
2020	2	104.2	10.3	23.6	0	0	70.4	0	0	70.4
2021	1	99.2	9.7	23.5	0	0	66	0	0	66
2021	2	91.6	8.7	23.8	0	0	59	0	0	59
2022	1	93.9	9.4	20.8	0	0	63.7	0	0	63.7
2022	2	90	8.8	21.1	0	0	60.1	0	0	60.1
2023	1	88.2	9.1	17.3	0	0	61.9	0	0	61.9
2023	2	88.2	9	17.5	0	0	61.7	0	0	61.7
2024	1	0	0	0	110	0	-110	0	0	0
2024	2	0	0	0	0	0	0	0	0	0
Totals		6839.2	605	1100.1	1186.7	269.9	3677.5		764	3787.5

Table 2: PRT Calculation (Part1) Explained

(J) Oil revenues per 6-months period

(K) Royalty = 12.5% × (J) - C&T costs.

The Conveying & Treating (C&T) Costs are approximately 70% of the CAPEX of the platform depreciated over eight years or the life of the field, whichever is the shorter, 60% of total platform operating costs and 100% of the costs of transportation. All these costs are given in GEM (2000).

(L) Operating expenditures per 6-month period

(M)Capital expenditures per 6-month period

(N) Uplift = 35% × (M).

It applies until the field reaches payback (i.e. when Net Profit 2 (R) turns positive).

(O) Net Profit 1 = (J) - (K) - (L) - (M) - (N)

(P) Cumulative losses = Losses in period *t* + losses from period *t-1*

(Q) Losses carried-forward: when Net Profit 1 (O) turns positive, Cumulative losses (P) start to be written off. Any loss, which is not written off, is carried forward to the following period, until all losses are written off (in this case, in year 2008).

(R) Net Profit 2 = Net-Profit 1 after all losses are written off.

Table 3: PRT Calculations (Continued)

Net Profit 2 £M	Oil Allowance £M	Taxable Profit £M	PRT Rate %	Mainstream PRT £M	Safeguard Limit £M	Base PRT £M	PRT Loss Repayment £M	PRT Paid £M
(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)
0	0	0	70	0	0	0	0	0
0	0	0	70	0	0	0	0	0
0	0	0	70	0	0	0	0	0
0	0	0	70	0	0	0	0	0
0	0	0	70	0	0	0	0	0
0	0	0	70	0	0	0	0	0
0	0	0	70	0	0	0	0	0
0	0	0	70	0	0	0	0	0
0	0	0	70	0	0	0	0	0
0	0	0	70	0	0	0	0	0
0	0	0	70	0	0	0	0	0
0	0	0	70	0	0	0	0	0
0	0	0	70	0	0	0	0	0
91.9	28.3	63.6	70	44.5	63	44.5	0	44.5
126.1	29	97	70	67.9	66.3	66.3	0	66.3
117.5	29	88.4	70	61.9	40.3	40.3	0	40.3
146.1	29.8	116.4	70	81.5	41.2	41.2	0	41.2
144.6	29.8	114.9	70	80.4	36	36	0	36
184.8	30.5	154.3	70	108	0	108	0	108
155.7	30.5	125.2	70	87.6	0	87.6	0	87.6
145.8	31.3	114.5	70	80.1	0	80.1	0	80.1
151.3	31.3	120	70	84	0	84	0	84
148	32.1	115.9	70	81.2	0	81.2	0	81.2
152.4	32.1	120.3	70	84.2	0	84.2	0	84.2
205.8	32.9	172.9	70	121.1	0	121.1	0	121.1
205.4	32.9	172.5	70	120.7	0	120.7	0	120.7
181.2	33.7	147.5	70	103.3	0	103.3	0	103.3
180.7	33.7	146.9	70	102.8	0	102.8	0	102.8
150.2	34.6	115.6	70	80.9	0	80.9	0	80.9
149.8	34.6	115.2	70	80.6	0	80.6	0	80.6
120.3	35.5	84.9	70	59.4	0	59.4	0	59.4
119.7	35.5	84.3	70	59	0	59	0	59
108.6	36.4	72.2	70	50.6	0	50.6	0	50.6
108.3	0	108.3	70	75.8	0	75.8	0	75.8
90	0	90	70	63	0	63	0	63
83.4	0	83.4	70	58.4	0	58.4	0	58.4
77.2	0	77.2	70	54	0	54	0	54
70.4	0	70.4	70	49.3	0	49.3	0	49.3
66	0	66	70	46.2	0	46.2	0	46.2
59	0	59	70	41.3	0	41.3	0	41.3
63.7	0	63.7	70	44.6	0	44.6	0	44.6
60.1	0	60.1	70	42	0	42	0	42
61.9	0	61.9	70	43.3	0	43.3	0	43.3
61.7	0	61.7	70	43.2	0	43.2	0	43.2
0	0	0	70	0	0	0	77	-77
0	0	0	70	0	0	0	0	0
3787.5	643.5	3144		2200.8	246.7	2092.9	77	2015.9

Table 3: PRT Calculations (Continued) Explained

(R) Net Profit 2 = Net-Profit 1 after all losses are written off (as calculated in Table 2).

(S) The Oil Allowance starts to apply when Net Profit 2 becomes positive. For detailed computation of the allowance, see Table 4.

(T) Taxable Profit = (R) - (S)

(U) PRT rate that applies to the taxable profit (T)

(V) Mainstream PRT = (U) × (V)/100

At this stage the Safeguard applies. This is a form of tapering relief.

(W) Safeguard Limit. For detailed computations of the Safeguard, see Table 5

(X) Base PRT: During the period where the Safeguard applies (the period until the field has reached payback plus half of that number of periods), the mainstream PRT (V) is compared with the Safeguard limit (W). The field pays whichever is less.

(Y) PRT loss repayment represents the repayment of Abandonment costs.

(Z) PRT paid = (X) - (Y)

Table 4: Oil Allowance Calculation

Year	Period	Oil Product. Mmbbl	Oil Rev. £M	Allow. 1 period	Allow. Available Bbl	Total Available £	Allow. Utilized £	Allow. Utilized bbl	Cumulative Allow. Utilized bbl
		(AA)	(J)	(BB)	(CC)	(DD)	(EE)	(FF)	(GG)
2002	1	0	0	1.9	0	0	0	0	0
2002	2	0	0	1.9	0	0	0	0	0
2003	1	0	0	1.9	0	0	0	0	0
2003	2	0	0	1.9	0	0	0	0	0
2004	1	0	0	1.9	0	0	0	0	0
2004	2	0	0	1.9	0	0	0	0	0
2005	1	5.1	71.6	1.9	0	0	0	0	0
2005	2	11	153.4	1.9	0	0	0	0	0
2006	1	12.4	178.3	1.9	0	0	0	0	0
2006	2	13	186.2	1.9	0	0	0	0	0
2007	1	13	190.9	1.9	0	0	0	0	0
2007	2	12.6	185.5	1.9	0	0	0	0	0
2008	1	17.2	259.1	1.9	1.9	0	0	0	0
2008	2	16.4	248.1	1.9	1.9	28.3	28.3	1.9	1.9
2009	1	16.1	248.7	1.9	1.9	29	29	1.9	3.8
2009	2	13.5	209.1	1.9	1.9	29	29	1.9	5.6
2010	1	13.4	212.9	1.9	1.9	29.8	29.8	1.9	7.5
2010	2	13.4	212.4	1.9	1.9	29.8	29.8	1.9	9.4
2011	1	15.2	247	1.9	1.9	30.5	30.5	1.9	11.3
2011	2	13.2	214.3	1.9	1.9	30.5	30.5	1.9	13.1
2012	1	13.9	232.4	1.9	1.9	31.3	31.3	1.9	15
2012	2	14.6	243.7	1.9	1.9	31.3	31.3	1.9	16.9
2013	1	13.5	231.1	1.9	1.9	32.1	32.1	1.9	18.8
2013	2	13.5	231.1	1.9	1.9	32.1	32.1	1.9	20.6
2014	1	15.7	275.4	1.9	1.9	32.9	32.9	1.9	22.5
2014	2	15.7	275.4	1.9	1.9	32.9	32.9	1.9	24.4
2015	1	13.5	243	1.9	1.9	33.7	33.7	1.9	26.3
2015	2	13.5	243	1.9	1.9	33.7	33.7	1.9	28.1
2016	1	11	202	1.9	1.9	34.6	34.6	1.9	30
2016	2	11	202	1.9	1.9	34.6	34.6	1.9	31.9
2017	1	8.8	165.7	1.9	1.9	35.5	35.5	1.9	33.8
2017	2	8.8	165.7	1.9	1.9	35.5	35.5	1.9	35.6
2018	1	7.7	148.7	1.9	1.9	36.4	36.4	1.9	37.5
2018	2	7.7	148.7	0	0	0	0	0	0
2019	1	6.4	127	0	0	0	0	0	0
2019	2	6	119.8	0	0	0	0	0	0
2020	1	5.5	111.6	0	0	0	0	0	0
2020	2	5.1	104.2	0	0	0	0	0	0
2021	1	4.7	99.2	0	0	0	0	0	0
2021	2	4.4	91.6	0	0	0	0	0	0
2022	1	4.4	93.9	0	0	0	0	0	0
2022	2	4.2	90	0	0	0	0	0	0
2023	1	4	88.2	0	0	0	0	0	0
2023	2	4	88.2	0	0	0	0	0	0
2024	1	0	0	0	0	0	0	0	0
2024	2	0	0	0	0	0	0	0	0
Totals		402.7	6839.2					37.5	

Table 4: Oil Allowance Calculation Explained

(AA) Oil production in Million Barrel per 6-month period. It is equal to daily production (A) × (365/2)/1000

(J) Similar to revenues as determined in Table 2

(BB) Oil Allowance per period is limited to a maximum of 250,000 tonne.
As 1tonne = 7.5 bbl (WoodMackenzie, 2000), the Oil Allowance per period is 250×7.5/1000 = 1.9.

(CC) The available Oil Allowance per period depends on the oil production per period (AA):
- If (BB) > (AA), the Oil Allowance available is equal to (AA)
- If (BB) < (AA), the Oil Allowance available is equal to (BB)

(DD) Oil Allowance per period expressed in £.

(EE) Oil Allowance utilised in £. The Oil Allowance per period (DD) is compared with Net Profit 2 (R):
- If (DD) < (R), then the Oil Allowance utilised in £ is equal to (DD)
- If (DD) > (R), then the Oil Allowance utilised in £ is equal to (R).

(FF) The Oil Allowance utilised is expressed in Barrel.

(GG) The cumulative Oil Allowance utilised. When it reaches 37.5 (=7.5bbl×5Mt, where 5 Mt is the maximum cumulative Oil Allowance available for an oil field), the Oil Allowance relief stops applying.

Table 5: Safeguard Calculation

Year	Period	Adjusted Profit £M	Payback £M	Safeguard Base £M	Safeguard Period	Safeguard Limit £M
		(HH)	(II)	(JJ)	(KK)	(W)
2002	1	0	-33.8	25	0	0
2002	2	0	-148.5	110	0	0
2003	1	0	-317.3	235	0	0
2003	2	0	-465.8	345	0	0
2004	1	0	-621	460	0	0
2004	2	0	-762.8	565	0	0
2005	1	46	-764	600	0	0
2005	2	122.5	-661.7	615	0	0
2006	1	136.7	-545.3	630	0	0
2006	2	143.4	-415.5	640	0	0
2007	1	146.1	-306.5	667.5	0	0
2007	2	140.7	-206.9	698	0	0
2008	1	203	-48.5	731	0	0
2008	2	194.4	91.9	771	0	63
2009	1	198.6	218	771	1	66.3
2009	2	166	335.4	771	2	40.3
2010	1	167.1	481.6	771	3	41.2
2010	2	160.6	626.2	771	4	36
2011	1	190.8	811	771	0	0
2011	2	160.7	966.8	771	0	0

(HH) The Adjusted Profit = Revenues (J) - Royalty (K) - OPEX (L)

(II) The payback period, K, can be found as the minimum value of K for which the following relationship is satisfied:

$$\sum_{t=1}^{K}(R_t - ROY_t - OE_t) > \sum_{t=1}^{K} CE_t(1+up_t)$$

As such, 2008 is the year during which the field reaches payback. From the start of production, payback is reached after 8 periods (4 years) therefore the Safeguard will apply for 4 additional periods (2 years), until 2010.

(JJ) Safeguard base is the cumulative Capital Expenditures (M)

(KK) Safeguard period is the period during which the Safeguard applies. It is equal to the Payback period (from the startg of production) plus half of that period.

(W) Safeguard limit = 80%× [(HH)-15%× (JJ)] (see Table 3). The Safeguard limit is then compared to the mainstream PRT as calculate in Table 2 (V):

- If (HH) < 15% of (JJ), no PRT is paid.
- If (HH) > 15% of (JJ), mainstream PRT is compared to the Safeguard limit (W) and the company pays whichever is the smaller amount.

Table 6: Corporation Tax Calculation

Rev £M	Roy. £M	Total OPEX £M	Capital Allow. £M	PRT Paid £M	Pre-Tax Income £M	Cum. Losses £M	Loss c/f Set-Off £M	Taxabl Income £M	CT Rate %	CT £M	CT Loss Repay £M	CT Paid £M
(J)	(K)	(L)	(LL)	(Z)	(MM)	(NN)	(OO)	(PP)	(QQ)	(RR)	(SS)	(TT)
0	0	0	25	0	-25	-25	0	0	52	0	0	0
0	0	0	85	0	-85	-110	0	0	52	0	0	0
0	0	0	125	0	-125	-235	0	0	52	0	0	0
0	0	0	110	0	-110	-345	0	0	52	0	0	0
0	0	0	115	0	-115	-460	0	0	52	0	0	0
0	0	0	105	0	-105	-565	0	0	52	0	0	0
71.6	0	25.6	35	0	11	-554	11	0	52	0	0	0
153.4	2.5	28.5	15	0	107.5	-446.5	107.5	0	52	0	0	0
178.3	12.4	29.2	15	0	121.7	-324.8	121.7	0	52	0	0	0
186.2	13.3	29.5	10	0	133.4	-191.5	133.4	0	52	0	0	0
190.9	15.3	29.5	27.5	0	118.6	-72.8	118.6	0	52	0	0	0
185.5	15.5	29.3	30.5	0	110.2	0	72.8	37.4	52	19.4	0	19.4
259.1	22.5	33.6	33	0	170	0	0	170	52	88.4	0	88.4
248.1	20.5	33.2	40	44.5	109.9	0	0	109.9	52	57.1	0	57.1
248.7	15.9	34.2	72.5	66.3	59.7	0	0	59.7	52	31.1	0	31.1
209.1	9	34.2	48.5	40.3	77.2	0	0	77.2	52	40.2	0	40.2
212.9	11.1	34.7	21	41.2	104.9	0	0	104.9	52	54.6	0	54.6
212.4	17.1	34.7	16	36	108.6	0	0	108.6	52	56.5	0	56.5
247	23.4	32.8	6	108	76.8	0	0	76.8	52	39.9	0	39.9
214.3	20.8	32.8	5	87.6	68.1	0	0	68.1	52	35.4	0	35.4
232.4	22.3	31.9	32.5	80.1	65.6	0	0	65.6	52	34.1	0	34.1
243.7	23	31.9	37.5	84	67.3	0	0	67.3	52	35	0	35
231.1	23.4	31.9	27.8	81.2	66.9	0	0	66.9	52	34.8	0	34.8
231.1	23.4	32.3	23.1	84.2	68.2	0	0	68.2	52	35.5	0	35.5
275.4	28.4	36	5.2	121.1	84.8	0	0	84.8	52	44.1	0	44.1
275.4	28.4	36.4	5.3	120.7	84.6	0	0	84.6	52	44	0	44
243	24.9	34.2	2.7	103.3	78	0	0	78	52	40.6	0	40.6
243	25	34.6	2.7	102.8	77.8	0	0	77.8	52	40.5	0	40.5
202	20.4	31.3	0	80.9	69.3	0	0	69.3	52	36	0	36
202	20.5	31.7	0	80.6	69.1	0	0	69.1	52	36	0	36
165.7	16.8	28.5	0	59.4	60.9	0	0	60.9	52	31.7	0	31.7
165.7	17.1	28.9	0	59	60.8	0	0	60.8	52	31.6	0	31.6
148.7	15.5	24.5	0	50.6	58	0	0	58	52	30.2	0	30.2
148.7	15.5	24.8	0	75.8	32.5	0	0	32.5	52	16.9	0	16.9
127	12.9	24.1	0	63	27	0	0	27	52	14	0	14
119.8	12	24.4	0	58.4	25	0	0	25	52	13	0	13
111.6	11.2	23.3	0	54	23.2	0	0	23.2	52	12	0	12
104.2	10.3	23.6	0	49.3	21.1	0	0	21.1	52	11	0	11
99.2	9.7	23.5	0	46.2	19.8	0	0	19.8	52	10.3	0	10.3
91.6	8.7	23.8	0	41.3	17.7	0	0	17.7	52	9.2	0	9.2
93.9	9.4	20.8	0	44.6	19.1	0	0	19.1	52	9.9	0	9.9
90	8.8	21.1	0	42	18	0	0	18	52	9.4	0	9.4
88.2	9.1	17.3	0	43.3	18.6	0	0	18.6	52	9.6	0	9.6
88.2	9	17.5	0	43.2	18.5	0	0	18.5	52	9.6	0	9.6
0	0	0	110	-77	-33	0	0	-33	52	0	17.2	-17.2
0	0	0	0	0	0	0	0	0	52	0	0	0
6839.2	605	1100.1	1186.7	2015.9	1931.5		565	1931.5		1021.5	[illegible]	1004.4

Table 6: Corporation Tax Calculation Explained

(LL) Capital Allowances providing 100% deduction of CAPEX (M)

(MM) Pre-tax Income = J - K- L- AL- Z

(NN) Cumulative Losses = Losses in period t + losses from period $t-1$

(OO) Losses carried-forward: when the pre-tax income (MM) becomes positive, Cumulative losses (NN) start to be written off. Any loss, which is not written off, is carried forward to the following period, until all losses are written off (in this case, in year 2007).

(PP) Taxable Income = pre-tax income (MM) after all losses are written off.

(QQ) CT rate

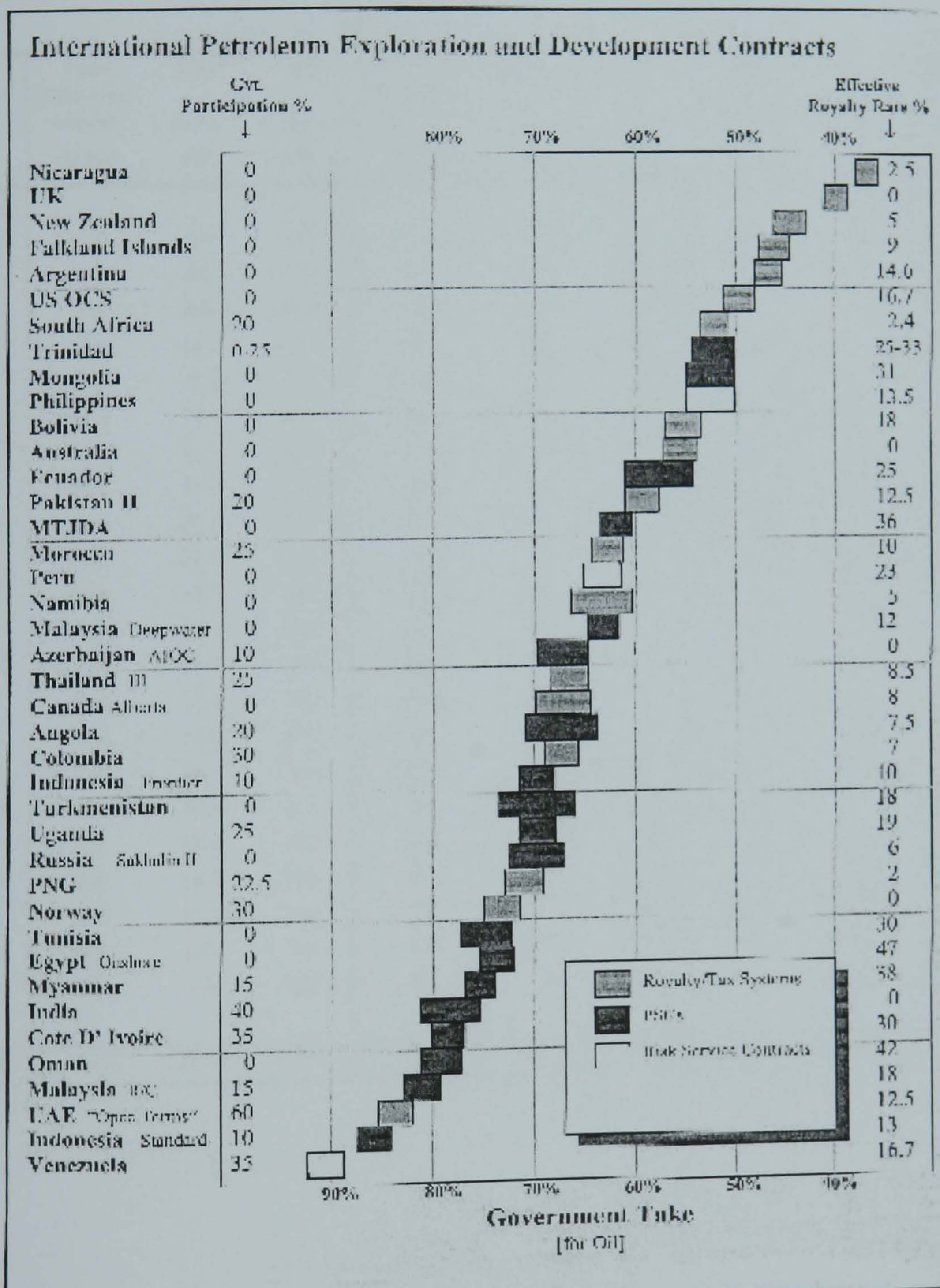
(RR) CT income = (QQ) × (PP)

(SS) Loss repayment represents the relief for Abandonment costs

(TT) CT paid = (RR) - (SS)

APPENDIX D

INTERNATIONAL PETROLEUM FISCAL REGIMES[1]



Source Johnston (2001)

APPENDIX E
FIELDS DATA

Very Small Fields Argyll				Arkwright			Birch		
Year	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M
2002	0.0	0.0	6.2	0.0	0.0	15.0	0.7	1.8	15.0
2003	0.0	0.0	17.0	1.0	1.0	40.0	0.7	1.8	0.0
2004	10.0	6.8	12.2	10.0	9.8	0.0	0.0	0.0	0.0
2005	22.5	14.2	2.9	7.0	10.9	0.0	0.0	0.0	0.0
2006	17.0	15.8	5.7	4.5	5.8	0.0	0.0	0.0	0.0
2007	14.0	14.4	5.3	4.8	4.8	0.0	0.0	0.0	3.0
2008	17.0	14.5	11.8	4.0	4.6	0.0	0.0	0.0	45.0
2009	16.0	15.0	12.9	4.0	4.7	3.0	7.0	8.3	55.0
2010	10.0	22.6	5.0	6.0	6.6	0.0	25.0	30.6	17.0
2011	16.0	22.3	14.0	5.0	6.4	0.0	18.5	23.9	0.0
2012	15.0	32.7	14.2	4.5	7.1	0.0	12.0	15.8	0.0
2013	8.5	16.5	7.5	4.0	7.6	0.0	5.3	9.0	0.0
2014	10.5	17.8	0.0	4.0	7.7	0.0	2.4	4.3	0.0
2015	10.0	16.0	0.0	4.0	7.9	0.0	3.4	4.4	0.0
2016	9.0	14.0	0.0	3.5	7.8	0.0	4.0	5.1	0.0
2017	7.0	12.5	0.0	3.0	7.7	0.0	3.5	4.6	0.0
2018	6.0	14.8	0.0	2.5	6.9	0.0	2.5	3.6	0.0
2019	4.7	11.0	0.0	2.0	6.7	0.0	2.0	3.1	0.0
2020	4.0	11.0	0.0	1.5	6.6	0.0	1.5	2.6	0.0
2021	4.0	11.0	2.0	1.5	6.7	0.0	0.5	1.5	0.0
2022	0.0	0.0	7.0	0.0	0.0	3.0	0.0	0.0	10.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals	201.2	282.9	123.7	76.8	127.1	61.0	89.0	120.3	145.0

FIELDS DATA (Continued)

Very Small Fields Blake				Kappa			Janice		
Year	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M
2002	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	85.0
2003	0.0	0.0	72.0	0.0	0.0	64.0	0.0	0.0	157.5
2004	18.2	10.9	78.0	11.5	10.0	12.0	41.1	25.2	33.0
2005	34.0	21.0	0.0	15.0	13.6	0.0	27.2	25.2	5.0
2006	26.0	16.9	0.0	15.0	13.9	0.0	24.3	21.5	3.0
2007	20.0	13.8	0.0	12.0	12.1	0.0	24.0	21.8	28.0
2008	16.0	11.7	0.0	12.0	12.4	0.0	22.5	20.0	0.0
2009	13.0	10.1	0.0	10.0	12.0	0.0	16.3	18.8	14.0
2010	11.0	19.1	0.0	9.0	10.7	0.0	13.2	16.3	0.0
2011	10.0	20.8	0.0	8.0	10.6	0.0	8.2	13.9	0.0
2012	9.0	21.6	0.0	7.0	10.5	0.0	5.1	13.3	0.0
2013	8.0	22.6	0.0	6.0	10.4	0.0	4.1	13.4	0.0
2014	7.0	25.2	0.0	4.0	8.5	0.0	3.1	12.8	0.0
2015	5.0	26.6	0.0	0.0	0.0	5.0	3.1	12.9	0.0
2016	0.0	0.0	15.0	0.0	0.0	0.0	0.0	0.0	30.0
2017	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals:	177.2	220.1	165.0	178.1	124.7	81.0	192.1	215.0	355.5

FIELDS DATA (Continued)

Very Small Fields Tiffani				Thelma			Toni		
Year	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M
2002	0.0	0.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0
2003	0.0	0.0	275.0	0.0	0.0	70.0	0.0	0.0	30.0
2004	0.0	0.0	270.0	3.5	2.8	60.0	0.0	0.0	70.0
2005	4.5	14.9	120.0	24.5	12.4	5.0	0.0	2.5	45.0
2006	38.5	40.6	30.0	24.3	12.3	18.0	9.0	8.3	0.0
2007	42.0	41.8	20.0	20.5	10.8	0.0	31.0	16.3	5.0
2008	37.5	40.2	10.0	17.1	9.5	0.0	23.5	13.6	0.0
2009	31.5	35.0	0.0	15.1	8.3	10.0	14.5	10.3	0.0
2010	21.5	24.2	0.0	15.0	8.4	10.0	18.0	10.2	0.0
2011	9.5	19.8	0.0	12.0	7.4	0.0	14.8	9.0	0.0
2012	8.1	19.4	0.0	8.0	5.4	0.0	10.2	7.3	0.0
2013	6.7	18.0	0.0	6.0	4.4	0.0	8.1	6.0	0.0
2014	8.0	18.8	0.0	3.0	3.2	0.0	6.0	5.3	0.0
2015	6.0	18.5	0.0	0.0	0.0	12.0	5.0	5.0	0.0
2016	5.0	12.1	0.0	0.0	0.0	0.0	4.5	5.0	0.0
2017	4.0	12.0	0.0	0.0	0.0	0.0	3.5	4.7	0.0
2018	3.0	11.9	0.0	0.0	0.0	0.0	2.5	4.1	0.0
2019	2.0	9.6	0.0	0.0	0.0	0.0	2.0	2.9	0.0
2020	1.5	7.6	0.0	0.0	0.0	0.0	2.0	3.0	0.0
2021	0.0	0.0	121.1	0.0	0.0	0.0	0.0	0.0	12.0
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals:	229.3	344.4	896.1	148.9	85.0	185.0	154.6	113.4	162.0

FIELDS DATA (Continued)

Very Small Fields	Highlander			Small Fields Arbroath			Beatrice		
Year	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M
2002	0.0	7.5	39.0	0.0	0.0	0.0	0.0	0.0	14.1
2003	20.0	15.0	46.0	0.0	0.0	55.0	0.0	0.0	21.0
2004	28.0	18.0	1.0	0.0	0.0	70.0	0.0	0.0	98.6
2005	28.0	18.0	6.0	25.0	39.1	60.0	0.0	0.0	169.9
2006	13.0	13.5	10.0	34.0	43.7	15.0	7.0	6.9	135.4
2007	22.0	22.6	8.0	35.5	40.2	0.0	33.0	39.9	76.1
2008	18.0	21.7	15.0	33.5	39.2	0.0	30.0	46.0	82.0
2009	14.0	20.3	0.0	32.0	38.5	0.0	46.0	52.6	47.6
2010	11.5	22.4	0.0	35.5	40.2	5.0	53.5	56.0	9.6
2011	8.5	21.1	10.0	31.5	38.2	10.0	42.0	53.6	9.8
2012	8.5	15.1	8.0	24.0	34.5	0.0	34.0	50.4	10.0
2013	5.9	14.0	2.0	24.5	49.3	0.0	30.5	40.0	3.2
2014	5.5	11.7	0.0	26.7	27.7	0.0	26.0	40.0	2.3
2015	2.5	10.2	0.0	21.3	30.2	5.0	25.0	35.0	0.0
2016	4.0	9.9	0.0	17.4	53.1	5.0	21.0	40.0	0.0
2017	2.1	8.2	0.0	20.0	43.1	7.0	15.5	40.0	0.0
2018	3.2	6.1	1.0	20.0	21.7	10.0	12.5	40.0	0.0
2019	3.9	3.6	2.0	19.0	20.4	1.0	11.5	35.0	0.0
2020	4.0	3.7	2.0	17.0	21.2	1.0	9.5	30.0	0.0
2021	3.5	3.7	2.0	14.0	21.9	1.0	9.0	30.0	0.0
2022	3.0	4.2	2.0	11.0	20.1	1.0	9.5	28.0	6.0
2023	2.5	3.6	1.0	9.0	18.7	1.0	8.0	21.5	5.0
2024	2.5	3.7	1.0	8.0	17.9	1.0	4.2	20.0	0.0
2025	2.5	3.4	1.0	7.0	17.2	1.0	3.0	20.0	0.0
2026	2.5	3.1	0.5	6.0	16.4	0.0	4.0	16.7	32.0
2027	2.0	3.0	0.5	6.0	16.7	0.0	9.5	17.0	0.0
2028	2.0	3.1	0.5	5.0	16.4	0.0	5.0	15.6	0.0
2029	0.0	0.0	15.0	5.0	16.8	0.0	3.5	14.6	0.0
2030	0.0	0.0	5.0	0.0	0.0	40.0	3.0	13.8	0.0
2031	0.0	0.0	5.0	0.0	0.0	0.0	0.0	0.0	75.0
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals:	223.1	290.4	183.5	487.9	742.4	289.0	166.3	802.6	797.6

FIELDS DATA (Continued)

Small Fields									
	Auk			Heather			Montrose		
Year	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M
2002	0.0	0.0	4.0	0.0	0.0	18.1	0.0	0.0	12.7
2003	0.0	0.0	8.3	0.0	0.0	55.5	0.0	0.0	45.6
2004	0.0	0.0	12.7	0.0	0.0	80.6	2.0	4.9	26.2
2005	0.0	0.0	22.8	3.0	4.0	64.9	17.0	28.6	10.8
2006	25.0	15.8	11.2	17.0	16.8	40.3	25.0	32.6	10.6
2007	48.0	17.5	11.6	14.0	17.2	21.9	28.0	34.3	9.4
2008	27.0	17.1	15.7	25.0	22.4	22.3	25.0	32.9	0.0
2009	17.0	16.9	4.8	33.5	25.8	29.0	23.0	34.3	2.7
2010	13.0	16.8	8.6	27.0	29.6	27.3	18.0	35.2	8.7
2011	13.0	20.0	9.4	24.5	33.8	20.1	15.0	38.2	3.4
2012	12.5	22.8	5.4	23.0	35.9	15.0	16.0	45.2	36.1
2013	12.0	26.3	0.0	20.0	33.1	4.0	13.5	31.7	0.0
2014	12.0	30.0	0.0	18.5	25.0	1.0	13.0	29.5	0.0
2015	9.0	32.0	0.0	15.0	20.0	5.0	11.0	28.8	0.0
2016	10.0	29.6	40.0	12.0	20.2	5.0	10.0	25.2	4.0
2017	10.0	17.0	20.0	11.0	22.0	11.0	4.0	21.5	2.0
2018	9.5	14.0	0.0	10.0	23.0	4.0	1.5	3.9	2.0
2019	6.0	14.0	0.0	9.0	26.0	0.0	1.5	3.9	0.8
2020	9.0	12.0	0.0	8.5	26.0	0.0	2.5	4.9	0.8
2021	9.0	12.0	0.0	7.5	25.0	0.0	2.0	14.5	0.0
2022	7.5	14.0	3.0	6.5	23.0	0.0	3.5	5.2	5.0
2023	8.5	14.0	26.0	7.0	23.0	0.0	2.5	4.7	0.0
2024	11.5	14.0	6.0	6.0	23.0	0.0	2.0	4.5	0.0
2025	12.5	14.0	10.0	5.0	22.8	0.0	1.3	3.8	8.0
2026	9.5	14.0	10.0	5.0	21.6	0.0	1.4	3.8	8.0
2027	13.5	18.4	10.0	4.7	20.7	17.0	1.3	4.0	0.3
2028	16.0	19.8	1.0	6.0	21.0	4.0	0.9	1.8	0.1
2029	12.8	18.0	0.0	6.1	21.5	8.1	1.1	1.7	0.1
2030	11.3	17.2	0.0	6.6	18.7	12.5	3.0	3.4	13.1
2031	9.5	14.2	7.0	7.7	19.4	10.7	4.0	2.5	13.0
2032	11.0	15.3	14.3	7.7	16.6	0.0	6.0	4.3	0.3
2033	16.0	18.5	26.1	6.4	16.3	0.0	5.0	4.1	0.3
2034	19.0	20.8	10.6	5.4	12.5	0.0	4.0	5.1	0.3
2035	18.0	20.7	0.0	4.6	12.5	0.0	3.5	4.9	0.3
2036	17.0	20.6	0.0	3.9	9.0	0.0	3.0	4.8	0.3
2037	9.0	16.1	0.0	3.3	6.5	0.0	3.0	4.9	0.3
2038	8.0	14.6	0.0	0.0	0.0	42.7	2.5	4.5	0.3
2039	7.0	13.1	0.0	0.0	0.0	0.0	2.0	4.3	0.0
2040	6.0	12.8	0.0	0.0	0.0	0.0	2.0	4.4	0.0
2041	0.0	0.0	30.0	0.0	0.0	0.0	2.0	4.5	0.0
2042	0.0	0.0	0.0	0.0	0.0	0.0	2.0	4.7	0.0
2043	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	58.6
2044	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals	465.6	623.8	328.5	370.4	693.9	520.1	283.9	536.1	284.0

FIELDS DATA (Continued)

Small Fields									
	Balmoral			Leadon			Osprey		
Year	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M
2002	0.0	0.0	135.1	0.0	0.0	420.0	0.0	0.0	5.0
2003	0.0	0.0	150.3	30.0	17.8	4.1	0.0	0.0	70.0
2004	1.0	9.1	120.0	50.0	22.0	0.0	0.0	0.0	85.0
2005	35.0	38.7	20.0	50.0	22.6	0.0	18.5	13.8	35.0
2006	35.0	38.7	0.0	50.0	23.1	0.0	27.5	26.0	25.0
2007	35.0	38.7	0.0	45.0	22.7	0.0	33.5	28.2	20.0
2008	36.5	39.6	0.0	37.0	21.6	0.0	25.0	25.1	20.0
2009	27.5	37.1	8.0	29.0	20.4	0.0	28.5	26.4	10.0
2010	28.0	36.9	4.0	22.0	19.4	0.0	26.5	25.7	20.0
2011	21.5	30.5	8.0	19.0	19.2	0.0	24.0	20.8	20.0
2012	17.0	28.2	1.0	16.0	19.0	0.0	15.5	17.7	0.0
2013	13.5	19.9	0.5	14.0	19.0	0.0	10.6	15.9	0.0
2014	8.5	16.8	0.5	12.0	19.0	0.0	6.6	11.3	10.0
2015	10.0	15.6	0.0	10.0	18.9	0.0	9.8	11.5	0.0
2016	8.5	13.8	0.0	7.0	18.6	0.0	9.0	8.9	0.0
2017	7.7	12.4	0.0	6.0	18.8	0.0	8.0	8.6	10.4
2018	5.9	7.9	0.0	0.0	0.0	20.2	7.0	7.6	0.0
2019	5.6	7.7	0.0	0.0	0.0	0.0	6.0	6.8	0.0
2020	3.0	6.3	0.0	0.0	0.0	0.0	5.0	6.4	0.0
2021	2.0	6.0	0.0	0.0	0.0	0.0	5.0	6.5	0.0
2022	1.5	5.9	0.0	0.0	0.0	0.0	4.0	6.1	0.0
2023	1.0	4.6	0.0	0.0	0.0	0.0	4.0	6.1	0.0
2024	1.0	4.3	0.0	0.0	0.0	0.0	3.5	5.8	0.0
2025	1.0	4.4	0.0	0.0	0.0	0.0	0.0	0.0	18.0
2026	0.0	0.0	19.5	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals	305.8	423.2	466.9	397.0	302.2	444.3	277.4	285.1	348.4

FIELDS DATA (Continued)

Small Fields				Medium Fields					
	Scapa			Captain			Clair		
Year	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M
2002	3.0	2.1	15.0	1.5	10.0	0.0	1.5	5.3	0.0
2003	8.0	16.6	85.0	0.0	0.0	0.0	0.0	0.0	0.0
2004	21.0	27.6	20.0	0.0	0.0	210.0	0.0	0.0	0.0
2005	13.0	21.5	10.0	0.0	0.0	190.0	0.0	0.0	0.0
2006	11.0	14.6	5.0	23.5	47.3	10.0	0.0	0.0	0.0
2007	25.0	24.3	10.0	51.0	67.3	20.0	0.0	0.0	15.0
2008	26.0	26.0	10.0	45.8	66.4	95.0	0.0	0.0	81.6
2009	28.0	29.4	0.0	44.7	88.2	85.0	0.0	0.0	177.6
2010	27.5	29.1	25.0	66.1	96.1	100.0	2.5	6.8	168.9
2011	23.5	26.3	5.0	85.0	101.4	65.0	30.0	28.6	39.5
2012	17.0	21.8	5.0	85.0	99.7	20.0	50.0	31.6	40.5
2013	19.0	20.2	7.5	80.0	97.0	0.0	60.0	34.0	41.5
2014	18.5	19.8	7.5	60.0	88.8	0.0	67.0	37.2	21.3
2015	15.7	16.9	0.0	45.0	81.2	0.0	63.0	39.1	0.0
2016	13.1	12.5	0.0	33.0	68.0	0.0	57.0	39.6	0.0
2017	9.4	9.5	0.0	30.0	59.6	100.0	53.0	40.6	0.0
2018	8.2	8.4	1.5	28.0	46.1	0.0	44.0	40.6	0.0
2019	9.0	8.9	0.0	24.0	43.9	0.0	34.0	40.5	0.0
2020	8.0	12.3	0.0	20.0	40.3	0.0	31.0	40.4	0.0
2021	6.0	7.1	0.0	18.0	38.2	0.0	28.0	40.9	0.0
2022	5.0	6.5	0.0	16.0	36.0	0.0	26.0	40.7	0.0
2023	3.5	9.5	0.0	14.0	30.2	0.0	24.0	40.6	0.0
2024	3.0	5.0	0.0	13.0	27.9	0.0	22.0	40.4	0.0
2025	2.5	4.4	0.0	12.0	25.5	0.0	21.0	39.5	0.0
2026	2.3	8.9	0.0	10.0	22.6	0.0	19.0	38.3	0.0
2027	2.0	3.9	0.0	9.0	22.1	0.0	17.0	37.3	0.0
2028	1.8	3.8	0.0	8.0	22.4	0.0	14.0	35.9	0.0
2029	1.7	8.5	0.0	7.0	22.7	0.0	12.0	36.4	0.0
2030	1.6	3.5	0.0	6.0	23.0	0.0	9.0	36.7	0.0
2031	1.4	3.2	0.0	5.0	23.2	0.0	0.0	0.0	80.0
2032	1.3	3.1	0.0	4.0	23.5	0.0	0.0	0.0	0.0
2033	1.2	2.8	0.0	3.0	11.5	0.0	0.0	0.0	0.0
2034	1.2	2.9	0.0	2.0	10.5	0.0	0.0	0.0	0.0
2035	1.1	2.6	0.0	0.0	0.0	120.0	0.0	0.0	0.0
2036	1.1	2.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2037	1.0	2.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2038	0.0	0.0	24.4	0.0	0.0	0.0	0.0	0.0	0.0
2039	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals	341.6	428.9	230.9	849.6	1440.6	1015.0	685.0	770.9	665.9

FIELDS DATA (Continued)

Medium Fields						
	Maureen			Tern		
Year	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M
2002	0.0	0.0	42.2	0.0	0.0	31.0
2003	0.0	0.0	124.7	0.0	0.0	125.0
2004	0.0	0.0	173.8	0.0	0.0	130.0
2005	0.0	0.0	188.7	0.0	0.0	80.0
2006	16.0	28.0	164.7	17.5	25.6	52.0
2007	75.0	60.0	51.1	34.0	44.0	15.0
2008	78.0	64.1	14.4	53.0	50.0	12.0
2009	75.0	59.0	0.0	73.5	50.0	6.0
2010	70.5	42.0	0.0	69.0	50.0	20.0
2011	61.0	35.0	0.0	64.5	50.0	41.0
2012	52.5	35.0	0.0	68.0	50.0	30.0
2013	46.0	30.0	0.0	57.0	48.0	25.0
2014	36.5	30.0	5.0	54.0	47.0	25.0
2015	25.0	25.0	12.5	46.9	43.3	25.0
2016	18.0	25.0	2.5	43.6	38.0	20.0
2017	15.5	23.0	0.0	37.0	35.6	35.0
2018	10.8	20.0	0.0	35.4	34.2	10.0
2019	9.0	18.5	0.0	30.0	31.9	15.3
2020	10.0	18.3	5.0	30.0	29.0	15.7
2021	9.5	18.0	5.0	30.0	26.5	16.1
2022	3.7	12.5	2.0	26.0	24.6	16.5
2023	0.0	0.0	3.0	23.0	22.2	0.0
2024	0.0	0.0	54.0	20.0	19.9	0.0
2025	0.0	0.0	0.0	15.0	18.0	0.0
2026	0.0	0.0	0.0	10.0	17.0	0.0
2027	0.0	0.0	0.0	6.5	16.1	0.0
2028	0.0	0.0	0.0	0.0	0.0	96.1
2029	0.0	0.0	0.0	0.0	0.0	0.0
Totals	611.9	543.4	848.6	843.9	771.0	841.5

FIELDS DATA (Continued)

Large Fields						
	Alba			Schiehallion		
Year	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M	Total Production Liquids 000b/d	Total Opex £M	Total Capex £M
2002	0.0	0.0	110.0	2.0	5.0	5.0
2003	0.0	0.0	235.0	0.0	0.0	140.0
2004	0.0	0.0	220.0	0.0	0.0	392.5
2005	44.0	54.0	50.0	18.0	16.8	172.5
2006	69.5	58.7	25.0	79.9	49.3	94.2
2007	70.0	58.8	58.0	106.0	51.2	49.2
2008	92.0	66.8	73.0	102.0	51.2	65.0
2009	81.0	68.4	121.0	108.0	53.4	20.0
2010	73.4	69.3	37.0	108.0	55.1	0.0
2011	77.6	65.7	11.0	108.0	55.5	0.0
2012	78.2	63.9	70.0	105.0	54.9	0.0
2013	74.0	64.1	50.9	100.0	55.7	0.0
2014	86.0	72.4	10.4	90.0	55.0	0.0
2015	74.0	68.8	5.4	80.0	52.0	0.0
2016	60.0	63.1	0.0	70.0	51.6	0.0
2017	48.0	57.4	0.0	55.0	47.7	0.0
2018	42.0	49.4	0.0	40.0	45.9	0.0
2019	34.0	48.5	0.0	30.0	44.0	0.0
2020	29.0	46.8	0.0	20.0	42.6	0.0
2021	25.0	47.3	0.0	17.0	41.0	0.0
2022	23.5	41.9	0.0	15.0	37.9	0.0
2023	22.0	34.9	0.0	12.0	35.4	0.0
2024	22.0	32.6	0.0	11.0	34.3	0.0
2025	20.0	30.4	0.0	10.0	35.2	0.0
2026	18.0	30.9	0.0	0.0	0.0	78.0
2027	16.0	31.7	0.0	0.0	0.0	0.0
2028	14.0	32.5	0.0	0.0	0.0	0.0
2029	12.0	33.3	0.0	0.0	0.0	0.0
2030	0.0	0.0	110.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0
Totals:	1205.2	1291.4	1186.7	1286.9	970.7	1016.4

APPENDIX F
OIL PRICE MODEL

GEOMETRIC BROWNIAN MOTION[1]

The GBM considers price changes in terms of two components: a constant drift, α, and a random deviation from the tendency written as the product of a volatility parameter, σ, and an error term, u_{t+1}:

$$\frac{(P_{t+1} - P_t)}{P_t} = \alpha + \sigma u_{t+1} \qquad \text{(F.1)}$$

Over a short interval of time, *dt*, the discrete time process is illustrated as:

$$\frac{(P_{t+1} - P_t)}{P_t} = \alpha dt + \sigma\sqrt{dt}u_{t+dt} \qquad \text{(F.2)}$$

When *dt* approaches zero, hence $dP_t = \lim(P_{t+dt} - P_t)$, the left hand side becomes an instantaneous percentage change in price: $\frac{dP_t}{P_t}$. The first term on the right side of the equation remains unchanged. As for the second term, the uncertain component, the series of discrete variables, u_t, are substituted with a term, *dz*, called the standard Brownian Motion, where $dz = \lim u_{t+1}\sqrt{dt}$, as *dt* approaches zero.

The continuous time equation illustrating the GBM process is:

$$\frac{dP_t}{P_t} = \alpha dt + \sigma dz \qquad \text{(F.3)}$$

---

[1] Source: Baker, Mayfield & Parsons (1998) and Emhejellen (1999).

Because the percentage changes in P are normally distributed, and since these changes are in the natural logarithm of x, the absolute changes in P are lognormally distributed.

If P(t) is given by equation (F.3) then F(t) = log P is given by:

$$dF = (\alpha - \frac{1}{2}\sigma^2)dt + \sigma dz \tag{F.4}$$

Over a finite time interval t, the change in the logarithm of P is normally distributed with mean $(\alpha - \frac{1}{2}\sigma^2)t$ and variance of $\sigma^2 t$. For P itself, if P(0) = P_0, the expected value of P(t) is:

$$\varepsilon[P(t)] = P_0 e^{\alpha t} \tag{F.5}$$

and the variance of P(t) is:

$$v[P(t)] = P_0^2 e^{2\alpha t}(e^{\sigma^2 t} - 1) \tag{F.6}$$

MEAN REVERSION MODEL

Brownian Motion tends to wander far from its starting point (Emhjellen, 1999). However, under Mean Reversion Model (MRM), price might fluctuate as a consequence of various events, but in the long run it might be drawn back towards an initial value.

The continuous time equation illustrating the MRM process is:

$$dP = \alpha(P' - P)dt + \sigma dz \tag{F.7}$$

where λ is the speed of reversion and P' is the normal level of P.

If the value of P is currently P_0 and P follows Equation (F.7), then the expected value of P(t) is:

$$\varepsilon[P_t] = P' + (P_0 - P')e^{-\lambda t} \tag{F.8}$$

and the variance of $(P_t - P')$ is:

$$v(P_t - P') = \frac{\sigma^2}{2\lambda}(1 - e^{-2\lambda t}) \tag{F.9}$$

As t becomes large, $\varepsilon(P_t)$ converges to P' and the variance converges to $\frac{\sigma^2}{2\lambda}$. Also, as λ tends to infinite, the variance tends to zero, and when λ tends to zero, P_t becomes a simple GBM.

In both GBM and Mean Reversion Model the distribution of futures prices is lognormal. However, under GBM, oil prices in the future have a lognormal distribution with variance growing proportionally to the time interval. Whereas under Mean Reversion model, the variance of the distributions grows in the beginning until a certain time t and remains constant after this.

APPENDIX G

DCF VERSUS MAP RESULTS: ALBA FIELD EXAMPLE

Table 1. Base Scenario (Pre-tax Scenario)

	Base Scenario			DCF			MAP			
Year	Revenues Liquids £M	Total OPEX £M	Total CAPEX £M	Pre-tax NCF £M	Real NCF £M	Discounted NCF £M	Revenues Liquids £M	Pre-tax NCF £M	Real NCF £M	Discounted NCF £M
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
2002	0.0	0.0	110.0	-110.0	-110.0	-110.0	0.0	-110.0	-110.0	-110.0
2003	0.0	0.0	235.0	-235.0	-229.2	-207.4	0.0	-235.0	-229.2	-224.7
2004	0.0	0.0	220.0	-220.0	-209.3	-171.3	0.0	-220.0	-209.3	-201.1
2005	224.8	54.0	50.0	120.8	112.1	83.0	189.3	85.3	79.1	74.5
2006	364.0	58.7	25.0	280.3	253.6	170.0	293.6	209.9	189.9	175.3
2007	375.8	58.8	58.0	259.0	228.6	138.6	291.9	175.2	154.6	139.9
2008	506.3	66.8	73.0	366.5	315.4	173.1	380.7	240.9	207.3	183.9
2009	456.9	68.4	121.0	267.4	224.5	111.5	333.9	144.5	121.3	105.4
2010	424.3	69.3	37.0	318.0	260.3	117.0	302.5	196.2	160.6	136.9
2011	460.1	65.7	11.0	383.4	306.2	124.5	321.1	244.4	195.2	163.0
2012	474.7	63.9	70.0	340.8	265.4	97.6	325.1	191.2	148.9	121.9
2013	460.7	64.1	50.9	345.7	262.6	87.4	310.4	195.4	148.4	119.1
2014	548.8	72.4	10.4	466.0	345.2	104.0	364.6	281.8	208.7	164.2
2015	484.0	68.8	5.4	409.8	296.1	80.7	317.6	243.4	175.9	135.6
2016	402.3	63.1	0.0	339.2	239.0	58.9	261.2	198.1	139.6	105.5
2017	329.9	57.4	0.0	272.5	187.3	41.8	212.2	154.8	106.4	78.8
2018	295.8	49.4	0.0	246.5	165.2	33.4	188.7	139.4	93.4	67.8
2019	245.5	48.5	0.0	197.0	128.8	23.5	155.5	107.0	70.0	49.8
2020	214.6	46.8	0.0	167.8	107.0	17.7	135.1	88.3	56.3	39.3
2021	189.6	47.3	0.0	142.4	88.5	13.2	118.8	71.5	44.4	30.4
2022	182.7	41.9	0.0	140.8	85.4	11.6	113.9	72.0	43.7	29.3
2023	175.3	34.9	0.0	140.5	83.1	10.2	108.8	74.0	43.8	28.7
2024	179.7	32.6	0.0	147.1	84.9	9.4	111.2	78.6	45.3	29.2
2025	167.5	30.4	0.0	137.0	77.1	7.7	103.3	72.9	41.0	25.9
2026	154.5	30.9	0.0	123.6	67.8	6.2	95.0	64.1	35.2	21.8
2027	140.8	31.7	0.0	109.1	58.4	4.8	86.4	54.7	29.3	17.8
2028	126.2	32.5	0.0	93.8	49.0	3.6	77.3	44.8	23.4	13.9
2029	110.9	33.3	0.0	77.6	39.5	2.7	67.8	34.5	17.6	10.2
2030	0.0	0.0	110.0	-110.0	-54.6	-3.3	0.0	-110.0	-54.6	-31.2
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals:	7695.7	1291.4	1186.7	5217.6	3728.0	1040.1	5265.9	2787.7	1976.2	1501.3

TABLE 1. BASE SCENARIO EXPLAINED

(A) Oil Revenue as given in Appendix E, Table 1
(B) OPEX as given in Appendix E, Table 1
(C) CAPEX as given in Appendix E, Table 1

NPV DCF Calculation

(D) Pre-tax Net Cash Flow = Revenues - OPEX - CAPEX
(D) = (A) - (B) - (C))

(E) Real pre-tax NCF = Pre-tax NCF (D) / Inflation Factor

(F) Discounted Real NCF is equal to Real NCF multiplied by the discount factor

$$(F) = (E) * e^{-rt},$$

where r is the discount rate assumed to be 10% in real terms and, t is the period, with year 2002 considered as period 0.

The total of column (F) gives the NPV using DCF technique.

NPV MAP Calculation

(G) Revenues adjusted for oil price risk. They are equal to revenues multiplied by the Risk Discount Factor (RDF), as given in Table 2, Column L.
(G) = (A) * RDF

(H) Pre-tax NCF is Revenues adjusted for risk less OPEX and CAPEX
(H) = (G) - (B) - (C)

(I) Real pre-tax NCF = Pre-tax NCF (H) / Inflation Factor

(J) Discounted Real NCF is equal to Real NCF discounted for time only, i.e. it is equal to Real NCF multiplied by the Time Discount Factor TDF, as calculated in Table 2, Column K.

The total of column (J) gives the NPV using MAP technique.

Table 2. DISCOUNT FACTORS COMPARISON

Risk adjustment factor of oil prices	$\phi = 0.3503$
Volatility factor of oil prices	$\sigma = 0.2$
Rate of mean reversion	$\lambda = 0.139$
Real risk free rate	$i' = 0.02$

Year	Period	TDF (Real) (K)	RDF (Mean Reversion) (L)	Total MAP Discounting (M)	DCF Discounting (N)
2002	0	1	1	1	1
2003	1	0.9801987	0.9366845	0.9181369	0.9048374
2004	2	0.9607894	0.8848569	0.8501611	0.8187308
2005	3	0.9417645	0.8420943	0.7930546	0.7408182
2006	4	0.9231163	0.8065664	0.7445546	0.67032
2007	5	0.9048374	0.7768711	0.702942	0.6065307
2008	6	0.8869204	0.7519204	0.6668936	0.5488116
2009	7	0.8693582	0.7308607	0.6353798	0.4965853
2010	8	0.8521438	0.7130145	0.6075909	0.449329
2011	9	0.8352702	0.6978393	0.5828844	0.4065697
2012	10	0.8187308	0.6848964	0.5607458	0.3678794
2013	11	0.8025188	0.6738287	0.5407602	0.3328711
2014	12	0.7866279	0.6643429	0.5225906	0.3011942
2015	13	0.7710516	0.6561968	0.5059616	0.2725318
2016	14	0.7557837	0.6491892	0.4906466	0.246597
2017	15	0.7408182	0.6431519	0.4764586	0.2231302
2018	16	0.726149	0.6379437	0.4632422	0.2018965
2019	17	0.7117703	0.6334458	0.4508679	0.1826835
2020	18	0.6976763	0.6295574	0.4392273	0.1652989
2021	19	0.6838614	0.626193	0.4282293	0.1495686
2022	20	0.67032	0.6232799	0.417797	0.1353353
2023	21	0.6570468	0.6207558	0.4078656	0.1224564
2024	22	0.6440364	0.6185676	0.3983801	0.1108032
2025	23	0.6312836	0.6166697	0.3892935	0.1002588
2026	24	0.6187834	0.6150228	0.3805659	0.090718
2027	25	0.6065307	0.6135932	0.3721631	0.082085
2028	26	0.5945205	0.6123518	0.3640557	0.0742736
2029	27	0.5827483	0.6112736	0.3562186	0.0672055
2030	28	0.5712091	0.6103368	0.3486299	0.0608101
2031	29	0.5598984	0.6095228	0.3412708	0.0550232

(G) $TDF = e^{-i't}$

(H) $RDF = \exp(-\varphi\sigma(1 - \exp(-\lambda t))/\lambda)$

(I) Total MAP Discounting = TDF * RDF

(J) DCF Discounting = e^{-rt}

Table 3. DCF versus MAP: Scenarios 2

Year	DCF Total Gov take £M	DCF Post-Tax NCF £M	DCF Real NCF £M	DCF Discounted NCF £M	MAP Total Gov take £M	MAP Post-Tax NCF £M	MAP Real NCF £M	MAP Discounted NCF £M
2002	0.0	-110.0	-110.0	-110.0	0.0	-110.0	-110.0	-110.0
2003	0.0	-235.0	-229.2	-207.4	0.0	-235.0	-229.2	-224.7
2004	0.0	-220.0	-209.3	-171.3	0.0	-220.0	-209.3	-201.1
2005	2.5	118.3	109.7	81.3	2.1	83.2	77.2	72.7
2006	25.7	254.6	230.4	154.4	20.7	189.2	171.2	158.0
2007	50.2	208.8	184.3	111.8	23.9	151.3	133.5	120.8
2008	233.0	133.4	114.9	63.0	141.1	99.8	85.9	76.2
2009	202.9	64.5	54.2	26.9	88.0	56.5	47.4	41.2
2010	217.9	100.1	81.9	36.8	113.1	83.1	68.0	58.0
2011	315.1	68.3	54.6	22.2	142.3	102.1	81.5	68.1
2012	278.4	62.5	48.6	17.9	114.8	76.5	59.6	48.8
2013	282.2	63.4	48.2	16.0	138.4	57.0	43.3	34.8
2014	386.5	79.5	58.9	17.7	232.9	48.8	36.2	28.4
2015	336.8	73.0	52.8	14.4	199.2	44.3	32.0	24.7
2016	274.3	64.9	45.7	11.3	159.1	38.9	27.4	20.7
2017	215.4	57.0	39.2	8.7	121.0	33.7	23.2	17.2
2018	204.3	42.1	28.2	5.7	107.3	32.1	21.5	15.6
2019	173.2	23.8	15.6	2.8	94.5	12.5	8.2	5.8
2020	147.6	20.2	12.9	2.1	78.1	10.2	6.5	4.5
2021	125.4	17.0	10.6	1.6	63.4	8.1	5.0	3.4
2022	124.0	16.8	10.2	1.4	63.8	8.2	5.0	3.3
2023	123.7	16.8	9.9	1.2	65.5	8.5	5.0	3.3
2024	129.6	17.5	10.1	1.1	69.5	9.1	5.2	3.4
2025	120.7	16.3	9.2	0.9	64.5	8.4	4.7	3.0
2026	109.0	14.6	8.0	0.7	56.8	7.3	4.0	2.5
2027	96.2	12.8	6.9	0.6	48.6	6.1	3.3	2.0
2028	82.8	11.0	5.7	0.4	39.9	4.9	2.6	1.5
2029	68.6	9.0	4.6	0.3	30.9	3.6	1.9	1.1
2030	-94.2	-15.8	-7.9	-0.5	-94.2	-15.8	-7.9	-4.5
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals:	4232.0	985.6	698.9	112.2	2185.2	602.5	402.9	278.8

Table 4. DCF versus MAP: Scenarios 3

Year	DCF				MAP			
	Total Gov take £M	Post-Tax NCF £M	Real NCF £M	Discounted NCF £M	Total Gov take £M	Post-Tax NCF £M	Real NCF £M	Discounted NCF £M
2002	0.0	-110.0	-110.0	-110.0	0.0	-110.0	-110.0	-110.0
2003	0.0	-235.0	-229.2	-207.4	0.0	-235.0	-229.2	-224.7
2004	0.0	-220.0	-209.3	-171.3	0.0	-220.0	-209.3	-201.1
2005	0.0	120.8	112.1	83.0	0.0	85.3	79.1	74.5
2006	0.0	280.3	253.6	170.0	0.0	209.9	189.9	175.3
2007	31.8	227.2	200.5	121.6	0.0	175.2	154.6	139.9
2008	180.0	186.4	160.5	88.1	99.9	141.0	121.3	107.6
2009	179.8	87.7	73.6	36.5	59.2	85.3	71.6	62.2
2010	208.4	109.6	89.7	40.3	65.0	131.2	107.4	91.5
2011	289.6	93.8	74.9	30.5	84.0	160.4	128.1	107.0
2012	253.5	87.3	68.0	25.0	101.7	89.6	69.8	57.1
2013	256.8	88.9	67.5	22.5	141.8	53.6	40.7	32.7
2014	356.5	109.4	81.1	24.4	213.7	68.0	50.4	39.7
2015	308.9	100.9	72.9	19.9	181.5	62.0	44.8	34.5
2016	249.1	90.1	63.5	15.7	143.3	54.8	38.6	29.2
2017	192.5	80.0	55.0	12.3	106.7	48.0	33.0	24.5
2018	206.4	40.1	26.9	5.4	105.1	34.2	22.9	16.7
2019	165.1	31.9	20.9	3.8	89.8	17.3	11.3	8.0
2020	140.7	27.1	17.3	2.9	74.1	14.2	9.0	6.3
2021	119.4	22.9	14.3	2.1	60.1	11.4	7.1	4.8
2022	118.2	22.7	13.7	1.9	60.5	11.5	7.0	4.7
2023	117.9	22.6	13.4	1.6	62.2	11.8	7.0	4.6
2024	123.5	23.6	13.6	1.5	66.0	12.5	7.2	4.7
2025	115.1	22.0	12.4	1.2	61.3	11.6	6.5	4.1
2026	103.8	19.7	10.8	1.0	54.0	10.2	5.6	3.4
2027	91.7	17.4	9.3	0.8	46.1	8.6	4.6	2.8
2028	78.9	14.9	7.8	0.6	37.8	7.0	3.7	2.2
2029	65.4	12.2	6.2	0.4	29.2	5.3	2.7	1.6
2030	-91.6	-18.4	-9.1	-0.6	-91.6	-18.4	-9.1	-5.2
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals:	3861.4	1356.2	981.9	223.7	1851.4	936.3	666.3	498.6

Table 5. DCF versus MAP: Scenarios 4

Year	DCF				MAP			
	Total Gov take £M	Post-Tax NCF £M	Real NCF £M	Discounted NCF £M	Total Gov take £M	Post-Tax NCF £M	Real NCF £M	Discounted NCF £M
2002	0.0	-110.0	-110.0	-110.0	0.0	-110.0	-110.0	-110.0
2003	0.0	-235.0	-229.2	-207.4	0.0	-235.0	-229.2	-224.7
2004	0.0	-220.0	-209.3	-171.3	0.0	-220.0	-209.3	-201.1
2005	0.0	120.8	112.1	83.0	0.0	85.3	79.1	74.5
2006	0.0	280.3	253.6	170.0	0.0	209.9	189.9	175.3
2007	28.9	230.1	203.1	123.2	0.0	175.2	154.6	139.9
2008	163.2	203.3	175.0	96.0	93.6	147.3	126.8	112.4
2009	154.2	113.3	95.1	47.2	55.3	89.1	74.8	65.1
2010	180.3	137.6	112.7	50.6	59.1	137.1	112.3	95.7
2011	228.7	154.7	123.6	50.2	76.8	167.6	133.8	111.8
2012	200.6	140.2	109.2	40.2	84.3	107.0	83.3	68.2
2013	203.2	142.4	108.2	36.0	112.6	82.8	62.9	50.5
2014	281.2	184.8	136.9	41.2	168.7	113.0	83.7	65.9
2015	244.0	165.8	119.8	32.6	143.6	99.9	72.2	55.6
2016	197.4	141.8	99.9	24.6	113.8	84.3	59.4	44.9
2017	153.3	119.2	81.9	18.3	85.3	69.5	47.8	35.4
2018	161.2	85.3	57.2	11.5	83.1	56.3	37.7	27.4
2019	128.9	68.1	44.5	8.1	70.1	36.9	24.1	17.2
2020	109.8	58.0	37.0	6.1	57.9	30.4	19.4	13.5
2021	93.2	49.1	30.5	4.6	46.9	24.6	15.3	10.4
2022	92.3	48.6	29.5	4.0	47.3	24.7	15.0	10.1
2023	92.0	48.4	28.6	3.5	48.5	25.4	15.0	9.9
2024	96.4	50.7	29.3	3.2	51.6	27.0	15.6	10.0
2025	89.9	47.2	26.6	2.7	47.8	25.0	14.1	8.9
2026	81.1	42.5	23.3	2.1	42.1	22.0	12.1	7.5
2027	71.6	37.5	20.1	1.6	36.0	18.7	10.0	6.1
2028	61.6	32.2	16.8	1.2	29.6	15.3	8.0	4.7
2029	51.1	26.6	13.5	0.9	22.8	11.7	6.0	3.5
2030	-88.0	-22.0	-10.9	-0.7	-71.5	-38.5	-19.1	-10.9
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals:	3076.0	2141.6	1528.5	373.6	1505.1	1282.6	905.4	677.7

Table 6. DCF versus MAP: Scenarios 5

Year	DCF				MAP			
	Total Gov take £M	Post-Tax NCF £M	Real NCF £M	Discounted NCF £M	Total Gov take £M	Post-Tax NCF £M	Real NCF £M	Discounted NCF £M
2002	0.0	-110.0	-110.0	-110.0	0.0	-110.0	-110.0	-110.0
2003	0.0	-235.0	-229.2	-207.4	0.0	-235.0	-229.2	-224.7
2004	0.0	-220.0	-209.3	-171.3	0.0	-220.0	-209.3	-201.1
2005	0.0	120.8	112.1	83.0	0.0	85.3	79.1	74.5
2006	0.0	280.3	253.6	170.0	0.0	209.9	189.9	175.3
2007	28.9	230.1	203.1	123.2	0.0	175.2	154.6	139.9
2008	110.2	256.2	220.6	121.0	72.5	168.4	144.9	128.6
2009	80.5	186.9	156.9	77.9	43.6	100.9	84.7	73.7
2010	95.7	222.3	182.0	81.8	59.1	137.1	112.3	95.7
2011	115.4	268.0	214.0	87.0	73.6	170.8	136.4	113.9
2012	102.7	238.1	185.5	68.2	57.7	133.6	104.0	85.2
2013	104.2	241.5	183.4	61.1	58.9	136.5	103.7	83.2
2014	140.4	325.6	241.2	72.6	84.9	196.8	145.8	114.7
2015	123.5	286.3	206.9	56.4	73.4	170.0	122.8	94.7
2016	102.3	236.9	167.0	41.2	59.8	138.3	97.5	73.7
2017	82.2	190.3	130.8	29.2	46.7	108.0	74.3	55.0
2018	74.4	172.1	115.4	23.3	42.1	97.3	65.2	47.3
2019	59.5	137.5	89.9	16.4	32.4	74.7	48.8	34.8
2020	50.7	117.1	74.7	12.3	26.7	61.6	39.3	27.4
2021	43.0	99.3	61.8	9.2	21.6	49.8	31.0	21.2
2022	42.6	98.2	59.6	8.1	21.8	50.2	30.4	20.4
2023	42.5	98.0	58.0	7.1	22.4	51.6	30.5	20.0
2024	44.5	102.6	59.2	6.6	23.8	54.8	31.6	20.4
2025	41.5	95.6	53.8	5.4	22.1	50.8	28.6	18.0
2026	37.4	86.2	47.3	4.3	19.4	44.7	24.5	15.2
2027	33.1	76.0	40.7	3.3	16.6	38.1	20.4	12.4
2028	28.4	65.3	34.1	2.5	13.6	31.2	16.3	9.7
2029	23.6	54.1	27.5	1.9	10.5	24.0	12.2	7.1
2030	-33.0	-77.0	-38.2	-2.3	-33.0	-77.0	-38.2	-21.8
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals:	1574.2	3643.5	2592.1	682.0	870.3	1917.5	1342.1	1004.3

Table 7. DCF versus MAP: Scenarios 6

Year	DCF				MAP			
	Total Gov take £M	Post-Tax NCF £M	Real NCF £M	Discounted NCF £M	Total Gov take £M	Post-Tax NCF £M	Real NCF £M	Discounted NCF £M
2002	0.0	-110.0	-110.0	-110.0	0.0	-110.0	-110.0	-110.0
2003	0.0	-235.0	-229.2	-207.4	0.0	-235.0	-229.2	-224.7
2004	0.0	-220.0	-209.3	-171.3	0.0	-220.0	-209.3	-201.1
2005	0.0	120.8	112.1	83.0	0.0	85.3	79.1	74.5
2006	0.0	280.3	253.6	170.0	0.0	209.9	189.9	175.3
2007	38.5	220.5	194.6	118.0	0.0	175.2	154.6	139.9
2008	147.0	219.5	188.9	103.7	96.6	144.2	124.2	110.1
2009	107.4	160.1	134.4	66.7	58.1	86.4	72.5	63.1
2010	127.6	190.4	155.8	70.0	78.8	117.4	96.1	81.9
2011	153.9	229.6	183.3	74.5	98.1	146.3	116.8	97.6
2012	136.9	203.9	158.8	58.4	76.9	114.3	89.1	72.9
2013	138.9	206.8	157.1	52.3	78.6	116.8	88.7	71.2
2014	187.2	278.8	206.5	62.2	113.2	168.5	124.8	98.2
2015	164.7	245.1	177.1	48.3	97.9	145.5	105.2	81.1
2016	136.4	202.8	142.9	35.2	79.7	118.4	83.4	63.1
2017	109.6	162.9	111.9	25.0	62.3	92.5	63.6	47.1
2018	99.2	147.3	98.7	19.9	56.1	83.2	55.8	40.5
2019	79.3	117.7	76.9	14.1	43.1	63.9	41.8	29.7
2020	67.6	100.2	63.9	10.6	35.6	52.7	33.6	23.4
2021	57.4	85.0	52.8	7.9	28.9	42.6	26.5	18.1
2022	56.8	84.1	51.0	6.9	29.1	42.9	26.0	17.5
2023	56.6	83.8	49.6	6.1	29.9	44.1	26.1	17.1
2024	59.3	87.8	50.6	5.6	31.7	46.8	27.0	17.4
2025	55.3	81.8	46.0	4.6	29.4	43.4	24.4	15.4
2026	49.9	73.7	40.4	3.7	25.9	38.2	21.0	13.0
2027	44.1	65.0	34.8	2.9	22.1	32.6	17.4	10.6
2028	37.9	55.9	29.2	2.2	18.2	26.7	13.9	8.3
2029	31.4	46.2	23.5	1.6	14.0	20.5	10.4	6.1
2030	-44.0	-66.0	-32.8	-2.0	-44.0	-66.0	-32.8	-18.7
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals:	2098.9	3118.7	2213.4	562.6	1160.3	1627.4	1130.8	838.6

Table 8. DCF versus MAP: Scenarios 7a

Year	DCF				MAP			
	Total Gov take £M	Post-Tax NCF £M	Real NCF £M	Discounted NCF £M	Total Gov take £M	Post-Tax NCF £M	Real NCF £M	Discounted NCF £M
2002	0.0	-110.0	-110.0	-110.0	0.0	-110.0	-110.0	-110.0
2003	0.0	-235.0	-229.2	-207.4	0.0	-235.0	-229.2	-224.7
2004	0.0	-220.0	-209.3	-171.3	0.0	-220.0	-209.3	-201.1
2005	0.0	120.8	112.1	83.0	0.0	85.3	79.1	74.5
2006	0.0	280.3	253.6	170.0	0.0	209.9	189.9	175.3
2007	59.2	199.8	176.4	107.0	0.0	175.2	154.6	139.9
2008	240.2	126.3	108.7	59.6	142.4	98.5	84.8	75.2
2009	170.5	97.0	81.4	40.4	78.6	65.9	55.3	48.1
2010	205.4	112.5	92.1	41.4	106.2	90.0	73.6	62.8
2011	251.0	132.5	105.8	43.0	158.9	85.5	68.3	57.0
2012	220.8	120.0	93.5	34.4	121.7	69.5	54.2	44.3
2013	223.8	121.9	92.6	30.8	124.5	70.9	53.8	43.2
2014	307.9	158.1	117.1	35.3	185.1	96.7	71.6	56.4
2015	268.0	141.8	102.5	27.9	158.0	85.4	61.7	47.6
2016	217.9	121.3	85.5	21.1	126.0	72.1	50.8	38.4
2017	181.2	91.3	62.8	14.0	95.3	59.4	40.8	30.3
2018	173.6	72.9	48.9	9.9	98.2	41.2	27.6	20.0
2019	138.8	58.2	38.1	7.0	75.5	31.5	20.6	14.7
2020	118.3	49.5	31.6	5.2	62.3	26.0	16.6	11.6
2021	100.4	41.9	26.1	3.9	50.5	21.0	13.0	8.9
2022	99.4	41.5	25.1	3.4	50.9	21.1	12.8	8.6
2023	99.1	41.3	24.5	3.0	52.3	21.7	12.8	8.4
2024	103.8	43.3	25.0	2.8	55.5	23.0	13.3	8.6
2025	96.8	40.3	22.7	2.3	51.5	21.3	12.0	7.6
2026	87.3	36.3	19.9	1.8	45.4	18.7	10.3	6.4
2027	77.1	32.0	17.1	1.4	38.8	15.9	8.5	5.2
2028	66.4	27.4	14.3	1.1	31.8	13.0	6.8	4.0
2029	55.0	22.6	11.5	0.8	24.6	10.0	5.1	3.0
2030	-77.0	-33.0	-16.4	-1.0	-77.0	-33.0	-16.4	-9.4
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals:	3484.8	1732.9	1223.8	260.7	1857.0	930.8	633.3	454.7

Table 9. DCF versus MAP: Scenarios 7b

Year	DCF				MAP			
	Total Gov take £M	Post-Tax NCF £M	Real NCF £M	Discounted NCF £M	Total Gov take £M	Post-Tax NCF £M	Real NCF £M	Discounted NCF £M
2002	0.0	-110.0	-110.0	-110.0	0.0	-110.0	-110.0	-110.0
2003	0.0	-235.0	-229.2	-207.4	0.0	-235.0	-229.2	-224.7
2004	0.0	-220.0	-209.3	-171.3	0.0	-220.0	-209.3	-201.1
2005	0.0	120.8	112.1	83.0	0.0	85.3	79.1	74.5
2006	0.0	280.3	253.6	170.0	0.0	209.9	189.9	175.3
2007	38.5	220.5	194.6	118.0	0.0	175.2	154.6	139.9
2008	210.8	155.6	133.9	73.5	96.6	144.2	124.2	110.1
2009	181.3	86.1	72.3	35.9	58.1	86.4	72.5	63.1
2010	209.0	108.9	89.2	40.1	78.8	117.4	96.1	81.9
2011	269.3	114.1	91.1	37.1	99.4	145.0	115.8	96.7
2012	239.6	101.2	78.8	29.0	134.6	56.7	44.1	36.1
2013	243.1	102.6	77.9	25.9	137.5	57.9	44.0	35.3
2014	327.6	138.4	102.5	30.9	198.2	83.6	61.9	48.7
2015	288.2	121.6	87.9	23.9	171.3	72.1	52.1	40.2
2016	238.7	100.5	70.9	17.5	139.4	58.6	41.3	31.2
2017	191.8	80.7	55.4	12.4	109.0	45.7	31.4	23.3
2018	173.6	72.9	48.9	9.9	98.2	41.2	27.6	20.0
2019	138.8	58.2	38.1	7.0	75.5	31.5	20.6	14.7
2020	118.3	49.5	31.6	5.2	62.3	26.0	16.6	11.6
2021	100.4	41.9	26.1	3.9	50.5	21.0	13.0	8.9
2022	99.4	41.5	25.1	3.4	50.9	21.1	12.8	8.6
2023	99.1	41.3	24.5	3.0	52.3	21.7	12.8	8.4
2024	103.8	43.3	25.0	2.8	55.5	23.0	13.3	8.6
2025	96.8	40.3	22.7	2.3	51.5	21.3	12.0	7.6
2026	87.3	36.3	19.9	1.8	45.4	18.7	10.3	6.4
2027	77.1	32.0	17.1	1.4	38.8	15.9	8.5	5.2
2028	66.4	27.4	14.3	1.1	31.8	13.0	6.8	4.0
2029	55.0	22.6	11.5	0.8	24.6	10.0	5.1	3.0
2030	-77.0	-33.0	-16.4	-1.0	-77.0	-33.0	-16.4	-9.4
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals:	3577.0	1640.7	1160.1	249.9	1783.1	1004.6	701.8	518.2

Table 10. DCF versus MAP: Scenarios 7c

Year	DCF				MAP			
	Total Gov take £M	Post-Tax NCF £M	Real NCF £M	Discounted Posttax CF £M	Total Gov take £M	Post-Tax NCF £M	Real NCF £M	Discounted NCF £M
2002	0.0	-110.0	-110.0	-110.0	0.0	-110.0	-110.0	-110.0
2003	0.0	-235.0	-229.2	-207.4	0.0	-235.0	-229.2	-224.7
2004	0.0	-220.0	-209.3	-171.3	0.0	-220.0	-209.3	-201.1
2005	0.0	120.8	112.1	83.0	0.0	85.3	79.1	74.5
2006	0.0	280.3	253.6	170.0	0.0	209.9	189.9	175.3
2007	38.5	220.5	194.6	118.0	0.0	175.2	154.6	139.9
2008	190.9	175.5	151.1	82.9	96.6	144.2	124.2	110.1
2009	170.5	97.0	81.4	40.4	58.1	86.4	72.5	63.1
2010	205.4	112.5	92.1	41.4	78.8	117.4	96.1	81.9
2011	251.0	132.5	105.8	43.0	98.1	146.3	116.8	97.6
2012	220.8	120.0	93.5	34.4	99.7	91.5	71.3	58.4
2013	223.8	121.9	92.6	30.8	124.5	70.9	53.8	43.2
2014	307.9	158.1	117.1	35.3	185.1	96.7	71.6	56.4
2015	268.0	141.8	102.5	27.9	158.0	85.4	61.7	47.6
2016	217.9	121.3	85.5	21.1	126.0	72.1	50.8	38.4
2017	170.5	102.0	70.1	15.6	95.3	59.4	40.8	30.3
2018	162.6	83.8	56.2	11.3	91.2	48.1	32.3	23.4
2019	138.8	58.2	38.1	7.0	75.5	31.5	20.6	14.7
2020	118.3	49.5	31.6	5.2	62.3	26.0	16.6	11.6
2021	100.4	41.9	26.1	3.9	50.5	21.0	13.0	8.9
2022	99.4	41.5	25.1	3.4	50.9	21.1	12.8	8.6
2023	99.1	41.3	24.5	3.0	52.3	21.7	12.8	8.4
2024	103.8	43.3	25.0	2.8	55.5	23.0	13.3	8.6
2025	96.8	40.3	22.7	2.3	51.5	21.3	12.0	7.6
2026	87.3	36.3	19.9	1.8	45.4	18.7	10.3	6.4
2027	77.1	32.0	17.1	1.4	38.8	15.9	8.5	5.2
2028	66.4	27.4	14.3	1.1	31.8	13.0	6.8	4.0
2029	55.0	22.6	11.5	0.8	24.6	10.0	5.1	3.0
2030	-77.0	-33.0	-16.4	-1.0	-77.0	-33.0	-16.4	-9.4
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals:	3393.3	1824.3	1299.0	298.1	1673.5	1114.2	782.6	581.7

APPENDIX H

THE BLACK-SCHOLES MODEL[1]

ORIGINAL BLACK SCHOLES FORMULA

The original Black-Scholes formula for the price of a European call option on stock has five parameters, four of which are directly observable and which are the price of the stock, the exercise price, the risk free rate and the time to maturity of the option.

The formula is:

$$\begin{aligned} C &= N(d_t)S - N(d_2)Ee^{-rT} \\ d_1 &= \frac{\ln(S/E) + (r + \sigma^2/2)T}{\sigma\sqrt{T}} \\ d_2 &= d_1 - \sigma\sqrt{T} \end{aligned} \quad \text{(H.1)}$$

Where:

- C: the price of the call
- S: the price of the stock
- E: the exercise price
- r : the risk-free interest rate (the annualised continuously compounded rate on a safe asset with the same maturity as the option)
- T: the time to maturity of the option (in years)
- σ: the standard deviation of the annualised continuously compounded rate of return on the stock
- *ln*: the natural logarithm
- *e*: the base of natural log function (approximately 2.71828)
- *N(d)*: the probability that a random draw from a standard normal distribution will be less than *d*

DEDUCTION OF THE PARTIAL DIFFERENTIAL EQUATION[2]

The Paddock, Siegel & Smith model is the most popular model for petroleum real options applications (Dias, 2001). The model is based on the Black-Scholes formula and is used to derive the option value of a petroleum project. This model has practical advantages due to its simplicity and few parameters estimation.

The following are the variables used in the model, where:

- B_t: the number of barrels of oil in the developed reserve
- V_t: the value per barrel of the developed reserve
- R_t: the return over an instant of time to the owner of the developed reserve. This return consists of the flow of profits from production and the capital gain on the remaining oil.
- $t = T$: the time to expiration.
- α_v: the risk adjusted expected rate of return to the owner
- σ_v: the standard deviation of the rate of return to the owner.
- dz: Wiener increment (random increment)
- ω : the fraction of oil in the reserve produced each year.
- $\prod$: the after tax profit from a barrel of oil
- δ: the dividend yield from a unit of developed reserve
- i : the risk-free interest rate (real and after tax)
- I: the investment cost per barrel

R_t is assumed to follow a Geometric Brownian Motion (GBM):

$$R_t dt / B_t V_t = \alpha_v dt + \sigma_v dz \qquad \text{(H.2)}$$

---

[1] Adapted from Bodie & Merton (2000)
[2] Adapted from Dias (2001) and Emhjellen (1999)

The production from a developed reserve is assumed to follow an exponential decline:

$$dB_t = -\omega B_t dt \tag{H.3}$$

Then, R_t can be written as:

$$R_t dt = \lambda B_t \prod_t dt + d(B_t V_t) = \lambda B_t \prod_t dt + B_t dV_t - \lambda V_t B_t dt \tag{H.4}$$

Combining (H.2) and (H.4) gives the equation for the value of a barrel of oil (V):

$$dV = (\alpha_v - \delta_t)Vdt + \sigma_v Vdz \tag{H.5}$$

Where:

$$\delta_t = \lambda(\prod_t - V_t)/V_t \tag{H.6}$$

Using equation (H.5) and letting the F(V,t) denote the value of an undeveloped barrel of oil, with the use of Ito's Lemma, F(V,t), must satisfy:

$$\frac{1}{2}\sigma_V^2 V_{et}^2 F''(V) + (i-\delta)V_{et} VF'(V) - iF = 0 \tag{H.7}$$

Equation (H.7) must be solved subject to the following boundary conditions:

$$F(0,t) = 0$$
$$F(V,t) = \max(V_t - I, 0)$$
$$F(V^*,t) = V^* - I$$
$$F'(V^*,t) = 1$$

Where:

- I is the project development cost
- $F(0,t)=0$ condition arises from the observation that if V goes to zero, it will stay at zero. Therefore the option to invest will be of no value when V=0
- V^* is the price at which it is optimal to invest
- $F(V^*,t)=V^*-I$ is the value matching condition where upon investing the firm receives V^*-I
- $F'(V^*,t)=1$ is the smooth pasting condition, where if F(V) were not continuous and smooth at the critical exercise point V^*, one could do better by exercising at a different point.

APPENDIX I

INTERNATIONAL COMPARISON- EXAMPLE

Table 1. Arbroath field pre-tax NCF

Year	Period	Total Production 000b/d (A)	Revenue £M (B)	Total Opex £M (C)	Total Capex £M (D)	Pre-tax NCF £M (E)	Real NCF £M (F)	Discounted Pretax CF £M (G)
2002	0	0	0	0	0.0	0	0	0
2003	1	0	0	0	55.0	-55	-53.6	-48.5
2004	2	0	0	0	70.0	-70	-66.6	-54.5
2005	3	25	127.9	39.1	60.0	28.8	26.7	19.8
2006	4	34	178.3	43.7	15.0	119.6	108.2	72.5
2007	5	35.5	190.9	40.2	0.0	150.7	133	80.6
2008	6	33.5	184.7	39.2	0.0	145.5	125.2	68.7
2009	7	32	180.9	38.5	0.0	142.4	119.5	59.4
2010	8	35.5	205.7	40.2	5.0	160.5	131.4	59.1
2011	9	31.5	187.2	38.2	10.0	138.9	110.9	45.1
2012	10	24	146.2	34.5	0.0	111.7	87	32
2013	11	24.5	153	49.3	0.0	103.8	78.8	26.2
2014	12	26.7	171.1	27.7	0.0	143.4	106.2	32
2015	13	21.3	139.9	30.2	5.0	104.7	75.7	20.6
2016	14	17.4	117.3	53.1	5.0	59.2	41.7	10.3
2017	15	20	138.1	43.1	7.0	88	60.5	13.5
2018	16	20	141.6	21.7	10.0	109.9	73.6	14.9
2019	17	19	137.9	20.4	1.0	116.5	76.2	13.9
2020	18	17	126.5	21.2	1.0	104.4	66.5	11
2021	19	14	106.8	21.9	1.0	83.9	52.2	7.8
2022	20	11	86.1	20.1	1.0	65	39.4	5.3
2023	21	9	72.2	18.7	1.0	52.5	31.1	3.8
2024	22	8	65.8	17.9	1.0	46.9	27	3
2025	23	7	59	17.2	1.0	40.8	23	2.3
2026	24	6	51.9	16.4	0.0	35.5	19.5	1.8
2027	25	6	53.2	16.7	0.0	36.5	19.5	1.6
2028	26	5	45.4	16.4	0.0	29	15.2	1.1
2029	27	5	46.6	16.8	0.0	29.8	15.2	1
2030	28	0	0	0	40.0	-40	-19.9	-1.2
2031	29	0	0	0	0.0	0	0	0
Totals:		487.9	3114.2	742.4	289.0	2082.7	1523.1	503.1

See Appendix E and G, for more detail regarding the pre-tax NCF calculation.

Table 2. Arbroath Field under Australian Regime

	PRRT calculations						CIT Calculations				
Year	Gross Revenues £M (H)	Comp. CAPEX £M (I)	Loss CF £M (J)	Taxable Income (K)	PRRT at 40% (L)	Dep. £M (M)	Taxable Income £M (N)	CT at 30% £M (O)	Gov. Take £M (P)	Real NCF Post-tax £M (Q)	Disc.NCF Post-tax £M (R)
2002	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2003	0.0	55.0	55.0	0.0	0.0	0	0.0	0.0	0.0	-53.6	-48.5
2004	0.0	133.3	133.3	0.0	0.0	0	0.0	0.0	0.0	-66.6	-54.5
2005	88.8	213.2	124.5	0.0	0.0	7.4	81.4	24.4	24.4	4.0	3.0
2006	134.6	158.2	23.6	0.0	0.0	8.0	126.6	38.0	38.0	73.9	49.5
2007	150.7	27.1	0.0	123.6	49.4	8.0	93.2	28.0	77.4	64.7	39.2
2008	145.5	0.0	0.0	145.5	58.2	8.0	79.2	23.8	82.0	54.7	30.0
2009	142.4	0.0	0.0	142.4	57.0	8.0	77.4	23.2	80.2	52.2	25.9
2010	165.5	5.0	0.0	160.5	64.2	8.3	93.0	27.9	92.1	56.0	25.2
2011	148.9	10.0	0.0	138.9	55.6	8.8	84.6	25.4	80.9	46.3	18.8
2012	111.7	0.0	0.0	111.7	44.7	8.8	58.2	17.5	62.2	38.6	14.2
2013	103.8	0.0	0.0	103.8	41.5	8.8	53.5	16.0	57.6	35.1	11.7
2014	143.4	0.0	0.0	143.4	57.4	8.8	77.2	23.2	80.5	46.6	14.0
2015	109.7	5.0	0.0	104.7	41.9	9.1	58.7	17.6	59.5	32.7	8.9
2016	64.2	5.0	0.0	59.2	23.7	9.5	31.0	9.3	33.0	18.5	4.6
2017	95.0	7.0	0.0	88.0	35.2	10.0	49.8	14.9	50.1	26.0	5.8
2018	119.9	10.0	0.0	109.9	43.9	10.9	65.1	19.5	63.5	31.1	6.3
2019	117.5	1.0	0.0	116.5	46.6	11.0	60.0	18.0	64.6	33.9	6.2
2020	105.4	1.0	0.0	104.4	41.7	11.1	52.6	15.8	57.5	29.9	4.9
2021	84.9	1.0	0.0	83.9	33.6	11.2	40.2	12.0	45.6	23.8	3.6
2022	66.0	1.0	0.0	65.0	26.0	11.3	28.7	8.6	34.6	18.4	2.5
2023	53.5	1.0	0.0	52.5	21.0	11.4	21.1	6.3	27.3	14.9	1.8
2024	47.9	1.0	0.0	46.9	18.7	11.6	17.5	5.3	24.0	13.2	1.5
2025	41.8	1.0	0.0	40.8	16.3	11.8	13.7	4.1	20.5	11.5	1.2
2026	35.5	0.0	0.0	35.5	14.2	11.8	9.5	2.8	17.0	10.1	0.9
2027	36.5	0.0	0.0	36.5	14.6	11.8	10.1	3.0	17.6	10.1	0.8
2028	29.0	0.0	0.0	29.0	11.6	11.8	5.6	1.7	13.3	8.2	0.6
2029	29.8	0.0	0.0	29.8	11.9	11.8	6.1	1.8	13.7	8.2	0.5
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-19.9	-1.2
2031	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0
Totals:	2371.7	635.7	336.3	2072.3	828.9	249.0	1293.8	388.1	1217.1	622.4	177.4

Table 2. Arbroath Field under Australian Regime- Explained

PRRT Calculation

(H) Gross Revenue = Revenue (B) - OPEX (C)

(I) Compounded $CAPEX_t$ = $CAPEX_t$(D)+ $LossCF_{t-1}(J) \times 1.15$

(J) Any losses not written off are carried for the following period.

(K) Taxable Income = Gross Revenue (H) - Compounded Capex (I)

(L) PRRT = 40% × Taxable Profit (K)

CT Calculation

(M) Depreciation = CAPEX are depreciated on a straight-line basis over field life.

(N) Taxable Income = Revenue (B) - OPEX (C) - Depreciation (M) - PRRT (L)

(O) CT = 30% × Taxable Income (N)

Pre-tax NCF Calculation

(P) Total Government Take = PRRT (L) + CT (O)

(Q) Real NCF Post-tax = [Pre-tax NCF (E) - Government Take (P)]/Inflation Factor

(R) Discounted NCF Post-tax = Real NCF (Q) × Discount factor.

Table 3. Arbroath Field under Norwegian Regime

	ST Calculations						CT calculations			
Year	Dep. £M (S)	Uplift £M (T)	ST Base £M (U)	Loss CF £M (V)	Taxable Income £M (W)	ST Payable 50% £M (X)	CT Base £M (Y)	Loss CF £M (Z)	Taxable Income £M (AA)	CT Payable 28% £M (BB)
2002	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2003	9.2	2.8	-11.9	-11.9	0.0	0.0	-9.2	-9.2	0.0	0.0
2004	20.8	6.3	-27.1	-39.0	0.0	0.0	-20.8	-30.0	0.0	0.0
2005	30.8	9.3	48.7	0.0	9.7	4.8	57.9	0.0	27.9	7.8
2006	33.3	10.0	91.3	0.0	91.3	45.6	101.3	0.0	101.3	28.4
2007	33.3	10.0	107.3	0.0	107.3	53.7	117.3	0.0	117.3	32.8
2008	33.3	10.0	102.1	0.0	102.1	51.1	112.1	0.0	112.1	31.4
2009	24.2	7.3	111.0	0.0	111.0	55.5	118.2	0.0	118.2	33.1
2010	13.3	3.8	148.4	0.0	148.4	74.2	152.2	0.0	152.2	42.6
2011	5.0	0.8	143.2	0.0	143.2	71.6	143.9	0.0	143.9	40.3
2012	2.5	0.0	109.2	0.0	109.2	54.6	109.2	0.0	109.2	30.6
2013	2.5	0.0	101.3	0.0	101.3	50.6	101.3	0.0	101.3	28.4
2014	2.5	0.0	140.9	0.0	140.9	70.4	140.9	0.0	140.9	39.4
2015	3.3	0.0	106.4	0.0	106.4	53.2	106.4	0.0	106.4	29.8
2016	3.3	0.0	60.9	0.0	60.9	30.4	60.9	0.0	60.9	17.0
2017	2.8	0.0	92.2	0.0	92.2	46.1	92.2	0.0	92.2	25.8
2018	4.5	0.0	115.4	0.0	115.4	57.7	115.4	0.0	115.4	32.3
2019	4.7	0.0	112.9	0.0	112.9	56.4	112.9	0.0	112.9	31.6
2020	4.8	0.0	100.5	0.0	100.5	50.3	100.5	0.0	100.5	28.1
2021	4.2	0.0	80.7	0.0	80.7	40.4	80.7	0.0	80.7	22.6
2022	3.5	0.0	62.5	0.0	62.5	31.2	62.5	0.0	62.5	17.5
2023	2.5	0.0	51.0	0.0	51.0	25.5	51.0	0.0	51.0	14.3
2024	1.0	0.0	46.9	0.0	46.9	23.4	46.9	0.0	46.9	13.1
2025	0.8	0.0	41.0	0.0	41.0	20.5	41.0	0.0	41.0	11.5
2026	0.7	0.0	34.8	0.0	34.8	17.4	34.8	0.0	34.8	9.7
2027	0.5	0.0	36.0	0.0	36.0	18.0	36.0	0.0	36.0	10.1
2028	0.3	0.0	28.7	0.0	28.7	14.4	28.7	0.0	28.7	8.0
2029	0.2	0.0	29.6	0.0	29.6	14.8	29.6	0.0	29.6	8.3
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals:	248.0	60.0	2063.7	-50.9	2063.7	1031.9	2123.7	-39.2	2123.7	594.6

Table 4. Arbroath Field under Norwegian Regime (Continued)

Year	Pre-tax NCF £M (CC)	Total tax Take £M (DD)	Abandonment cost (EE)	Abandonment grant £M (FF)	Post-tax NCF £M (GG)	Real NCF Post-tax £M (HH)	Dis. NCF Post-tax £M (II)
2002	0.0	0.0	0	0.0	0.0	0.0	0.0
2003	-55.0	0.0	0	0.0	-55.0	-53.6	-48.5
2004	-70.0	0.0	0	0.0	-70.0	-66.6	-54.5
2005	28.8	12.7	0	0.0	16.1	14.9	11.1
2006	119.6	74.0	0	0.0	45.6	41.3	27.7
2007	150.7	86.5	0	0.0	64.1	56.6	34.3
2008	145.5	82.5	0	0.0	63.0	54.2	29.8
2009	142.4	88.6	0	0.0	53.8	45.2	22.4
2010	160.5	116.8	0	0.0	43.7	35.8	16.1
2011	138.9	111.9	0	0.0	27.0	21.6	8.8
2012	111.7	85.2	0	0.0	26.5	20.7	7.6
2013	103.8	79.0	0	0.0	24.8	18.8	6.3
2014	143.4	109.9	0	0.0	33.5	24.8	7.5
2015	104.7	83.0	0	0.0	21.7	15.7	4.3
2016	59.2	47.5	0	0.0	11.7	8.3	2.0
2017	88.0	71.9	0	0.0	16.1	11.1	2.5
2018	109.9	90.0	0	0.0	19.9	13.3	2.7
2019	116.5	88.0	0	0.0	28.5	18.6	3.4
2020	104.4	78.4	0	0.0	25.9	16.5	2.7
2021	83.9	63.0	0	0.0	20.9	13.0	1.9
2022	65.0	48.7	0	0.0	16.2	9.8	1.3
2023	52.5	39.8	0	0.0	12.7	7.5	0.9
2024	46.9	36.5	0	0.0	10.3	5.9	0.7
2025	40.8	32.0	0	0.0	8.9	5.0	0.5
2026	35.5	27.1	0	0.0	8.3	4.6	0.4
2027	36.5	28.1	0	0.0	8.4	4.5	0.4
2028	29.0	22.4	0	0.0	6.6	3.5	0.3
2029	29.8	23.1	0	0.0	6.7	3.4	0.2
2030	0.0	0.0	40	30.6	-9.4	-4.6	-0.3
2031	0.0	0.0	0	0.0	0.0	0.0	0.0
Totals:	2122.7	1626.5	40	30.6	486.9	349.8	92.4

Tables 3 and 4. Arbroath Field under Norwegian Regime- Explained

ST Calculation:

(S) Depreciation for CAPEX (D) is allowed on 6-year straight-line basis

(T) Uplift applies on CAPEX (D) at a rate of 5 per cent over 6 years

(U) ST Base = Revenue (B) - OPEX (C) - Depreciation (S) - Uplift (T)

(V) Any loss not written off in a particular period is carried forward to a following period.

(W) Taxable Income is equal to the ST base (U) when all losses have been written off.

(X) ST Payable = 50% × Taxable Income (W)

CT Calculation:

(Y) CT Base = Revenue (B) - OPEX (C) - Depreciation (S)

(Z) Any loss not written off in a particular period is carried forward to a following period.

(AA) Taxable Income is equal to the CT base (Y) when all losses have been written off.

(BB) CT Payable = 28% × Taxable Income (AA)

Post-Tax NCF Calculation:

(CC) Pre-tax NCF excluding Abandonment Cost (EE)

(DD) Total Government Take = ST (X) + CT (BB)

(EE) Abandonment Cost

(FF) Abandonment Cost Grant = 76.6% × Abandonment Cost (EE), where 76.6% is the effective tax rate.

(GG) Post Tax NCF = Pre-tax NCF (CC) - Government Take (DD) - Abandonment Cost Grant (FF)

(HH) Real NCF Post-tax = Post-tax NCF (GG)/Inflation Factor

(II) Discounted NCF Post-tax = Real NCF (HH) × Discount factor.

Table 5. Arbroath Field under Indonesian Regime

	FTP calculation				
Year	Total FTP 20% £M (JJ)	Gov. Share 64% £M (KK)	Contractor Share 36% £M (LL)	Net Revenue £M (MM)	DMO £M (NN)
2002	0.0	0.0	0.0	0.0	-
2003	0.0	0.0	0.0	0.0	-
2004	0.0	0.0	0.0	0.0	-
2005	25.6	16.4	9.2	102.3	-
2006	35.7	22.8	12.8	142.6	-
2007	38.2	24.4	13.7	152.7	-
2008	36.9	23.6	13.3	147.7	-
2009	36.2	23.2	13.0	144.7	-
2010	41.1	26.3	14.8	164.6	13.9
2011	37.4	24.0	13.5	149.7	12.6
2012	29.2	18.7	10.5	117.0	9.9
2013	30.6	19.6	11.0	122.4	10.3
2014	34.2	21.9	12.3	136.9	11.5
2015	28.0	17.9	10.1	112.0	9.4
2016	23.5	15.0	8.4	93.8	7.9
2017	27.6	17.7	9.9	110.5	9.3
2018	28.3	18.1	10.2	113.3	9.6
2019	27.6	17.7	9.9	110.3	9.3
2020	25.3	16.2	9.1	101.2	8.5
2021	21.4	13.7	7.7	85.5	7.2
2022	17.2	11.0	6.2	68.8	5.8
2023	14.4	9.2	5.2	57.8	4.9
2024	13.2	8.4	4.7	52.6	4.4
2025	11.8	7.6	4.2	47.2	4.0
2026	10.4	6.6	3.7	41.5	3.5
2027	10.6	6.8	3.8	42.6	3.6
2028	9.1	5.8	3.3	36.4	3.1
2029	9.3	6.0	3.4	37.3	3.1
2030	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0
Totals:	622.8	398.6	224.2	2491.3	152.0

Table 6. Arbroath Field under Indonesian Regime (Continued)

Year	Cost Recovery Calculation Intangible CAPEX £M (OO)	Tangible CAPEX £M (PP)	Dep. £M (QQ)	Inv. Credits £M (RR)	Total Cost Recovery £M (SS)	Cost Recovery Limit £M (TT)	Cost CF £M (UU)	Cost recovery allowed £M (VV)
2002	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2003	16.3	38.8	0.0	0.0	16.3	0.0	0.0	0.0
2004	25.0	45.0	0.0	0.0	25.0	0.0	16.3	0.0
2005	27.5	32.5	29.1	21.7	117.4	102.3	41.3	102.3
2006	11.3	3.8	22.7	0.0	77.7	142.6	56.3	134.0
2007	0.0	0.0	17.1	0.0	57.3	152.7	0.0	57.3
2008	0.0	0.0	12.8	0.0	52.0	147.7	0.0	52.0
2009	0.0	0.0	37.2	0.0	75.7	144.7	0.0	75.7
2010	3.8	1.3	1.5	0.0	45.5	164.6	0.0	45.5
2011	7.5	2.5	0.9	0.0	46.6	149.7	0.0	46.6
2012	0.0	0.0	0.6	0.0	35.2	117.0	0.0	35.2
2013	0.0	0.0	0.5	0.0	49.8	122.4	0.0	49.8
2014	0.0	0.0	0.7	0.0	28.3	136.9	0.0	28.3
2015	1.3	3.8	1.7	0.0	33.2	112.0	0.0	33.2
2016	3.8	1.3	1.0	0.0	57.9	93.8	0.0	57.9
2017	5.2	1.7	1.2	0.0	49.5	110.5	0.0	49.5
2018	7.5	2.5	1.5	0.0	30.7	113.3	0.0	30.7
2019	0.3	0.8	2.2	0.0	22.9	110.3	0.0	22.9
2020	0.3	0.8	1.3	0.0	22.7	101.2	0.0	22.7
2021	0.3	0.8	1.3	0.0	23.4	85.5	0.0	23.4
2022	0.3	0.8	1.3	0.0	21.7	68.8	0.0	21.7
2023	0.3	0.8	0.8	0.0	19.7	57.8	0.0	19.7
2024	0.3	0.8	0.8	0.0	18.9	52.6	0.0	18.9
2025	0.3	0.8	0.8	0.0	18.2	47.2	0.0	18.2
2026	0.0	0.0	0.6	0.0	17.0	41.5	0.0	17.0
2027	0.0	0.0	0.4	0.0	17.1	42.6	0.0	17.1
2028	0.0	0.0	0.3	0.0	16.7	36.4	0.0	16.7
2029	0.0	0.0	0.2	0.0	17.1	37.3	0.0	17.1
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals:	110.7	138.2	138.2	21.7	1013.1	2491.3	113.8	1013.1

Table 7. Arbroath Field under Indonesian Regime (Continued)

Profit oil			Income Tax				Gov. take & Contractor NCF			
Total Profit Oil £M (WW)	Gov. Share 64% £M (XX)	Contractor Share 36% £M (YY)	Bonus £M (ZZ)	Contractor Total Profit £M (AAA)	Taxable Income £M (BBB)	Income tax 44% £M (CCC)	Gov. Take £M (DDD)	NCF £M (EEE)	Real NCF £M (FFF)	Contractor Dis. NCF £M (GGG)
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-55.0	-53.6	-48.5
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-70.0	-66.6	-54.5
0.0	0.0	0.0	0.0	9.2	30.9	13.6	30.0	-1.2	-1.1	-0.8
8.6	5.5	3.1	0.0	15.9	15.9	7.0	35.4	84.2	76.2	51.1
95.4	61.1	34.4	0.0	48.1	48.1	21.2	106.7	44.0	38.8	23.5
95.7	61.3	34.5	0.0	47.8	47.8	21.0	105.9	39.5	34.0	18.7
69.0	44.2	24.9	0.0	37.9	37.9	16.7	84.0	58.4	49.0	24.3
119.1	76.2	42.9	0.0	57.7	43.8	19.3	135.7	24.8	20.3	9.1
103.1	66.0	37.1	0.0	50.6	38.0	16.7	119.3	19.6	15.7	6.4
81.8	52.4	29.5	0.0	40.0	30.1	13.3	94.2	17.5	13.6	5.0
72.7	46.5	26.2	0.0	37.2	26.9	11.8	88.3	15.5	11.8	3.9
108.5	69.5	39.1	0.0	51.4	39.8	17.5	120.4	23.0	17.0	5.1
78.8	50.4	28.4	0.0	38.4	29.0	12.8	90.5	14.2	10.3	2.8
36.0	23.0	13.0	0.0	21.4	13.5	5.9	51.9	7.3	5.2	1.3
61.0	39.0	21.9	0.0	31.9	22.6	9.9	75.9	12.1	8.3	1.9
82.5	52.8	29.7	0.0	39.9	30.3	13.4	93.8	16.0	10.7	2.2
87.5	56.0	31.5	0.0	41.4	32.1	14.1	97.1	19.5	12.7	2.3
78.5	50.3	28.3	0.0	37.4	28.8	12.7	87.7	16.7	10.6	1.8
62.0	39.7	22.3	0.0	30.0	22.8	10.0	70.6	13.3	8.3	1.2
47.2	30.2	17.0	0.0	23.2	17.4	7.6	54.7	10.3	6.2	0.8
38.1	24.4	13.7	0.0	18.9	14.0	6.2	44.7	7.9	4.6	0.6
33.7	21.6	12.1	0.0	16.9	12.4	5.5	39.9	7.0	4.0	0.4
29.0	18.6	10.5	0.0	14.7	10.7	4.7	34.8	6.0	3.4	0.3
24.5	15.7	8.8	0.0	12.6	9.1	4.0	29.8	5.6	3.1	0.3
25.5	16.3	9.2	0.0	13.0	9.4	4.1	30.8	5.7	3.0	0.2
19.6	12.6	7.1	0.0	10.3	7.3	3.2	24.6	4.4	2.3	0.2
20.2	12.9	7.3	0.0	10.6	7.5	3.3	25.3	4.4	2.3	0.2
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-40.0	-19.9	-1.2
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1478.2	946.1	532.2	0.0	756.4	626.1	275.5	1772.1	310.6	230.3	58.6

Tables 5-7. Arbroath Field under Indonesian Regime- Explained

FTP & DMO Calculation:

(JJ) First Tranche Petroleum (FTP) = 20% × Revenue (B)

(KK) Government Share of FTP = 64% × Total FTP (JJ)

(LL) Contractor Share of FTP = 36% × Total FTP (JJ)

(MM) Net Revenue = Revenue (B) - FTP (JJ)

(NN) Domestic Market Obligation = Revenue (B) × 75% × 25% ×36%

After 60 months of production (i.e. 5 years), the contractor sells 25% of its share of oil (36%) to national oil company at 25% of the market price (Price differential of 75%)

Cost Recovery Calculation:

(OO) Intangible CAPEX = 75% × Development and Drilling expenditures + 25% × Facilities (Equipment and Transportation), which are provided separately in GEM.

(PP) Tangible CAPEX = Total CAPEX (D) - Intangible CAPEX (OO)

(QQ) Depreciation on tangible CAPEX at 25% per year, using the Declining Balance method with the undepreciated amount written off in year five

(RR) Investment credits = 15.5% × Facilities and Equipment.

(SS) Total Cost Recovery = OPEX (C) + Intangible CAPEX (OO) + Depreciation (QQ) + Investment Credits (RR)

(TT) Cost Recovery Limit = 80% × Total Revenue (B) (or 100% of Net Revenue (MM)

(UU) Any cost recovery, which exceeds the limit is carried forward to the following period.

(VV) Cost Recovery Allowed = Minimum of Cost Recovery Limit (TT) and Total Cost Recovery (SS), taking into account Cost Carried Forward (UU).

Profit Oil Calculation:

(WW) Total Profit Oil = Total Revenue (B) - Total FTP (JJ) - Cost Recovery Allowed (VV)

(XX) Government Share of Profit Oil = 64% × Total Profit Oil (WW)

(YY) Contractor Share of Profit Oil = 36% × Total Profit Oil (WW)

Income Tax Calculation:

(ZZ) Bonus = 0, because in this example, the daily production of Arbroath field does not reach 50,000 bbl.

(AAA) Contractor Total Profit = Contractor Profit Oil (YY) + Contractor Share of FTP (LL)

(BBB) Taxable Income = Contractor Total Profit (AAA) + Investment Credits (RR) - DMO (NN) - Bonus (ZZ)

Government Take & Contractor NCF:

(CCC) Total Government take = Government share of FTP (KK) + DMO (NN) + Bonus (ZZ) + Income Tax (BBB)

(DDD) Contractor NCF = Total Revenue (B) - OPEX (C) - CAPEX (D) - Gov. FTP (KK) - DMO (NN) - Gov. Profit Oil (XX) - Bonus (ZZ) - Income Tax (BBB)

(EEE) Real NCF = NCF (DDD)/Inflation Factor

(FFF) Discounted NCF = Real NCF (EEE) × Discount factor.

Table 8. Arbroath Field under Chinese Regime

Year	Royalty £M (EEE)	VAT 5% £M (FFF)	Net Revenues £M (GGG)	Dep. £M (HHH)	Total Cost Recovery £M (III)	Cost Recovery Limit 62.5% £M (JJJ)	Cost CF £M (KKK)	Cost Recovery Allowed £M (LLL)
2002	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2003	0.0	0.0	0.0	55.0	55.0	0.0	0.0	0.0
2004	0.0	0.0	0.0	75.0	75.0	0.0	0.0	0.0
2005	1.0	6.4	120.4	66.7	105.9	79.9	0.0	79.9
2006	3.4	8.9	166.0	15.0	58.7	111.4	25.9	84.6
2007	3.9	9.5	177.4	0.0	40.2	119.3	0.0	40.2
2008	3.4	9.2	172.1	0.0	39.2	115.4	0.0	39.2
2009	2.9	9.0	168.9	0.0	38.5	113.0	0.0	38.5
2010	4.2	10.3	191.2	5.0	45.2	128.6	0.0	45.2
2011	2.9	9.4	174.9	10.0	48.2	117.0	0.0	48.2
2012	1.0	7.3	137.9	0.0	34.5	91.4	0.0	34.5
2013	1.1	7.7	144.3	0.0	49.3	95.7	0.0	49.3
2014	1.7	8.6	160.8	0.0	27.7	106.9	0.0	27.7
2015	0.3	7.0	132.6	5.0	35.2	87.5	0.0	35.2
2016	0.0	5.9	111.4	5.0	58.1	73.3	0.0	58.1
2017	0.0	6.9	131.2	7.0	50.1	86.3	0.0	50.1
2018	0.0	7.1	134.5	10.0	31.7	88.5	0.0	31.7
2019	0.0	6.9	131.0	1.0	21.4	86.2	0.0	21.4
2020	0.0	6.3	120.2	1.0	22.2	79.1	0.0	22.2
2021	0.0	5.3	101.5	1.0	22.9	66.8	0.0	22.9
2022	0.0	4.3	81.8	1.0	21.1	53.8	0.0	21.1
2023	0.0	3.6	68.6	1.0	19.7	45.1	0.0	19.7
2024	0.0	3.3	62.5	1.0	18.9	41.1	0.0	18.9
2025	0.0	3.0	56.1	1.0	18.2	36.9	0.0	18.2
2026	0.0	2.6	49.3	0.0	16.4	32.4	0.0	16.4
2027	0.0	2.7	50.5	0.0	16.7	33.2	0.0	16.7
2028	0.0	2.3	43.2	0.0	16.4	28.4	0.0	16.4
2029	0.0	2.3	44.3	0.0	16.8	29.1	0.0	16.8
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals:	25.9	155.7	2932.6	260.7	1003.1	1946.4	25.9	873.2

Table 9. Arbroath Field under Chinese Regime (Continued)

Profit oil				Income Tax		Gov. Take & Contractor NCF			
Total Profit Oil £M (MMM)	Gov. Share of Profit Oil % (NNN)	Gov. Share £M (OOO)	Contractor Share £M (PPP)	Taxable Income £M (QQQ)	Income tax 33% £M (RRR)	Gov. Take £M (SSS)	NCF £M (TTT)	Real NCF £M (UUU)	Discounted Pretax CF £M (VVV)
0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0	0.0	0.0	-55.0	0.0	0.0	-55.0	-53.6	-48.5
0.0	0	0.0	0.0	-75.0	0.0	0.0	-70.0	-66.6	-54.5
40.5	7.8%	3.2	37.4	11.4	3.8	14.3	14.4	13.4	9.9
81.4	9.7%	7.9	73.5	99.4	32.8	53.0	66.6	60.3	40.4
137.2	9.9%	13.6	123.6	123.6	40.8	67.9	82.8	73.1	44.3
132.9	9.6%	12.8	120.1	120.1	39.6	65.0	80.4	69.2	38.0
130.4	9.4%	12.2	118.2	118.2	39.0	63.2	79.2	66.5	33.0
146.0	9.9%	14.5	131.5	131.5	43.4	72.4	88.1	72.1	32.4
126.7	9.3%	11.8	114.9	114.9	37.9	62.0	77.0	61.5	25.0
103.4	7.5%	7.8	95.7	95.7	31.6	47.6	64.1	49.9	18.4
95.0	7.7%	7.3	87.7	87.7	29.0	45.0	58.8	44.6	14.9
133.1	8.3%	11.0	122.1	122.1	40.3	61.6	81.8	60.6	18.3
97.4	6.6%	6.4	91.0	91.0	30.0	43.8	61.0	44.1	12.0
53.3	5.7%	3.0	50.3	50.3	16.6	25.5	33.7	23.7	5.9
81.1	6.0%	4.9	76.2	76.2	25.2	36.9	51.1	35.1	7.8
102.8	6.0%	6.2	96.6	96.6	31.9	45.1	64.7	43.4	8.8
109.6	5.9%	6.5	103.2	103.2	34.0	47.4	69.1	45.2	8.3
98.0	5.6%	5.5	92.5	92.5	30.5	42.4	62.0	39.5	6.5
78.5	5.1%	4.0	74.5	74.5	24.6	34.0	49.9	31.0	4.6
60.7	4.4%	2.6	58.0	58.0	19.1	26.1	38.9	23.6	3.2
48.9	4.0%	2.0	46.9	46.9	15.5	21.1	31.5	18.6	2.3
43.6	4.0%	1.7	41.8	41.8	13.8	18.8	28.0	16.2	1.8
37.9	4.0%	1.5	36.4	36.4	12.0	16.5	24.4	13.7	1.4
32.9	4.0%	1.3	31.6	31.6	10.4	14.3	21.1	11.6	1.1
33.9	4.0%	1.4	32.5	32.5	10.7	14.7	21.8	11.7	1.0
26.8	4.0%	1.1	25.7	25.7	8.5	11.8	17.2	9.0	0.7
27.4	4.0%	1.1	26.3	26.3	8.7	12.1	17.7	9.0	0.6
0.0	0.0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0.0	0.0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2059.4		151.2	1908.2	1778.3	629.7	962.5	1160.2	826.3	237.3

Tables 8-9. Arbroath Field under Chinese Regime- Explained

Cost Recovery Calculation:

(EEE) Royalty is calculated on a Sliding Scale Basis (See Chapter 8, Table 8.2). For example, the on the first tranche of production (<=20,000 bbl/d) Royalty rate is zero. On the second tranche of production (>20,000 bbl/d <=30,0000 bbl/d0 Royalty rate is 4%... Then, the total Royalty in one year is the sum of the Royalty payment on each tranche in that year. Finally, the annual Royalty value is determined by multiplying Total Royalty by the oil price.

(FFF) Value Added Tax = 5% × Total Revenue (B)

(GGG) Net Revenue = Total Revenue (B) - Royalty (EEE) - VAT (FFF)

(HHH) Depreciation is 100% of CAPEX as spent. Any unrecovered balance is carried forward to the following period and is compounded at a 9 per cent interest rate

(III) Cost Recovery = OPEX (C)- Depreciation (HHH)

(JJJ) Cost Recovery Limit = 62.5% × Total Revenue (B)

(KKK) Any cost recovery, which exceeds the limit, is carried forward to the following period.

(LLL) Cost Recovery Allowed = Minimum of Cost Recovery Limit (JJJ) and Total Cost Recovery (III), taking into account Cost Carried Forward (KKK).

Government Take & Contractor NCF:

(MMM) Total Profit Oil = Net Revenues (GGG) - Cost Recovery (LLL)

(NNN) Government Share of Profit Oil (%) is determined by the X Factor (See Table 8.3, Chapter 8), depending on annual Production.

(OOO) Government Share of Profit Oil = Government share in percentage (NNN) × Total Profit Oil (MMM)

(PPP) Contractor Share of Profit Oil = Total Profit Oil (MMM) - Government Share (OOO)

(QQQ) Taxable Income = Net Revenue (GGG) - OPEX (C) - Depreciation (HHH) - Government Share of Profit Oil (OOO)

(RRR) Income Tax = 33% × Taxable Income

(SSS) Total Government Take = Royalty (EEE) + VAT (FFF) + Gov. Share of Profit Oil (OOO) + Income Tax (RRR)

(TTT) Contractor NCF = Net Revenue (GGG) - OPEX (C) - Depreciation (HHH) - Income Tax (RRR) - Gov. Share of Profit Oil (OOO)

(UUU) Real NCF = NCF (DDD)/Inflation Factor

(VVV) Discounted NCF = Real NCF (EEE) × Discount factor.

Table 10. Arbroath Field under Iraqi Regime

Year	Total cost £M (WWW)	Limit 50% £M (XXX)	Net Income £M (YYY)	Cumulative Net Income £M (ZZZ)	Cost Recovery allowed £M (AAAA)	Cost Unrecovered £M (BBBB)	Cumulative Unrecovered £M (CCCC)	Handover Date (DDDD)
2002	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-
2003	55.0	0.0	-55.0	-55.0	0.0	55.0	55.0	-
2004	70.0	0.0	-70.0	-125.0	0.0	70.0	125.0	-
2005	99.1	63.9	-35.2	-160.2	63.9	35.2	160.2	-
2006	58.7	89.1	30.5	-129.7	89.1	-30.5	129.7	-
2007	40.2	95.4	55.2	-74.5	95.4	-55.2	74.5	-
2008	39.2	92.3	53.1	-21.4	92.3	-53.1	21.4	-
2009	38.5	90.4	52.0	30.6	59.9	-21.4	**0.0**	Handover
2010	45.2	102.9	57.6	88.2	45.2	0.0	0.0	Date
2011	48.2	93.6	45.4	133.6	48.2	0.0	0.0	-
2012	34.5	73.1	38.6	172.2	34.5	0.0	0.0	-
2013	49.3	76.5	27.3	199.4	49.3	0.0	0.0	-
2014	27.7	85.5	57.9	257.3	27.7	0.0	0.0	-
2015	35.2	70.0	34.8	292.0	35.2	0.0	0.0	-
2016	58.1	58.6	0.6	292.6	58.1	0.0	0.0	-
2017	50.1	69.0	19.0	311.6	50.1	0.0	0.0	-
2018	31.7	70.8	39.1	350.6	31.7	0.0	0.0	-
2019	21.4	69.0	47.6	398.2	21.4	0.0	0.0	-
2020	22.2	63.3	41.1	439.3	22.2	0.0	0.0	-
2021	22.9	53.4	30.5	469.8	22.9	0.0	0.0	-
2022	21.1	43.0	21.9	491.7	21.1	0.0	0.0	-
2023	19.7	36.1	16.4	508.1	19.7	0.0	0.0	-
2024	18.9	32.9	14.0	522.1	18.9	0.0	0.0	-
2025	18.2	29.5	11.3	533.4	18.2	0.0	0.0	-
2026	16.4	25.9	9.5	542.9	16.4	0.0	0.0	-
2027	16.7	26.6	9.9	552.9	16.7	0.0	0.0	-
2028	16.4	22.7	6.3	559.2	16.4	0.0	0.0	-
2029	16.8	23.3	6.5	565.7	16.8	0.0	0.0	-
2030	40.0	0.0	-40.0	525.7	0.0	40.0	40.0	-
2031	0.0	0.0	0.0	525.7	0.0	0.0	0.0	-
Totals:	1031.4	1557.1	525.7	8196.8	991.4			-

Table 11. Arbroath Field under Iraqi Regime (Continued)

Cum. CAPEX Handover Date £M (EEEE)	Remun. Index (FFFF)	Expected Cum. CAPEX £M (GGGG)	Overall Remun. £M (HHHH)	Contractor Remun. £M (IIII)	Cumulative Remun. to handover £M (JJJJ)	Balance to be recovered £M (KKKK)	8Quarters £M (LLLL)
0.0	1.5	200.0	300	0.0	0.0	300.0	0
55.0	1.5	200.0	300	0.0	0.0	300.0	0
125.0	1.5	200.0	300	0.0	0.0	300.0	0
185.0	1.5	200.0	300	12.8	12.8	287.2	0
200.0	1.5	200.0	300	17.8	30.6	269.4	0
200.0	1.5	200.0	300	19.1	49.7	250.3	0
200.0	1.5	200.0	300	18.5	68.2	231.8	0
200.0	**1.5**	**200.0**	**300**	**18.1**	**86.3**	**213.7**	0
200.0	1.5	200.0	300	0.0	0.0	0.0	106.9
200.0	1.5	200.0	300	0.0	0.0	0.0	106.9
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
200.0	1.5	200.0	300	0.0	0.0	0.0	0.0
5565.0				86.3	247.5	2152.5	213.7

Table 12. Arbroath Field under Iraqi Regime (Continued)

Year	Total Income £M (MMMM)	NCF £M (NNNN)	Real NCF £M (OOOO)	Discounted NCF £M (PPPP)	Gov. Take during contract £M (QQQQ)
2002	0.0	0.0	0.0	0.0	0.0
2003	0.0	-55.0	-53.6	-48.5	0.0
2004	0.0	-70.0	-66.6	-54.5	0.0
2005	76.7	-22.4	-20.8	-15.4	51.1
2006	107.0	48.3	43.7	29.3	71.3
2007	114.5	74.3	65.6	39.8	76.4
2008	110.8	71.6	61.6	33.8	73.9
2009	78.0	39.5	33.1	16.5	102.9
2010	106.9	106.9	87.5	39.3	53.6
2011	106.9	106.9	85.3	34.7	32.1
2012	0.0	0.0	0.0	0.0	-
2013	0.0	0.0	0.0	0.0	-
2014	0.0	0.0	0.0	0.0	-
2015	0.0	0.0	0.0	0.0	-
2016	0.0	0.0	0.0	0.0	-
2017	0.0	0.0	0.0	0.0	-
2018	0.0	0.0	0.0	0.0	-
2019	0.0	0.0	0.0	0.0	-
2020	0.0	0.0	0.0	0.0	-
2021	0.0	0.0	0.0	0.0	-
2022	0.0	0.0	0.0	0.0	-
2023	0.0	0.0	0.0	0.0	-
2024	0.0	0.0	0.0	0.0	-
2025	0.0	0.0	0.0	0.0	-
2026	0.0	0.0	0.0	0.0	-
2027	0.0	0.0	0.0	0.0	-
2028	0.0	0.0	0.0	0.0	-
2029	0.0	0.0	0.0	0.0	-
2030	0.0	0.0	0.0	0.0	-
2031	0.0	0.0	0.0	0.0	-
Totals:	700.7	300.0	235.8	74.9	461-.3

Tables 10-12. Arbroath Field under Iraqi Regime- Explained

Cost Recovery Calculation:

(WWW) Total Costs = OPEX (C) + CAPEX (D)

(XXX) Cost Recovery Limit = 50% × Revenue (B)

(YYY) Net Income = Total Costs (WWW) - Cost Recovery Limit (XXX)

(ZZZ) Cumulative Net Income$_t$ = Net Income$_t$(YYY) + Cumulative Income$_{t-1}$(ZZZ)

(AAAA) Cost Recovery Allowed = Minimum between Total Costs (WWW) and Cost Recovery Limit (XXX)

(BBBB) Cost Unrecovered = Cost Recovery Allowed (AAAA) - Total Costs (WWW)

(CCCC) Cumulative Cost Unrecovered$_t$ = Cost Unrecovered$_t$ (BBB) + Cumulative Unrecovered $_{t-1}$(CCCC)

(DDDD) When all costs are recovered (i.e. Cumulative Unrecovered = 0), the field reaches Handover date, which is in this example 2009.

Remuneration Calculation:

(EEEE) Cumulative CAPEX = Cumulative CAPEX (D) until field reaches Handover date.

(FFFF) Remuneration Index is assumed to be 1.5.

(GGGG) Expected Cumulative CAPEX = Maximum of Cumulative CAPEX (EEEE) to Handover date.

(HHHH) Overall Remuneration = Remuneration Index (FFFF) × Expected Cumulative CAPEX (GGGG)

(IIII) Contractor Remuneration = 10% × Revenue (B)

(JJJJ) Cumulative Remuneration of Contractor Remuneration (IIII)

(KKKK) Balance to be recovered = Overall Remuneration (HHHH) - Cumulative Remuneration (JJJJ)

(LLLL) 8 Quarters after Handover (i.e. 2 years) means that the balance to be recovered at Handover will be recovered in 8 quarters, by equal instalments.

Contractor NCF Calculation:

(MMMM) Total Income = Contractor Remuneration (IIII) + 8 Quarters CAPEX (LLLL) + Cost Recovery Allowed (AAAA)

(NNNN) NCF = Total Income (MMMM) - Total Costs (WWW)

(OOOO) Real NCF = NCF (NNNN)/Inflation Factor

(PPPP) Discounted NCF = Real NCF (OOOO) × Discount factor.

(QQQQ) Government take during contract = Revenue (B) - Total Costs (WWW) - Contractor NCF (NNNN).