EXPLORING THE RATIONALES FOR RELAXATIONS IN THE UK PETROLEUM FISCAL REGIME 1980-2000

Volume One: Chapters 1-7

by

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ABSTRACT

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The UK is considered a new oil province compared with other oil producing countries, such as Saudi Arabia. The UK petroleum fiscal regime was established since 1975 and tightened up with a number of different new taxes till 1981. The objective of the tight fiscal terms was to secure more rent from the UK oil resources for the nation. However, the period 1983-2000 had witnessed three petroleum tax relaxations. These took place in 1983, 1987-88, and 1993. These relaxations presented a clear change in the type of the UK governance of its petroleum resources from a proprietorial to a non-proprietorial regime. This new type of governance petroleum resources continued to be accommodated under a unique type of mineral ownership in the UK, which was called in terms of the UK oil industry "the North Sea Model". This unique type of minerals ownership grants the concessionaire a mining and economic right but not a mineral right. Therefore, it accommodates private interests under public control.

This thesis explores and tests the historical rationales for the three UK petroleum tax relaxations. The investigation of these rationales is based on three viewpoints: the Government, the UK oil industry, and academics. The tests of the rationales showed that the 1983 petroleum tax relaxation was not successful in achieving its proposed aims, which were expressed in the rationales. The 1987-88 petroleum tax relaxation was successful in stimulating extra investments in new areas, and in increasing the cash flow of the UK oil industry. This increase in investments and cash flow were at the expense of the Government who paid £216 million in 1992 because of PRT allowances and relief. However, the 1993 petroleum tax relaxation left the Government with a very small economic rent from new oil fields, which was based only on the ordinary corporation tax.

The results of this thesis show that the UK Government was always the revenue loser as a consequence of these tax relaxations. These were the key drivers of changing the UK governance of its petroleum resources from proprietorial to non-proprietorial regime. This might be because of depending on wrong judgment to any potential petroleum resources *in situ,* and a wrong following to the Ricardian rent theory.

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LIST OF ABBREVIATIONS

APRT	Advance Petroleum Revenue Tax
BGC	British Gas Corporation
BNOC	British National Oil Corporation
BP	British Petroleum
BRINDEX	The Association of British Independent Oil Exploration Companies
CT	Corporation Tax
DOE	Department of Energy
DTI	Department of Trade and Industry
EMV	Expected Monetary Value
FA	Finance Act
FT	The Financial Times
GEM	Global Economic Model
IEA	International Energy Agency
IIAPC	Independent Indonesian American Petroleum Company
IPC	Iraq Petroleum Company
IRR	Internal Rate of Return
Mbo	Million Barrels of Oil
Mboe	Million Barrels of Oil Equivalent
MCM	Million Cubic Metres
MT	Million Tonnes
NOC	National Oil Company
NPV	Net Present Value
PRT	Petroleum Revenue Tax
PSC	Production Sharing Contracts
SOV	Statement of Value
SPD	Supplementary Petroleum Duty
UKCS	United Kingdom Continental Shelf
UKOOA	United Kingdom Offshore Operators Association

CHAPTER 1: INTRODUCTION

1.1 Background to the Research Problem

Oil and gas exploration and production activities, and the companies which are involved in them, generally face taxation additional to that which applies to other industries and services. This is because the price of oil, for geological, market and political reasons, generally bears little relation to its cost of production, thereby giving rise to an economic rent, the size of which is mainly unrelated to the efforts of oil and gas companies. Such a prospect, reinforced by concepts of sovereignty over natural resource endowments, has encouraged governments to establish specific oil and gas fiscal regimes, both to prevent oil and gas companies from capturing all of the oil rent, and also to make a claim on that rent on behalf of the citizens of oil and gas producing countries.

The fiscal regimes are set out in oil and gas contracts which regulate the relationship between an oil and gas company and a host government. These agreements may be in one of two broad forms: concessions or contracts. The oil and gas agreement establishes and defines the share, or 'take',[1] of its two parties in the exploitable natural resources. Governments usually have power to impose fiscal terms which may secure their requirements from the resources. However, these terms vary according to the governance[2] of the mineral resources that a government is seeking to establish; proprietorial or non-proprietorial (see section 2.4.1). This is because each one of these two types has a different focus towards the ownership of the mineral resources, hence, the adoption of a particular one of

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[1] This expression is used to express the shares of a host government and an oil and gas company of the oil and gas resources. It is a synonymous with the government tax revenues and the revenues of an oil and gas company, or, 'rent', from these resources.

[2] This expression is used by Mommer (2002) to express the control of a proprietor over his mineral resources.

these two types determines the amount of revenue a government may obtain, or 'the government take'.

Investments in upstream oil and gas business are risky in general terms. [3] This is because of the uncertainty which is associated in particular with the exploration phase of this business. Furthermore, there is no necessary correlation between the costs of exploration and development expenditure incurred and the value of the oil and gas reserves discovered as a result of these activities. Revenues from oil investments are not generated for more than a decade in general, because of the time required for performing the many investment stages of this industry before revenues can be generated (Inland Revenue, 2005). Moreover, the capital required for these investments is high compared with other industries. This is because of the high costs of the fixed assets and essential infrastructure required for producing crude oil. These aspects make the investment in this industry distinguishable from other industries, and as a performance measure means that the oil industry requires a higher Internal Rate of Return (IRR) compared to other industries.[4] Investment in the upstream oil and gas is carried out in three separate stages. These are exploration, development and extraction (See section 5.4). Investment decisions in any of these stages are usually based on a number of parameters, such as prices and costs. These factors directly affect the IRR. Therefore, during times of increased oil prices governments may intervene by using the fiscal terms to take larger shares from the gross rent arising to the industry. On the other hand, in order to stimulate investments during periods of declining oil prices, the government may reduce the tax, as part of the overall costs of the oil industry. However, the above discussion raises the question of what kind of fiscal regime should be established, for example, whether or not it should just charge a rent for the use/extraction of sovereign natural resources. It also raises the question of whether it should become more involved in influencing the behaviour of oil and gas companies, by using the fiscal regime, to encourage or discourage production.

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[3] The upstream oil and gas industry includes exploration, appraisal, development, production and basic processing of crude oil and natural gas.

[4] The Internal Rate of Return (IRR) is the discount rate that will cause the net present value of an investment to be zero (Drury, 2005, p. 236).

This thesis is set in the context of the two broad alternatives (proprietorial and non-proprietorial), presented above, because the UK has, over time, come to use its fiscal regime more and more as a tool of intervention. This became particularly apparent from the 1980s onwards after the initial period of fiscal tightening which had occurred in the 1970s with the aim of securing a higher share of rents for the UK during a period of high oil prices. The Government became increasingly concerned and wanted to stimulate more production and then to sustain it, particularly after 1986 when oil prices fell very sharply. Thus, it was that the UK underwent three fiscal 'relaxations' in 1983, 1987-88 and 1993 (see section 4.2) by the end of which new fields would only be subject to ordinary corporation tax (CT), and royalties were on their way to being abolished (see sections 3.4.3 and 3.4.4). But did these interventions actually work? This thesis asks this question, almost for the first time,[5] and the answer or answers are extremely important for assessing the validity of the interventionist approach. In other words, the UK appears to have sacrificed fiscal revenues in order to stimulate or maintain production, but was this sacrifice actually worth it in terms of the results which were achieved?

The oil and gas industry commenced profitable operations in the UK sector of the North Sea earlier in the 1970s. The UK Government tried in the first decade or so of operations to secure as much as it could of the output from North Sea oil. This was through establishing and tightening up a petroleum fiscal regime. This helped the Government to obtain more than 90 per cent of the oil industry's revenues from the North Sea oil during the late 1970s and early 1980s.[6] The very tight terms of the fiscal regime had negatively affected oil operations in the North Sea during that period. These effects, in addition to pressure from the oil and gas industry, had caused the Government to introduce the first petroleum tax relaxation in 1983 (see section 4.3.1). However, a number of factors, beside the sharp decline in oil prices in the mid 1980s, had made the Government introduce the second petroleum tax relaxation in 1987-88 (see section 4.3.2). It was claimed

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[5] For similar studies see section 5.7 on page 150 of this thesis.

[6] The marginal tax rate during the late 1970s was 91.6 per cent. This rate is calculated at 12.5 per cent royalty; 20 per cent Supplementary Petroleum Duty, 75 per cent Petroleum Revenue Tax; and 52 per cent Corporation Tax (see chapter three).

that this tax relaxation cost the Government money in 1992, and this was a major reason that persuaded the Government to form the third petroleum tax relaxation in 1993 (see section 4.3.3). The first two petroleum tax relaxations, 1983 and 1987-88, were directed towards specific areas, or 'new fields', which were in deeper water and which experienced harsher weather conditions and expected to generate extremely high costs. The third relaxation did not target a specific area, but was directed to fields which developed after 1993.

This section has presented a general introduction to the research problem. The next section introduces the objectives of this research.

1.2 Research Objectives

This research is exploratory in nature. It aims first at exploring the historical rationales which underpinned the UK petroleum tax relaxations, and secondly, at testing them from an *ex-post* viewpoint. This investigation will use resources from the Government, the oil and gas industry, and the work previously done by academics. The testing will help in deciding whether the Government policies behind the rationales for the tax relaxations were achieved. Moreover, testing should clarify the type and judge the successfulness of mineral governance that is being used in the UK. These objectives will show the significance of this research and its uniqueness first in exploring, and secondly, in testing the historical rationales for the petroleum tax relaxations. Furthermore, it will evaluate the success of the interventionist approach in accelerating oil and gas investments by using the fiscal regime in the UK. These objectives will be achieved by a sequence of steps that will be demonstrated in the following chapters of this thesis. The following section indicates the thesis structure and how it will address these issues.

1.3 Thesis Structure

To achieve the above-mentioned objectives, this thesis is divided into nine chapters, which are linked together methodologically. The first four chapters, apart from this introduction, present a clear theoretical basis which will help in extracting the rationales and testing them in the following three chapters and

drawing a conclusion in the last chapter. The following paragraphs outline the structure of this thesis with a brief description of each chapter's contents.

Chapter Two (Literature Review: International Oil and Gas Agreements)

This chapter will present a general introduction outlining the emergence of different types of oil and gas contracts. This is to show the type of contracts which have been used globally for upstream oil and gas investments over time, and to highlight the types of oil and gas contracts which are in use in the UK oil and gas industry. It will also tackle the issue of sovereign rights over oil and gas resources. This will illustrate the differences between two types of governing mineral resources, namely proprietorial and non-proprietorial. This last will be a key point in defining the type of governance exercised over UK mineral resources, and this will be based on the results of testing the rationales for the UK petroleum tax relaxations. The chapter will shed light, from different viewpoints, on the concept of economic rent, because this latter is considered a target for owners of mineral resources for tax takes (see section 2.3.1).

Chapter Three (The Evolution of the UK Petroleum Fiscal Regime)

This chapter will explain the history of UK petroleum legislation up to 2000. It will address the components of the UK petroleum fiscal regime. This will, in addition to reviewing the petroleum tax system, illustrate the nature and mechanism of these components. The chapter will discuss three main key issues of historical significance, namely, tax changes, licensing, and oil and gas production. These issues will be discussed over defined time periods, which are: 1964-1980, 1980-1990, and 1990-2000. The significance of choosing these dates is discussed in section 3.1. The discussion of the historical evolution of the UK oil and gas taxation system will provide context to the UK petroleum tax relaxations. Defining these relaxations is a step which is succeeded by exploring and defining the historical rationales for these relaxations. This issue will be the subject of chapter four.

Chapter Four (Rationales for the UK Petroleum Tax Relaxations)

This chapter will illustrate the meaning of a tax relaxation from the Government and the oil and gas industry points of view. It will also shed light on possible

Government aims for such relaxations. After that, the rationales for the UK petroleum tax relaxations will be presented in chronological order: 1983, 1987-88, and 1993. The discussion of the rationales for each relaxation will be presented from the different viewpoints involved. These are those of the Government, the oil and gas industry and academics commentary and analysis. The summary of this chapter will present in three tables the extracted rationales from the above-mentioned three sources for the three petroleum tax relaxations. Tables will be used to demonstrate the rationales of each petroleum tax relaxation. The tables will refer to each party's underlying beliefs in each rationale.

Chapter Five (Methods and Methodology)

This chapter will highlight the nature of investments in the oil and gas industry, and define and explain the three investment stages in this industry. After that, the criteria for making investment decisions in the oil industry will be clarified. The role of oil prices in making investment decisions will also be discussed. These sections will illustrate the criteria which oil and gas companies use when making investment decisions. They will also clarify how a government may use the fiscal regime as a tool to encourage investment at any particular stage, or in a specific geographical area of its territories. Based on these sections, the broad lines of the methodological approach of testing the rationales will be set out. The chapter will consider a number of studies similar to this research, and also show differences between this research and others. After that, it will define and explain the research methods used in collecting data. The nature of the data required for this research will also be defined. The chapter describes the Global Economic Model (GEM, v. 3.01) of Wood Mackenzie (2004), one of the main sources of data for this research, and an essential tool for running the tests. With regard to the methodology issues, the chapter will point out that the detailed methodologies for testing the rationales are presented in the analytical chapters.

Chapter Six (Testing the Rationales for the UK 1983 Petroleum Tax Relaxation)

This chapter will present the tests of the individual rationales for the first UK petroleum tax relaxation. It will first name fields which benefited from the 1983

petroleum tax relaxation. After that it will present the *ex-post* and the *ex-ante* analyses for the effects of using actual or predicted oil prices on investment decisions. Finally, a summary of the conclusions of the rationales' tests will be presented.

Chapter Seven (Testing the Rationales for the UK 1987-88 Petroleum Tax Relaxation)

This chapter will present the tests of the individual rationales for the second petroleum tax relaxation. After showing the tests, the chapter will highlight the conclusions of these tests.

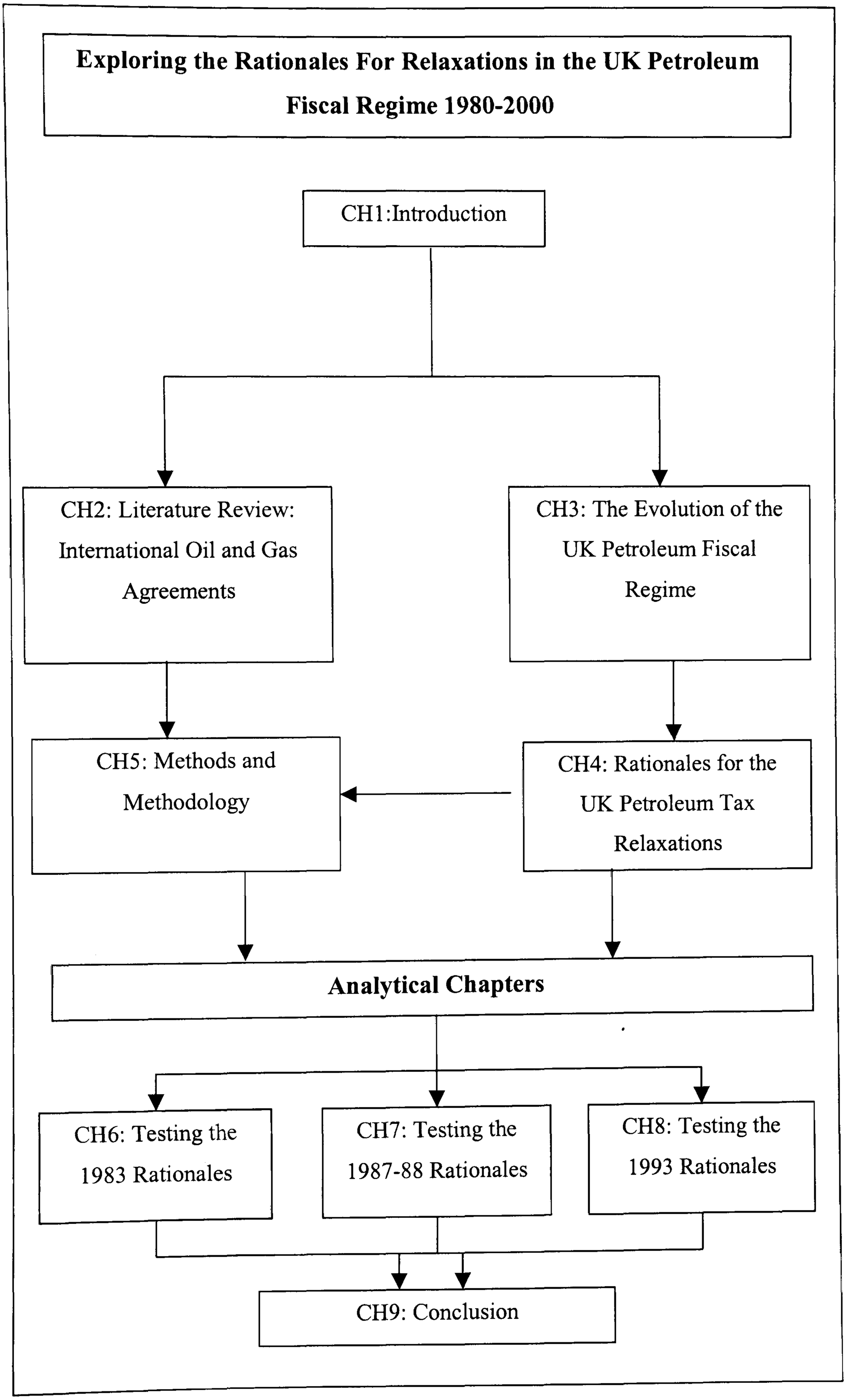
Chapter Eight (Testing the Rationales for the UK 1993 Petroleum Tax Relaxation)

This chapter will present the tests of the rationales for the third UK petroleum tax relaxation. It will also summarise the conclusions of these tests.

From the above description it can be seen that the work on this research is in two main stages. These are: 1) theoretical part which includes the literature review chapter, the evolution of the UK petroleum fiscal regime chapter, the rationales chapter, and the methods and methodology chapter; and 2) the analytical part which includes the three rationales' test chapters and the conclusion chapter. Figure 1-1 illustrates this structure and shows these levels.

The next chapter goes on to describe the different type of oil and gas agreements and the type of oil contracts that are in use in the UK.

Figure 1-1: Thesis Structure



CHAPTER 2: LITERATURE REVIEW: INTERNATIONAL OIL AND GAS AGREEMENTS

2.1 Introduction

This chapter is one of the keystones of the structure of this thesis. This is because of its role in the theoretical part of the thesis, which aims at exploring and testing the rationales for the UK petroleum tax relaxations, and evaluating the successful of the oil tax relaxation policy in increasing oil investments. The purpose of this chapter is to describe the different forms of oil and gas agreements in general, and the UK type of oil and gas contracts in particular. It also describes the concept of economic rent in general and provides a developmental conceptualisation of this concept regarding the oil and gas industry. In so doing, it will shed light on the issue of governance mineral resources. This last is a significant one for two reasons: 1) it will help developing an understanding of the behaviour of an owner of mineral resources in collecting his economic rent from a contractor; and 2) it will provide an understanding of the interventionist approach in accelerating investment activities by using the fiscal regime. The next paragraph outlines the contents of this chapter.

In achieving the above-presented purposes, this chapter will be in two parts. The first will cover the contents of oil and gas agreements in some detail. First of all it will discuss the evolution of different types of oil and gas agreements. This section will deal with the issue of the sovereign rights over oil and gas resources according to different types of oil and gas agreements. This will clarify the major differences between two main types of oil and gas agreements (concession and contractual). After that it will illustrate the main categories of oil and gas agreements in each type, namely; concession systems, concession agreements with the government participation, production-sharing contracts, and service contracts. It will shed light on the reasons for developing these agreements into new forms and the probable reasons for rejecting certain types in favour of others,

resulting in possible movement from one type of agreements to another. This will provide a suitable basis for discussing the UK type of oil and gas agreements, and presenting its unique features compared with the ordinary concession. These will be followed by discussing the idea of what is an ideal fiscal regime. The second part deals with issues of governance the oil and gas resources. This will be through recognising how a landlord behaves when targeting the output of the tenant according to different types of governance. This in turn will help to define the type of UK governance of its oil and gas resources. In doing this, the first section will illustrate why there are special taxes and duties in the oil and gas industry. Then it will illustrate different definitions and attitudes towards the economic rent concept. Subsequently, it will explain how different types of mineral governance target different parts of the tenant's outcome, or 'rent' (see section 2.3).

The international oil and gas company, in order to obtain the right to conduct an international oil and gas business, must enter into a contract with the host country, 'the minerals' owner'. This contract gives the international oil and gas company the right to explore for oil and gas reserves. These contracts are complex and vary widely from country to country (Gallun et al., 2001, p. 581). The contract between a host government and an international oil and gas company will establish what kind of payments the host government should receive, and how much of the reward the international oil and gas company will be entitled to retain. Usually the local legal system of the host government determines the exact nature of payments that the host government receives. These payments could be: 1) up-front bonuses; 2) exploration and production related bonuses; 3) royalties; 4) federal and provincial income taxes; and 5) duties and special petroleum taxes (Gallun et al., 2001, p.581; Johnston, 1994, p. 20). It could also be dividends from state oil companies and a share of the production under Production Sharing Contracts (PSCs).

The next sections describe in some detail the empirical components[7] of oil and gas agreements.

2.2 Evolution of Different Types of Oil and Gas Agreements

A number of authors, (Gallun et al., 2001, p. 582; Johnston, 1994, p. 21; Barrows, 1983, p. 1), argue that there are two systems for oil and gas agreements. These systems are concessionary and contractual. They divide concessions into: a) concession systems; and b) concession contracts. Also, they divide contracts into two types, namely: (1) production sharing contracts (PSCs); and (2) service contracts. These types do not have a standardized format, in that each of them may contain some characteristics of the others plus its own format (Machmud, 2000, p. 34). Johnston (1993, p. 61) points out that, in general, PSC terms and conditions, compared with the terms and conditions of the concession system, are complex. This needs to be considered together with geological dimensions, political risk, distance to supply bases, transportation costs, the history of the country's relations with foreign investors, and other economic factors (Mikesell, 1984, p. 2).

The questions that may be asked here are: what are the main differences between these two systems of agreements, and why might a contractor prefer concessions to contracts? The next section explains in some detail the main difference between these two systems of agreements in terms of sovereign rights.

2.2.1 Sovereign Rights

The main difference between the two systems, concessions and contracts, arises from different attitudes towards ownership of the mineral resources. Under the concession system the concessionaire is the owner of the minerals, while the state is the owner of these minerals under the contractual system (Johnston, 1994, p. 21; Gao, 1993, p. 30; 2000, p. 36). In this regard Knowles (1973, p. 75) states:

> "The most important thing in the difference between a concession and non-concession is the matter of ownership of the oil. The fundamental

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[7] The empirical contents of the oil and gas agreements refer to the theoretical description and the mechanism of these contracts.

> principle underlying a concession, and highly favoured by foreign oil companies, is that the government owns oil in its natural geological form, but as soon as man has done something to it, he is the owner of the oil. In other words, oil at the well-head becomes foreign property".

Generally, under the concession system the landowner (proprietor) receives his rent for granting a lessee a right to his land in forms of royalties in kind or cash or even a percentage based royalty. The landowner receives his rent which may or may not take account of issues such as limitations on production volumes, selling prices, and so on. In other words, the tenant, 'the oil and gas company', is the legal owner of the minerals during the concession period, but not of the land or the sea where the minerals lie. Thus, the tenant has the right to operate freely within the concession land, according to terms and conditions of the concession agreement, which governs the relationship between the state and the oil and gas company. At the end of the concession agreement the ownership of the minerals returns to the state, 'the land/sea owner', unless the concessionaire carries on by making a new agreement with the state or by some extension of the concession agreement. However, the case of UK concessions is different. The law grants the concessionaire the right only to obtain the products from the concession area of the UK land or sea and gives him a title to these products only. The right here is similar to the right granted to catch fish. Hence, it gives the concessionaire a title to the production but not to the minerals *in situ*. Also the Government keeps the right to change any of the concession terms (Cameron, 1983. p. 50; Inland Revenue, 2006).

In the case of a contractual system the state is the owner of the minerals, and the oil and gas company plays a role as a partner in the operations for a share of the final products. In some cases the oil and gas company, according to the contractual terms, has to pay rent in form of royalties and/or bonuses to the host government for access to the host government's land. However, considering the terms of mineral rights, mining rights, and economic rights enables us to understand the difference between concessions and contracts. Under concession agreements, the concessionaire who pays royalties to the host government owns all mineral rights, mining rights, and economic rights, during the concession period. In the UK case the concessionaire is granted mining rights and economic

rights. Under the contractual system mineral rights and mining rights are owned by the host government and the contractor obtains an economic right based on his working interest share of production at the export when commercial production starts (Machmud, 2000, p. 38). [8] Generally speaking, it can be seen from the above discussion that oil and gas companies prefer to work under concession agreements than contractual agreements. The former grants them more freedom and flexibility of work conditions, and also grants them a larger share in the output and management of resources.

The next sections will discuss the empirical content and the conceptualisation frameworks of these types of agreements in some detail.

2.2.2 Concessions

This section deals, mainly, with the definition of a concession and the main features of both the old and new concession agreements.

Gao (1994, p. 12) defines a concession as:

> "A privilege granted by a government to an individual or group, for developing certain resources or of constructing certain public works".

In the oil and gas industry field, Machmud (2000, p. 34) defines a concession as:

> "A grant by a country to a foreign company to develop its oil reserves on an exclusive basis in a defined area during the duration of the agreement".

Based on these definitions, the host country grants the international oil and gas company a right to explore, develop, drill, and produce within the concession area for a defined period of time, and sell the minerals. Royalties, and bonuses in some cases, may be paid to the host government.

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[8] Machmud (2000, p. 37) defines mineral rights as: "the rights that deal with the ownership of the minerals in the ground", mining rights as: "the rights to bring the minerals to surface", and economic rights as: "economic rights deal with the ownership of the minerals once they have been mined".

According to the old concession concept oil and gas companies had rights to control large areas of land and/or sea to carry out their operations. Governments of producing countries interfered little in oil and gas activities, and had a fairly small share of the oil and gas output (Noreng, 1980, p. 13). Most of the old concessions, although they varied from one country to another, had the following features:

1. The international oil and gas company was given the right to carry out its explorations and developments in a defined large area (the concession area).
2. The international oil and gas company had to carry out a minimum amount of drilling over a certain period of time.
3. Old concessions defined a period of time, roughly 60 to 75 years, for international oil and gas companies to carry out their exploration and production activities.
4. In some cases, according to the concession terms, the international oil and gas company had to supply the local government with a certain amount of produced oil for local consumption. This oil could be free of charge or at a price below those prevailing in world market.
5. The international oil company had to pay an annual rent and royalties to the host government.
6. Foreign companies had exclusive rights to all facets of petroleum operations.
7. Foreign companies had property rights in the petroleum resources.
8. The property, licensed area, was to be transferred to the government upon expiry of concession (Mikesell, 1984, p. 21; Gao, 1994, p. 13).

The next paragraphs shed light on two types of concessions namely: concession systems and concession agreements.

Concession Systems

This section illustrates the contents and describes the mechanism of the concession system.

Under this system the oil and gas company, or 'the contractor', pays all of the costs associated with exploration, development, drilling, and production activities without any view to recovering these costs if oil and gas are not discovered. However, if commercial reserves are discovered and oil and/or gas produced, then title to the oil or gas resources ('production' in the UK case) will pass to the contractor.[9] At this stage the contractor should pay royalties to the host government when production occurs. The government of the host country usually receives revenues of some kind from the contractor in the form of production taxes, petroleum revenue taxes, value add taxes (VAT), and resources rent taxes (Gallun et al., 2001, p. 583). In terms of a concession period, because there was no standard format for concessions, duration was extremely long as it could run for about 75 years as in the Middle East and Indonesia (Machmud, 2000, p. 34). Countries having concessionary systems are, sometimes, referred to as tax/royalty countries.

Concession Agreements with Government Participation (Joint Ventures)

This section covers the contents of the concession agreements and sheds light on the main difference between the concession system and concession contracts, or 'joint ventures'.

Joint ventures between international oil and gas companies and host governments began to appear during the late 1950s in the Middle East (Seba, 1998, p. 458). At that time the host governments started to adopt policies based on nationalisation of their oil and gas industry and also created national oil and gas companies. These companies had to play pivotal roles in representing the governments while dealing with foreign oil and gas companies and at the same time playing an important role in the national economy (Machmud, 2000, p. 5). Under this type of agreement the government participated in the operations via a government-owned oil and gas company as a working interest owner. Under these agreements the contractor paid all of the exploration costs, exploratory drilling costs, and any

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[9] The ownership of a piece of land that contains minerals could be separated into ownership of the surface and ownership of the minerals. In such a case a piece of land might have two owners: one has the right to the surface and another has the right to the minerals. So, minerals rights refer to the ownership of any minerals beneath the surface (Gallun et al., 2001, p. 8).

other specified costs in the contract. In the case of finding commercial reserves, the government could share in the operations, and the contractor might be allowed, by agreement, to recover all or a portion of his up-front exploration-related expenditure. There were two methods the contractor could recover his costs: 1) by direct payment from the government; or 2) the contractor could keep the government's share of production until recovering the allowed costs (Gallun et al, 2001, p. 585). However, under these agreements, the contractor still had to pay royalties, income taxes, and other fiscal obligations required by the law and regulations of the host country. These types of agreements are generally referred to as "government participation" or "joint venture arrangements", as in the case of Colombia via the state oil company 'Ecopetrol' (Mikesell, 1983, p. 28).

The main difference between the concession system and concession contracts lies in the type of minerals control, or in other words, who grants the concession. If the ownership of the minerals, before the discovery stage, is private, then it is a concession system. If the state is the owner of these minerals then we are dealing with concession contracts. In both cases title to the minerals will pass, at the point of successful discovery, to the concessionaire who will hold this title until the end of the concession period (Gallun et al, 2000, p. 582). Figure 2-1 below presents the general structure of the concession. It shows how royalties are paid first, then operation costs (costs recovery), [10] to arrive at the taxable income. After deducting the income taxes we have the contractor's net income. The figure shows that the total contractor's share is $12.78, which comes to 64%, while the government's take is $7.22, which equals 36% (Johnston, 1994, p. 31).

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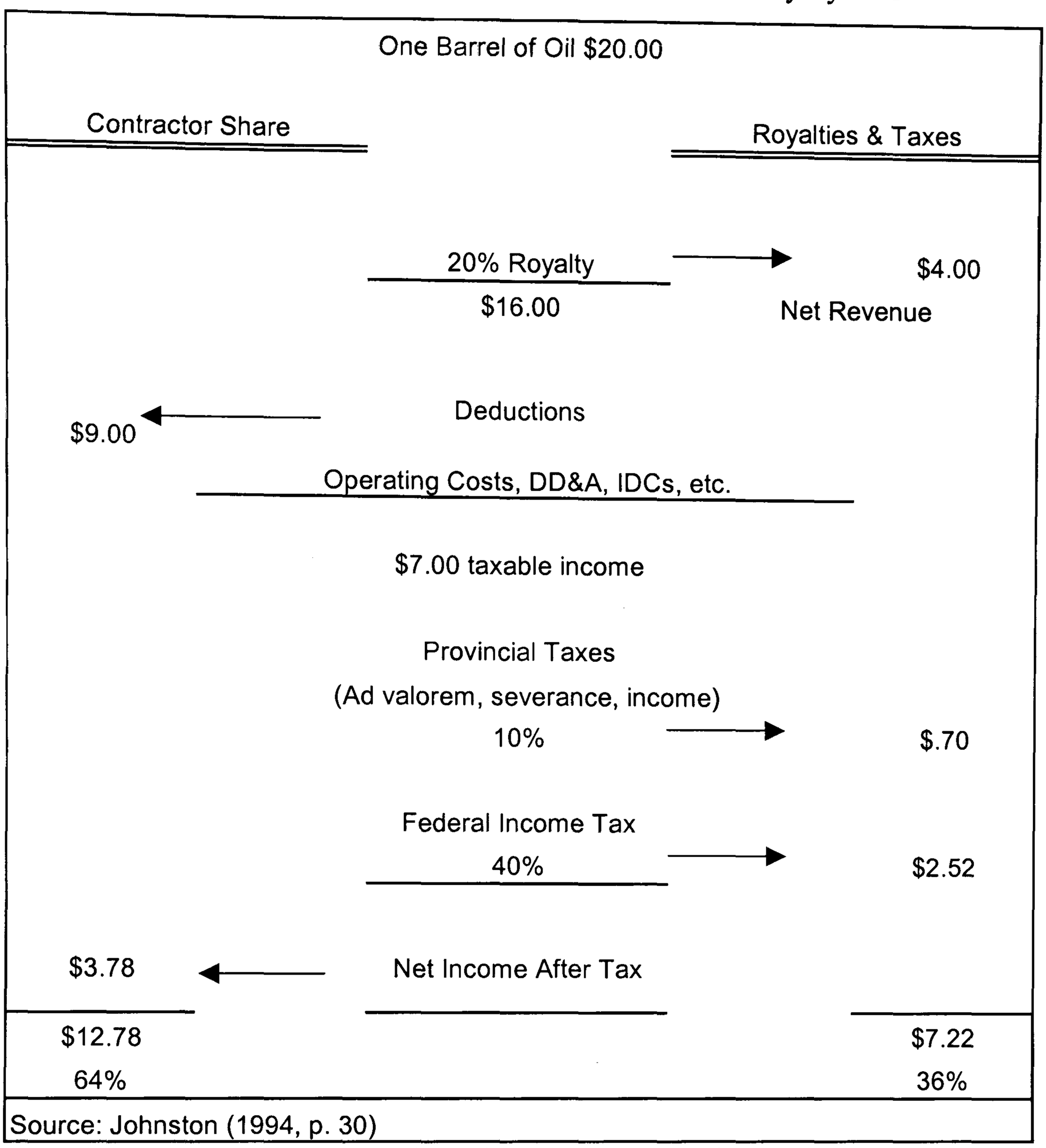
[10] Operation costs are: depreciation, depletion, and amortization (DD&A), and intangible drilling costs (IDCs).

Figure 2-1: General Structure of the Concessionary System



Source: Johnston (1994, p. 30)

Note: this diagram gives an example to show the sequence of tax and other deductions at different stages of oil and gas investments. It also shows the final take for each party. For a price of a barrel of oil at $20, the host government receives royalties ($4) straight away after the barrel is produced. After that the oil company deduct its operation costs ($9), to arrive at the taxable income ($7). Taxes might be deducted at different stages ($3.22), and after that what is left ($3.78) goes to the oil company as net income, or 'take'.

After describing the main features of the old concessions, the next section will illustrate how this system was established and the reasons for its demise towards the new concessions.

The Establishment and the Demise of the Concessions

Concession agreements were established in the early 20th century, and this system was the fashionable form of petroleum agreements between host governments and

international oil and gas companies until the 1950s (Machmud, 2000, p. 34). In the 1940s concession agreements in their traditional principles started to be less frequently used. In 1943 Venezuela set taxes on the profits of international oil companies in addition to royalties, and in 1948 Venezuelan tax law presented a concept of 50-50 profit-sharing scheme. This concept was followed by Saudi Arabia in 1950, and then most of the concession agreements around the world started to follow suit. So, profit-based taxes became a main financial feature of the new concessions, beside royalties which are not a profit related duty. Other changes to the traditional concession forms started to appear, such as changes to royalty rates, and the method of paying it. In 1952 the Iraq and Iraq Petroleum Company (IPC) introduced a new agreements based on a 12.5 per cent royalty to be paid in kind or cash equivalent. Furthermore, the introduction of a different type of bonus payments, the introduction of price controls, and the removal of tax holidays were all new features of the new concessions (Machmud, 2000, p. 36; Gao, 1994, p. 14).

The old concept of these agreements was no longer useful for countries wishing to place more control on their petroleum resources (Gao, 1993, p. 30). In this regard, Mikesell (1984, p. 23) argues that most of the old concession agreements in developing producing oil and gas countries were established and negotiated while these countries were under the control of the developed countries. So, when these developing countries became independent, they started to put extra control on their natural resources with the purpose of gaining extra revenues and, nationally, developing their own resources. The action of governments over time took two forms:

1 - Renegotiation of old concession agreements with international oil and gas companies; and
2 - Establishment of national oil and gas companies to carry out national petroleum policies and dominate the countries' oil and gas operations.

However, companies which still had concessions in developing countries in that period (1970s) lost their power to determine the volume and timing of production. Furthermore, in some cases, old concessions' owners continued to provide host

governments with technical services for fees paid by the host government (Mikesell, 1984, p. 24).

A number of factors helped the demise of the old concept of concession agreements and the appearance of the new forms of contracts. These factors are:

a. Oil and gas producing countries wished to control their oil and gas resources by "hands on" ownership and management of these resources. They were not able to practise this control through the concessions, e.g., the Indonesian case.[11]
b. The considerable increase in oil and gas prices on the world oil market in the early 1970s motivated producing countries to bargain for a greater share of the oil and gas resources.
c. Oil and gas producing countries felt that, under the concession system, they were not getting a fair share of their oil and gas resources. This led to the consideration of other types of agreements, which would enable the state to gain a higher share of its resources and more experience in the oil and gas industry.
d. Increasing the number of oil and gas companies decreased the bargaining power of the older international petroleum companies in competing for sources of crude oil in developing countries.
e. Competition among international oil and gas companies for concessions gave the host governments a good chance to force changes in the old concession agreements' terms, and to introduce new forms of agreements, such as joint ventures, with the purpose of increasing the host government revenues and having more control over natural resources.
f. The increased role of state-owned oil and gas companies in oil and gas operations decreased the dependence on foreign oil and gas companies. This put host governments in a strong position to negotiate the terms and conditions of petroleum agreements. The traditional role of these national oil companies was as ground rent collectors. Later on, and when they matured,

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[11] For wider discussion regarding the Indonesian case see Knowles, 1973 and Bartlett III et al., 1972.

they became fully producing companies, paying a ground rent and high tax bills in the same way as any foreign tenant. They played an important role by being a cover for any new or potential changes in legislation and taxation. This might be by paying taxes on behalf of the international oil and gas companies, 'the foreigner tenant', or even indemnities (Mommer, 2002, p. 183; Mikesell, 1984, p. 23; Bartlett III et al., 1972, p. 290; Gao, 1994, p. 18). However, on the other hand, these national companies might play roles unfavourable to the state. These roles are commenced when such companies distribute high dividends to their shareholders, or hide some of their profits in the form of different types of reserves or accumulated depreciation, or maybe investing all or part of their international profits outside the state to keep these profits out of the state's control.

Furthermore, in this regard Machmud (2000, p. 22) states:

> "An equally important issue was the government right to manage and, through managing, to learn and master the complex business of running an international oil and gas business, expertise they had hitherto been denied. The only way to obtain this expertise was by exercising hands-on management—something that could not be achieved under a concession type of arrangement. The production-sharing concept gives the state enterprise the right to manage; the concession does not".

Thus, the management issue was a major reason for countries to start thinking about reforming the old concession system into a new format which would enable them to have more control over their oil and gas resources, or present a new type of agreement providing the required control. The alternatives to the concession were production sharing contracts and/or service contracts. Machmud (2000, p. 22) adds:

> "If one's aim is to achieve a level of control or involvement in the exploration and production activities greater than that offered by the usual concession agreements, the solution must be sought in a risk-service or production-sharing type of agreement"

If production sharing and service contracts are the most suitable alternatives to the concession system, the question arises of why western countries keep using the

concession type of agreements. Machmud (2000, p. 22) argues the reason that western world never adopted the PSC system is that the concession concept fits the western way of doing business as the concession provides governments with a good level of control over their oil and gas industry. Moreover, it ensures a reliable supply of oil and gas, even if private oil and gas companies are running the industry. Machmud (2000) continues by saying that western governments are able to control their petroleum industry indirectly, and this can be done through representation or shareholding; also taxation is the instrument of collecting rent. As a result, Machmud (2000) points out, the UK found that there was no reason to change its then current regulator policies. This is because it would need more influence with exploration, development, and production activities, and it would be able to control and manage its oil and gas resources through the concession system. In this regard, the UK had its own model of concession that was, in fact, a modified version of the traditional concession concept. This model has often referred to as 'the North Sea Model'. The main features of the North Sea Model are:

1. Because of lack of knowledge and experience in the oil and gas industry and the need for such experience, dependence on international oil and gas industry was essential for the UK.
2. Licences were granted according to administrative allocation in areas smaller than in other producing oil and gas countries.
3. Gaining the required experience in the oil and gas industry, and at the same time benefiting from the oil and gas wealth, was to be achieved through state participation and the introduction of special additional petroleum taxation.

The North Sea Model allowed private and international oil and gas companies to be granted licences to participate in exploration, development, and production activities and to be regulated under royalties and special taxation to be paid in addition to ordinary company taxes. In other words, and consistent with Noreng's (1980, p. 34) statement, "it accommodates private interests under public control". The next chapter will deal with the UK petroleum fiscal regime in more detail.

The next section will discuss the contractual system in some detail.

2.2.3 Contractual System

Under this system the government, through a government-owned oil and gas company, plays an active role in development, and production activities, while the contractor acts as an operator, carrying out exploration activities at its own risk. If petroleum reserves are found and production occurs, then the contractor is entitled to recover all or a portion of the exploration and development costs, otherwise the contractor would not be able to recover any of the exploration costs (Gallun et al., 2001, p. 586; Bell et al., 1990, p. 95). Usually, under the contractual system, a kind of joint management group is made up of representatives from the contractor side, the government side, and from the government-owned company. The contractor is normally required to submit an annual work programme, or 'plan', and budget to the joint management group for review and approval. The joint management group generally makes all major decisions regarding the management of the project, including approval of all major expenditure, evaluation of results of exploration, planning and drilling of wells, and determination of the commerciality of drilling results (Gallun et al., 2001, p. 586).

The main feature of the production sharing contracts is that the state owns the resources, while the contractor receives a share of production for his services (Johnston, 1994, p. 39; Bell et al., 1990, p. 95).

The next sections present explanations for two types of contracts. These are production sharing contracts and service contracts.

Production Sharing Contracts (PSCs)

This section describes the main elements of production sharing contracts. It covers the following main points: definition, bonuses, royalties, cost recovery, and commerciality of discovery.

Indonesia is the pioneer of the PSCs, and the Independent Indonesian American Petroleum Company (IIAPC) signed the first Indonesian production sharing contract in 1966 for exploration of 14,000,000 acres offshore northwest Java. A discovery was made in August 1970, while production started in 1971 (Seba,

1998, p. 459; Johnston, 1994, p. 22; Machmud, 2000, p. 37). Johnston (1994, p. 22) states that the Indonesian PSCs are the standard of comparison for all PSCs.[12] Machmud (2000, p. 37) defines the production sharing contract as:

> "...a contract for cooperation between a National Oil Company (NOC) and a foreign or international oil company for a period of 20-30 years".

This definition refers to the two sides of the oil and gas operations agreement and the period of this agreement, though it does not illustrate the rest of the contract's terms and conditions.

However, according to the PSCs, the international oil and gas company bears all the pre-production risks and, when a commercial production from the contract area starts, is entitled to recover its costs plus a share of production, or 'profit oil', according to a predetermined proportion. However, if the contractor cannot find oil and gas in commercial quantities within the contract period then the contract will finish unless an extension is granted. If commercial petroleum is found then the host government owns the resources and the national oil company (NOC) joins the international oil and gas company in carrying out development and production of oil and gas activities (Machmud, 2000, p. 37).

The contractor has to pay to the host government, under the PSC and concessionary systems, an up-front bonus for signing the agreements. Such bonuses are referred to as a 'signing' or 'signature bonuses' (Gallun et al., 2001, p. 587; Johnston, 1994, p. 52). These bonuses are significant tools that motivate the minerals' owner to sign a lease with a contractor, and their value depends mainly on the expectation of discovering minerals and on the distribution of knowledge between the two sides of a negotiation (Mommer, 2002, p. 12). In this regard, Noreng (1980, p. 21) states:

> "The more governments understand about the energy market and the operations, motivations and calculations of the energy industry, the

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[12] For a sample of Indonesian PSCs, see appendix in Bartlett III et al (1972), pp. 337-363.

> greater their chances of imposing their points of view on the companies".

Moreover, the government receives 'production bonuses' when production reaches an agreed level, and in some cases also receives 'exploration bonuses'. These bonuses may not be recovered, for tax purposes, by the international oil and gas company as a part of its operation's costs (United Nations, 1995a, p. 7). Under the production sharing contracts system the contractor still has to pay royalties to the government, which range from zero to 15 per cent or higher. Some PSCs contain a sliding scale for royalties, taxes, and various other items. These provide lower royalty amounts when production is lower, and increases when production increases. Production levels in sliding scales should be carefully chosen, as if rates are too high then the system does not, effectively, have a flexible sliding scale (Johnston, 1994, p. 55).

The PSC should specify the cost, which could be recoverable, and the order of recoverability. It should also specify any limits on recoverability,[13] and whether costs not recovered in one period can be forwarded to subsequent periods (Johnston, 1994, p. 56). However, Johnston (1994, p. 57) identifies a few exceptions to the standard cost recovery rule. Some contracts do not have a limit on cost recovery (the second generation of the Indonesian PSCs), whereas other PSCs have no cost recovery at all (1971 and 1978 Peruvian model contracts). Furthermore, some PSCs put a ceiling on cost recovery and out of a total agreed percentage of the cost recovery the international oil and gas company recover a specified percentage and the remainder goes to the host government (the Egyptians and the Syrian PSCs).[14] Oil and/or gas that the international oil and gas company use to recover its costs is referred to as "cost oil", while the remaining oil after deducting royalties, taxes, and cost recovery is referred to as "profit oil". Profit oil is shared between the parties based on the terms and conditions in the contracts (Gallun et al., 2001, p. 590; Johnston, 1994, p. 41).

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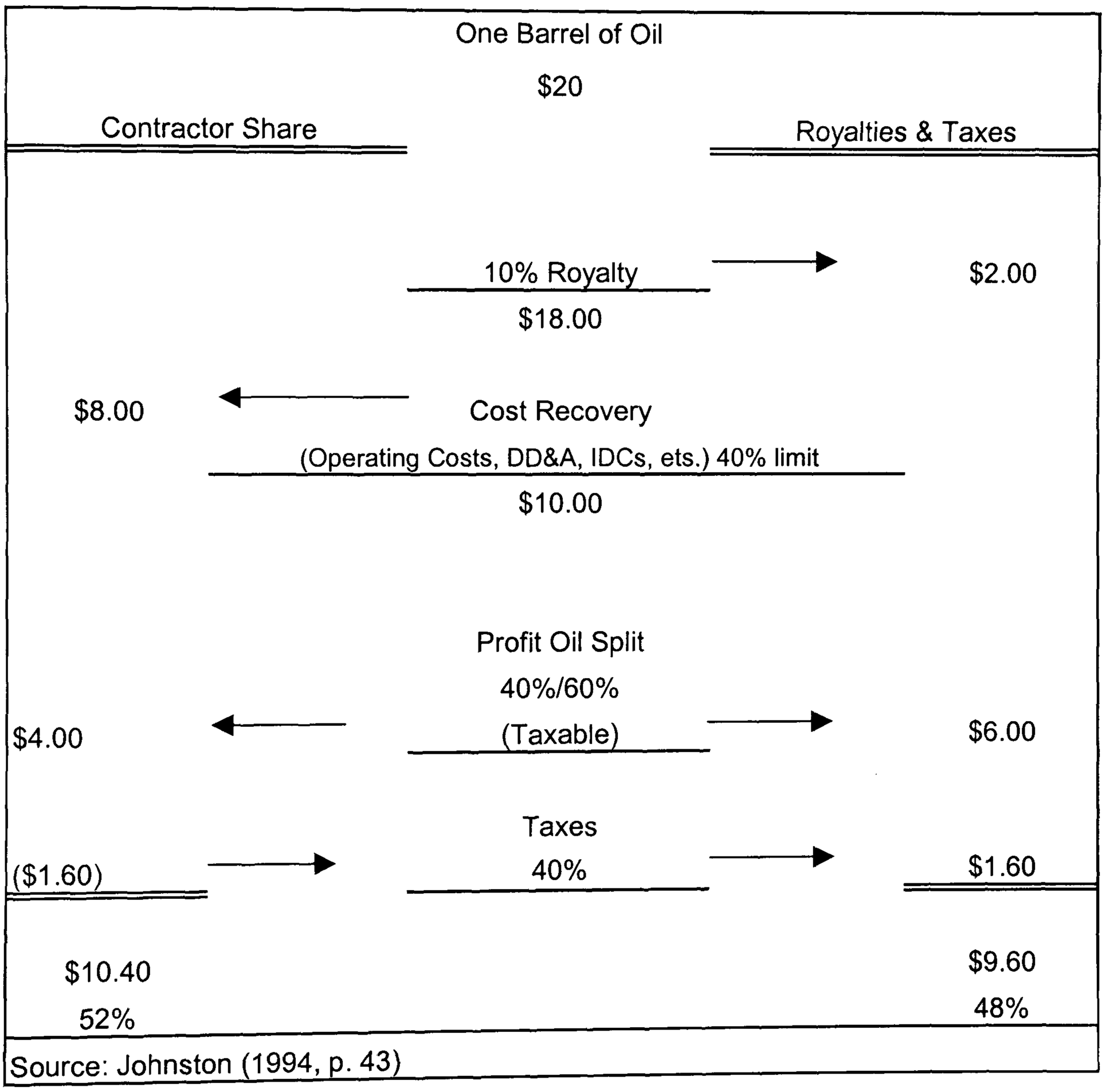
[13] Cost recovery limit or "cost recovery ceiling" typically ranges from 30 to 60 per cent (Johnston, 1994, p. 56).

[14] If the ceiling is 45 per cent on cost recovery, the company, for example, is entitled to recover 65 per cent out of the 45 per cent, while the 35 per cent goes to the government.

The decision as to commerciality is an important aspect of international exploration. Such a decision means that the contractor will recover all or part of his exploration costs which are of considerable value. On the other hand, the government looks at these costs as a liability. However, in some cases the contractor, according to the fiscal regime terms and conditions, is allowed to decide the commerciality. Then the contractor is required to prove that developing the discovery will generate profits for parties, the government and the contractor (Johnston, 1994, p. 65). Figure 2-2 illustrates general structure of PSCs.

Figure 2-2 General Structure of a Production Sharing Contract



Source: Johnston (1994, p. 43)

Figure 2-2 shows that the royalty comes "right off the top" (as it is in the concession agreement). After that comes the step of cost recovery.[15] So, we have, after the cost recovery, profit oil, which, unlike the concession case, is split

[15] General costs that are allowed to be recovered are: 1 - operating costs; 2 - intangible capital costs; 3 - DD&A; 4 - investment credits; 5 - interests on financing; and 6 - unrecoverable costs carried forward. However, most PSCs place limits on cost recovery (Johnston, 1994, p. 56).

between the international oil and gas company and the host government according to agreed percentages. Then the contractor's share of profit oil is subject to taxation.

Mikesell (1984, p. 28) claims that the initial forms of PSCs tried to prevent problems related to levying taxes by having them paid by the national oil and gas company. It was not necessary for the state-owned oil and gas company to decide the contractor's costs or even output prices. Each party to the agreement had the right to market its own oil and set the price as it pleased. However, in the early 1970s when oil and gas prices increased, oil and gas producing governments wanted to increase their revenue, or 'take'. Hence, they required renegotiation of the old PSC terms and they set new conditions for new PSCs to enable them to gain a greater share of the net profits.

To sum up, the main elements of a production sharing contract are duration of operations, royalties, cost recovery, taxation, commerciality, and profit oil split. These are among the essential points that should be covered when a fiscal regime is negotiated and designed based on PSC.

Service Contracts

Service contracts can be divided into risk service contracts and non-risk service contracts. In a non-risk service contracts the international oil and gas company provides the host country with services in the form of exploration, development and production activities. The host government pays a fee for these services to the contractor, and these fees cover all costs (Gallun et al., 2001, p. 594). Johnston (1994, p. 24) claims that this kind of contract is rare. The motivation for oil producing countries to use such contracts is because of the limited technical capacity available to them. They tend to hire the services of international oil and gas companies that have appropriate skills and equipment, e.g., Argentinean and Brazilian service contracts (Mikesell, 1984, p. 29). In this regard, Seba (1998, p. 46) states:

> "This type of agreement has great popularity in countries where the government finds it highly advantageous to be able to say that there is

> no taint of ownership, or claim on the host country's oil resources by a foreign entity".

Under risk service contracts the international oil and gas company bears all of the costs and risks associated with exploration, development and production activities. In the case of production, the contractor is entitled to recover his costs once the product is sold, and fees paid by the host government for his services (Gallun et al., 2001, p. 594; Barrows, 1983, p. 18). In other words, the contractor's revenues after taxes are based on a pre-agreed formula for sharing of revenues with the host government, that is, if the operations are successful (Machmud, 2000, p. 39).

Seba (1998) argues that there is another type of contract, which he calls a 'Tolling Contract'. According to Seba (1998, p. 461):

> "In tolling contracts the operating company takes on the entire economic burden of exploring, developing and pipelining and is paid only for each barrel, or tonne, of crude oil eventually delivered to the NOC at the designated point of delivery".

From Seba's explanation of tolling contracts it can be seen that it is more like a modified type of service contract.

The main differences between PSCs and service contracts lie in the types of contractor revenue. Under service contracts the contractor might receive his take in cash or crude oil, while under PSCs the contractor receives his share only in kind, not in cash. Under the former, if the production stage were reached then the contractor would be entitled to recover all his spent costs (Cameron, 1983, p. 16).

Based on the above discussion it could be said that different types of oil and gas agreements, and different types of minerals' governance, might suit different producing countries. The adoption of any of the agreement types and the forms of the mineral's governance depends mainly on different issues such as the geological and geographical nature of the country, the level of accumulated experience in the oil and gas industry available to the country, and its government's aims of developing its mineral resources. The question that could be

asked here is whether there is any kind of agreement, or a fiscal regime, providing fairness, or 'balance', for the two sides of an oil and gas agreement. The next section will discuss a number of authors' opinions about forming such an ideal oil and gas fiscal regime, which might provide balance and fairness to the two sides of the agreement.

2.2.4 An Ideal Fiscal System Design?

Bell et al. (1990, p. 89) state:

> "The diversity of laws, cultures, languages, and economic parameters has prevented a standardization of international agreements".

This suggests that one would not find the same contract terms and conditions in different countries or even in different territories within the same country. This is because geographical, political, and economic conditions differ from one country to another, or within the same country. There are several points to be taken into consideration when forming an oil and gas agreement. These are: 1) allocation mechanism; 2) work program; 3) duration and relinquishment;[16] 4) bonuses; 5) royalties; 6) cost recovery limit; 7) profit oil split and tax; and 8) government participation (Johnston, 2000, p. 122). Johnston (2000, p. 127) adds:

> "Fiscal design must be country specific, and there are often many tradeoffs. Yet, the design outlined here should accommodate a variety of conditions including shallow vs. deep water, high vs. low prospectivity, different cost environments, as well as substantial fluctuations in oil prices. It has built-in flexibility and efficiency, and this should provide a more stable investment environment."

Dur (1994, p. 115) adds further points:

1 . Progression of rights from exploration to development and production.

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[16] Relinquishment is a widely accepted provision in international oil contracts provides for the periodic reduction of either the geographical area covered by the agreement or the percentage interest owned by the oil company. In general, a typical schedule would provide six to eight years for exploration in three exploration periods with 25 per cent relinquishment of the original area in a contiguous block of acreage after each of the first two phases of exploration. After that, all but development areas associated with discoveries should be relinquished (Bell, 1990, p. 102; Johnston, 2000, p. 124; Machmud, 2000, p. 77).

2. Time for determining commerciality. Usually the host government determines if the discovery is to be considered commercial. However, in many countries the standard of commerciality means one discovery well plus one or two appraisal wells, which are able to give oil in commercial quantities.
3. Flexibility of exploration work commitment. Normally exploration commitments consist of: a) work scope; b) expenditure obligations; c) liquidated damages; and d) performance bond.
4. Nature of the irrevocable commitment. The most important expenditures in a project are those which are irrevocably committed to exploration. This is because of the high-risk nature of this investment.
5. Marketing rights. If the host country is an oil importer, then it is fair enough that produced oil, or a portion of it, goes to the domestic market.
6. Abandonment and restoration. Where the regime requires environmental impact studies and the restoration of the area to its pre-existing condition, the extent of obligations and costs associated with abandonment can be forecast, and obligations can be predetermined regarding who will bear these costs and duties when a field is to be closed down.
7. Sliding scale production sharing. It is beneficial to a contractor to persuade the host government that tax takes should be calculated on a field-by-field, but not on a company, basis. This is because such a treatment would reduce the total taxable profit for oil companies and would provide an incentive to bring new fields on stream.
8. Economic stability clauses. These are regarding the stability of tax treatments. Where new taxes are imposed or existing tax rates are increased the contractor will lose part of his rent. Therefore, this point should be clarified upon signing an oil and gas agreement with a host country to prevent any possible conflict between the two parties to the agreement.

However, there is some agreement among authors and specialists in the area of oil and gas contracts, for example Dur, 1994, Bond et al., 1987, Johnston, 2000, that an ideal regime should: (a) maximise stability of the business environment and minimise sovereign risks; (b) minimise or discourage undue speculation; (c) ensure a kind of balance between risk and rewards for both the international oil

and gas company and the host government; (d) minimise and limit the administrative process and complexity; (e) encourage market efficiency and healthy competition; and (f) provide enough flexibility to cope with changes in perceived prospectivity, and economic conditions (Johnston, 2000, p. 121).

Information about the geology of the area of the potential contract, political risks, and potential rewards is an important factor in designing and forming optimal rules. There should be a balance between the geological conditions of a contract area and the terms of a fiscal regime relating to that area (Hampson et al., 1991, p. 51; Johnston, 1994, p. 17; 1993, p. 6; 1997a, p. 238). Where the geological prospectivity is low and the industry infrastructure is undeveloped, the reward should be high for the oil and gas industry. In other words, the state take should be low to attract the oil industry to such areas of low geological prospectivity (Petroconsultant, 1996). In addition, systems with a high presence of factors such as government participation, royalties, and bonus systems negatively influence exploration and development activities. Hence, such factors are often viewed as inefficient as they can provide a disincentive to production (Gallun et al., 2000, p. 587; Bell et al., 1990, p. 97, Mahmud et al., 2002, p. 28).

In practice, when negotiating terms and conditions of oil and gas agreements, oil and gas companies' objectives are:

a) To maximise wealth, which can happen by finding and producing oil and gas reserves at the lowest possible costs and highest possible profit margin; and
b) To create a condition of long-term stability for themselves.

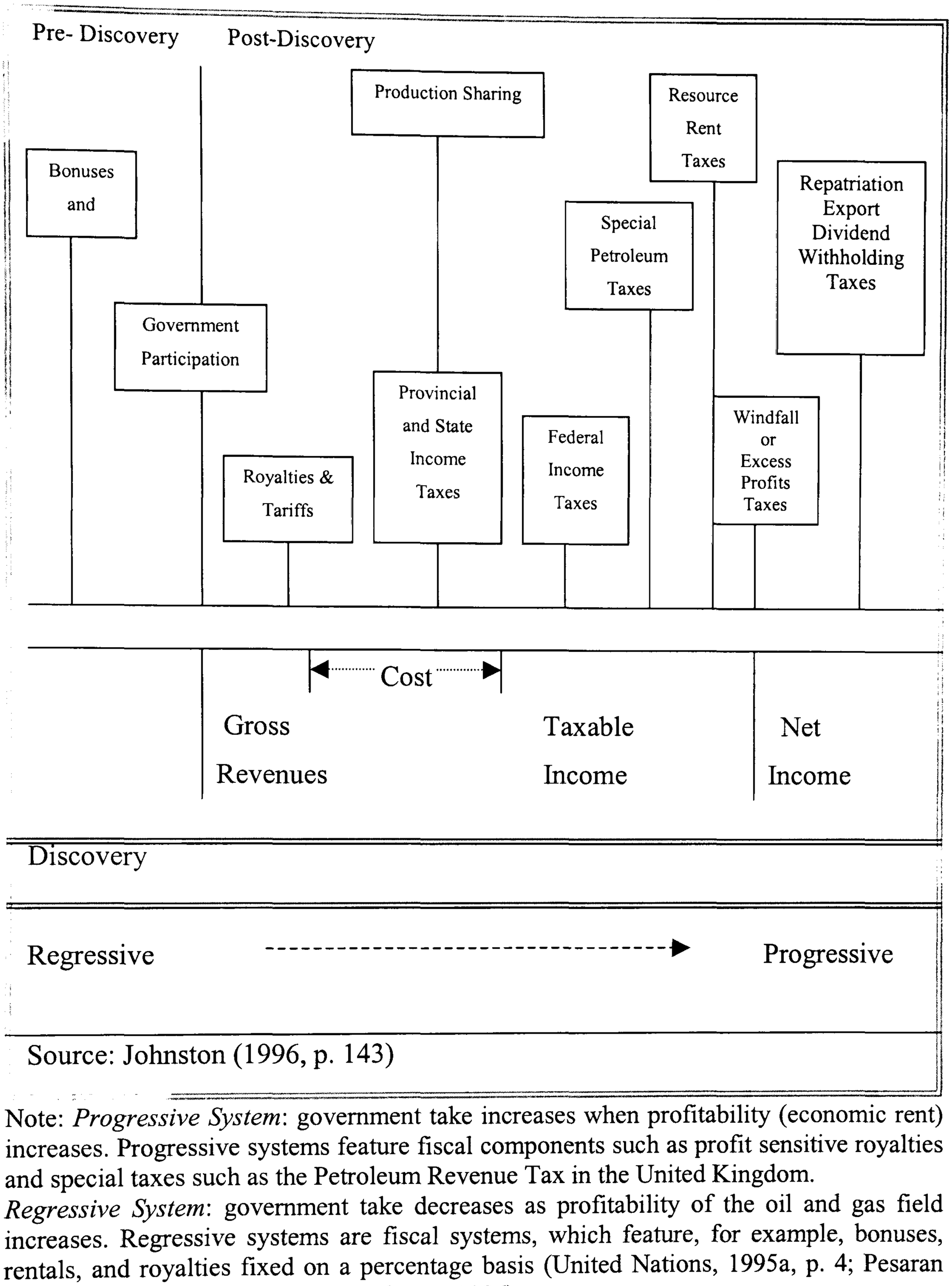
On the other hand, the government's objectives are to maximise the economic rent from its resources, control them, and consider development of experience in the oil and gas business which all provide the country with the ability to participate in the oil and gas operations (Johnston, 1994, p. 18; Noreng, 1980, p. 21; Seba, 1998, p. 454). For a government to achieve its objectives, there should be a combination of fiscal arrangements. For example, royalty payments guarantee early revenues for the host government, while resources rent taxes can play a role

in maximising the overall state take. At the same time, such taxes do not play a negative role in attracting oil and gas companies to explore and develop new fields (Kemp and Rose, 1983, p. 6). In other words, governments can achieve their objectives by adopting a proprietorial type of minerals' governance.

International oil and gas companies meet regularly with petroleum producing governments to discuss petroleum fiscal regimes' terms and conditions. However, governments still have a powerful position as they award licences to the highest bidder, and still have the ability to establish very harsh terms like high bonuses and low cost recovery. Further, some other governments require international oil and gas companies to relinquish a certain percentage of the contract area after oil is discovered, while others require the international oil and gas companies to relinquish all the undeveloped acreages. (Johnston, 2001a, p. 120). Figure 2-3 shows a possible process for designing an oil and gas fiscal regime.

The diagram illustrates how the intensive use of different items of the fiscal regime such as pre-production bonuses, government participation, high royalty rates, exploration, and production bonuses affect the description of the fiscal regime as being progressive rather than regressive. This is because the host government depends on pre-production payments beside a fixed royalty rate, and in the case of increasing oil prices; this would not increase the state take. The movement of a fiscal regime from regressive to progressive means an increase in the government's take at the expense of the contractor's take via harsh use of high profit tax rates. This causes disincentives to the oil and gas industry to operate in a country adopting such a policy unless the mineral resources promise a considerable over all profits to the oil and gas industry.

Figure 2-3 Elements of Oil and Gas Fiscal Regime



Source: Johnston (1996, p. 143)

Note: *Progressive System*: government take increases when profitability (economic rent) increases. Progressive systems feature fiscal components such as profit sensitive royalties and special taxes such as the Petroleum Revenue Tax in the United Kingdom.
Regressive System: government take decreases as profitability of the oil and gas field increases. Regressive systems are fiscal systems, which feature, for example, bonuses, rentals, and royalties fixed on a percentage basis (United Nations, 1995a, p. 4; Pesaran and Favero, 1990, p. 14; Petroconsultants, 1996).

To sum up, the basic economic aspects of a contract's or a licence's negotiation are the work commitment, or 'the plan', financial management capability, technical competence, and the fiscal terms. There must also be a balance between risk and reward (Johnston, 1994, p. 18; 1999, p. 138; Inland Revenue, 2006). The work commitments, Johnston (1994, p. 18) argues, control the risk side of the

equation, while the fiscal terms dominate the success ratio and the reward side of the equation. Johnston (1994) expresses this idea in an equation as follows:

$$EMV = (Reward \times SP) - [Risk\ capital \times (1-SP)]$$

Where:

EMV = expected monetary value.

Risk capital = bonuses, dry hole costs, geological and geophysical costs.

SP = success probability.

Reward = present value of a discovery based on discounted cash flow analysis discounted at corporate cost of capital (Johnston, 1996, p. 146).

Johnston (2000, p. 126) points out that the UK oil fiscal system is poorly designed, because licences are awarded on a work programme bids basis (see section 3.3). Furthermore, the commercial terms are almost entirely captured in a single profits-based corporation tax at 33 per cent.[17] Moreover, while the UK has a concession system, the royalty rate is zero for fields that obtained development permits after 31/03/1982, and there is no cost recovery limit. In this regard, Petroconsultants (1996) states:

> "The regime which most notably does not fit into any of the general trends identified above is the UK. Geological prospectivity and the development of infrastructure in the UK is relatively good and recent exploration successes suggest that large, profitable fields continue to be found".

This section has clarified the nature and mechanism of oil and gas agreements in some detail and has presented the more likely motivations for developing oil and gas producing countries to move from the concession system to other types of agreement, or even modify the old concession concept to increase the benefit to host countries. It also highlighted characteristics of an ideal fiscal regime. However, this ideal fiscal regime does not exist in reality, but rather two different forms of mineral resources governance i.e., proprietorial and non-proprietorial regimes. The next sections will discuss the issue of governance mineral resources and will also explain these two perspectives.

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[17] Currently 30 per cent (see footnote 28) for "large companies" into which category oil and gas companies fall.

2.3 Conceptualising Different Forms of Minerals Governance

This section defines different attitudes and understandings of the concept of economic rent. This in turn will be an essential step to understanding *how* the owner of mineral resources behaves, *why* he behaves in a certain way, and *what* he targets when charging his tenant for the use of his land and/or sea. This will help to identify the UK type of governance mineral resources. To start with, the following question can be addressed: why an international oil and gas company should, initially, pay royalties, taxes, or any type of duties, to a host government. This could be for one or more of the following reasons:

a For oil and gas companies to have access to a piece of land or sea to pursue their activities with the purpose of generating income from an expected commercial discoveries, they should bear a cost. These costs are in form of royalties and/or tax to be paid initially to the landlord, or 'the host government', to obtain the required access to his land or sea.

b Oil and gas are, by nature, exhaustible resources. Hence, to extract these resources from a property owned by another party, sell these resources, and make considerable profits, oil and gas companies should have to pay for depleting these non-renewable resources, which are the actual assets of the landlord.

c Profits being generated from the oil and gas resources are, in fact, supernormal, since there is a significant difference between the cost of extracting the oil and the selling price. Of course, oil and gas companies bear high levels of different types of risks during the long process of finding and producing oil and gas, but these supernormal profits should be taxed to secure a share of the value of these natural resources for the state and its citizens (Rutledge and Wright, 2000, p. 5; Bond et al., 1987, p. 34).

Therefore, for an oil and gas company to work in a host government's land or sea, certain duties and taxes are to be paid to the host government, or 'the landlord'. However, how does the landlord behave in collecting these duties and taxes from the oil and gas company? The next sections discuss the concept of economic rent

and the governance of mineral resources with the purpose of answering the above question.

2.3.1 Economic Rent

There is a variety of definitions for rent, and most of them show an inconsistent understanding of the concept. This section outlines a number of views of the concept of rent and how it applies to the oil and gas industry in general and to the UK oil industry in particular. It starts with outlining the Ricardian rent theory.

Ricardo (1821, p. 33) stated:

> "Rent is that portion of the produce of the earth which is paid to the landlord for the use of the original and indestructible powers of the soil. It is often, however, confounded with the interest and profit of capital, and, in popular language, the term is applied to whatever is annually paid by a farmer to his landlord".

He added,

> "In the future pages of this work, then whenever I speak of the rent of land, I wish to be understood as speaking of that compensation which is paid to the owner of land for the use of its original and indestructible powers".

Thus, according to Ricardo's definition, rent is what a landlord receives for the use of his land by another party. It would be a portion of the *produce* of the land. This becomes clearer as Ricardo (1821) made a link between the produce of a land and a profit from capital. If the investor cannot make profit out of capital, then he would not pay any share or dividends to his trade partners or shareholders. Therefore, the tenant would not be willing to pay rent to his landlord unless the land produced. Furthermore, the Ricardian rent theory is based on the idea of the existence of land of different richness and capacity for production. For an investor, or 'farmer', to gain access to a land he should expect to pay high rent for the best land and less for the poorer land. The difference in rent between the average quality land and the richer land is the Ricardian rent (Eatwell et al., 1987, p. 192). Figure 2-4 illustrates Ricardo's concept of rent. This theory can be applied to oil and gas resources. Oil in ground differs from one reserve to another in terms of quantities, qualities, and extraction costs. Different qualities of oil have different prices, and in general the larger an oil reserve is, the less the cost

and the greater the profit. This means that oil reserves of the best quality, with lower costs, and producing larger quantities are expected to yield higher rent in terms of royalties, bonuses, and other taxes. In this regard, governments try to impose new taxes or increase rates of existing taxes when oil prices increase, and stay high for a long time, to capture more economic rent from their oil resources.

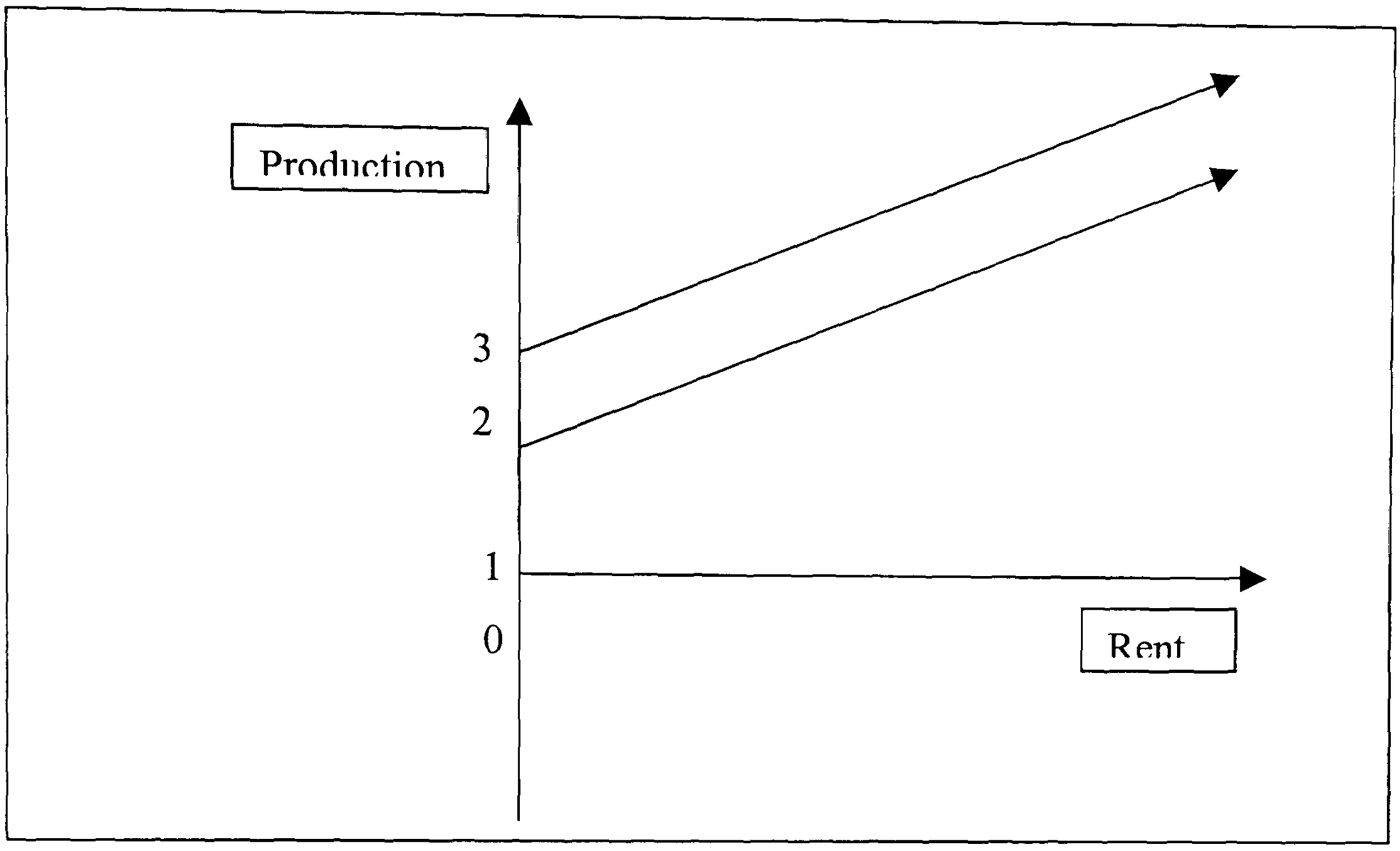


Figure 2-4: A Depiction of Ricardian Rent

Note: arrow number 1 represents the normal Ricardian rent which starts with production, while arrows 2 and 3 refer to the rent paid according to the richness of the land. This rent increases with the richness and fertility of the land.

Johnston (1994, p. 6) defines economic rent as:

> "The difference between the value of production and the costs to extract it. These costs consist of normal exploration, development, and operating costs as well as an appropriate share of profit for the petroleum industry. *Rent* is the surplus. Economic rent is synonymous with excess profits. Governments attempt to capture as much economic rent as possible through various levies, taxes, royalties, and bonuses".

This definition illustrates the technique of calculating the economic rent from the oil and gas industry point of view. Moreover, according to Johnston's definition, and from the oil industry point of view, rent is the share of oil that is considered as 'profit oil'. On the government's side, rent is what is annually extracted from the

oil industry for using its land or sea, or 'government take'. The government might receive the rent in different forms of taxes and bonuses, beside its share of the oil. Johnston's definition does not set production as a necessary condition for paying rent as it could be paid even in case of *nil* production. Up-front bonuses, clearly, represent this case. Figure 2-5 illustrates Johnston's concept of rent.

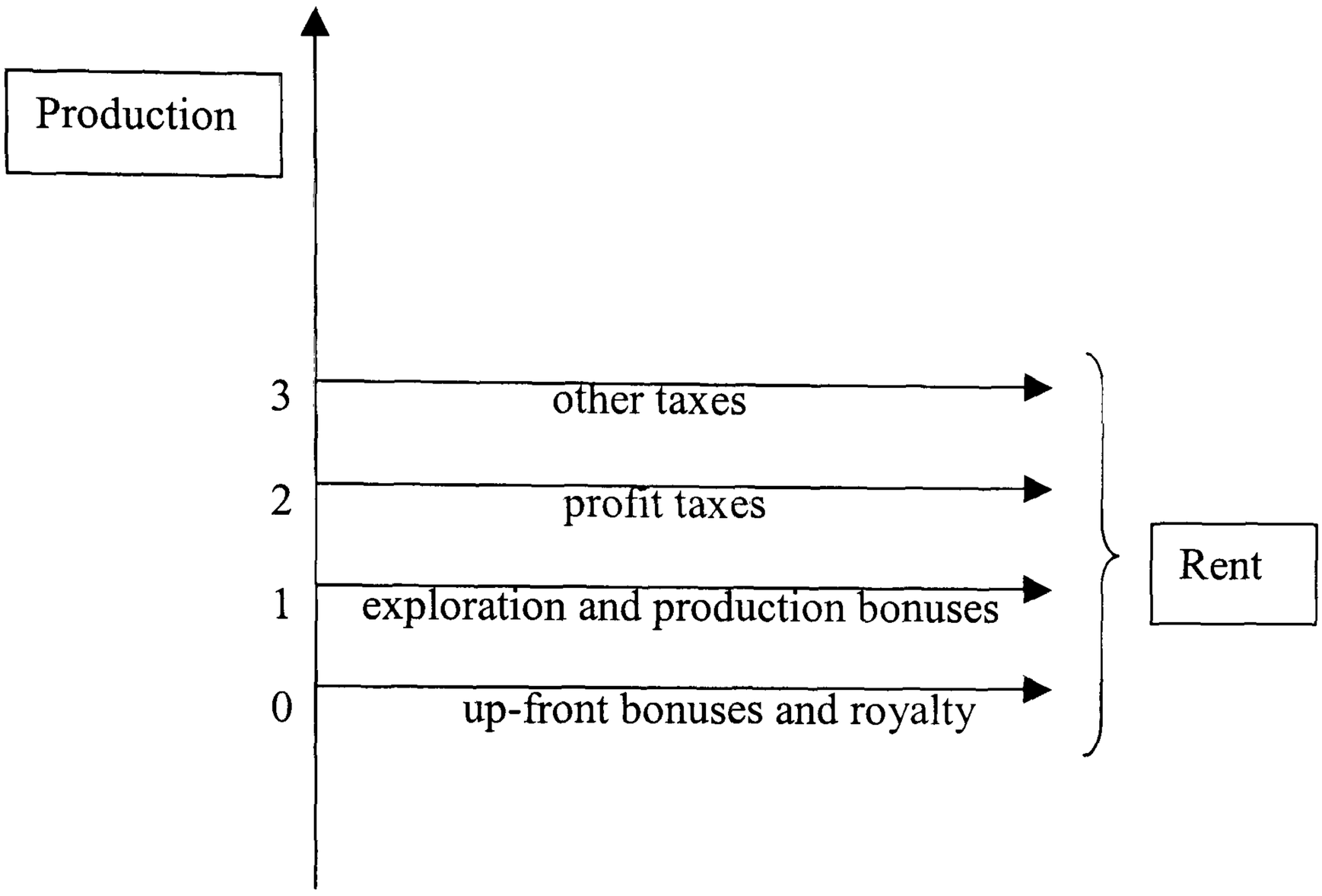


Figure 2-5: A Depiction of Johnston's Concept of Rent

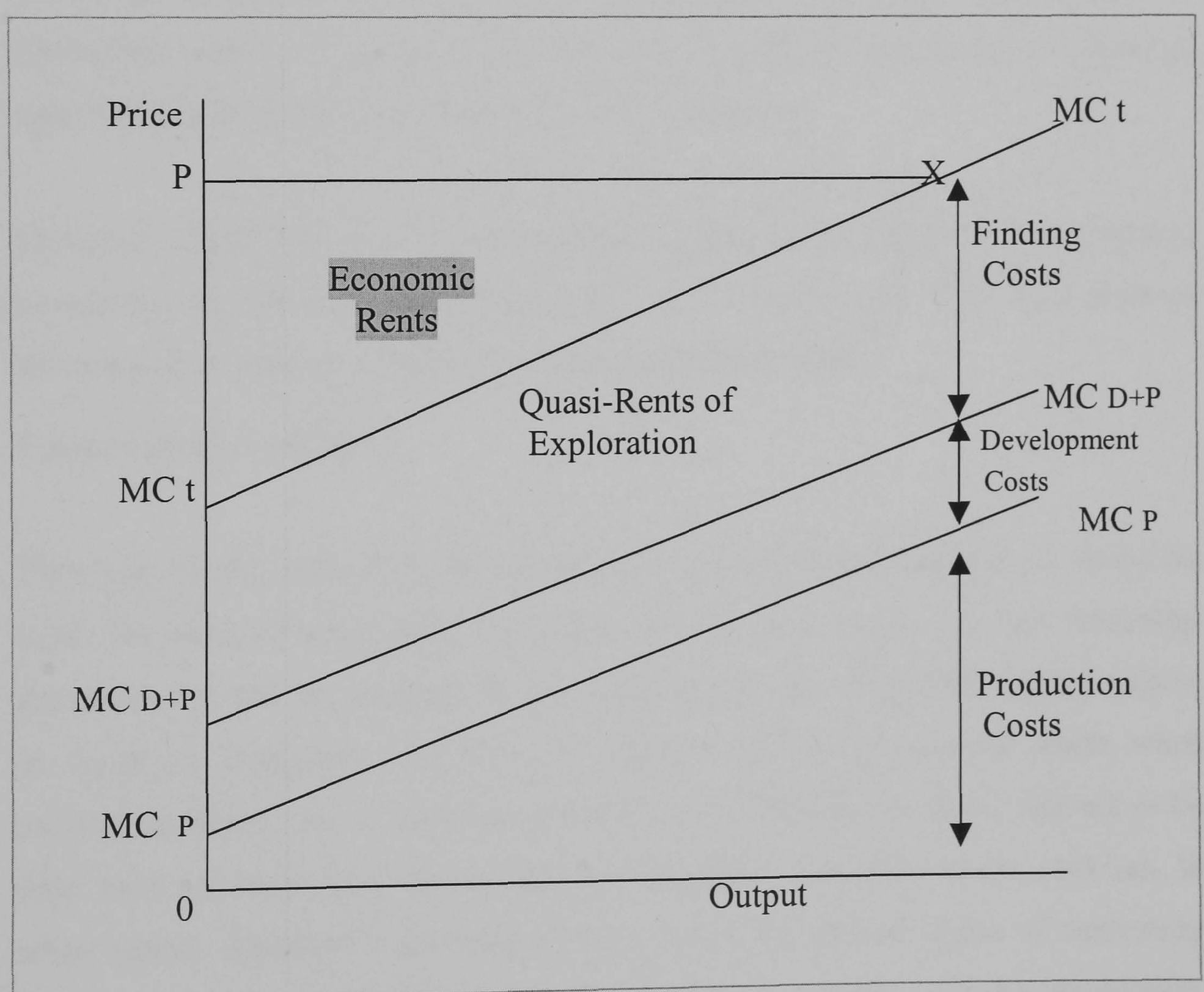
Note: arrow number 0 indicates a situation when the production is zero while the tenant has to pay rent in the form of up-front bonuses. Arrow 1 represents the state of production when the landlord receives an exploration and production bonuses and/or royalties. Arrows 2 and 3 indicate a high level of rent in the form of different taxes.

Rowland and Hann (1987) are of a similar opinion to Johnston regarding economic rent. They maintain that economic rent which occurs to an oil and gas company is the net present value of its investments. In this context, Rowland and Hann (1987, p. 4) state:

> "The economic worth of a licence to produce oil from a tract of the UKCS sea bed may be measured by the present value of the flow of future revenues from that tract's production less the present value of the flow 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".

Kemp and Stephens (1996, p. 63) see that economic rent arises after an oil and gas company recover its costs of production, development and finding. In other words, oil companies collect economic rents exactly after the break-even point.[18] Governments target this economic rent by different taxes, like PRT in the UK, while some other duties are not levied on this economic rent, like royalties and SPD in the UK. These two duties (royalties and SPD) were, according to Kemp and Stephens (1996, p. 65), regressive with respect both to oil price and cost variations because they were based on gross revenues. Kemp and Stephens present their argument regarding economic rent in a graphical figure. This figure is reproduced below.

Figure 2-6: Kemp and Stephens Representation of Economic Rent for Oil and Gas Industry



Source: Kemp and Stephens (1996, p. 63)

[18] Break-even point represents the level of sale at which profit is zero. In other words, where total sales equal to total expenses or as the point where total contribution margin equals total fixed expenses (Seal et al., 2006, p. 272).

According to Kemp and Stephens (1996), and based on Figure 2-6, oil production can be continued only at a minimum price of 0MCp. Development of new fields can be encouraged at a minimum price of 0MCd+p. exploration can also be encouraged at a minimum price of 0MCt. The economic rents, according to Kemp and Stephens (1996) are thus the shaded area in Figure 2-6 (the area MC t, P, X). This concept of economic rent represents the oil industry's view because it makes recovering exploration, development and production costs a necessary condition to collect economic rent. However, royalties and SPD did not target the shaded area in the above diagram, as they were directed at gross revenues which is the area above the production axis. Kemp and Stephen (1996, p. 63) add that economic rent at development stage can be measured by the net present value (NPV) at the investor's discount rate. However, governments might start collecting economic rent even before production starts (the area below the production axis in the above figure). This could be practiced by imposing signature and/or exploration bonuses on oil companies.

Mommer (2002, pp. 13-16) distinguishes between two types of rent, namely, customary ground rent, and differential or Ricardian rent. The next sections illustrate the meaning of these two concepts in some detail.

Customary Ground Rent

This type of rent represents the necessary payments to the landlord for using his land. The landlord could collect this kind of rent at two stages. The first represents the minimum that the landlord would accept for the use of his land and it could be in forms of signature bonuses[19] and surface rental. The second starts when production starts, and it could be a portion of production or fixed amount to be paid over a regular periods of time, or 'royalties'. The first phase matches, to some extent, Johnston's meaning of rent, while the second phase of customary ground rent matches Ricardo's concept of rent as it starts with the production. Figure 2-7 shows Mommer's (2002, pp. 13-16) concept of the customary ground rent.

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[19] These are sums of money paid by the contractor to the host government upon signing a PSC and known as 'signing' or 'signature bounces' (Gallun et al., 2001, p. 587).

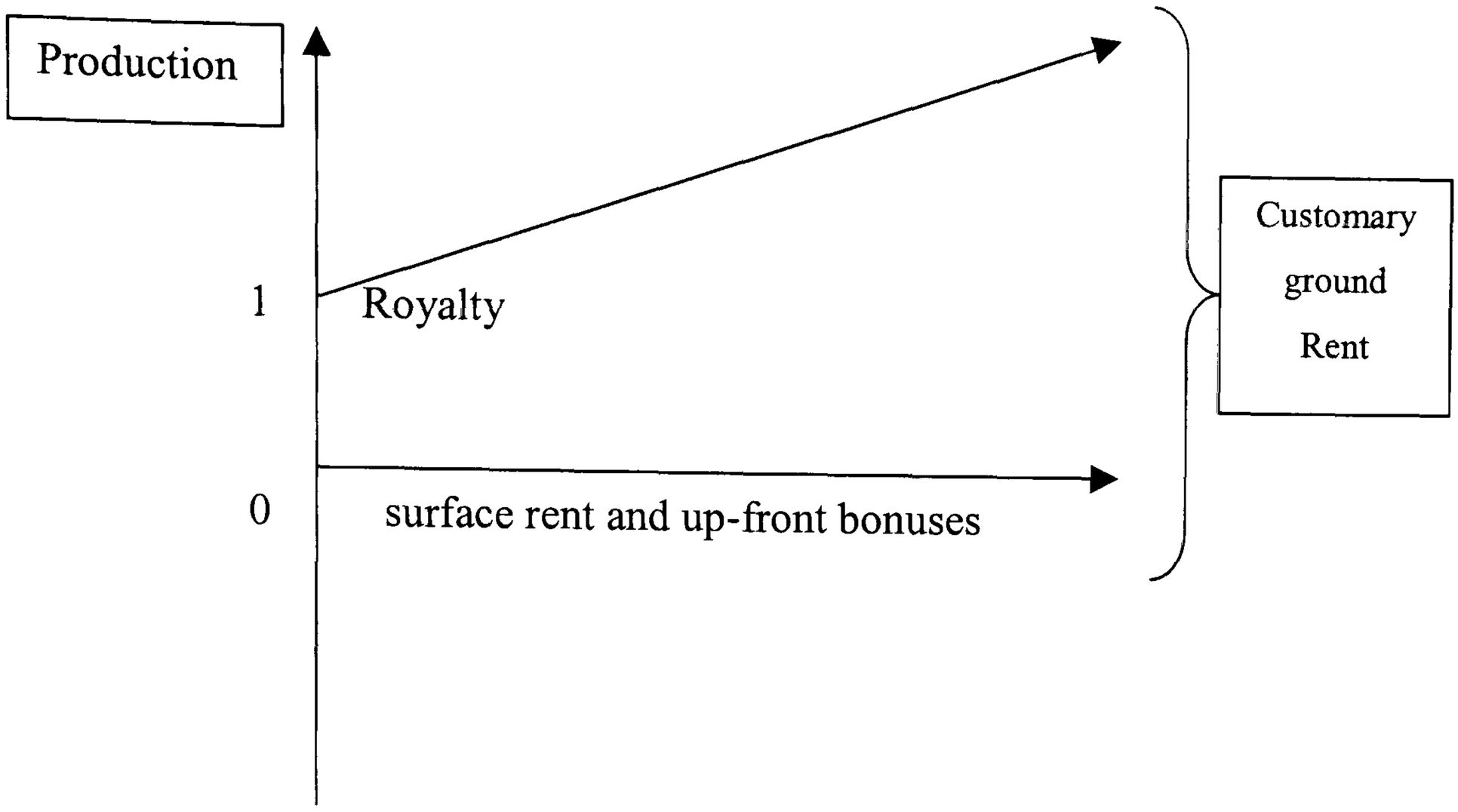


Figure 2-7: A Depiction of Mommer's Concept of Customary Ground Rent

Note: arrow number 0 refers to the minimum payments to the landlord that he will accept for granting access to his land or sea and this could be before the production point. Arrow 1 represents the second phase of customary ground rent, which starts with production, or 'royalties'.

Differential or Ricardian Rents

Mommer (2002, p. 13) considers that the extra payments to the landlord for using his property represents this type of rent:

> "There are always some parcels of land becoming available that may command higher ground rents or profits than usual. These excess rents are generally called economic rents… more specifically, when these economic rents result from the exceptional richness and fertility of nature, they are called differential, or Ricardian, rents".

Figure 2-8 illustrates Mommer's representation of differential, 'Ricardian', rent.

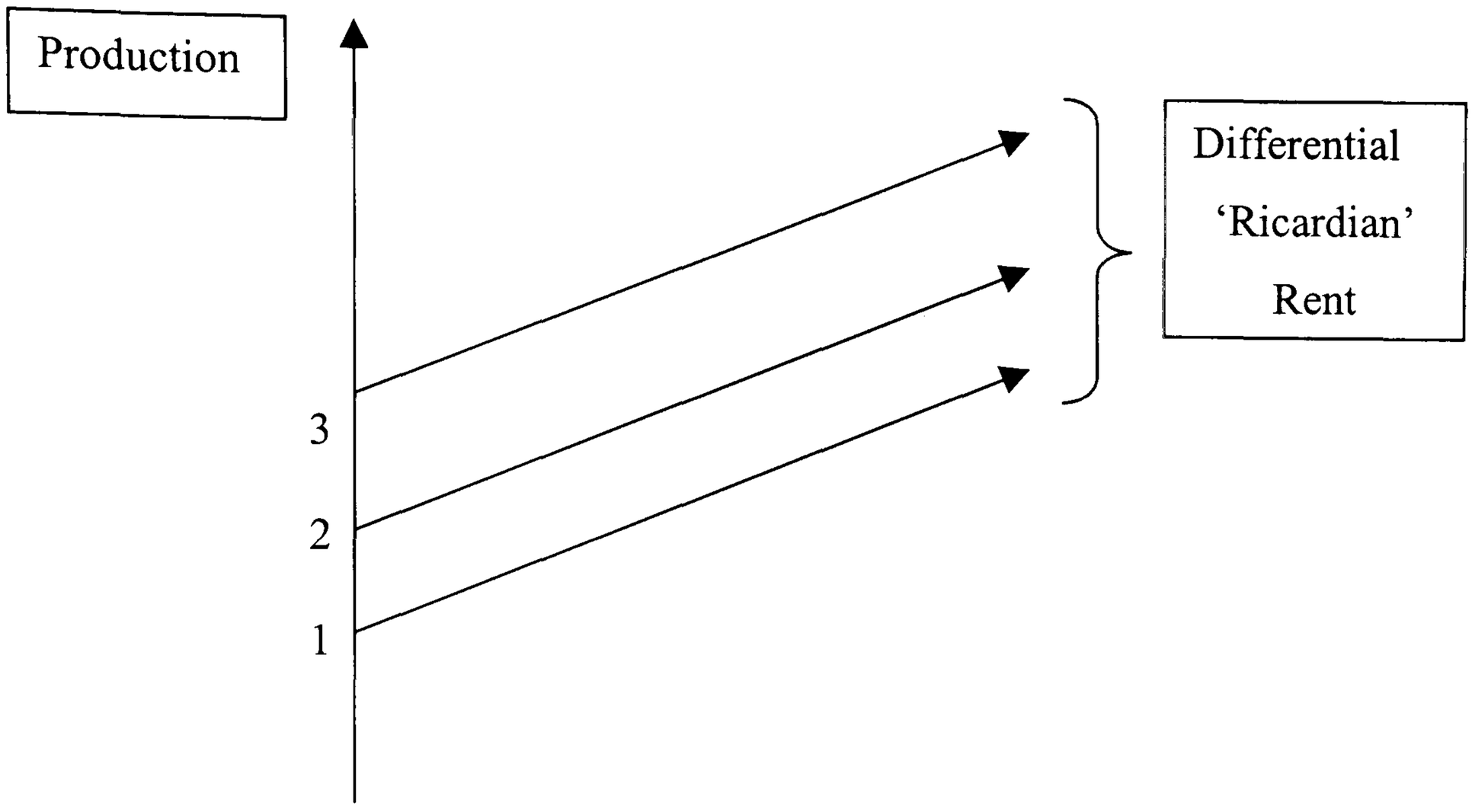


Figure 2-8: A Depiction of Mommer's Representation of Differential Rent

Note: arrows 1, 2, and 3 indicate that the tenant expects to pay higher rent if he looks for lands with high productivity, and here production is an essential condition of paying the rent.

From the above discussion it can be stated that there are two opinions regarding economic rent: (1) economic rent is the total gain of the landlord from granting access to his land where the landlord is targeting different aspects of the tenant's rewards, or 'gross revenues and profits'; and (2) economic rent is the extra amount paid to the landlord for access to his land compared with other land where the landlord is targeting the tenant's profits.

2.4 Developmental Conceptualisation

Based on the above, it can be seen that the concept of rent is, to some extent, confusing and not easily recognised or understood, especially when looking at the meanings of the concept from different schools of thoughts. The Ricardian concept, historically, is the first, and might be considered as raw material for the later meanings and understandings of the economic rent concept. This raw material has been developed and shaped over time to fit different aspects of economic life. The concept was originally applied to agriculture, particularly in growing corn in the UK, and then it was applied to other economic activities in

different industries such as the oil and gas industry. Secondly, different schools of thought add more meanings and difficulties in developing the concept. Matching the concept of economic rent to the oil and gas industry is a useful process, because it shows and classifies the targets of a host party (state or private) in regard to the tenant's output. This is because the host government or the private minerals' owner may target the tenant's gross revenues and/or the net profits. This is, of course, based on the type of governance of mineral resources first and secondly on the understanding and adoption of a particular meaning of the economic rent concept by the host party. However, there are different views about the classification of the form of the host party's revenues, or 'take, through the life of an oil and gas project. For example, matching the concept of economic rent to the oil and gas industry might give the following understandings and classifications to oil and gas expenses and duties: 1) up-front bonuses and royalties represent Mommer's concept of customary ground rent, and at the same time match Johnston's definition; 2) exploration and production bonuses represent Mommer's interpretation of differential or Ricardian rent, and they also match Johnston's definition; and 3) profit taxes and production share are understood by Johnston to be part of the government's rent.

Ricardo has two concepts of rent. The first starts when production starts, and this in the oil and gas industry might match royalties' and production bonuses' payments. The second is based on the richness of the resources. This concept could be represented in payments of royalties and production bonuses on a sliding scale, or even high royalty rates and profit taxes. The question that could arise here is: how will the landlord behave in charging the tenant for access to his land? In order to answer this question and according to Mommer (2002), it could be worth recognising first of all two possible types of governance of mineral resources, namely *proprietor* and *non- proprietor*. This will be the focus of the next section.

2.4.1 Proprietorial vs. Non- Proprietorial Conceptualisation

Proprietorial: this could be one of two entities: (a) an individual landlord, or 'private owner'. A good example of this case is the United States of America

where individuals can possess oil and gas reserves; and (b) the state, or 'public owner', like the case of other producing oil and gas countries.[20] The individual proprietor grants his tenant access to his land or sea for a customary ground rent, which will be in form of royalties and, sometimes, up-front bonuses. In this case, the proprietor would not care about his tenant's profits or, in fact, whether his tenant makes profits from his activities or not. The key issue for the proprietor is to have the customary ground rent for the access to his land. In some cases the ground rent could be a fixed sum or set at an increased percentage of the production and again, for the proprietor it does not matter whether the tenant generates profit or not, as long as he obtains his share of the tenant's production. Moreover, the proprietor might ask for production bonuses. In the case that the proprietor is the government, or 'the state', here the tenant would expect to pay his landlord the rent in forms of customary ground rent i.e., royalties and bonuses, and different income taxes. In the first case, while the proprietor is an individual, a group or a company, the tenant might still have to pay profit taxes to the state, but not to his landlord, in addition to the customary ground rent. Based on the above, the proprietor focuses on receiving the customary ground rent and goes further to target the tenant's production and profits (Mommer, 2002, p. 88). In this regard and in reviewing Mommer's Book, Professor Wälde (2003, p. 2) from Dundee University States:

> "A Proprietorial model where the regime (consisting of mineral title rules, licensing rules and commercial practices to get access to mineral resources) focuses on the right of the owners of the resources to dispose of the resources as they see fit and allows them to extract maximum payment for access".

Non-Proprietorial: here the landlord, or 'the state', will grant his tenant, or 'the oil and gas company', access to his land and/or sea for free (or free in practice) and his target will be the tenant's economic rent. Of course, access is granted through a 'licensing agency', which regulates the process of granting licences to

---

[20] Public ownership of mineral resources is very common. Mining in general, and deeper mining in particular, require a significant amount of capital and technical knowledge, which could hardly be available to the private owner. Public mineral ownership offers greater possibility and flexibility in dealing with the tenant company than private ownership does. Furthermore, public mineral ownership does not face the problem of fragmentation, which is major problem for private land 'minerals' ownership (Mommer, 2002, p. 95).

the tenants according to certain conditions set by the agency itself. The landlord's aims of giving free access into his land might be to attract tenants to invest in his land, to benefit the private investor and the consumer of the natural resources as being a free gift of nature, and at the same time develop marginal resources that could exist in this land or sea (Moose, 1982, p. 57). Figure 2-9 illustrates the situation of proprietor and non-proprietor.

In the diagram, the area under the production axis represents the necessary pre-production investment stages i.e., acquisition, exploration, appraisal, and development (see section 5.4). The area under the zero line represents the minimum payments that a proprietor would accept for granting access to his land/sea. The area e, eb, x represents the stage of finding oil and/or gas. In this stage, if the land/sea is a newly opened field which promises relatively large resources of very good quality oil and gas, then the tenant expects to pay his landlord exploration bonuses if he wants to invest in such areas. The curve 'MC' represents the marginal cost of producers which increases with the expected increase of productivity of the land/resources. The tenant in high producing areas pays higher fees to gain access to these areas in the form of different bonuses and ground rent which pushes up the marginal costs. The non-renewable resources' cost increases when level of resources goes down, as this requires more energy and specialised equipment to extract the resources from a greater depth. Producers who produce at quantity q1 and sell at price P2 get higher profits than producers who produce q1 and sell at P1. So producers of q1 and P2 generate higher 'differential' profits. These profits are represented in the diagram by the box P1, a, b, P2, while the area 1, c, a, P1 represents the normal profits of an average piece of land.

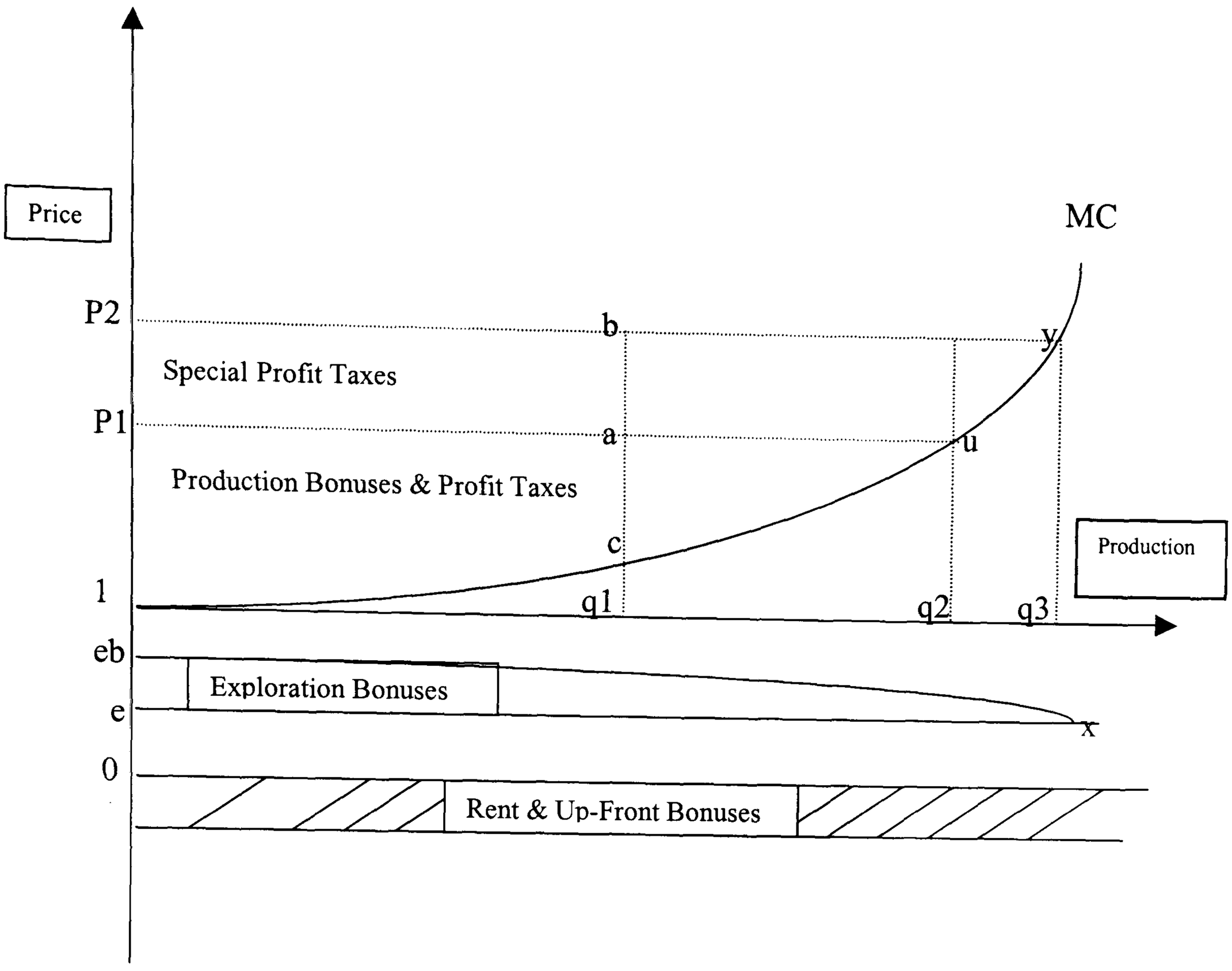


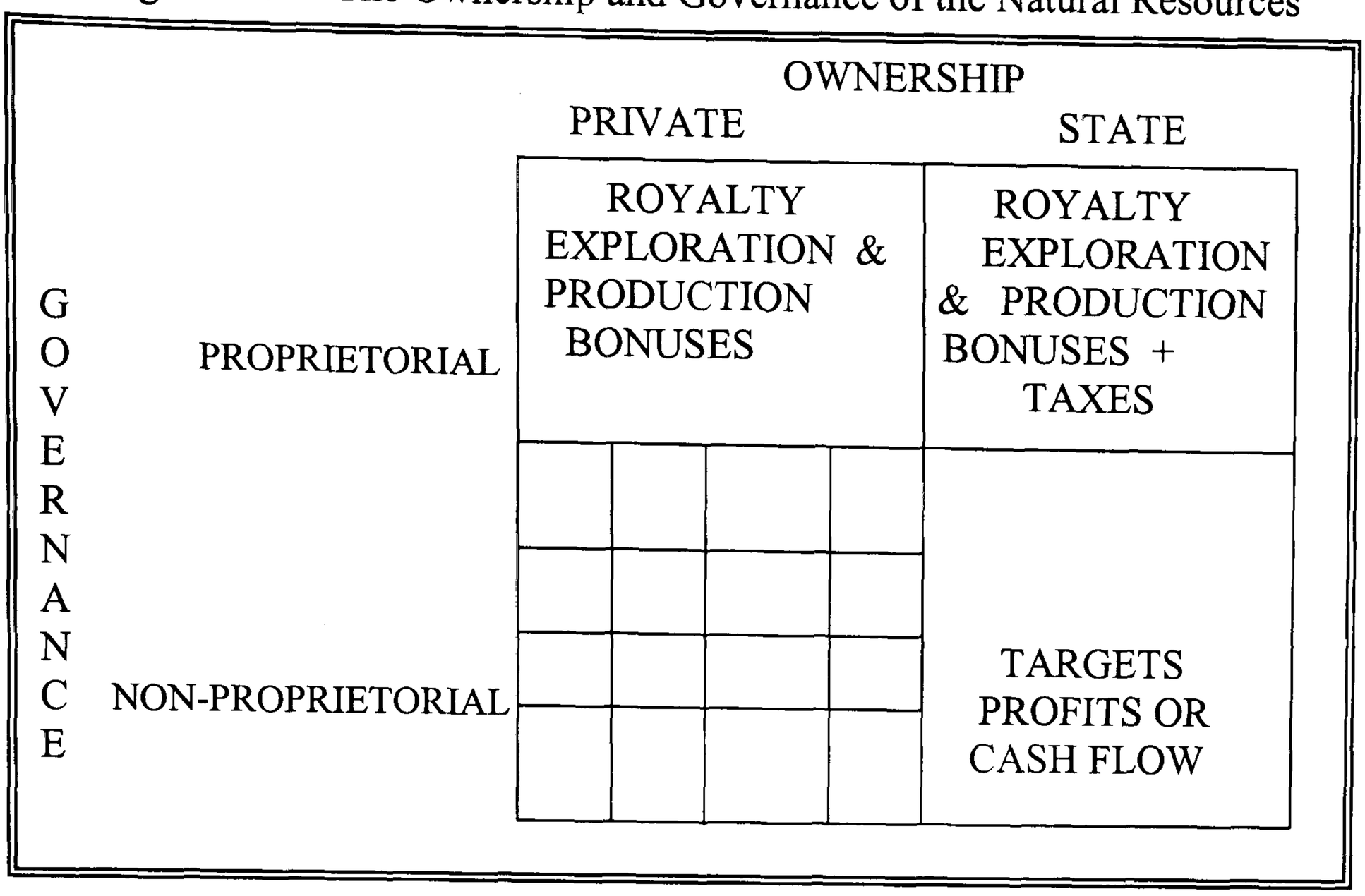
Figure 2-9: Proprietorial and Non-Proprietorial Rent Targets

To obtain his ground rent, the proprietor first of all targets the area under the zero line. His income, or 'rent', in this stage could be in the form of ground rent and up-front bonuses. Then if the area promises big exploration and production, he targets the area e, eb, x to obtain more rent in form of exploration bonuses. Then when production starts he will receive his share in the form of royalties and taxes to be paid to the government if the proprietor is a private owner. In the case that the tenant would generate differential profits, the proprietor will target these extra profits and collect extra rent in form of high royalties or special taxes collected on a sliding scale, while if the landlord is a non-proprietor he will target the area 1, c, a, P1 which represents normal profits. This attitude of the non-proprietor is that natural resources are a free gift of nature. In reality the landlord might choose the non-proprietor type of mineral governance to serve other purposes. These purposes could be social aims, or the state might intend, by adopting this type of minerals governance, to develop marginal resources.

In the case of developing marginal resources that do not even promise profits to the tenant and consequently to the state, or provide very little profits like the area c, u, a on Figure 2-9, however, the state aim from developing such resources could be to secure a greater supply of natural resources for domestic consumption, and/or to decrease unemployment. Also, the oil and gas company might benefit from developing such resources in recovering some of its spent costs. It is notable that private ownership of minerals is not available under the non-proprietorial form of governance. This is because the main concept of the non-proprietorial regime is based on the idea that the natural resources are a free gift of nature, and access to them is free, whilst the private owner would not allow free access to his land. The UK case is a good example of the non-proprietorial type of oil and gas resources' governance (Mommer, 2002, p. 88). Figure 2-10 presents the ownership and the governance of the mineral resources and summarises the above discussion.

Based on the above discussion of proprietor and non-proprietor behaviour, and the description of different types of oil and gas agreements, it could be argued that the non-proprietorial form of minerals' governance fits governments which do not have enough experience in the field of the oil and gas industry and aim, beside developing probable and possible existing reserves, to develop different aspects of the country's economic life. Generally speaking, this form of mineral resources' governance fits countries that use the old concession concept of agreements. However, when countries and individuals gain more experience and self-confidence to develop their mineral resources, they move to the proprietorial form of control, which focuses on granting the mineral's owner more shares of the minerals i.e., the Indonesian case. The proprietorial form of governance exists in governments and individuals using a new form of the concession concept or a contractual system.

Figure 2-10 The Ownership and Governance of the Natural Resources



Oil and gas producing states or private parties, as owners of mineral resources, 'proprietorial and/or non-proprietorial', have the right to set out terms and conditions for access to their resources, and negotiation is the best method to resolve conflicts over sovereign rights (Mommer, 2002, p. 235). Mommer (2002) points out that the type of ownership (government or private) of natural resources has never been important in setting out such terms and conditions, while the type of governance of these resources plays an important role in developing such terms and conditions. This is because the type of minerals' governance shapes these terms, which might be very strict under the proprietorial regime and less strict under the non-proprietorial regime. Based on this, in the case of a state ownership of mineral resources, the terms of an oil and gas contract would be strict or very strict under the proprietorial type of governance, whilst they would be less strict under the non-proprietorial type of control. Furthermore, fiscal regimes are less stable under public governance than private governance, and changes in fiscal regimes cost much less under public governance. For instance, the cost of changing one aspect of any fiscal regime under private governance is relatively high, as it requires different meetings and negotiations amongst all lessees and lessors within one country, which might take a long time and need many meetings and this is a costly process. Such changes under public governance might take place according to new regulation or a new law (Mommer, 2002, p. 230).

Last, but not least, the non-proprietorial type of minerals' governance is not the perfect choice for governments because they would not gain all possible advantages of their mineral resources under this type of governance. In this regard Mommer (2002, p. 235) states:

> "A few years will probably be enough to show the heavy losses in fiscal revenues that non-proprietorial governance will entail for exporting countries. Lessons may be learned in the future, but at what price?"

However, the above discussion is a critical one, and Mommer's statement might not be true in all circumstances. A country might, by adopting the non-proprietorial type of governance, achieve a number of economic goals. For example, a government may use such type of minerals' governance with the purpose of developing marginal resources. In this case the government might possibly sacrifice financial revenues from these marginal resources. However, at the same time it might succeed in solving some social problems such as unemployment, also perhaps increasing the supply of the mineral resources for local consumption.

2.5 Summary

Oil and gas agreements vary according to the time at which they were formed and the countries in which they are made. Host governments started to use the concession system in the early days of the petroleum industry. From the 1960s onwards, different types of contracts were implemented in certain countries, while in others, however, the concession system was modified, as in the case of the UK, or 'the North Sea Model'. The main differences between concessions and contractual systems arise from differences in the ownership and management of mineral resources. Host countries can practise these rights directly through Production Sharing and Service Contracts. These types of contracts provide the host country with a greater share of its oil and gas resources than do the concessions.

There are different understandings and attitudes towards the meaning of economic rent among academic authors, and hence towards the target of a landowner of his contractor rent. The type of minerals' governance, as proprietorial or non-proprietorial regime, clearly affects the governments', or private, ownership's share of the resources. The proprietorial type of minerals' governance grants the landlord a bigger share of the mineral resources than the non-proprietorial does. Theoretically proprietorial regime does not necessarily or automatically result in higher share – it is simply that, in its pure form, the landlord does not agree to vary his take according to the tenant's economic performance. It actually does. However, there is no standard form of oil and gas fiscal system in the world. However an ideal fiscal regime is the one which links the risk and rewards together, and grants both sides of petroleum contract a fair share of the resources.

The next chapter will characterise the UK petroleum fiscal regime by explaining the evolution of the UK taxation system and the relaxations applied to the UK upstream oil and gas industry. This will help in identifying the UK petroleum tax relaxations as a step followed by defining the rationales for these relaxations and testing these rationales in the succeeding chapters.

CHAPTER 3: THE EVOLUTION OF THE UK PETROLEUM FISCAL REGIME

3.1 Introduction

Oil and gas are arguably the most important natural resources to be discovered and produced in the UK during the last century. They provide energy and essential chemicals for the home, industry, and the transport system, as well as earning valuable export and tax revenues to support the UK economy (Mabro et al., 1986). North Sea oil has become an important source of world energy supply. Currently the North Sea produces a relatively recognisable portion of the world's oil and gas. In 1985 the North Sea produced more oil and gas than Saudi Arabia (Mabro et al., 1986, p. v), and its world ranking is fifth based on the output. It produced 4.58 per cent of the world's daily oil and gas production (Petroleum Economist, 1995). In many subsequent years it ranked sixth.

The North Sea has three unique characteristics, which make it a recognised oil and gas region. These are: 1) rapid development when the world demand for energy was heavy, and when the Organization of the Petroleum Exporting Countries (OPEC) was at its most powerful; 2) location in the centre of a major refining and consuming area; and 3) development, which led to the creation of highly active spot and forward markets for crude oil (Mabro et al., 1986, p. v). On the other hand, the water depth and the weather conditions make the North Sea different from other oil and gas producing areas, for example, the Middle East and the Gulf of Mexico. However, during the 1960s, the North Sea was still a new oil region, and it had development and production problems (Noreng, 1980, p. 17; Seymour, 1990, p. 18).

The purpose of this chapter is to provide a basic description of the fiscal regime which applied to companies engaged in oil and gas extraction activities in the UK Continental Shelf (UKCS) up to the year 2000. The chapter will address the history of oil and gas legislation in the UK focusing on the period from 1964

onwards. [21] It will highlight issues relating to oil and gas licensing rounds, while presenting the history of UK oil and gas legislation, in order to clarify how the petroleum tax regime has been changed and developed over time in the UK. For the purpose of this research, the history of the UK oil and gas industry will be divided into four periods: up to 1964, from 1964 to 1980, from 1980 to 1990, and from 1990 to 2000. The justification for these divisions is that in 1964, the UK Government approved the international legal framework with regard to division of the sub-sea bed resources, and in 1980 the UK became oil self-sufficient. After 1980 a lag of ten years has been chosen to describe the history of the petroleum tax regime. The starting year of each later period (1980 and 1990) provides enough time to explore the rationales and test the effects of the main petroleum tax relaxations, which took place in 1983, 1987-88 and 1993.

Over the last 30 years or so, the UK has developed into one of the world's major oil production countries. Successive administrations have developed a fiscal regime which provides financial incentives to oil and gas companies to explore and develop the UK oil and gas reserves while at the same time securing an appropriate share of these resources to the nation. Fiscal policy has had to remain flexible enough to cope with changes in oil prices but at the same time provide the industry with the necessary stability for future planning. From the introduction of the first duty (royalty) on UK oil and gas production, up until 2000, three special taxes were used beside the standard Corporation Tax (CT). These taxes are: Petroleum Revenue Tax (PRT), Supplementary Petroleum Duty (SPD), and Advance Petroleum Revenue Tax (APRT). Removing these duties defines the UK petroleum fiscal regime as one that would fall into the non-proprietorial regime, discussed in the previous chapter (see section 2.4.1).

In the subsequent sections the specific details of the introduction of, and changes in, these taxes will be charted.

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[21] The year 1964 has been chosen as it is the year of the Continental Shelf Act, and from this year onward, the UK oil and gas resources started to be explored and developed extensively.

3.2 Components of UK Petroleum Fiscal Regime

3.2.1 Royalty

Royalty on oil and gas is, in fact, not a tax: it is a charge on the value of production. In the UK oil industry, a royalty was introduced at a rate of 12.5 per cent of the landed value of the petroleum production less an allowance for the costs associated with the conveying, treating and initial storage of the oil and gas between the well head and the point of valuation, usually the terminal onshore (Inland Revenue, 2005). However, as royalties allowed for costs of conveying, transportation and treatment, this meant that the actual rate of royalty, according to this basis, is less than 12.5 per cent of the well-head value (Mabro et al., 1986, p. 111). In the UK, royalties were not charged on a field basis but on the licence. In this regard, there is no difference between the field and the licence. However, there are several cases where a licence covers more than one field, or where a field is covered by more than one licence (Bond et al., 1987, p. 10; Nakhle. 2004, p. 56; Inland Revenue, 2006a).

Royalties were collected and administered by the Oil and Gas Royalty Office within the Department of Trade and Industry (DTI). After April 2000, royalties were collected and administered by the Inland Revenue's Oil Taxation Office (OTO), but they were entirely abolished with effect from 1st January 2003. All petroleum production licences, other than exempt fields, were to pay royalties to the Secretary of State for Energy. The Secretary of State formally had the option and power to require royalties to be paid in kind, but this option was abolished from 1st January 1989 (KPMG, 2000). Royalties were paid on a six-monthly basis. These six months periods ran from 1st January to 30th June and from 1st July to 31st December of each year (KPMG, 2000, p. 1). A Statement of Value (SOV), or 'a return', was required two months after the end of each period. This SOV included a royalty liability that should be paid on account when the return was due two months after the end of each chargeable period (Bland, 1991, p. 27). If royalties were overpaid, then the Secretary of State would repay the extra with interest calculated, normally, from two months after the end of the chargeable

period.[22] A royalty was paid even if the international oil and gas company's profit was zero as it was not a profit-related duty (Kemp and Mommer, 1996, p. 12). Royalties were deductible against PRT and CT profits.

3.2.2 Petroleum Revenue Tax (PRT)

PRT was introduced in 1975 to target economic rent. This tax is similar to Resource Rent Tax (RRT) and Cash Flow Tax. In this regard, Bond et al. (1987, p. 11) state:

> "The principal difference between the basic structure of PRT and a resource rent tax is the treatment of development expenditure carried forward to be offset against future profits. A resource rent tax would allow such expenditures to be carried forward in real terms, together with an interest mark-up. PRT compensates for the absence of this relief by allowing an 'uplift' on most development expenditure… but tax losses can only be carried forward at historic cost".

The cash flow based tax is calculated on the net cash flow, and hence it exploits the relationship between economic rent and observed cash flow (Bond et al., 1987, p. 41). Differently, the PRT is a profit-based tax. The PRT measure of profits is not calculated according to the normal accounting profit. The Oil Taxation Act 1975 stated:

> "(2) the assessable profit or allowable loss so accruing in the period is the difference (if any) between the sum of the positive amounts for the period and the sum of the negative amounts for the period; and that difference (if any) is an assessable profit if the sum of the positive amounts is greater than the sum of the negative amounts, and is otherwise an allowable loss." (Great Britain, 1975b, S. 2)

The Government intended that PRT, the royalty charge, and Corporation Tax would secure 70 per cent of oil net revenues for the United Kingdom Exchequer, and would, therefore, be available to the nation for the achievement of wider economic objectives (DOE, 1978, p. 7).

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[22] For example, if an oil company overpaid its royalty charge to the Secretary of the State for the first chargeable period ending on 30th June 199x, the Secretary of State would pay back the extra royalties plus interest on these extras. This interest would be calculated for the period 1st September 199x to the date of the repayments.

In a meeting with the researcher, Mr Geoff Barnard from the Oil Taxation Office on 20th January 2004 said:

> "PRT was only intended to tax the super profit of the very large fields. In theory some small fields may pay PRT if they are very profitable. Generally, most small fields will never pay PRT, and it was never intended that they should; because they are generating profit in the sort of normal commercial range, not the super profits of the likes of Forties and Brent fields developments".

PRT has unique rules and features that distinguish it from certain standard taxes such as income tax and/or CT.[23] Some of these rules and features are given below.

1. PRT profits differ from accounting profits (the balance sheet concept). They have emerged as a difference between income and expenditure, which is called operating profit (Great Britain, 1975b, S. 2; Zhang, 1997, p. 1106). The interesting point here is that expenditures were only allowed to be deducted when they were claimed and allowed rather than incurred (Nigg et al., 1983, p. 63). Furthermore, according to the PRT profit measure, no distinction is made between revenues and capital earnings or expenditures (Inland Revenue, 2006b):[24] not all expenditure may be deducted from the revenues for the purpose of this tax. In this regard the Oil Taxation Act ,1975, stated:

> "(4) expenditure allowed under this section for any oil field does not include—
>
> (a) expenditure in respect of interest or any other pecuniary obligation incurred in obtaining a loan or any other form of credit; or
>
> (b) the cost of acquiring any land or interest in land, other than the cost of making to the Secretary of State any payment falling within subsection (1) (*b*) above; or
>
> (c) the cost of acquiring any building or structure on land,…" .
>
> (Great Britain, 1975b, S. 3)

---

[23] Most of these features were introduced in the 1975 Finance Act, and I am presenting them here to give a general idea about this tax, while changes to this tax are to be clarified later on in this chapter according to the year in which they took place.

[24] Capital expenditure is any spending on assets contributing to the long–term capital accumulation of an organisation. Revenue expenditure is any spending made by a business related to the revenue generated within the same financial period (Black, 2005, p. 9).

This means that in calculating the taxable profit for the PRT not all expenditure is allowed before arriving at the taxable profit. This calculation also did not follow accounting concepts regarding deducting expenditures when incurred, as it only deducted them if they were allowed by the DTI. The above-mentioned balance sheet concept allows the deduction of every expense that is necessary for generating total revenues. This is known in accounting as "the matching concept". This convention states that expenses should be matched to the revenue that they helped to generate (Atrill and McLaney, 2005, p. 68).

2. PRT is paid twice a year (every six months). The Oil Taxation Act, 1975, stated:

> "(3) In relation to any field–
> *(a)* the first chargeable period ending at the end of the critical half year (including an unlimited time prior to the beginning of that half year); and
> *(b)* each subsequent half year is a chargeable period (a)".
>
> (Great Britain, 1975b, S. 2)

3. PRT is assessed on each company's share of the assessable profit from each separate oil field. These fields are determined on geological grounds by the Department of Trade and Industry (DTI) (Great Britain, 1975b, S.1). Moreover, PRT is applied to oil produced from licensed areas onshore as well as offshore from the UK Continental Shelf (UKCS). It is applied to a participator in an oil field within the UKCS, while a holder of an indirect interest is not subject to the PRT charge (Great Britain, 1980, S. 107; Bland, 1991, p. 37). In this regard the Oil Taxation Act, 175, defined a participator as:

> "…means, in relation to an oil field and any chargeable period–
> (*a*) a person who is or was at any time in that chargeable period a licensee in respect of any licensed area then wholly or partly included in the field; and
> (*b*) a person who is no longer a licensee in respect of any licensed area wholly or partly included in the field, but who was such a licensee at any time in either of the two chargeable periods preceding that chargeable period; and
> *(c)* a person who is no longer a licensee in respect of any licensed area wholly or partly included in the field (and who does not fall within paragraph (*b*) of this definition), but who has or had at any

time in that chargeable period a share of oil won (whether or not in that period) from the field, being a share with respect to any part of which either of the following conditions is or was satisfied at that time, that is to say–

(i) he has or had neither disposed of that part nor relevantly appropriated it; or

(ii) he has or had disposed of, but not delivered, that part"

(Great Britain, 1975b, S. 12)

4. PRT allows "uplift" on investment expenditure (75 per cent originally, reduced later to 35 per cent). This uplift means that 35 per cent of *certain* investment expenditure was allowed to be written off when calculating the PRT profits (Great Britain, 1975b, S. 2). The intention behind this uplift was to encourage investors to increase their investment expenditure.
5. PRT is applied on a field-by-field basis, or is 'ring-fenced'. This ring-fence concept means that profits arising from each field are charged to tax separately from other fields' profits. This means that a company with operations in a number of oil fields will have to pay PRT for each one of its fields separately from the others, and losses in one field cannot be deducted from profits in other fields. The Secretary of the State for Energy determines the extent of each field.
6. An exception to the previous rule is that any accumulated remaining unrelieved loss at the end of any field's life might be set against profits from other fields.
7. When a claim for expenditure allowance was accepted, a treatment of this expenditure occurred without looking at the accounting period in which they incurred. In other words, if expenditure is accepted to be allowed against the PRT operating profits in any taxable period, it is not necessary for that expenditure to have been incurred in the same taxable period of question, but it may have been incurred in previous periods.
8. PRT is a deductible charge when calculating profits for CT purposes, while royalties are a deductible charge when calculating profits for PRT purposes. Hence, royalties were charged first, then PRT, and then CT.
9. PRT payable by a participator in an oil field for any chargeable period should not exceed 80 per cent of the gross profits, and should be levied only if his adjusted profit for that period exceeds 15 per cent of his accumulated capital

expenditure at the end of that period. This concept is called the 'Safeguard Concept' (Great Britain, 1975b, S. 9).

10. Several deductions and reliefs are made against income assessed for the PRT liability, which are:

a. Royalties. Royalty in kind was not an allowable expense for PRT: only royalty in cash was to be considered as an allowable deduction for the purpose of PRT.

b. Licence fees. Licence holders are required to pay a fee for the licence itself. This fee consists of one payment of a fixed sum for each square kilometre included in the licensed area.

c. Uplift. A supplementary allowance of 75 per cent was given on past capital expenditure, which was carried forward to the payback period[25] to compensate for interest[26] and other finance costs, which were non-deductible against PRT.

d. Losses. When income is less than expenditure, then losses can be carried forward or backward indefinitely - on a per field basis only.

e. Expenditure incurred in finding and producing oil from the field subject to PRT. These expenditures include costs related to: the primary geological survey; exploration appraisals; evaluating reserves in the field; development; initial treatments and storage; and transport from the oil field to a UK delivery point. However, as PRT is applied on a field-by-field basis, so treatment of exploration expenditure for PRT depends on whether or not it can be allocated to a specific field. If the exploration expenditure could be allocated to such a specific field then it was directly deductible (for full explanation of these expenditures see Inland Revenue, 2006b).

f. Oil allowance, which before 1979 was 500,000 metric tonnes per taxable period, up to a cumulative maximum amount of 10 million metric tonnes.

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[25] The payback period covers the time when the cumulative field income exceeds the cumulative costs.

[26] Interest on unpaid unsettlements of PRT runs from the due date of each payment, while interest on the balance of the PRT liability runs from two months after the end of each chargeable period. If the balance of the liability is overpaid, then interest is paid also to the taxpayer on similar basis.

This allowance was reduced after 1979 (see tax changes in Section 3.4.2). The oil allowance is a defined quantity of oil which was excluded from being liable to PRT for each oil field for each chargeable period. The value of a participator's share of the oil allowance for any chargeable period depends on its cash equivalent. The Oil Taxation Act 1975 provided a formula for calculating this value. This formula is expressed as

$$£\,(A\frac{B}{C})$$

where A is the participator's gross profit accruing in the period; B is the participator's share of the oil allowance in metric tonnes; and C is the participator's share of the total oil won from a certain field during a chargeable period (Great Britain, 1975b, S. 8).[27]

g. Cross-field allowance (see tax changes in Section 3.4.3).

The aim of PRT was to allow each project to recover its costs rapidly, then to tax it severely. The various allowances gave protection from PRT where no economic rent was likely. Table 3-1 presents a sample measure of PRT profit.

The Oil Taxation Acts 1983 defined "tariff receipts" as:

> "the aggregate of the amount or value of any consideration (whether in the nature of income or capital) received or receivable by him in that period (and after 30th June 1982) in respect of–
>
> (*a*) the use of a qualifying asset; or
>
> (b) the provision of services or other business facilities of whatever kind in connection with the use, otherwise than by the participator himself, of a qualifying asset."
>
> (Great Britain, 1983b, S. 6 (2))

[27] For example, a participator with a 45 per cent share in an oil field that produces one million metric tonnes (mt) of oil per chargeable period has a gross profit for the chargeable period of £65 million. The cash equivalent of his oil allowance will be calculated as follows: share of oil allowance: 500,000 x 45% = 225,000mt; share of oil won: 1,000,000 x 45% = 450,000mt; cash equivalent of oil allowance: £65,000,000 x (225,000 / 450,000) = £32,500,000.

Table 3-1 Sample PRT Revenues Computation

	£	£
Gross Profit/(Loss)		*
Tariff Receipts (Less Allowance)		*
Assets Disposal Receipts		*
Royalty and Licence Debit/ (Credit)		*
Provisional Expenditure Allowance	*	
Share of Field-Related Expenditure	*	
Participator's Own Field Expenditure	*	
Uplift	*	
Exploration and Appraisal Expenditure	*	
Cross-Field Allowance	*	
Research Expenditure	*	
Losses From Abandoned Fields	*	
Total		**(*)**
Assessable Profit/ (Allowable Loss)		*
Loss Relief		(*)
Oil Allowance		(*)
Taxable Profit/(loss)		*
Source: Arthur Andersen (2000, p. 16)		

3.2.3 Supplementary Petroleum Duty (SPD)

SPD was introduced in 1981 and it was one of the windfall profit taxes, like PRT, that were used to curb international oil companies' profits. Governments set such taxes against international oil and gas companies revenues in cases where present fiscal regimes did not secure a fair share of profits for the host governments, in particular during periods when oil and gas prices were increasing (Fleites Melo, 1991, p. 96). In other words, if the fiscal regime is regressive, the governmental share of revenues does not increase when oil prices increase. This means that the oil industry enjoys the extra profit arising from the increased prices. Therefore,

governments impose this type of taxes to capture a higher share of the rent occurring to the oil industry.

From the above, it can be seen that SPD was introduced mainly to take a reasonable share of the super profits occurring in the industry as a result of the oil price increase in the late 1970s and the early 1980s. SPD was charged at a rate of 20 per cent of gross production revenue, minus an annual allowance of one million metric tonnes a year. The cash equivalent value of this allowance was calculated in the same way as the oil allowance of PRT (Great Britain, 1981, S. 124). Like PRT, a ring-fence was applied to this tax. SPD was a deductible charge against PRT profits (Inland Revenue, 2006a).

3.2.4 Advance Petroleum Revenue Tax (APRT)

APRT was charged from 1st January 1983 to 31st December 1986 on oil and gas revenues, less an allowance of the value of 500,000 metric tonnes of oil per field in each chargeable period. The cash equivalent value of this allowance was calculated similarly to the oil allowance of the PRT (Great Britain, 1982, S. 142). APRT was introduced to accelerate the receipt of PRT into the early years of fields' lives. This duty was similar to SPD, apart from the fact that it was not deductible when calculating PRT profits (Inland Revenue, 2005). APRT represented an advance payment of PRT, while SPD was an allowable expense for PRT. APRT was credited in full against normal PRT liabilities when they arose and, if it could not be set off in this way within five years, it was repaid, and no further APRT was collected (Great Britain, 1982, S. 139; DOE, 1982, p. 19; Nigg and keeling, 1983, p. 62; Favero, 1990, p. 3).

3.2.5 Corporation Tax (CT)

CT is charged on oil and gas companies' profits in the same way as on any other industry's. CT and PRT are collected and administered by the Inland Revenue. Responsibilities for oil taxation matters lie primarily with them and the Treasury (DTI, 2000a, p. 37). CT was first introduced in the 1964 Budget to be applied with effect from 1965 as the only tax on the profits of commercial bodies. The rate of this tax was changed many times and the current rate is 30 per cent, which

represents one of the lowest company tax rates in the world (DTI, 2000a, p. 37). [28] This tax is payable nine months after the end of the accounting year. CT is paid by companies resident in the UK for their profits are generated in the UK. Non-resident companies may be subject to CT where they trade in the UK through any permanent establishment. In this regard, a company incorporated in the UK is treated as UK resident; a non-UK incorporated company is treated as resident in the UK if its central management and control is exercised in the UK (the Dyer Partnership, 2002). CT is applied to all corporate bodies in the UK; therefore UK oil and gas companies are subject to this tax. In the case of new oil and gas fields which were developed during the period March 1993-2000, CT was the only tax on profits (DTI, 2001a, para. 3.27). Moreover, foreign oil and gas companies producing in the UK are subject to this tax for profits generated from UK oil fields (Bland, 1991, p. 164). Unlike PRT, the CT is levied on the oil and gas company but not on the individual oil and gas fields (Mabro et al., 1986, p. 118). In this context, profits from upstream oil and gas activities are ring-fenced in computing profits for CT purposes. The CT ring-fence is entirely different concept from the PRT ring fence. This ring-fence relating to CT is for exploration and extraction activities of oil and gas companies in the UKCS. Its purpose is to prevent taxable profits from oil and gas extraction in the UKCS from being reduced by losses from other activities or by excessive interest payments (Inland Revenue, 2005; KPMG, 2000, p. 75) In calculating oil and gas companies' profits for CT, both royalties and PRT were deducted for this purpose (DTI, 2000a, p. 37).

The above-mentioned duties were the main ones introduced in the UK fiscal regime between 1964 and 2000. The next sections will demonstrate the historical changes to the UK fiscal regime based on periodical divisions, as was mentioned earlier in this chapter. In doing so, three main variables will be discussed and illustrated in detail. These are production, licensing, and tax changes. This research focuses on the period 1980-2000, but historical events before 1980 will

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[28] The main rate of CT was raised from 40 per cent to 52 per cent in 1974. In 1983, the rate was reduced to 50 per cent and to 45 per cent in 1984, then to 40 per cent in 1985, and to 35 per cent in 1986. In 1993the CT rate was reduced to 34 per cent and to 33 per cent in 1997. This rate was further reduced to 30 per cent with effect from 1st April 1999 (DOE, 1985, p. 29,; Inland Revenue, 2005).

be outlined in this chapter as a historical background to the UK fiscal regime. Before illustrating the evolution of the UK petroleum fiscal regime, it is appropriate to explain the two methods of allocating exploration licences which were both used in the UK. This will be the issue explored in the next section.

3.3 Auction and Discretionary Allocation Systems Compared

3.3.1 Auction Allocation System

According to this system, a bidder in a competitive auction gains a licence when giving up the most expected economic rent to a government. From the government standpoint, the realised economic rent based on this licences' allocation system may be more or less than the expected rent, but the possibility of either supernormal profit or loss should tend to balance each other out (Hann, 1986, p. 47). In other words, the bidding system for allocating licences enables the government to capture the maximum possible economic rent. A related point is that under this system the leasing agency (DTI in the UK) needs a certain amount of information as regards deciding the timing and size of auctions. However, competition between bidding companies would ensure government capture of fair economic rent. Therefore, it is not crucial to the auctioning agency to have detailed information and wide experience in this area.

3.3.2 Discretionary Allocation System

According to this system, licences are allocated based on a set of criteria. These criteria are established by the government, and may include political, management and economic considerations. However, in spite of the economic advantages of the auction system described above, the discretionary method may be still chosen by a government. This is because this latter, by not focusing on extracting more rent, establishes an environment in which oil companies would be encouraged to invest in an unproved area. Furthermore, this method allows the government to award licences to national and favoured local companies. It also creates the impression of the government being in control of the activities of foreign oil companies whilst protecting the national interests. A related point is that the licensing agency would need significant information regarding the proposed area and the types of investment activities. This is because applicants are required to

submit work programmes which would be analysed by the licensing agency (Hann, 1986, p. 49). The discretionary system provides the government with more control over oil and gas activities. In this regard, Hann (1986, p. 49) states:

> "...the discretionary system also enabled the government establish a framework of control. The oil companies were answerable to the government in that if their performance was inconsistent with government attitudes and preferences the companies could lose the opportunity of a licence award in the next round. The oil companies had to prove their worthiness according to the criteria of politicians and civil servants".

3.4 The Evolution of UK Petroleum Taxation, Licensing, and Production Up to 2000

3.4.1 The Period Up to 1964

Britain had been producing oil for more than a hundred years before the discovery of North Sea oil. The history of the exploration and development of oil and gas resources in the North Sea is extensive. For centuries small quantities of oil were extracted in Britain from shale to produce kerosene, known as lamp oil. In 1913 production was over 3.25 million tonnes. The First World War conditions created difficulties in importing oil to the UK (DTI, 1996b, p. 2). Therefore, the UK Government considered the idea of exploring and drilling for oil in UK territory. This idea was officially expressed in the Petroleum (Production) Act of 1918. This Act granted the Crown the right to control petroleum activities in the UK and to grant licences for exploration and production purposes (Inland Revenue, 2005). In 1934 a new Petroleum (Production) Act was passed, and this Act replaced the 1918 Petroleum Act. The Petroleum (Production) Act of 1934 established the national ownership of petroleum resources existing in natural conditions in the UKCS and granted the Crown property rights to onshore petroleum exploitation and the power to grant licences for its exploration and development (DTI, 1996b, p. 2, Inland Revenue, 2005). In other words, this Act established the Government's authority to regulate and grant applications for issuing licences, to define the licences' contents and set licence fees (Arthur Andersen, 2000, p. 4).

Earlier in 1937 an onshore gas field was found in Yorkshire. The first *commercial* oil discovery in the UK was in 1938 at Eakring. In 1943 UK oil production reached 3,000 barrels a day from 106 wells (DTI, 1998, p. 7; Upton, 1996, p. 20; UKOOA, 1981, p. 1). The early production came from a few oil fields in different places around the UK such as Eakring (Nottinghamshire), Gainsborough (Lincolnshire), Kimmeridge (Dorset), plus production from a small Scottish shale oil industry. Oil produced at that time was used for heating, lighting and medical purposes. Production, however, decreased from about 200,000 tonnes a year during the 1920s to about 60,000 tonnes in 1960 (Robinson and Marshall, 1984, p. 1).

The international oil and gas industry first took an interest in the UK North Sea waters in 1959. This was after one of the biggest natural gas fields was discovered by the Shell and ESSO oil and gas companies in the mid 1950s in the Netherlands (Robinson and Marshall, 1984, p. 2). In 1962 the UK Government received the first application for agreements to explore for oil and gas within the UK Continental Shelf. The UK was not able at that time to respond positively to these applications, as the Continental Shelf had not at the time been divided among UK, Denmark, West Germany, Netherlands and Norway. In 1964 the UK approved the international legal framework, which was provided by the 1958 Geneva Convention with regard to the division of sub-sea bed resources. The most significant rule of the Geneva Convention in 1958 was that countries with coastlines were given rights to explore and produces the natural resources in the Continental Shelf to a distance of 200 miles from shore (Inland Revenue, 2005). In 1965 the above-mentioned five countries were able to establish the median line, which divided the area of the 62nd Parallel between the UK and Norway (Robinson and Marshall, 1984, p. 2).

3.4.2 The Period 1964-1980

Tax Changes

In 1964-65 the UK Government put into operation the first comprehensive regime for exploration and production of petroleum in the North Sea. The important

features of this regime were that the UK Government had the right to control the working programme, and that a system of relinquishment (see footnote 16 on page 28) had been adopted (Noreng, 1980, p. 42). In June 1970, Conservative Government came to power. The new Government reviewed the existing licensing system. At that time, because of the effects of the international oil and gas markets, the UK had to depend on domestic oil production to cover local demand. The new British oil policy aimed to maximise exploration and development efforts, and to grant a good representation of British interests (Kemp, 1992, p. 94).

In the mid 1970s there were some remarkable changes in the UK oil industry. These were a sharp increase in the oil and gas prices resulting from the 1973 Arab-Israeli conflict; the recovery of oil and gas production; and 40 new offshore discoveries over the period 1970-1974. These changes, beside the advantage of the proximity of the North Sea to the European market, led to a boost in the UK oil and gas industry and resulted in high profits (Liverman, 1982, p. 458). This in turn created a need for the new legislation of 1975 in order to capture the expected super profits. On 11th July 1974 the Government published a 'White Paper' entitled "United Kingdom Oil and Gas Policy" (DOE, 1974). This paper was presented to Parliament by the Secretary of the State for Energy and it included the following main features.

1) It focused on possible losses to the country under existing fiscal regimes.
2) It stated that by 1980 oil production should be in the range of 100-140 million tonnes, and 100-150 million tonnes, or even more, a year through the 1980s.
3) It aimed at increasing the Government take, maximising the increase in the balance of payments, and providing more public control of over oil and gas resources.
4) It suggested the creation of a special additional tax on oil and gas companies working in the UK North Sea.
5) The White Paper encouraged the adoption of a new system of state participation in new licences, and renegotiating existing licences to obtain more state participation. The Government hoped to do this without causing

harm to licensees as it recognised that the costs of exploration and development had been heavy.

6) It proposed the creation of the British National Oil Corporation (BNOC), to act as a Government representative in the oil industry. It was suggested that BNOC would gain the power to extend its future activities to the refining and distribution of oil and gas products.

7) It intended to control the physical aspects of oil and gas production and pipelines in order to protect the environment, and adopt a suitable planning for infrastructures.

8) It aimed at benefiting Scotland by developing North Sea oil and gas. In this regard, the Government decided to establish a Scottish Development Agency to strengthen the development of the Scottish economy (Noreng, 1980, p. 51).

The White Paper reflected the importance for the Government and oil industry leaders of having future plans for the oil and gas industry. It also reflected the determination of the UK Government to act quickly to benefit fully the nation from its oil and gas resources, especially the regions in need of development at that time, 'Scotland and Wales', (DOE, 1974, p. 4). However, in 1974 when oil prices increased, the Labour Government introduced a policy aimed at providing more protection for national interests in relation to North Sea oil. This protection was seen through state participation in oil and gas operations alongside international oil and gas companies. Liverman (1982, p. 458) states:

> "Mr Wilson's Government of March 1974 pursued the same principal objectives as Mr Heath's, namely the increase of government take and an improvement in security of supplies, together with a greater degree of government regulation over development and production... The Labour manifesto included a commitment to bring UKCS oil and gas operations under full government control with majority public participation".

The year 1975 was significant for the UK oil industry. In this year, as the White Paper of 1974 had proposed, the UK Government created the British National Oil

Corporation (BNOC),[29] the aim of which was to represent the state in the oil and gas industry. In doing so, and to involve the BNOC in oil and gas operations, negotiations began with private oil companies that already had activities in the North Sea. The consequences of such negotiations resulted in national companies, such as BNOC and the British Gas Corporation (BGC) acquiring participation rights. The aim of these rights was that national companies should control at least 51 per cent of the oil extracted from the UKCS. This was achieved through the right to purchase this 51 per cent of produced oil from private companies at market price. The UK Labour Government aims of this policy were as follows.

1. The BNOC would be used as a device to secure the national ownership of produced oil.
2. The BNOC would be used as a control device over the conduct of the oil industry within the UKCS.
3. State revenues would be increased from the oil industry through this Corporation.
4. The 51 per cent share would help the Government to control fluctuation in oil prices in the short term.
5. The 51 per cent share would secure access to oil and gas which produced in the UKCS, and would be employed to ensure security in oil supply (Robinson and Marshall. 1984, p. 7; Machmud, 2000, p. 21; Kemp, 1992, p. 107).

The interesting point here is that the UK form of participation in the oil and gas operations was different from participation elsewhere in the industry. This is because the BNOC was given the option to buy up to 51 per cent of the oil at market price. This form of participation is referred to as 'a purchase agreement'. Furthermore, the Labour Government insisted that the BNOC should have representation on all the operating fields. This representation allowed the BNOC to have a 51 per cent stake in each block in the fifth licensing round, while under the sixth licensing round, the BNOC was given a minimum of 51 per cent (see the next section). The Corporation was allowed to obtain licences outside the normal

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[29] The BNOC was formally established on 1 January 1976 (Liverman, 1982, p. 460).

licensing rounds, and it was exempted from paying PRT. The BNOC was given a seat on the licence operating committee. These features gave the BNOC a very powerful position in comparison with other private oil and gas companies operating within the UKCS (Robinson and Marshall, 1984, p. 7).

In this year (1975) large profits were generated and more were expected from North Sea oil. These profits resulted from an increased production rate, and also from the very sharp increase in oil and gas prices arising from the Arab-Israeli conflict in 1973. In the light of these events, the UK introduced a Petroleum Revenue Tax (PRT) to tax a high proportion of the super profits from the exploitation of the UKCS's oil and gas. In other words, PRT was a suitable device to secure more economic rent, or 'take', in accordance with the aims of the White Paper of 1974. In this regard, the Oil Taxation Act, 1975, stated:

> "A tax, to be known as petroleum revenue tax, shall be charged in accordance with this part of this Act in respect of profits from oil won under the authority of a licence granted under either the Petroleum (Production) Act 1934 or the Petroleum (Production) act (Northern Ireland) 1964". (Great Britain, 1975b, S. 1)

In other words, companies earning profits from oil extraction under an oil and gas licence from the UK and its continental shelf were liable to PRT on their share of production.

The Oil Taxation Act of 1975 introduced a 'safeguard concept', which aimed to encourage the development of explored marginal fields. This concept meant that a participator would pay PRT when his adjusted profits for a period exceeded 15 per cent of his accumulated capital expenditure, in which the total payment of PRT did not exceed 80 per cent of the participator total gross profits (Nigg and Keeling. 1983, p. 66; Rutledge and Wright, 2000, p. 5; Mommer, 2002, p. 185; KPMG, 2000, p. 53). The safeguard concept aimed to provide a form of marginal relief that would benefit less profitable fields regardless size of the fields' reserves. In this regard, Liverman (1982, p. 459) states: "a number of safeguards were introduced to ensure that the less profitable fields would not be hit too hard". Also in this year (1975) the concept of a 'ring-fence' was introduced for the CT payments around any oil company's North Sea trade. This concept meant that

losses from abroad or from other activities could no longer be set against profits from North Sea production to reduce tax liabilities (see section 3.2.5). The CT ring-fence was an instrument which helped the Government to capture more of the super-profits earned by oil and gas companies during this period.

In March 1978, a White Paper entitled "The Challenge of North Sea Oil" was presented to Parliament (DOE, 1978, p. 3). This White Paper listed the benefits of North Sea oil. It would: 1) boost the total national income; 2) help the balance of payments; and 3) increase the Government's yearly revenues by £4,000 million by the mid 1980s. The White Paper presented very ambitions plans based on income from the extra oil and gas revenues. It was proposed to use the oil revenues in many different ways: a) investing in industry; b) improving industrial performance; c) investing in energy; and d) increasing essential services. By employing this oil and gas wealth, the UK Government believed that Britain would be able to increase its economic activities and employment, and at the same time benefit Scotland (DOE, 1978, p. 3). In this regard the DOE (1978, p. 5) stated in the White Paper:

> "North Sea provides a unique opportunity for Britain to improve her economic performance, raise her living standards, move forward to full employment, and develop as a socially just society. It will also put her in a stronger position to discharge her international responsibilities, not least in relation to developing countries."

Furthermore, the White Paper mentioned the possible indirect effects of North Sea revenues, which might help to reduce the import bill, as well as the constraints on the balance of payments. It was proposed to achieve the above aims by employing North Sea oil and gas revenues. The White Paper did not mention the details of the possible fiscal regime that might be used to achieve these aims. The Government intended that some part of the North Sea oil revenues should be used to tackle the long standing problems of Scotland and other assisted areas such as Wales, and Northern Ireland (DOE, 1978, p. 11). However, a key question here is: to ask what extent would the UK Government be able to achieve the aims set in the 1974 and 1978 White Papers.

The main fiscal changes during 1979 were to reduce the uplift for allowable expenditure from 75 to 35 per cent. The oil allowance for the purpose of PRT profits calculations was reduced from 500,000 to 250,000 metric tonnes a year (Great Britain, 1975a). Also in this year the rate of PRT was increased from 45 to 60 per cent (Great Britain, 1975b).

Licensing

During the early 1960s, the UK was facing the fact that successful discoveries of petroleum would make the UKCS more attractive to the oil industry. This would consequently give the UK a powerful bargaining position and gain experience in oil and gas industry operations. Therefore, the UK Government had to depend on private and foreign companies, which had the required capital and experience, for exploration and production (Robinson and Marshall. 1984, p. 6; Noreng, 1980, p. 41).

On 15th April 1964 the Continental Shelf Act was passed in the UK, declaring the sovereignty of the UK over the continental shelf. This Act regulated granting offshore exploration and production licences. The Act referred very clearly to the Petroleum Act of 1934, which regulated and controlled granting onshore exploration and production licences in the UK. However, the 1934 Act was applied to the continental shelf and offshore provinces with some modifications (Noreng, 1980, p. 39; Upton, 1996, p. 21; Kemp, 1992, p. 93).

In 1964 the UK Government (Conservative) called for applications for exploration and production licences. Government policy aimed at encouraging the most rapid exploration and economic exploitation of the UKCS petroleum resources. The Conservative Minster for Power announced this policy, which included the following main criteria:

1. Encouraging rapid exploration and economic exploitation of the North Sea oil and gas resources.
2. Applicants had to be incorporated in the UK, as their profits would be taxable there.

3. Foreign applicants were to be treated as UK companies were treated in their countries of origin.
4. Granting a licence to an applicant should be based on the applicant's work programme and also on the availability of finance and other resources to implement it.
5. In granting a licence to an applicant, the applicant's past, present, and future contribution towards developing the UKCS resources was to be taken into consideration (HC, 1973, p. xii; Hann, 1986, p. 50).

The outcome of the first licensing round was 53 licences granted in 348 blocks to 51 companies. This was the first oil and gas licensing round in the UK (DTI, 2000a, p. 106).

During the summer of 1965, 37 licences were granted in 127 blocks to 44 oil and gas companies by the new Labour Government.[30] This was the second round of oil and gas licences (DTI, 2000a, p. 106). The terms and conditions of these licences were consistent with the American references with only one main exception. This exception was that the UK Government had participated in development, whereas the American had not (Mommer, 2002, p. 184). The new UK Government reviewed and slightly modified the oil policy. The aims of the new oil policy were to grant the UK more experience, obtain a greater contribution towards the UK balance of payment, to improve and support public and private industry, and focus on employment.

In 1970, 37 licences were granted in 106 blocks to 61 companies. This was the third licensing round (DTI, 2000a, p. 106). By the early 1970s, oil and gas had become an essential part of the UK economy and political life. Licensing methods and taxation were the very important issues and by that time the UK had obtained good experience in the oil and gas industry (Hann, 1986).

Owing to a significant slowdown in the North Sea activities because of the small size of previous licensing rounds, the Conservative UK Government invited, in

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[30] The Labour party took over the Government in the election of October 1964.

June 1971, applications for the fourth round of licensing in 15 areas. The highest bidders were given the licences. In total, 118 more licences were granted on the basis of discretionary allocation to 213 companies in 282 blocks (DTI, 2000a, p. 106; Noreng, 1980, p. 43). The interesting point about the fourth round is that the Government invited applicants in four main areas. Applicants were divided between the four areas with the largest number of licences granted in the area of the northern basin of the North Sea. Table 3-2 shows information relating to the fourth licensing round in terms of the number of blocks offered, applied for and licensed in each of these areas, as well as the totals.

Table 3-2: Allocation of Licences in the Fourth Round.

	Offered	Applied For	Licensed
Southern Basin	71	24	24
Northern Basin	209	161	158
Western Approaches and Celtic Sea	68	42	42
West of Orkneys and Shetlands	88	59	58
Total	436	286	282
Source: HC (1973, p. xvi).			

In August 1976 the Labour Government invited applications for the fifth licensing round and the outcome was the awarding of 28 licences. The terms of the fifth round were tougher than before, as the state had to have a minimum of 51 per cent participation in the oil and gas operations. This was represented by a 51 per cent stake to be given to the BNOC in each block (Kemp, 1992, p. 95). State participation was proposed through the BNOC alone or together with another state corporation (Noreng, 1980, p. 56; DOE, 1986, p. 64). In this year, the BNOC was set up also to hold the Government's interests in commercial fields and new licences. Later on, the BNOC was able to undertake exploration and production activities on its own account (DOE, 1978, p. 7; Liverman, 1982, p. 462). Royalties for licences issued after 20th August 1976 were calculated on UK landed values without deduction for conveying and treatment costs (KPMG, 2000, p. 3; Bland, 1991, p. 25).

In August 1978 the sixth round of licences took place. The outcome was 26 awards were granted in 42 blocks to 59 companies. These licence awards were subject to two main conditions, as follows.

1. An agreement between the Secretary of State for Energy and the prospective licensees, including the BNOC, for an obligatory work programme for the blocks; and
2. The conclusion by the BNOC and each group of co-licensees, with the approval of the Secretary of State for Energy, of a joint operating agreement (DOE, 1980, p. 6).

The Conservative Government announced in December 1979 a proposal for the seventh oil and gas licensing round. In this round the Secretary of State for Energy aimed to give licences to cover 90 blocks. The round, however, was launched in May 1980. This licensing round had three new features: (1) Companies were given the option to apply for blocks of their own choice within a specified area in the northern North Sea, in addition to blocks listed by the Department; (2) companies had to pay a cash premium of £5 million, for any licence of own choice area; and (3) BNOC should had oil option, at market price, to 51 per cent of any oil produced (Liverman, 1982, p. 462). Licences in this round were awarded by the normal discretionary method of allocation. The results of the round were 90 licences awarded in 90 blocks to 157 companies (DTI, 2000a, p. 106). The BNOC was to have the same opportunity as private sector companies to apply for licences, but would not have priority over other private companies with regard to future production licences. In this regard the DOE (1980, p. 6) stated:

> "Under these revised arrangements, the Secretary of State's previous reserved right to require a licence applicant to offer BNOC the option of 51 per cent equity partnership in the application does not apply to licences granted after 5 August 1980. Instead, applicants are now required to give BNOC an option to purchase, at market price, up to 51 per cent of the petroleum produced from the licensed area".

The aim behind this 51 per cent entitlement was to secure supply of oil to the UK. Table 3-3 presents information regarding licensing rounds during this period of time.

Table 3-3: Oil and Gas Licensing Rounds over the Period 1964-1980.

Round (Year)	Blocks offered	Blocks applied for	Total No. applications	Blocks awarded	Licences awarded	No. of companies
1st (1964)	960	394	31	348	53	51
2nd (1965)	1102	127	21	127	37	44
3rd (1970)	157	117	34	106	37	61
4th (1971/72)	421	271	228	282	118	213
	15 (cash bid)	15	31			
5th (1976/77)	71	51	53	44	28	64
6th (1978/79)	46	46	55	42	26	59
7th (1980/81)	specified area, 80 others	97	125	90	90	157
Source: DTI (2001a, Appendix 2).						

As can be seen from the above table, the first, fourth, and seventh rounds offered more blocks and awarded more licences to oil and gas companies than the second, third, fifth, and sixth rounds. This clear variation in the number of blocks and licences awarded reflects the interests of the UK Governments (Labour and Conservative). The Conservatives tended to offer more blocks and award more licences in order to boost the UK oil and gas industry, whilst Labour was trying to control the exploitation of the UK oil and gas commodities.

Oil and Gas Production

In November 1965 the British Petroleum Company (BP) found the first offshore gas in commercial quantities in the UK waters in the West Sole gas field. The major gas fields (Indefatigable, Viking, Leman, Hewett) were discovered and had started production by 1969. Natural gas was being used in British homes by 1967 (DTI, 1996b; Upton, 1996, pp. 22-24; Robinson et al., 1984, p. 3). The first offshore oil discoveries were made by Shell in Gannet F oil field in March 1969,

and by BP Amoco in December 1969 and November 1970 in the Arbroath and Forties oil fields respectively. However, Arbroath and Gannet F oil fields did not start production until April 1990 and June 1997 respectively, while production from Forties started in September 1975 (DTI, 1996a).

During the 1970s oil and gas production increased rapidly, amounting to 94.2 million tonnes of oil equivalent in 1978, as opposed to 10.6 million tonnes in 1970. The UK oil and gas industry experienced more and more new successful discoveries, which totalled 38 discoveries over the period 1976-1978. The Government's revenues increased to £245 million, which was a significant amount of revenue. These factors made the Government think about two main issues, namely: boosting the oil and gas industry, and using the revenues to improve the social and economic life of Britain (DTI, 2000; 1996a).

However, exploration and development activities decreased during the late 1970s and early 1980s. The reason for this was probably a result of companies' focus on developing existing wells and disappointment over increasing tax rates (Robinson and Marshall. 1984, p. 4). Table 3-4 and Figure 3-1 present information about oil and gas production over the period 1975-1980.[31] Also the table shows changes in yearly production over the period.

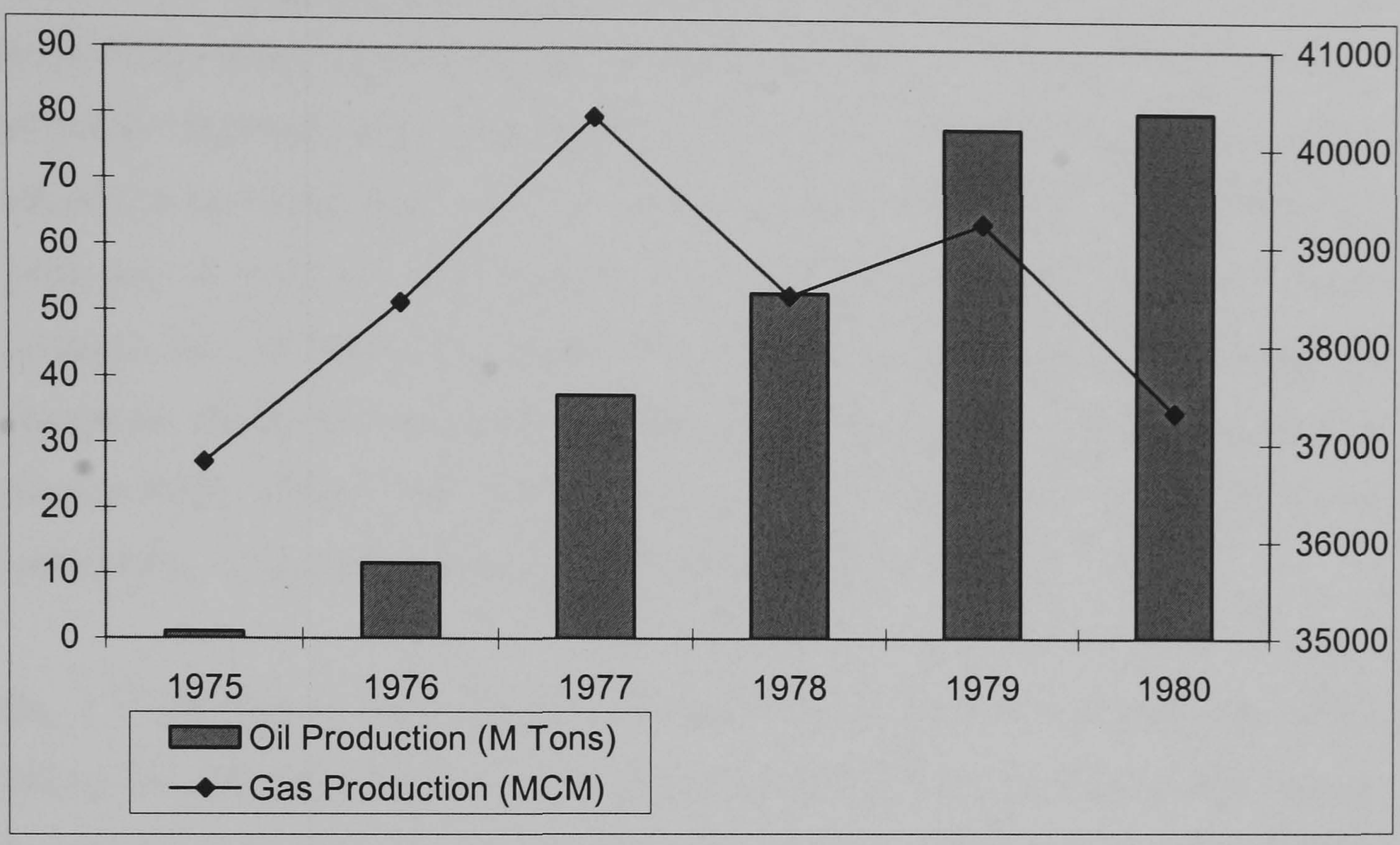
Table 3-4: Oil and Gas Production Over the Period 1975-1980.

Year	Oil Production (M Tons)	% Change	Gas Production (MCM)	% Change	Total Production (MTE)	% Change
1975	1.1	955	36,805	4.37	32	34.38
1976	11.6	222	38,415	4.92	43	65.12
1977	37.3	42	40,304	-4.48	71	19.72
1978	52.8	48	38,497	1.90	85	29.41
1979	77.9	3	39,228	-4.86	110	0.91
1980	80.5	#	37,320	#	111	#
Source: DTI (1975-1980).						

[31] There is a break in the official statistical information available in the DTI official publication series, *Development of the oil and gas resources of the United Kingdom*, which is known as "the Brown Book" with regard to the oil and gas production for the period before 1975. However, the period before 1980 is not of main interest for this research as the main focus is on the period 1980-2000.

Note: M Tons stands for million tonnes, MCM stands for million cubic metres, and MTE stands for million tonnes of oil equivalent. The sign # means that the percentage was not calculated for the year in question.

Figure 3-1: Oil and Gas Production Over the Period 1975-1980.



The table and the figure above show that oil production increased from 1.1 million tonnes in 1975 to 77.9 million tonnes in 1979, whilst gas production fluctuated until 1980 as shown in Figure 3-1.

3.4.3 The period 1980-1990

Tax Changes

By the early 1980s, the UK experienced a significant decrease in the number of new oil and gas projects being brought forward by the industry. Therefore, the Government made changes to the oil taxation system in order to encourage exploration and development activities. The following paragraphs explain these changes in detail.

When the new Conservative Government came to power, in mid-1979, the advantages of the BNOC compared with private companies decreased for two main reasons. The first was the change of policy of the new Government, which

focused on and supported the private sector; and the second was that the oil volumes that the BNOC had to purchase were very large and inflexible in the short term. This caused problems as the BNOC did not have major storage facilities, and did not operate actively in the forward market (Liverman, 1982, p. 461). It was suggested that while the BNOC could operate on a self-financing basis during times of rising oil prices, it experienced increasing difficulties when oil prices decreased from their peaks of the early 1980s. Oil and gas companies refused to buy back their own oil, which had been sold before to the BNOC to fulfil the 51 per cent requirement. This was because these companies could purchase the oil from other suppliers for cheaper prices on the spot-market. Therefore, the BNOC experienced losses during the periods of fall in oil prices (Fleites Melo, 1991, p. 106; Kemp, 1992, p. 97). In this year the rate of PRT was increased to 70 per cent (Great Britain, 1980, S. 104).

On 17th December 1981 the Oil and Gas (Enterprise) Bill was published (HC, 1981). The Bill provided for the disposal of the BNOC oil-production business to the private sector. It was proposed to carry out the disposal by transferring the Corporation's oil-producing assets into a subsidiary named 'Britoil'. It was planned that 51 per cent of Britoil's shares would be offered for sale to the public. The Government hoped that this would be done before 1982; and the Corporation would remain wholly state-owned, principally to trade in oil to which it had access through participation agreements (DOE, 1982, p. 10). The reminder of the Corporation, 'the trading sector', kept the original name of the Corporation and retained one main role. This role was taking 51 per cent of North Sea oil production at market price, plus the 'in kind' royalty oil taken by the state (Robinson and Marshall, 1984, p. 7). One more reason for the disposal of the BNOC was that the strategy of the Thatcher Government, which disliked any kind of state interference, led to the close of the Corporation and the selling of Britoil. Therefore, the UK no longer had a state oil company to fulfil the role played by state oil companies elsewhere (Fleites Melo, 1991, p. 106). In other words, the Conservative Government worked to privatise national oil and gas companies.

Following the substantial increase in oil prices in 1979/80, the Budget of 1981 introduced a new tax called Supplementary Petroleum Duty (SPD). The Financial Act, 1981, stated:

> "*Every participator in an oil field shall, in accordance with this part of this Act, be chargeable with a tax (to be known as supplementary petroleum duty) on the gross profit accruing to him from the field in any chargeable period to which this section applies*"
>
> (Great Britain, 1981, S. 122)

SPD was initially introduced for 18 months but it was extended to two years ending on 31st December 1982 (Great Britain, 1981, S. 122: 5; DOE, 1981, p. 17; DOE, 1982, p. 19 and p. 61). In this regard Lawson (1983a, p. 8) stated:

> "it was introduced on a temporary basis in order to give the oil industry an opportunity to suggest alternative ways of raising a similar level of revenue if there was a better structure".

By introducing SPD, there was thus a combination of taxes on oil and gas production during the period 1980-1981, and North Sea oil taxation became extremely complex and unstable. The instability of the petroleum fiscal regime came from ten major changes over the period 1975-1983,[32] the many changes of tax rates over this period, and the introduction and abolition of SPD and APRT. The complexity of this fiscal regime arose from the existence of four separate taxes at the same time, i.e., Royalties, Petroleum Revenue Tax, Supplementary Petroleum Duty, and Corporation Tax. Kemp and Rose (1983, p. 15) present the combination of these taxes in the following equation:

$$R + S + P\,(1 - R - S) + T\,(1 - R - S - P + PR + PS)$$

where R is the rate of royalty, S the rate of SPD, P the rate of PRT and T is the rate of CT, with R at 12.5 per cent and P at 70 per cent. The above equation shows on the one hand the component of the fiscal regime during the early 1980s, and on the other hand reflects the complexity of the UK petroleum fiscal regime. This combination expresses a total of 89.9 per cent as a marginal tax take for the UK Government out of the final revenues (output) of the UK oil and gas resources

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[32] Major changes to the petroleum fiscal regime over the period 1975-1983 were: the Oil Taxation Act 1975, provisions contained in seven Finance Acts, the Petroleum Revenue Tax Act 1980, and the Petroleum Royalties (Relief) Act 1983.

during that period of time. This percentage is calculated based on the tax rates that were applied during 1981, these are: royalties at 12.5 per cent; SPD at 20 per cent; PRT at 70 per cent; and CT at 52 per cent.

By 1982, the Government tax take have been more than 80 per cent.[33] The Government decided that exploration and development activities were affected by the tax regime, and the development of North Sea oil was put at risk by the high level of taxation and the frequency of changes (Liverman, 1982, p. 467). Therefore, there should be a relaxation of the tax burden to help recovery and to increase exploration and development activities (Robinson and Marshall, 1984, p. 8). In this year, the rate of PRT was increased to 75 per cent with effect from 31st December 1982 (Great Britain, 1982, S. 132).

The year 1983 was a time of change for the UK petroleum fiscal regime. In this year and in the Chancellor's 1983 Budget Statement, royalties were abolished in the Petroleum Royalty Act 1983 for qualifying fields receiving development approval from the Secretary of State for Energy on or after 1st April 1982 (Great Britain, 1983a). In this sense, the Financial Act 1983 exempted a number of relevant new fields from royalty (Bland, 1991, p. 25). Financial Act ,1983, stated:

> "Relevant new field" means an oil field–
> *(a)* no part of which lies in a landward area, within the meaning of the Petroleum (Production) Regulations 1982 or in an area to the East of the United Kingdom and between latitudes 52° and 55° north; and
> *(b)* for no part of which consent for development was granted to the licensee by the Secretary of State before 1st April 1982; and
> *(c)* for no part of which a programme of development had been served on the licensee or approved by the Secretary of State before that date".
>
> (Great Britain, 1983a, S. 36)

---

[33] With royalty at 12.5 per cent, PRT at 70 per cent, SPD at 20 per cent, and CT at 52 per cent the marginal tax rate is 89.92 per cent. this marginal tax rate is calculated as (100 x 12.5%) +([100 – 12.5%] x 70%) + ([100 – 12.5% - 70%] x 20%) + ([100 – 12.5% - 70% - 20%] x 52%) = 89.92%.

This was the first stage of abolishing royalties. Moreover, offshore fields outside the Southern Basin of the North Sea that had development consent after 31st March 1982 were entitled to double oil allowance for the purpose of calculating PRT profits, i.e., 500,000 metric tonnes per chargeable period up to a total of ten million tonnes per field (Great Britain 1983a, S. 36). Furthermore, since 16th March 1983 exploration and appraisal expenditure outside an existing field were allowed to be deducted against the PRT income from these existing producing fields (Great Britain, 1983a, S. 37).

On 31st December 1982, SPD was replaced by another tax called Advanced Petroleum Revenue Tax (APRT). APRT was abolished after one year. It was scheduled to be phased out in four stages with reducing rates as follows:

1) 1st January 1983 to 30th June 1983 = 20 per cent
2) 1st July 1983 to 31st December 1984 = 15 per cent
3) 1st January 1985 to 31st December 1985 = 10 per cent
4) 1st January 1986 to 31st December 1986 = 5 per cent

Then APRT was abolished (Great Britain, 1982, S. 139).

Changes relating to oil and gas taxation in the 1983 Budget evolved as a response from the Government to oil and gas companies' requirement to provide more incentives to develop marginal fields (Devereux, 1983, p. 75). In this regard, a letter sent from the Secretary of State at the Department of Energy to the Chairman of the Select Committee on Energy on 29th March 1983 stated:

> " When your Committee published its further report on North Sea Oil Depletion Policy in January, you confirmed your views about the adverse effects of tax regime on the development of high cost and marginal fields and called for modifications over and above those introduced under the 1982 Finance Act.
>
> You will be aware that the Chancellor has made further significant concessions in his recent Budget, which should be of particular benefit to future high cost and marginal fields. In particular, we have decided to abolish royalties in relation to new offshore fields outside the Southern Basin area approved for development on or after 1 April 1982. We are also ready to discuss the position of the Southern Basin with the industry and if concessions are found to be necessary they

will take effect from Budget day this year. I enclose copies of press releases from the Inland Revenue and from this Department which give details.

I hope that the Committee will see these changes as substantially meeting their concerns over future North Sea development; the industry appears to be responding positively." (Lawson, 1983a, p. 4)

From the above statement one can see that changes in the UK petroleum fiscal regime in the 1983 Budget were discussed between the Government and the oil and gas industry. The changes clearly benefited the oil and gas industry.

In brief, the 1983 oil tax changes consisted of the following.

1. Phasing APRT out, which was completed by the end 1986.
2. PRT allowance was doubled for new fields.
3. Royalties were abolished for fields outside the Southern Basin of the North Sea area that were developed after March 1982.
4. Immediate PRT relief against any field for expenditure incurred after 15th March 1983 on searching for oil or appraising reserves discovered.

However, the expected adverse effects yielded by this relief was a scarifying of £800 million of the Government's revenues over the four years 1983-1987, which would give substantial reduction in tax for future fields (DOE, 1983, p. 20). The task of this research is to explore in depth, and examine the rationales and effects of this relaxation, and evaluate the tax policy engendered by this relaxation.

During the period 1985-1986 there were no major changes in oil taxation, as the aim was to provide stability in the tax regime applied to the oil and gas industry. However, in 1985 it was announced that immediate PRT relief from exploration and appraisal expenditure was to be withdrawn (DOE, 1986, p. 2, Great Britain, 1985, S. 90). On 25th July 1986 the Gas Act allowed the property rights and liabilities of the British Gas Corporation to be transferred to a public limited company (British Gas plc). From the above date British Gas plc became one of the private companies with upstream operations and was subject to the same controls and restrictions as private companies (DOE, 1987, p. 67). Also in this year (1986) the Advance Petroleum Revenue Tax Act (APRTA) stated that if an

operator who had never won a profit from UK oil and gas fields had paid APRT for a chargeable period before 31st December 1986, the APRT was to be paid back to the operator (Great Britain, 1986, S. 1).

The Finance Act 1987 introduced the concept of the 'Cross Field Allowance', which stated:

> "Where an election is made by a participator in an oil field (in this section referred to as "the receiving field"), up to 10 per cent. of certain expenditure incurred on or after 7th March 1987 in connection with another field, being a field which is for the purpose of this section a relevant new field, shall be allowable in accordance with this section in respect of the receiving field…". (Great Britain 1987, S. 65)

In other words, this concept allowed 10 per cent of the development expenditure of offshore fields outside the Southern Basin of the North Sea and approved for development after 17th March 1987 to be deducted from income in other fields for the purpose of calculating PRT.

The Chancellor of the Exchequer announced in the 1988 Budget that all Southern Basin and onshore fields for which a development permit was given after 31st March 1982 would be exempted from royalties with effect from 1st July 1988 (Great Britain, 1989; DOE, 1988, p. 72; Bland, 1991, p. 26). In this regard, the Petroleum Royalties (Relief) and the Continental Shelf Act 1989 stated:

> "**1**. —(1) Petroleum won and saved from any relevant Southern Basin or onshore field or relevant onshore area shall be disregarded in determining whether any and, if so, what—
> (a) payments of royalty; and
> (b) deliveries of petroleum, are to be made in relation to chargeable periods ending after 30th June 1988 as consideration for the grant of a licence to which this section applies". (Great Britain, 1989, S. 1)

This was the second stage of abolishing royalties. In the same year (1988) the Income and Corporation Taxes Act (ICTA) 1988 tackled interest payments to a participator on the extra payment of PRT to the Government. It stated that this interest should not be considered when calculating the operator's profits for corporation tax purposes. In this regard the Act stated:

> "Where any amount of petroleum revenue tax paid by a participator in an oil field is, under any provision of Part I of the 1975 Act, repaid to him with interest, the amount of the interest paid to him shall be disregarded in computing the amount of his income for the purposes of corporation tax". (Great Britain 1988, S. 501)

Also, in June 1988 it was announced that royalties would be taken in cash after 31st December 1988 rather than in kind (DOE, 1989, p. 85; SC (A) 1988, clause. 129). In the 1988 Budget, the Chancellor of the Exchequer reduced the PRT oil allowance. In this regard DOE (1988, p. 72) states that there would be

> "A reduction in the PRT oil allowance from 250,000 to 100,000 tonnes per chargeable period with the cumulative limit reduced from 5 to 2 million tonnes. This measure would also be effective from 1 July 1988. This will be implemented in this year's Finance Bill."

This proposal was amended following consultation with the oil and gas industry and the result was that the allowance was set at 125,000 tonnes with a maximum cumulative amount of 2.5 million tonnes (DOE, 1989, p. 85; KPMG, 2000, p. 9; Great Britain, 1988, S. 138). In this context, Mr Lilley, MP, in a Parliamentary debate on the 16th June 1988 stated:

> "It was no part of our objectives to increase the aggregate amount of tax paid by base fields, taken as a whole. Instead, we wanted to set the petroleum revenue tax oil allowance at a level that would leave the overall tax take unchanged over the life of the fields affected by the restructuring". (SC (A), 16th June 1988, c. 129)

In summary, the main changes to the petroleum fiscal regime during 1987-1988 were:

1. Introducing the Cross Field Allowance concept in the 1987 Finance Act (S. 65).
2. Abolishing royalties for Southern Basin and onshore fields.
3. Royalty payments to be received in cash rather than in kind.
4. Reducing PRT allowance to 125,000 million metric tonnes.

Licensing

During this period (1980-1990) four licensing rounds were announced and completed on a two year lag basis. This section presents a detailed explanation of these rounds.

On 14th June 1980 amending regulations came into effect. The change effective was in the form of revising the surrender of territory provisions so that the licensee would be able to retain 50 per cent of the area originally licensed at the end of six years (DOE, 1980, p. 4; 1981, p. 6). The eighth round of licensing was launched in 1982. In this round 184 blocks were put on offer, including 15 for cash tender. This round aimed at providing new opportunities to explore for gas in the southern North Sea and to open exploration up in a number of hitherto not drilled areas (DOE, 1983, p. 7). The most significant point in this round was that only 70 blocks were awarded to 81 companies out of the 184 blocks offered. In this year the Government decided, after reviewing the policy on royalties in kind, to continue taking royalties in kind, apart from in some of the small fields (Hann, 1986, p. 63). The Secretary of State formally had an option to require royalty payments to be in kind or in cash. The BNOC acted as an agent for the Secretary of the State in handling the royalty oil, which amounted in 1982 to 11.1 million tonnes (DOE, 1983, p. 7).

The proposal for the ninth petroleum licensing round was announced in February 1984. The oil industry, through the UK Offshore Operators Association (UKOOA) and Association of British Independent Oil Exploration Companies (BRINDEX), relevant local authorities and environmental interests, was involved in discussing the petroleum round proposal. The Government put 195 blocks on offer, 15 of which were for cash tender and 180 were offered on the usual discretionary terms. The most significant feature of this round was that the Government offered 36 blocks in the deep water of the frontier areas of the Rockall and Faroes troughs. The exploration and development costs of these areas were relatively high, as these areas had not been explored before. In order to

incentivise the oil industry to explore these areas, the Government announced that applicants for frontier blocks would be treated more favourably than those applying for acreage in more mature areas. The results were that 32 applications were received for 13 of the cash tender blocks and 117 applications for 107 of the discretionary blocks. The outcome was 89 licenses awarded in 93 blocks to 103 companies (DOE, 1985, p. 4). The increased number of applications in this round reflects the increased interest of the oil and gas industry in working under the new petroleum fiscal regime and in benefiting from the oil taxation relaxation that had taken place in 1983 (DOE, 1985, p. 4).

The tenth offshore licensing round took place in 1987. In all, 75 applications were received for 127 blocks from 84 companies. The results of this round were 51 awards granted in 51 blocks to 60 companies, all of the awards being granted under the discretionary arrangements. The DOE (1988, p. 5) states that the smaller size of the tenth licensing round was to some extent due to a downturn in oil prices early in 1986. The awareness of the reduction of the oil and gas companies' cash flow, as a result of the 1986 oil price shock, along with the high cost of exploring new blocks offered in mature areas, led the Government to make the size of the tenth round relatively smaller than the ninth (HC, 1986, p. xxviii).

The DOE announced proposals for the eleventh offshore licensing round on 24th March 1988. This round offered 212 blocks around the UKCS. In all, 84 companies were offered 125 applications for 115 blocks out of the 212. The DOE set a number of rules for this round, namely that: the awarded tenant should complete a work programme within six years, and 50 per cent of the licensed area should be relinquished if not developed after two years. Licences for blocks in certain deep water areas had longer periods of validity. The main objective of the DOE was to ensure the continuation of the UK Continental Shelf as an oil and gas province well into the next century. The new licence terms were broadly welcomed by the industry (DOE, 1989, p. 7). The results of the round were announced on 29th June 1989. In all, 105 awards were made covering 115 blocks, all under the discretionary arrangements. The Secretary of State for Energy stated, "the 11th Round was confirmed as one of the most successful offshore licensing

round so far" (DOE, 1990, p. vi). Table 3-5 summarises information regarding licensing rounds over the period 1980-1990.

Table 3-5: Oil and Gas Licensing Rounds Over the Period 1980-1990.

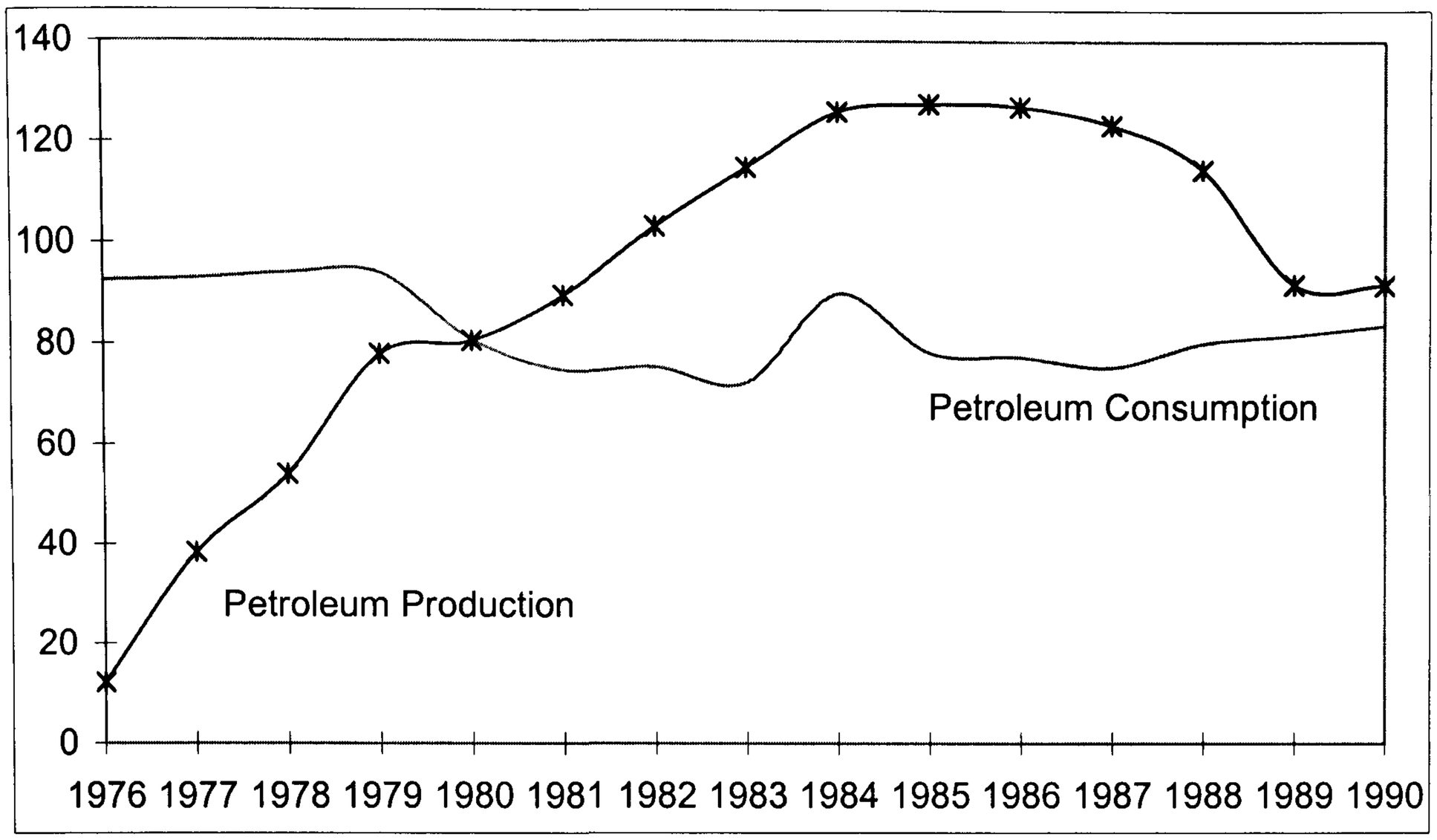
Round (Year)	Blocks offered	Blocks applied for	Total number of applications	Blocks awarded	Licences awarded	Number of companies
8th (1982/83)	169	76	40	70	55	81
	15 (cash bid)	8	20			
9th (1984/85)	180	107	117	93	89	103
	15 (cash bid)	13	32			
10th (1986/87)	127	61	75	51	51	60
11th (1988/89)	212	115	125	115	105	69
Source: DTI (2001a, Appendix 2).						

Oil and Gas Production

The year 1980 was an important year in the history of UK petroleum production, as UK oil self-sufficiency was reached in this year. Based on data extracted from the DTI (1996a, pp. 148-149), total oil and gas production in 1981 was 121.7 million tonnes of oil equivalent while the total oil and gas consumption was roughly the same (122.1 million tonnes). Oil production was 80.5 million tonnes in 1980 while the total oil consumption was 80.8 million tonnes (DOE, 1981, p. 20). In this context, Robinson and Marshal (1984, p. 16) calculated a ratio for this self-sufficiency over the period 1973-1983 and the ratio equalled 'one' in 1980, which expresses the self-sufficiency case in another way. Figure 3-2 presents production and consumption over the period 1976-1990.[34] The diagram shows the point at which the UK reached self-sufficiency in oil very clearly.

[34] Data is presented here since 1976 to show the distance between production and consumption lines before the self-sufficiency point in 1980.

Figure 3-2: UK Oil Production and Consumption Between 1976 and 1990



Source: based on data extracted from the DOE (1976-1992). MT stands for million tonnes.

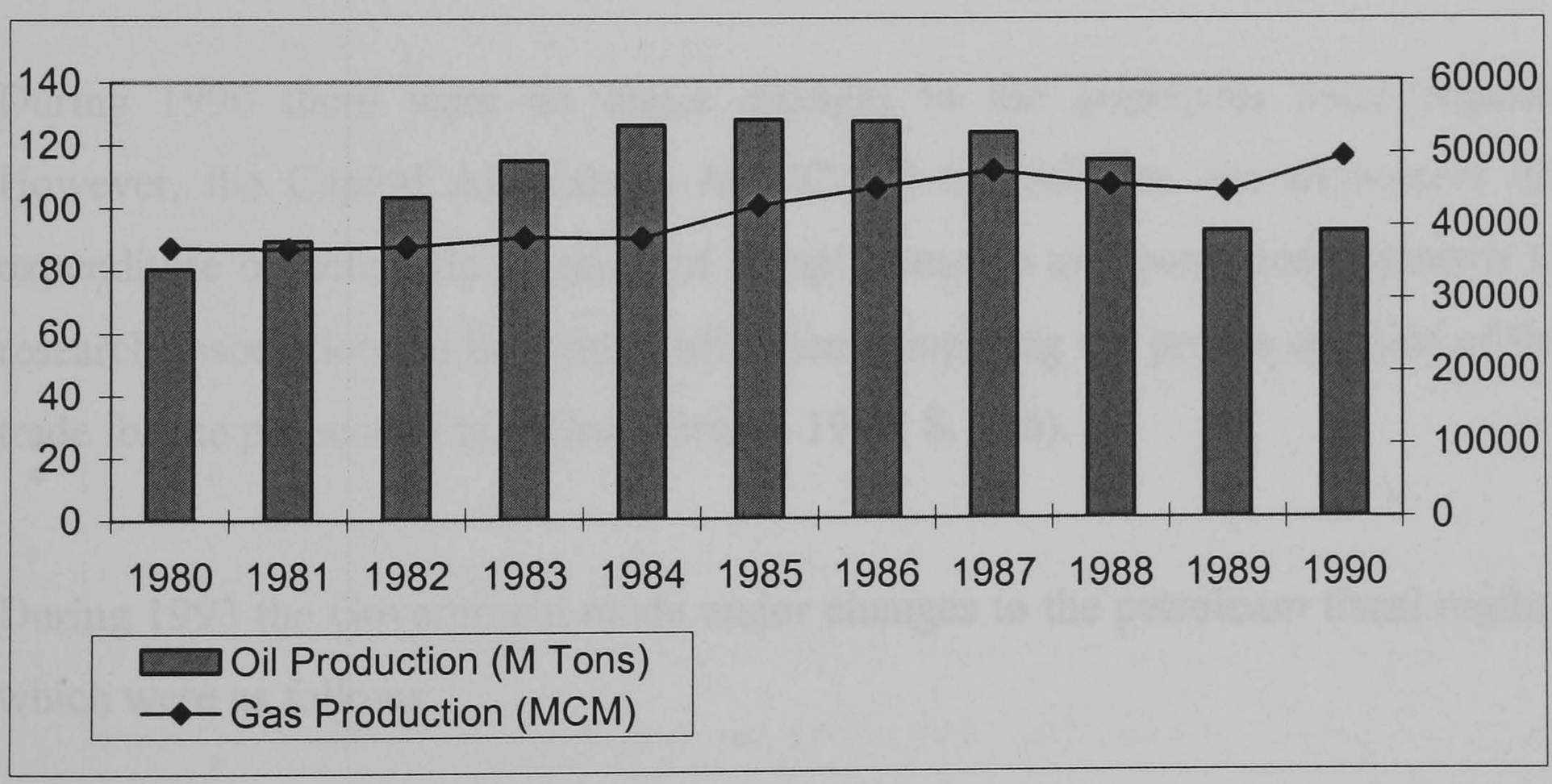
Looking at the actual production figure in 1980, it can be seen that the White Paper of 1974 (DOE, 1974) was rather ambitious in terms of forecasting future oil production (see tax changes in section 3.4.2). Oil production totalled 80.5 million tonnes in 1980. It continued to increase (but by less than 10 million tonnes a year) until 1982, when oil production was 103.2 million tonnes. Moreover, the Government's revenues from the oil and gas industry rose from £3,743 million in 1980 to £12,148 million in 1984. After that, Governmental revenues sharply declined to £4,803 million in 1986. This decline was a result of the sharp decrease in oil prices and because of the influence of the 1983 petroleum tax relaxation, as will be seen later on in the next chapter. Table 3-6 and Figure 3-3 show figures for UK oil and gas production, and the total equivalent production over the period 1980-1990. Also, they show the oil consumption over the period, and show UK oil self-sufficiency in 1980. In addition, the table presents the yearly change ratios over the period 1980-1990.

Table 3-6: UK Oil and Gas Production and Consumption Over the Period 1980-1990

Year	Oil Production (M Tons)	% Change	Gas Production (MCM)	% Change	Total Production (MTE)	% Change	Oil Consumption (M Tons)
1980	**80.5**	11.06	37,320	-0.34	111	8.11	**80.8**
1981	**89.4**	15.55	37,192	0.78	120	12.50	**74.8**
1982	**103.3**	11.23	37,481	3.25	135	8.89	**75.5**
1983	**114.9**	9.57	38,700	-0.44	147	7.48	**72.4**
1984	**125.9**	1.35	38,529	11.53	158	3.16	**89.9**
1985	**127.6**	-0.42	42,971	5.43	163	1.23	**78.3**
1986	**127.07**	-2.89	45,304	5.16	165	-1.21	**77.4**
1987	**123.4**	-7.21	47,641	-3.95	163	-6.75	**75.4**
1988	**114.5**	-19.83	45,758	-2.19	152	-15.13	**80.1**
1989	**91.8**	-0.22	44,755	10.71	129	3.10	**81.7**
1990	**91.6**	#	49,549	#	133	#	**83.6**
Source: DOE (1980-1990).							

Source: data relating to oil and gas production was extracted from the DOE (various years). Note: total production was self-calculated based on the equation 1 billion cubic metres gas = 0.83 million tonnes of oil equivalent (source, DOE, 1992, p. iv). The yearly percentage changes were calculated using the equation %=(B-A)/A*100. A is total production in the first year, and B is total production in the second year. MCM stands for million cubic metres; MTE stands for million tonnes of oil equivalent.

Figure 3-3: Oil and Gas Production Over the Period 1980-1990



From the above table it can be seen that oil production gradually increased from 1980 to peak in 1985 at 127.6 million tonnes. After that it decreased when the industry experienced a very sharp decline in the oil prices in 1986. This slump in oil prices in 1986 might have been the main reason for decreasing production in that year. The decline in oil production over the years 1988 and 1989 reflects the effects of the Piper Alpha accident and subsequent incidents (DOE, 1990, p. 34).

The cause is rather different when talking about gas production, as it increased from 1980, when it was 37,320 million cubic metres, up to 47,641 million cubic metres in 1987, then it slightly decreased over 1988 and 1989 and increased again in 1990.

3.4.4 The Period 1990-2000

Tax Changes

During the early 1990s the petroleum fiscal regime had some problems as fields that were paying PRT faced a high marginal tax rate. This high tax rate led oil and gas companies to try to avoid, to some extent, a heavy tax burden. For example, some companies tried to shift income into fields that did not pay PRT and shift expenditure into PRT paying fields, as immediate tax relief was available for PRT paying fields. This behaviour, plus the low oil prices during that period of time, resulted in a decline in the Government tax take from the oil industry. These reasons made the Government think about another type of another relaxation in the petroleum fiscal regime.

During 1990 there were no major changes to the petroleum fiscal regime. However, the Capital Allowances Act (CAA) of 1990 set out allowances for expenditure on scientific research of a capital nature and permitted payments to research associations to be written off when computing the profits or gains of the trade for the purpose of tax (Great Britain 1990, S. 136).

During 1993 the Government made major changes to the petroleum fiscal regime which were as follows.

1. PRT was abolished for oil fields with development consents on or after 16th March 1993. In this regard the Financial Act 1993 stated:

> "(3) Petroleum revenue tax shall not be charged in accordance with the Oil Taxation Acts in respect of–
>
> (a) profits from oil won from a non-taxable field under the authority of such a licence as is referred to in section 1(1) of the principal Act; or

(b) any receipts accruing to a participator in a non-taxable field which, in the case of a taxable field, would be tariff receipts or disposal receipts attributable to the field for any period".[35]

(Great Britain 1993, S. 185)

2. The oil allowance for PRT purposes was abolished as well. In this regard Financial Act 1993 (S. 185 (4)) stated "(e) no expenditure shall be regarded as allowable (or allowed) for a non-taxable field under the Oil Taxation Acts"

3. The rate of PRT was reduced for oil fields that had development consents before 16th March from 75 to 50 per cent. In this sense the Financial Act 1993 stated:

"(1) With respect to chargeable periods ending after 30th June 1993 the rate of petroleum revenue tax (relevant only to taxable fields) shall be 50 per cent. And accordingly, with respect to such periods, in section 1(2) of the principal Act for "75" there shall be substituted "50"."

(Great Britain 1993, S. 186)

The interesting point is that there was a contradiction between the Government intention of keeping the PRT rate relatively stable and what occurred in reality. In this regard Nigg and keeling (1983, p. 63) state:

> "Government stated that it was a tax which would not be amended significantly. Subsequently to its introduction in 1975, the legislation has been amended in seven different Finance Acts and one Petroleum Revenue Tax Act".

The period up to 2000 had not seen major changes in the petroleum fiscal regime. As can be seen from the above, the tax regime, which applies to any particular oil and gas field, depends on the date of receiving development approval. Depending on the age of any field and its taxable state, the current marginal rates of tax vary between 69.4 per cent and 30 per cent. If the field were liable to royalties, PRT and CT then the marginal tax rate would be 69.4 per cent. If the field were liable

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[35] Financial Act 1993 (S. 185) defines a non-taxable field as a field:
(a) for no part of which consent for development was granted to a licensee by the Secretary of State before 16th March 1993; and
(b) for no part of which a programme of development was served on a licensee or approved by the Secretary of State before that date"

to PRT and CT then the marginal tax rate would be 65 per cent. The marginal tax rate would be 30 per cent for fields that are liable for CT only (DTI, 2001a, S. 3.28). Changes to the petroleum tax regime were initially intended to simplify the regime, as well as making the UK an attractive investment prospect for international oil and gas companies. This opinion was supported by a statement from Tony Blair, the Prime Minister, "the UK oil industry enjoyed an 'enormously favourable tax regime'" (Corzine, 1998, p. 16).

Licensing

Over this period (1990-2000) seven licensing rounds took place, and there was a tendency for a decrease in licences awarded. In all, 80 licences were granted in 1990 in the twelfth licensing round, whilst only seven licences were awarded in 2000 in the nineteenth round. The next paragraphs will give details of these rounds.

On 26th April 1990 the Department of Energy announced the twelfth offshore licensing round. This round offered 120 blocks across a range of areas of the UKCS with the same terms as those for the eleventh round. In all, 115 applications were received from 80 companies for all areas on offer. Results of this round were that 74 awards were made, covering 107 blocks. On 19th April the Department of Energy announced a separate round of offshore licensing for the same year, 'the Frontier Round', which was considered to be the thirteenth licensing round. Eleven tranches covering 117 blocks were made available for applications. The main objective of this round was to provide a licensing framework for exploration activity in relatively unexplored areas. In all, 13 applications were received from 37 companies, but six awards were granted to 17 companies in 66 blocks (DOE, 1991, p. 12; 1992, p. 12).

The fourteenth offshore licensing round was announced over three stages by the Department of Energy in 1992, on 5th March, 30th July and 26th November. The round offered 484 blocks, and the results were 97 applications received for 128 blocks from 64 companies. In total, 79 awards were given in 110 blocks to 50 companies. The Department of Trade and Industry (DTI) announced the fifteenth

offshore licensing round in 1994. This round invited applications for 81 blocks in the established area of the central and southern North Sea. The round requested applicant companies to make commitments to early drilling. In all, 29 blocks were awarded to 36 companies in this round (DTI, 1995, p. 30).

During 1995 the DTI concluded the sixteenth licensing round. This round requested applications for 104 blocks. The awards for this round were made in two stages for 61 companies. In the first stage 26 blocks were awarded, and 53 blocks were awarded in the second stage (DTI, 1996a, p. 22). In the same year, on 21st November, the DTI offered 275 blocks in 68 tranches for applications under the seventeenth licensing round. In total, 32 companies were awarded 25 licences in 114 blocks.

The eighteenth licensing round was announced by the DTI in 1998 inviting applications for unlicensed acreages in the northern, central, and southern North Sea and in Liverpool Bay, Morecambe Bay and the adjacent Irish Sea. The round offered 602 blocks in mature areas close to existing fields or infrastructure. The round was expected to provide opportunities for companies to explore close to existing developments, and thus allow incremental discoveries to be brought on stream. In all, 47 licences were awarded in 78 blocks to 44 companies (DTI, 1999a, p. 5).

On 10th November 2000 the DTI announced the nineteenth offshore petroleum licensing round. The round invited applications for blocks in the "white zone", the area most recently designated part of the UKCS between the Faroe Islands and Shetland. There was strong interest in the blocks available for licences. In all, 13 companies were awarded licences in twelve blocks. Table 3-7 presents data relating to licensing rounds over the period 1990-2000.

Table 3-7: Oil and Gas Licensing Rounds Over the Period 1990-2000

Round (Year)	Blocks offered	Blocks applied for	Total No. applications	Blocks awarded	Licences awarded	No. of companies
12th (1990/91)	161	116	115	107	74	69
13th Frontire Round (1990/1991)	11 tranches (117 blocks)	6 tranches (66 Blocks)	13	6 tranches	6	17
14th (1992/93)						
1st and 2nd stages	435	122	96	104	78	48
3rd stage	49	6	1	6	1	2
15th (1994)	81	34	25	29	20	36
16th (1994/95)						
1st stage	101	26	24	26	18	27
2nd stage	63	56	37	53	27	34
17th (1996/97)	68 tranches (275 blocks)	28 tranches (127 blocks)	3225 tranches (114 blocks)	25 tranches (114 blocks)	25	32 plus further 24
18th (1998)	602	82	43	78	47	44
19th (2000/01)	44	12	13	12	7	13
Source: DTI (2001a, Appendix 2).						

Oil and Gas Production

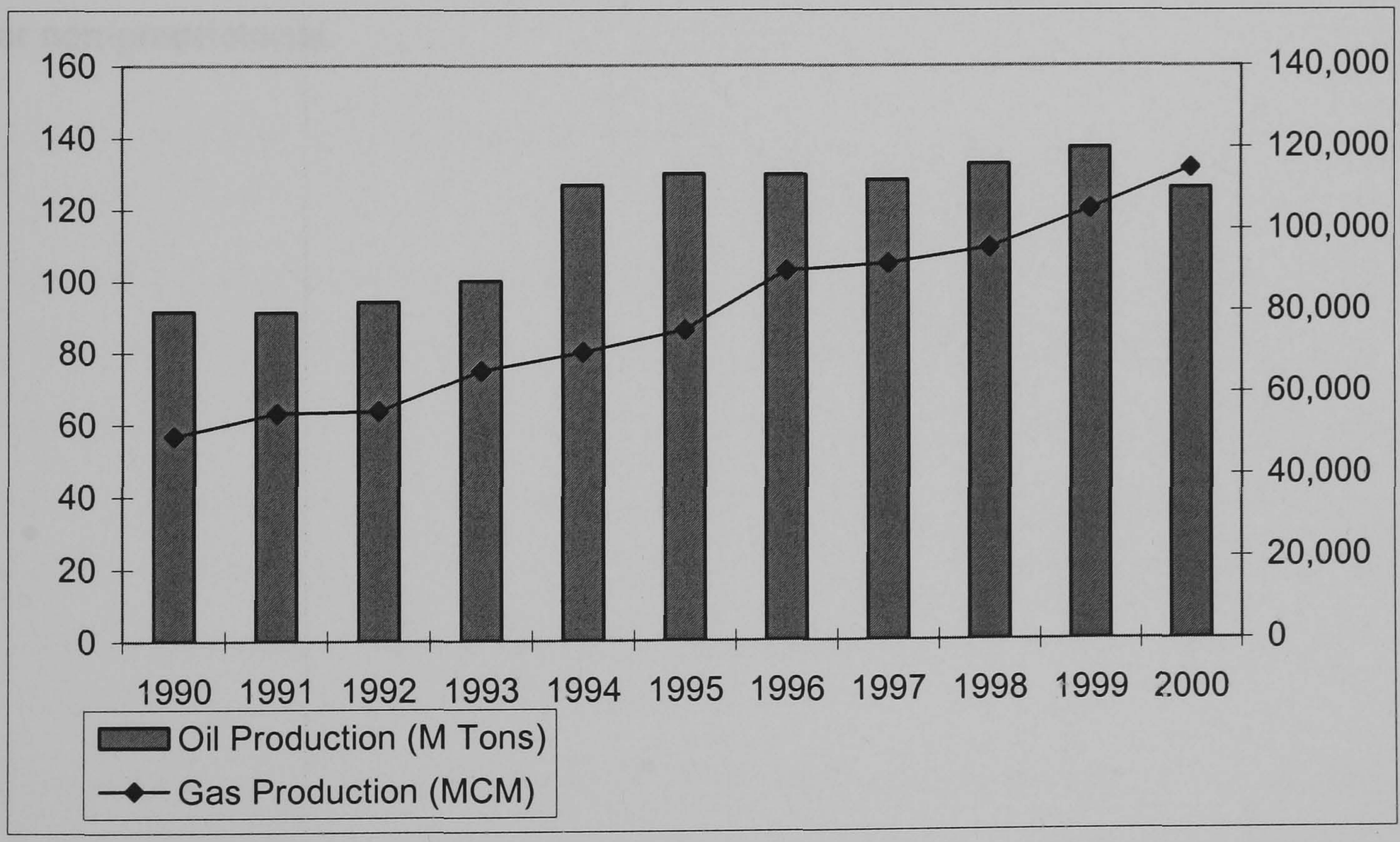
After 1991 production started to increase gradually. It declined very slightly in 1996 and 1997 then it increased in 1998 and 1999 to decline again in 2000 when it totalled 126 million tonnes. Gas production was increasing over the period 1990-2000: it was 49,549 million cubic metres in 1990 and peaked at 115,000 million cubic metres in 2000. Table 3-8 and Figure 3-4 show figures relating to individual oil and gas production and the total production over the period 1990-2000 and the change ratios.

Table 3-8: Oil and Gas Production Over the Period 1990-2000

Year	Oil Production (M Tons)	% Change	Gas Production (MCM)	% Change	Total Production (MTE)	% Change
1990	91.6	-0.33	49,549	11.40	133	2.92
1991	91.3	3.18	55,200	0.88	137	2.14
1992	94.2	6.26	55,686	17.62	140	9.09
1993	100.1	26.67	65,500	6.81	154	16.76
1994	126.8	2.44	69,960	7.89	185	4.15
1995	129.9	-0.15	75,480	19.17	193	5.39
1996	129.7	-1.16	89,949	2.03	204	0.00
1997	128.2	3.43	91,778	4.18	204	3.77
1998	132.6	3.39	95,614	9.85	212	5.36
1999	137.1	-8.10	105,028	9.49	224	-1.36
2000	126	#	115,000	#	221	#
Source: DTI (1990-2000).						

Not: the sign # indicates that the percentage change is not applicable in the year of question.

Figure 3-4: Oil and Gas Production Over the Period 1990-2000.



3.5 Summary

This chapter presented the historical evolution of the UK petroleum fiscal regime in four consecutive periods. In each period changes are explained and discussed with regard to tax effects, licensing, and oil and gas production. It demonstrates

the main tax changes, 'relaxations', to the UK petroleum fiscal regime that took place in 1983, 1987-88, and 1993. It also reflected on the Government policy, as prior to 1975 the Government policy was directed at establishing the legal framework, an offshore licensing regime and a fast production record. After 1975, but prior 1982, policies were directed at ensuring high tax take for the state, more regulated development investment, practicing more control on oil supply, and encouraging the offshore supplies industry in UK. Hence, the policy was changed for the period 1982-2000 for the satisfaction of the oil industry by relaxing the petroleum fiscal regime three times.

The next chapter will explore and explain the rationales for these relaxations in more detail from different perspectives, namely the Government, the oil and gas industry, and academic commentary and analysis. This will be the first step before testing these rationales and evaluating the performance and validity of the UK petroleum tax relaxation policy. In turn, this will lead to finding a better description for the UK manner of governing mineral resources, i.e., proprietorial or non-proprietorial.

CHAPTER 4: RATIONALES FOR THE UK PETROLEUM TAX RELAXATIONS

4.1 Introduction

The previous chapter presented the evolution of the UK petroleum fiscal regime and highlighted main relaxations to this fiscal regime that took place in 1983, 1987-88, and 1993. The purpose of this chapter is to highlight the rationales behind these relaxations prior to studying the effects of these relaxations and testing their rationales. It presents these rationales in chronological order, based on the timing of each relaxation. Rationales will be discussed from different points of view which are those of the Government, oil and gas industry, and academics' commentary and analysis. However, before considering rationales it is essential to clarify and define the meaning of a tax relaxation first. This is discussed in the next section.

4.2 What Does 'Tax Relaxation' Mean?

This section illustrates the meaning and nature of a tax relaxation. In doing so, it discusses the expected effects of changes in oil and gas prices on the oil and gas industry's activities, and this will be compared with the effect of tax changes on these activities. Then it considers the possible meaning of the tax relaxation from the Government and the oil and gas industry points of view. It also discusses the possible Governmental aims behind tax relaxations.

Governments might present new taxes or increase existing tax rates when oil and gas prices increase. This action might be taken by a government so as not to allow the oil and gas industry alone to enjoy a windfall profit, and to capture more economic rent (Seymour, 1990, p. 3). [36] The price increase should benefit the host Government and the oil and gas Industry as well, but in reality this might not

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[36] This is what the British Government did by introducing PRT in 1975 and then increasing its rates several times, also by introducing SPD and APRT in the early 1980s (see Martin, 1997, p. 17).

always be the case. For example, if the total increased tax take is equal to or more than the total increase in company's profit caused by oil and/or gas price increase, then only the government benefits in this case. In other words, the increase in oil and/or gas prices does not always mean increasing oil and gas companies' profit and cash flow.

Any tax and/or increased rates of existing taxes can cause disincentives to oil and gas companies, because almost usually taxes do not allow the industry to enjoy extra profits and saving, as they often target gross revenues or production rather than net profit. Moreover, the more tax changes and the greater the instability in the petroleum fiscal regime, the more political and economic risk is faced by the oil and gas industry and fewer incentives arise for this industry (Rowland and Hann, 1987, p. 79). This uncertainty could lead the oil and gas industry to act in ways that counteract government's plans and wishes. For example, if oil companies expect an increase in tax rates during certain periods of time, they might postpone development activities and increase exploitation rates so as to benefit as much as possible from existing low tax rates. In other words, oil and gas companies will focus in such cases on exploiting more oil and gas at the existing tax rates before government increases them. Such behaviour from the oil and gas industry might not be favoured by the government who might want to keep exploitation rates at specified levels, and control the supply rates in order to keep prices unchanged during the short term.

Kemp & Macdonald (1994, p. 344) concluded that oil and gas activities including:

1. Number of new fields' developments;
2. Total number of fields in production;
3. Production levels;
4. Development expenditure; and
5. Gross revenues.

are very sensitive to changes in oil and gas prices. On the other hand, Lawson (1983a, p. 7) argues that a decline in oil prices would discourage investment in energy efficiency and adversely affect exploration and development for oil and the

development of other energy supplies. So based on the above, it can be said that when oil and gas prices increase, levels of the above activities, referred to by Kemp & Macdonald (1994), are expected to be increased and decline if prices decrease.

From the oil and gas industry perspective, tax changes have similar effects to prices changes. Introducing a new tax to the fiscal regime plays a similar role to a decrease in oil and gas prices. In both cases revenues of the oil and gas industry would be expected to decline. Hence if oil and gas activities slow down, government revenues from the oil and gas sector would be expected to decline as well. This decline would not happen immediately as a decline in the oil and gas industry's activities would take a considerable time to take effect. Therefore, governmental revenues might be expected to increase but not for some time. Based on the above, it can be said that presenting new taxes does not always benefit the government and might cause disincentives for the oil and gas industry. In order to accelerate investment activities, the government might have to phase existing taxes out or reduce their rates, to control adverse effects on the oil and gas activities caused by introducing taxes in the first instance or increasing existing tax rates.

From the above discussion, the nature of disincentives affecting the oil and gas industry because of any increase in tax rates can be understood, also how these incentives might negatively affect exploration and development activities. On the other hand, if the government decides to lower petroleum tax rates, abolish some taxes, or increase tax allowances, it can very clearly be understood that the government is trying to create incentives for the industry and these incentives should have positive effects on the oil and gas industry's activities (Seymour, 1990, p. 3). Sometimes the government might introduce more than one tax incentive to form a package of tax relief. An example of this might be the case of 1993 petroleum tax changes (see tax changes in section 3.4.4).

At this point it can be stated that a relaxation in the petroleum fiscal regime might consist of one or more of the following tax changes:

1. Abolishing certain taxes partly or entirely in certain geographical regions or for the whole producing area of a country.
2. Reducing rates of other taxes applied during a specific time on the whole or part of the producing area.
3. Presenting different types of relief and allowances for the purpose of calculating one or more of the applied taxes.

Such measures or a package of such measures might have different effects on different working companies according to the work area or dates of certain activities such as exploration, development or production. In other words, they might have a lighter burden in one area and a heavier burden in another.

With regard to the second component of the suggested package of relaxation (reduction in taxes rates), this might be applied through a number of devices. One of these is changing the way of calculating taxes to give different results and thus reducing the tax being paid by a working company to a host government. For example, royalties in the UK used to be calculated before PRT and the former used to be a deduction from the latter. If, arguably, the Government decided for one reason or another that PRT was to be calculated first and decided not to allow royalties to be deducted when calculating revenues for it, the whole Government's revenues would be changed, as the burden of PRT would be extended and the industry would be paying more PRT. Moreover, if the Government decides to allow more expenses before calculating the commodities' value subject to royalties, here the Governmental revenues raised by this duty would be less, because of reducing the royalty burden.

One more thing to be taken into account is eligibility: who will benefit from the tax relaxation? It might be applied to companies working in certain geographical areas, companies from certain jurisdictions, fields based on certain characteristics such as dates of granting exploration or development consents or even on the field reserves' volumes. Furthermore, allowances may be granted in many different ways, as they may be in the form of deducting certain costs like exploration, development, research, and appraisal and/or production, when calculating profits for any kind of taxes. Also they might be in the form of an oil allowance, by

exempting certain volumes of production from certain taxes. Tax relaxation may have different meanings and purposes for the government and the industry. What a government might consider a relaxation might not have the same meaning for the industry.

The next sections illustrate the possible meaning of tax relaxation from the point of views of the government and the oil and gas industry.

4.2.1 Government Perspective

For the government, a tax relaxation might mean reduction in tax rates, giving more allowances against taxes or abolishing some taxes, which might result in a reduction in the governmental total tax revenues. These relaxations should be statutory since they deal with tax changes. These tax relaxations will, at first sight, reduce the government's revenues from taxes. However, if the relaxation is accompanied by an increase in oil and gas production and maybe a decline in oil and gas operations' costs, as a result of using advanced technology, for example, the total governmental tax revenues will increase in this case, as the oil and gas industry's profit margin will be increased. The question that might be asked here is: how can a tax relaxation be characterised from a government's point of view? One or more of the following suggestions might be used to answer this question.

1. In such a situation, the reduction in the government tax revenues can be recognised and measured as a reduction in the tax for each production unit, or 'barrel of oil'.
2. One more measure in the reduction in the petroleum tax is in calculating the percentage of the tax being paid for a barrel of oil in relation to the selling price of that barrel before and after the relaxation. This measure is a useful one when a government intends to keep tax as a fixed, or approximately fixed, percentage of the price. Therefore, when oil and gas prices change, the total amount of tax will change as well.
3. Another useful measure is the one that takes prices and costs into account, as prices are not the only variables that might change over time, as, for example, cost might change as well. In this case the measure will be a

percentage of the tax paid in relation to the profit of oil and gas operations. This measure can be applied to a production unit, tonne of oil or equivalent gas, well, field or even a company.

Presumably, the above measures should individually or all together show the effects of a petroleum tax relaxation on government revenues from the oil and gas sector. The difficulty of using these measures is that different fields have different operating costs, capital costs, production levels and selling prices, which make the comparison and measuring their effect a difficult process.

Prior to clarifying oil and gas industry's perspective of a petroleum tax relaxation and, identifying the specific UK petroleum tax relaxations rationales the next section will illustrate why governments may implement a tax relaxation in the first place.

Possible Governmental Aims of Tax Relaxations

As was mentioned above, a government might have different aims in implementing a tax relaxation. With regard to the oil and gas industry, these aims might be one or more of the following:

a. Increasing supply.
b. Creating incentives for the industry to invest in new areas or reinvest in existing areas.
c. Developing marginal fields.
d. Helping the industry to earn and save more money to be used in covering exploration and developing costs in new areas.
e. Simplifying the fiscal regime to reduce political and economic uncertainties.

With regard to the first aim above (increasing supply) the government may present a package of relaxation measures to encourage the industry to increase production. This will enable the government to harvest more revenues from the increased exploitation rate of its natural resources by taxing the extra production volumes. In this regard, Martin (1997, p. 33) sums up:

> "Since 1991, UK North Sea oil production has been chiefly insensitive to the international oil prices. While prices have languished at relatively low levels, oil output has risen strongly. Part of the reason for this insensitivity is the existence of the fiscal regime, which divorces the price that is actually received by producers from the international oil price".

This issue is still critical, as government revenues do not only depend on production levels or exploitation rates, as costs and prices of the commodities also have pivotal effects on the revenues. Therefore, if a government wants to benefit from a proposed tax relaxation, which may serve the purpose of collecting more revenues through increased production, possible changes in prices and costs should be taken into consideration in the short term. This is if the government aims to reduce the tax burden for existing producing fields. If the aim is to increase production from new fields, then forecasts of prices, costs and use of technology should be made for the long run.

The aims b, c, and d above are, on the whole, likely to be of a similar nature, in that all of them are targeting potential fields. Exploring new areas needs more effort and costs to cover geological researches and the building up of the required infrastructures for the industry. In these cases, if a government wants new areas to be opened for exploration, development and production, it should create incentives for the industry to face the exploration risk in these areas. However, when such new areas become promising, such that they can provide a suitable proportion of revenues to the industry, then the government might present and apply new taxes and duties to gain more shares of the new revenues.

4.2.2 The Oil and Gas Industry's Perspective

Tax relaxation might have a meaning for the oil and gas industry different from government's. For example, a reduction in tax rates or an increase in allowances might be accompanied by a reduction in oil and gas prices and an increase in oil and gas operation costs. In this case other factors might absorb the effects of the reduction in the rate of taxes and not allow the industry to feel any tax relaxation. Therefore, for the oil and gas industry, a tax relaxation means tax reduction,

which helps the industry to increase its profits and also add to its cash flow. In other words, it will create incentives to the oil and gas industry to increase investment in new or existing areas in order to benefit from the reduced tax rates. It may also mean an increase in profits available to pay shareholders' dividends. Even though a tax change might mean a tax relaxation for some companies, it might not have the same meaning for other companies within the oil and gas industry. Some companies might benefit from tax changes, and consider them as a tax relaxation, whilst other companies might not benefit from this relaxation or may even consider them harmful because of changes in the structure of the fiscal regime. Therefore such changes do not in any way mean a tax relaxation for companies affected in this way.

A tax relaxation may be made manifest financially in the results of the oil and gas companies, such as:

1. An increase in the post tax profits of oil and gas companies after applying a new fiscal regime at reduced tax rates, while prices remain stable.
2. The ability of the industry to finance internally its existing investments or the ability to open new investments because more funds are available.
3. An increased rate of dividends to shareholders as a result of the improved profitability. However, an increase in dividend payments does not always mean an increase in a company's profitability. It might be achieved by using the financial reserves or retained profits rather than current period profits. However, in integrated companies, which have different investment activities, it is not an easy task to link the main reason for distributing more dividends to a certain activity.

The question that might be asked here is: how therefore can a tax relaxation be characterised and measured from the industry's viewpoint? The answer to this question might be one or more of the following.

1. By measuring the increase in profits and cash flow from existing and potential investments resulting from the tax reduction.

2. Also using a profitability measure could be a good indicator of the benefit occurs to the oil and gas industry of a tax relaxation. However, as profitability is affected by costs, then the most suitable profitability measure may be to calculate the percentage of tax paid in relation to the profit or price of a production unit. If this percentage declines after applying a reduced tax rate, and without any changes in other factors, this will indicate a positive effect of this reduction in tax rate on the industry's profit and cash flow. This reduction in the tax rate would be considered as a tax relaxation. However, this measure is limited by the safeguard concept, as an oil field may be liable to a high marginal tax rate when paying PRT in one year, and a low rate in another if not paying this duty.

However, as was mentioned above, a government might present a tax reduction in any form, but the industry may not consider it as a tax relaxation if it does not benefit from it, for example, by seeing improved profitability and cash flow. Also a tax reduction may not be considered as a relaxation if it does not create incentives to the industry to make more investments in existing or potential areas. On the other hand, a tax reform, which might be considered to be a tax relaxation from a government standpoint, might affect some oil companies negatively and in this case, it cannot be considered as a tax relaxation from the point of view of the negatively affected companies, as in the case of the 1993 changes in respect of the British-Borneo Petroleum Syndicate, the oldest UK exploration company. The 1993 tax changes caused this company's share price to decrease from 185p to 150p. The company's liability for PRT was raised from 17p for every £1 spent to 64p.[37] The chief executive of the company, Mr. Alan Gaynor, stated that, because of the negative effects, the company would increase its investment in the Gulf of Mexico rather than the North Sea (Thomson, 1993). On the other hand, it was estimated that the windfall from the 1993 tax changes would add £150 million a year to BP's profits (*The Independent*, 1993a, p. 19). Also the Offshore

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[37] The 1993 petroleum tax reforms abolished the Cross Field Allowance. Oil companies with large oil fields had benefited from this allowance by paying less PRT, and removing it increased these companies' liabilities to this duty. This increase in tax payment should have reduced these companies' profits and pulled their share prices down. However, different companies were differently affected as the majority of them had benefited from this tax reform, which represented a true tax relaxation for them (e.g., BP).

Contractors Council, which had 50 members by 1993, declared that the PRT changes would have benefits for its member companies in the medium and long term (*The Independent*, 1993b, p. 27).

Measuring the effects of a tax relaxation on the revenues or activities of the oil and gas industry is, however, not an easy task. There are many factors affecting the oil and gas industry's revenues other than tax changes such as costs, prices and production levels. For example, it might not be commercial to develop a small field at certain price, cost and taxes levels, but finding another field just next to the first one might make developing both of them commercial. In this case, developing both fields might play a pivotal role in reducing not only the operation costs but also the fixed costs.

After establishing this theoretical background regarding the meaning and aspects of a tax relaxation, the next section will show the main rationales for the UK petroleum fiscal regime tax relaxations.

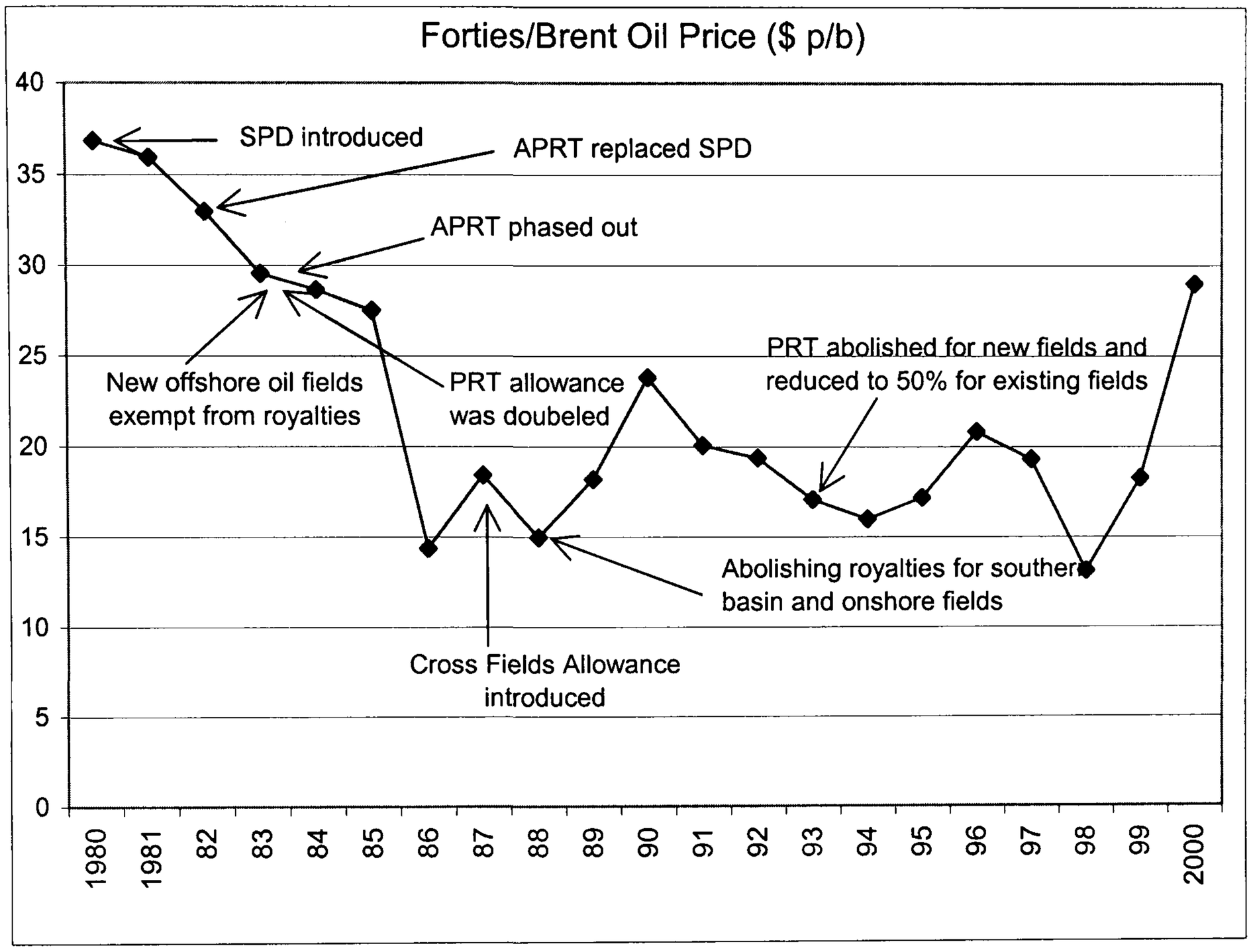
4.3 Rationales for the UK Petroleum Tax Relaxations

As the UK experience in the oil and gas industry was relatively new compared with major oil and gas producing countries, for example, Saudi Arabia and Iran, UK Governments have had to develop a fiscal regime which would offer oil companies sufficient financial incentives to explore for, and develop, the nation's oil and gas reserves. This would also reap benefits for the UK economy as a whole (Martin, 1997, p. 16). In this regard the Chairman of British Petroleum (BP, 1983, p. 4) stated, "the North Sea can be stimulated by arranging the fiscal regime in such a way as to provide the risk-taker with the right incentive".

With regard to the above, the UK petroleum fiscal regime experienced many adjustments as was shown in the previous chapter. In a general sense, these adjustments could be linked to changes in oil prices. Figure 4-1 shows some of these changes over the period 1980-2000. What can be seen from the figure is that all changes to the petroleum fiscal regime, apart from changes in 1980 and 1981,

represent reductions in the tax burden. These changes also formed packages which represent tax relaxations according to my definition (see section 4.2).

Figure 4-1: Link Between Changes in Oil Prices and Changes to the UK Petroleum Fiscal Regime.



Source: Martin, 1997, p. 17

In the history of the UK petroleum tax up to 2000 there were three relaxations, as was presented in chapter three, and as can be seen from Figure 4-1. Each of these relaxations was a package consisting of multiple changes to the petroleum fiscal regime, and each individual change within the whole package had different effects from other changes in regard to the oil and gas industry and the Government's revenues. These relaxations took place in 1983, 1987-88, and 1993 and these relaxations are characterised by the following changes:

1983 relaxation:

a. Phasing APRT out.

b. Doubling PRT allowance for new fields.

c. Abolishing royalties for fields outside the Southern Basin of the North Sea that were developed after March 1982.

d. Immediate PRT relief against any field for exploration and appraisal expenditure incurred after 16th March 1983.

1987-88 relaxation:

a. Introducing the Cross Field Allowance concept.

b. Abolishing royalties for the Southern Basin and onshore fields.

1993 relaxation:

a. Abolishing PRT for new fields.

b. Abolishing exploration and appraisal expenditure relief for PRT purposes.

c. Reducing the rate of PRT for existing fields from 75 to 50 per cent.

Every relaxation package involved phasing out one or more of the petroleum taxes totally or partly based on geographical criteria. For example, in the 1983 relaxation package, APRT was abolished and the royalty was partly abolished. In the 1987-1988 relaxation package the royalty was abolished for the Southern Basin and offshore fields, which obtained development consent after 31st March 1982, but with effect from 1st July 1988. So by 1st July 1988 any offshore or onshore oil field that had gained development consent after March 1982 was exempted from paying royalties. Fields that obtained development consents before that date kept paying royalties up to January 2003, when royalties were entirely phased out. Abolishing royalties was, therefore, not just a simple action by the Government but was complex and took place over an extended time period. The story is different for PRT, as this duty was abolished for fields that had development consent after 16th March 1993. Fields that obtained development consent before that date had to pay PRT at a reduced rate (50 instead of 75 per cent). Based on the above discussion, it can be seen now that fields which had development consent after 16th March 1993 have not had to pay royalties or PRT, and the only duty to be paid in respect of these fields is CT on corporate profits at 33 per cent up to 1997, 31 per cent up to 1st April 1999, and 30 per cent afterwards.

In searching for and finding the rationales for the UK petroleum tax relaxation, this study will focus on a number of key resources. These are:

1. The Government. This source includes the Department of Trade and Industry (DTI), the Inland Revenue (the Oil Taxation Office), a number of reports from Selected Committees and the Parliamentary reports and papers, as well as the official publications of these Governmental bodies.
2. The oil and gas industry. This includes:
   (a) The United Kingdom Offshore Operators Association (UKOOA). This organisation is the representative for the UK offshore oil and gas industry. Its members are companies licensed by the Government to explore for and produce oil and gas in UK waters.
   (b) The Association of British Independent Oil Exploration Companies (BRINDEX). This organisation seeks to promote the role played by British independent exploration and production companies in maintaining a powerful and effective UK based oil and gas industry.
   (c) Individual oil and gas companies that have activities on the UKCS, the annual reports of which will provide material for detailed study.
3. Academic Commentary and Analysis. This source includes publications of academics who have worked on the issue of the UK petroleum fiscal regime, and/or supervised research students who have worked on this or related topics. It also includes an interview with Professor Alex Kemp from Aberdeen University, as he is a key person in academia with regard to the issue of North Sea taxation from the early 1970s up to the present.[38]
4. The press. This requires a search for any materials concerned with the UK oil and gas industry.
5. Wood Mackenzie, Global Economic Model (GEM, v.3.01, 2004). This source will be used mainly to extract statistical financial data with regard to oil and gas companies and fields for the period of study (see section 5.8.4).

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[38] Professor Kemp did not allow me to tape record the interview I had with him, so I used the note taking method to capture what he said during the interview.

A limitation indent from some of these resources, especially the interviews, is the small number of people still working in oil and gas organisations and business, who have witnessed the changes in the tax regime and who retain a grasp of the reasons for them. On the other hand, access to Governmental and the oil and gas industry's data is very limited. Moreover, there is lack of research available in the public domain that provides a systematic analysis of the factors underpinning the recovery in UK North Sea oil production (Martin, 1997, p. xi). Because of the lack of resources and to make sure that this research covers most, if not all, of the rationales, interviews are to be used as a method of collecting more information concerned with the rationales. These interviews will be with people who have rich information about the UK petroleum tax relaxations and their rationales because of the nature of their jobs or academic research.[39] Interviews will be semi-structured and questions will be open-ended to allow the interviewees to give as much information as possible. However, interviews can only be used when access is granted.

4.3.1 Rationales for the 1983 Relaxation

This section presents the rationales for the 1983 petroleum tax relaxation from the Government's, the oil and gas industry's and academic's standpoints. It starts with the Government's standpoint.

The Government's Standpoint

This section presents the rationales from the Government point of view. These views will be presented in the order: Ministers, Parliamentary Debates, and interviews with civil servants who deal directly with oil and gas taxation in the Inland Revenue and the Department of Trade and Industry. Changes to the petroleum fiscal regime were seen as a need, mainly, for boosting the oil and gas industry's activities, albeit in accordance with Government policy. In this regard Lawson (1983a, p. 3) states:

> "the Government agrees with the Committee on the need to encourage exploration, appraisal and development of the nation's reserves of oil

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[39] Full transcripts of these interviews are available in Appendix One.

> and gas. This has been and remains the Government policy and its stance on the North Sea fiscal regime is to make sure that the regime is consistent with that objective whilst at the same time securing an adequate share of North Sea revenues for the nation".

The Government's justification for abolishing APRT was to help the oil and gas industry's cash flow in the hope of accelerating development activities. In this regard Lawson (1983a, p. 9) states:

> "But in the light of current pressure on the oil and gas industry's cash flow the Chancellor has decided to phase out the acceleration of PRT through the APRT system to provide some easement in cash flow over the next few years, to help finance new development."

In an interview with the author, Mr Geoff Barnard, a civil servant from the Oil Taxation Office (OTO), on 20th January 2004, provided an argument which was consistent with Lawson's opinion. Mr Barnard said, "the phasing out of APRT that was replaced by the instalment regime under which PRT is paid in instalments, replaced it [SPD], and the speed of collecting it [PRT]".

In justifying the relaxation in new areas of investment only and supporting the Government action, Lawson (1983a, p. 4) states:

> "Analysis of profitability of existing fields led the Government to conclude that there was no economic justification for tax or royalty reduction to improve returns on those fields viewed in isolation. Likewise the prospective rates of return of the future incremental projects to existing fields that were looked at appeared attractive enough not to justify special relief. But the Government accepted on the basis of its analysis of the new information on actual projects provided by the operators that future free-standing fields were likely in general to be less profitable, because they would be smaller, geologically more complicated and proportionately more costly to develop than previous fields."

The Government believed that there were many other factors in addition to taxation that affected the future development decision and rate. These are oil prices and technology which helps bringing costs down, but still these changes had to be made to provide the right fiscal environment for successful development of the next generation of fields (Lawson, 1983a, p. 10). However, the changes

simplified the oil tax regime and made the new tax regime more sensitive to changes in the world oil price by linking taxation exclusively to profit rather than to a mixture of profits and revenues (Lawson, 1992, p. 190).

Lawson (1992, p. 188) claims that all the biggest and most accessible discoveries had been made by 1982. Hence smaller, and more costly fields had to bear the same tax rates as bigger fields. This discouraged exploration and development in the North Sea. A discussion was held between the Department of Trade and Industry, the Treasury, the Inland Revenue and the industry about the case of the North Sea. General agreement was reached that the tax regime was discouraging investments in new fields, which tended to be smaller than earlier discoveries. This led the Government to announce changes in the petroleum tax regime in the 1983 Budget. Mr Barnard, from the Oil Taxation Office, agreed with this argument. In the interview of 20th January 2004 with the author, he said:

> "As far as I know, the rationale behind abolishing it [royalty] for post 1982 fields was that it was thought the major fields had been discovered in the North Sea and royalty was disincentive to invest, because it takes 12.5 per cent of the gross revenues, so by removing it was giving an incentive" [Sic].[40]
>
> He continued:
> "Indeed the whole of 83[Sic] changes were to some extent aimed at providing an incentive to further exploration. The increase in the oil allowance for PRT meant that smaller fields would be more viable to develop because they would not be paying PRT".

Mr Hamish Gray, the Minister for Energy, said, in an interview with the Petroleum Review Journal of the Energy Institute, that tax relaxation was significant to an extent which would help developing the most marginal fields in the North Sea, and at the same time encourage the oil and gas companies to keep investing within the UKCS rather than moving elsewhere (Petroleum Review, May 1983, p. 6). Another view suggested that the aims behind this significant relaxation in the petroleum fiscal regime (1983) were to encourage exploration and appraisal of UK petroleum resources and develop marginal and small oil fields with accumulated reserves between 40 and 50 million barrels, or with a

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[40] The symbol [Sic] is used throughout the thesis to refer to an English mistake in the original text.

daily production up to 20,000 barrels, to the maximum national benefit. It was also suggested that defining the size of marginal fields and areas benefiting from the relief would allow the Government to extend the relief to other areas when circumstances changed in these areas. It would also be easy for the Government in this case to backdate the relief (SC Deb (A), 14 July, 1983-84, c1). This is exactly what happened in 1987, as this chapter will show (SC Deb (A), 12 July, 1983-84; Bland, 1991, p. 7).

Mr. Skeet (MP) argued during the Parliamentary Debate on 12th July 1983 that phasing out royalties for new and small fields would motivate companies to increase exploration and development activities in these fields and the outcome would be more PRT and taxes to be paid by the industry to the Government. It was also suggested that the Chancellor abolish APRT to decrease the pressure on the oil industry's cash flow, and at the same time provide some easement in cash flow over the following years to help finance new development activities. This opinion agrees with what Lawson said about the former APRT (Great Britain, 1982, S 139: 2; Lawson, 1983a, p. 7; Boyle, 1984, p. 71).

In an interview with the author on 23rd December 2003, Mr Mike Earp,[41] a civil servant from the DTI, claimed that the main rationales for the 1983 petroleum tax relaxation were to boost the oil and gas industry's activities. As there had been a period of rapid discoveries and development of fields before the 1980s, a number of fields had been discovered but had not been put forward for development. Earp also considered the question of why many existing discoveries were eventually developed. The petroleum tax relaxation of 1983 would have given some stimulation to the development of some fields. Royalties were a non-profit-related duty and without them the system was being made more profit-related. In other words, without a royalty, we have a more sensitive regime to changes in oil prices. However, many fields had been discovered and suddenly they were developed after 1983, but we cannot say that their development was only because of changes to the fiscal regime in 1983, as the additional factors of improvement in technology, the accumulated experience and the availability and capacity of the

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[41] Mike Earp is a Senior Economist - North Sea Tax and Infrastructure, DTI.

infrastructures, which had spread in the North Sea over time, were still influential. Thus, a reasonable question to be asked here is: why did the development of these fields not take place earlier? Sometimes a decision to develop certain fields is based on a new discovery of another field in the area which makes it worthwhile to create the necessary infrastructure. The 1983 changes were probably not as successful as might have been hoped, as oil price changes influenced the oil and gas industry's activities during that period. Nevertheless, the driver of the 1983 petroleum tax relaxation was the level of activity.

The Oil and Gas Industry's Standpoint

Petroleum tax changes in the 1982 Budget were welcomed by the oil and gas industry and were looked at by the industry as if they matched exactly with industry hopes by offering the sort of incentives that would encourage investment in new areas. In this regard, the BRINDEX wrote to the Government:

> "The oil taxation changes in the Finance Bill are very welcome in so far as they have application, particularly, [Sic] because of the reinstatement of "front end" relief by the phasing out of APRT and the abolition of royalty. Furthermore, the doubling of the oil allowance will soften the impact of PRT, although at the margin, the tax rate of 88% is still too high. What was needed in the Budget, [Sic] was some relatively simple mitigation of tax in order to encourage new developments and in this respect, the Budget probably achieved its purpose." (Lawson, 1983a, p. 14)

A similar statement by Thomson North Sea Ltd, to the Energy Committee, makes it very clear that the oil and gas industry was happy and satisfied with the tax changes:

> "In our view there is little doubt that the recent Budget changes in oil taxation are a major step in the right direction to stimulate exploration and the development of small elds[Sic] which will form the bulk of future North Sea discoveries. Changes rightly concentrate on lowering the reserves threshold for viable field development, which has been the major thrust of the oil industry's (and also the Select Committee's) representations over the past two years. Rate of Return will be materially important, the incentive for cost reduction to lower the threshold still further (perhaps below 40 million barrels reserves depending upon field parameters) through technological advances will still be important. Hopefully these changes have come in time enough

> to sustain indigenous production beyond about 1988/90 when, under almost any production scenario, self-sufficiency will be otherwise lost".
>
> (Lawson, 1983a, p. 18)

The most welcome tax change of the package was the removal of the APRT, in this regard BP wrote to the Government:

> "For existing fields, the removal of APRT as a non-profit related [Sic] tax has been pressed unanimously by all oil companies since its introduction: it was a bad tax when introduced and particularly harmed less profitable fields. Its removal will release some additional funds which could be used for further investment".
>
> (Lawson, 1983a, p. 23)

However, the pre-1983 petroleum tax regime together with the small size of new discoveries and the fall in oil prices were seen as discouraging UK oil and gas activities. The 1983 petroleum tax changes were considered the probable best solution for this problem as they aimed at stimulating the oil and gas activities. In this regard Mr George Uthlaut, the Managing Director of ESSO Petroleum Company stated:

> " 'The major improvements announced by the British government this year in recognition of this serious problem have, as predicted, created an economic climate which is stimulating renewed efforts'. Mr Uthlaut continued: 'Exploration and appraisal drilling in 1983 has been the highest in a number of years. Field development plans are coming forward, and projects that have been shelved are under appraisal' ".
>
> (Oil and Gas Journal, 1983a, p. 90)

The 1983 petroleum tax changes encouraged companies to rethink and re-evaluate their discoveries that had been considered uncommercial prior to 1983. In this regard Phillips Petroleum Company stated:

> "Because of the recent revision in U.K. tax and royalty rates, the company is revaluating the commercial potential of several other oil discoveries in the U.K. sector of the North Sea".
>
> (Phillips Petroleum Company, Annual Report, 1983)

In general, most of the industry's opinions expressed a welcome for the tax changes that were aimed at encouraging exploration and production activities and

at bringing small and marginal fields into production. At the same time these changes matched the oil and gas industry's expressed hopes that the Government would adjust the petroleum fiscal regime.

The Academics' Commentary and Analysis

Moose (1982, p. 56) claims that paper number 17 of the UK Energy Commission uses an econometric distribution of the remaining undiscovered UK oil and gas fields. The distribution refers to 15 to 20 per cent of the commercial, but undiscovered, oil in the UK sector of North Sea. The paper points out that this oil exists in fields which could be marginal and not commercial under the old UK petroleum tax system. Therefore, developing these fields would have probably required, at some points, a reformation of the UK petroleum tax regime. Moose' (1982) justification for the rationale of the relaxation in the petroleum fiscal regime can be accepted as one of the main reasons for the relaxations, in that the Government was trying to push the oil and gas industry to explore in areas outside the Southern Basin of the North Sea. Taking into consideration the limited geological knowledge at that time and the special characteristics of these areas, such as the offshore location, the deeper water and the tougher weather conditions, which required new technologies and large-scale installations, and also the fact that operations would be capital intensive and risky, these conditions might have provided a reason for the Government to abolish royalties for fields outside the Southern Basin (Andersen, 1993, p. 2).

Hann (1986) maintains that changes in the UK petroleum tax system in 1983 came as a response from the Government increased pressure from the oil and gas industry. This pressure aimed at reducing the tax burden, and hence at halting the slowdown in UK oil and gas activities, especially development activities. However, the main reasons for the decline in development activities during the late 1970s and early 1980s might be one or more of the following.

(a) The increased pressure by the Labour Government on the oil and gas industry to sign and accept a partnership with the BNOC during the late 1970s.

(b) The implementation of SPD in 1981 prior to phasing it out and implementing APRT instead of SPD and phasing it out as well.

(c) The instability and uncertainty which arose from the Government's advance announcements and the practical applications regarding the fiscal regime. The Labour Government announcement in the fifth licensing round that there should be regular licensing rounds in both size and timing. In actuality, the Government's intention did not match the reality with regard to the sizes and timing of licensing rounds.

These factors, plus substantial changes in the petroleum tax system, created uncertainty for the oil and gas industry. This uncertainty was one of the main reasons for the industry to postpone exploration and development activities during that time (Hann, 1986, p. 20). It was also suggested that the aims behind these changes in the oil fiscal regime were that the Government was to keep the whole revenue from existing fields and at the same time attract international oil and gas companies to explore and develop new fields. Moreover, the Government aimed to encourage further economic development of the UK oil and gas resources by giving oil and gas companies a chance to save money which could be used in exploring and developing new oil and gas fields (Favero and Pesaran, 1991, p. 3; DTI, 1999a, p. 25).

In a meeting with the author on 16th January 2004, Professor Alex Kemp suggested that the 1983 petroleum tax relaxations were too generous and there was no need to double the PRT allowance. Professor Kemp considers that the APRT was not a harmful duty in concept, but it was putting pressure on the oil and gas companies' cash flow, and removing this duty was to relieve this pressure. However, the package was mainly designed to stimulate exploration and appraisal activities in the central and northern North Sea. Professor Kemp added that it was intended that the 1983 petroleum tax relaxation should be a corrective action by the Government to the 1981 petroleum fiscal regime package, which introduced the SPD and the gas levy. Seymour's view (1990, p. 24) about the rationales for the 1983 relaxation agrees with Professor Kemp's view regarding the point that the 1983 tax relaxation was to some extent a corrective measure to mitigate the harm caused by the 1981 petroleum fiscal regime package. Seymour

is also of the same mind as Professor Kemp regarding the generosity of the UK fiscal regime, which stimulated oil and gas companies to go ahead and develop a number of fields in spite of the high costs. In this regard Seymour (1990, p. 31) states:

> "From the companies' viewpoint, the investments criteria used to justify their development decisions, the internal rate of return and the net present value were much more sensitive to delays than to escalations in their cost estimates. This bias against a cost conscious attitude was further reinforced by the generous terms of the UK taxation system".

4.3.2 Rationales for the 1987-1988 Relaxations

The sharp decline in the oil price in 1986 had very negative effects on the oil and gas industry's activities, especially 'development'. In this regard and according to the third report from the Energy Committee (HC, 1986, p. xiii), no entirely new oil developments had occurred between May 1986 and March 1987 and only three developments had taken place earlier in 1986.

This section will discuss the rationales for the second petroleum tax relaxation from the Government's, the oil and gas industry's, and academics' points of view.

The Government's Standpoint

The solution for halting the decrease in development activities during 1986-1987, which arose because of the dramatic drop in the oil price in 1986, was to adjust the petroleum fiscal regime. In this regard, Mr Sportt, MP, stated in his comments to the Energy Committee:

> "...it is that we have to improve, bring forward, further developments in the North Sea. We must bring it forward when the price is low. The way is through fiscal adjustments". (HC, 1986, p. 130)

Such a policy perspective seeing it to be the government's role to compensate for adverse market conditions – is an overt confirmation of the non-proprietorial character of the fiscal regime.

The oil and gas industry used the opportunity of their meeting with the Energy Committee to address suggestions to the Government with regard to changing the fiscal regime. In this context BRINDEX made comments to the Energy Committee (HC, 1986, p. 33), which suggested permitting PRT relief for development costs on new fields to be claimed against tax liabilities on existing fields. They claimed that this measure would encourage the direct re-investment of profits from mature fields into new development. This in turn would encourage development expenditure in new fields. The United Kingdom Offshore Operator Association (UKOOA) had raised the issue of providing a tax relief to Southern Basin fields (HC, 1986, p. 35). This relief, they suggested, would be by reducing royalty burdens and making the UK oil taxation system purely profit-related.

The Budget of 1987 introduced the concept of the Cross Field Allowance (Great Britain, 1987), as BRINDEX suggested (see tax changes in section 3.4.3). The purpose of the Cross Field Allowance was, as stated in the third report of the Energy Committee (HC, 1986, p. xxx), to raise the post-tax rate of return for oil and gas companies. The Budget of 1987 did not include any fiscal changes with regard to the Southern Basin fields of the North Sea. The reason for this was that, as the Government expressed, the comparatively low level of costs and the proceeding development activity (HC, 1986, p.xxxi). The Cross Field Allowance broke the field-by-field basis underlying PRT. It allowed oil companies to set off ten per cent of development expenditure in new oil fields against their PRT profits in other paying fields. Mr Geoff Barnard from the Oil Taxation Office said, in the interview of 20th January 2004 with the author, that the aim behind the Cross Field Allowance:

> "...was mainly to encourage development, because there were a lot of fields discovered forty years ago and they have never been developed and tax is one reason but mainly they were too small and uneconomic using the technology available at time".

In accordance with UKOOA suggestions, the Chancellor of the Exchequer announced in the 1988 Budget that all Southern Basin and onshore fields for which development permits were given after 31st March 1982 would be exempted

from royalties with effect from 1st July 1988 (Great Britain, 1989). The Budget of 1988 points out that aims behind these changes were to reduce costs and improve development activities in the marginal fields in the Southern Basin area of the North Sea. In this regard, Mr Peter Lilley (the Economic Secretary to the Treasury) in a debate in Parliament on 16th June 1988 stated:

> "To achieve an improvement in the profit-relatedness of the south North Sea oil regime, we had to abolish royalty entirely". He continued: "the effect of changing the regime in that way was to make it more likely that marginal fields would be brought forward for development and the cost of reducing the royalty generally was met by increasing the bourdon tax on more profitable fields".
>
> (SC Deb (A), 16 June 1988, c129)

Mr Lilley mentioned the reduction of the PRT allowance. He stated that the oil allowance for PRT purposes in the Southern Basin and onshore fields had been reduced from 250,000 to 125,000 metric tonnes for each chargeable period, and the total allowance for a field also had been reduced from 5 million to 2.5 million metric tonnes (Great Britain, 1988, S. 138). After July 1988 all Southern Basin fields that obtained development permits after 31st March 1982 were exempted from royalties and at the same time had less PRT allowance.

Mr Mike Earp from the DTI stated on 23rd December 2003, in an interview with the author: "The 1983 tax changes are probably not as successful as they might have been planned to be". From this statement we can see that the Government might have felt a need to implement more tax relaxation, and this might be one rationale for the 1987-88 tax relaxation.

The Oil and Gas Industry's Standpoint

The industry expressed its welcome of changes introduced by the 1988 Budget in the memorandum that was sent to the Energy Committee (HC, 1989, p. 45) as these changes would help exploration activities in the United Kingdom. BP indirectly welcomed changes to the fiscal regime. Furthermore, fiscal changes helped a number of companies to increase their profits, either through stimulating oil and gas activities or directly by reducing the cost of activities (Sun Oil, 1987, p. 13).

There was a view held by independent oil companies that tax changes were benefiting the industry in general, and not just the independents. In this regard a Montagu-Smith and Company Limited memorandum to the Energy Committee stated:

> "Offshore, they hold particular advantage for the private independents and it is not clear that the measures related to Southern Basin gas will have the intended motivation impact. Onshore, prospects are likely to be enhanced but, again, with no particular emphasis on easing independent activity". (HC, 1989, p. 50)

The Academics' Commentary and Analysis

Seymour (1990) points out that in 1988 development activities returned to pre-1986 levels, and these activities could have only been stimulated by fiscal incentives. Therefore in 1987, the Government introduced the Cross Field Allowance concept and in 1988, abolished royalties for Southern Basin fields. Seymour (1990, p. 24) adds:

> "From 1978 onward one can, therefore, identify a relationship between development activity and the fiscal regime that seems to offset the problems created by low and volatile oil prices".

The dramatic fall in post-tax company cash flows from North Sea operations, and the implications of this for expenditure on new field projects, represented one of the main factors for introducing the Cross Field Allowance. This aimed at helping the oil and gas industry cash flow with the purpose of exploring and developing new areas. It was suggested that the Cross Field Allowance would be a device for reducing tax payments, which would enable current investment plans to proceed and would result in more taxes being harvested in the future (Saunders, 1987, p. 57). Professor Alex Kemp from Aberdeen University suggested, in an interview on 16th January 2004 with the author, that the changes of 1987-88 came as a response by the Government to the sharp drop in oil prices in 1986 to encourage development activities and to make the petroleum fiscal regime a profit-related system.

4.3.3 Rationales for 1993 Relaxations

The Government's Standpoint

With regard to the effect of PRT reform the Prime Minister John Major contended that the reforms were beneficial for both jobs and the UK and would improve development incentives (Oil & Gas Journal, 1993a, p. 27). The Inland Revenue (2003) stated:

> "In his budget speech on 16 March 1993 the Chancellor announced a number of significant changes to the PRT regime. The changes were aimed at encouraging the further development of the UK's oil and gas resources by allowing companies to keep more of their profits, whether from additional investment in existing oil and gas fields, or from the development of new ones."

Mr Mike Earp from the DTI claimed, in an interview with the author on 23rd December 2003, that the 1993 tax relaxation took place to create incentives for oil and gas companies to keep investing in old fields, and in a way to maintain a sort of balance between investing in new and old fields. Mr Earp stated that abolishing PRT for new fields, and reducing the rate to 50 per cent for old fields, came mainly because PRT cost the Government £216 million in 1992 (see footnote 43 on page 122). He added that the 1993 changes had not come as a result of any pressure or influence from the oil and gas industry as these changes came from the Treasury and the Inland Revenue.[42] According to Earp, the changes shocked the DTI at that time, as they were unexpected. These changes were mainly based on a Government decision and there was no influence or pressure from any other third party. Mike Earp's view corresponds with the BRINDEX memorandum to the Energy Committee as it stated:

> "We believe that, while changes do not appear to be required at the moment to stimulate new developments, the fiscal system applied to the Southern Sector should be kept under review. We would be concerned if the differentiated system were distorting the pattern of investment between the Southern sector and the other parts of the North Sea". (HC, 1989, p. xvi)

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[42] For a full transcription of the interview with Mr Mike Earp, see Appendix One.

Mr Geoff Barnard from the Oil Taxation Office (OTO) pointed out, in the interview of 20th January 2004 with the author, that in 1992 the Government was not making any money out of the oil and gas companies because of the negative effect of the Cross Field Allowance. Because of this, the Government abolished it for new fields and reduced the rate from 75 to 50 per cent for paying companies to balance the effect of removing the Cross Field Allowance on the PRT paying fields. In other words, the adverse effects of the Cross Field Allowance on the Government revenues were a major reason for the 1993 petroleum tax reform.[43] The 1993 petroleum tax changes were looked at as the main approach for simplifying the tax regime and of reducing the tax marginal rate from 89.5 per cent to 88 per cent for old fields, and the marginal tax rate from 70 per cent to 60 per cent for some other fields, which would benefit the operators in the UKCS (Oil and Gas Journal, 1993b, p. 54).

The Oil and Gas Industry's Standpoint

At the time UKOOA claimed that abolishing PRT could potentially unlock a further 500 to 700 million barrels of oil equivalent by developing uneconomic North Sea discoveries. These new developments could represent capital investment in the region of $3 to $4 billion. (OilOnline, April 16, 2003). However, UKOOA warned that the 1993 changes would benefit large North Sea operators who paid a great deal of tax on producing fields, while smaller operators who managed to fund their drilling programmes by reclaiming taxes from producing fields, would be hit hard (Knott, 1993, p. 31).

Shell UK supported the tax changes, because it looked at them as being an incentive to investment and the right step by the Government as there was a need

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[43] Mr Geoff Barnard's comments in this regard were: "but the question here is: did introducing the Cross Field Allowance encourage exploration? Because the rate of tax on PRT paying fields was round about 80 per cent if not slightly higher because of accumulated effects of CT and PRT. Allowing the Cross Field Allowance meant that almost the entire cost of exploration was met by tax relief. So the number of exploration wells drilled absolutely rocketed because the Government was paying almost of the entire cost, through tax relief. It was not costing the companies anything to drill and that what was led to the 1993 changes, because of the cost of the Cross Field Allowance relief, which was thought originally to be no more perhaps 20-50 million. Abolishing PRT in the 1992-93 we were not getting any money and in a one year 92 we repaid more than we collected, and that was the direct result of the Cross Field Allowance". For full transcription of the interview see Appendix One.

to encourage development of discovered fields. At the same time Shell looked at abolishing PRT on all new areas as the right incentive to explore these risky areas which at the same time might promise large enough discoveries (Oil & Gas Journal, 1993a, p. 27). Texaco (1993, p. 27) declared that the 1993 tax changes purely benefited the company's profits. It stated:

> "Total operating earnings for 1993 included a benefit of $169 million related to the change in the tax treatment of certain items under the UK Petroleum Revenue Tax and the tax rate reduction of this tax from 75% to 50%".

Enterprise Oil (1993, p. 26) expressed the same opinion towards the 1993 tax changes:

> "Earnings benefited from slightly increased production from the new oil and gas fields...and an exceptional tax credit of £27 million relating to changes in UK oil and gas Taxation"

Amerada Hess pointed out that eliminating the deductibility of exploration and appraisal costs against PRT profits would increase the after-tax cost of exploration. This factor would be partially offset by lower rate of PRT on production from existing fields (Amerada Hess, 1993, p. 24). Arthur Andersen argues that the effect of the reduction in PRT and abolishing it for new fields would generate additional cash flow to the industry estimated to be about £1.7 billion during the following three years of 1993 (Oil & Gas Journal, 1993a, p. 27). In contrast, British-Borneo Petroleum lobbied against the 1993 changes as the abolition of the exploration and appraisal relief affected the company's share price badly as the company's liability to the PRT rose from 17p to 64p for every £1 spent. This was the reason why the company planned to increase investments in the Gulf of Mexico (Thomson, 1993).

From the above, it can be seen that the PRT reform divided oil and gas companies into two groups: those that would have benefited from the PRT reductions (e.g., BP, Shell) and those who would have lose out on the exploration and appraisal concession removal (e.g., British-Borneo). This can explain why the 1993

petroleum tax reforms were considered as tax relaxations by some oil and gas companies and not considered as such by others (see section 4.2.2).

The Academics' Commentary and Analysis

Zhang (1995, p. 4) argued that abolishing PRT for new fields and reducing the rate to 50 per cent for old fields was not a permanent, but only a temporary Government device to combat the drop in oil prices. When oil prices increased the Government would bring PRT back. This issue had increased the political risk of the UK fiscal regime (Kemp and Stephens, 1996, p. 76). Martin (1997, p. 19) argued that the economics of developing new fields were boosted by the abolition of PRT for those fields approved after 15th March 1993. Hence boosting development activities might be the reason for abolishing PRT. Kemp and Stephens (1996, p. 76) argue that the removal of PRT altogether from new fields makes the UK very competitive internationally, but raised the question of whether the Government's share of the output was adequate. Hargreaves and Lascelles (1993) point out that there were three objectives behind the petroleum tax relaxation in 1993: (a) making production from developed fields more profitable; (b) creating incentives to increase production, and boost tax revenues; and (c) bringing North Sea taxation in line with the Government's overall approach of reducing tax rates and eliminating allowances. The article goes on to quote the following:

> " 'The Budget is rewarding successful exploration by reducing production taxes, but any exploration must be carefully cost and justified rather than be merely a gamble as was often the case under the old regime,' Mr Fay said". (Hargreaves and Lascelles, 1993, p. 17)

Two other rationales were pointed out in another article in the Financial Times on 17th March 1993 and in the Independent on the same date (Financial Times, 1993; The Independent, 1993c). These are:

1. Adjusting the petroleum fiscal regime to the benefit of the Government as the Exchequer was not getting a fair return; and in 1991-92, the PRT regime cost the Exchequer £200 million.
2. Simplifying the tax regime for new fields.

With regard to the first point, the Independent wrote on 19th April (1993a, editorial page 19):

> "Companies dug holes and wrote off much of the cost against tax. Every dozen or so holes, they struck lucky and made a find with commercial potential… but exploration companies did not worry much about the other 11 holes: the Government was paying for them".

It was expected that development spending would rise by 13 per cent to £4.4 billion by 1996, in part because of the 1993 fiscal regime reform, that had been introduced by the Government initially to encourage development of discovered oil fields (Corzine, 1995). It was also felt that the profit-based taxation system offered a sort of stability without distorting the pre-tax and post-tax viability of a project. However, it is important to look at the expected effects of the 1993 petroleum tax changes at the time. In this regard, it was argued that the 1993 changes to UK North Sea oil taxation would be a reason for companies to explore elsewhere other than the UKCS. At the same time it was expected that these changes would help developing existing projects, extending the lives of mature fields, and improving development economics for the many marginal discoveries that had been made in recent years. In other words, changes were viewed as an attempt by the Government to create incentives for oil companies to produce, but changes played a role in weakening exploration incentives. In this regard, the Editorial report of the Oil & Gas Journal (1993c, p. 19) stated:

> " 'Companies will produce in the U.K. and use profits to explore for replacement reserves somewhere else. What the government has implemented, therefore, is a policy of protracted liquidation of the U.K. offshore producing industry'. The report ended saying: 'Reducing the 75% rate, thereby easing the incentive to shelter incomes against PRT, was a good start. Offsetting the rate cut with elimination of exploration cost deductibility will prove to have been a horrible finish' ".

Professor Alex Kemp from Aberdeen University suggested, in the interview on 16th January 2004 with the author, that the 1993 petroleum tax relaxation package was not the right action by the Government, because the Government mainly planned fiscal changes on a short-term basis. He said that the 1993 changes came

because the Government was losing money because of the exploration expenditure relief against PRT, and removing PRT entirely would make the Government gain more money. The Government thought that by that time there would not be any more profitable fields that would be liable for PRT, so it was wise to abolish it for new fields. Reducing the rate for old fields was an action by the Government to make the petroleum fiscal regime roughly the same in the different parts of the North Sea.

4.4 Summary

The UK petroleum tax relaxations took place in 1983, 1987-88, and 1993, and each relaxation package had different features from the others. The main rationales underpinning these petroleum tax relaxations, as stated by the Government, the oil and gas industry, and academics were largely similar. The following tables summarise these rationales and show the party supporting the rational behind each relaxation.

Table 4-1: The Rationales For the 1983 Petroleum Tax Relaxation.

The 1983 Petroleum Tax Relaxations Rationales	Government	Industry	Academics	Total
Encouraging oil and gas activities, which include exploration, appraisal and development activities.	√	√	√	3
Making sure that the regime secures an adequate share of North Sea revenues for the nation.	√	*	*	1
Helping the oil and gas industry's cash flow to accelerate development activities.	√	*	√	2
Encouraging the smaller and more costly fields (the marginal fields) in new areas to be explored and developed.	√	√	√	3
The relaxation would encourage more exploration and development and this would help increasing the production level, which means more PRT and taxes to be paid by the industry to the Government.	√	*	*	1
Making the whole tax regime more sensitive to changes in the world oil price by linking taxation exclusively to profit rather than to mixture of profits and revenues.	√	*	*	1
Sustaining indigenous production beyond about 1988/90.	*	√	*	1
Removing APRT would release some additional funds, which could be used for further investments.	√	√	*	2
Correcting action by the Government to the 1981 petroleum fiscal regime package, which introduced the SPD and gas levy.	*	√	√	2
Keeping the whole Governmental revenues from existing fields and at the same time attracting the oil and gas industry to explore and develop new fields in new areas.	*	*	√	1

Note: a tick (√) indicates the parties believe in the related rationale, while the star (*) indicates that the related party does not believe in the rationale in question.

Table 4-2: Rationales For the 1987-88 Petroleum Tax Relaxation.

The 1987-88 Petroleum Tax Relaxations Rationales	Government	Industry	Academics	Total
The unsuccessful 1983 petroleum tax relaxation was a reason for forming the 1987-88 relaxation.	√	*	*	1
To encourage further exploration and development expenditure on new fields.	√	√	√	3
To develop explored marginal fields.	√	√	*	2
To reduce costs and encourage development activities in the marginal fields in the Southern Basin area of the North Sea.	√	√	*	2
Abolishing royalties for old fields was to achieve an improvement in the profit-relatedness of the south North Sea regime.	√	√	√	3
Introducing the Cross Field Allowance was mainly because of the dramatic fall in post-tax company cash flow from North Sea operations and the implications of this for expenditure on new field projects.	*	*	√	1

Note: a tick (√) indicates the parties believe in the related rationale, while the star (*) indicates that the related party does not believe in the rationale in question.

Table 4-3: Rationales For the 1993 Petroleum Tax Relaxation.

The 1993 Petroleum Tax Relaxations Rationales	Government	Industry	Academics	Total
Encouraging more exploration and development activities of UK oil and gas resources by allowing companies to keep more of their profits.	√	√	√	3
Creating incentives for oil companies to invest in old fields.	√	√	√	3
Abolishing PRT for new fields and reducing the rate to 50 per cent for old fields came because PRT allowances cost the Government money in 1992, and removing it would enable the Government to gain more money.	√	*	√	2
Abolishing PRT for new fields and reducing the rate to 50 per cent for old fields was to balance the effect of removing the Cross Field Allowance on the PRT paying fields.	√	*	*	1
An attempt by the Government to make the petroleum fiscal regime roughly the same in different areas.	*	*	√	1

Note: a tick (√) indicates the parties believe in the related rationale, while the star (*) indicates that the related party does not believe in the rationale in question.

The aim of this research is to test the above-mentioned rationales from an *ex-post* position, and conclude whether they were/were not/were partly met by the policy. Prior to testing the above rationales, the next chapter will set out the methodology and methods to be used to achieve the above aim.

CHAPTER 5: METHODS AND METHODOLOGY

5.1 Introduction

This chapter details the methods that were used in collecting data for this research. In order to arrive at appropriate methodology and methods for analysing and testing the rationales for the UK petroleum tax relaxations, it is appropriate first of all to define the nature of this research. After that it is essential to illustrate the nature of the investments in the oil and gas industry. This illustration aims to show how these investments operated in the UKCS during the period from 1983-2000, and the effectiveness of the UK petroleum tax relaxation policy in stimulating these investments.

Highlighting investments in the oil and gas industry is necessary in order to show the nature and various stages typical of these investments in this industry. This in turn will clarify how Governments may encourage investments at any stage, and how economic and/or fiscal factors can affect one stage rather than another. It also helps to identify how changes in oil and gas investment activities can be measured quantitatively. After that, it will illustrate the criteria underlying making investment decisions in the oil and gas industry. This will be followed by an explanation of how oil prices affect investment decisions within the UKCS. This is to demonstrate how changes in oil and/or gas prices may affect oil and gas industry investment activities. Subsequently, it will examine studies in the same area as this research to show how this study differs from the previous studies, and also to show the main differences between the assumptions and targets of this research and previous studies. After that it will describe the research methods used in collecting data.

It is essential to define the nature of this research study and fit it within the types of research that are presented in the literature. It is also important to present the theoretical assumptions, which form a basis for this research and any conclusions driven from it. These issues will be discussed in the following sections.

5.2 The Nature of This Research

The following brief explanation of two different types of research will help in clarifying the nature of this research.

Hakim (1987, p. 3) recognises the differences between two types of research namely, theoretical and policy. In this regard, she points out:

> "Theoretical research is concerned primarily with causal processes and explanation…Theoretical research is essentially concerned with producing knowledge for understanding, usually within the framework of a single social science discipline… a great deal of theoretical research is carried out with small local studies, the results of which cannot readily be generalized".

In terms of policy research Hakim (1987, p. 3) states that this:

> "…is ultimately concerned with knowledge for action, and the long-term aim is in line with the famous dictum that it is more important to change the world than to understand it".

Hakim (1987, p. 4) added that the long-term aim of theoretical research is to develop the knowledge of social science, while policy research aims at changing the world. In accordance with the above meanings, this research can be classified as theoretical, in that it is exploratory research, which aims at developing knowledge about petroleum fiscal regimes, and evaluating the performance, validity, and success of petroleum tax relaxation policies to governments in achieving their aims of these relaxations.

Creswell (1994, p. 1) argues that designing a study starts with choosing a topic and a suitable paradigm. Paradigms in social science help the understanding of phenomena, and help in the formation of assumptions. Moreover, paradigms encompass both theories and methods. The next paragraph will shed light on theoretical assumptions, definitions of 'paradigm', and on the differences among paradigms. This will enable the selection of a paradigm to fit this research study.

5.3 Theoretical Assumptions and Paradigms

5.3.1 Theoretical Assumptions

Sjobery and Nett (1968, p. 58) argue that the scientist's assumptions combine to form a kind of logical system 'a set of logical-theoretical constructs'. They state:

> "In sociology, structural-functionalism, symbolic interactionism, and positivism all involve, for example, certain assumptions about reality, the nature of man, and the scientist's relationship to his empirical data-assumptions that are usually linked together logically to some extent. These sets of assumptions serve as paradigms (to appropriate Kuhn's terminology) or frameworks within which the sociologist proceeds to formulate or test his substantive generalizations."[44]

Sjobery and Nett (1968, p. 59) mention different types of assumptions. These are: (1) assumptions about social reality; (2) assumptions about the nature of man and his potentialities; (3) assumptions concerning the observer's relationship to observe social phenomena; (4) assumptions concerning the level of theory; and (5) assumptions about causal or explanatory variables. Sjobery and Nett (1968, p. 65) point out that the sociologists are likely to employ one or more variables. They categorize these variables as: a) historical variables; b) economic and technological variables; c) cultural values; d) social power; and e) other variables.[45]

However, the assumptions for this research study fit in the third and fifth types of the above assumptions. These assumptions are:

1. The UK government used the petroleum tax relaxation as a successful policy in stimulating more investments, and hence generated more production from the North Sea; and
2. The policy of petroleum tax relaxation was successful in generating more tax take for the UK Government.

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[44] Baily (1978, p. 21) defines sociology "a *categorical*, not a *normative*, discipline; that is, it confines itself to statements about what is, not what should or ought to be".

[45] For wider knowledge about these assumptions and variables see Sjoberg and Nett (1968, pp. 58-66).

5.3.2 Paradigms

Baily (1978, p. 18) defines a paradigm as:

> "The mental window through which the researcher views the world… it is used in the social science as a perspective or frame of reference for viewing the social world, consisting of a set of concepts and assumptions".

Burrell and Morgan (1979, p. 24) state: "to be located in a particular paradigm is to view the world in a particular way". Creswell (1994, p. 4) addresses two types of paradigm namely, quantitative and qualitative. These two paradigms differ from one other on a number of points. These are ontological, epistemological, rhetorical, and methodological assumptions. The ontological issue is about what is real. The quantitative researcher sees reality as 'objective'. This reality can be achieved and measured objectively by using one or more of the available instruments such as questionnaires, interviews, or case studies. The epistemological question defines the relationship of the researcher to what is being researched. The two paradigms have different views. The quantitative researcher should be independent from what is being researched, and he/she has to control for bias, selecting samples, and has to be objective in assessing a situation. In contrast, the qualitative researcher tries to make him/her self as close as possible to the subject being researched. The axiological issue represents the role of the researcher's values in the study. The personal values of the quantitative researcher should be kept away from the research study. The researcher's values are clear in a qualitative study, especially when he/she uses the form of first person, for instance, "in my opinion", "I see", and "I believe". In terms of methodology, for quantitative research, Creswell (1994, p. 7) states:

> "The intent of the study is to develop generalizations that contribute to the theory and that enable one to better predict, explain, and understand some phenomenon. These generalizations are enhanced if the information and instruments used are valid and reliable".

Concerning the methodologies of the qualitative approach, Creswell (1994, p. 7) states:

> "Categories emerge from informants, rather than are identified as ***a priori*** by the researcher. This emergence provides rich "context-bound" information leading to patterns or theories that help explain a phenomenon".

Moreover, Creswell (1994, p. 8) defined five factors that the researcher should take into his/her consideration when choosing one paradigm above others. Table 5-1 illustrates these five factors.

Table 5-1: Factors that Influence the Choice of a Paradigm.

Criteria	Quantitative Paradigm	Qualitative Paradigm
Researcher's worldview	A researcher's comfort with the ontological, epistemological, axiological, rhetorical, and methodological assumptions of the quantitative paradigm.	A researcher's comfort with the ontological, epistemological, axiological, rhetorical, and methodological assumptions of the qualitative paradigm.
Training and experience of the researcher	Technical writing skills; computer statistical skills; library skills.	Literary writing skills; computer text-analysis skills; library skills.
Researcher's psychological attributes	Comfort with rules and guidelines for conducting research; low tolerance for ambiguity; time for study of short duration.	Comfort with lack of specific rules and procedures for conducting research; high tolerance for ambiguity; time for lengthy study.
Nature of the problem	Previously studied by other researchers so that body of the literature exists; known variables; existing theories.	Exploratory research; variables unknown; context important; may lack theory base for study.
Audience for the study (e.g., journal editors and readers, graduate committees)	Individuals accustomed to/ supportive of quantitative studies.	Individuals accustomed to/ supportive of qualitative studies.
Source: Creswell (1994, p. 9).		

In accordance with the above, it can be said that this research study is a mixture of qualitative and quantitative. This is because 'reality' will be achieved by using investigation of documents and analysis plus interviews. Furthermore, although other researchers have already investigated to some extent similar problems to this, this research tackles the problem from a unique perspective. This perspective focuses on exploring the historical rationales for the three UK petroleum tax relaxations first, and secondly testing these rationales from an *ex-post* point of view. This makes the research quantitative in nature, but the other aspects give it a

qualitative aspect at the same time. In particular it is an exploratory in nature and as there is a dearth of literature and theories regarding the topic it can be little else. Exploring the historical rationales for the UK petroleum tax relaxations have been achieved using a qualitative approach (chapter four), while testing these rationales will be based on a quantitative approach.

Hussey and Hussey (1997, p. 47) point out two main research paradigms - positivist and phenomenological. They reproduced Creswell's table (Table 5-1) regarding assumptions of the two main paradigms, quantitative and qualitative. Hussey and Hussey (1997, p. 48) add an explanation for the assumptions as: ontological: what is the nature of reality; epistemological:[46] what is the relationship of the researcher to what researched; axiological: what is the role of values; rhetorical: what is the language of research; and methodological: what is the process of research.

The next section discusses positivist and phenomenological paradigms from the Hussey and Hussey framework.

Hussey and Hussey Paradigms

With regard to the positivistic paradigm, Hussey and Hussey (1997, p. 51) argue that this paradigm is based in the social sciences, historically derived from the approach used in natural science, such as biology, and physics. This approach seeks the facts or causes of social phenomena, with little reference to the subjective state of the individual. This involves a logical meaning being applied to the research, and the researcher builds his/her research on the basis of precision and objectivity instead of hunches, experience, and intuition. Positivism is based on the assumption that social reality is independent of researchers, and the act of investigating reality has no affect on reality itself. The phenomenological paradigm is concerned with understanding human behaviour from the two reference frames of the participant (Hussey and Hussey, 1997, p. 52). This paradigm assumes that social reality exists within the researcher, and the process

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[46] Blaikie (1993) defines epistemology as "a theory of knowledge; it represents a view and a justification for what can be regarded as knowledge. What can be known, and what criteria such knowledge must satisfy in order to be called knowledge rather than belief".

of investigating the reality has an effect on the reality itself. Hussey and Hussey (1997, p. 53) state:

> "There is no reality independent of the mind; therefore, what is researched cannot be unaffected by the process of the research".

The positivistic and phenomenological paradigms in Hussey and Hussey (1997) framework are similar to the qualitative and quantitative paradigms in Creswell (1994) framework. Table 5-2 presents alternative terms for the main research paradigms.

Table 5-2: Alternative Terms For Main Research Paradigms.

Positivistic Paradigm	Phenomenological Paradigm
Quantitative	Qualitative
Objectivist	Subjectivist
Scientific	Humanistic
Experimentalist	Interpretivist
Traditionalist	
Source: Hussey and Hussey (1997, p. 47).	

Burrell and Morgan Paradigms

In the Burrell and Morgan (1979, p. 21) framework there are four paradigms, namely, 'radical humanist', 'radical structuralist', 'interpretive', and 'functionalist'. They put these four paradigms in a diagram as in Figure 5-1 and state (p. 23):

> "It will be clear from the diagram that each of the paradigms shares a common set of features with its neighbours on the horizontal and vertical axes in terms of one of the two dimensions but is differentiated on the other dimension."

Figure 5-1: Paradigms in the Burrell and Morgan Framework.

The Sociology of Radical Change			
Subjective	Radical Humanist	Radical Structuralist	Objective
	Interpretive	Functionalist	
The Sociology of Regulation			

Source: Burrell and Morgan (1979, p. 22).

Burrell and Morgan (1979, p. 23) argue that all social theorists can be located, according to the meta-theoretical assumptions reflected in their work, in the context of these four paradigms. They see the division of paradigms into four places and gather them in a figure 'map' guiding the researcher to know where he/she is at his/her present work, and where he/she will go in the future. The following paragraphs will try to give a brief insight into Burrell and Morgan's paradigms. This will help fitting this research into one or more of these paradigms.

Burrell and Morgan (1979, p. 23) define the 'Functionalist Paradigm' as:

> "It represents a perspective which is firmly rooted in the *sociology* of *regulation* and approaches its subject matter from an *objectivist* point of view."

They suggest that this paradigm provides essentially a rational explanation of social affairs. It is also a highly pragmatic perspective in orientation, concerned with understanding society in a way to create and develop knowledge that can be used. Furthermore, it seeks to provide practical solutions to practical problems. Burrell and Morgan (1979, p. 26) added in this regard:

> "The functionalist approach to social science tends to assume that the social world is composed of relatively concrete empirical artefacts and relationships which can be identified, studied and measured through approaches derived from the natural sciences."

With regard to the 'interpretive paradigm', Burrell and Morgan (1979, p. 28) state:

> "The interpretive paradigm is informed by concern to understand the world as it is, to understand the fundamental nature of the social world at the level of subjective experience".

This paradigm recognizes the social world as a developing of social process that the individuals create.

Burrell and Morgan (1979, p. 32) clarify the 'radical humanist paradigm' as:

> "The radical humanist paradigm is defined by its concern to develop a *sociology of radical change* from a *subjectivist* standpoint. Its approach to social science has much in common with that of the interpretive paradigm, in that it views the social world from a perspective which tends to be *nominalist*, *anti-positivist*, *voluntarist* and *ideographic*. However, its frame of reference is committed to a view of society which emphasises the importance of overthrowing or transcending the limitations of existing social arrangements."

In defining the 'radical structuralist paradigm', Burrell and Morgan (1979, p. 33) wrote:

> "Radical structuralism is committed to *radical change*, *emancipation*, and *potentiality*, in an analysis which emphasises *structural conflict*, *modes of domination*, *contradiction* and *deprivation*. It approaches these general concerns from a standpoint which tends to be *realist*, *positivist*, *determinist*, and *nomothetic*."[47]

According to Burrell and Morgan's classification of paradigms, this research is located in the 'interpretive paradigm' as it tries to explore and understand the historical rationales for the relaxations of UK petroleum fiscal regime. Also it tries to reflect upon the policy of petroleum tax relaxations, the interventionist approach, by testing these rationales from an *ex-post* position.

This brief description of the theoretical research assumptions and paradigms is designated to clarify and define the assumptions of this research. It also defines the broad research paradigms into which this research fits. These are quantitative and qualitative. The next section briefly describes stages of oil investment.

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[47] For wider discussion about paradigms, see Burrell and Morgan, 1979, pp. 21-37.

5.4 Oil and Gas Industry Investments

Investment in the oil and gas industry involves three main and separate stages which are: exploration, development and production. These stages form an investment cycle which starts with exploration. Adelman (1996, p. 13) summarises the investment cycle in mineral resources as:

> "Mineral production is a flow from an unknown physical resource, first through exploration from "basins" to "plays," then into identified "fields" and "reservoirs," then through development into current inventories or "proved reserves," to be extracted and sold".

Moving from one stage to another needs different investment decisions, as each stage involves different activities from the others and requires a different amount of finance. Undertaking any investment decision at any stage needs a certain level of care because amounts of money required to be invested are significant, especially for building necessary infrastructures for production. The next sections describe, very briefly, each of the above investment stages.[48]

5.4.1 Exploration

Investment at this stage requires large amount of initial capital that might equal, on average, up to £12 million for a single field (MacMillan, 2000, p. 93). In the case of finding commercial mineral deposits, an oil company does not usually have the prospect of generating revenues for a period extending up to fifteen years from discovery. This is because oil and gas activities require a long period of set - up before production commences and revenues are generated. This stage involves first of all identifying areas that may contain oil and/or gas reserves. Geological and geophysical exploration studies are therefore essential for this stage. Seismic studies are also essential for providing detailed information about sub-surface structures. By the time of completing these studies, and if an area is proved to have probable reserves,[49] an oil company will then obtain a licence from a host

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[48] For full description of the oil and gas investment stages, see UKOOA (2002).

[49] Probable reserves are those that are currently appraised or for which reasonably accurate estimates or reserves are available, and development seems likely in the next few years (Kemp

government to be able to undertake its exploration activities. Finding oil and/or gas resources does not guarantee that minerals exist in economically producible quantities. Therefore, oil companies have to drill appraisal wells to be able to identify whether reserves discovered have sufficient potential commercial to be extracted or not. If so, then the operator will move to the second stage of oil investment. Exploration efforts can be reflected by the number of exploratory wells and accumulated exploration expenditure (Pesaran and Favero, 1990, p. 4; Lewis and McNicoll, 1978, p. 10). The second stage after the exploration is development, and the next section illustrates what is involved at this stage.

5.4.2 Development

The development stage includes establishing the necessary infrastructure, which is needed for extracting and transporting commodities. In other words, development expenditure involves drilling and completing wells, installing equipment, and connecting to a pipeline or tanker terminal. The required amount of money for investment at this stage is significant, and might total £500 million for a normal oil field (MacMillan, 2000, p. 93; UKOOA, 2002; Adelman, 1996, p. 17). Development expenditure is significantly more than exploration expenditure. For example, within one year, 1999, total exploration and appraisal expenditure in the UKCS equalled £0.5 billion, while development expenditure during the same year totalled £2 billion (DTI, 2000a, p. 23). In 1999, in the UK an exploratory well cost, on average, £10 million, while developing a well cost £14 million. The time needed for developing any given field is defined by the interval between a discovery of an oil field and production start-up of this field. Therefore, any development decision is considered as a strategic decision for oil companies, because of the time lag and the necessary volume of finance. Similar to exploration efforts, development efforts can be reflected by the number of development wells and accumulated development expenditure.

Oil companies operating in the UKCS have to obtain Annex B approval before they can proceed with development activities. Annex B is a satisfactory project

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and Macdonald, 1994, p. 342). For more explanation regarding oil and gas reserves categories, see SPE (1997).

plan approved by the Department of Trade and Industry (DTI). This plan specifies the type of development, the offshore loading system, location of platforms, sub-sea wells, pipelines, terminals and the expected yearly production. The key issue for the DTI to grant development consent is that the development option is to secure a full recovery of economic reserves (DTI, 2001b). [50] After completing the development stage, the oil company moves into the extraction stage. This will be the subject matter of the next section.

5.4.3 Extraction

After developing an oil and/or gas field, an operator can start producing the minerals straight away if the economic environment and the necessary production conditions allow this. Operating costs increase when the volume of reserves decreases, because the amount of reserves in the ground determines the pressure dynamics of the reservoir. Production rate is negatively related to costs and positively to prices (Gallun et al., 2001; Favero and Pesaran, 1994; Burke and Starcher, 1993).

The above sections present the main investment stages in oil and gas industry. The next section illustrates the criteria that may be used when making investment decisions in the oil industry.

5.5 Criteria For Making Investment Decisions in the Oil and Gas Industry

This section will illustrate the criteria in use in the oil and gas industry for making investment decisions. This will help in defining the available measures for decision-making, which can be used in testing the rationales. A decision to work an oil field in any investment stage is an economic one, which is based on an explicit comparison of the expected benefits and costs (Duffy-Deno and Robson, 1995, p. 555). The development stage is the most important one because of (1) the finance issue, (2) the irreversible nature of investment at this stage, and (3) the

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[50] Economic reserves are those of which have a (pre-tax) market value greater than the (pre-tax) resource cost of their extraction, where costs include both capital and operating costs but exclude sunk costs and costs (like interest charges) which do not reflect current use of resources (DTI, 2001b).

risk issue. For an oil and gas company working in the UK, to proceed with any field's development plan, it should obtain Annex B Approval, which should in turn assure the existence of economic recovery. This economic recovery is based on a plan which provides evidence of the commerciality of an oil field to be developed. The proposal of commerciality of an oil and/or gas field is based on expectations and predictions of future economic factors linked directly to the production, such as costs and prices.

However, the development stage requires a relatively long period of time, which might extend in normal terms from three to eight years. It therefore follows that all changes in the tax system cannot be known at the time development decisions are taken. Moreover, reforms in oil taxation are unpredictable as they are usually driven more by unpredictable political pressures than by predictable economic factors (Pesaran & Favero, 1990, p. 15). Therefore it can here be safely assumed that any investment decision regarding oil and gas industry in the UKCS made before any of the three tax relaxations had used only the normal predictable economic factors, including the existing tax regime or anticipated changes in the latter, in so far as these could be known.

In making investment decisions or judging previous investment decisions, oil companies and analysts may use different measures. Suitable, well known, measures of future revenues being used within an economic environment in making investment decisions are:[51] expected monetary value (EMV), risk analysis, decision tree analysis, net present value (NPV), future cash flow (CF), internal rate of return (IRR), the hurdle rate (HR), Monte Carlo simulation and the pay back period.[52] However, each of these measures has its limitations, which might be inherent or might be caused by scarcity of data and information needed for applying them. For example, the Monte Carlo simulation technique is used for risk analysis. This technique helps the analyst to assess the effect of risk and uncertainty on project results. Also it helps to identify those factors that have the

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[51] For detailed discussion about these economic measures, see Seba, 1998, pp. 155-199.

[52] "Payback period is the period of time required for future net cash inflows to cover the initial cash outlay" (Pike & Neal, 2003, p. 162).

most significant effects on the resulting values of profits. This tool has been criticised for not allowing for any marginal flexibility (MacMillan, 2000, p. 118).

NPV is widely used in investment appraisal decision-making, and considered to be the most straightforward way of determining whether a project yields a return in excess of the alternative equal risk investment in typically traded securities (Drury, 2001, p. 247). A decision-maker assumes, when applying the NPV method, that the values of the many input parameters are known. These are: original oil in place, decline rate, yearly oil price throughout the production life of the project in question, yearly costs, inflation rates and tax rates applicable. Applying this technique is mainly based on future predictions of these parameters' values, which might not be accurate. For this reason sensitivity analysis measures are applied to take the risk and uncertainty into account when making investment decisions. Because other methods are subject to similar limitations, the best measure may be to use a combination of these tools to allow decision-makers to gain maximum insight into the investments (MacMillan, 2000, p. 70 and p. 90).

MacMillan (2000, pp. 90-143) addresses the most common techniques that are in use in the decision-making process in the upstream oil and gas industry. MacMillan (2000) also mentions a number of decision-making theories in application within the upstream oil industry, such as: preference theory, portfolio theory and option theory. However, it is not the intention of this research to illustrate these theories as they have been widely explained elsewhere in the management and decision-making literature (see Seba, 1998; MacMillan, 2000). The main point of this paragraph is to stress that there is a variety of tools, techniques and theories available for the decision-maker in the upstream oil and gas industry to be used when making investment decisions. As there are many different factors that might affect such investment decisions (such as share of market, existence of transportation infrastructure and political factors), it is therefore not an easy task to make an investment decision. Meanwhile, with regard to development activity, and in ranking options, the UK Department of Trade and Industry (DTI) focuses on pre-tax NPVs calculated using an

appropriate discount rate (currently 10 per cent real[53]). In this regard MacMillan (2000, p. 95) points out that most firms that use the NPV tool of profitability measure appear to be using discount rates in the range of 9-15 per cent for petroleum exploration investment. For this research a 10 per cent real discount rate is being used as was chosen by the DTI (2001b), and as used by Bond et al (1987), Kemp and Cohen (1980), and Kemp (1985).[54]

In terms of measuring changes in oil investment in any stage, Favero and Pesaran (1992, p. 9) argue that oil and gas companies' total costs consist of exploration expenditure, development expenditure and operating expenditure. The number of exploratory wells drilled measures the rate of exploratory efforts. The unit (well) cost of exploratory efforts during a certain period of time (year) is measured as a ratio of the total exploration expenditure to the number of exploratory wells drilled during that period. The number of development wells drilled measures the rate of development efforts. The unit cost (a well) of development stage is obtained as the ratio of total development expenditure to the number of development wells drilled. This criterion of measurements is to be used in this research when testing the rationales for petroleum tax relaxations with regard to changes in exploration and development activities in the UKCS.

In accelerating the investment cycle, governments might use the fiscal regime as a device for this purpose, in which case the regime is likely to be a non-proprietorial.[55] Petroleum taxes target the production stage where profits are generated. Because the oil industry's revenue is a key factor for any potential investment decision, tax relaxations might be used to stimulate investment at any stage of the oil and gas industry operations in order to move the investment cycle

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[53] "Real" means after the effect of inflation has been deducted, whilst "nominal", on the contrary, means that inflation effects are not considered (Kemp and Cohen, 1980, p. 6).

[54] The discount rate that is used in calculating the NPV represent the required rate of return that investors can expect on comparable alternative investment in the market place. It is the rate which is used to discount streams of cash inflows and outflows to arrive at the NPV. This rate is referred to as the cost of capital. The IRR presents the true interest rate earned on an investment over the course of its economic life. It is the interest rate that when used to discount all cash flows resulting from an investment, will vase the NPV of this investment to be zero. A zero NPV indicates that a firm should be indifferent to whether the project is accepted or rejected (Drury, 2005, pp.231-233).

[55] It is suitable to refer here that only under non-proprietorial regime would there be a government interest in accelerating investment.

on, and hence generate revenues. This stimulation could be incurred by relieving the subsequent impact of the taxes on taxable profits. Investments can be stimulated by tax breaks and relaxations because, for the oil industry, a tax relaxation in general terms means less tax (cost), which in its turn means more net profits and better post-tax cash flow (Petroconsultants, 1996). Increasing post-tax cash flow will, arguably, push the oil investment cycle ahead for more exploration, development and production. However, as marginal tax rates affect decisions being taken in the UK upstream oil industry, the UK Government has used the tax relaxations as a driver for accelerating certain activities through introducing certain allowances (Kemp and Cohen, 1980, p. 17). In this regard, the introduction of exploration and appraisal relief might have stimulated exploration and appraisal activities. The Cross Field Allowance also should have helped to boost development activities in the UKCS. [56] In contrast, removing the exploration and appraisal relief in the 1993 Budget might have a negative effect on exploration and appraisal activities, as the rate of drilling and appraisal activities noticeably decreased after 1993. Meanwhile, from the Government perspective, any acceleration in any investment activity will have the purpose of increasing production and consequently the tax take.

Oil and gas prices and costs have their own effects on investment decisions in the oil and gas industry, as prices define the level of the final turnover and consequently the gross revenues. Also, prices are likely to be the most important driver of investment in general, as with a high price level, i.e., $65 - $75 all the other tax and technological incentives will have less or no effects on investment decisions. The next section will consider the role of oil prices in making investment decisions in the oil and gas industry.

5.6 The Role of Oil Prices in Making Investment Decisions in the Oil and Gas Industry

This section details the relationships between oil prices and investment decisions in the oil and gas industry. The purpose here is to justify the use of a number of

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[56] The Cross Field Allowance concept includes offsetting 10 per cent of qualifying development expenditure of new fields against a company's PRT liabilities in other fields (see tax changes in section 3.4.3).

techniques in the methodologies of testing the rationales for the UK petroleum tax relaxations in the next three chapters.

The relationship between commitments made to explore, develop and extract oil and/or gas resources and prices of these commodities is a complex one. These commitments might take many years to complete, and in the meantime market, economic and political conditions may have well changed (Seymour, 1990, p. 7). The dramatic increase in oil prices early in the 1970s was a major factor in improving the economics of exploration and development of oil and gas reserves which were of a particularly high cost due to the harsh weather conditions of their locations in the North Sea (Martin, 1997, p. 1; Seymour, 1990, p. 32). Therefore oil prices had a recognisable influence affecting investment decisions in the North Sea, and in turn contributed to the increased number of discoveries. Effects of the changes in oil and gas prices should always be taken into account when considering investment decisions within the oil and gas industry. In this way, when oil and gas prices are high there will be more finance available to be invested in oil industry, as the price increase plays a role in relaxing financial constraints and making more finance available for investment. Hence, a price increase therefore affects the prospective profitability position, and this affects oil companies' financial and investment capability.

Oil prices are directly affected by changes in the (unpredictable) political environment. Therefore difficulty arises from the methodology of building up price expectations, which is a well-known fact in the oil industry. For example, the Arab embargo on oil in 1973, the Iranian Revolution in 1978, the Iraqi invasion of Kuwait in 1990 and the British-American invasion of Iraq in 2003 were unpredictable political events that had direct effects on the international oil and gas prices. Therefore, oil and gas investment decisions that were made before the Iranian Revolution could not take the price shock of 1978 into account, because nobody could have predicted that the Revolution would take place in the first place. The same can be said with regard to investment decisions taken in the early 1980s, as changes in oil prices afterwards would affect economic measures such as IRR, and NPV. Analysts and researchers had used these and other similar measures in judging the criteria that oil companies might use in making

investment decisions based on oil price predictions. This research will use the actual prices and costs of this judgment as it mainly uses the *ex-post* data and intends to create the *ex-post* judgement.

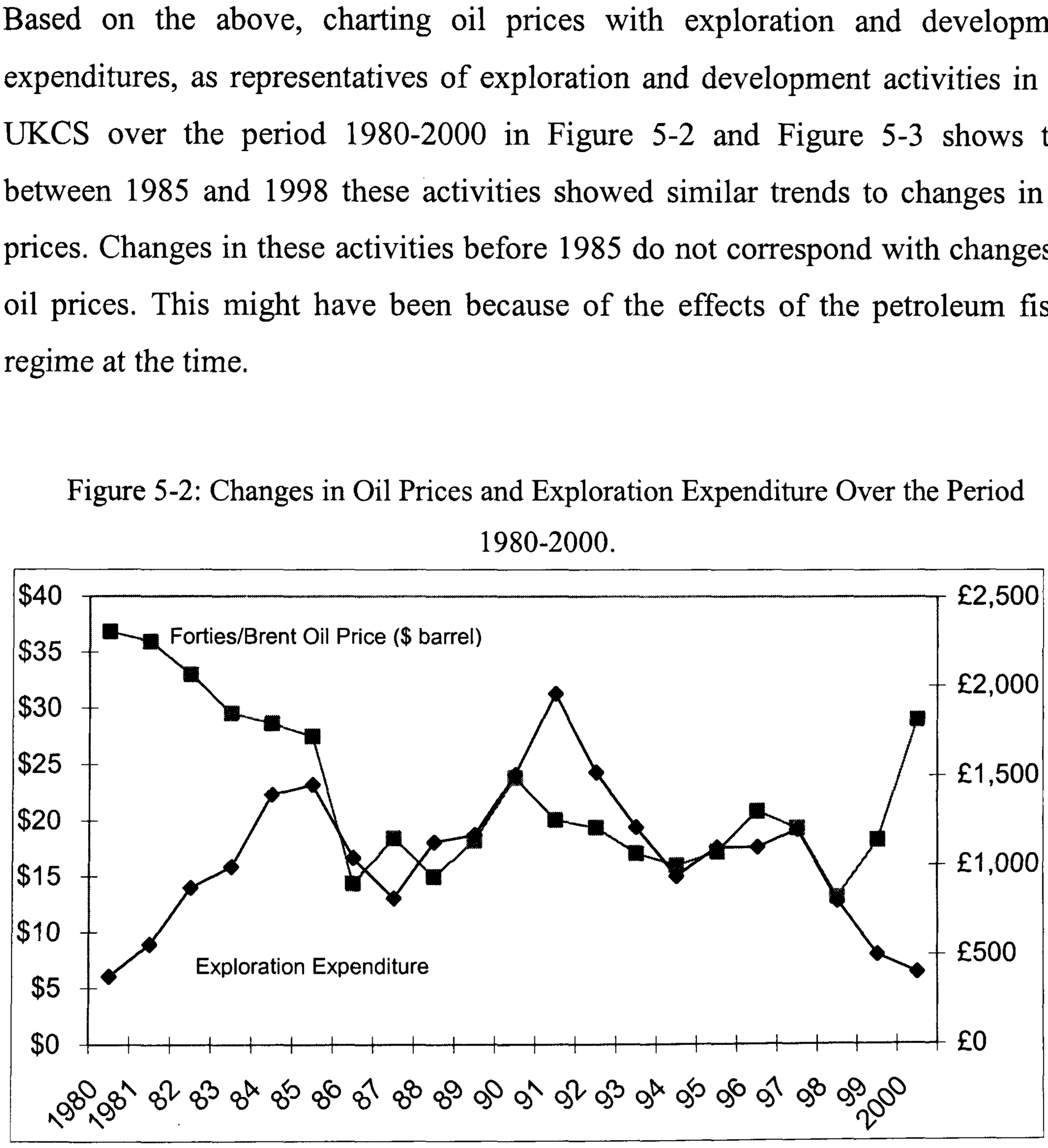
Oil and gas prices have a considerable role in the process of investment decision-making. A one-dollar change in oil and/or gas prices represents almost a one-dollar change in the net unit revenue. Investment decision-makers in the oil and gas industry mainly base their decisions on estimated values of the decisions' variables (i.e., reserves' volumes, costs, prices, production rates) for an average period of a decade over which these variables might dramatically change. This is particularly true of the oil prices (MacMillan, 2000, p. 94; Mabro, 1998, p. 6). In this study the *ex-post* prices are being used in the analyses for each field under consideration, which are available from the Wood Mackenzie (2004, GEM, v. 3.01) database. Meanwhile, the *ex-ante* price expectations for the period 1980-2000 are to be used for judging the effects of these expectations on investment decisions in the UK oil and gas industry through the *ex-ante* analysis.

Pesaran and Favero (1990, p. 8) found out that there is a certain degree of correlation between exploration efforts, reflected in the real total exploration expenditure, and changes in oil and gas prices. Also they found that development efforts are related to actual and future oil and gas prices. In this regard, Seymour (1990, p. 9) points out that development activities are more likely to be price sensitive than exploration activities, because development involves larger capital expenditure than exploration. Oil companies might be motivated to explore, whatever the oil price is, in order to build up a portfolio of reserves for eventual development. The interesting result Pesaran and Favero (1990) found is that there is a non-linear relationship between production and prices. This is because operations of a reservoir can be heavily constrained by a number of factors. These are: legal obligations, immediate cash flow required of the operator, the need to recover the exploration and development costs as soon as possible, oil field dynamics and the availability of the transportation infrastructure. This is true of the large oil fields that have a massive production flow but not of the small and marginal fields with high costs. In this context Seymour (1990, p. 12) states, "the more significant an oilfield is in terms of supply the less price sensitive its

production profile will be". However, given that investments at exploration and development, as stages in the oil investment cycle, are more sensitive to price changes than investments at production stage, therefore improvement in any of these activities arising as a result of price changes will affect, in one way or another, the production stage of the investment cycle. Meanwhile, it is still appropriate to say that prices on the economic side are not the only factor affecting the investment cycle, as there are effects which come from the geology of the location and on the policy making side, the fiscal regimes.

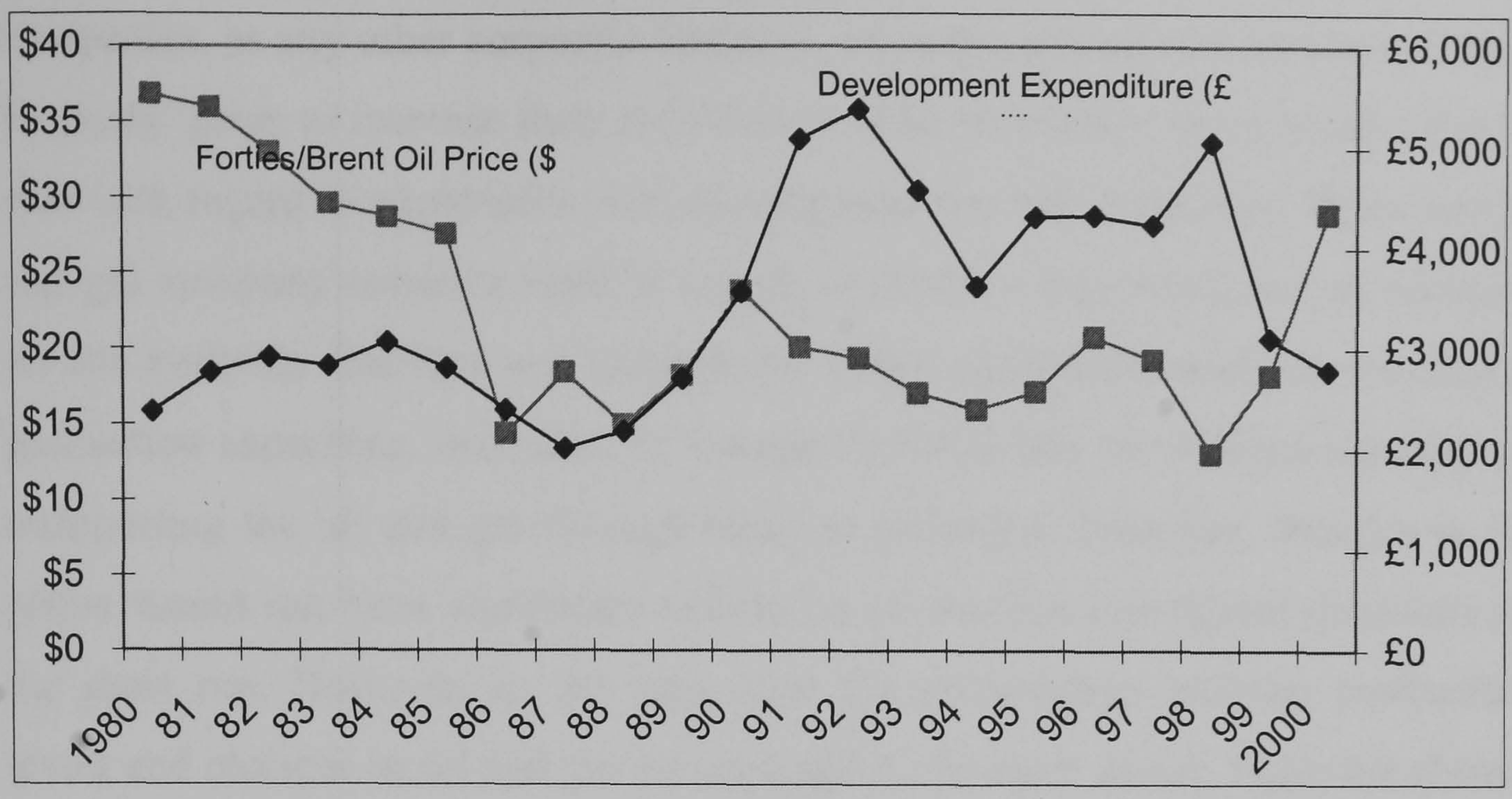
Based on the above, charting oil prices with exploration and development expenditures, as representatives of exploration and development activities in the UKCS over the period 1980-2000 in Figure 5-2 and Figure 5-3 shows that between 1985 and 1998 these activities showed similar trends to changes in oil prices. Changes in these activities before 1985 do not correspond with changes in oil prices. This might have been because of the effects of the petroleum fiscal regime at the time.

Figure 5-2: Changes in Oil Prices and Exploration Expenditure Over the Period 1980-2000.



Source: based on data extracted from DTI (1980-2000).

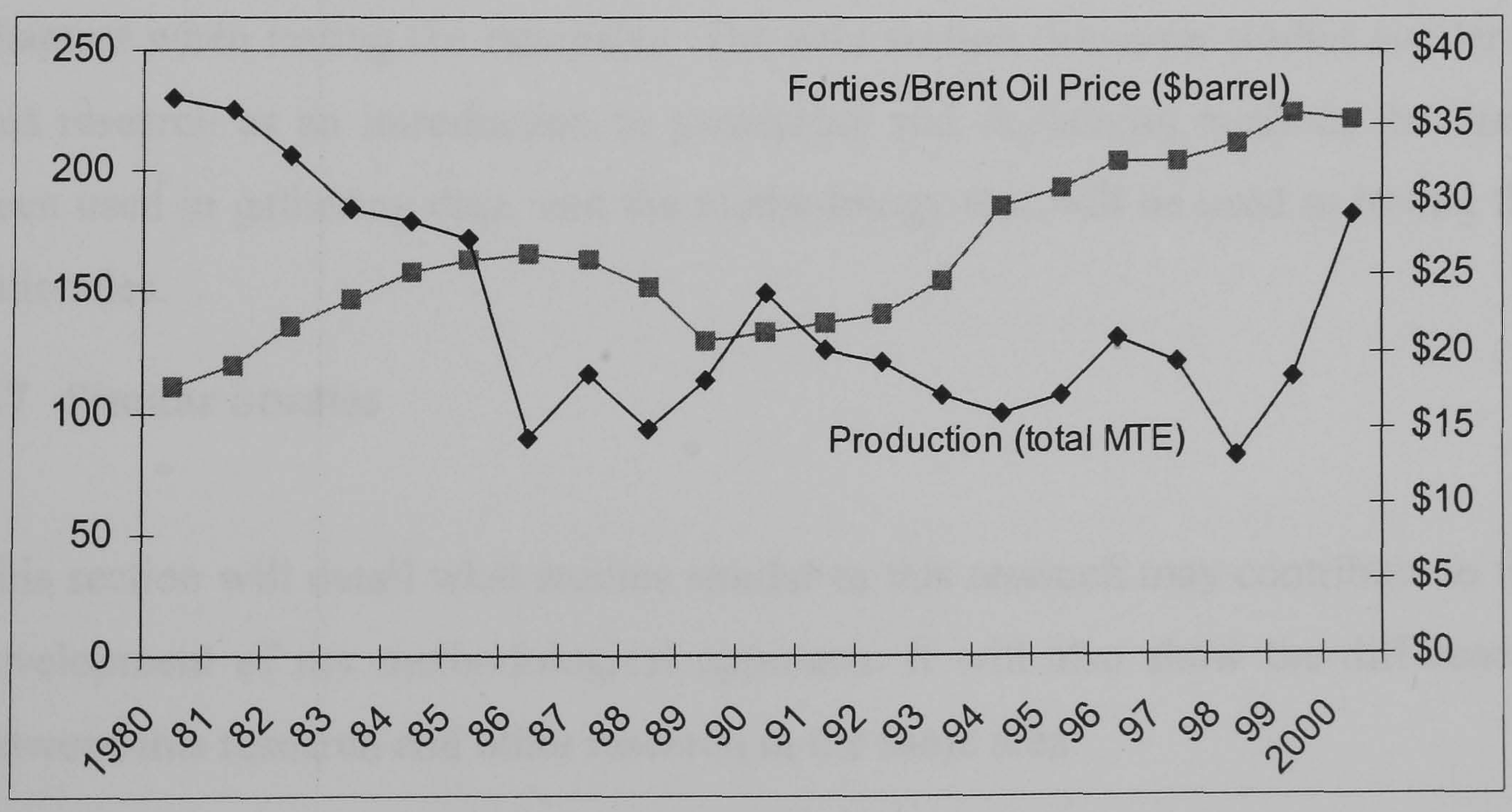
Figure 5-3: Changes in Oil Prices and Development Expenditure Over the Period 1980-2000.



Source: based on data extracted from DTI (1980-2000).

Similarly, charting oil prices with total oil and gas production in the UKCS over the period 1980-2000 in Figure 5-4 shows that there was no linear relationship between price and production. This result supports the above discussion of Pesaran and Favero (1990) and Seymour (1990) regarding the relationship between oil prices and oil and gas investment activities.

Figure 5-4: Changes in Oil Prices and Total Oil and Gas Production Over the Period 1980-2000.



Source: based on data extracted from DTI (1980-2000).

As making profit is the main objective for any commercial entity, there is a direct relationship between the increase in prices and the increase in revenues. Oil companies, as any other corporate business, are motivated by the increase in their products' price to increase their activities in order to capture more profit. This is true with regard to exploration and development but not extraction. When an oil and gas company commits itself to supply contracts it bases this sort of decision on the available facilities and constraints. These constraints relate to maximum production capacities, limitation of storage facilities and the limited capacity of transporting the oil and gas through tanks or pipelines. Therefore changes in oil prices would not have significant effects on production investment decisions in the short run. However, in the long term the relationship between production levels and changes in oil and gas prices ought to be more linear. From the above, it can be pointed out that changes in oil and gas prices have direct influences on exploration and development activities, and indirectly on production activity. These changes in oil prices should be taken into account when judging exploration and development decisions.

The above sections illustrated stages in the oil and gas industry's investment and showed the probable criteria for making investment decisions. It also illustrated the relationship between oil prices and investment decisions in the oil and gas industry. The benchmarks from these sections will be used in the following chapters when testing the rationales. The next section discusses studies similar to this research as an introduction to presenting and explaining methods that have been used in gathering data, and the methodology that will be used in testing the rationales.

5.7 Similar Studies

This section will detail what studies similar to this research may contribute to the development of my methodological approach. It will also show the differences between this research and other research in the same area.

Kemp and Rose (1983) conducted a study focusing on new exploration and development decisions in future fields. They categorised fields firstly according to

the size of recoverable reserves. The categories are: (1) Field A = 500 million barrels = high volume; (2) Field B = 250 million barrels = medium volume; (3) Field C = 100 million barrels = low volume; and (4) Field D = 50 million barrels = very low volume. Secondly, they categorised fields according to the size of development costs as: (a) $6,000 per peak daily barrel produced = low cost; (b) $15,000 per peak daily barrel produced = medium cost; (c) $20,000 per peak daily barrel produced = high cost; and (d) $30,000 per peak daily barrel produced = very high cost.

Kemp and Rose (1983) used a computerised model for the analysis, and they compared different figures such as tax take and net present value (NPV) for four countries - the UK, Denmark, Netherlands and Norway. Kemp and Rose (1983) studied the sensitivity of the fiscal regimes in relation to assumed changes in oil prices. Their results concluded that the sensitivity of a fiscal regime to changes in oil prices differed from one country to another based on the structure of the petroleum tax system in each country.

Devereux (1983) took the production, cost and expenditure profiles of existing fields and recalculated the rate of return which these fields would have produced if they had applied the pre-1983 Budget system throughout their lives; and once more if they had applied the post-1983 Budget system for new fields. From this study, Devereux (1983, p. 77) states:

> "More interesting is the effect on different fields. Although there are exceptions, the largest increases in rates of return tend to be those for the more marginal fields (like Heather, Tartan and Maureen) while the more profitable fields (similar to Forties or Piper) tend to have lower increase".

This means, according to Devereux (1983), that marginal fields should have benefited more from the 1983 petroleum tax relaxation than large profitable fields. Devereux (1983, p. 75) states:

> "We concluded that the expected rate of return for such fields [existing fields] rises significantly, particularly for the more marginal fields. The effect of the Budget should be to encourage exploration and development".

Kemp et al. (1995) studied the impact of the fiscal systems of the main North Sea countries and a number of the Far East countries. These countries are: the UK, Norway, Australia, China, Indonesia, Malaysia and Papua New Guinea. They modelled fields according to volume of reserves as medium size (MV), low size (LV), very low size (VLV) and very, very low volume (VVLV). They also applied different price scenarios to the different fields' volumes in the different countries, and they considered that the volume of development costs represented the size of an oil field. Kemp et al. (1995) concluded that post-tax returns to investors in new fields were highest under the UK fiscal terms and this was the case under all the costs and oil price scenarios examined. This, in other words, means that the post-tax returns to an investor in a small UK oil field were higher than those available in another country from a considerably larger field. This, in its turn, meant that the UK petroleum fiscal regime was more favourable to the oil and gas industry than other fiscal regimes in other countries.

Martin (1997) tried in his study to illustrate the effects of the petroleum tax relaxations and improved technology on the development decisions for marginal fields. He assumed that decisions to develop fields would be made if their IRR should exceed 15 per cent. Martin developed a taxation model for his analysis. With regard to the impact of fiscal changes Martin (1997, p. 39) applied five different scenarios. These are:

Scenario one: the imposition of royalty. Under this scenario Martin assumes that the effective royalty rate was 9 per cent;

Scenario two: the size of the oil allowance. Here Martin assumes that the oil allowance was not doubled for new fields;

Scenario three: the rate of petroleum revenue tax. According to this scenario, it is assumed that the rate of PRT was not reduced to 50 per cent for old fields and was not abolished for new fields after 1993;

Scenario four: without the 1983 fiscal changes. This scenario evaluates the impact on the tax position and the IRR of new fields assuming that the 1983 tax changes had not been made; and

Scenario five: without the 1983 and the 1993 fiscal changes. This scenario was used to indicate the profitability of new fields if tax changes had not taken place in 1983 and 1993.

Martin (1997) concluded (based on his model and analysis) that a number of fields benefited from the tax relaxations and the decisions to develop them were made as a result of these relaxations. He points out that the impact of abolishing royalties for new fields had the greatest impact if compared with doubling the oil allowance and reducing the rate of PRT to 50 per cent. This is because many of the new fields were not liable to PRT, since their output was low or because of the safeguard provisions. More significant results were achieved by applying scenarios four and five, as they showed how the relaxations in 1983 and 1993 affected the IRR and the development decisions as well. In this regard Martin (1997, p. 41) states:

> "Thus, there is a case for arguing that changes to the UK fiscal regime in 1983 and 1993 have played a role in the development decision of fields which, between them, have contributed an average 400,000 b/d to total UK North Sea oil production since 1994."

A number of other studies have been conducted to figure out the effects of the petroleum tax regime on the oil and gas production, such as that by Devereux and Morris (1983a ; 1983b). Khadr (1987) linked changes in the petroleum fiscal regime with the risk associated with oil and gas industry and the effects of that on the production levels.

5.7.1 How Does this Research Study Differ From Other Studies?

Compared with previous research, this research is unique in a number of aspects. The first is in its attempt to explore the historical rationales underlying the UK petroleum fiscal regime relaxations, and the second is in its testing of these rationales to judge if the main intentions, or policies, behind these relaxations have been achieved and if so to what extent. Thirdly, the research will explore the effects of these relaxations on the Government's revenues and on the oil industry's activities and revenues as well. Fourthly, it will try to classify the UK manner of governing petroleum resources as a proprietorial or non-proprietorial regime (for details about these concepts see section 2.4.1).

However, although Martin's is the closest to this research study, there are several identifiable differences between Martin's study and this research. These differences relate to the methodology of conducting the research, collecting data and the main research hypotheses. The following points illustrate the main critiques of, and differences between, Martin's study and this research:

(a) Martin (1997, p. 3) divided the oil fields into two groups: the 1985 group, which are fields already on stream in 1985, and the new fields which are those fields that commenced operations after 1985. The focus of this thesis is on fields developed after 1983, as any field that was developed before that date had already proved to be commercial for development and extraction under the pre-1983 tax system. Those fields that were developed after 1983 can be isolated and identified as those whose developments had been stimulated by the 1983 petroleum tax relaxation, and those that would have been developed despite the tax relaxation. This will show the effects of the 1983 petroleum tax relaxation, if any, on developing new oil fields. In other words, it will uncover the effectiveness of the petroleum tax relaxation policy on development investment in the UKCS. Here it is important to take into consideration that Annex B approval takes on average up to three months to be granted from the day an application is submitted. Therefore, any fields that obtained development consent within three months from the tax relaxation dates in the 1983 group should be included in the 1983 fields in question. The same methodology applies with regard to the other two tax relaxations, 1987-88 and 1993. Therefore, Martin's division of the oil fields into the 1985 group and the new fields was inappropriate.

(b) In his study, Martin mainly used Wood Mackenzie's data of 1996. Thus any data produced for the period post-1996 was mainly estimated, with regard to prices, production, costs, taxes and fields' productive lives. Further, the economic measures that would have been used for any decision-making process, such as IRR or NPV, would have been based on estimations (the *ex-ante* position). In this research Wood Mackenzie's data incorporated in GEM (version 3.01, Release 2004) are being used and applied. These data

are updated regularly and contain more accurate figures than the 1996 version and allow a closer look at the actual figures. By the year 2004, the effects of fiscal regime relaxations up to the year 2000 can be tested, using the 2004 data, and effectively compared with results based on estimated data, in particular for fields developed during the 1980s (the *ex-post* position). Moreover, Wood Mackenzie's data is only one source of the many data sources being used in this research, which include data from the DTI and the Inland Revenue.

(c) Martin's assumption of a 15 per cent IRR indicator for commerciality of oil and gas fields and justifying this percentage with the lower end of the PRT safeguard is inappropriate. [57] This is mainly because PRT was introduced to tax the super profits but not the normal profits, and the safeguard was initially introduced to protect marginal fields from being liable to PRT (Liverman, 1982, p. 459). The lower end of the safeguard was meant to protect an operator's profits from a marginal oil field against PRT. In other words, if an operator's gross profit should not exceed 15 per cent of his capital expenditure at the end of a period subject to PRT, then he would not be liable to this duty. This 15 per cent (the lower end of the safeguard) represents the accounting rate of return (ARR) but not the IRR, and there is a wide difference between the two rates (Horngren et al., 2005, p. 668). [58] The ARR is a profit based performance measure, whilst IRR is a cash flow based measure. Therefore a link between the safeguard lower end and a 15 per cent IRR is inappropriate. Even if the adjusted PRT profits for an oil field do not reach 15 per cent of the capital expenditure in any certain year, it does not mean that extracting oil and/or gas from this field is not commercial. Also this does not mean in any sense that fields with IRR of less than 15 per cent are not commercial.

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[57] The Oil Taxation Act (1975) stated: "the tax payable by a participator in an oil field for any chargeable period to which this subsection applies shall not exceed 80 per cent. [Sic] of the amount (if any) by which his adjusted profit for that period (as defined in this section) exceeds 15 per cent of his accumulated capital expenditure at the end of that period (as so defined)." (Great Britain, 1975b, S. 9).

[58] ARR is calculated by dividing the average annual accounting profits from a project into the average investment cost of the project in question (Drury, 2005, p. 243). Managers usually use the term return on investment (ROI) in the context of evaluating the performance of a division and accrual accounting rate of return when evaluating projects.

(d) In his analysis, Martin tries to measure the effects of fiscal regime changes of 1983 and 1993 both together on the development decision, ignoring the effects of the 1987-88 petroleum tax changes. This research is going to measure the effects of each of the three tax relaxation packages individually on investment decisions for the purpose of testing the rationales.

(e) The essential difference between Martin's study and this research is that he assumes a number of factors which might have affected development decisions in the UKCS. These factors are: oil price, changes in the internal organisation of the oil industry, infrastructure, gas consideration, new technology and the fiscal regime. Of the above factors, he focused on the last two. The focus in this research is on the true rationales for the UK petroleum fiscal regime relaxations. These rationales are real factors as extracted by applying different research methods mentioned in the previous chapter (see section 4.3), and as will be explained later on in this chapter. For example, a number of rationales mentioned that increasing development activities was a reason behind tax relaxations. Therefore this research and Martin's study have the same interest with regard to this activity, development, but from different perspectives. Because Martin focuses on factors that might influence development decisions, while this research takes development as one rationale that underpins the UK petroleum tax relaxations' policy. Hence, the focus of this research in testing this rationale (development) is on the effect of petroleum tax changes on this activity. In other words, while Martin's study focused on the activity side, this research focuses on the policy side – and whether this resulted in stimulating investment activities, including the development activity.

In exploring the effects of the UK petroleum tax relaxations, the effects on the development decisions are to be tested at a 10 per cent real discount rate, as is assumed by the DTI, and used by other researchers, e.g., Kemp (1985), assuming that oil and gas companies make development decisions when the IRR reaches 15

per cent.[59] The IRR will be used, as it is an appropriate measure of pre- and post-tax return earned by investment (Bond et al., 1987, p. 64). However, development decisions for oil fields do not solely relate to fiscal changes, as economic and geological factors have their effects on these decisions. However, it is not my intention here in this study to analyse in detail and isolate the effects of the fiscal, economic and geological factors that affect developing oil fields. The centre of attention will be on testing the UK petroleum tax relaxation rationales to see if these rationales were/were not/were partly met by the tax relaxation policy.

The previous sections mentioned similar research and showed the main differences between them and this research. The next section will illustrate and justify research methods that were used to collect data for this research.

5.8 Research Methods

The previous chapter briefly mentioned sources used for collecting data for this research. This chapter explains this in more detail and justifies the data collection methods. Research methods refer to the various means by which data can be collected and analysed. The methods of collecting data for this research varied according to purpose. As this research is an exploratory and its objective is to explore and test the rationales for the UK petroleum tax relaxations and conclude on the success of the interventionist approach in stimulating oil investments (by using tax relaxation policy in the light of the adopted type of mineral governance (proprietorial vs. non-proprietorial)) it needs more than one set of data. Therefore, data was collected in two stages. The first set of information helped to extract the rationales, and the second set is numerical data which will help in testing these rationales. The next three sections explain and justify the process and collection of these data.

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[59] Petroconsultants (1996, Table 5s) found that the average IRR for marginal UK oil fields is 16.37 per cent.

5.8.1 Collecting the First Set of Data

In exploring the historical rationales for the UK petroleum tax relaxations, information was collected from primary resources - Governmental, industrial and secondary resources such as academic articles, also the relevant press material. In determining the reliability of such data, Williamson et al. (1977, p. 264) state:

> "There are some records, however, which, by their very nature, we can logically assume to be most accurate. We would, for example, expect there to be no intentional deceit or error in stenographic or taped records of courts, political bodies, or committees. Notebooks and other memoranda are also high in credibility because they are intimate and confidential records".

From this statement, it can be said that primary Governmental and industrial sources, which are being used in this research, can be trusted. These sources match to a very large extent the above stated description. The description can also be safely generalised to include the statistical published data, which is being used in the second part of this research in testing the rationales. The next sections will describe each data source in some detail.

Governmental Resources and Publications

These resources are mainly official state documents plus two interviews with Government civil servants. The following is a description of each of these resources.

a. The Oil Taxation Acts. This source shows how the UK petroleum tax regime was built and how it was amended over time.

b. Parliamentary debates. This source details discussion in the House of Common with regard to any of the petroleum tax amendments and reliefs, from the MPs' point of views, as they suggested the amendments at the time.

c. Energy Committee reports. These reports include full justification for any of the tax relaxations and comments on them.

d. Standing Committee reports. These reports explain and comment on each tax relaxation from the Government point of view.

e. The Brown Book "Development of the Oil and Gas Resources of the United Kingdom". The Brown Book is an official annual publication of the DTI. This source contains a brief explanation, and discussion of petroleum tax relaxations, their rationales and contains statistical data on a field-by-field basis.

f. The official web sites of the DTI and the Inland Revenue that contain information about petroleum taxes and their treatments.

g. Interviews. To make sure that I covered the rationales from the Government standpoint, I conducted interviews with civil servants from the DTI, with Mr Mike Earp, and from the Oil Taxation Office of the Inland Revenue, with Mr Geoff Barnard. Both of these interviews were tape-recorded. Mr Barnard reviewed the transcription of his interview. Interviews were semi-structured and questions were open-ended to allow for full responses from the interviewees. However, the information that was obtained by interviews is very similar in nature to that which was found in the published Governmental documents.

These Governmental resources, which are mainly State documents, provide information about the rationales for the UK petroleum tax relaxations from the Government point of view.

Industrial Resources

For the purpose of determining the rationales for the UK petroleum tax relaxations from the oil and gas industry's standpoint the following resources were used:

1. Individual companies' annual reports. All the annual reports of oil and gas companies that had new developments during the period 1980-2000 were searched. This was to obtain the comments on the petroleum tax relaxations by these companies, and also to see what these companies wished to acquire from the relaxations.
2. Minutes of evidence taken before Energy Committees. This source comprises memoranda of the oil and gas organisations, i.e., UKOOA and BRINDEX, and a number of individual companies, to the Energy

Committees, expressing their wishes and own justifications for tax relaxations.

I tried to conduct interviews with members of the oil and gas organisations but unfortunately could not do any, as people did not want to talk to me because of the confidential and sensitive nature of the information. Even obtaining information directly from oil and gas companies was not possible. This is because such information would quite probably be classified as commercially sensitive and not for public disclosure (Rutledge and Wright, 1998a, p. 8). Also the information I am seeking is historical and there might not be any member of these organisations who witnessed any of the tax relaxations.

Academic Resources

This comprised academics' commentary and analysis regarding the UK petroleum tax relaxations. The following sources were accessed:

1. Books, research papers and journal articles. These sources establish what had been written about the UK petroleum tax relaxations and their rationales.
2. Interview. I managed to conduct one interview with Professor Alex Kemp from Aberdeen University. Professor Kemp has been working on the economics of the North Sea oil since the early 1970s. He witnessed the UK petroleum tax relaxations and wrote about them and their rationales. This interview was not tape recorded, as Professor Kemp did not wish this.

Apart from this interview I was not able to conduct any others as academics who worked on similar subjects to mine have left the country, e.g., Steve Martin, or have been unable to provide helpful information as they worked on the subjects many years ago, e.g., Professor Mike Devereux, and a number of them did not have the same perspective on the subject, e. g., Professor Paul Steven.

The Press

To complement the previous sources and make sure that I covered everything with regard to the rationales for the UK petroleum tax relaxations, I conducted a search for relevant journals e, g., the Oil and Gas Journal, European Energy Profile and Oxford Energy Forum. I also searched past issues of newspapers such as The Independent on Sunday, the Independent, the Financial Times (FT) and the Daily Telegraph. This was essentially to shed light on what was said at the time about any petroleum tax changes. Rich information was found here giving a different perspective, to support the Governmental, industrial and academic resources.

5.8.2 Justifying the Use of the Above Research Methods

From the above description, it can be clearly seen that these methods fit the description of qualitative research. In this regard Potter (1996, p. 95) states:

> "When texts are the focus of the investigation, documents must be examined". He adds: "the examination of documents is especially important to historians who investigate patterns and trends from the past".

In this regard, Easterby-Smith et al. (1991, p. 118) state:

> "Finally there are written records and indices. House journals, internal reports, memoranda, chairman's statements, and newspaper articles have always provided good material for the qualitative research".

Moreover, Hakim (1987, p. 36) has the same description and opinion with regard to the documents and primary resources and their use in social science research. Gash (2000, p. 18) points out that over 20 per cent of the cited documents today are reports. Reports are challenging journal articles as being the most creative tool of literature. Gash (2000) adds that reports are very valuable sources of information in social science. As governments have been producing reports for a long time, they are considered as valuable sources of historical information. From these statements, and because this research study is of an exploratory nature, Governmental and industrial documents and reports are an essential source of highlighting the rationales for the UK petroleum tax relaxations. Bryman (2001, p. 371) and Punch (1998, p. 190) categorise documents into the following: (1)

personal documents, which include diaries, letters and autobiographies; (2) visual objects; (3) official documents deriving from the state; (4) official documents deriving from private sources; (5) mass media output; and (6) virtual output.

From the above list the following documents and reports are being used in this research:

(a) Autobiography. This is the one written by Nigel Lawson (1992) "The View From No. 11, Memory of a Tory Radical".

(b) Official documents deriving from the State. Bryman (2001, p. 375) and Silverman (2001, p. 135) point out that the State is considered as a source for a great deal of information of potential significance for social researchers. Bryman (2001) adds: "the state is the source of a great deal of textual material of potential interest, such as Acts of Parliament and official reports". Bryman's description and illustration of these types of resources justify and support my use of the Governmental resources explained above.

(c) Official documents deriving from private sources. In this regard Bryman (2001, p. 376) points out that company documents have been used a great deal in research. Some of these documents are in the public domain such as annual reports, while other documents are not available for the public. The difficulty of gaining access to some organisations means that many researchers have to rely on public domain documents alone. Bryman's statement supports and justifies my use and reliance on companies' annual reports as one of the main sources for extracting the rationales for tax relaxations from the oil and gas industry's standpoint.

(d) Mass media output. Newspapers are potential sources for social scientific analysis. This source can be used for the content analysis methodology, which makes it flexible tool to be used in quantitative and/or qualitative research (Bryman, 2001, p. 377). In this regard, newspapers, e.g., The Times, The Independent and The Guardian, have been used as sources for this research to extract rationales for the UK petroleum tax relaxations.

(e) Virtual output. Bryman (2001, p. 379) states: "However, the vastness of the Internet and its growing accessibility make it a likely source of documents for both quantitative and qualitative data analysis". This statement justifies

and supports my use of the official web sites of the DTI and the Inland Revenue as sources of searching for the rationales and testing them.

Regarding interviews, my main interest was extracting new rationales from interviewees. Therefore I used flexible open-ended questions for interviewing people. Because the focus of the questions was to extract historical information, I allowed enough time for the interviewees to think and reply, in accordance with Easterby-Smith et al. (1991, p. 72):

> "A positivistic approach can be retained where the interview follows a fairly standardised set of questions, whilst offering some flexibility, and allowing the views of the interviewee to become known. This type of interview might be appropriate, for example, when questions require a good deal of thought and when responses need to be explored and clarified". Also they state, "interviews are appropriate methods when it is necessary to understand the constructs that the interviewee uses as a basis for her opinions and belief about a particular matter or situation".

However, the number of interviews, though small, is adequate as interviews were conducted with people who were involved personally in Government decision making as civil servant or as academics consulted because of established expertise in the field. A justification for the small number of interviews conducted is found in Hussey and Hussey (1997, p. 55) "However, the aim of a phenomenological paradigm is to get depth, and it is possible to conduct such research with a sample of one". Therefore, the sample size is not a big problem for qualitative researchers as adequate information can be obtained. However, interviews were just one out of several methods used in this research, as using several different methods prevented this research from being method-bound. This approach of collecting data from different resources is known as triangulation where data are collected over different times frames or from different sources. In this regard Easterby-Smith et al. (1991, p. 134) state:

> "Our advice to the researcher is to use different methods from within the same paradigm whenever possible, and also to move across paradigms occasionally, but with care".

5.8.3 Collecting the Second Set of Data

In order to test the rationales that were obtained from the first set of resources, other quantitative data were needed. Each rationale represents a hypothesis for this research that can be formulated as one or more research questions. For example, the first rationale of the 1983 petroleum tax relaxation can be formulated as the following research questions: [60]

(a) What was the situation in the oil and gas industry's activities before the 1983 petroleum tax relaxation? The enquiry in this question relates to the *ex-ante* position.

(b) Have the state of these activities changed after the tax relaxation? The enquiry in this question relates to the *ex-post* position.

(c) If the answer to (b) above is yes the, are these changes related to the 1983 petroleum tax relaxation?

In order to answer the above questions, a set of detailed data is required. These data is related to the size of expenditure on each of the UK oil investment activities, and to the number of wells drilled in each activity before and after the tax relaxation. These data enable one to know whether there had been any noticeable difference in these activities or not. It is also essential to test whether there was a noticeable effect of each tax relaxation on the number of new projects. This will help in distinguishing those fields that would have gone ahead even without the tax relaxation's effects from those where the tax relaxation was the main reason for their start. In this regard, data to calculate the number of financial parameters such as cash flow (CF) and internal rate of return (IRR) are needed. The IRR is to be calculated and compared for each project before (the *ex-ante*) and after (the *ex-post*) the tax relaxation to see if there was a material change in this measure (assuming that the oil and gas companies develop any project when its IRR reaches 15 per cent). The selection of a 15 per cent IRR for this research seems appropriate on the basis that the Government set an average financial target

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[60] Encouraging oil and gas activities, which includes exploration, appraisal and development activities (see Table 4-1 on page 127).

for the BNOC for the years 1980-1983 at 9 per cent, after depreciation but before interest and tax (HC, 1981). It was illustrated before in this thesis that the BNOC had been granted a 51 per cent share in each licence, and was also exempted from paying PRT (see tax changes in section 3.4.2). This means that the corporation's costs and possible risks were lower compared to other oil companies in the North Sea at that time. Furthermore, the above target was calculated after depreciation which means that it should be higher if it was calculated before depreciation. Moreover, a 15 per cent IRR was used by a number of analysts as a target for oil companies when making investment decisions such as Martin (1997), and Kemp and Macdonald (1994). Therefore, a 15 per cent internal rate of return seems appropriate to be used for this research.[61] However, to be able to do the above, data for each project, or 'field-by-field', and for the whole petroleum fiscal regime are required. These data were collected through four channels. As follows:

1. The Brown Book, which contains annual statistical data related to individual fields, and gross figures related to the UKCS.
2. The North Sea Field Development Guide, which includes data relating to individual North Sea oil fields, and gives a brief explanation of each field's development conditions and plans.
3. The Wood Mackenzie database, Global Economic Model (2004) Version 3.01. This database contains data presented on a field-by-field basis and also on a company-by-company basis. The model allows the application of different fiscal terms to fields and companies. This application will be used for calculating the Governmental and industrial take from each field according to different fiscal and price scenarios. Also the model allows defining the IRR for each project using different fiscal and price scenarios.

In justifying the use of the Wood Mackenzie's database as a main source for data, I can refer to Easterby-Smith et al. (1991, p. 116):

> "We distinguish four main ways of gathering quantitative data: interviews, questionnaires, tests/measures, and observation.

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[61] See footnote 54 on page 144.

Information can also be gathered from archives and databanks".

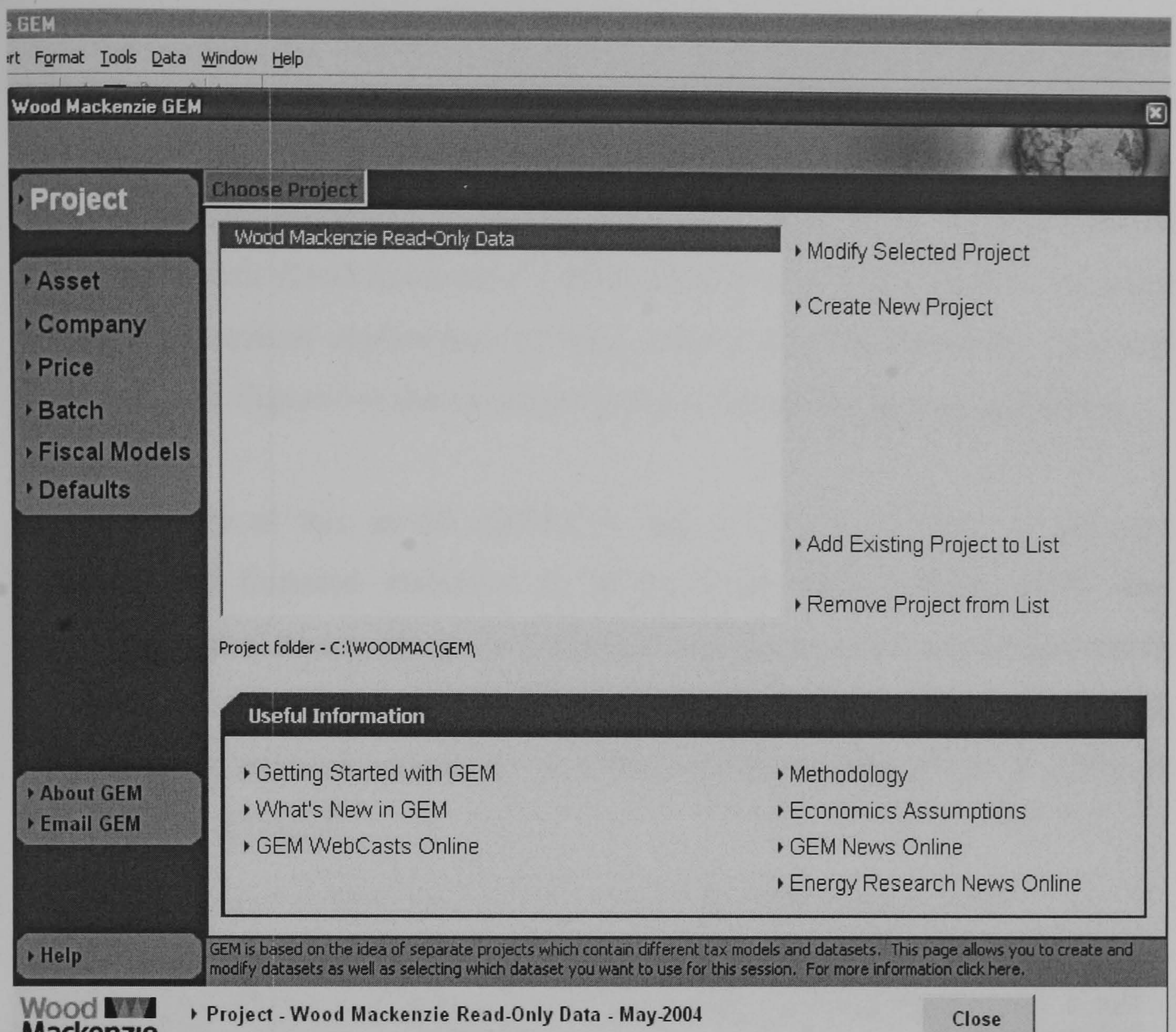
4. The web sites of the DTI and the Inland Revenue, which have different types of data and statistics. Information on these web sites will be used as a major source in testing the rationales for the UK petroleum tax relaxations.

The above sections describe the data sources being used in this research for the purpose of collecting the rationales and testing them. The Wood Mackenzie Global Economic Model (GEM) 2004, version 3.01 is a major source of data and an essential tool for this research. This model will be used to obtain a field-by-field and a company-by-company data, and also in applying the tests. The next section describes the GEM and its assumptions in some detail.

5.8.4 Describing the Global Economic Model (GEM)

The Global Economic Model (GEM) is an Excel - based economics and financial evaluation tool for the upstream oil and gas industry (Wood Mackenzie, 2004). The GEM software offers a variety of options and functions. For example, the main page of this model provides the following: (1) getting started with GEM; (2) what is new in GEM; (3) GEM Web Casts Online. This function is a very useful as it provides instructions for using the GEM for different purposes, for example, working with different projects, creating a global price series, defining defaults, creating a new price scenario, creating a batch, running an asset calculation, running a field in a different fiscal regimes, and running a company calculation; (4) methodology; (5) economic assumptions; (6) GEM news online; and (7) energy research news. Figure 5-5 shows the main page of the GEM (v. 3.01) software.

Figure 5-5: Main Page of Wood Mackenzie GEM (2004, v. 3.01).



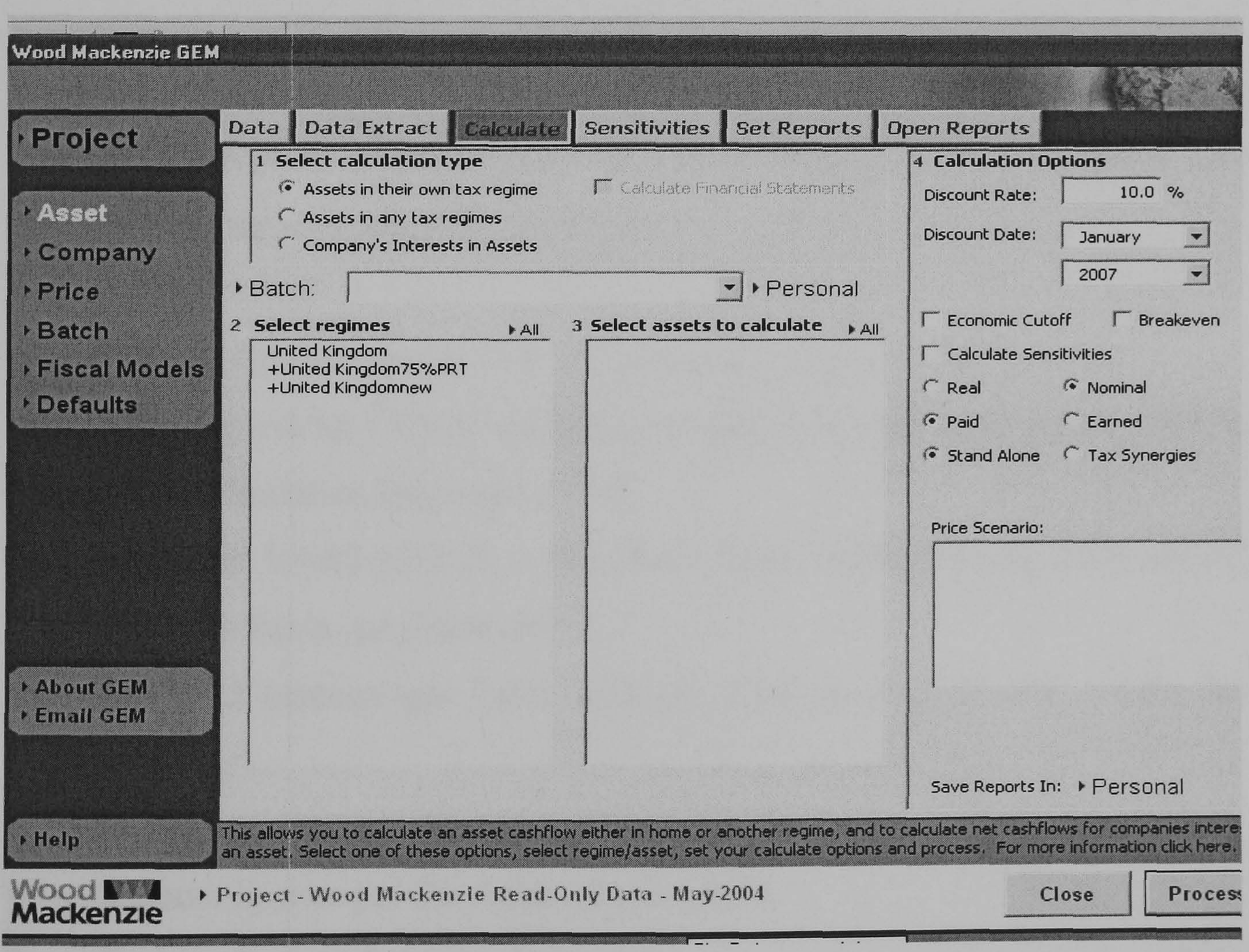
Source: Wood Mackenzie (2004)

The above figure shows on the top left hand side the modes which describe the type of data that can be used regarding assets (fields), company, price, batch, fiscal models and defaults. Within each mode there is a number of functions that can be chosen which define the exact task that can be performed with the selected data. The asset mode allows running fields' calculations and sensitivities for these assets. The asset files contains data regarding each fields in the UKCS, these fields can be traced according to six batches. These batches are: 1) central North Sea, 2) northern North Sea, 3) UK onshore, 4) probable development, 5) Southern Gas Basin, and 6) West of Britain. Each of these asset files includes data regarding production, cost, and fiscal assumptions as well as a link to price files. The company mode allows running companies' calculations. Company files contain financial assumptions which facilitate the production of financial statements. The price mode allows fields' and companies' calculations to be run

with different price scenarios. Price files contain the main economic assumptions for Brent oil prices, exchange rates, inflation rates and interest rates. With regard to inflation, a 2.5 per cent per annum rate is used as a default inflation rate, a 10 per cent rate as a default discount rate. The date chosen for discount in the GEM (v. 3.01) for this research is 1st January 2004. The fiscal model mode allows the user to work with Wood Mackenzie's models and also to create his/her own fiscal models (for practical applications of these calculations see Appendix Two, and Appendix 5-3). Figure 5-6 shows the main page of the asset files in the GEM.

One advantage of this model (GEM) is that it allows a variety of different economic and financial indicators to be produced when running fields' and companies' calculations. These are: detailed cash flows and financial statements for fields and companies, company post- and pre-tax IRR, NPV at different discount rates, payback period for projects, and break-even points at different scenarios and options.[62]

Figure 5-6: Main Page of Asset Files in the GEM (2004, v. 3.01)



[62] For break-even definition see footnote 18. In the GEM, the break-even option allows the user to calculate the oil/gas price at which the remaining present value of a chosen field will be equal to zero at a selected discount rate and date (Wood Mackenzie, 2004).

The assumptions made in this research are consistent with the above assumptions. Because this research tackles oil and gas activities within the UKCS, the Brent price is a suitable price to be used for tests and calculations. Also a 2.5 per cent inflation rate and a 10 per cent real discount rate are to be adopted for this research. The use of a discount rate of around 10 per cent is now generally agreed to be the best, at least, as far as the UK oil industry is concerned (Rutledge and Wright, 1998a, p. 11; Kemp and Stephens, 1996, p. 64). Wood Mackenzie (2004) sets exchange rates based on different currencies, and what is important for this research is the exchange rate between the pound sterling and the US dollar, which is also available in the GEM (v. 3.01). This exchange rate assumption is to be adopted for this research. This is because different parameters such as revenues, expenses, and cash flow, are expressed in pounds sterling in the GEM, whilst the international accepted currency for pricing crude oil is the US dollar.

In terms of the UK fiscal regime, the GEM is based on nine tax regimes' assumptions, which appear in the model under the title 'Tax Marker'. Each of these assumptions represents a measure for a specific petroleum tax package that was or is applied in a certain batch of the UKCS or during certain times. These assumptions (tax packages) are as follows:

1. Offshore-licence rounds 1- 4 (fields paying royalties, PRT and CT).
2. Annex B 1/4/82-15/3/93 excluding Southern Basin (fields paying PRT and CT; not Southern Basin gas fields).
3. Annex B 1/4/82-15/3/93 – Southern Basin (fields paying PRT and CT; Southern Basin gas fields only).
4. Pre–1975 contract gas fields (old gas fields paying CT but exempt from PRT).
5. Onshore licence pre-76-Annex B post 1/4/82.
6. Onshore licence pre-76-Annex B pre 1/4/82.
7. Onshore licence between 1976 and 1982, (onshore fields paying royalties, PRT and CT).
8. Onshore licence post- 82-Annex B pre 15/3/93 (onshore fields paying PRT and CT).

9. Annex B post 15/3/93 (fields paying CT only).

A separate Excel fiscal model has been produced for each of the above regimes in the GEM. With regard to field files, the model allows calculations of each field parameter according to different scenarios and options, e.g., real and nominal. It also allows the output to be controlled, in term of the currency and production units measure, e.g., barrel/day or tonnes/year. Furthermore, the GEM allows the required reports to be calculated, such as summary cash flow, present value (PV) tables, expanded cash flow, pre-tax cash flow, annual Government cash flow, standard cash flow, PRT calculation reports, and corporation tax calculation reports. In addition, the model offers the creation of standard charts with regard to total production, capital costs, net cash flow and other factors.

An important function of the GEM for this research is that it allows different fiscal and price scenarios to be applied to oil fields, which, in turn allows testing the rationales. This can be applied by comparing figures arising from applying pre- and post-tax relaxation regimes on fields developed after any of the tax relaxations. In other words, the model allows field calculations to be run against different fiscal and price assumptions that already exist in the GEM, and this process allows figures resulting from these applications to be included. [63] As one of the main objectives of this research is testing rationales, rather than to build models, it seems sensible to rely on Wood Mackenzie's long experience with what is viewed by the industry as a reputable model. Besides being a very well known model in the upstream oil and gas industry, the GEM has also been widely used by researchers in the area of oil and gas related research such as Kemp and Crichton, 1979; Martin, 1997; and Nakhle, 2004. Further, it contains rich data with regard to the upstream oil and gas industry, which is not usually available from other sources such as the oil industry or the Governmental bodies because of its confidential nature. Therefore, it seems to be a very suitable tool to be used in this research.

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[63] For more information about the GEM technique see Appendix 5-1.

5.9 Methodology of Testing the Rationales

Testing the rationales for the UK petroleum tax relaxations will be carried out by taking the rationales for each tax relaxation, and finding out whether each of them was/wan not/ or was partly met by the policy. In other words, this will be achieved by looking at the rationale itself as an aim behind a petroleum tax relaxation, and testing whether these aims have been met. Each rationale *ex-ante* and *ex-post* the tax relaxation will be tested as appropriate. As was shown in the previous chapter each tax relaxation has different rationales. These rationales are sometimes similar to one another. For example, for each petroleum tax relaxation there was an aim of encouraging oil and gas activities in the UKCS. Testing these rationales will be applied by using similar methodologies. These methodologies will use measures suggested in the literature, for example, the quantitative representatives of exploration, development and appraisal activities (see section 5.5). Where there are no insights given by academic or other literature into a methodology for testing a certain rationale, a methodology will be created specifically.

The next three chapters will tackle testing the UK petroleum tax relaxation rationales. Each chapter will focus on testing the rationales for one petroleum tax relaxation. Methodologies for testing each rationale will be described in detail first before applying the test. The reason for postponing describing the methodologies for testing the rationales to the next three chapters is that because in total there are twenty-two rationales for the three tax relaxations. These are: ten rationales for the 1983 petroleum tax relaxation, six for the 1987-88 petroleum tax relaxation and five for the 1993 petroleum tax relaxation. Describing the methodology of testing each rationale individually in this chapter will make it difficult for the reader when moving into the practical application of testing these rationales in the further chapters. Therefore, and to make a stronger link between the methodologies and the tests, I will present the methodologies for testing each rationale individually in the next three chapters.

5.10 Summary

Oil and gas investment is carried out as a cycle that has fixed sequence of stages, starting with exploration. Each stage represents a clear investment, and the investment decision in each stage is based on a variety of different factors, such as geological, economic and political. The development stage is the most important one for oil and gas companies as it requires the highest volume of finance and is also considered an essential stage coming before the production stage where revenues are generated.

This research is exploratory in nature. It uses historical data extracted from a variety of sources. It follows a mixed methodology, as data collected concerning rationales is of a qualitative nature, while quantitative data was collected for testing these rationales. In other words, triangulation is being used regarding data collection process and research strategy. Rationales for the UK petroleum tax relaxations are classified on the basis of the division of tax relaxation packages, and each rationale will be tested individually to see if the policies underpinning the petroleum tax relaxations were achieved.

The next chapter presents the individual methodologies, tests and results of the rationales for the 1983 petroleum tax relaxation. Chapter seven presents the methodologies, tests and results of the rationales for the 1987-88 petroleum tax relaxation, and chapter eight presents the methodologies, tests and results of the 1993 petroleum tax relaxation rationales.

CHAPTER 6: TESTING THE RATIONALES FOR THE1983 UK PETROLEUM TAX RELAXATION

6.1 Introduction

In order to test the rationales for the 1983 petroleum tax relaxation, fields that obtained development consents between April 1982 and 1987 are to be investigated.[64] The reason for choosing this period is because fields developed before April 1982 were not affected by the 1983 petroleum tax relaxation. Choosing 1987 as an end date allows the rationales for the second petroleum tax relaxation to be tested separately, and at the same time allows the 1983 petroleum tax relaxation rationales to be tested without interference from the 1987-88 petroleum tax relaxation.

In performing tests for the 1983 petroleum tax relaxation rationales, first of all, the population of fields that could have benefited from this tax relaxation should be identified. Fields that were initially developed because of the 1983 petroleum tax relaxation, or 'benefiting fields', are to be defined based on an IRR criterion. After this the chapter will show the rationale tests. Here each rationale will be tested individually using data extracted from the second set of data sources which was explained in chapter five (section 5.8.3, page164). A general conclusion will be drawn concerning the rationales, deciding if they have been justified or not in relation to the 1983 petroleum tax relaxation, and hence if the UK policy of using tax relaxations in stimulating oil and gas investments was successful in this case.

In defining fields where the 1983 petroleum tax relaxation was a main reason for their development, the IRR criteria of investment appraisal methods is used in this research. The IRR is the discount rate that results in the net present value of an investment decision being zero. This method takes into account the time value of money. This makes it a reasonable method for making investment appraisal decisions that is well recognised in the world of financial management (Drury, 2001, p. 249), as discussed in chapter five (section 5.7.1).

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[64] The rationales for the 1983 petroleum tax relaxation are presented in Table 4-1 on page 127.

The next section defines the fields that could have benefited from the 1983 petroleum tax relaxation.

6.2 Fields which Benefited from the 1983 Petroleum Tax Relaxation

In defining fields which were targeted by the 1983 petroleum tax relaxation, or 'new fields', the 1983 Finance Act stated:

"Subject to subsection (3) below, in this section "relevant new field" means an oil field—

(a) no part of which lies in a landward area, within the meaning of the Petroleum (Production) Regulations 1982 or in an area to the East of the United Kingdom and between latitudes 52° and 55° North; and

(b) for no part of which consent for development has been granted to the licensee by the Secretary of State before 1st April 1982; and

(c) for no part of which a programme of development had been served on the licensee or approved by the Secretary of State before that date.". (Great Britain, 1983a, S. 36, p. 200)

From the above definition it can be seen that fields which were targeted by this tax relaxation include only offshore oil fields that are mainly located in the central and northern North Sea and which did not obtain development consents before 1st April 1982.

Based on the above and for the purpose of testing the 1983 petroleum tax relaxation rationales, the benefiting oil fields that obtained development consents during the period April 1982 - 1987 were extracted from the DTI website publication (DTI, 2004d). The list of these fields consists of 14 offshore oil fields, ten of which are located in the central North Sea. These are: Clyde, Duncan, Highlander, Balmoral, Innes, Cyrus, Scapa, Ivanhoe, Rob Roy and Petronella. The other four are located in the northern North Sea, these are: North Alwyn, Deveron, Tern and Eider. Table 6-1 presents data in relation to the above-mentioned fields including discovery dates, and the date when Annex B approval was obtained, and other information shown on the table.

Table 6-1: Data in Respect of Oil Fields Developed Between April 1982 and 1987.

Field Location	Field Name	Discovery Date	Annex B Approval	Production Start Up	Operator at Approval Time	Reserves	
						Oil (mmb)	Gas (bcf)
Central North Sea	Clyde	Jun-78	Dec-82	Mar-87	Britoil	154	40
	Duncan	Dec-80	Sep-83	Nov-83	Hamilton	19	0
	Higlander	Apr-76	Nov-83	Feb-85	Texaco	48	0
	Balmoral	Jul-75	Dec-83	Nov-86	Sun Oil	100	0
	Innes	Apr-83	Nov-84	Jan-85	Hamilton	6	0
	Cyrus	Oct-79	Nov-84	Dec-89	BP	20	0
	Scapa	Jul-75	Sep-85	Sep-85	Occidental	116	0
	Ivanhoe	Oct-75	Jan-86	Jul-89	AmeradaHess	175	45
	RobRoy	May-84					
	Petronella	Feb-75	Apr-86	Nov-86	Texaco	35	20
Northern North Sea	N Alwyn	Oct-75	Oct-82	Nov-87	Total	219	1,235
	Deveron	Sep-72	Sep-84	Sep-84	Britoil	18	2
	Tern	May-75	Feb-85	Apr-89	Shell	300	40
	Eider	May-76	Oct-85	Nov-88	Shell	110	17
Source: Oilfield Publications Limited (OPL). 2004.							

Source: data presented in the above table were obtained from OPL (2004), but data regarding Annex B approval dates and operators at the approval time was obtained from the DTI (2004d). [65] Note: sometimes there are contradictions between the OPL and the DTI. The latest update of the DTI website, at the time of writing this thesis, was 3rd November 2004, and the DTI is the Governmental body that grants Annex B approval to oil companies, therefore their data concerning approvals was considered in building up the above table. In the above table mmb stands for million barrels and bcf stands for billion cubic feet.

6.3 Impact on Project Economics

In order to perform the test for the rationales of the 1983 petroleum tax relaxation, it is essential to define the effect of the tax relaxation on various fields, and after that categorise these fields into different groups according to the effects:

Group one: those in which development would have gone ahead without stimulation from the 1983 petroleum tax relaxation (non-benefiting fields).

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[65] For a definition of Annex B approval see section 5.4.2 on page140.

Group two: those in which the tax relaxation seems to be a main reason for their developments (benefiting fields).

In performing the above task, the IRR criteria will be employed here by using the GEM of Wood Mackenzie (2004, v. 3.01). In this regard, it is important here to mention that in examining the outcome, the *ex-post* analysis is to be applied. In other words, the GEM in this case will make use of the *ex-post* data, i.e., actual prices, actual production, and costs. Also an *ex-ante* analysis is to be performed in an effort to shed light on the probable economic environment at the time of making development decisions.

6.3.1 The *Ex-Post* Analysis

This section will show the impact of the 1983 petroleum tax relaxation on project economics. This impact will be shown by studying the increase, if any, in the post-tax IRR calculated according to the post-1983 Budget petroleum tax system in comparison with the post-tax IRR calculated according to the pre-1983 petroleum tax regime for fields developed during the period 1982-1987. The investigation is done by applying the pre-1983 Budget petroleum tax regime to oil fields which were developed between April 1982 and 1987. This application uses the tax regime that was defined as 'offshore licence rounds 1-4' in the 'Tax Marker' option of the GEM, at a 10 per cent real discount rate. The results show material improvement between the post-tax IRR according to the pre- and post-1983 Budget tax system of those fields. These results are presented in Table 6-2 below.

Table 6-2: IRR of Offshore Oil Fields Developed Between April 1982 and 1987.

Category	Field Name	Development Consent Date	IRR %				Total Reserve (mmboe)
			Post-1983 Budget		Pre-1983 Budget		
			Post-Tax	Pre-Tax	Post-Tax	Pre-Tax	
IRR Less Than 15 %	Alwyn North	Oct-82	10.32	13.4	9.96	13.4	677.7
	Clyde	Dec-82	6.26	8.19	6.08	8.19	153.8
	Cyrus	Nov-84	#	1.38	#	1.38	26.9
	Balmoral	Dec-83	8.74	10.75	8.48	10.75	113.6
IRR Improved to be More Than 15 %	Innes	Nov-84	20.57	25.43	13.67	25.43	6.2
	Duncan	Sep-83	15.96	26.96	2.57	26.96	18.1
IRR More Than 15 %	Petronella	Apr-86	108.23	120.25	86.44	120.25	48.4
	RobRoy	Jan-86	23.38	30.58	20.1	30.58	123.2
	Ivanhoe	Jan-86	29.05	34.86	22.75	34.86	80
	Eider	Oct-85	16.79	21.54	15.88	21.57	111
	Scapa	Sep-85	45.98	51.98	36.81	51.98	127
	Tern	Feb-85	16.13	21.58	15.21	21.58	288
	Deveron	Sep-84	171.52	190.11	146.31	190.1	17.1
	Highlander	Nov-83	162.48	183.95	118.57	183.95	79.7

Source: development consent dates were obtained from the DTI (2004d), and total reserve volumes were obtained from OPL (2004). Note: The equivalent reserves volumes were calculated by using conversion factors obtained from the DTI (1994, p. vi), and the IRR figures were obtained from Wood Mackenzie (2004) as results of applying the GEM (v. 3.01) on the above fields. In the above table '#' refers to undefined IRR, mmboe stands for million barrels of oil equivalent.

The test shows that the post-1983 Budget tax system increased the IRR to over 15 per cent for the Innes and Duncan oil fields. Under the pre-1983 Budget system the IRR would have been less than this percentage. Furthermore, the test shows that although the post-Budget regime improved the IRR for a number of fields, their IRR was still less than 15 per cent, as was the case for Alwyn North, Clyde, Cyrus and Balmoral. In this regard it can be seen from Table 6-2 above that although Balmoral, which obtained its development consent in December 1983, would have a post-tax IRR of 8.4 per cent under the pre-1983 Budget system, it went up only very slightly to 8.7 per cent according to the post-Budget system. It is safe to assume from this observation of Balmoral's IRR that development of this field would have gone ahead despite the 1983 petroleum tax relaxation; it also indicates that companies were willing to contemplate investments substantially

below the 15 per cent threshold. The same can be said about Alwyn North, Clyde, and, in particular, Cyrus, which has undefined post-tax IRR under both the post- and pre-1983 petroleum tax regime.[66] In other words, developments of these fields have occurred despite their low IRR for reasons other than the 1983 petroleum tax relaxation. On the other hand, there are a number of fields where, although the post-Budget regime increased their IRR, this would have already been high under the pre-1983 Budget system. This can be seen from the following examples. Petronella has an IRR of 108.2 per cent, while under a pre-1983 Budget regime the IRR would have been 86.4 per cent; Deveron which has a post-Budget IRR of 171.5 per cent (pre-Budget 146.3 per cent); and Highlander which has a post-1983 Budget IRR of 162.4 per cent (pre-Budget 118.5 per cent). It can be safely said that developments of the latter three fields would have gone ahead despite effects from the 1983 tax relaxation because of their high returns. Based on the above, and according to the IRR criteria, the offshore oil fields developed between 1982 and 1987 can be put into three categories:

1. Fields where the post-1983 Budget tax regime materially increased their post-tax IRR from less than 15 per cent to more than 15 per cent.
2. Fields where the post-tax IRR would have been less than 15 per cent under the pre-1983 Budget and would remain less than 15 per cent according to the post-1983 petroleum tax regime.
3. Fields where the post-tax IRR is higher than 15 per cent according to the post-1983 petroleum tax system, and would have still been more than 15 per cent under the pre-1983 Budget petroleum tax regime.

This categorisation is reflected in Table 6-2 above. However, based on the above divisions and as mentioned earlier in this section, I can classify the above fields as benefiting and non-benefiting fields into two groups, as follows.[67]

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[66] Running the calculations for this field under the pre- and post-1983 petroleum tax regimes gives undefined post-tax IRR of this field. This is mainly because the results shows that the remaining reserves life of this field at time of calculations as 2.5 years, while the payback period is 69.5 years (Wood Mackenzie, 2004). This means that Cyrus would not payback, and consequently its operations will result in a loss.

[67] All of the fields targeted by the 1983 petroleum tax relaxation were benefited in the form of a tax reduction. However, I am using the expression "benefiting fields" to refer only to those fields which the tax relaxation increased their IRR from less to more than 15 per cent.

Group One: non benefiting fields - these include fields that would have an IRR higher than 15 per cent according to the pre- and post-1983 petroleum tax systems or would have an IRR less than 15 per cent under the pre- and post-1983 petroleum fiscal regimes while the 1983 relaxation contributed by less than one per cent into their IRR.

Group two: benefiting fields - these include fields that would have an IRR less than 15 per cent according to the pre-1983 petroleum tax system and the 1983 tax relaxation increased this IRR, by more than one per cent, to 15 per cent or higher.

From the above discussion, it can be said that the 15 per cent IRR is not a fixed target for oil companies to use when making development decisions, as was suggested by Martin (1997). There are several other considerations (which were mentioned in the previous Methods and Methodology chapter) which oil companies take into account when making development decisions. In this regard Nakhle (2004, p. 46) states:

> "In fact, problems result from the determination of the threshold at which RRT should be levied. The threshold presents the rate of return that investors require to undertaking 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".

At this stage it can be stated again that the 15 per cent IRR is not a clear-cut criterion for making development decisions. The material increase of the IRR because of the 1983 petroleum tax relaxation over the pre-1983 Budget petroleum tax system does play a pivotal role in some cases in making development decisions. This increase in the IRR represents the economic improvement in these fields, for example Innes and Duncan in this case. In this regard it is still reasonable to point out that improved technology as well as strategic considerations, which also involve financial consideration, production and marketing factors, play an essential role in making investment decisions regardless of the results of the investment appraisal methods (Jones and Lee,

1998). This argument is true as can be seen from the above analysis which shows that in a number of fields the IRR was less than 15 per cent and Annex B Approval for development was still obtained; for example, Alwyn North (10.3 per cent), Clyde (6.2 per cent), Cyrus (#), and Balmoral (8.4 per cent). The next sections explain the individual cases of the above four fields plus Duncan and Innes in order to suggest possible reasons and incentives for developing these fields, other than the 1983 petroleum tax relaxation.

Alwyn North

This field is operated by the Total Oil Company and was developed with two bridge-linked platforms, "NAA" and "NAB". Both oil and gas are produced from this field. Alwyn North is linked to Ninian central platform for the purpose of delivering the produced oil to the Sullom Voe oil terminal in Shetland, while gas is being piped to the Frigg TPI platform, which is operated by the Total Oil Company (OPL, 2004, p. 438). The design of the Alwyn North of two platforms has the advantage of safety, and it also allowed the installation of the NAA platform and drilling operations from this platform a year before the NAB (Alwyn North, 15/11/2004). The Total Oil Company has massive interests in the area of Alwyn North (geological area number 3 on the UKCS map) represented by the many fields being operated by this company such as Dunbar, Dunbar South, Ellon, Grant and Nuggets beside Alwyn North. The Total Oil Company discovered Alwyn North in 1975, and obtained Annex B Approval for this field in October 1982. In 1980 the company discovered an oil field close to Alwyn North, and the new field, which is called Alwyn North Extension, had a reserve volume of 22 mmbbl (million barrels) oil and 160 bcf (billion cubic feet) gas.

Although the post-tax IRR of Alwyn North is 10.3 per cent, the Total Oil Company had its own interests and incentives for developing this field. These interests are represented by the discovery of the Alwyn North Extension field in 1980 and also in the licensing area of Alwyn North itself. This licensing area contains the other above-named fields which are operated by the Total Oil Company. This interest is reflected by using the infrastructure that was built up for Alwyn North as a base for other fields' developments, for example, Dunbar oil

field which was discovered by the Total Oil Company in 1972, where Annex B Approval was obtained in November 1992. Although Dunbar is a smaller field than Alwyn North in term of reserves volume (119 mmbbl oil and 14 bcm gas) the IRR is 20 per cent. However, in spite of Dunbar being a marginal field, the development of this oil field was made viable by its proximity to Alwyn North (OPL, 1998, p. 441). To sum up, the incentive for developing Alwyn North seems to be the creation of the necessary infrastructure that was needed for developing other fields being operated by the Total Oil Company in the same geological location of Alwyn North, rather than solely the 1983 petroleum tax relaxation.

Clyde

This oil and gas field uses a single steel platform with oil and gas being produced from this field being transferred to Fulmar. As was mentioned earlier in this chapter, Clyde was developed in spite of its lower post-tax IRR (6.2 per cent). However, another three small oil fields namely, Orion, Medwin and Leven, which were discovered in 1975, 1979 and 1983 respectively, were developed by drilling from the Clyde platform (OPL, 1998, p. 89; 2004, p. 431). Using the GEM (v. 3.01) shows that these three fields have post-tax IRR of 40.4 per cent, # and 171.6 per cent respectively.

Based on the above, it can be said that Orion, Medwin and Leven benefited from the Clyde platform and also from improved technology in their developments. This means while Clyde had to bear a high capital cost because of the necessary steel platform, Orion, Medwin and Leven did not. By putting all the four fields together, although individually they are just small fields, an incentive for the operating company was created to develop them one by one. The benefit of the post-1983 petroleum tax system to Clyde was limited, reflected in the very slight increase in the post tax IRR from the pre- to post-1983 Budget system which is just a 0.18 percentage points (6.26 per cent – 6.08 per cent).

Cyrus

Cyrus, a small oil field with a reserve volume of 28.5 mmbbl, was discovered in 1979 and obtained Annex B Approval in November 1984. Cyrus was considered

the first BP's field to use the SWOPS vessel system of production, which was considered flexible as it could be transferred to another field. BP mainly introduced this system for production from marginal fields.

The field is also connected to another field, which is called Andrew oil field, for the purpose of production continuation (OPL, 2004, p. 239). From this information, it can be said that the improved technology, which uses the SWOPS system that reduced capital costs for fields using it, is the main driven behind developing Cyrus. This statement is based on the post- tax IRR of this field which is undefined according to both pre- and post-1983 Budget petroleum tax regimes (see Table 6-2). In other words, without the new technology, Cyrus might not have been developed as its IRR is undefined, which makes it not commercial.

Balmoral

This field was discovered in 1980 and obtained Annex B Approval in December 1983. Like Cyrus, the development of Balmoral incorporated the first use of a Floating Production Vessel (FPV). The field has 13 production wells, and is connected to the Glamis oil field, which lies seven kilometres from Balmoral (OPL, 2004, p. 204; 1998, p. 391).

The 1983 petroleum tax relaxation contributed slightly to the improvement of commerciality in this field. The increase in the post-tax IRR is only 0.26 percentage points up from the pre- to post-1983 petroleum tax system (8.74 per cent – 8.48 per cent). Therefore it can be pointed out here that the improved technology, based on the above mentioned FPV system of production, was a major reason for developing this field, rather the 1983 petroleum tax relaxation.

Duncan

This oil field consisted of two fields, which were Duncan and East Duncan. This field was developed as a satellite of the Argyll oil field, which was the first field to produce oil in the British sector of the North Sea in 1975. Duncan was connected to Argyll through a main flow line. Production from Duncan was achieved only two months after Annex B Approval was granted to the field. The

connection to Argyll and the use of the latter facilities, plus the 1983 petroleum tax relaxation, reduced the investments costs of Duncan. Furthermore, it made it commercial to be developed and drilled (OPL, 1998, p. 62). In this regard, the 1983 petroleum tax relaxation contributed towards the increase in the post-tax IRR in this field by 13.4 percentage points. Using the GEM (v. 3.01) shows that the IRR of this field would have been 2.5 per cent under the pre-1983 Budget petroleum tax regime, and it improved to 15.9 per cent based on the post-1983 petroleum tax regime (see Table 6-2). This is one case where the 1983 petroleum tax relaxation was a reason for increasing the IRR of an oil field from less to more than 15 per cent. Furthermore, the total cash flow from Duncan was £54 million, while it would have been £24.1 million under the pre-1983 petroleum tax regime.

This shows that the 1983 petroleum tax relaxation materially affected the commerciality of this field. This can be seen from the increase in the IRR and the field's cash flow under the post-1983 Budget over the pre-1983 petroleum tax system. This conclusion can be used to state that Duncan might not have been developed without the 1983 petroleum tax relaxation.

Innes

Within the North Sea this field was the smallest oil field to be explored and developed. Innes is located in the same block as the Argyll and Duncan oil fields. Innes was originally developed with a unique triple riser system installed on sub-sea wells and tied to the TW58 production facility of the Argyll field. Like Duncan, the use of Argyll facilities and the 1983 petroleum tax relaxation made this small oil field viable for commercial exploitation. In this context it is appropriate to mention that the 1983 petroleum tax relaxation did increase the post-tax IRR of Innes by 6.9 percentage points. The IRR would have been 13.6 per cent under the pre-1983 Budget. However, it improved to 20.5 per cent using the post-1983 petroleum tax regime. All the three fields Argyll, Duncan and Innes, were shut down in 1992 (OPL, 1998, p. 63).

Summary

These fields that were developed between April 1982 and 1987 were divided into two groups, as was mentioned in section 6.3 above. These are benefiting fields, and non-benefiting fields, from the 1983 petroleum tax relaxation.[68] The criteria which are used in this context is as follows: group one includes fields that have a post-tax IRR more than 15 per cent under the pre- and post-1983 Budget fiscal regime; or less than 15 per cent under the pre-1983 fiscal regime, but the increase in these fields' post-tax IRR is less than one percentage point as a consequence of the 1983 relaxation. The rest of the fields are classified in group two (fields which had benefited from the relaxation).

Based on the above-explained criteria, fields can be classified as follows:

Group one: Petronella, Rob Roy, Ivanhoe, Eider, Scapa, Tern, Deveron, Highlander, Clyde, Alwyn North, Cyrus and Balmoral.

Group Two: Innes and Duncan.

The above tests and fields' classification are based on *ex-post* data available from the GEM (v. 3.01), which is being updated frequently. The situation might have been different with regard to the commerciality of these fields based on assumed data at the time of planning projects, especially for oil prices which play an essential role in deciding whether projects are commercial or not. Therefore, running the test by using prices forecast at the time of developing the above fields seems to be ideal for estimating about the circumstances that surrounded development decisions of these fields. This will be the issue of the next section.

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[68] In practice, all the offshore oil fields that obtained development consents between 1982 and 1987 have benefited from the 1983 petroleum tax relaxation in the form of reduced tax liabilities. However, I mean by a benefiting field, in this context, any offshore oil field where the 1983 petroleum tax relaxation was a main reason for its development.

6.3.2 The *Ex-Ante* Analysis

In applying the *ex-ante* analysis on fields that obtained Annex B approval between 1982 and 1987, a number of possibilities and oil price scenarios may be examined, for example:

a. Using the Security and Exchange Committee (SEC) year-end prices as disclosed from 10-K reserves valuation for the purpose of the annual reserves valuation. [69] Specifically this would involve raising the year-end price for the year in which development consent was obtained. The problem with this method is that while it does reflect the price environment at the time the decision was made, it projects this environment unchangingly and unrealistically into the future. However, this is more or less what oil companies do in considering future prices: they use fixed price projections and only change this price assumptions at infrequent intervals when it is clear that the market is generating new long-term expectations.

b. Using a base actual oil and gas price and assuming a steady yearly increase in this price. This might give an idea regarding the situations which surrounded investment decisions made by oil and gas companies at the time. A limitation in this assumption which prevents running this test, is that oil companies might have used self-estimated future prices at the time of planning for projects. Taking a fixed oil price and accounting for the inflation means the forecast oil price will be constant over time, while the historical real oil price shows that it would fluctuate (Lerche, 1999). Oil price is not the only factor being used in preparing cash flows and calculating IRR. There are several other factors which should be taken into account, such as exchange rates, interest rates, and depletion level. In addition, there are supply and demand matters affecting price, and technology issues affecting costs (Eden et al., 1981).

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[69] SEC is the US government agency responsible for administration of federal securities laws (Van Horne and Wachowicz, 2005, p. 688).

From the above argument it can be said that performing the test based on an assumed price should be accompanied by assumed costs, production, exchange rates, inflation rates and technology improvement expectations that individual companies might take into account when making investment decisions. Any test based on a lack of data is unrealistic, because these forecasts are not publicly disclosed and even if it is possible to obtain a number of them, it might not be possible to obtain them all. However, it is still worth doing this test. This can be performed based on internationally published oil and gas prices which might have been used by oil companies when making their investment decisions.

In applying the above-mentioned test, oil price forecasts for the period 1982-95 were obtained from the EIA (1983, Table: ESI, p. xi11). These were based on the 1983 US dollar per barrel of oil, while prices for the period 1996-2000 were held constant at the level of 1995 price ($50). The reason for this action is that forecast oil prices are not available for the whole period (1983-2000). These prices are used in the GEM (v. 3.01) with its complete set of data regarding costs, production and any other assumptions. Table 6-3 shows the actual (the *ex-post*) and the EIA (the *ex-ante*) oil prices over the period 1983-2000.

Table 6-3: Actual and EIA Predicted Oil Prices Over the Period 1983-2000.

Year	Actual Prices £	EIA Predicted Prices £	Year	Actual Prices £	EIA Predicted Prices £
1983	19.79	18.7	1992	10.48	23.46
1984	22.3	19.71	1993	22.69	29.8
1985	21.64	22.68	1994	10.39	32
1986	10.27	17.68	1995	10.9	31.45
1987	11.2	16.98	1996	13.3	31.45
1988	8.3	17.03	1997	11.82	31.45
1989	11.1	20.23	1998	7.92	31.45
1990	13.16	22.15	1999	11.21	31.45
1991	11.37	21.54	2000	19.14	31.45

Source: actual prices were obtained from Wood Mackenzie (2004), while predicted prices were obtained from EIA (1983, p. xi11).

Calculating the IRR for the above mentioned 14 fields using the forecast oil prices gives significant results. These results are shown in Table 6-4.

Table 6-4: IRR of Offshore Oil Fields Developed Between April 1982 and 1987 Based on Oil Prices Forecast by EIA.

Field Name	IRR %			
	Post-1983 Budget		Pre-1983 Budget	
	post-tax	pre-tax	post-tax	pre-tax
Alwyn North	18.83	25.21	17.78	25.21
Clyde	24.63	29.35	21.71	29.35
Duncan	29.28	38.24	18.01	38.24
Highlander	162.48	183.95	118.57	183.95
Balmoral	27.04	32.2	23.51	32.2
Deveron	172.3	187.72	150.88	187.72
Innes	54	62.2	43.7	62.2
Cyrus	9.78	11.99	8.82	11.99
Tern	31.6	41.72	28.78	41.72
Scapa	46.28	52.21	37.21	52.21
Eider	40.5	50.36	33.45	50.36
Ivanhoe	59.65	67.45	46.61	67.45
Rob Roy	49.39	61.04	40.3	61.04
Petronella	108.23	120.26	86.44	120.26

From the above table it can be seen that all of the fields, apart from Cyrus, have a post-tax IRR of more than 15 per cent. Based on the EIA predicted oil prices, these fields, with the exception of Cyrus, would be considered as commercial, according to the 15 per cent IRR criterion. One more thing to be seen from the above table is that the fields' IRRs were increased when applying the post-1983 Budget regulations in comparison with the pre-1983 petroleum tax regime. The commerciality of the above fields that is expressed in the IRR arises as a result of applying the above forecast oil prices, which are different from the actual prices.

However, as was mentioned before in this chapter, there are several limitations to this test arising from using the EIA *pre,* or 'forecast', oil prices and the GEM (v. 3.01) *post*, or 'actual', costs together in one test. However, this combination of data is an *ex-post* data. There was no possibility of obtaining the forecast costs for this research, as they are company specific. Oil companies when making their investment decisions might not use even the prices predicted by the EIA. Therefore, and to keep using the same sets of data, the researcher has restricted

himself to the data available from the Wood Mackenzie's GEM (2004, v. 3.01), because the main objective of this research is to test the rationales based on the *ex-post* position.

After classifying oil fields into two groups based on the above-mentioned criteria, and performing the *ex-post* and the *ex-ante* analysis, which together form a basis for testing the rationales, the next stage of this chapter will test the specific rationales for the 1983 petroleum tax relaxation, and this will be the issue of the following sections.

6.4 Testing the Rationales for the 1983 Petroleum Tax Relaxation

The rationales for 1983 petroleum tax relaxation were obtained from different sources as was mentioned in chapter four of this thesis. These rationales are the reasons underpinning the 1983 petroleum tax relaxation that were expressed by the Government, the oil industry and academics. Because these rationales were set at the time of the 1983 relaxation, it can be assumed that they were built on the *ex-ante* assumptions regarding, for example, oil prices, costs, production, and marketing expectations. However, as was mentioned above in this chapter, tests for these rationales will be based on the *ex-post* data, as one of the overall objectives of this research is to investigate whether the policies for tax relaxations have been successful. Using the *ex-post* data, which are actual data, allows testing and hence evaluation of the policies that were behind these relaxations. This will help in deciding the extent to which the policies reflected by the rationales were achievable.

The next sections will test the 1983 petroleum tax relaxation's rationales individually, and derive a general conclusion for each of these tests in terms of whether the outcome of each test matches the rationale. These tests will show whether the rationales are justified, and whether the policies underpinning the rationales were successful.

6.4.1 Encouraging Oil and Gas Activities

This rationale will be tested by studying exploration, appraisal and development activities over the period 1980-87. In an attempt to investigate and explain this rationale, these activities will be studied in relation to changes in oil prices and effects of the 1983 petroleum tax relaxation. Consistently with what has been said in the previous chapter, with regard to indicators of oil companies' activities data were extracted from the DTI (Brown Book, 1980-1987). These data are concerned with exploration expenditure, the number of exploratory wells started each year, the number of appraisal wells started each year, development expenditure and the number of development wells started each year. These data were extracted for the period 1980-1987. The reason for choosing 1980 as a start date, as mentioned before in this thesis, is to allow reasonable time for obtaining clear picture of the oil and gas activities from well before the tax relaxation. Selecting 1987 as an end date enables the study of the sole effects of the 1983 tax relaxation on the UK oil and gas industry's activities with no interference from the 1987-88 tax relaxation.

The next section illustrates the behaviour of exploration and appraisal activities over the period 1980-87.

Exploration and Appraisal Activities

This section investigates changes in exploration and appraisal activities first, and second, inspects any possible link between exploration activity and changes in oil prices. Table 6-5 presents data regarding exploration and appraisal activities.

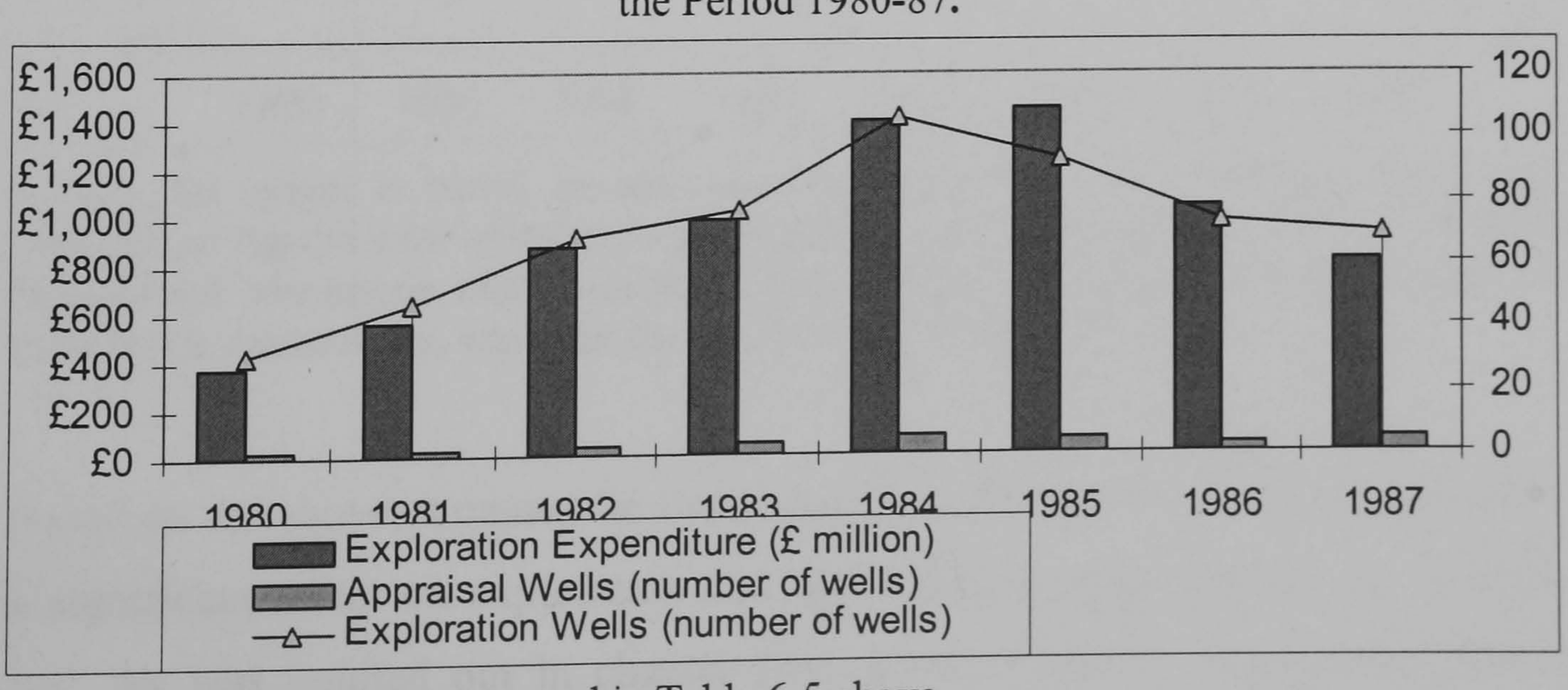
Table 6-5: Exploration Expenditure, Exploratory Wells and Appraisal Wells Over the Period 1980-87.

Year	Exploration Expenditure (£M)	Changes to Exploration Expenditure %	Number of Exploration Wells	Number of Appraisal Wells
1980	379	0	32	22
1981	558	0.47	48	26
1982	875	0.57	68	43
1983	993	0.13	77	51
1984	1,395	0.40	106	76
1985	1,450	0.04	93	64
1986	1,042	-0.28	73	40
1987	816	-0.22	69	63
Source: DTI (1980-1987).				

Source: the table is based on data extracted from the DTI (1980-87). Data regarding exploration expenditure was obtained from Appendix Twelve (exploration, development and operating expenditure) in the Brown Book, whilst numbers of exploration and appraisal wells were obtained from Appendix Two (drilling activities).

It can be seen from the above table that exploration activity, represented by exploration expenditure, increased by 13 per cent from £875 million in 1982 to £993 million in 1983. It then rose to £1,395 in 1984, an increase of 40 per cent. The increase was only four per cent in 1985, as exploration expenditure totalled £1,450 million in 1985 and declined to £1,042 million in 1986, a drop of 28 per cent from 1985. The number of exploration and appraisal wells both increased, peaking in 1984 (106 exploratory wells and 76 appraisal wells) and decreasing after that. Figure 6-1 illustrates this graphically.

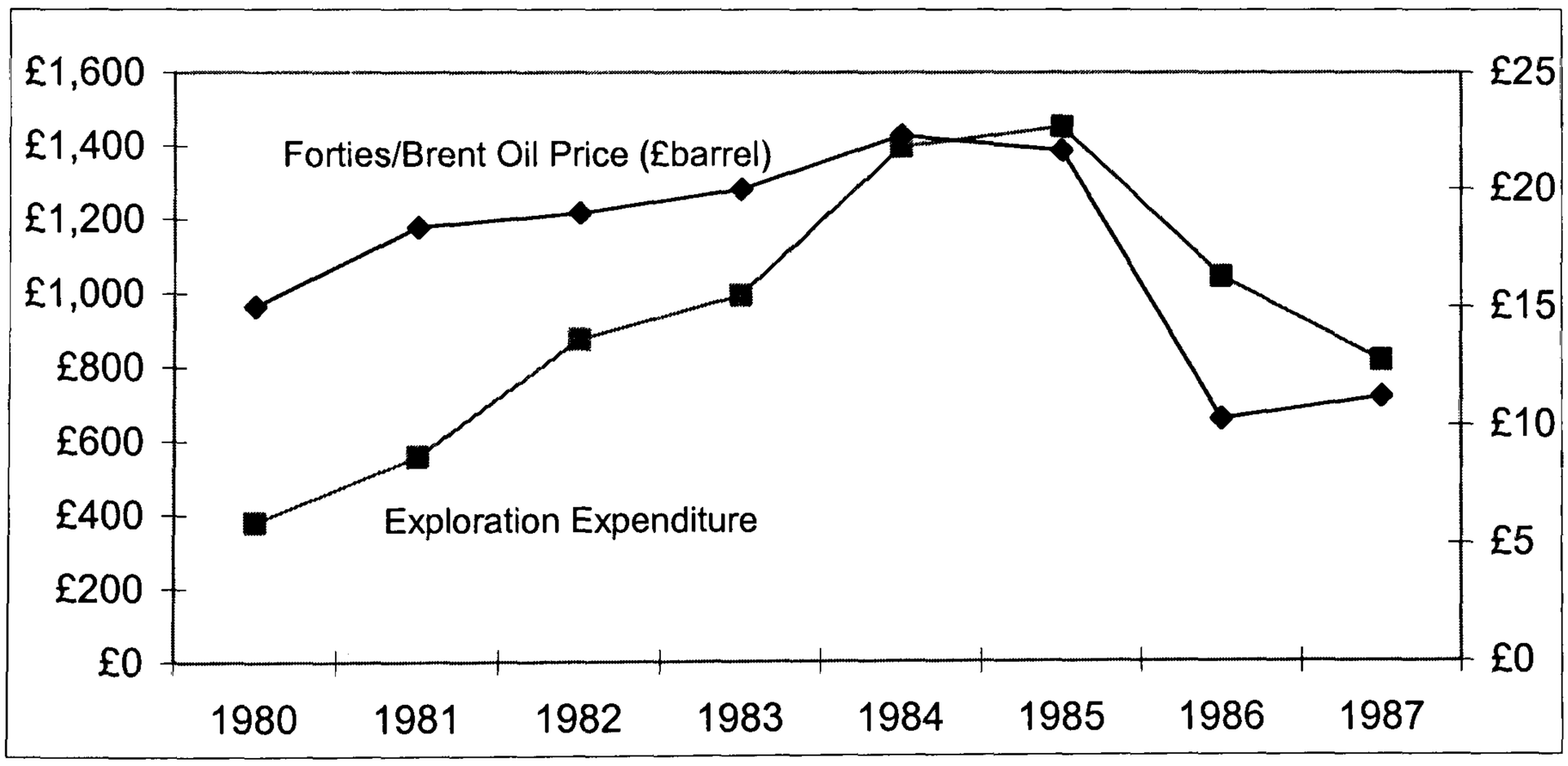
Figure 6-1: Exploration Expenditure, Exploratory Wells and Appraisal Wells Over the Period 1980-87.



Source: is based on data presented in Table 6-5 above.

However, while the behaviour of exploration and appraisal activities may, according to the behaviour of these variables, seem to reflect the impact of the relaxation, there is also the potentially more important impact of changing oil prices to consider. In order to test this, a correlation coefficient was plotted with regard to exploration expenditure and oil prices presented in Table 6-3 for the period 1982-87 and found to be 0.63. This value indicates a fairly strong link between these two variables over the above period. However, plotting the correlation for the period 1980-87 shows a weaker link with a value of 0.45. This can be seen clearly from Figure 6-2 over the period 1980-85, as exploration expenditure increased together with oil prices. Even after 1985 movements in exploration expenditure were in line with changing in oil prices. Here it can be seen that the dramatic drop in oil prices after the mid 1980s had a negative effect on exploration activity. The sharp drop in this expenditure, from £1,450 million in 1985 to £1,042 million in 1986 and £816 million in 1987, represents this negative effect (DTI, 1994, p. 146). Figure 6-2 shows the above argument in a graph.

Figure 6-2: Link Between Exploration Expenditure and Oil Prices Over the Period 1980-87.



Source: the graph is based on data extracted from the DTI (1980-87). Exploration expenditure figures were obtained from Appendix Twelve, while oil prices were obtained from Wood Mackenzie (2004, GEM. v. 3.01). Note: the left hand side axis relates to exploration expenditure, while the axis on the right relates to oil prices.

Based on the above, it cannot be stated that the 1983 petroleum tax relaxation had a significant effect on exploration and appraisal activities, changes in oil prices had. As was pointed out in chapter five of this thesis by Pesaran and Favero

(1990, p. 8) exploration expenditure has been empirically related to oil prices. In other words, the 1983 petroleum tax relaxation was not successful in accelerating exploration activity.

After shedding light on exploration and appraisal activities, and the link between exploration activity and changes in oil prices, the next section will examine the behaviour of development activity over the period 1980-87.

Development Activity

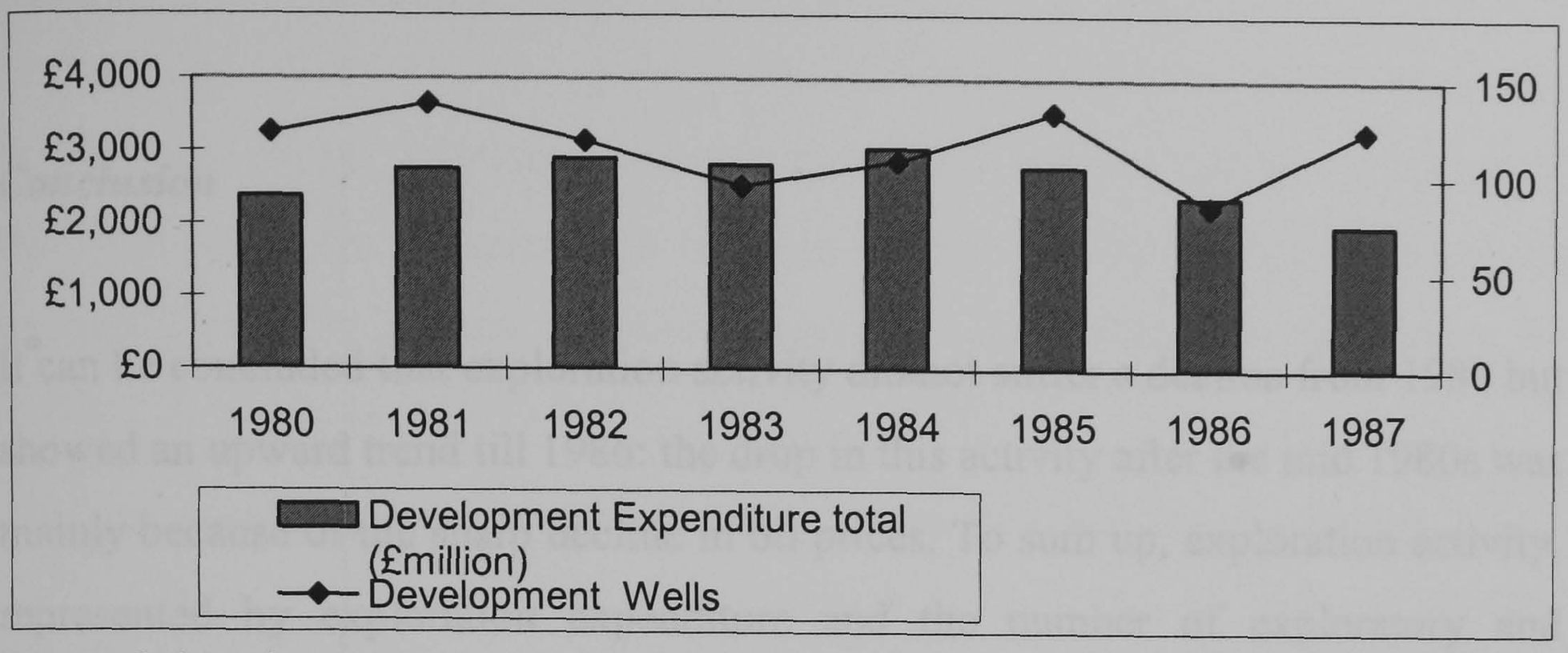
This section examines the development activity over the period 1980-87. After that it examines any possible link between this activity and changes in oil prices. Table 6-6 below presents data related to development activities in the UKCS over the period 1980-1987.

Table 6-6: Development Expenditure and Development Wells Over the Period 1980-87.

	Development Expenditure(£m)	Changes to Development Expenditure %	Number of Development Wells
1980	2,380	0	122
1981	2,759	0.16	137
1982	2,911	0.06	118
1983	2,826	-0.03	95
1984	3,052	0.08	108
1985	2,800	-0.08	133
1986	2,391	-0.15	85
1987	2,008	-0.16	124
Source: DTI (1980-87).			

From the above table it can be seen that development expenditure increased up to 1982 when it totalled £2,911 million, and then it decreased to £2,826 million in 1983. After that it increased to £3,052 million in 1984 but it kept declining to reach £2,008 in 1987. The number of development wells fluctuated over the period 1980-87. It is noticeable that the number of development wells increased after 1983 to peak at 133 wells in 1985 and then dramatically declined in 1986 to 85 wells, and increased again in 1987 to 124 wells. This is also shown in Figure 6-3.

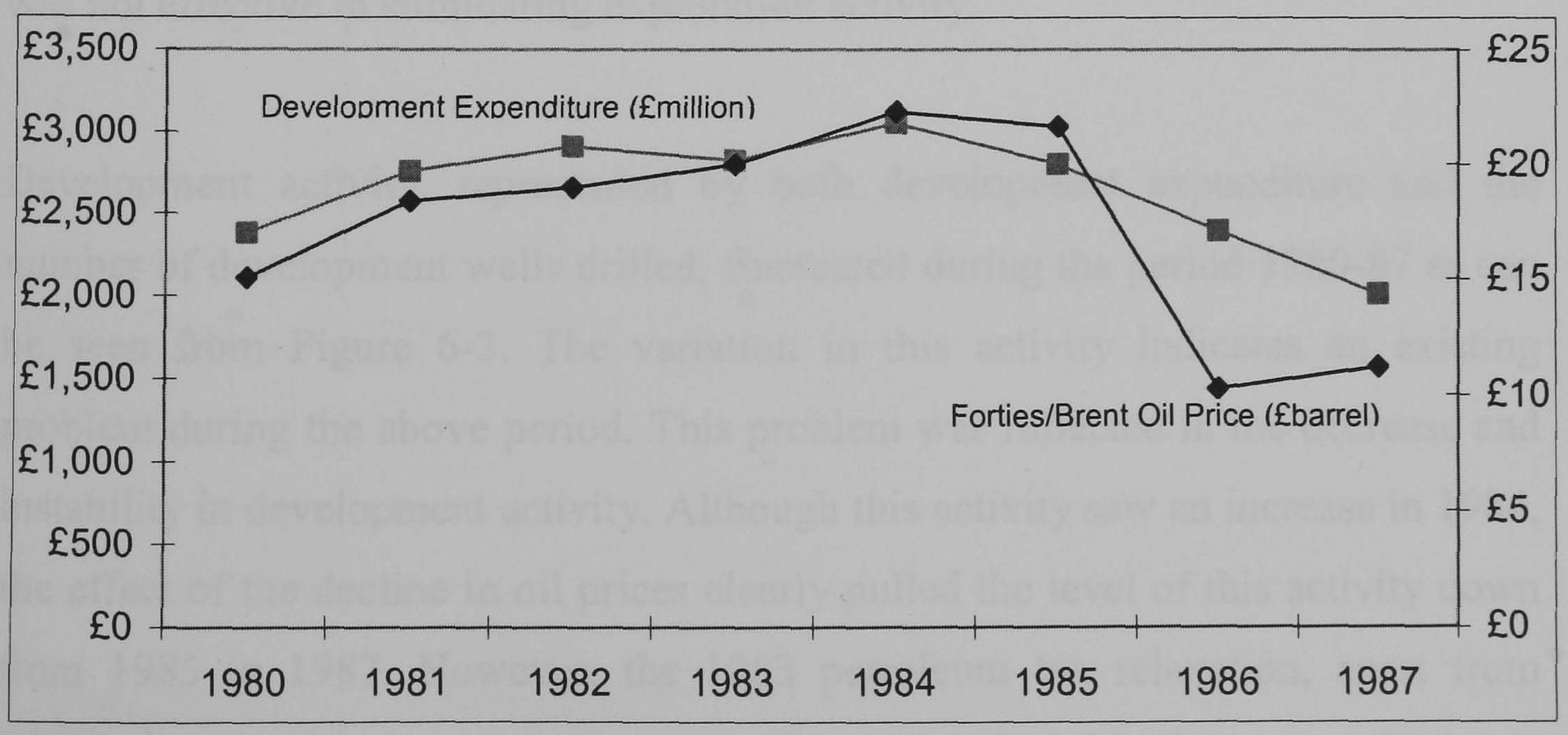
Figure 6-3: Development Expenditure and Development Wells Over the Period 1980-87.



Source: is based on data presented in Table 6-6, which was extracted from the DTI (1980-87). Note: The right axis relates to the number of development wells, while development expenditure is represented on the left axis of the figure.

In examining a possible link between development activities, represented by development expenditure, and changes in oil prices, the author plotted a correlation coefficient for these two variables over the period 1980-87. A significant result was found, which is that the correlation was very strong (0.9). This result confirms the theory, presented in chapter five, regarding this relationship. The result also agrees with Pesaran and Favero (1990, p. 8) and Seymour (1990, p. 9) that development activity is more sensitive to changes in oil prices than exploration activity. This is also shown in Figure 6-4 below.

Figure 6-4: Link Between Development Expenditure and Oil Prices Over the Period 1980-87.



Source: is based on development expenditure data that were extracted from the DTI (1980-87) while oil prices were obtained from Wood Mackenzie (2004, GEM. v. 3.01).

Note: the right axis relates to oil prices while the left axis relates to development expenditure.

Conclusion

It can be concluded that exploration activity did not suffer a decline from 1980 but showed an upward trend till 1986: the drop in this activity after the mid 1980s was mainly because of the sharp decline in oil prices. To sum up, exploration activity, represented by exploration expenditure and the number of exploratory and appraisal wells, increased from 1980 and the drop in this activity in 1986 was because of the dramatic decrease in oil prices from £21.45 in 1985 to £10.27 in 1986.

However, it is still appropriate to say that the 1983 tax relaxation increased exploration and appraisal activities for some companies. This conclusion is supported by a statement of BP (1984, p. 8):

> "Encouraged by new exploration incentives in the 1983 Budget, we have increased substantially our North Sea exploration activities. In the UK sector, for example, 35 exploration and appraisal wells in which BP has an interest were drilled".

However, this is just an exception as in general the 1983 petroleum tax relaxation was not effective in stimulating exploration activity.

Development activity, represented by both development expenditure and the number of development wells drilled, fluctuated during the period 1980-87 as can be seen from Figure 6-3. The variation in this activity indicates an existing problem during the above period. This problem was reflected in the decrease and instability in development activity. Although this activity saw an increase in 1984, the effect of the decline in oil prices clearly pulled the level of this activity down from 1985 to 1987. However, the 1983 petroleum tax relaxation, apart from stimulating the development of two small satellite oil fields (Innes and Duncan), was insufficient to solve the development activity problem. In other words,

development activities were mainly driven by changes in oil prices rather the 1983 petroleum tax relaxation.

Based on the above, it can be stated that this rational was not met by the policy, as the 1983 petroleum tax relaxation failed in encouraging oil and gas exploration, appraisal, and development activities. Changes in these activities were driven by changes in oil prices.

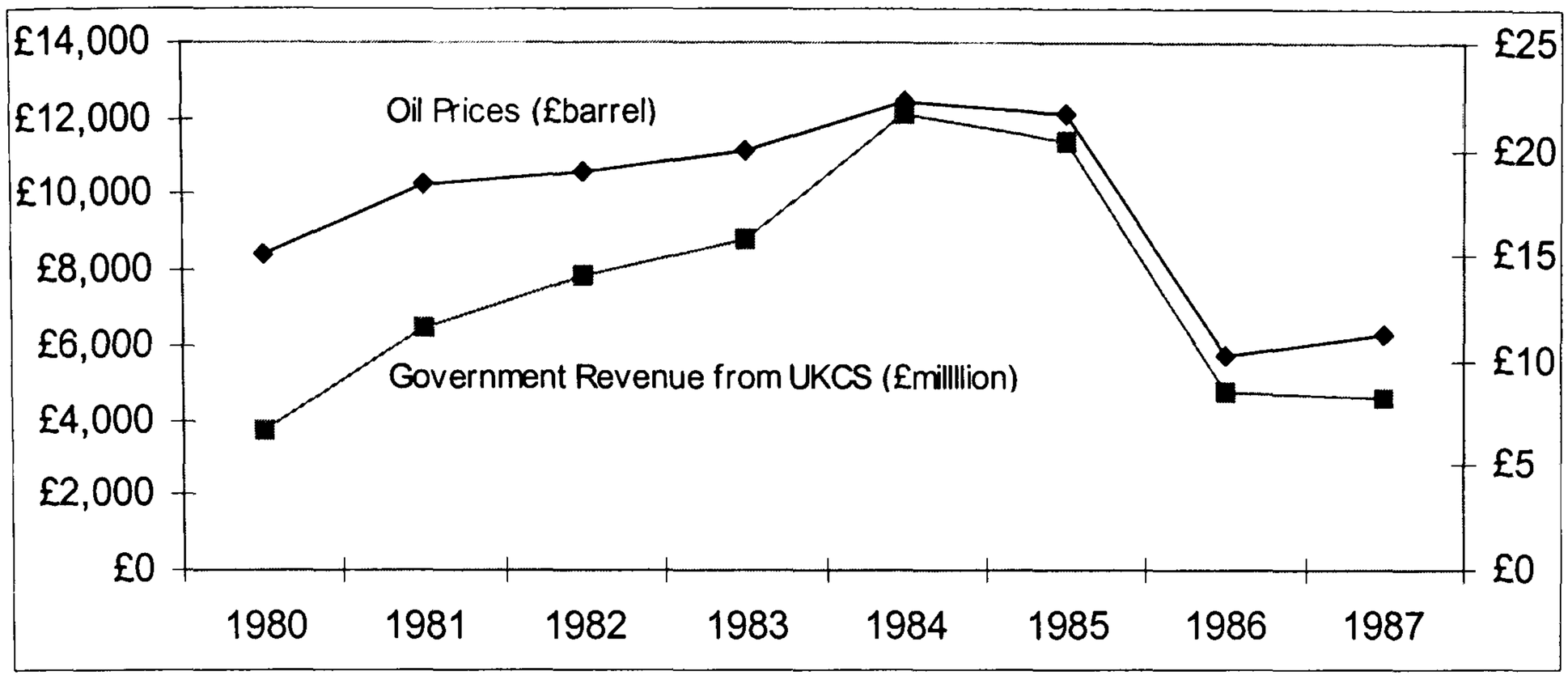
6.4.2 Securing an Adequate Share of North Sea Revenue for the Nation

Testing the above rationale is not an easy task especially as the meaning of "adequate share" is not clear. However, the test for this rationale will compare Governmental revenues from the 14 oil fields which were developed during the period April 1982-1987 according to the post- and pre-1983 Budget tax systems. This will show whether the 1983 petroleum tax relaxation allowed the Government to increase its revenues. Further, it will consider the contribution of the UK oil and gas industry to the Gross National Product (GNP) during the above-mentioned period. It will also show the difference in marginal tax rates between old and new oil fields, which reflect the Governmental revenues according to the pre- and post-1983 Budget petroleum tax regimes. These observations should help in forming a reliable conclusion to the overall test of this rationale.

Governmental Revenues From New Fields According to Pre- Versus Post-1983 Budget

From Figure 6-5 it can be seen that Governmental revenues from petroleum taxes increased from 1980 to 1984 when it totalled £12.4 million, and declined after that to £4.5 million in 1987.

Figure 6-5: Behaviour of Governmental Petroleum Tax Revenues and Oil Prices Over the Period 1980-87.



Source: is based on data presented in Table 6-7. Governmental revenues data was extracted from the DTI (1980-87), while oil prices were obtained from Wood Mackenzie (2004). Note: the axis on the right hand side of the graph relates to oil prices while Governmental revenues are presented on the left hand side axis in £millions.

Obviously the dramatic drop in oil prices in the mid 1980s had an effect on Governmental revenues. In this context the 1983 petroleum tax relaxation cannot be solely blamed for the sharp drop in total Governmental tax take, as it mainly targeted new fields, which gained development consents after April 1982. Fields developed before that date were still subject to the old petroleum fiscal regime. Taking into account that only 14 oil fields were developed during the period April 1982-1987, it becomes clear that the loss in the Governmental take as a consequence of the petroleum tax relaxation is just a small fraction of the total drop in Governmental revenues during the above period. In other words, the decline in Governmental revenues shown in Figure 6-5 is closely related to the drop in the oil prices over the period of time shown in the graph. Table 6-7 shows that when oil prices increased by twelve per cent in 1984 the Governmental revenues from the UKCS increased by 38 per cent, whilst these revenues declined by 58 per cent in 1986 when the oil price declined by 53 per cent.

Table 6-7: Changes in Governmental Revenues and Oil Prices Over the Period 1980-87.

Year	Governmental Revenues £m	Changes %	Oil Prices £	Changes %
1980	3,743	#	15.06	#
1981	6,492	0.73	18.41	0.22
1982	7,822	0.20	19	0.03
1983	8,798	0.12	20	0.05
1984	12,148	0.38	22.3	0.12
1985	11,370	-0.06	21.64	-0.03
1986	4,803	-0.58	10.27	-0.53
1987	4,645	-0.03	11.2	0.09
Source: DTI, 1980-87 and Wood Mackenzie (2004, GEM, V. 3.01).				

The limitation here, as was mentioned above in this test, is that there is no available data regarding taxes from the oil sector regarding which might be used to investigate the impact of changes in oil prices on Governmental revenues. However, the above data is related to Governmental revenues from oil and gas production from the UKCS but not solely from oil production.

Gross National Product

The UK oil and gas industry's contribution to the Gross National Product (GNP) also showed an increasing trend after 1980 when it was 6.4 per cent. This contribution peaked at 16.3 per cent in 1984 and then it declined to 15.1 per cent in 1985 and 7.5 per cent in 1986 (DTI, 1980-87). However, this does not mean that the decline in the UK oil industry's contribution to the GNP was a consequence of the 1983 petroleum tax relaxation. The decline in oil prices had its effects on the total Governmental revenues derived from the UKCS, and therefore on the contribution towards the GNP.

Petroleum Tax Marginal Rate

To overcome the above limitations to this test, changes in the marginal rate of petroleum tax will be compared for new and old fields and the impact of changing this marginal rate on the Governmental revenues will be illustrated. The marginal

tax rate for new fields (fields developed after April 1982) is less than the marginal tax rate for old fields, namely 79.3 per cent as apposed to 88.45 per cent respectively. By using the Wood Mackenzie field-by-field data, it was found that the total Governmental tax take from the new fields over the period 1982-87 was less under the post-1983 Budget tax regime than the pre-1983 Budget tax system. Taking into account the fact that Innes and Duncan oil fields were developed as a result of the 1983 tax relaxation, Government tax take from these two fields was not added to the other fields' take under the pre-Budget scenario. This is because it was decided before in this chapter that these two fields would not have been developed if the 1983 tax relaxation had not taken place. The total Government tax take out of the new fields under the post-1983 Budget was £232.8 million, whilst it would have been £246.3 million under the pre-1983 Budget, which simply means a reduction in Government tax take over the period April 1982-1987 of £13.5 million. In other words, a relatively insignificant reduction.

In supporting the above arguments, Wood Mackenzie's GEM (2004, v. 3.01) was used in obtaining data which allow the calculation of Governmental tax take per barrel of oil. These calculations were performed for new oil fields under the pre- and post-1983 petroleum tax regimes. The Governmental tax take as a percentage of the oil price was also calculated for the new oil fields according to the above-mentioned fiscal regime scenarios. Table 6-8 shows these calculations and results.[70] From this table, it can be seen first of all that different fields present different cases. That is to say, for example, that while Governmental tax take per barrel of oil was $8.1from Highlander in 1986 under the post-1983 petroleum tax regime, it was $19.7 from Duncan. This take varies from year to year for the same field. For instance, while it was $8.8 from Innes in 1988, it was $10.8 in 1989 from the same field. Moreover, the results may seem contradictory sometimes. For example, the Government take per barrel of oil from Duncan was $19.7 in 1986 under the post- 1983 petroleum fiscal regime, while this take is only $11.3 under the pre- 1983 tax system in the same year. However, running the calculations for this field according to the pre- and post- 1983 fiscal regimes shows different results. The Annual Entitlement Cash Flow table in the GEM

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[70] For more fields see Table 1 in Appendix Three.

(2004, v. 3.01) shows that the total Government take in 1986 for Duncan was $58.2 million under the post-1983 petroleum fiscal regime, and this take would have been only $2.1 million under the pre-1983 fiscal regime. However, the total Government take from Duncan over its producing life was $69.3 million under the post-1983 petroleum fiscal regime, while it would have been $111.2 million under the pre-1983 petroleum tax system. This means that although the results may seem contradictory from year to year when comparing them according to the pre- and post-1983 petroleum fiscal regimes, in total oil fields were liable to less tax payments under the post-1983 regime. One more thing to be added in this context is that the calculations show that in some years the Government take per barrel of oil exceeded the oil price per barrel. For example, Government take of $15.7 a barrel from Highlander in 1988 according to the post-1983 petroleum tax regime when the oil price was only $14.8 a barrel. This is due to high tax payments in these years, and also because the petroleum tax system was not a profit-related in these years. However, it can be seen that Government take per barrel in some other years was very low compared to the oil price. For example, the Government take per barrel of oil from Highlander was $1.4 in 1989 according to the post-1983 petroleum fiscal regime.

Comparing the tax take per barrel of oil for each oil field based on the pre- and post-1983 petroleum tax regimes shows that it would have been less under the post-1983 tax system than the pre-1983 regime. For instance, the tax take from the Duncan oil field in 1988 would have been $8.6 per barrel under the pre-1983 tax regime. This take was reduced to $0.036 under the post-1983 tax system, which forms less than one percentage point of the oil price in that year. These figures support my statement that the 1983 petroleum tax relaxation was the main reason for developing this small oil field. This discussion shows that the 1983 petroleum tax relaxation reduced the Government share of the new oil fields' revenues. However, it is still appropriate to investigate if the overall UK petroleum tax regime secured an adequate share of the oil revenues to the nation when compared with other nations.

In a review of petroleum fiscal regimes (RFR) carried out by Petroconsultants (1996) it was found that the UK take from the oil and gas industry was much less

than the average 'state take' which ranged between 73 per cent and 81 per cent. In this regard Petroconsultants (1996) state:

> "Of the 20 largest producing regimes only the UK, Argentina and the US generate a State Take of less than 70%. The UK stands out as particularly lenient with a State Take of only 33%. Indeed, of the 110 regimes reviewed only Ireland generates a lower State Take than the UK".

However, this statement was made in 1996, which means the Government obtained 33 per cent take from new fields that benefited from the three tax relaxations. Table 6-9 shows an international comparison for Government tax take in two types of oil fields, marginal and economic fields.71 The table shows that the UK Government received the least tax take from its oil fields compared with other countries in 1996. However, comparing the above-mentioned petroleum tax marginal rates, of 1983, in the two types of fiscal regimes in the UK, old fields at 88.45 per cent and new fields at 79.3per cent, with the average standard of 70 per cent mentioned in the above statement, it can be said that the 1983 UK petroleum fiscal regime secured an adequate share of the North Sea for the nation at that time.72

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[71] According to Petroconsultants (1996) marginal fields have an NPV of between 0 and $2.3 per barrel and economic fields between $2.3 and $4.1 per barrel.

[72] It may seem odd to compare the UK take in 1983 with the average governmental take in 1996, but the earliest data regarding international comparison was available only since 1996.

Table 6-8: Government Tax Take Per Barrel of Oil, and the Ratio of this Take to Oil Prices for New Oil Fields.

Governmental Take Per Barrel of Oil ($Barrel)																	
Year	Oil Price $Barrel	Highlander				Duncan				Balmoral				Innes			
		Post-1983 Budget	% of Oil Price	Pre-1983 Budget	% of Oil Price	**Post-1983 Budget**	% of Oil Price	Pre-1983 Budget	% of Oil Price	**Post-1983 Budget**	% of Oil Price	Pre-1983 Budget	% of Oil Price	**Post-1983 Budget**	% of Oil Price	Pre-1983 Budget	% of Oil Price
1983	30.34	0	0	0	0	**0**	0	4.00	13.18	**0**	0	0	0	**0**	0	0	0
1984	29.8	0	0	0	0	**0**	0	5.60	18.79	**0**	0	0	0	**0**	0	0	0
1985	28.04	0	0	5.71	20.36	**0**	0	5.30	18.90	**0**	0	0	0	**0**	0	4.74	16.90
1986	15.04	8.08	53.72	12.72	84.57	**19.7**	130.98	11.31	75.20	**0**	0	0	0	**0**	0	1.55	10.31
1987	18.37	10.5	57.16	17.13	93.25	**0**	0.00	0.05	0.27	**0**	0	0.89	4.84	**0**	0	3.5	19.05
1988	14.82	15.75	106.28	17.87	120.58	**0.036**	0.24	8.62	58.16	**0**	0	0.7	4.72	**8.8**	59.38	2.4	16.19
1989	18.22	1.41	7.74	3.73	20.47	**0**	0.00	0.74	4.06	**0**	0	0	0	**10.8**	59.28	10.06	55.21
1990	23.69	7.99	33.73	14.01	59.14	**22.96**	96.92	-0.05	-0.21	**0**	0	0	0	**7.5**	31.66	7.47	31.53
1991	20.11	6.8	33.81	8.11	40.33	**0**	0	0	0	**1.19**	5.92	0.68	3.38	**0**	0	0	0
1992	19.35	6.42	33.18	7.86	40.62	**0**	0	0	0	**4.9**	25.32	4.9	25.32	**0**	0	0	0
1993	16.64	4.39	26.38	4.02	24.16	**0**	0	0	0	**5.08**	30.53	5.68	34.13	**0**	0	0	0

Source: is based on data extracted from the GEM (v.3.01, 2004) for the above fields over the period shown on the table. Note: Government tax take per barrel of oil was calculated by dividing the total Government tax take from each field, after converting the figures from £ to $ using the GEM (2004, v. 3.01), over the total oil production of that certain field in each year of production. Calculations were performed under the pre- and post-1983 petroleum tax regimes. The percentages of the Government tax take to the oil price were calculated for each year and for each fiscal regime scenario for the oil fields.

Table 6-9: Average Government Tax Take: International Comparison.

MARGINAL FIELDS			ECONOMIC FIELDS		
1	UK	33.27%	1	UK	33.03%
2	LIBYA	54.15%	2	LIBYA	42.91%
3	CHINA : ONSHORE	54.16%	3	ARGENTINA	47.18%
4	ARGENTINA	55.41%	4	CHINA : ONSHORE	50.28%
5	INDIA	57.91%	5	USA : OCS	53.29%
6	USA : OCS	62.28%	6	USA : ALASKA	54.00%
7	USA : ALASKA	63.51%	7	INDIA	64.86%
8	NORWAY	68.58%	8	ALGERIA	66.01%
9	UAE : ABU DHABI	78.13%	9	ANGOLA : STANDARD	66.05%
10	RUSSIA	78.97%	10	UAE : ABU DHABI	69.55%
11	ALGERIA	80.12%	11	CANADA : ALBERTA	72.96%
12	VENEZUELA	83.03%	12	NORWAY	73.76%
13	ANGOLA : STANDARD	84.51%	13	RUSSIA	76.30%
14	NIGERIA : STANDARD	85.64%	14	EGYPT : STANDARD	81.16%
15	INDONESIA : STANDARD	86.20%	15	VENEZUELA	83.94%
16	CANADA : ALBERTA	87.66%	16	NIGERIA : STANDARD	84.57%
17	MALAYSIA : STANDARD	97.06%	17	OMAN	85.83%
18	EGYPT : STANDARD	97.77%	18	INDONESIA : STANDARD	86.40%
19	OMAN	97.82%	19	MALAYSIA : STANDARD	86.62%
20	SYRIA	101.00%	20	SYRIA	95.59%
AVERAGE		75.36%	AVERAGE		68.71%
Source: Petroconsultant (1996).					

This discussion indicates a situation where the Government reduced the tax rate for new fields and lost a portion of its total revenue from these fields. This means that the 1983 petroleum tax relaxation combined with the situation of a sharp drop in the oil prices in the mid 1980s failed to increase the Governmental revenues. However, using the international scale for government tax take shows that although the UK take from the oil industry was reduced after 1983, it was still securing an adequate share of the oil resources for the nation. Thus, the above rationale was reflected in the outcome of the above tests. In other words, the rationale was met by the policy.

6.4.3 Helping Oil and Gas Companies' Cash Flow to Accelerate Development Activities

Most oil companies which worked or are still working in the UKCS have interests in international oil and gas fields. For example, BP produced oil and gas from 12

countries during 1984 (BP, 1984, p. 8). Furthermore, some of these companies are integrated, which means that they have upstream and downstream activities. Also different companies hold interests at the same time in one field. Therefore, statements and tables disclosed in oil and gas companies' annual reports do not show if an increase in cash flow arose from certain area, e.g., oil and/or gas field, or in certain activity, e.g., upstream or downstream. The alternative to inspecting changes in companies' cash flows is to examine cash flows from oil fields developed during the period April 1982-87. Those fields were defined as new fields. Any changes in these fields' cash flow during this period will reflect changes in the oil and gas industry's cash flow. Comparing fields' cash flow by means of two scenarios will allow examination of any changes to oil fields' cash flow. These scenarios are the post- and pre-1983 Budget tax system. This comparison will answer a number of queries, the first being related to whether the tax relaxation was a major reason for developing a number of oil fields. If so, then the additional cash flow of these fields is to be considered as a gain to the industry's cash flow which arose because of the tax relaxation. If fields were to be developed despite the 1983 tax relaxation, then we will be confronted by one of two cases, which are: (1) The post-1983 Budget cash flow of these fields will be higher than pre-Budget, which means an increase to oil and gas industry cash flow; or (2) the pre-1983 Budget cash flows of these fields will be higher than the post-Budget, which will mean that the difference is a loss to the oil and gas industry's cash flow. This is the core of the above rationale. The aim of the second question is to see whether it was only the increase in the oil and gas industry's cash flow, resulting from the 1983 petroleum tax relaxation, that stimulated development activity in the UKCS. The next section therefore examines the cash flow state of the UK oil and gas industry after the 1983 petroleum tax relaxation.

UK Oil and Gas Companies' Cash Flow

Comparing the cash flow of fields over their producing lives according to the post- and pre-1983 Budget regimes will not show the sole effect of the 1983 tax regime. This is because influences of 1987-88 and 1993 petroleum tax relaxations will be reflected in the total cash flow. Therefore, the cash flow for each field in

my field population under the post-1983 Budget tax system will be calculated up to the year of 1987. This will be compared with the cash flow for the same fields under the pre-1983 Budget tax regime based on the same time period. This comparison will show the changes in the cash flow of oil fields that happened because of the 1983 tax relaxation. This in its turn will reflect any changes in the cash flow of the oil and gas industry. From Table 6-10 below it can be seen that, according to the post-1983 Budget tax regime, there appears to be a material increase in the cash flow of a number of oil fields in comparison with the pre-1983 Budget tax system.

Table 6-10: Cash Flow Improvement For Fields Developed Between1982 and 1987.

Cash Flow up to 1987 (£ Million)		
Field Name	Post-1983 Budget	Pre-1983 Budget
Alwyn North	-2,369.70	-2,369.70
Clyde	-780.3	-780.3
Petronella	11.1	2.1
RobRoy	-218.2	-218.2
Ivanhoe	-109.1	-109.1
Eider	-382	-372.8
Scapa	-70.6	-91.3
Tern	-580.6	-566.4
Cyrus	-193.8	-189
Innes	5.6	0
Deveron	78.3	64.7
Balmoral	-699.9	-706.9
Duncan	58.8	0
Highlander	287.9	178.9
Total	-4,962.50	-5,158.00
Source: Wood Mackenzie (2004, GEM, v. 3.01).		

From the above table it can be seen that the total cash flow for Petronella, for example, was £11.1 million up to 1987 while it would have been only £2.1 million under the pre-1983 Budget tax system. The total cash flow of Innes was £5.6 million (£-4.9 million under the pre-1983 petroleum fiscal regime), and Duncan £58.8 million (29.1 million under the pre-1983 petroleum fiscal regime). Furthermore, the total cash flow of the 14 oil fields between 1982 and 1987 is

£-4,962.5 million,[73] while it would have been £-5,158 million under the pre-1983 Budget tax regime. Cash flows from Innes and Duncan were excluded form the pre-1983 calculations because, as was stated earlier in this chapter, the development of these two fields has been posited as a consequence of the 1983 petroleum tax relaxation. These two fields would not have been developed without this tax relaxation and consequently they would not have generated any cash flow. This means that the cash flow of the UK oil industry had increased by £195.5 (5,158-4,962.5) million over the period 1982-87 mainly as a result of the 1983 petroleum tax relaxation. Other factors may have helped this increase such as prices, interest rates, and exchange rates. However, examination of effects of these factors is beyond the scope of this thesis.

In performing this analysis and based on the petroleum tax regime affecting fields developed after April 1982 it was found that, [74] in general, fields that were developed during the period April 1982-87 benefited more from the removal of royalties than the PRT allowance.[75] This is reflected in the increase in the cash flow of these fields resulting from the above measures. Table 6-11 shows figures relating to royalties and PRT payments calculated according to the pre- and post-1983 Budget rules.

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[73] Negative cash flow indicates to the idea that fields have not recovered their initial investment yet, or in other words have not reached their payback periods.

[74] For a full description of this fiscal regime, see chapter three of this thesis.

[75] These reliefs were doubling the oil allowance for PRT purpose and giving immediate PRT relief against any field for searching and appraisal expenditures.

Table 6-11: Pre- and Post-1983 Budget Royalty and PRT Payments Over the Period 1982-1987.

Oil Fields	Royalty £M		PRT £M	
	Post-Budget	Pre-Budget	Post-Budget	Pre-Budget
Alwyn North	0	0	0	0
Clyde	0	0	0	0
Petronella	0	9	0	0
Robroy	0	0	0	0
Ivanhoe	0	0	0	0
Eider	0	0	0	0
Scapa	0	20.9	0	0
Tern	0	0	0	0
Cyrus	0	0	0	0
Innes	0	10.5	0	0
Deveron	0	20.5	0	0
Balmoral	0	6.9	0	0
Duncan	0	47.7	0	0
Highlander	0	75	22.7	89.3
Totals	0	190.5	22.7	89.3

Source: Wood Mackenzie (2004, GEM, v. 3.01).

For example, while the total increase in the cash flow of the above fields as a result of abolishing royalty stands at £132.3 million (without royalty payments from Innes and Duncan, i.e., £190.5 – £10.5 – £47.7), the differences in the PRT payments between the post- and the pre-1983 Budget cases is £66.6 million (£89.3 – £22.7).

Different fields experience different situations. For example, while Petronella benefited by £9 million as a consequence of abolishing royalties, it did not benefit from the PRT relief. The significant conclusion that can be drawn here is that cash flows of the very small oil fields benefited more from abolishing royalties than increasing PRT allowances. This result was to be expected, because these fields have very small reserves and they, apart from Highlander, would never have been liable to PRT under the pre-1983 Budget scenario. These fields would be liable to royalties at a 12.5 per cent rate, and the new tax regime exempted them from this duty.

The next section will illustrate the relationship between the increase in the cash flow of these fields and the development activity over the period April 1982-1987.

Development Activity

Concerning the second question of increasing development activities within the UKCS as a consequence of the improvement of the cash flow, it cannot be decided if this statement is true. This is because, as was mentioned earlier for this rationale, oil and gas companies have multiple interests. Improvement in development activity in any particular area around the world does not only depend on the increase of the cash flow that arises from this area. Business strategies and economic and political factors play pivotal roles in making development decisions. To support this argument, data was gathered from the BP annual reports with regard to annual capital expenditure based on geographical areas and total annual cash flow. Table 6-12 presents the above data for the period 1983-1987.

Table 6-12: BP's Regional Capital Expenditure and Total Cash Flow During the Period 1983-87.

Region	1983	1984	1985	1986	1987
UK $	936	703	913	1,205	2,478
Rest of Europe $	461	464	676	787	576
USA $	2,891	3,007	3,380	2,618	1,730
Rest of World $	729	938	749	957	1,048
Total Capital Expenditure $	**5,017**	**5,112**	**5,718**	**5,567**	**5,832**
Total Cash Flow$	1,065	1,052	1,115	-222	-6,189
Source: BP (1983-87).					

BP is the operator of Cyrus which is the only field developed by this company during the period 1983-1987. As can be seen from Table 6-10, the increase of the cash flow of this field during the above period was zero. This means that the 1983 petroleum tax relaxation did not improve BP's cash flow during the period 1983-87. However, from Table 6-12 it can be seen that there was material increase in the total capital expenditure, which includes development expenditure, from year to year over the above period. In other words, capital expenditure (the investment)

by BP followed an upward trend, despite the cash flow situation which was a result of the 1983 petroleum tax relaxation. This fact becomes clearer when observing changes in the capital expenditure in the UK in Table 6-12. The capital expenditure in UK increased over the period 1983 – 1987, but the total company cash flow decreased over this period. This means there was no link between the increase in cash flow and the increase in capital expenditure.

One more thing to be added in this context is that the yearly increase in cash flow does not equal the yearly increase in the capital expenditure. For example, from Table 6-12 it can be seen that the total cash flow increased by $63 million from 1984 to 1985, while the total capital expenditure increased by $606 million during the same period. Further, when the total cash flow decreased from $ -222 million in 1986 to $ -6,189 million in 1987, the total capital expenditure increased by $265 million during that year. From this comparison it seems that capital expenditure did not follow the same trend as cash flow. However, in searching for a link between cash flow and investment expenditure, a correlation coefficient based on data presented in Table 6-12 was plotted between these two variables for the period 1983-87. The result was –0.63, which means that there was no direct link between the cash flow and capital expenditure. This result can be used to state that the above rationale is found to be flawed.

Moreover, the rationale was also clearly flowed, a priori because the increase in the cash flow of an oil company from certain fields in any geographical area will not necessarily be invested in that particular area. In this regard Rutledge and Wright (1998a, footnote 10, p. 19) state: "this would imply that the North Sea is now probably becoming a cash cow to be milked for investment overseas". In supporting this statement Rutledge and Wright (1998b, p. 811) quote Oryx Energy:

> " 'The UK North Sea provides a strong stream of earnings and cash flow with relatively modest reinvestment needs. This is important for the funding of the Company's plans in other strategic areas.' (Oryx Energy, 1996, p. 4)' ".

In addition, an increase in the cash flow of a field cannot be traced through companies' published data. Such increase can be used for any purpose that fits into the oil companies' strategies and decisions. For example, the extra cash flow can be used for extra dividend payments, donations or any other kind of payment that oil companies might make. Although it is requested by various accounting regulations to provide detailed disclosures, it is not necessary that companies publicly disclose in detail where they spend their revenues.

However, it was concluded in rationale one above (section 6.4.1) that development activity in the UKCS suffered from a distinct problem reflected in the up-and-down movements in this activity over the period 1982-87, and the 1983 petroleum tax relaxation was not a suitable remedy for this problem in spite of increasing the cash flow of the UK oil industry. This discussion supports the above argument of no existing direct link between improvement of an oil company's cash flow and improvement of this company's development activity.

Conclusion

As a conclusion it can be stated that although the cash flow of the UK oil industry was increased as a consequence of the 1983 petroleum tax relaxation, this increase did not identifiably accelerate development activity within the UKCS. The investigation and tests also showed that this rationale is flawed, because it was found that there was no direct link between changes in cash flow from a certain area or activity and changes in investments in that area or activity. Therefore, it can be stated that this rationale was not met by the policy.

6.4.4 Encouraging Smaller and More Costly Fields in New Areas to be Explored and Developed

It is a generally accepted truth in the oil and gas industry that larger fields are more likely to be discovered first. By the early 1980s most of the biggest oil and gas fields had been discovered in the North Sea. Therefore, it was believed at the time that unexplored fields would contain smaller reserves compared with previously discovered fields (Lawson, 1992, p. 88). It was also believed at the

time that new fields would be more costly because of the location of these fields in areas of deeper water and harsher weather conditions.

The test of this rationale will be in two parts. In the first part, the size and costs of new fields will be looked at and compared with the sizes and costs of old fields. This is to see if new fields tended to be more costly to develop than old fields, something which will tell us whether the rationale was flowed from the outset. In the second part, improvements in oil and gas activities in new areas will be investigated. This is to decide whether the 1983 petroleum tax relaxation stimulated the exploration and development of smaller and more costly fields.

Cost and Volume Analysis

Links between costs and sizes of fields that were developed between April 1982 and 1987 (new fields) will be made by calculating unit costs of reserves and production, i.e., per barrel of oil. Calculations will be performed based on the total figure for each field over the life of fields. Data regarding costs and production are to be obtained from Wood Mackenzie (2004, GEM, v. 3.01), using a 10 per cent real discount rate. Recoverable reserves' data were obtained from OPL (2004). [76] The calculated unit costs of reserves and production will be compared between new fields and fields developed before April 1982 (old fields). Comparison will be made between old and new fields from the same reserves' volume category and within the same geographical area, to allow comparison of like with like. In this regard, the field size categorisation that has been presented in the literature by a number of academics, e.g., Martin (1997), and Kemp and Rose (1983) will be used in this context. This categorisation is as follows: a field with reserve volume of less than 50 million barrels of oil equivalent (mmboe) is very small; a field with reserve volume of 51-200 (mmboe) is small; a field with reserve volume of 201-400 (mmboe) is medium; a field with reserve volume of 401-1,000 (mmboe) is large; and a field of reserve volume of more than 1,000 (mmboe) is very large. The main objective of this comparison and test is to see if the new fields tend to be more costly than the old fields, and if any small and costly fields were

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[76] Recoverable reserves include 65 (70) proven reserves, 50 (55) probable reserves and 25 (30) possible million tonnes oil reserves in fields under first development (DTI, 2000a, p. 16).

developed because of the 1983 petroleum tax relaxation. In other words, the above calculations and comparisons aim at checking if fields developed after April 1982 were of a smaller size and more costly than fields developed before that date. This will answer the question whether the 1983 petroleum tax relaxation stimulated exploration and development activities in new, smaller and more costly fields.

As was mentioned above, Wood Mackenzie (2004) data are used in performing the calculations. In this regard the total capital cost is added to the total operating cost to create *total cost*, which is discounted at 10 per cent real, for each field. The total production of oil equivalent was calculated for each field, in a standard way, by applying the following formula to gas production and adding the result to oil production to create total equivalent oil production: [77]

1,000 toe = 0.04254 bcf

where toe stands for tonne of oil equivalent, and bcf stands for billion cubic feet of gas. The total production of oil equivalent for each field is used to calculate the cost of a production unit (barrel of oil) for each field. The recoverable volumes of oil and gas reserves that were obtained from OPL (2004) are used to calculate the total equivalent reserve for each field, and these totals are used to calculate the unit cost of reserve for each field. Table 6-13 presents the above calculations.[78]

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[77]This formula was developed based on conversion factors presented by the DTI (1994, p. vi), these conversion factors are: 1 tonne of crude oil = 7.5 barrels, and 1 cubic meter = 35.31 cubic feet.

[78] Detailed calculations are shown in Tables 1 and 2 in Appendix Three.

Table 6-13: Comparison of Production and Reserves Unit Costs Between Old and New Fields.

Central North Sea (Small Sized Reserves)					
Development Consents Between April 1982 and 1987			Development Consents Before April 1982		
Field Name	Reserve Unit Cost $	Production Unit Cost $	Field Name	Reserve Unit Cost $	Production Unit Cost $
Clyde	23	23.356	Argyll	32.79	31.901
RobRoy	12.09	13.022	Auk	24.97	24.298
Ivanhoe	12.46	12.789	Buchan	28.26	27.502
Scapa	12.44	12.115	Beatrice	37.52	36.512
Balmoral	20.68	20.121	Tartan	32.67	33.406
Highlander	14.64	14.242			
Northern North Sea (Small Sized Reserves)					
Development Consents Between April 1982 and 1987			Development Consents Before April 1982		
Field Name	Reserve Unit Cost $	Production Unit Cost $	Field Name	Reserve Unit Cost $	Production Unit Cost $
Eider	16.47	16.027	hutton	32.95	32.069
Northern North Sea (Large Sized Reserves)					
Development Consents Between April 1982 and 1987			Development Consents Before April 1982		
Field Name	Reserve Unit Cost $	Production Unint Cost $	Field Name	Reserve Unit Cost $	Production Unit Cost $
Alwyn North	12.03	24.006	Cormorant North	23.07	22.92

Source: is based on data extracted from Wood Mackenzie (2004) and OPL (2004). Note: the table shows a comparison, in terms of production and reserves unit costs (boe) between old and new fields within the same geological areas and from the same size categories. The table is divided into three parts according to the geological locations and reserve volumes of the oil fields. The top part of the table shows a comparison between the old fields (developed before April 1982) and the new fields (developed between April 1982 and 1987) which are located in the central North Sea and which are of a small size (51-200 mmboe). The middle part shows comparison between the old and the new fields, with small sized reserves, located in the northern North Sea. The lower part of the table presents comparison between the large sized (401-1,000 mmboe) old and new fields located in the northern North Sea.

Cost Analysis

From Table 6-13 it can be seen that the average cost of a production unit in the central North Sea in a small new fields was $15.9, while it was about $30.7 in an old fields. The cost of a reserve unit for the new fields was approximately $15.8, while it was about $31.2 in the old fields. For the oil fields of small size reserves,

which are located in the northern North Sea, the cost of a production unit was $16 in a new field (Eider), while it was $32.9 in an old field (Hutton). With regard to the large fields, which are located in the northern North Sea, I found that the cost of a reserve unit was $12 for Alwyn North (new field) and $23 in an old field (Cormorant North), but the cost of a production unit for the latter was $22.9, whilst it was $24 for Alwyn North.

However, with regard to Innes and Duncan oil fields, which were both very small fields with a reserve volume of less than 50 mmboe, The calculations show that the costs of a production unit were $29.8 and $44.8 respectively. The costs of a reserve unit were $30.5 for Innes and $44.7 for Duncan. The development of these two fields after the 1982 Financial Act, in spite of their very small reserves size and relatively high costs, supports my conclusion that the 1983 petroleum tax relaxation did facilitate their development. Taking into account that the 1983 petroleum tax relaxation improved dramatically the IRR of these two fields and reduced the tax burden on them supports this conclusion. In other words, the 1983 petroleum tax relaxation increased the post-tax cash flow in these two fields, or 'the post-tax IRR'.

To support this contention that old fields were more costly in terms of development and extraction, average operating and capital costs of reserve unit were calculated for new and old fields of small reserves' volume which are located in the central North Sea. The average operating costs of the six new fields and the five old fields, which were presented in Table 6-13 above, were found to be $7.5 and $14.5 respectively. The average capital costs of these fields were $7.5 for new fields and $16.6 for old fields. These calculations are shown in Table 4 of Appendix Three.

Volume Analysis

In terms of the volume of the explored fields, it can be seen that the 16 offshore oil fields which were discovered during the period April 1982-1987 were divided

as follows: 12 very small, one small, one medium and two large.[79] Fields developed between April 1982 and 1987 tended to be small and very small with only one large field (Alwyn North). Fields developed before that date contained small, medium, large and very large reserves. This outcome supports what was said in the introduction of this chapter regarding reserve volumes of the new fields and corresponds with Lawson's statement (1992, p. 88).

Results

From the above discussion and table it can be stated that, although fields developed between April 1982 and 1987 tend to be small and very small, in general, investment in old fields was more costly than investment in new fields. Investments in new fields, although they were small and very small, had benefited from the existing infrastructure. This point was mentioned above in this chapter when discussing development motivations for a number of oil fields such as Cyrus, Clyde and Balmoral. It was necessary to spend money (capital cost) on building up the required platforms and pipelines when investments first took place in any area of the North Sea. These investments increased the capital cost and consequently increased the total costs of the old fields. The new oil fields made use of these already existing infrastructures, which saved them a portion of their capital costs. Further, the benefits that the oil and gas industry gained from improved technology and accumulated experience should have helped to reduce operating costs of new fields. These factors together are likely to have reduced the capital and operating costs to make the costs of reserves and production units less for fields developed after April 1982 than for fields developed before this date. This conclusion is consistent with what Nakhle (2004, p. 82) states in this regard:

> "Although times have changed, the UKCS can still provide opportunities of which discovery of the Buzzard field is an example. Similarly, advances in technology can significantly help in reducing exploration and development costs".

Similarly, Rutledge and Wright (2000, p. 82) state:

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[79] For more information regard discovered offshore oil fields during the period April 1982-87 see Table 6 in Appendix Three.

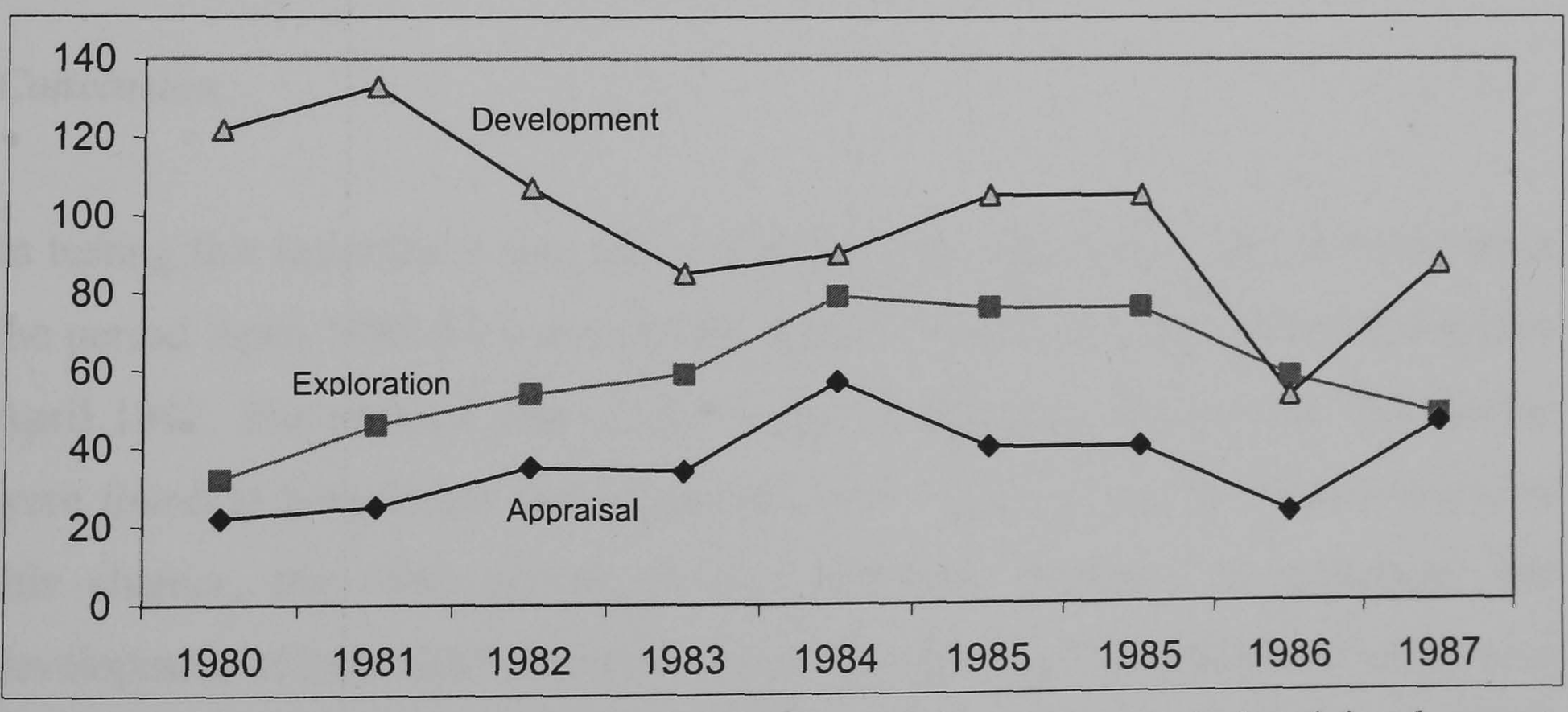
> "Maturity brings with it all kinds of advantages - in particular the existing of infrastructure and great body of knowledge concerning the geological nature of area".

These two statements support the empirical results that were presented above.

Analysing Activities of the Oil Industry in New Areas

This section looks at the progress of exploration and development activities in areas that were mentioned in the 1983 petroleum tax relaxation, which are offshore areas outside the Southern Basin of the UKCS. These areas are: east of Scotland (central North Sea), east of Shetland and west of Shetland (northern North Sea). The number of offshore exploration and development drilling wells in these areas represents changes in exploration and development activities. From Figure 6-6 it can be seen that exploration-drilling activity in new areas (central and northern North Sea, and east of Shetland) increased from 1980, when 32 wells were drilled, peaked in 1984 at 79 wells, and after that declined gradually to 48 wells in 1987. Appraisal-drilling activity followed roughly the same trend as exploration drilling over the period 1980-87. Development drilling fluctuated during the period 1980-87, peaking in 1981 at 133 wells while the lowest number of wells was 53 in 1986.

Figure 6-6: Exploration, Appraisal and Development Activities in New Areas Over the Period 1980-1987.



Source: is based on data relating to the number of exploration, appraisal and development drilling wells in new areas. This data was extracted from the DTI (Appendix 2, 1980-87) and is presented in Table 4 of Appendix 3. Note: this graph shows that exploration and appraisal activities increased from 1980 up to 1986 when they started to decline, while development activity fluctuated during the period 1980-1987.

Based on the above discussion and graph, it can be seen that exploration and appraisal activities were increasing from 1980 in new areas. These activities slowed down after 1985, which was mainly because of the influence of the sharp drop in the oil price at that time, as mentioned when testing rationale one (section 6.4.1). Development drilling was unstable during the above period, which indicates an existing problem with this activity in the UK oil industry during the period 1980-87. This statement was made when rationale one above was tested. However, it can be seen that the number of exploration, appraisal and development wells increased dramatically after 1983 in the above-mentioned new areas. Exploratory wells increased by 34 per cent between 1983 and 1984, while appraisal wells increased by 68 per cent after decreasing by three per cent between 1982 and 1983. The number of development wells increased by six per cent over the period 1983-84 after decreasing by 21 per cent between 1982-83 and 20 per cent between 1981-82. Exploration and appraisal activities decreased in 1984 by four per cent and 30 per cent respectively, while development activity, represented by development wells, increased by an extra 17 per cent in that year. However, as mentioned in testing rationale one in this chapter, the improvement of exploration, appraisal and development activities relates mostly to the increase in oil prices. It can also be pointed out in this context that the drop in oil prices in the mid 1980s not only prevented these activities from further increasing, but actually caused them to decrease.

Conclusion

In testing this rationale it was found that oil fields which were discovered during the period April 1982-87 were smaller than fields which were discovered before April 1982. The same is true of the fields developed in this period. The former were found to have lower costs than the latter. However, as mentioned before in this chapter, the 1983 petroleum tax relaxation managed to encourage the development of two small oil fields: Innes and Duncan. The operating unit cost of Innes was $16.5 and the capital unit cost was $14.3, while these costs were $20.1 and $24.6 for Duncan respectively. The new fields were found to be less costly to be developed compared with old fields. Therefore, as the 1983 petroleum tax

relaxation managed to encourage these two small and costly fields to be developed, it can be stated that the outcome corresponds with this rationale. However, the 1983 petroleum tax relaxation was not very successful in motivating smaller and more costly fields to be explored and developed. This conclusion agrees with what Mike Earp, from the DTI, stated in the interview on the 23rd December 2003 with the author concerning the lack of success of the 1983 petroleum tax relaxation. This opinion was presented in chapter four of this thesis in section 4.3.1 . Therefore, it can be stated that this rationale was partly met by the policy.

6.4.5 Increasing the Production Level, and Consequently the Government Tax Take

In testing rationales one, three and four above, exploration and development activities were considered over the period 1983-87. In testing the current rationale the focus is on production and Governmental revenues from petroleum taxes. The aim is to see if production levels, and consequently petroleum taxes, had increased as a result of the 1983 petroleum tax relaxation. However, while 1982-1987 is the period of concern here, most of fields that obtained development consents after April 1982 only started production three or four years after their development consent date.[80] Thus, the output of these fields during this period will not reflect the true picture of the production and petroleum taxes. In order to trace the increase in production and tax payments, the test period will be extended up to 1993 to give an effective time period. This will show the effects of this tax relaxation on production and tax revenues. Here the test results are neither affected by the 1993 petroleum tax relaxation nor by the second petroleum tax relaxation (1987-88). This is because the population fields consist of fields developed between April 1982 and 1987, and located in the central and northern North Sea. The 1987-88 petroleum tax relaxation targeted different fields in different areas from the group of fields used here. Therefore, extending the test period up to 1993 in this case is appropriate. The test of this rationale will first investigate any changes in the production level, and secondly it will consider

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[80] Production started in November 1986 from Petronella, Balmoral and Highlander; March 1987 from Clyde; November 1988 from Eider; February 1989 from Tern and July 1989 from Ivanhoe (OPL, 1998).

changes in the Government tax take as a consequence of increasing oil production.

Oil Production Level

This part of the test deals with changes in the production level as a result of the 1983 petroleum tax relaxation. It can be argued that, because the 1983 petroleum tax relaxation was a reason for developing Innes and Duncan oil fields, the total output of these two fields (3,625 mtoe) over the period 1983-93 is to be considered as a positive contribution from the petroleum tax relaxation as regards total UK oil production. Table 8 in Appendix Three shows the monthly, yearly and total oil production of these two small oil fields over their productive lives. Table 6-14 shows the yearly production of Duncan and Innes, and the percentage of their total yearly production to the total oil production from the UK over their producing lives. It can be seen from Table 6-14 that the contribution of these two fields to the total UK oil production was very small, which always stood at less than one per cent.

Table 6-14: Oil Production from Duncan and Innes Over the Period 1983-1992

Year	Duncan (mm ton)	Innes (mm ton)	Total Duncan and Innes (mm ton)	Total UK (mm ton)	% of Total Innes and Duncan to Total UK
1983	0.10	0	0.10	115	0.09
1984	0.66	0	0.66	126.1	0.53
1985	0.74	0.21	0.94	127.7	0.74
1986	0.37	0.23	0.60	127	0.47
1987	0.23	0.13	0.36	123.3	0.29
1988	0.13	0.09	0.22	132.311	0.16
1989	0.07	0.06	0.13	105.3	0.12
1990	0.05	0.04	0.09	106.5	0.09
1991	0.04	0.00	0.04	105.1	0.04
1992	0.04	0.00	0.04	107.7	0.03
Source: DTI (1983 - 1992)					

Note: mm ton stands for million tonnes.

Government Tax Take

This section deals with changes in the Governmental revenues from the petroleum taxes as a result of the 1983 tax changes. These tax changes were designed to

benefit new fields only. By using GEM (v. 3.01) produced by Wood Mackenzie (2004), the impact of these tax changes on the Governmental revenues on my fields are to be looked at over the period 1983-93. In performing this task the Government tax take for the latter period from these fields is to be compared using two scenarios which are the post- and pre-1983 Budget tax regimes. During the above period, 14 oil fields were developed. Tax payments in respect of these fields are to be considered according to the post-1983 scenario. Regarding the pre-1983 Budget tax system scenario the take from 12 oil fields only is to be calculated. The tax take from Innes and Duncan is to be excluded from the calculations. This is because, as was already stated before in this chapter, these two fields would never have been developed under the pre-1983 Budget tax regime.

By applying the above-described test, it was found that total Government tax take over the period April 1982-87 from the new fields would have been £321 million ($330.7m) according to the pre-1983 Budget scenario. This take would have been £200.7 million ($147.6m) under the post-1983 Budget. In order to allow more time and to develop a clearer picture for the Government revenues from the above fields, the test was extended to include the period 1982-1993. It was found that Governmental revenue would have been £344.2 million ($582) less under the post-1983 Budget case than the pre-1983 Budget tax system. Furthermore, it can be noted that while the extra Government take from Innes and Duncan over the period 1983-93 was £54.5 million ($73.5 m), the Government sacrificed £344.2 million ($582 m) from the other 12 fields, which were developed between April 1982 and 1987, as a consequence of the 1983 petroleum tax relaxation. This means that the Government take from these two fields did not compensate for the loss from the other 12 fields. The total Government loss was £344.2 million ($582.2m) because of the 1983 tax relaxation during the period 1983-93. Table 9 in Appendix Three shows figures regarding Government tax take from my group fields based on the above named two scenarios.

Conclusion

It can be stated that although the 1983 tax relaxation stimulated more production, it was a very small output from two small oil fields. The core of this rationale is the Government tax take, which was less, as a consequence of the tax relaxation, and not compensated for the small proportional increase in oil production. In other words, this tax relaxation failed to increase the Governmental petroleum tax revenues by increasing total oil production. This result leads one to state that the outcome of the above tests does not correspond with the core of this rationale. Therefore, I can state that this rationale was not met by the policy.

6.4.6 Making the Whole Tax Regime More Sensitive to Changes in World Oil Prices by Linking Taxation Exclusively to Profit Rather Than to a Mixture of Profits and Revenues

Claiming that the 1983 petroleum tax relaxation would have made the whole UK tax regime more sensitive to changes in world oil prices is not rational. Since the 1983 tax relaxation targeted fields located in the central and northern North Sea, which obtained development consents after April 1982. This means that fields, which were developed before that date, or located outside the central and northern North Sea, were still subject to the old tax regime. Therefore, in fact the 1983 petroleum tax relaxation would have made the tax regime more sensitive to changes in the world oil prices, only for new fields, but not for the whole area of the UKCS.

The 1983 petroleum tax relaxation package included abolishing royalties, which was a duty of 12.5 per cent on production. Therefore, it can be said that abolishing royalties was an action by the Government to link taxation to profit rather than a mixture of profit and revenues. This is true for new fields that had development consents after April 1982. Royalties were not a profit related duty: they were levied (fixed percentage) on gross production. By removing them the tax regime in new fields was directly linked to profits. These profits are fundamentally affected by changes in oil prices, and are subject to petroleum taxes. In other words, royalties was a duty of 12.5 per cent of the gross production, so, changes

in oil prices would affect the total Government take from this duty; but it would never have affected the percentage itself, as it would have still been 12.5 per cent of the gross production. Oil companies had to pay this duty at 12.5 per cent on production but not on profits generated.

Testing the sensitivity of the fiscal regime was carried out, for the above reason, to the new fields only. In this context the sensitivity of the fiscal regime to changes in oil prices means that when oil prices change the Government take and the oil industry share of output also change systematically (Kemp and Crichton, 1979, p. 38). Here we are confronted by two cases: (1) oil price increase: this would lead to profit increase and consequently increase the Governmental and oil industry takes; (2) oil price decrease: this would lead to less profit and less take for the Government and the industry (or maybe even a loss).

The current task is to check and investigate the sensitivity of the UK petroleum fiscal regime for the new fields under the above meaning of sensitivity, and furthermore, to compare the results for pre- and post-1983 petroleum tax regimes for the same fields in order to check if level changed at all. It is important to mention that observing the yearly changes in tax payments, cash flow and IRR of oil fields based on the yearly changes in oil prices cannot determine sensitivity. This is because there are many factors changing from year to year, e.g., production level, operating and capital costs, and technology. These factors, in addition to prices, affect directly cash flow and total tax payments. Therefore, examining the sensitivity of the fiscal regime should be carried out for the whole productive life of oil fields. In particular the IRR is usually calculated for the whole productive life of oil fields.

The test of this rationale is carried out by applying different price scenarios to new fields based on the post- and pre-1983 Budget petroleum tax regimes. This test will allow observation of the effects of changes in oil price on the financial measures of the above named fields. The test will be preformed by using the GEM of Wood Mackenzie (2004, v. 3.01) at a ten per cent real discount rate. In terms of oil price, the following assumptions are applied: an increase and decrease in the

oil prices as follows: at three per cent, four per cent, ten per cent, and at another ten per cent on the top of the previous ten.

With regard to changes in the oil price, a fixed price cannot be taken in a given year or an assumed yearly increase percentage specified for this price. This is because, if we do so, we are assuming that oil prices are following an increasing trend all the time, while in reality they go up and down. What can be done in this regard is to take the actual price series for fields that are used in this test and apply an increase and decrease to it. This can be done by multiplying the yearly prices firstly by 1.03 and 1.04 assuming that the price increases by three and four per cent, and secondly by 0.97 and 0.96 assuming a yearly decline in the actual prices by three and four per cent,[81] then multiplying the actual price series once by 1.10 and then multiplying the new series by 1.10, assuming an increase in the actual oil prices by ten per cent first and secondly by another ten per cent on the top of the first ten. Then the actual series is to be multiplied by 0.9 and after that the new series by 0.9, assuming a decrease in the actual oil prices by ten per cent first, and another ten per cent on the top of the first decrease. The assumed series will have the same trend, increasing and decreasing, as the actual one. This process will allow studying the effects of price changes on financial figures such as IRR, total Government take, Government take per barrel of oil, and total field cash flows. The summaries that the price changes assumptions are applied cumulatively and related to changes in revenues under the pre- and post- 1983 fiscal regimes.

A similar methodology was applied in a study which was undertaken by Kemp and Crichton (1979, p. 39). The differences between my application and Kemp's and Crichton's are that they applied the price sensitivity test on one Norwegian fiscal regime, i.e., the 1975 petroleum tax package, assuming a five and ten per cent change in oil prices. In this section the test is being applied on two different UK petroleum fiscal regimes which are the pre- and post-1983 Budget. This application will allow measuring and comparing the sensitivity of the UK petroleum fiscal regime to changes in oil prices at different price levels. Another

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[81] The three and four per cent increase and decrease in oil prices were randomly chosen, and here the new series moves in line with the original prices series assuming oil prices changed once upwards by extra three and four per cent and another downwards by three and four per cent.

difference between the application of Kemp and Crichton and this study is that they used a price at $14 constant to 1980, with a five per cent annual increase afterwards. In this study the actual price series is being used with assumed increased and decreased percentages in prices. In my case the new series of oil prices will follow the same trend as the original one, while in Kemp's and Crichton's case the price series increased all the time after 1980.

However, if I use the assumption of changes to oil prices, I should also assume similar changes in costs. This is because a lower oil price might stimulate reduction in prices of certain types of equipment. For this test it is not possible to know the changes in costs that may have occurred when oil prices changed, because of scarcity of data in this regard. Furthermore, if it is to be assumed that capital or operating costs are also increased by three or four per cent first and secondly by 10 per cent, then in this case the results will be unrealistic. As costs would not necessarily mirror increasing or decreasing oil prices.

Assuming Three and Four Per cent Increases and Decreases in Oil Prices

Performing the test according to the pre- and post-1983 Budget petroleum fiscal regimes for the population fields gives significant results. The results indicate that when oil prices increase by three per cent, the above financial parameters will be changed differently based on the terms of the fiscal regime applied. For example, under the assumption of a three per cent increase in oil price the above measures for Clyde will be as follows.

1. Under the post-1983 Budget petroleum tax regime, the total cash flow of the field would increase by 18 per cent, the post-tax IRR would increase by 0.9 percentage points, and total Government take would increase by 12 per cent.

2. Under the pre-1983 Budget petroleum tax system, the total cash flow of the field would increase by 17 per cent, the change in the post-tax IRR would be 0.86 percentage points up, and the total Government take would increase by 13 per cent.

By applying a scenario assuming a four per cent increase in the oil prices I obtained very similar results to the above. Table 6-15 presents figures relate to Clyde with regard to the above test and discussion.

Table 6-15: Sensitivity of Petroleum Fiscal Regime to Changes to Oil Prices.

CLYDE		Total Fields Cash Flow $M	Post-Tax IRR %	Total Government Take $M	Average Governmental Take Per Barrel of Oil $
Pre-1983 Budget	actual prices plus 4 %	582.9	7.19	372.5	2.45
	actual prices plus 3 %	559.4	6.94	355	2.34
	actual prices	476.1	6.08	315.1	2.08
Post-1983 Budget	actual prices plus 4 %	607	7.45	348.4	2.3
	actual prices plus 3 %	578.2	7.16	336.2	2.22
	actual prices	491.3	6.26	299.9	1.98
Percentage Change when Prices Increase by Three per cent					
Pre-1983 Budget		0.17	0.86	0.13	11.1
Post-1983 Budget		0.18	0.90	0.12	10.8
Percentage Change when Prices Increase by Four per cent					
Pre-1983 Budget		0.22	1.11	0.18	15
Post-1983 Budget		0.24	1.19	0.16	14

Source: is based on data extracted from Wood Mackenzie (2004) by applying different price scenarios using the GEM (v. 3.01). The actual prices are available from the GEM, and the scenarios are applied by assuming an increase and a decrease in the actual yearly prices by three and four per cent. Note: the top part of the table shows total figures at different price scenarios according to pre- and post-1983 Budget petroleum tax regimes, while the lower parts show the percentage changes in the above figures under the two fiscal regimes, pre- and post-Budget, calculated using actual prices.

It can be seen, from the above discussion and table, that the results of any oil price increase according to the post-1983 Budget would be more to the benefit of the oil industry than the Government. This result is reflected in the increase in the total cash flow and IRR of the Clyde oil field. It can also be seen that there would be a loss in Government tax take under the post-1983 Budget petroleum tax system

over the pre-1983 Budget tax regime. For instance, when the price increases by three per cent the total Government tax take would increase by 13 per cent under the pre-1983 Budget scenario whereas the increase is 12 per cent under the post-1983 Budget tax regime. This reflects a one percentage point loss in the total Government take and in this case reflects the loss in Government tax take because of abolishing royalties for new fields. Conversely, applying the test by assuming a three and four per cent reduction in the yearly actual oil prices, and performing a test similar to the one above, gives significant results. The results show that the decline in the total cash flow of the Clyde oil field would be greater according to the post-1983 Budget petroleum tax regime than the pre-1983 Budget tax system. The same can be said with regard to changes to the IRR, while the total Government tax take decreases by a smaller percentage under the pre-1983 Budget terms than the post 1983 Budget case. Table 6-16 shows figures relating to Rob Roy oilfield regarding the results of applying scenarios of decreases in oil prices of three and four per cent.

Table 6-16 : Sensitivity of Petroleum Fiscal Regime to Declines in Oil Prices.

ROBROY		Total Fields Cash Flow £M	Post Tax IRR %	Total Government Take £M
Pre-1983 Budget	actual prices minus 4 %	725.7	19.25	886.6
	actual prices minus 3 %	735.2	19.46	907.1
	actual prices	763.7	20.1	968.2
Post-1983 Budget	actual prices minus 4 %	921.8	21.95	690.6
	actual prices minus 3 %	940.2	22.31	702.1
	actula prices	995.2	23.38	736.6
Percentage Change when Prices Increase by Three per cent				
Pre-1983 Budget		-0.04	-0.64	-0.06
Post-1983 Budget		-0.06	-1.07	-0.05
Percentages Change when Prices Increase by Four per cent				
Pre-1983 Budget		-0.05	-0.85	-0.08
Post-1983 Budget		-0.07	-1.43	-0.06

Source: is based on figures extracted from applying different price scenarios on RobRoy oil field according to the pre- and post-1983 Budget tax systems using Wood Mackenzie's (2004) GEM (v. 3.01).

The table shows that assuming a three per cent cut in the yearly actual oil prices pulls the total cash flow of RobRoy under the pre-1983 Budget regime by four per cent, while the decline would be six per cent under the post-1983 Budget tax regime. Under the pre-1983 Budget the IRR would decrease by 0.64 percentage points, while under the post-1983 Budget petroleum tax regime the decline would be 1.07 percentage points. On the other side, the total Government tax take out of this field would decline by six per cent under the pre-1983 Budget petroleum tax system, but it would decrease by five per cent according to the post-1983 Budget case. Applying the above tests on different fields gives similar results but with different percentages with regard to the above financial measures, which is normal because different fields have different costs, reserves' volumes, and different production capacities.[82]

Assuming a First Ten Per Cent and Second Ten Per Cent on the Top Increase and Decrease in Actual Oil Prices

To make sure the fiscal regime was sensitive to changes in oil prices, and in support of the above results, the test is applied one more time at the following assumed price levels.

1) A ten per cent increase to the actual prices series once, and another ten per cent increase on the top of the first one.
2) A ten per cent decrease to the actual price series once, and another ten per cent decrease on the top of the first one.

A sample of the results is shown in Table 6-17.

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[82] For more calculations of sensitivity test, see Table Ten in Appendix Three.

Table 6-17: Sensitivity of the UK Petroleum Fiscal Regime to Changes in Oil Prices, with Reference to Alwyn North.

Increase in Oil Prices by 10% and Another 10% on the Top					
Alwyn North		Total Field Cash Flow $M	Post-Tax IRR %	Total Government Take $M	Avarage Governmental Take Per Barrel of Oil $
Pre-1983 Budget	Plus 10 per cent	4118.6	11.04	4702.4	6.83
	Plus 10 per cent on top	4641.6	12.36	5121.8	7.44
	Actual Prices	3733.4	9.96	4231.1	6.15
Post-1983 Budget	Plus 10 per cent	4503.5	11.48	4317.3	6.27
	Pluse 10 per cent on Top	5035.9	12.77	4727.4	6.87
	Actual Prices	4039.9	10.32	3924.6	5.70
Percentage Change When Prices Increase by First 10 per cent					
Pre-1983		10.318	10.843	11.139	11.14
Post-1983		11.476	11.240	10.006	10.01
Percentage Changes When Prices Increase by 10 per cent on Top of the First 10 per cent					
Pre-1983		24.326	24.096	21.051	21.05
Post-1983		24.654	23.740	20.456	20.46

Decrease in Oil Prices by 10% and Another 10% on the Top					
ALwyn North		Total Field Cash Flow $M	Post-Tax IRR %	Total Government Take $M	Avarage Governmental Take Per Barrel of Oil $
Pre-1983 Budget	Minus 10 per cent	3279.4	8.73	3828.4	5.56
	Minus10 per cent on the Top	2910.4	7.68	3426.5	4.98
	Actual Prices	3733.4	9.96	4231.1	6.15
Post-1983 Budget	Minus 10 per cent	3552.3	9.07	3555.6	5.17
	Minus10 per cent on the Top	3140.4	7.97	3196.5	4.65
	Actual Prices	4039.9	10.32	3924.6	5.70
Percentage Change When Prices Increase by First 10 per cent					
Pre-1983		-12.160	-12.349	-9.518	-9.52
Post-1983		-12.070	-12.112	-9.402	-9.40
Percentages Change When Prices Increase by 10 per cent on Top of the First 10 per cent					
Pre-1983		-22.044	-22.892	-19.016	-19.02
Post-1983		-22.265	-22.771	-18.552	-18.55

Source: Wood Mackenzie (2004, GEM, V. 3.01).

From Table 6-17 it can be seen that in the case of Alwyn North if the oil price had increased by ten per cent the total cash flow of the field would have increased by 10.3 per cent under the pre-1983 Budget tax regime. [83] The cash flow would have increased by 11.4 per cent under the post-1983 Budget tax system based on a ten per cent increase in the oil price. The Government take per barrel of oil would have increased by 11.1 per cent according to the pre-1983 Budget tax system, while the increase would have been 10 per cent under the post-1983 petroleum tax regime. Similar results were obtained upon applying a ten per cent increase in the oil price on the top of the first ten per cent. Conversely, different results were obtained in the case of decreasing the oil prices. For example, from Alwyn North's case in Table 6-17 it can be seen that when oil prices decrease by ten per cent on the top of the first ten per cent decrease the results will be as follow: (1) total field cash flow would have decreased by 22.2 per cent under the post-1983 petroleum tax system, and by 22 per cent under the pre-1983 petroleum tax regime; (2) average Government take per barrel of oil would have decreased by 19 per cent under the pre-1983 Budget, while it would have decreased by 18.5 per cent according to the post-1983 Budget. This leads one to suggest that in the case of a declining oil price, the Government take would decreases less under the post-1983 petroleum fiscal regime than the pre-1983 fiscal system. Also, the oil industry's share would decrease more under the post-1983 petroleum tax system than the pre-1983 system. This means in the case of declining oil prices the post-1983 petroleum fiscal regime is more sensitive to the benefit of the Government than the oil industry.

From the above table and discussion it can be stated that the pre-1983 UK petroleum fiscal regime was sensitive to changes in oil prices. This sensitivity was changed by the post-1983 Budget tax system to the benefit of the oil industry. This was mainly because of the partial abolition of royalties, which were not a profit related duty. For example, if oil prices increased by ten per cent, the average Government take per barrel from Alwyn North would be $6.8 under the pre-1983 tax regime, while this average take would be $6.1 under the post-1983 petroleum tax system. This means although the Government take per barrel would increase

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[83] For one more example see Table 10 in Appendix Three.

when oil prices increase, this increase in the Government tax take would be less under the post-1983 petroleum tax system than the pre-1983 system. On the other hand, upon a ten per cent increase in the oil price the total field cash flow would be $4,118.6 million under the pre-1983 petroleum tax regime, while the total field cash flow would be $4,503.5 million under the post-1983 petroleum fiscal regime.

Conclusion

To sum up, as can be seen from the above tables and discussion, the pre-1983 Budget petroleum tax system was sensitive to changes in oil prices. This sensitivity was increased to the benefit of oil companies as a result of the post-1983 petroleum fiscal regime in the case of an increase in oil prices. In other words, the tax burden increased more likely as prices rose and reduced more rapidly as prices fell. According to the post-1983 Budget, any decline in oil prices would affect the Government revenue less negatively than the oil industry. That is to say, the gain/loss for the oil and gas industry from any increase/decrease in oil prices would be higher according to the post-1983 Budget than the pre-1983 petroleum tax system. Therefore it can be concluded that the outcome of the above tests correspond with the above rationale of making the new fiscal regime, but not the whole UK fiscal regime, more sensitive to changes in world oil prices. Hence, it can be said that this rationale was partly met by the policy.

6.4.7 Sustain Indigenous Production Beyond 1988/90

This rationale will be tested by looking at change, if any, in oil and gas production which arose as a result of the 1983 petroleum tax relaxation. In so doing, the sole effects of the 1983 petroleum tax relaxation on production will be isolated from the effects of the second tax relaxation of 1987-88. The focus in this context will be on production from fields which obtained development consents between April 1982 and 1987. Out of these fields the focus is on fields for which the 1983 petroleum tax relaxation was a main reason for their development. It was already stated in this chapter that Innes and Duncan oil fields were probably developed as a consequence of the 1983 tax relaxation. Therefore, their yearly productions are to be traced to measure their total contribution to the total UKCS production and self-sufficiency. In performing this task, data is extracted from the DTI (2004a)

regarding the yearly production of these two fields. Data which relates to the total UK oil and gas production and consumption are extracted from the DTI (The Brown Book, 1988-97). Data which relates to the net exportation of crude oil are extracted from the DTI (2004c). As mentioned in this thesis, the UK reached self-sufficiency of oil in 1980. After that date the UK was a net oil exporter, as production exceeded domestic consumption. Net crude oil exported in 1981 totalled 15.3 million tonnes.

Duncan oil field started production in 1983, while Innes production started in 1985. Therefore, these two fields contributed to the net oil exportation after 1988, as self-sufficiency was reached earlier than this date. Hence, as both of these two fields were small ones, their contributions were a small proportion of the total UK offshore oil production. The production contribution of these two fields was 0.16 per cent of the total UK offshore oil production and 0.75 per cent out of the total net UK oil exportation in 1988. These percentages increased over time to peak at 0.24 per cent and 9.76 per cent out of the total UK offshore oil production and total UK oil exportation respectively in 1993. However, crude oil imported exceeded exported oil in 1991 and 1992. This is why negative contributions of the above two fields to the total net oil exported are shown in1991 and 1992. Table 6-18 presents data which relates to the contribution of Duncan and Innes to the total UK offshore oil production and total oil exportation.

However, although the contribution of the above two fields into total UK offshore oil production and net oil exportation was a small proportion, it was still a positive contribution. It can be concluded that the 1983 petroleum tax relaxation was successful, to a very limited extent, in sustaining oil production after 1988, by encouraging the development of Duncan and Innes and increasing production. This production contributed to the total UK oil production. With this conclusion it can be stated that this rationale was partly met by the policy.

Table 6-18 : Duncan's and Innes' Contribution to UK Oil Production and Exportation.

	Oil Production (K tonnes)				Total UK Oil Consumption (mt)	Total UK Net Oil Export (mt)	Total Duncan's and Innes' Production to Total UK Oil Production %	Total Duncan's and Innes' Production to Total UK Oil Export %
	Duncan	Innes	Total	Total UK				
1988	130	88	218	132,311	80	29.06	0.16	0.75
1989	69	57	126	105,318	82	2.16	0.12	5.82
1990	51	41	92	106,480	84	4.29	0.09	2.15
1991	43	0	43	105,097	83	-1.95	0.04	-2.20
1992	36	0	36	107,717	83	-0.06	0.03	-64.29
1993	158	107	265	112,752	85	2.71	0.24	9.76
1994	84	69	153	139,121	110	29.30	0.11	0.52
1995	62	49	111	144,393	109	35.83	0.08	0.31
1996	52	0	52	146,507	115	31.46	0.04	0.17
1997	43	0	43	144,727	115	29.41	0.03	0.15
Source: DTI (2004a, 2004c, and 1988-1997)								

Note: mt stands for million tonnes. The percentage of total Duncan's and Innes' production to total UK oil export is calculated after converting total Duncan's and Innes' production into million tonnes. The 1988 figure is calculated as follows. ([218/1,000]/29.06) x 100 = 0.75. The 1988 figure regarding the percentage of total Duncan's and Innes' production to total UK production is calculated as follows. (218/132,311) x 100 = 0.16.

6.4.8 Removing the APRT Would Release Some Additional Funds to the Industry, Which Could be Used for Further Investment

As was illustrated above (chapter three) SPD was introduced in 1981 at 20 per cent of gross production revenues. This duty was replaced on 31st December 1982 with the Advanced Petroleum Revenue Tax (APRT). APRT had the same principles as SPD apart from not being a deductible charge for CT. APRT was mainly introduced to accelerate the receipt of PRT into earlier financial years. Therefore, APRT was not, in reality, a harmful duty to oil and gas companies who were liable to it, as payments of this tax were advance payments of PRT.

From the above it can be said that SPD represented a cost for the oil industry in the form of a tax and this tax put a burden on profit and loss accounts and cash flows of oil fields. The APRT was not an additional cost itself but it put a burden on the cash flows of fields as it was an upfront payment of PRT. Hence, removing

APRT would have increased these cash flows temporarily by allowing more funds for the industry. These funds should have contributed either to the oil industry's further investments, but not necessarily within the UKCS, or have been used to pay higher dividends to shareholders. Removing APRT might, in some cases, have helped oil companies in reducing the immediate need for capital and thus their cost of capital.

According to statistics published by the DTI (2004b), the total receipt by the Government from SPD equalled £2,025 million in 1981 and £2,365 million in 1982. The official website of the DTI does not present figures relating to yearly APRT payments, as these payments are included in the PRT figures. However, the GEM can reveal these yearly APRT payments of the oil and gas industry to the UK Government. Table 6-19 below shows the total yearly payments of these two duties, i.e., SPD and APRT.

Table 6-19: Payments of Supplementary Petroleum Duty (SPD) and Advance Petroleum Revenue Tax (APRT) Over the Period 1981-88.

	1981	1982	1983	1984	1985	1986	1987	1988	Totals £ M
Total SPD £ M	7,127.90	9,759.80							16,887.70
Total APRT £ M			10,765.40	9,504.70	8,241.50	2,570.60	-696.60	-1,181	29,204.60
Total SPD & APRT £ M	7,127.90	9,759.80	10,765.40	9,504.70	8,241.50	2,570.60	-696.60	-1,181	46,092.30

Source: is based on data extracted from Wood Mackenzie (2004, GEM, v.3.01).

As can be seen from the above table, SPD and APRT payments formed considerable sums of money paid to the Government. For example, in 1983 APRT was £10,765.4 million (Wood Mackenzie, 2004). Also, according to the same source, at an individual company level, BP, for instance, paid £1,552.3 million in 1983 as APRT. From the table it can be seen that the total APRT payments over the period 1983-88 were £29,204.6 million. These funds were taken out of the

industry's cash flow and put into the Government's. This in other words, meant greater burdens on the industry's cash flow at the same time.

Based on the above table and discussion, it can be stated here that removing SPD released funds for the UK oil and gas industry. These funds should have had a material effect on the oil and gas companies' profit and cash flow. Removing APRT released pressure, in the short term, on the companies' cash flow during the early days of any financial period. This pressure arose because this was an advance payments of PRT.

Conclusion

By linking this rationale to the conclusions derived from testing rationales one, four and five above, it was stated that appraisal, exploration and production activities were enhanced after 1983. However, it was concluded in rationale three above, that there is no direct link between changes in cash flow from certain activities or geographical areas and changes of oil and gas activities in the same area. Hence the above rationale does not definitely link changes in the cash flow to particular changes in the oil investment activities, as it included the word "could". It therefore follows that the outcome of the above discussion relates to this rationale. In other words, the sums released as a result of removing APRT increased the oil industry's cash flow. There is also a probability that these funds could be employed in further investment somewhere around the world but not necessarily within the UKCS. Based on this, it cannot be stated decisively one way or another this rationale is justified or not, likewise whether the underpinning policy was achieved is unclear. This is because sufficient data are not available to support statement one way or another. It can therefore be stated that this rationale was partially met by the policy.

6.4.9 Corrective Action by the Government to the 1981 Petroleum Fiscal Regime Package

Testing this rationale will be in two parts. The first will be by investigating if the 1981 petroleum fiscal regime was harmful to the oil and gas industry. The second will be to check whether the 1983 petroleum tax regime maintained or corrected

any aspects of the former regime which were deleterious to the oil and gas industry. In doing so, this section will illustrate the effects of the 1981 petroleum tax package on the oil and gas activities within the UKCS. It will also investigate whether the 1983 petroleum tax relaxation directly relieved any negative effects of the former regime on the oil and gas activities in the whole area of the UKCS.

The introduction of SPD in the 1981 Budget meant there was a combination of taxes on oil and gas production during the period 1980-81. The marginal tax rate increased from 85.5 per cent in 1980 to 88.4 per cent in 1981. This is because the petroleum tax regime consisted of: royalty at 12.5 per cent, SPD at 20 per cent, PRT at 70 per cent and CT at 45 per cent. SPD was introduced in 1981 after the oil price had dramatically increased from $20.3 in 1979 to $37.2 in 1981. However, after that it declined to $31.7 in 1982 and $29 in 1983. It was essential to remove this duty because the reason behind its introduction (the dramatic increase in oil prices) had changed, and also the Government wished to stimulate oil and gas activities. However, looking at figures for production, exploration expenditure, exploration and appraisal drilling, development expenditure and development drilling, it can be seen that these activities increased over the period 1978-1983. This is a fairly logical pattern that was consistent with the increase in the oil prices, which helped to keep these activities on an upward trend over the above period. Table 6-20 below presents data relating to the above named parameters.

From Table 6-20 it can be seen that oil and gas investment activities had an upward trend after 1979, apart from exploration and appraisal drilling, which had dramatically declined from 176 wells in 1980 to 73 wells in 1981. However, it cannot be stated that the decline in number of appraisal wells was solely the result of the 1981 petroleum tax regime. In this regard, looking at offshore licensing rounds shows that the fifth and sixth licensing rounds, which were offered by the Government in 1976/77 and 1978/79 respectively, were relatively small ones. In the fifth round, 28 awards were granted in 44 blocks, and in the sixth round, 26 awards were granted in 42 blocks. This means that by the early 1980s companies would have not found suitable available sites for exploration, as the small number of blocks awarded would have almost all been explored. In 1980/81 the

Government issued the seventh licensing round where 90 awards were granted in 90 blocks to 157 companies. This licensing round gave the industry sufficient opportunity for more exploration and appraisal activities and this is what happened in reality, as can be seen from Table 6-20 below. The same can be said with regard to the decline in development expenditure. However, at the same time there seemed to be a negative influence on these activities from a decline in oil prices, from $37 in 1981 to $32 in 1982 and $29 in 1983.

Table 6-20: Figures For Oil and Gas Activities Over the Period 1987-85.

Year	1978	1979	1980	1981	1982	1983	1984	1985
Exploration & Appraisal (Offshore Wells Drilled)	158	156	176	73	111	128	182	157
Exploration Expenditure (£ M)	261	241	379	558	875	993	1395	1450
Appraisal Wells (Number of Wells)	25	15	22	26	43	51	76	64
Exploration Wells (Number of Wells)	37	33	32	48	68	77	106	93
Government Revenues from Petroleum Taxes (£milion))	562	2313	3743	6492	7822	8798	12148	11370
Production (Total mtoe)	85	110	111	120	135	147	158	163
Development Expenditure Total (£M)	1974	2032	2380	2759	2911	2826	3052	2800
Oil (£M)	1691	1841	2163	2479	2304	1772	1804	1860
Gas (£M)	283	191	217	280	607	1054	1248	940
Development Drilling Wells	96	102	122	137	118	95	108	133
Brent Oil Price $	14	20	35	37	32	29	29	27
Source: DTI (The Brown Book, 1978-1985)								

Source: Brent oil prices were obtained from Wood Mackenzie (2004, GEM, v. 3.01) for the period shown on the table above. Note: Mtoe stands for million tonnes of oil equivalent.

However, as was mentioned in chapter three of this thesis the UK petroleum fiscal regime was unstable (see tax changes in section 3.4.2). This instability arose because of too many adjustments to this fiscal regime, which came with the SPD

in 1981. This instability, plus the regressive nature of the regime itself might have prompted the Government to make it more stable and progressive by targeting economic rent from new oil fields. [84]

Conclusion

It can be stated that the above rationale is flawed for a number of reasons. These are: (1) SPD was phased out in December 1982; (2) APRT was not a harmful duty to the oil and gas industry; and (3) The (1983) petroleum tax relaxation targeted mainly new areas. This means that any harm caused by the 1981 petroleum tax package was removed by removing SPD before 1983. Furthermore, apart from removing APRT in stages, nothing was changed in the fiscal regime applicable to old fields. In other words, no fiscal changes occurred in 1983 in respect of old fields.

However, the above rationale can be seen as meaningful when looking at the stability and progressive roles of the fiscal regime as regards new oil fields. Even so, it was a partial solution as this fiscal regime targeted new fields, whilst old onshore and offshore oil and gas fields were still governed by the pre-1983 Budget petroleum fiscal regime. Therefore, the new fiscal regime cannot be viewed as a mere corrective action to the 1981 fiscal regime. Based on this it can be stated that the above rationale was not met by the policy.

6.4.10 Keeping all Governmental Revenues From Existing Fields and at the Same Time Encouraging the Oil and Gas Industry to Explore and Develop New Fields in New Areas

Results from and comments about testing rationales one, two and five are being used here for the purpose of testing this rationale. This is because those results and comments share some aspects with this rationale. In testing rationale one it was concluded that the oil industry was attracted by the exploration incentives in the 1983 Budget to do more exploration. It was also concluded that the 1983 petroleum tax relaxation was insufficient in overcoming the weakness in

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[84] For explanation of Regressive and Progressive fiscal systems see methodological note after Figure 2-3 on 32.

development activities in the UKCS (see section 6.4.1). Moreover, in testing rationale two it was stated that the 1983 tax relaxation targeted new fields whilst old fields, that obtained development consents before April 1982, were subject to the old petroleum fiscal regime (see section 6.4.2). This means that the Government would have never lost any portion from its revenues from old fields as a consequence of the 1983 petroleum tax relaxation. Furthermore, it was concluded in rationale five that the 1983 petroleum tax relaxation caused the Government to lose £1,451.1 million over the period 1982-93 from its petroleum tax revenues in these fields (see section 6.4.5).

Conclusion

Based on the above it can be stated that this rationale is correct in that it assumes that the 1983 petroleum tax relaxation aimed at keeping Government revenues from old fields and stimulating the industry to explore new areas. However, the rationale ignored the loss resulting from the petroleum tax relaxation in these new areas, as was found in testing rationale five. Therefore, it can be concluded that this rationale was partly met by the policy.

6.5 Summary

In terms of changing the economics of new projects and triggering new developments, the 1983 petroleum tax relaxation only had a minor effect. In terms of fulfilling the expectations in the rationales for its introduction, in only one case was there a successful outcome, which is making sure the regime secure adequate share of the North Sea revenues for the nation. Most of the other cases were partly successful, while the rest were unsuccessful as can be seen from Table 6-21. the following paragraphs summarise the results obtained from testing the rationales for this tax relaxation.

In carrying out the above tests, it was found that the 1983 petroleum tax relaxation was not effective in stimulating exploration activities, although there was no observable problem with this activity. Fluctuations in development activity have been clearly observable since the early 1980s, but the 1983 petroleum tax relaxation was insufficient to resolve this instability. It encouraged the exploration

and development of two small oil fields. These were Innes and Duncan. The analysis shows that investment in new fields was not costly compared with investment in old fields. This is because it was necessary for investments in old fields first to build up the required infrastructure and bear the costs of these infrastructures that were later on available for new fields. As the tax relaxation was the main reason for developing Innes and Duncan, it stimulated very minor increase in UK oil production. However, at the same time it caused the Government to sacrifice £344.2 ($582) million from new fields over the period 1982-93, compared to the situation as it would have been before the1983 Budget tax regime.

The above analysis shows that the sensitivity to changes in oil prices of the petroleum fiscal regime existed under the pre-1983 Budget system. This sensitivity was increased as a result of the post-1983 petroleum tax regime, and benefited oil and gas companies. Furthermore, the tax relaxation released the pressure, in the short term, on oil industry cash flow during the early days of any financial period, by phasing out APRT. This pressure had previously arisen as a consequence this being an advance payments of PRT.

The 1983 petroleum tax relaxation was aimed primarily at keeping the Government revenues from old fields, whilst at the same time encouraging the oil and gas companies to explore new areas. However, the tax relaxation caused the Government to sacrifice part of its revenues from new fields. This meant that although the 1983 petroleum tax relaxation managed to slightly increase oil and gas production, it failed to increase the Government tax take. At the same time, the new fiscal regime secured, on an international scale (see Table 6-9), an adequate share of the petroleum resources for the nation.

Finally, it can be said that, based on the above rationales and the results of testing them, the 1983 petroleum tax relaxation was not as successful as it might have been in every aspect. This was possibly because of the sharp decline in world oil prices in the mid 1980s which had a significant impact on the activities of the UK oil and gas industry. It was the oil and gas industry, and not the Government, which most benefited in terms of economic rent from the 1983 petroleum tax

relaxation. Therefore, it could be claimed that, apart from minor benefits to the nation, in terms of a very slight increase in oil production as a consequence of this relaxation, this tax relaxation package was not entirely successful. Table 6-21 shows the occasions when the rationales for this petroleum tax relaxation were/were not/or were partly met by the policy.

Table 6-21: Summary of the Results of Testing the Rationales for the 1983 Petroleum Tax Relaxation

The 1983 Petroleum Tax Relaxations Rationales	The Rationale		
	Was	Was not	Was partly
	Met by the Policy		
Encouraging oil and gas activities, which include exploration, appraisal and development activities.		√	
Making sure that the regime secures an adequate share of North Sea revenues for the nation.	√		
Helping the oil and gas industry's cash flow to accelerate development activities.		√	
Encouraging the smaller and more costly fields (the marginal fields) in new areas to be explored and developed.			√
The relaxation would encourage more exploration and development and this would help increasing the production level, which means more PRT and taxes to be paid by the industry to the Government.		√	
Making the whole tax regime more sensitive to changes in the world oil price by linking taxation exclusively to profit rather than to mixture of profits and revenues.			√
Sustaining indigenous production beyond about 1988/90.			√
Removing APRT would release some additional funds, which could be used for further investments.			√
Correcting action by the Government to the 1981 petroleum fiscal regime package, which introduced the SPD and gas levy.		√	
Keeping the whole Governmental revenues from existing fields and at the same time attracting the oil and gas industry to explore and develop new fields in new areas.			√

CHAPTER 7: TESTING THE RATIONALES FOR THE UK 1987-88 PETROLEUM TAX RELAXATION

7.1 Introduction

The 1987-88 petroleum tax relaxation consisted of two major tax changes, as was mentioned in chapter three. These changes were:

1. Introducing the Cross Field Allowance concept in the 1987 Finance Act.
2. The 1988 Budget announcement that royalties were abolished for Southern Basin and onshore fields for which development consent was given after 31st March 1982, with effect from 1st July 1988.

Chapter four of this thesis presented the main rationales for the 1987-88 petroleum tax relaxation, which were:

a. The lack of success of the 1983 petroleum tax relaxation.
b. Encouraging further exploration and development expenditure on new fields.
c. Introducing the Cross Field Allowance to enhance the development of discovered marginal oil fields.
d. Introducing the Cross Field Allowance to compensate for the dramatic fall in post-tax company cash flows from North Sea operations and the implications of this for expenditure on new field projects.
e. Abolishing royalties, to reduce costs and encourage development activities in the marginal fields in the Southern Basin area of the North Sea.
f. Abolishing royalties for the Southern Basin of the North Sea, to make the petroleum tax regime profit-related.

This chapter will test these rationales that underpin the above petroleum tax relaxation. In so doing, this chapter will start with defining fields which have benefited from this tax relaxation and fields that will be used for the test. After

that the chapter will look at individual tests of the above rationales. These tests will be considered in the next sections.

7.2 Fields which Benefited from the 1987-88 Tax Relaxation

In order to test the above rationales, it is important first to identify fields which could benefit from the 1987-88 petroleum tax relaxation, and therefore the fields which will be used for the test. This tax relaxation targeted two different areas with two different tax reforms. Therefore, the fields in question consisted of two types. These were: 1) in terms of abolishing royalty: oil fields which are located in the Southern Basin of the North Sea and onshore fields, which were developed after 31st March 1982. 2) with regard to the introduction of the Cross Field Allowance: oil fields which are located in the central and northern North Sea (i.e., not between latitudes 52° and 55° North), which gained development consents after 17th March 1987 and before 15th March 1993.

Each of these tax changes targeted different areas and fields and each has different effective dates. The test of each rationale will use the fields that were targeted by the relaxation in question. A number of these rationales relates to the Cross Field Allowance and a number of them to abolishing royalties for southern and onshore oil fields. Some other rationales are general like the first rationale above.

The next sections show the fields benefiting from each tax reform.

7.2.1 The Cross Field Allowance Fields

In defining fields benefiting from the Cross Field Allowance, 'relevant new fields', the 1987 Finance Act stated:

> "8. —(1) for the purpose of the principal section "relevant new field" means, subject to sub paragraph (2) below, an oil field—
>
> (a) no part of which lies in a landward area, within the meaning of the Petroleum (Production) Regulations 1982 or in an area to the East of the United Kingdom and between latitudes 52° and 55° North; and

(b) for no part of which consent for development has been granted to the licensee by the Secretary of State before 17th March 1987; and
(c) for no part of which a programme of development had been served on the licensee or approved by the Secretary of State before that date".

(Great Britain, 1987, Sch. 14, Part III)

The Cross Field Allowance concept can be simplified to mean that a participator in the UK oil industry was allowed to deduct up to 10 per cent of certain development expenditure incurred after 16th March 1987 (in connection with an offshore taxable oil field outside the Southern Basin of the North Sea, 'field of origin') against PRT profits in any other field, 'receiving field', in which he was a participator (KPMG, 2000, p. 46). Therefore it can be understood here that this allowance was mainly aimed at encouraging development activities in a second generation of oil fields in new areas. It is notable in this context that the Cross Field Allowance would not have had the effect of encouraging *new companies* to invest in the North Sea. These companies would not have had any PRT liabilities that could be reduced by offsetting 10 per cent of development expenditure in other fields, 'benefiting fields'. A new company may have had to sacrifice the benefits of the Cross Field Allowance in the first few years of investment to aim at benefiting from this allowance in later years. In this case, such a company would need to discover oil fields large enough and commercially valid, 'receiving fields', to be liable to PRT. This would be necessary so as to be able to offset ten per cent of developing costs of benefiting fields against PRT liabilities of these receiving fields. This was not the case at that time, as fields explored in the late 1980s and in 1990s tended to be of a very small and small reserves. This indicates that these fields would have been protected by the safeguard concept against PRT. [85] This means that the Cross Field Allowance should have benefited existing oil companies that had PRT liabilities in other oil fields within the UKCS at the time, but not new oil companies which had not been liable to PRT.

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[85] PRT payable by a participator in an oil field for any chargeable period should not exceed 80 per cent of the gross profits, and should be levied only if his adjusted profit for that period exceeds 15 per cent of his accumulated capital expenditure at the end of that period. This concept is called the 'Safeguard Concept' (Great Britain, 1975b, S. 9).

In accordance with the above definition, fields that benefited from the Cross Field Allowance were obtained from the DTI (2004d). These were 32 offshore oil fields developed after 17th March 1987 and before March 1993. The reasons for choosing March 1993 as an end date are first to test the effects of the 1987-88 petroleum tax relaxation on the benefiting fields separately from the effects of the 1993 petroleum tax relaxation on these fields, and secondly, because the Cross Field Allowance was removed in 1993.

Table 7-1 below presents historical data regarding fields which benefited from this tax relaxation in terms of discovery date, Annex B Approval, production start up and reserves' volume. By looking at these data it can be seen that a number of fields like Arbroath, Gannet A, Tiffany, Osprey, Crawford, Toni, Dunbar, Lyell and Strathspey, though discovered in the 1960s and 1970s, had development consents that were obtained after March 1987.

Table 7-1: Historical Data of Offshore Oil Fields Developed Between March 1987 and March 1993.

Field Location	Field Name	Discovery Date	Annex B Approval Date	Production Start up Date	Operator at Approval Time	Reserves	
						Oil (mmb)	Gas (bcf)
Central North Sea	Kittiwake	Sep-81	Sep-87	Sep-90	Shell	70	25
	Glamis	Sep-82	Dec-87	Jul-89	Sun Oil	17.5	0
	Chanter	Sep-85	Dec-87	Apr-93	Occidental	3	2.2
	Arbroath	Dec-69	Dec-87	Apr-90	Amoco	103	0
	Miller	Mar-83	Oct-88	Jun-92	BP	278	570
	Moira	Apr-88	Aug-89	Aug-90	Philips	5.5	0
	Gannet A	Apr-78	Sep-89	Nov-93	Shell	59	411
	Gannet C	Sep-82	Sep-89	Dec-92	Shell	59	140
	Gannet D	Aug-87	Sep-89	Oct-92	Shell	31	30
	Hamish	Jan-88	Feb-90	Feb-90	Amerada Hess	2.5	0
	Blair	May-83	Mar-90	Jun-89	Sun Oil		
	Tiffany	Jul-79	Jul-90	Nov-93	Agip	125	100
	Scott	Jan-84	Aug-90	Sep-93	Amerada Hess	450	290
	Toni	Mar-77	Nov-90	Dec-93	Agip	40	60
	Saltire	Jan-88	Jan-91	May-93	Elf Enterprise	140	150
	Alba	Aug-84	Apr-91	Jan-94	Chevron	370	0
	Nelson	Mar-88	Jul-91	Feb-94	Shell	56.7	0
	Angus	May-83	Nov-91	Dec-91	Amerada Hess	10.6	0
	Donan	May-87	Nov-91	Apr-92	Britoil	26	0
	Leven	Jun-81	Sep-92	Sep-92	BP	11.3	0
Northern North Sea	Ness	May-86	Apr-87	Aug-87	Mobil	45	0
	Don	Jul-76	Mar-88	Oct-89	Britoil	56	0
	Crawford	Feb-75	Sep-88		Hamilton		
	Osprey	Jan-74	Nov-88	Jan-91	Shell	60	6.5
	Emerald	Oct-81	Jan-89	Aug-91	Sovereign	17.27	0
	Linnhe	Aug-88	Sep-89	Oct-89	Mobil	0.8	0
	Staffa	Jul-85	Oct-90	Mar-92	Lasmo	8	20
	Lyell	Jul-75	Jan-91	Mar-93	Conoco	15.15	375.3
	Strathspey	Feb-75	Sep-91	Dec-93	Texaco	79.5	334
	Dunbar	Mar-72	Nov-92	Dec-94	Total	119	14
	Gryphon	Jul-87	Dec-92	Oct-93	Kerr-McGee	96	0
	Hudson	Jul-87	Dec-92	Jul-93	Amerada Hess	87	0
Sources: OPL (1998); DTI (2004d).							

Source: data presented in the above table were mainly obtained from OPL (1998), but data regarding Annex B approval dates and operator at the time was obtained from the DTI (2004d). Note: 'mmb' stands for million barrels, and 'bcf' stands for billion cubic feet.

7.2.2 The Royalty Relief Fields

In defining fields benefiting from the 1988 petroleum tax reform, the Petroleum Royalties (Relief) and Continental Shelf Act 1989 stated:

> "(3) For the purposes of this section—
>
> (a) "relevant Southern Basin or onshore field" means an oil field (within the meaning of Part I of the Oil Taxation Act 1975) other than one—
>
> (i) which is a relevant new field for the purposes of section 36 of the Finance Act 1983 (allowance for fields in seaward areas other than the North Sea Southern Basin having no development consent granted or development programme served or approved before 1st April 1982); or
>
> (ii) for any part of which consent for development was granted to the licensee by the Secretary of State before 1st April 1982; or
> (iii) for any part of which a programme of development was served on the licensee or approved by the Secretary of State before that date;
>
> (b) "relevant onshore area" means any onshore area for which a licence has been granted under section 2 of the Petroleum (Production) Act 1934 which incorporates all or any of the model clauses listed in Part II of the Schedule to this Act other than so much of such a licensed area as is or forms part of an onshore field (within the meaning of the definition in paragraph (a) above disregarding the exclusions);" (Great Britain, 1989, S. 1)

Based on the above definition of new offshore oil fields in the Southern Basin of the North Sea, and from investigating the development consents granted to offshore oil fields since 1975 till 2004 (DTI, 2004d), no offshore oil fields were developed after 1982 in the Southern Basin.

Regarding developments of onshore oil fields, a list of fields was obtained directly from the DTI through email, because it has not previously been in public domain. This list includes the following 19 onshore fields which were developed after March 1982: Welton (Nov.84), Humbly Grove (Jan.85), Farley's Wood (Jul.85), Nettleham (Sep.85), Hatfield (Dec.85), Stainton (Dec.86), West Beckingham (Sep.87), Crosby Warren (Oct.87), Horndean (Sep.88), Scampton North (Nov.88),

Stockbridge (Dec.89), Palmers Wood (Dec.89), Wareham (Jan.90), Whisby (Apr.90), Long Clawson (Oct.90), West Firsby (Jan.91), Kirklington (Mar.91), Rempstone (Apr.91) and East Glentworth (Sep.92). However, the rationales do not refer to these fields, hence they will not be used in the analysis.

This section defined and showed the fields benefiting from each of the above tax relaxations. The next section will deal with testing the 1987-88 petroleum tax relaxation rationales.

7.3 Testing the Rationales for the 1987-88 Petroleum Tax Relaxation

In testing the 1987-88 set of rationales in the next sections, the Cross Field Allowance related rationales will be tested first, and secondly the royalty relief rationales. The first rationale to be tested is a general one as will be seen from the discussion of its content and test.

7.3.1 The Lack of Success of the 1983 Petroleum Tax Relaxation was a Reason for Formulating the 1987-88 Tax Relaxation

There were ten rationales cited for the 1983 petroleum tax relaxation in chapter six of this thesis. The tests of these rationales showed that although there was minor success in some related aspects, the whole tax relaxation package was not successful. The sharp drop in oil prices in the mid 1980s limited to a large extent the expected effects of the 1983 petroleum tax relaxation in a number of major respects. These aspects are: development activity, improvement in the oil industry's cash flow and the Government revenues out of oil taxation. In other words, the sharp decline in oil prices in 1985-86, in addition to the badly planed package of tax relaxation, would have restricted the expected effects of the 1983 petroleum tax relaxation. This situation might have led the Government to introduce the 1987-88 petroleum tax relaxation in order to widen the incentives for the oil industry to increase investment within the UKCS. This last point is discussed in detail in section 7.3.4 in this chapter. However, the Government had had the intention anyway since 1983 of introducing further tax relaxations to the petroleum fiscal regime. The introduction of the Cross Field Allowance reflected the Government's aim of keeping the UKCS as province attractive to the oil and

gas industry. This was to secure a greater supply of oil by extraction from marginal fields, and to create more revenues by taxing the extra production.

In supporting the above argument that led to the statement of Government intention to introduce further tax relaxations, two pieces of discussion are to be considered in this context.[86] First, in Parliamentary Debates (SC Deb (A) 14 July 1983) it was suggested that defining the size of marginal fields and area benefiting from the 1983 petroleum tax relief would allow the Government to extend the relief to other areas when circumstances changed in these areas. It would also be easier for the Government in this case to backdate the relief. Secondly, the letter that was sent from the Minister of State at the Department of Energy to the Chairman of the Selected Committee on Energy on 29th March 1983 stated:

> "We have decided to abolish royalties in relation to new offshore fields outside the Southern Basin area approved for development on or after 1 April 1982. We are also ready to discuss the position of the Southern Basin with the industry and if concessions are found to be necessary they will take effect from Budget day this year".
>
> (Lawson, 1983b, p. 5)

Therefore, it can be understood that the Government had been thinking since 1983 of further royalty reforms in the Southern Basin of the North Sea, and of any other possible relaxation required for developing small marginal fields. Moreover, the oil prices slump in 1986 might have presented a sufficient reason in itself for the Government to introduce the (1987-88) petroleum tax relaxation.

Thus, it cannot be stated that the lack of success of the 1983 petroleum tax relaxation alone led the Government to introduce the 1987-88 petroleum tax relaxation. This is because the Government had an existing intention for further tax reforms. It may therefore be better to reform a late rationale as "the unsuccessful aspects of the 1983 petroleum tax relaxation and the sharp decline in the oil prices in the mid 1980s encouraged the Government to introduce the 1987-88 petroleum tax relaxation". This reformulation fits this rationale into the meaning of rationale number four ((d) in the list above in section 7.1), which will

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[86] This argument was first presented in chapter four of this thesis.

be tested later in this chapter. Thus, it can be stated that this rationale was partly met by the policy.

7.3.2 Encouraging Further Exploration and Development Expenditure in Areas of New Fields[87]

This rationale is similar to rationales number one[88] and four in chapter six of this thesis. In testing this rationale, similar methodology to that used in testing rationale four[89] of the previous chapter will be applied here in investigating the behaviour of exploration and development activities through the size of expenditure on these activities. The definition of 'new field' in the 1987 Finance Act corresponds with the 1982 Finance Act definition for new fields with only one difference - namely the development consent date. A new field according to the 1987 Finance Act should have obtained development consent after 17th March 1987. The new areas according to the definition are: east of Scotland (central North Sea) and east of Shetland (northern North Sea). Therefore, the test will focus on these areas in term of exploration and development activities.

The task of this test is to measure changes in exploration and development activities represented by changes in related expenditure. However, there are no available separate data regarding expenditure in the new areas on exploration and development activities in the pubic domain. An adequate alternative measure is to investigate the state of exploration and development drillings as an indicator of exploration and development activities, and hence of exploration and development expenditures. Using the available exploration and development drilling data in these areas acts as a substitute to check the state of exploration and development activities in the areas of new oil fields. This investigation will be the topic of the next sections.

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[87] This rationale was identified by Mr. Geoff Bernard, from the Oil Taxation Office, speaking with regard to the Cross Field Allowance.
[88] Encouraging oil and gas activities.
[89] Encouraging the smaller and more costly fields in new areas to be explored and developed.

Exploration and Development Drilling in The New Areas

In this section the behaviour of exploration and development drillings will be looked at over the period 1980-1992 in the new areas defined by the 1987 Finance Act. The aim is to compare changes in these activities in two areas. These are: the central and northern North Sea (area of new fields) and the other offshore areas of the UKCS. The comparison will focus on these activities before and after the 1987-88 tax relaxation in these two mentioned areas. This observation and comparison will show the increase, if any, in these two activities in the areas of new fields after the Cross Field Allowance was passed on. Table 7-2 shows figures relating to exploration and development drilling in the above-mentioned two areas.

Table 7-2: Exploration and Development Drilling Activities in the Central and Northern North Sea and Other Offshore Areas of the UKCS Over the Period 1980-1992.

Area	Central and Northern North Sea				Other UKCS Offshore Areas			
Year	Offshore Exploration Drilling Wells	% of Changes in Offshore Exploration Drilling	Offshore Development Drilling Wells	% of Changes in Offshore Development Drilling	Offshore Exploration Drilling Wells	% of Changes in Offshore Exploration Drilling	Offshore Development Drilling Wells	% of Changes in Offshore Development Drilling
1980	47		122		7		0	
1981	69	**47**	133	**9**	5	**-29**	4	
1982	82	**19**	107	**-20**	29	**480**	11	**175**
1983	85	**4**	85	**-21**	43	**48**	10	**-9**
1984	130	**53**	88	**4**	52	**21**	20	**100**
1985	106	**-18**	96	**9**	51	**-2**	37	**85**
1986	73	**-31**	49	**-49**	40	**-22**	36	**-3**
1987	89	**22**	83	**69**	43	**8**	41	**14**
1988	120	**35**	119	**43**	57	**33**	48	**17**
1989	125	**4**	97	**-18**	85	**49**	58	**21**
1990	156	**25**	85	**-12**	68	**-20**	39	**-33**
1991	131	**-16**	101	**19**	55	**-19**	43	**10**
1992	90	**-31**	116	**15**	41	**-25**	51	**19**

Source: DTI (1980-92, Appendix 2).

Note: exploration and appraisal drilling in the east of Scotland and east of Shetland were added up to create figures in the central and northern North Sea areas.

The next sections discuss each of the above-mentioned drilling activities individually to show if there was any increase in these activities after 1987 in the areas of new fields.

Exploration Drilling

From Table 7-2 above it can be seen that the number of exploratory wells in the areas of new fields (central and northern North Sea) decreased over the years 1985-1986. These figures decreased also in the other areas of offshore oil fields during the same years. It can be argued here that the decline in these activities resulted from the dramatic fall in oil prices in 1985-86. However, exploration drilling decreased by 18 per cent and 31 per cent in the new fields in 1985 and 1986 respectively. The reductions in this activity in the other areas of offshore fields were only two per cent and 22 per cent. Taking into account that the new fields had also benefited from the 1983 petroleum tax incentives during 1985-86, it can be pointed out that exploration activities seem to be affected more clearly by changes in oil prices in the areas of new fields than in the other offshore areas. This statement is supported by the 1987 exploration drilling and oil price figures. When the oil price increased from £10.2 in 1986 to £11.2 in 1987, exploration drilling increased in areas of new fields by 22 per cent, while it increased by 8 per cent in the other offshore areas of the UKCS.

Nevertheless, in 1987 the new fields had benefited from both petroleum tax relaxations (1983 and 1987-88), and so the state of exploration drilling was changed. That is to say, exploration drilling was increasing in higher percentages, as the oil price increased, prior to 1985 in the UK offshore areas other than in central and northern North Sea. The increase in exploration drilling activities was higher after 1987 in the areas of new fields than in the other UK offshore areas. This statement is supported also by the 1991 figures. In 1991 oil prices declined to £11.3 from £13.1 in 1990. Exploration drilling decreased by 16 per cent in the areas of new fields, and by 19 per cent in other offshore areas. More interestingly, when oil prices decreased to £8.3 in 1988 from £11.2 in 1987, exploration drilling increased by 35 per cent in the areas of new oil fields, while it increased by 33 per cent in the other offshore areas. These examples show that after 1987 exploration drillings in the new areas were less affected by the decline in the oil prices than in other offshore areas. It can also be seen that exploration drilling in the central and

northern North Sea was driven by a different force when compared with the other offshore areas, namely by the Cross Field Allowance.

This discussion indicates that the Cross Field Allowance had a positive influence on exploration drilling, and hence on exploration expenditure in areas of new fields. However, another decrease in oil prices in 1992, to £10.4, changed the balance of exploration drilling between areas of new fields and other offshore areas of the UKCS. Offshore exploration drilling decreased by 31 per cent in the new areas, but it decreased by only 25 per cent in the other offshore areas in 1992. Furthermore, it is remarkable that in 1989 exploration drilling increased by 4 per cent in the areas of the new fields, while this activity had increased by 49 per cent in the other offshore areas. This change in exploration drilling can be explained by the fact that there is no fixed model for investment in the oil and gas industry. In fact, there are many factors influencing investment decisions in the oil and gas activities other than the oil prices and the fiscal regime. Some of these influencing factors are geology, technology, available finance, workforce, companies' own investment policies, and political reasons. These factors (or some of them) might have affected exploration drilling in the areas of the new oil fields in 1989 and 1992.

Using a simple statistical measure can illustrate the relationship between exploration drilling and oil prices in the areas of new fields and the other offshore oil fields. Plotting the number of exploratory wells drilled against oil prices during the period 1980-1992 in the two mentioned areas in a correlation coefficient measure gives results that are presented in Table 7-3.

Table 7-3: Correlation Coefficient Between Exploration Drilling Wells and Oil Prices.

Period	Central & Northern North Sea	Other UKCS Areas
1980-1992	-0.13	-0.30
1980-1986	0.69	0.35
1987-1992	0.45	0.25

It can be seen from the above table that the correlation coefficient between exploration drilling and oil prices became weaker in the central and northern North Sea after 1987, in comparison with the period to 1986. The same applies to the other UKCS areas. However, it can be seen that exploration drilling in the central and northern North Sea was more effectively linked to oil prices than in the other UKCS areas, as the correlation value is 0.69 as opposed to 0.35 in the other UKCS areas. This might be because of the marginal nature of oil fields in this area. Hence, it still can be said that the 1987-88 petroleum tax relaxation did have an influence on exploration drilling activity after 1986, which weakened the negative oil price effect on these activities. This result supports the conclusion that exploration drilling, and hence exploration expenditure, were stimulated after 1987 by the Cross Field Allowance.

Development Drilling

Table 7-2 above shows the number of development wells drilled in the areas of new fields and in the other offshore areas of the UKCS over the period 1980-1992. It can be seen from this table that development drilling increased in higher percentages in the other offshore areas of the UKCS than in the areas of new fields up to the year 1987. In 1984, for example, the increase in development drilling was 100 per cent in the other offshore areas of the UKCS: it was only 4 per cent in the areas of new fields. However, in 1987, after the Cross Field Allowance was introduced, the new fields were benefiting from the 1983 and the 1987 petroleum tax relaxations. The balance of the development drilling was changed to favour the areas of new fields. This is to say, before 1987 development drilling increased in higher percentages in the other offshore areas of the UKCS than in the new offshore oil fields areas. After 1987 development drilling increased in the areas of new oil fields more than in other offshore oil fields areas. For example, in 1987 development drilling increased by 14 per cent in the other areas of offshore oil fields, while it increased by 69 per cent in the areas of new fields. Development drilling declined by 18 per cent in 1989 in the areas of new fields, while it increased by 21 per cent in other offshore fields areas. This change in the balance between these two areas in terms of development drilling in 1989 might be as a result of the declining oil price in the second half of 1988, down to

£13.7 per barrel. This argument can be backed up by the fact that development activities are very sensitive to changes in oil prices in areas of small and marginal oil fields, like the central and northern North Sea. Nevertheless, after 1989 the balance in development drilling between the above-mentioned areas was as normal.

Similar to the way in which the effects of the 1987-88 petroleum tax relaxation on the exploration drilling activity were investigated, oil prices are plotted against development drilling wells in the new areas over the period 1980-1992. Table 7-4 shows the results.

Table 7-4: Correlation Coefficient Between Development Drilling Wells and Oil Prices.

Period	Central & Northern North Sea	Other UKCS Areas
1980-1992	0.07	-0.67
1980-1986	0.37	-0.09
1987-1992	-0.80	0.43

From the above table it can be clearly seen that after 1986 the link between development drilling and oil prices was negative. As was shown in Table 7-2, development drilling in central and northern North Sea increased in 1987-1988, and in 1991-1992 separately from the oil price influence. This means that the Cross Field Allowance had a clear effect on development activities in the areas of new fields. This is not a surprising result as oil companies worked to benefit from the Cross Field Allowance to reduce their PRT liabilities in other paying fields, and hence to reduce the final costs of their investment. Table 7-2 shows that development drilling in the areas of new fields behaved in a similar way (increasing and decreasing), to development drilling in the other offshore areas. The development drilling rate was always higher in the new areas of offshore oil fields than in other offshore areas after 1986. The opposite is true with regard to the period up to 1986. This definitely indicates that the Cross Field Allowance pushed development drilling up in the areas of new fields. One more thing to be added in this context is that the yearly number of development consents

noticeably increased after 1987. Table 7-5 depicts the number of Annex B Approvals and the number of offshore oil fields developed each year over the period 1976-1993.

Table 7-5: Number of Annex B Approvals Granted During the Period 1976-1993.

Year	Number of Annex B Approvals	Number of Offshore Developments	Year	Number of Annex B Approvals	Number of Offshore Developments
1976	1	1	1985	5	2
1977	0	1	1986	2	3
1978	5	4	1987	3	5
1979	1	4	1988	7	4
1980	2	2	1989	7	6
1981	0	0	1990	8	6
1982	2	2	1991	9	7
1983	4	3	1992	4	4
1984	3	3	1993	3	3
Source: DTI (2004d) and Martin (1997, p. 18).					

From the above table it can be seen that the number of Annex B Approvals and the number of offshore oil fields developed increased after 1987. The average number of Annex B Approvals and number of offshore oil fields developed during the period 1976-1986 is a little above two approvals a year. As can be seen from the above table the yearly numbers of Annex B Approvals and offshore oil fields developed from 1987 onward are considerably more than two. This indicates an influence on development activity after 1987. This influence came from the Cross Field Allowance.

The above investigation of exploration and development drilling shows that the Cross Field Allowance in the areas of new offshore oil fields encouraged these activities. It is common sense that the increase in drilling activities requires an increase in the expenditure. This means that exploration and development expenditure has been increased in the areas of the new offshore oil fields as a consequence of introducing the Cross Field Allowance. However, it is still worth checking the exploration and development expenditure, based on the available data, to see if it does give any insight into the increase in these expenditures in the

central and northern North Sea after 1987. This issue will be the focus of the following section.

Exploration and Development Expenditure

From Table 7-6 and Figure 7-1 below it can be seen that exploration and development activities in the UKCS slowed down in 1986-87. This slow-down might have been caused by the sharp slump in the oil prices in the mid 1980s. After that, these activities started to increase with the increase in oil prices. However, figures in Table 7-6 present the total exploration and development expenditure in the UKCS over the period 1980-93. Exploration expenditure represents the total yearly exploration expenditure occurring, including the cost of appraisal wells within the UKCS, offshore and onshore, and also on oil and gas fields. Development expenditure figures represent total development expenditure on offshore and onshore oil fields. The figures represent total figures for the whole expenditure within the UKCS. This creates a limitation on the use of these data. This is because it cannot be said that an increase in any one of these expenditure in any certain year is derived from certain factor in any particular area.

Figure 7-1: Exploration and Development Expenditure Over the Period 1980-1993

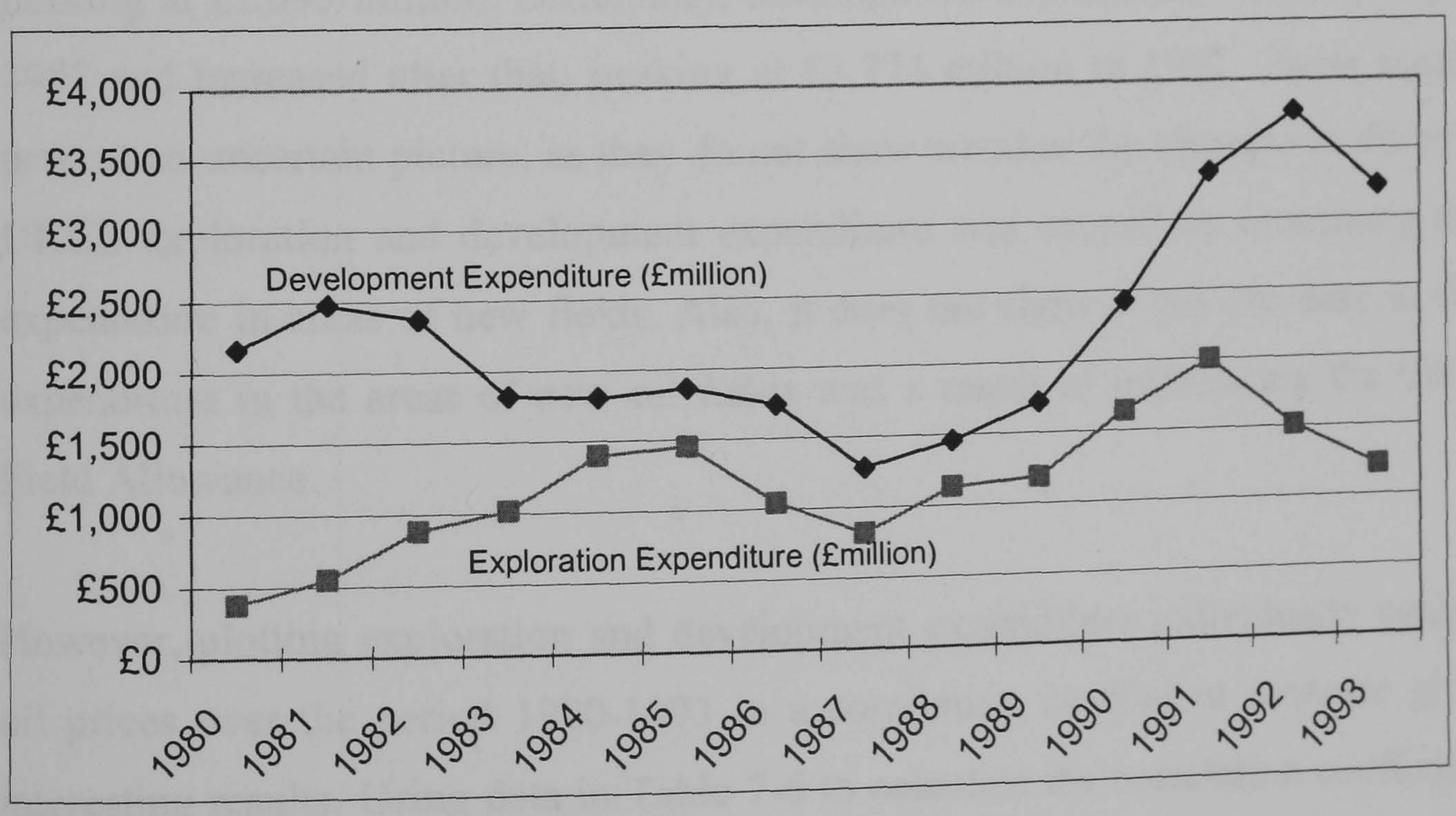

Table 7-6: Exploration and Development Expenditure Over the Period 1980-1993

Year	Oil Price £barrel	Exploration Expenditure £ million	% Change in Exploration Expenditure	Development Expenditure £million	% Change in Development Expenditure
1980	15.06	378.8		2163	
1981	18.42	550.2	45	2477	15
1982	19.00	880.1	60	2370	-4
1983	19.79	1016.8	16	1818.1	-23
1984	22.30	1395	37	1802	-1
1985	21.64	1450	4	1859	3
1986	10.27	1042	-28	1735	-7
1987	11.20	816	-22	1274	-27
1988	8.30	1129	38	1454	14
1989	11.10	1182	5	1712	18
1990	13.16	1637	38	2425	42
1991	11.37	1995	22	3343	38
1992	10.48	1508	-24	3774	13
1993	22.69	1213	-20	3229	-14
Source: DTI (the Brown Book, 1980-1993).					

Source: exploration and development expenditures were extracted from Appendix 12 of the Brown Book in different years. The oil prices were obtained from the GEM (2004, v. 3.01).

From the above table, it can be seen that total UKCS exploration expenditure increased along with oil prices from 1980 up to 1985. After that year exploration expenditure decreased over the next two years and increased again up to 1991 peaking at £1,995 million. Differently, development expenditure fluctuated up to 1987 and increased after that, peaking at £3,774 million in 1992. These figures present an uncertain picture, as they do not show whether the increase in the total UKCS exploration and development expenditure was caused by increasing this expenditure in areas of new fields. Also, it does not show if any increase in this expenditure in the areas of new oil fields was a result of introducing the Cross Field Allowance.

However, plotting exploration and development expenditure individually against oil prices over the period 1980-1993 in a correlation coefficient measure gives interesting results. Using data in Table 7-6 to calculate the correlation coefficient of the exploration expenditure along with oil prices gives a result of –0.12. This result shows that exploration expenditure was inconsistent with changes in oil prices. Breaking the period down and plotting the above two variables together

over shorter periods gives very interesting results. The correlation coefficient for the period 1980-1986 is found to be 0.46. This means that exploration expenditure were linked to changes in oil prices during this period. The result of the correlation coefficient calculation over the period 1987-1993 is negative (-0.4), meaning that there was not direct association between these two variables. This simply might mean that the Cross Field Allowance divorces the influence of changes in oil prices from total exploration expenditure. This can be seen from Table 7-6, as in 1988, while the price declined to ($14.8) £8.3 from ($19.3) £11.2 in 1987, exploration expenditure increased to £1,129 million, from £816 million in 1987. Furthermore, in 1991, the oil price declined from ($23.6) £13.1, in 1990, to ($20.1) £11.3, while exploration expenditure increased by 22 per cent.

Linking the above observations to the results of investigating the behaviour of exploration drilling activities together over the periods 1980-1986 and 1987-1990, reveals that there was some consistency between the two observations. This may be a sign of the direct influence of the Cross Field Allowance on exploration activity. With regard to development activity, plotting development expenditure against oil prices in a correlation coefficient gives positive results, which are: 0.06 for the period 1980-1993, 0.06 for the period 1980-1986, and 0.04 for the period 1987-1993. From these results it can be seen that although development activity seemed to be more sensitive to changes in oil prices than exploration activity, the association between development expenditure and oil prices seems to become less strong after 1987 than before. This also means that development expenditure was driven after 1986 by another force, which is likely to be the Cross Field Allowance. However, it is worth pointing out that because oil investment, particularly in the development stage, takes place over up to 25 years, one would not expect a very strong relationship between short-term changes in oil prices and oil investments. Moreover, and as discussed in chapter six, oil companies use a particular oil price in making project decisions and only change this price slowly in response to short-term price signals - and even then just to new levels not to track changes in oil prices. Oil companies do have more money to invest when current prices are high. Exploration and development drillings can be expected to be more sensitive to price, where there are good prospects. However, there may be many other factors (such as costs, technology, and market issues) in the decision

making process, which intervene in the relationships between oil price and investment.

Conclusion

May now be concluded that the Cross Field Allowance did have an effect on exploration and development drilling, and hence on investment expenditure in the areas of new fields. However, although investigating exploration and development expenditure gives insights into increase in these activities, no general conclusions can be drawn. This is because, as discussed, data on exploration and development expenditure are only available for the whole area of the UKCS. Moreover, in spite of concluding that development activities were enhanced in new offshore oil fields areas after 1987, it is important to draw attention to the nature of development decisions. Development drilling is just one aspect of the development investment, which includes building up platforms, pipelines, and any other necessary infrastructures. Therefore, an increase in development drilling may not indicate an increase in total development expenditure, or an increase in development activity as a whole. However, the test conducted does show that exploration and development drilling activities in the areas of new oil fields moved in line with exploration and development expenditure within the UKCS.

Overall, it can be concluded in the light of the results obtained that exploration and development drilling, and hence exploration and development expenditure, did increase in the areas of the new offshore oil fields after 1987 in response to the introduction of the Cross Field Allowance. Based on this conclusion, it can be stated that this rationale did have the anticipated outcome and that this policy aimed at encouraging further exploration and development expenditure was reasonably effective. In other words, this rationale was met by the policy.

7.3.3 The Cross Field Allowance will Enhance the Development of Discovered Marginal Oil Fields

This rationale is similar to rationale number four in the previous chapter.[90] The main difference between them is that the focus of this rationale is on the economic side of the development decisions, while the former focused on size of the fields.

A marginal field is a field that may not produce enough net income to make it worth developing at a given time, but should technical or economic conditions change, such a field may become commercially valid (Nakhle, 2004, p. 329). This definition makes it clear that oil companies require certain level of profit, 'economic rent', to develop an oil field. For simplicity in testing this rationale the minimum accepted IRR will be assumed at 15 per cent as discussed in chapter six of this thesis.[91] Tracing the effects of the Cross Field Allowance on marginal and other fields is not an easy task. The concept allowed ten per cent of development expenditure of a benefiting field to be offset against the PRT profit of another field, 'a receiving field'. The difficulty arises because there are no available sources (in the public domain) which mention fields which receive and so benefit from the Cross Field Allowance. Nevertheless, investigating the IRR of offshore oil fields that were developed after 16th March 1987 helps in performing the test.

The Cross Field Allowance was not a field development incentive, but a company incentive, though it had a field level effect. This means that a benefiting field would not have actually benefit directly from the Cross Field Allowance in the form of increasing its cash flow. The financial benefits would appear in the cash flow of a receiving field. This is because the concept would reduce the PRT profits of such a field by ten per cent of the development costs of the benefiting field. Hence, this would benefit the operating company's cash flow by reducing the PRT liabilities in one or more of its PRT paying fields. Therefore, it can be seen that the Cross Field Allowance acted as a company incentive.

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[90] Encouraging the smaller and more costly fields in new areas to be explored and developed.

[91] Bond et al. (1987) argue that if the IRR were less than the company's discount rate for a certain field, then such a field would not be commercial in terms of development and extraction.

Oil companies would not develop an oil field without ascertaining whether it were commercially valid. Therefore, the current task is to investigate how the Cross Field Allowance affected the level of commerciality of benefiting fields. This will show if the Cross Field Allowance encouraged the development of any of these fields. In investigating the effects of the Cross Field Allowance on the commerciality of the benefiting fields, the following methodology is applied. Ten per cent of the development costs of a benefiting field will be calculated over the period 1987-1992. The results will be multiplied by 75 per cent, 'the PRT rate', and the final result will be deducted from the development costs of the field in question. This deduction is logical because the 75 per cent (PRT rate) out of the ten per cent development costs of a benefiting field (Cross Field Allowance rate) means an increase in the cash flow of the benefiting field. The increase in the cash flow of a marginal field might mean that this field would become commercially valid, and hence stimulate the operating company to develop it. This methodology will be referred to henceforth as the Cross Field Allowance scenario. The improvement in a field's cash flow can result either from an increase in the revenues of the field or a reduction in its costs.

The GEM (2004, v. 3.01) does not have a separate tax package for the Cross Field Allowance as it has for the 1983 tax changes. Therefore, a calculated adjustment, in respect of data for benefiting fields in the GEM, is to be applied. The adjustment will be calculated by using the current available financial data from the GEM (2004) regarding each of the benefiting fields. As was mentioned above, development costs for these fields will be reduced by the 75 per cent of the ten per cent of the development costs. After that the field calculations are to be run under a ten per cent real discount rate.[92] Amending development costs is straightforward, while amending the revenues requires adjusting either the production or the price figures. Both of these amendments lead to the same results in the cash flow and IRR of a field.

Fields that had benefited from the Cross Field Allowance had benefited from the 1983 petroleum tax relaxation as well. In a number of cases the 1983 petroleum

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[92] An example of this methodology is given in Appendix 4-1.

tax relaxation was sufficient incentive for the development of these fields as this relaxation increased their IRR to more than 15 per cent. The Cross Field Allowance on the top of the 1983 tax changes would have increased the IRR for some other fields from less to more than 15 per cent. Therefore, the investigation will be applied by comparing the IRR for each of the benefiting fields based on three scenarios. These are: (1) the pre-1983 petroleum tax relaxation; (2) the post-1983 tax package; and (3) the post-1987 tax system (the Cross Field Allowance scenario). Regarding the pre-1983 tax scenario, the application uses the tax regime that was defined as 'offshore licence rounds 1-4' in the 'Tax Marker' option of the GEM, at ten per cent real discount rate. Concerning the post-1983 petroleum tax package, the base mode in the GEM (2004) is to be used. The Cross Field Allowance scenario will provide the post-1987 results.[93] Table 7-7 shows fields that had benefited from the Cross Field Allowance, and presents the IRR for each oil field based on the above-mentioned three different scenarios.

The rationale mentions developing discovered marginal fields, which means that any offshore oil fields discovered after April 1987 are excluded from this analysis. Therefore, ten oil fields are to be excluded from the analysis, as they were discovered after April 1987. These fields are Donan, Gryphon, Hudson, Gannet D, Angus, Hamish, Saltire, Nelson, Moira and Linnhe. Further, it continues to be assumed that the 15 per cent IRR is a benchmark for oil companies in terms of developing oil fields. Therefore any oil field with a post-1983, but pre-1987 IRR of more than 15 per cent will be excluded. Such a field is not marginal in terms of the above meaning. In this context, a further nine oil fields are to be excluded from the analysis, which are, Arbroath, Dunbar, Osprey, Toni, Leven, Glamis, Gannet C, Alba and Ness. In addition, any oil field with undefined or a negative post-tax IRR according to the post-1983 and post-1987 Budgets will be excluded. Development of this type of fields would have been driven by some other factors, technical or economic, but not fiscal incentives. This group contains six of the 32 fields which benefited from the Cross Field Allowance. These six fields are, Lyell, Don, Tiffany, Emerald, Blair and Crawford. Based on this narrowing of the number of relevant fields, in Table 7-7, the field-by-field analysis is applied to the

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[93] For the application of the Cross Field Allowance scenario see Appendix 4-1.

residual seven oil fields out of the 32 fields that had benefited from the Allowance. These are: Chanter, Staffa, Gannet A, Strathspey, Scott, Miller, and Kittiwake.

Table 7-7: Discovery and Annex B Approval Dates, IRR According to Pre-1983, Post-1983 and Post-1987 Budgets of the Fields Benefiting From the 1987 Petroleum Tax Relaxation

Field Name	Discovery Date	Annex B Approval	IRR %			Total Benefit £M
			Pre-1983	Post-1983	Post-1987	
Arbroath	Dec-69	Dec-87	24.95	30.41	36.3	25.42
Dunbar	Nov-73	Nov-92	17.2	19.71	20.13	7.92
Osprey	Jan-74	Nov-88	12.92	16.24	20.36	26.28
Strathspey	Feb-75	Sep-91	10.14	13.28	15.16	20.36
Lyell	Jul-75	Jan-91	#	-3.92	-2.71	9.14
Don	Jul-76	Mar-88	#	#	#	15.37
Gannet A	Apr-78	Sep-89	7.23	8.66	10.09	31.86
Tiffany	Jul-79	Jul-90	#	#	#	65.00
Toni	Jul-79	Nov-90	19.6	22.61	24.91	10.76
Leven	Jun-81	Sep-92	138.49	217.15	362.01	1.59
Kittiwake	Sep-81	Sep-87	7.73	10.53	14.47	31.98
Emerald	Oct-81	Jan-89	#	#	#	6.47
Glamis	Sep-82	Dec-87	82.5	104.06	131.49	4.14
Gannet C	Sep-82	Sep-89	23.39	27.16	30.46	19.95
Miller	Mar-83	Oct-88	12.9	14.43	16.71	133.30
Scott	Jan-84	Aug-90	11.6	14.01	15.62	47.30
Alba	Aug-84	Apr-91	13.35	15.09	16.15	37.10
Staffa	Jul-85	Oct-90	2.47	10.9	19.02	3.35
Chanter	Sep-85	Dec-87	1.01	4.45	6.91	2.42
Ness	May-86	Apr-87	1087.8	1806.3	#	8.88
Donan	May-87	Nov-91	58.04	71.61	83.78	2.22
Gryphon	Jul-87	Dec-92	15.99	19.22	19.22	0.00
Hudson	Jul-87	Dec-92	128.48	239.72	239.72	0.00
Gannet D	Aug-87	Sep-89	19.86	22.11	24.4	8.17
Angus	Dec-87	Nov-91	177	237.82	312.75	2.21
Hamish	Jan-88	Feb-90	105.6	133.45	166.29	0.87
Saltire	Jan-88	Jan-91	3.55	5.62	7.7	39.02
Nelson	Mar-88	Jul-91	24.34	27.22	29.38	48.97
Moira	Apr-88	Aug-89	12.48	20.89	30.58	2.70
Linnhe	Aug-88	Sep-89	#	#	#	4.11
Blair	1983	Mar-90	#	#	#	1.15
Crawford	1975	Sep-88	#	#	#	7.43
Total Cash Benefit for Fields Benefiting From the Cross Field Allowance						625.39

Source: Fields names and approval dates were obtained from the DTI (2004d). Discovery dates were obtained from OPL (1998). Notes: IRR figures were calculated by using the GEM (2004) based on different scenarios. Total benefits to oil fields from the Cross Field Allowance were calculated based on fields' annual summary cash flows' statement calculated by using the GEM (2004).

The next section presents a field-by-field qualitative analysis of the above-mentioned seven oil fields in the light of their IRR presented in Table 7-7.

Field-By-Field Analysis

This section investigates each of the above counted seven oil fields individually, to explain the circumstances of the development of each field. This will clarify the role of the fiscal regime incentives in developing these fields. It also shows which fields were more likely to be developed chiefly because of the fiscal incentives represented in the Cross Field Allowance.

Chanter Oil Field

This oil field was discovered in September 1985 and obtained development consent in December 1987. This consent was amended in 1991 (OPL, 1998, p. 181). Chanter oil field was formally known as 'Southeast Piper'. This field was tied into the Piper B platform as a single well satellite. Chanter oil field is located in the area of Piper field, UK 15/17. This area is described as having a combination of favourable geological conditions and export infrastructure, and remains one of the most productive in the central North Sea.

Applying the pre-1983 petroleum fiscal regime to this field using the GEM (2004, v. 3.01) shows that it would have an IRR of 1.01 per cent. It has an IRR of 4.4 per cent according to the post-1983 petroleum fiscal regime, with 6.9 per cent according to the Cross Field Allowance scenario. This means that the 1983 petroleum tax relaxations and the Cross Field Allowance increased the IRR for this field by 5.9 percentage points. This in its turn means that the Cross Field Allowance on the top of the 1983 petroleum tax relaxation could not push the IRR of Chanter oil field above 15 per cent. However, the field was developed in spite of its low IRR, which means that there were some reasons other than the fiscal incentives for its development.

Chanter oil field can be considered as a marginal oil field, because it has an IRR of 4.4 per cent according to the post-1983 relaxation. The calculated benefit to this field's cash flow from the Cross Field Allowance is £25.4 million. These

benefits are in forms of direct tax saving from the 1983 petroleum tax relaxation and indirect saving from the Cross Field Allowance. These savings aided Chanter's cash flow. Chanter was developed in spite of its low IRR, which is less than 15 per cent under the Cross Field Allowance scenario. However, the operating company had other interests in the Piper area, which provided an incentive to this company to develop this field. Also, by looking at the lag between the discovery date and the development approval date, which is two years, it can be stated that the existing infrastructure and the applied technology were the major drivers for developing Chanter. This conclusion is consistence with Martin (1997, p. 57) who concluded that this field was developed as a consequence of new technology but not the fiscal incentives.

Staffa Oil Field

This oil field was discovered in July 1985 and obtained Annex B approval in October 1990. Staffa was the first Lasmo's development project in the North Sea. It was a very small field of 11.5 mboe reserves. This field was previously known as East Ninian, and was operated as a satellite field tied into Ninian southern platform, which is operated by Lasmo Oil Company (OPL, 2004, p. 206). Staffa is a very small oil field and Lasmo Oil Company used a simple sub-sea tie-in to Ninian south in operating it, by using two production wells via a pipeline system (OPL, 1998, p. 226).

The fiscal improvement is very clear for the development of this oil field. The 1983 petroleum tax relaxations increased its IRR by 8.4 percentage points (10.9 per cent) over the pre-1983 petroleum tax system (2.4 per cent). The Cross Field Allowance scenario shows that the IRR of this field would be 19 per cent. The 1983 petroleum tax relaxation would have increased the cash flow of this field by £5.2 million over the pre-1983 tax scenario. The Cross Field Allowance scenario shows an increase in Staffa's cash flow by £3.3 million over the post-1983 tax system. Although this field would not have been liable to PRT under the pre-1983 petroleum tax regime, it is supposed to have benefited from the Cross Field Allowance as it was developed after March 1987. However, Lasmo did not have any PRT liability at the time of developing Staffa, as it was the first development

for this company.[94] Although it is a marginal field by reference to its IRR according to the post-1983 fiscal system (10.9 per cent), it did not benefit from the Cross Field Allowance in its development. This is one case where oil companies do not benefit from a tax relaxation, and in such a case the Cross Field Allowance would not be considered as a tax relaxation from Lasmo Oil Company's point of view.

As a conclusion, it can be stated that the 1983 petroleum tax relaxation incentives, improved technology and the location of this very small field, and not only the Cross Field Allowance, together played a role in the development of this field.

Gannet A and Other Gannet Oil Fields

Gannet A was discovered in April 1978 (C in September 1982), and both of them obtained Annex B Approvals in September 1989. Shell UK Exploration and Production Ltd operates these two fields. From Table 7-7 above, it can be seen that the IRR of Gannet A would have been less than 15 per cent under the pre-1983 petroleum tax regime (7.2 per cent), and improved by 1.4 percentage points because of the 1983 petroleum tax relaxation to become 8.6 per cent. The Cross Field Allowance scenario shows that the IRR of this field would be 10 per cent. However, Gannet A really cannot be considered alone. It is in the same area as other, less marginal fields. For example, Gannet C would have an IRR of 23.3 per cent according to the pre-1983 petroleum tax regime and 27.1 per cent under the post-1983 regime. This means it was commercially viable for development without the effect of the Cross Field Allowance.

Looking at the state of Gannet fields it can be seen that three Gannet fields (A, C, and D) were developed in September 1989, although they had different discovery dates. This might mean that Shell was waiting to build up a portfolio of oil fields in the same area that could make use of the same infrastructure to make it more economic and profitable for the company. This discussion can be supported by the fact that Shell had seven Gannet fields (A-F) in the same geological area (UK

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[94] The second development for Lasmo was Birch oil field in March 1994, after the abolition of the Cross Field Allowance.

22/21, 21/25, 21/30 and 22/30), and all of these fields are linked to Gannet A (DTI, 1997, p. 92).

At this point it can be stated that, although Gannet A and C benefited from the 1983 tax relaxation and the Cross Field Allowance in their development, these fiscal incentives were not the main reason for developing Gannet A. This is because it would have an IRR of 10 per cent according to the Cross Field Allowance scenario, which is below the assumed target of 15 per cent. Building a portfolio of oil fields in the same area that would benefit from the same infrastructure and technology seems to be the main driver for developing the Gannet A field.

Strathspey Oil Field

This oil field was discovered in February 1975, and obtained Annex B approval in September 1991. It was a small oil field with 143 mboe (DTI, 1995, p. 133). Applying the pre-1983 petroleum tax regime to this field resulted in an IRR of 10.1 per cent. The post-1983 IRR is 13.2 per cent, while the Cross Field Allowance scenario resulted in an IRR of 15.1 per cent. This means that the 1983 petroleum tax relaxation improved the commerciality of this field by means of 3.1 IRR percentage points, it did not push it to higher than 15 per cent, but the Cross Field Allowance did.

Strathspey is one of three fields developed as satellite fields of Ninian. It is located in the Brent and Statfjord area (OPL, 2004, p. 298). Therefore it can be said that this field had benefited from the existing infrastructure and new technology in its development. However, given that this field was discovered in 1975, and had not obtained Annex B approval until 1991, it can be argued, therefore, that primarily the fiscal incentives and particularly the Cross Field Allowance drove development of this field. The fiscal factors translated into a £85.6 million increase in the cash flow of this field because of the 1983 fiscal relaxation over the pre-1983 fiscal terms, and £3.3 million because of the Cross Field Allowance on the top of the 1983 fiscal changes. This increase in the cash flow arose mainly from savings in royalties and from allowable development

expenditure based on the Cross Field Allowance. To sum up, development of Strathspey oil field was driven by the Cross Field Allowance.

Scott Oil Field

This oil field was discovered in 1984 and obtained development consent in 1990. Scott oil field benefited from the 1983 petroleum tax relaxation, and from the Cross Field Allowance. The IRR of this field would be 11.6 per cent according to pre-1983 regime, 14 per cent under the post-1983 regime and 15.6 per cent according to the Cross Field Allowance scenario. In terms of cash flow, the field benefited from the 1983 petroleum tax relaxation by £357.6 million and £47.3 million from the Cross Field Allowance. From these statistics it can be said that the 1983 petroleum tax relaxation benefited Scott more than the Cross Field Allowance. In other words, the 1983 petroleum tax relaxation was more effective for the commerciality of this field, but was not sufficient to drive the development decision.

However, it cannot be stated that the 1983 and 1987 tax relaxations were the only reasons for the development of this field, because it is a large oil field with reserves of 539 mbo only at a 145 metre water depth. The discovery of a nearby small field in 1990 (South Scott) might have formed a reason for building up a pair of bridge-linked platforms and developing this large oil field (OPL, 1998, p. 28). However, based on the results of applying different fiscal scenarios to this field and taking into account that this field was discovered in 1984 and obtained Annex B Approval in 1990, it can be stated that the fiscal factors formed a main reason for the development of this field. The 1983 petroleum tax relaxation should have benefited the commerciality of this field, but was not sufficient to push the IRR to more than 15 per cent: the Cross Field Allowance on top did so. At this point it can be stated that the commerciality of this oil field was validated because of the fiscal incentives from the 1987 petroleum tax relaxation, its reservoir size, the improved technology and discovering a nearby South Scott oil field. These factors together helped in making worthwhile the development of Scott oil field.

Miller Oil Field

Miller was discovered by BP in 1983, and obtained development consent in October 1988. The field has a medium sized reserve of 394 mboe, at a water depth of 108 meters, and located in an area of a very well built infrastructure. It was clarified by BP (1995, p. 17) that Miller's costs rank among the lowest in the North Sea. The field was benefited from the 1983 petroleum tax relaxation by 1.5 percentage points in term of IRR, and by £205.3 million in terms of cash flow increase. The Cross Field Allowance scenario shows a rise in the IRR of this field from 14.4 per cent to 16.7 per cent, and a cash flow benefit estimated at £47.3 million. Therefore, it can be said that the 1987 petroleum tax changes did provide an incentive for developing this field.

Kittiwake Oil Field

Kittiwake was discovered in September 1981 and obtained development consent in September 1987. The field is of a small size as its reserve has 78 mbo. The 1983 petroleum tax relaxation improved the IRR of this field by 2.8 percentage points (from 7.7 per cent to 10.5 per cent) and also increased its cash flow by £40.3 million. The Cross Field Allowance scenario increased Kittiwake's IRR to 14.4 per cent, and showed a cash flow benefit of £31.9 million to this field. This increase arose mainly from saving on royalty payments. The field would not have been liable to PRT under the pre-1983 petroleum tax relaxation, because it was just a small oil field and protected by the safeguard concept against PRT liability. Kittiwake was originally one of five fields comprising the 'Gannet Group'. The low development costs of Kittiwake made development possible before the other Gannet fields. This was because of the location of this field among a ready built infrastructure at a low water depth of 85 meters (OPL, 1998, p. 365; 2004, p. 398).

It is clear that the fiscal conditions had an effect on the commerciality of this oil field. This is shown by the increase of the IRR of this field from 7.7 per cent according to the pre-1983 tax system to just less than 15 per cent (14.4 per cent) according to the post-1987 tax scenario. It can be stated that the 1983 fiscal

regime incentive and the Cross Field Allowance on the top of these incentives materially improved the commerciality of the Kittiwake oil field. However, these fiscal changes were not sufficient to increase the IRR to higher than 15 per cent. The low development costs which might have occurred because of the new technology and existing infrastructure in the Gannet area in addition to the fiscal incentives should have aided the development of this field.

Conclusion

From the above field-by-field analysis, it can easily be seen that different oil fields have different conditions and therefore have different development incentives. These incentives could be in the form of improved technology, reduced development and operating costs, the existence of a portfolio of fields in one geological area, or a tax relief. The Cross Field Allowance for instance, benefited most of the above-described seven fields. Table 7-7 above shows that the total theoretical benefit of the Cross Field Allowance to the totality of benefiting fields would have been £625.3 million. However, a number of oil fields would not have benefited from the allowance in practice because development expenditure on these fields (such as Osprey) started in 1993. Staffa oil field would not have benefited from the allowance because its operating company was not liable to PRT elsewhere at the time. The field-by-field analysis shows that the Cross Field Allowance motivated the development of three explored oil fields. These were Strathspey, which was explored in 1975 and obtained development consent in 1991; Scott which was discovered in 1984 and obtained Annex B Approval in 1990; and Miller which was discovered in 1983 and obtained development consent in 1988. These three fields would have been considered as marginal fields before their development consent dates, otherwise they would have been developed. The 1987 fiscal changes were major factors among other economic and technological factors for developing three fields. These are: Strathspey, Miller, and Kittiwake. Based on this discussion it can be stated that this conclusion justifies this rationale, but it cannot be said that the policy behind this rationale was effective. This is because there were 85 oil fields discovered but not

developed before 1987,[95] and the Cross Field Allowance was a main reason for the development of three fields only. Therefore, the role of the Cross Field Allowance in developing three oil fields could justify its introduction, but at the same time this was only a small fraction of the candidate-discovered oil fields. Therefore, it can be concluded that this rationale was partly met by the policy.

7.3.4 Introducing the Cross Field Allowance was to Compensate for the Dramatic Fall in Post-Tax Company Cash Flows From North Sea Operations, and the Implications of this for Expenditure on New Field Projects

Testing this rationale involves both assessing whether the problem addressed by the policy actually existed at the time, and assessing what effect it had. Therefore, the test will be in two parts. The first will look at oil companies' cash flow between 1984 and 1987, in other words, in the three years prior to the measure being introduced. Secondly, I will examine what happened to oil industry activities in the areas of the new fields as a result of introducing the Cross Field Allowance. This has in fact already been addressed in the previous tests.

UKCS Post-Tax Cash Flow

The root of the dramatic fall in post-tax company cash flow is a result of the dramatic fall in company revenues as a consequence of the sharp drop in oil prices in 1986. Nevertheless, the decline in oil price was the reason for the negative effects at the time on companies' cash flows, not the fiscal regime. Oil companies called for a 'smoothing' in the fiscal regime in order to increase their cash flows, though this would be at expense of the Government tax take. In this regard, Bond et al. (1987, p. 7) point out:

> "The collapse of the world oil price in early 1986 led to many calls from oil companies for a reduction in the level of taxation on the exploitation of oil and gas from the United Kingdom Continental Shelf (UKCS). A familiar argument was that the regime was based on a price exceeding $30 per barrel. With price crashing to around $12,

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[95] For a list of these fields see Appendix 4-1.

before recovering to $18, there would need to be some relaxation of taxation".

Table 7-8 represents the cash flow of a number of oil companies from their operations within the UKCS during the 1980s. The choice of companies in the table is based on one criterion, namely that companies should have had operations in the UKCS well before 1987. Figures in the table were obtained from Wood Mackenzie (2004) by running the GEM (v. 3.01) to produce companies' reports. The annual summary cash flow table, in the companies' reports, is a detailed cash flow.[96]

Table 7-8: Oil Companies' Cash Flow Over the Period 1984-87

Oil Companies' Cash Flow £million				
Year	1984	1985	1986	1987
Allfields	10,422.50	6,688.30	-3,593	4,625.40
Eni	129.2	138.7	30	42.5
Amerada	173.5	143.3	-38.7	-1.1
Murphy	23.1	22.2	-32.6	16.5
BP	2,288.30	1,308.80	-700	433.1
ExxonMobil	1,082.70	1,082	-336.8	472.5
Oil Price $	29.34	27.55	14.73	18.06

Looking at the cash flow of each company in the table, along with the oil price from year to year, it can be seen that the companies' cash flow sharply decreased in 1986 when oil price decreased to $14.7 from $27.5 in 1985. This is an expected result as a decline in the price means a decline in the revenues and the cash inflow.

Oil companies might be operating onshore and offshore at the same time, and most of them have oil and gas activities. Their cash flows do not reflect only the state of their offshore oil activities. Therefore, investigating the cash flows of a number of North Sea oil fields, rather oil companies' cash flow, should give a better idea of the oil and gas industry's cash flow from the UKCS.

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[96] Appendix 4-2 presents an annual summary cash flow table for all fields of the UKCS.

Table 7-9 shows the cash flow of a number of UK offshore oil fields over the period 1984-87. Figures in the table were obtained from Wood Mackenzie (2004) by running the GEM (v. 3.01) for oil fields. Fields in the table were chosen based on the criterion that a field should be begun operation well before 1987. The annual summary cash flow of the fields contains detailed information regarding revenues and expenditure.[97]

Table 7-9: Cash Flow of Oil Fields Over the Period 1984-87.

Oil Field Cash Flow £Million				
Year	1984	1985	1986	1987
Argyll	12.8	38.7	-4.9	12.7
Auk	30.1	5.5	-47.5	5.1
Buchan	28.8	47.4	-22.3	24.3
Beatrice	227.4	273.2	-43.9	41.5
Magnus	614.5	710.5	111	275
Maureen	370	431	53.2	147.2
Tartan	139.5	140.5	-23.7	79.4
Hutton	115.4	250	138	234.8
Oil Price $	29.34	27.55	14.73	18.06
Source: Wood Mackenzie GEM (2004, v. 3.01)				

From Table 7-9 it can be seen that in 1986 the cash flow of each of the above fields decreased. It can be understood, by linking the cash flow in 1986 to the oil price in this year, that the decline in the cash flow of the oil fields was caused by the sharp decline in the oil price. This result agrees with the result obtained based on the observation of oil companies' cash flow.

Based on the above inspection of UK oil companies' cash flow, and also the cash flow of a number of central and northern North Sea fields, it can be stated that there was a real problem with the UK oil industry's cash flow after the mid 1980s. Although the above tables (Table 7-8 and Table 7-9) show that cash flows of oil companies and fields had recovered quickly after 1986, they stayed low compared with the years prior to 1986. This outcome justifies the first part of the rationale regarding the dramatic fall in the companies' cash flow. The next section deals

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[97] Appendix 4-2 presents a table which shows information available for the annual summary cash flow of the Argyll oil field.

with the second half of the above rationale, which relates to the implication of the cash flow problem.

The Implication of the Cross Field Allowance for New Field Projects

In testing rationale number two above, in section 7.3.2, it was concluded that the Cross Field Allowance positively affected oil and gas expenditure, and hence activities, in new areas. Also, in testing rationale number three above, in section 7.3.3, it was concluded that the Cross Field Allowance enhanced the development of three discovered marginal fields, and was a relevant factor for developing other fields. These conclusions showed the implication of the Cross Field Allowance.

Conclusion

The condition is that this rationale could be justified on the basis of the dramatic decline in companies' cash flow during 1986. However, the cash flow quickly recovered and the net position of companies over the four years period 1984-1987 was very positive. The effect of the policy, based on the rationale, was already covered by the analysis conducted in sections 7.3.2 and 7.3.3 above. These sections showed that the Cross Field Allowance increased exploration and development expenditure in the central and northern North Sea. Also, the allowance enhanced the development of a number of discovered oil fields. Although the policies underpinned by the above two rationales (two and three) were not very effective, the rationales seemed to be justified. This in its turn makes it possible to claim that this rationale also had the expected outcome.

From this perspective, it can therefore be said that the Cross Field Allowance was mainly about responding to the sharp drop in oil companies' cash flow that resulting from of the sharp decrease in oil prices in the mid 1980s. This was to encourage and enhance oil and gas operations in the central and northern North Sea. Therefore, it can be stated that this rationale was met by the policy.

7.3.5 Abolishing Royalties, to Reduce Costs and Encourage Development Activities in the Marginal Fields in the Southern Basin Area of the North Sea

The definition of the 'new area' that was presented in section 7.2.2 clarifies that only oil fields in the Southern Basin of the North Sea would have benefited from the 1988 royalty reform. Abolishing royalties would have reduced the tax burden on oil fields, as this would have relieve the oil industry from paying them and thus improve cash flow of the oil industry. However, the Southern Basin of the North Sea does not have any oil fields, but does contain gas fields. The definition did not mention gas fields. Therefore, this rationale was not met by the policy: abolishing royalties for the Southern Basin of the North Sea was not an effective policy for developing oil fields.

7.3.6 Abolishing Royalty for the Southern Basin of the North Sea, to Make the Petroleum Fiscal Regime More Profit-Related

This rationale is similar to rationale number six in chapter six which was discussed in section 6.4.6. [98] Royalty was not a profit related duty, but it was an imposition on production (quantity or value). Therefore, although applying this duty to oil fields granted the Government early revenues from oil fields, it had a material effect on the cash flow of the operating companies and fields. This is because it ignored the profitability of the oil fields, and placed a burden on the cash flow of these fields in the early stages of their productive lives. This opinion agrees with Bond et al. (1987, p. 51) regarding the nature of royalty and its effects, but in fact reflect a non-proprietorial perspective because if the royalty is proving such a barrier, the field has been developed at too lower oil price and it is not for Government to try and counteract the market.

Although royalty was a deductible charge for PRT, abolishing it for Southern Basin oil fields would have linked the petroleum taxes of these fields to profitability and changes in costs and prices. At the same time, the fiscal regime

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[98] Making the whole tax regime more sensitive to changes in the world oil prices by linking taxation exclusively to profit rather than to mixture of profits and revenues.

of the North Sea would have been made flat for oil fields by linking petroleum taxes to profits rather than a mixture of profits and revenues. However, as mentioned in the previous rationale (section 7.3.5) the Southern Basin had not benefited from abolishing royalty, as there was no development of any oil fields in that basin. Therefore, it can be said that this rationale was not met by the policy.

7.4 Summary

The 1987-88 petroleum tax relaxation was successful to a fairly good extent in achieving the main targets of the Government. These targets are in encouraging more investments in the central and northern North Sea. The Cross Field Allowance on the top of the 1983 petroleum tax relaxation does appear to have had a discernible impact on exploration and development activities in the central and northern North Sea. The Cross Field Allowance had compensated for the dramatic fall in post-company cash flow resulted from the dramatic fall in oil prices in the mid 1980s. However, the Cross Field Allowance did not appear to have a strong impact on developing explored marginal fields. Table 7-10 presents a summary of the results of testing the rationales for this petroleum tax relaxation, while the following paragraphs summarise these results.

In testing the rationales for the 1987-88 petroleum tax relaxation, it was stated that the 1983 petroleum tax relaxation was not successful although it had a number of minor successful aspects. These aspects were, for example, stimulating the development of two small oil fields. The 1987-88 tax relaxation was a further step by the Government aimed first at attracting and increasing further oil activities in the UK North Sea, and secondly, reducing the pressure on the cash flow of UK oil industry, which arose because of the 1986 oil price crises. The lack of success of the first petroleum tax relaxation plus the already existing intention by the Government, formed the main reasons for the introduction of the 1987-88 petroleum tax relaxation.

Table 7-10: Summary of the Results of Testing the Rationales for the 1987-88 Petroleum Tax Relaxation

The 1987-88 Petroleum Tax Relaxations Rationales	The Rationale		
	Was	Was not	Was partly
	Met by the Policy		
The unsuccessful 1983 petroleum tax relaxation was a reason for forming the 1987-88 relaxation.			√
To encourage further exploration and development expenditure on new fields.	√		
To develop explored marginal fields.			√
To reduce costs and encourage development activities in the marginal fields in the Southern Basin area of the North Sea.		√	
Abolishing royalties for the Southern Basin of the North Sea, to make the petroleum fiscal regime more profit-related.		√	
Introducing the Cross Field Allowance was to compensate for the dramatic fall in post-tax company cash flow from North Sea operations, and the implications of this for expenditure on new field projects.	√		

The analysis shows that the 1987-88 relaxation was effective in developing three discovered marginal oil fields. These fields are Strathspey, which was explored in 1975 and obtained development consent in 1991; Scott which was discovered in 1984 and obtained Annex B Approval in 1990; and Miller which was discovered in 1983 and obtained development consent in 1988. Also, the Cross Field Allowance, together with other economic and technological factors, was a main reason for developing the Kittiwake oil field.

Abolishing royalties for Southern Basin oil fields of the North Sea aimed at targeting taxes on profits. As royalty was not a profit related duty, removing it would have made the fiscal regime purely profit related. However, this aim was still theoretical and not applicable, as the Southern Basin had not seen any oil field development after 1982. Therefore, no oil fields had benefited from the 1988

royalty relief in the Southern Basin area of the North Sea. The Cross Field Allowance would have benefited the existing oil companies at the time that had PRT liabilities in other oil fields, but not companies with new operations in the North Sea or existing companies with no PRT liabilities in other fields.

From the above summary and table, it can be seen that the 1987-88 petroleum tax relaxation had shown success in encouraging oil and gas activities in the central and northern North Sea, and also in maintaining oil companies' cash flow problems after the oil prices drop in 1986. However, this success was on the expense of the Government who lost fiscal revenues because of the Cross Field Allowance. This is just one character of the non-proprietorial regime discussed in chapter two (section 2.4.1 on page 42).