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Production-Sharing Agreements: An Economic Analysis

Kirsten Bindemann

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CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF ABBREVIATIONS

bbl	Barrel(s) of oil
b/d	Barrel(s) per day
bn	Billion
cfd	Cubic feet of gas per day
DD&A	Depreciation, Depletion and Amortisation
DMO	Domestic market obligation
EIA	Energy Information Administration
FOC	Foreign oil company
FSU	Former Soviet Union
FT	Financial Times
FTP	First Tranche Petroleum
Gov	Government
IIAPCO	Independent Indonesian American Petroleum Company
IRR	Internal rate of return
mb	Million barrels
mb/d	Million barrels per day
MEES	Middle East Economic Survey
mn	Million
n/a	not applicable
NCF	Net cash flow
NIOC	National Iranian Oil Company
NOC	National oil company
NPV	Net present value
OGJ	Oil and Gas Journal
OPEC	Organization of Petroleum Exporting Countries
PIW	Petroleum Intelligence Weekly
PON	Platt's Oilgram News
PR	Petroleum Review
PSA	Production-Sharing Agreement
ROR	Rate of return
sqm	Square miles
TCF	Trillion cubic feet

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1 INTRODUCTION

Production-Sharing Agreements (PSAs) are among the most common types of contractual arrangements for petroleum exploration and development. Under a PSA the state as the owner of mineral resources engages a foreign oil company (FOC) as a contractor to provide technical and financial services for exploration and development operations. The state is traditionally represented by the government or one of its agencies such as the national oil company (NOC). The FOC acquires an entitlement to a stipulated share of the oil produced as a reward for the risk taken and services rendered. The state, however, remains the owner of the petroleum produced subject only to the contractor's entitlement to its share of production. The government or its NOC usually has the option to participate in different aspects of the exploration and development process. In addition, PSAs frequently provide for the establishment of a joint committee where both parties are represented and which monitors the operations.

PSAs were first introduced in Indonesia in 1966. After independence nationalistic feelings were running high and foreign companies and their concessions became the target of increasing criticism and hostility. In response to this the government refused to grant new concessions. In order to overcome the subsequent stagnation in oil development, which was a disadvantage to both the country and the foreign firms, new petroleum legislation was brought in. PSAs were regarded as acceptable because the government upholds national ownership of resources. The major oil companies were initially opposed to this new contract form as they were reluctant to invest capital into an enterprise which they were not allowed to own or manage. More importantly, however, the FOCs did not want to establish a precedent which might then affect their concessions elsewhere. The first PSAs were therefore signed by independent FOCs who showed a greater willingness to compromise and accept terms that had been turned down by the majors. Furthermore, it has been argued that the independents saw this as an opportunity to break the dominance of the big oil companies and gain access to high quality crude oil (Barnes 1995). Thus challenged, the major FOCs bit the bullet and entered into PSAs (and found that in reality the foreign firm usually manages and operates the oilfield directly). From Indonesia PSAs spread globally to all oil-producing regions with the exception of western Europe where only Malta offers this type of contract.

PSAs are distinguished from other types of contracts in two ways. First, the FOC carries the entire exploration risk. If no oil is found the company receives no compensation. Second, the government owns both the resource and the installations. In its most basic form a PSA has four main properties. The foreign partner pays a royalty on gross production to the government. After the royalty is deducted, the FOC is entitled to a pre-specified share (e.g. 40 percent) of production for cost recovery. The remainder of the production, so called profit oil, is then shared between government and FOC at a stipulated share (e.g. 65 percent for the government and 35 percent for the FOC). The contractor then has to pay income tax on its share of profit oil. Over time PSAs have changed substantially and today they take many different forms.

This study concerns itself with the balance between risks and rewards and the division of benefits among the parties to the contract which have not yet been analysed with the tools of modern industrial economics. The first part identifies the rationale behind PSAs and forms the basis for the following theoretical argument.

We start with an overview of ownership issues in general and contrast PSAs with other major contract types namely concessions, service agreements and joint ventures (Chapter 2). PSAs are then explained in more detail. Some simulations serve to highlight the sensitivity of the contract parameters to changes in endogenous (e.g. alteration of cost oil) and exogenous (e.g. price change) variables (Chapter 3). This is followed by some theoretical considerations. The framework for the analysis is a principal-agent model incorporating incentive structures and risk- and reward-sharing (Chapter 4). In this context, the role of national oil companies is evaluated with regard to both its relationship with the government and its interaction with the foreign contractor.

The empirical part of the study is based on a data set comprising 268 PSAs signed by 74 countries between 1966 and 1998. The various contract variables will be evaluated with regard to global PSA developments over time, regions (South and Central Africa, Eastern Europe, Asia and Australasia, Central America and Caribbean, Middle East, North Africa, and South America), exporting and importing countries as well as OPEC, and onshore and offshore terms and conditions (Chapter 5). This analysis will be further disaggregated into selected country studies. Indonesia serves as an example to illustrate how the contracts work in practice as well as how and why they have been altered. In addition we analyse Angola, Azerbaijan, India, Iran, and Peru (Chapter 6).

While the chapters of this study build up on each other, every attempt has been made for them to be self-contained so that readers can pick and choose the issues that are of special interest to them. The purpose of Chapter 2 is to provide an overall framework of fiscal regimes in the oil industry, and to give a background understanding to readers who are not familiar with the history of oil contracts. Those with a firm understanding of PSAs may want to skip Chapter 3 which explains this particular contract form. If the main interest is in the empirical analysis it is not strictly necessary to read the theoretical considerations presented in Chapter 4.

Part I: The Background

2 THE RATIONALE BEHIND PRODUCTION-SHARING AGREEMENTS

2.1 MINERAL DEVELOPMENT IN GENERAL

One highly specific feature of the mineral sector is that exploration and development of mineral resources must take place where the resources are located. Ventures in this sector are of a high risk nature in the physical, commercial, and political sense as it is difficult to determine in advance the existence, extent and quality of mineral reserves as well as production costs and the future price in the world market. Profitability is not assured, and the fact that the resource is finite requires the continual acquisition of new deposits. Since virtually all mineral ownership regimes are based on state sovereignty[1] companies may have to concern themselves with government policies and regulations in more detail than they would in other sectors. The government decides whether resources can be privately owned or whether they are state property. If they are state owned the development can be conducted by a state company or it can be contracted to a private firm. Most countries grant development rights to private companies through a process of either negotiation or bidding.

The most common combination of agents in mineral development is a host government which represents a developing country with one or more mineral resources and a multinational company from a developed country. It is not surprising that the objectives of the two frequently clash. The main aim of the multinational firm is profit maximisation whereas the government of the host country is mainly interested in maximising its revenue. Since the objectives of firm and government do not necessarily coincide and indeed may diverge substantially it is all the more important that they identify the likely sources of future conflicts and write a contract that is as comprehensive as possible.[2] This divergence of objectives is frequently manifested in a lack of trust between the contractual partners. The relationship worsens if the government changes existing legislation and applies the new rules to contracts agreed under the old regime. In addition, Mikesell (1975) in his study on the copper industry finds that disagreement often arises from the demand for renegotiation which increases with the profitability of a mine. Other potentially contentious issues are the taxation of the (foreign) firm and the split of revenue between firm and government.

Considerable time may elapse between investment in the mineral industry and the realisation of profits. Investment is therefore long-term. The relative bargaining positions of the two parties change throughout the stages of the project. The government may find it difficult to gain access to risk capital. It may also lack the expertise needed for resource exploration and development. Furthermore, governments may be unwilling to take the risks connected with the above. The foreign company is assumed to have the upper hand in the pre-exploration phase. At this stage geological information is often negligible. Hence, investment is made with risk capital. The firm is not only able to provide this kind of capital but also the necessary expertise. In the case of successful exploration the government's bargaining position strengthens. If the initial contract was for the exploration phase only, the host country can now invite competing bids for exploitation or proceed

[1] Problems of sovereignty may arise in offshore areas; the latest example being the Caspian offshore oilfields.

[2] Contracts can only be comprehensive. They will never be complete as not all future events are foreseeable.

with the project without foreign participation. Generally speaking, it can be assumed that an increase in geological and marketing knowledge improves the government's hand. However, this happens only ex post. With regard to existing contracts it thus raises the question of whether there exists an opportunity for renegotiation on the basis of this newly acquired information. Moreover, one would expect to see the additional data reflected in subsequent contracts.

Contract terms usually vary over time. There appears to be a first-mover advantage. Early investors can secure more favourable terms than latecomers since the government has the desire to induce exploration by offering certain incentives. A lack of knowledge on the part of the government can also lead to attractive deals for foreign companies. As time goes by the host government will try to increase its share of revenue. Frequently this has been achieved through changes in the tax system. However, even if these changes can be implemented without violating the initial contract, they can have a counterproductive effect in so far as production and investment may decline. The history of the UK North Sea licences is a case in point. First movers obtained favourable terms. The first wave of latecomers had to accept harsher conditions while the second wave of latecomers was offered attractive contracts. Thus, it is not surprising that many governments attempt to intervene at an early stage. This intervention may take various forms such as the establishment of an artificial exchange rate, posted prices for valuing exports, and participation in decisions regarding production level and accounting practices. One way for companies to prevent the government from implementing policies that are detrimental to their interests is entering into joint ventures with national companies. It could be argued that the interest of a foreign firm then becomes more closely associated with that of the national firm and thereby of the government. At the same time the national company will obtain expertise from the partnership with the long-term view of eventually replacing it. Many mineral contracts in the 1970s introduced phaseout investments under which the role of the foreign partner is phased out or reduced according to an agreed time schedule. A phaseout forces the foreign firm to invest or face a penalty. This practice is intended to induce the quick development of a province. In order to provide a sound basis for the negotiation of a contract and to ensure that it is a long lasting agreement that satisfies both parties, geological knowledge is crucial as it reduces uncertainty.

A country with a well developed mineral sector may be able to stimulate domestic private-sector exploration. The government can for example take a share in the exploration risk and establish a fund that channels financial help to private companies. Another approach is the introduction of work or service contracts. This route was taken in the 1970s by Peru and Bolivia for the petroleum sector and by Indonesia and Iran with regard to several minerals. The foreign company, frequently a multinational, takes the exploration and feasibility risk in return for a share in the production if the venture is successful. As argued before, this practice will only work if the mineral sector is well developed; that is, if there exists a reasonable amount of knowledge about the geological structure of the country.

Mineral development is a long-term investment whose benefits can only be reaped some time well into the future. It forms, or should form, part of an overall economic strategy. The host country's objectives can be distinguished into three categories which are sovereignty, economic growth, and environment (or quality of life). Some of the sub-objectives are the optimal use of mineral resources, earning foreign exchange, satisfying domestic demand especially with regard to setting up an industrial sector, minimising adverse effects of mineral exploitation on the environment, fostering both direct and indirect employment, accumulating expertise and so forth. These goals can only be achieved within the framework of an explicit mineral policy. Sovereignty over national resources might be the overriding objective, yet there are different ways of exploiting a nation's resources. Between the two extremes of pure state and pure private development one can frequently observe a combination of the two. Bosson/Varon (1977) in their World Bank study on the mining industry in developing countries list ten parameters that are of importance for the successful development of mineral resources. First, the terms and conditions of the contract have to be clearly defined. Then the costs and benefits of domestic processing of the extracted resources on the one hand and the export of raw materials on the other hand need to be evaluated. The future control and ownership of the industry should be spelt out, and mineral conservation measures have to be incorporated into the country's mineral policy. This leads to the fifth parameter which is the formulation of such a policy together with a framework for the gathering and dissemination of geological and resource data. Sixth, environmental control and the allocation of costs of negative externalities have to become part of the mineral policy. The latter should provide for the efficient use of mines including the closure of non-profitable ones. Finally, infrastructure, employment and training as well as an equitable revenue share from mining activities have to be considered. Given the significance of a mineral policy it should be embedded in a legal framework with a mining code, which stipulates issues such as investment rights, tenure, and development rights, and a special tax regime. The tax regime can specify elements such as royalties, export and import duties, income tax and so forth. Governments might be tempted to overstate the issue of revenue sharing. Shortsightedness of this kind increases current revenue but will in all likelihood have a negative impact on future foreign investment and thus decrease government revenue in the long run.

2.2 OWNERSHIP AND MINERAL DEVELOPMENT RIGHTS

There are two methods of contracting: bilateral negotiation and competitive bidding. When a contract is negotiated bilaterally, the firm, usually a multinational, approaches a country's government in order to obtain a concession for exploration, development, and export of a mineral deposit. Traditionally the contract is then granted in exchange for a royalty payment from the company to the government. These agreements are often regarded as one-sided in favour of the private contractor who obtains broad rights and control over mineral reserves as well as over production levels (assuming minerals are discovered). This imbalance can for instance be attributed to a lack of information possessed by government representatives and the difficulty of achieving alternative means of finance for the purpose of exploration. A modification of the process of private negotiation is a model contract which outlines the basic terms of an agreement and thus serves as a kind of first offer. A model contract might for example specify that the firm has to pay a royalty but the size of the royalty is negotiable. The model contract for production-sharing agreements in Abu Dhabi for instance leaves open the payment of various bonuses, royalty, and other financial incentives as well as acreage and the number of wells to be drilled. One effect of formulating model contracts is that they are widely publicised and thus available to potential partners, and to other countries. Whether this publicity is desirable, and whom it benefits will be discussed later in the context of production-sharing agreements.

Frequently contracts are negotiated between the foreign firm and the national oil company, rather than the government. The national oil company, NOC, has the power to negotiate either due to legislation and regulation or because it controls the mineral reserves. One can immediately think of three reasons why the national oil company should replace the government in negotiations with a foreign contractor. First, the NOC is likely to possess more and better information about the mineral deposit, the technology that is best suited for exploration, and the ability of the foreign company to conduct the required work. Second, the NOC might be perceived as being less politically motivated than the government.[3] Third, given the usual goal of the NOC to eventually control the entire exploration and development activities in the domestic mineral sector, cooperation with foreign companies will involve nationals in the operations of the foreign company and thus increase their expertise.

In a bidding process applicants are usually required to meet certain standards in order to participate. The contract is then invariably awarded to a qualified bidder solely on the basis of competitive and sealed bids. The bidding may be based on royalties, bonus payments and so forth with the highest bidder receiving a contract whose terms are prescribed by legislation. As with private negotiation there is a modification to the pure form. Under a discretionary bidding system the government has discretion when awarding a contract. Legislation usually provides little or no guidance for provisions that should be contained in a production licence but for each licensing round model clauses are prepared. The basis for awarding a licence is not a sealed bid but the applicant's ability to comply with the goals sought to be achieved by the host government in any specific licensing round. This process is favoured by the UK with regard to granting licences for North Sea exploration and development. The rationale behind it is the realisation that the bidding can be misused by companies who put in a high bid without having the necessary expertise and/or equipment to conduct the required work.[4]

As stated before, mineral resources are usually owned by the state which then decides whether development and exploration rights will be granted to publicly owned or private companies or a combination of the two. If a contract is signed with a private firm, be it foreign or domestic, three issues arise with regard to sovereign risk. First, can the government unilaterally enforce changes to the contract at a later date? Second, what is the likelihood of renationalisation or expropriation? Third, has the state relinquished its rights over its mineral resources for the duration of the contract? Examples of states attempting to regain control over their resources were single acts of expropriation in Iran (1951B53) and Mexico (1938), gradual expropriation through tax increases and forced relinquishments in Venezuela, and modifications to existing contracts in Saudi Arabia. In the case of Mexico expropriation led to an international boycott of Mexican oil, while Iran lured back foreign companies a few years after nationalisation because of its inability to market its oil. The only exception to the concept that mineral resources are owned by the state can be found in the USA.[5] Another way of shifting power and control can be illustrated by considering the history of ARAMCO, the Arabian-American Oil Company. ARAMCO was originally owned by four multinationals to hold concessions obtained from the King of Saudi Arabia. When in 1948 Saudi Arabia decided that its take was not adequate several rounds of negotiations started.

[3] There is of course an opposing view to this idea. Some NOCs, e.g. the national oil company of Mexico, PEMEX, are regarded as the most powerful institutions in their respective countries.

[4] A more detailed analysis of different licensing systems can be found in e.g. Dam (1976).

[5] The US government, however, owns reserves by virtue of its rights in the continental shelf and on federal land. The US states own reserves on state land..

Dissatisfied with the royalty arrangements the Saudis finally achieved a 50B50 profit sharing in 1950. In addition ARAMCO agreed to pay the local sovereign tax. Furthermore, under the new agreement the country was allowed to appoint two members to the board of directors. After the formation of OPEC the idea of participation was discussed resulting in the Saudi government receiving a 25 percent stock interest in ARAMCO, a proportion which increased over time until the state became the sole shareholder.

2.3 A BRIEF HISTORY OF PETROLEUM CONTRACTS

We can distinguish four basic contract types; concessions, production-sharing agreements, service contracts, and joint ventures. Each form can be used to accomplish the same purpose. The differences between the types of contracts are of a conceptual nature mainly with regard to levels of control granted to the foreign contractor, compensation arrangements, and levels of involvement by NOCs.

The Middle East experience with classical concessions has been characterised by four features. First, the development rights granted to foreign companies covered vast areas and sometimes even an entire country. Second, contracts were signed for long periods of time. Third, the foreign contractor had complete control over schedule and the manner in which mineral reserves were developed. There was no requirement to produce. Hence, in times of low oil prices the firm could reduce production without incurring penalties. The host government had hardly any rights apart from the right to receive a payment based on production. The following examples illustrate archetypal Middle East concessions. In 1901 William D'Arcy obtained a concession from the Shah of Persia to explore 500,000 sqm of land for a duration of 60 years. In return the company had to pay a US$100,000 bonus, a 16 percent royalty, and give the government a share worth US$100,000 in the company. Similarly, the 1933 contract between the King of Saudi Arabia and Standard Oil of California specified that the foreign contractor had to pay 50,000 pounds of gold to the King in return for a concession covering 500,000 sqm for a 66 year period. The Abu Dhabi concession of 1939 granted a consortium of five major oil companies the right to explore the entire country for 75 years. The same type of concession could also be found in the USA up to 1930 with single leases covering all property over a very long period of time. However, by 1930 the standard US contract varied significantly from the Middle East concessions. Leases now expired if no production occurred after a specified number of years. Also incorporated in the new contracts was a clause specifying a royalty of $^1/_8$ of production. From the 1950s onwards many Middle East contracts were renegotiated. This was initiated by Saudi Arabia and its attempt to change its take from the ARAMCO concession. The original contract stated that the government should receive 21 cents per barrel at a time when the barrel sold for over US$2. Under the new agreement profits were shared fifty-fifty between the parties, and the firm had to pay a royalty. The Iran and Iraq concessions underwent similar changes. Also introduced were changes in taxation. In addition OPEC, after its foundation in 1960, sought to readdress control over production and prices by changing the balance of bargaining power in favour of the producing countries and away from the majors. Renegotiations became thus the vehicle for a substantial restructuring of the traditional concession system. There are three main reasons that explain the willingness of the oil companies to renegotiate contracts that had served them well. First, knowing that the original terms were unreasonable, they were afraid that a refusal to negotiate new conditions would increase hostilities towards foreign firms which could potentially result in the nationalisation of the industry and the loss of assets.

Second, the concessions were highly profitable and less favourable terms would still mean profitable production. Therefore, any arrangement that would allow the multinationals to reap the benefits of vast oil resources was deemed acceptable. Third, the big oil companies were vertically integrated. Access to reserves was hence more important than a drop in profits as long as profitability was ensured.

Modern concessions and licences are exemplified by the concession agreements that were developed in Oman (1967) and Abu Dhabi (1974). They still granted the foreign contractor exclusive rights to explore, develop, and export petroleum. At the same time they provided for shorter contract periods, a work obligation, relinquishment clause, higher royalties, and bonus payments. It has also become quite common for the state or the national oil company to participate in the venture. The restructuring of the concession system addressed three essential questions that will accompany us throughout this research. How much control is given to the foreign company? How is the share of revenue defined? How should the foreign firm become involved in the country?

In the mid 1960s the Indonesian government introduced production-sharing agreements in response to increasing criticism and hostility towards the existing concession system. We will describe this contract form in more detail in Chapter 3. Thus, for the moment we only consider the basic features of a PSA. The oil is owned by the state which brings in a foreign company to explore and, in case of commercial discovery, develop the resource. The FOC operates at its sole risk and expense, and receives a specified share of production as reward. Thus, the main difference to concessions is the ownership of the mineral resource. Whereas under concessions all crude oil produced belongs to the FOC, under PSAs it is owned by the host government, and the share of production allocated to the FOC can be regarded as payment or compensation for the risk taken and services rendered. PSAs spread from Indonesia to countries such as Egypt, Libya, Algeria and other oil producers in Africa, Asia, the Middle East, and South and Central America. They have become increasingly popular in the Former Soviet Union (FSU) and especially in the Caspian region.

While some forms of service agreements bear similarities to PSAs, pure service agreements differ significantly from the latter. The FOC is the sole bearer of the financial risk and engages in exploration and development for an agreed fixed fee or other form of compensation. As the name of the contract implies the FOC supplies services and know-how. It has, however, no equity position in the venture. Due to the combination of risk and services these contracts are now frequently called risk-service agreements.[6] Some early service contracts were signed by Petroleos Mexicanos (PEMEX) and Yacimientos Petroliferos Fiscales (YPF) in the 1950s. However, the concept became more widely popular in the late 1960s when Iran and Iraq in particular concluded several such agreements. While some service contracts are disguised PSAs, especially with regard to ownership of the resource, the main differences between the two contract forms are the remuneration of the contractor and the control over operations (see Table 2.1)

In joint ventures both the FOC and the government, or one of its agencies, participate actively in the operation of the oilfield and acquire ownership of a specified part of production. Therefore, in addition to royalties, taxes, and profit oil,

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[6] Some countries such as Saudi Arabia and Venezuela offer so-called pure service contracts. This pure form provides that the FOC is paid a flat fee for its services, and entails no element of exploration risk.

the government is entitled to a share of profits. However, this benefit comes at a cost since development and operating costs are shared between the partners. Although it should be added that it is quite normal for the FOC to assume the entire exploration risk by carrying the government's participation until commercial discovery. Joint ventures take either an equity or a contractual form. In the first case a joint stock company is established and each partner owns a specified percentage of the equity. The latter on the other hand is governed by a joint operating agreement and each partner owns a share of the production. Initial joint ventures between FOCs and governments often had a 50B50 share but after the agreement between Libya and Occidental in 1973 it became common for governments to hold 51 percent or more in the venture.

To sum up then, oil exploration and development can only be conducted by virtue of one of several forms of contracts granted either by the government or its NOC. In countries with large or potentially large oil deposits, the resource and its extraction tend to become vital cornerstones of that country's economy. Not surprisingly, governments have increased their involvement in the oil sector. This has resulted in increased state participation, the establishment of NOCs, and greater government shares arising from the financial rewards of oil operations.

The existing types of contracts can be broadly categorised into risk-bearing and non-risk bearing agreements with most arrangements falling into the former category. The types as well as the terms of contracts vary not only between but also within countries. Furthermore, many contract forms have some overlapping features. The type of agreement offered and the terms applied to it can be due to specific legislation or free negotiation. A great many parameters determine the nature of the contract. Among them are the maturity of the oil sector, the fiscal regime, import or export dependency, geological aspects, costs, and the regulatory framework.

Table 2.1: Risk and Reward of Main Contract Types

Contract	Foreign Contractor	Government
Concession	all risk/all reward	reward is function of production and price
PSA	exploration risk/share in reward	share in reward
Joint Venture	share in risk and reward	share in risk and reward
Pure Service Agreement	no risk	all risk

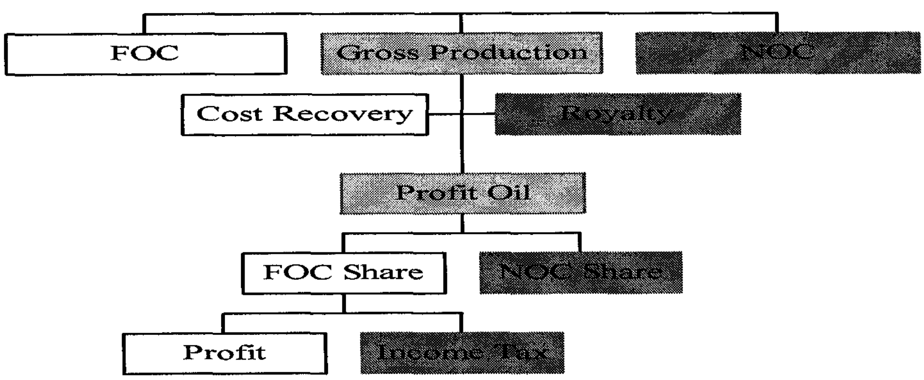
3 PRODUCTION-SHARING AGREEMENTS IN GENERAL

Following the brief outline of PSAs in the preceding chapter we now analyse the details of this particular contract type. Some simple simulations show how risks and rewards are shared between the parties to the contract, and how sensitive the results are to endogenous and exogenous changes.

3.1 THE CONTRACT ELEMENTS

PSAs come in a variety of styles. Figure 3.1 shows a very basic form. There are two parties to the contract, a foreign oil company (FOC) and a government representative which can be a head of state, a ministry or a national oil company (NOC). The latter is the more common case. On the side of the foreign contractor we frequently find joint ventures or consortia rather than an individual firm. However, the number of FOCs involved has no impact on the structure of the contract. As far as the PSA is concerned the members of a consortium or a joint venture are treated as one partner. The FOC operates the oilfield although many contracts provide for an option that allows the NOC to participate directly in the development process. Once oil is produced the FOC may have to pay royalty levied on gross production to the government.[7] Royalty constitutes an immediate cash flow to the government if it has to be paid in cash. If it is an in-kind payment it provides a cost-free source of crude oil for the domestic market or for export. In the case of cash payment it is crucial how the value of output is determined. Assume the PSA stipulates a posted

Figure 3.1: The Basic Features of a PSA



price. If on delivery the posted price is higher than the spot (or market) price this is an advantage for the government. On the other hand, a posted price below the spot price benefits the foreign firm. Either way, royalty is guaranteed minimum revenue flow from the FOC to the government regardless of the profitability of the project. This implies that the lower the profitability the higher is the adverse impact of the royalty on the FOC. If the royalty payment is deductible from income tax liabilities, the government's overall revenue will be reduced. Hence, the government is better off if it treats royalties as expenses.

[7] It should be pointed out that not all PSAs require a royalty payment.

In a second step the operator can recover some of its costs at a pre-specified percentage of production, the so-called cost oil. Most contracts have a cost-oil limit of say 50 percent of production although contracts with unlimited cost recovery are also in existence.[8] The level of cost recovery often varies according to the special characteristics of the field. Marginal deposits for example may need higher cost-oil ceilings in order to guarantee the expected return on a company's investment. If the cost oil is not sufficient to cover operating costs plus depreciation, depletion, amortisation and, where applicable, investment credits and interest the balance will be carried forward and recovered in the following period. The more generous the cost recovery limit is the longer it takes for the government to realise its take.

The remainder of production, the profit oil, is then split between NOC and FOC at an agreed rate, say 60/40. If we assume that no royalty has to be paid and cost oil is 50 percent, the profit oil split will be calculated on the basis of the remaining 50 percent of gross production. Thus, the NOC would receive 60 percent out of 50 percent of production, and the FOC is entitled to 40 percent out of 50 percent of total output. The latter then has to pay income tax on its share of profit oil.[9] In many instances tax is paid by the NOC on behalf of the FOC, or the government forfeits its right to tax altogether. Figure 3.2 illustrates the average cash flow and the take each party receives over the lifetime of a basic PSA. Let's assume the market price is $20/bbl. The FOC has to pay a royalty of 10 percent to the government. From the remaining $18 it can cover its costs. In this example the average cost oil over the lifetime of the PSA is 33.3 percent.[10] The FOC then receives 40 percent of the $12 left while the government obtains 60 percent. The latter is also entitled to 30 percent tax on the FOC's share of profit oil. As a consequence the government has gained $10.64 of the $20/bbl with the FOC having to settle for $9.36. However, the more important figures are those indicating the net cash flow. Here it has to be noted that on the FOC side the $6 cost recovery will not count for the cash flow as cost oil is simply a reimbursement of operating and some other expenditures. Thus, the net cash flow for the FOC is calculated by deducting the tax payment from the profit-oil share. The aggregate cash flow for the project is therefore $14 of which the government takes 76 percent and the FOC 24 percent. In this basic form the government has three sources of revenue: royalty, tax, and its share of profit oil. Occasionally contracts allow for uplifts as an incentive to the FOC. With an uplift the FOC can recover an additional percentage of capital costs through cost oil.[11] This reduces the profit oil available to both parties. However, uplifts are usually not tax deductible.

In reality PSAs have a much larger number of variables. Apart from the already mentioned parameters cost oil, profit oil, royalty and income tax, one will find contract clauses on duration of exploration and exploitation, bonuses, duties, state participation in the operation, work programme, pricing, marketing,

[8] In fact, PSAs with no cost recovery at all are not unheard of. Some contracts in Peru and Trinidad and Tobago, for example, opted for zero cost oil as did the early Libyan PSAs. This has two main consequences. First, total profit oil increases. FOC and NOC each obtain more crude in terms of volume from their respective shares in profit oil. If taxation prevails, government revenue increases as the tax base has risen. Second, the FOC has to recover its costs out of its share of profit oil.

[9] It is quite important to be clear on this point: tax is levied on the share of profit oil, NOT on profits.

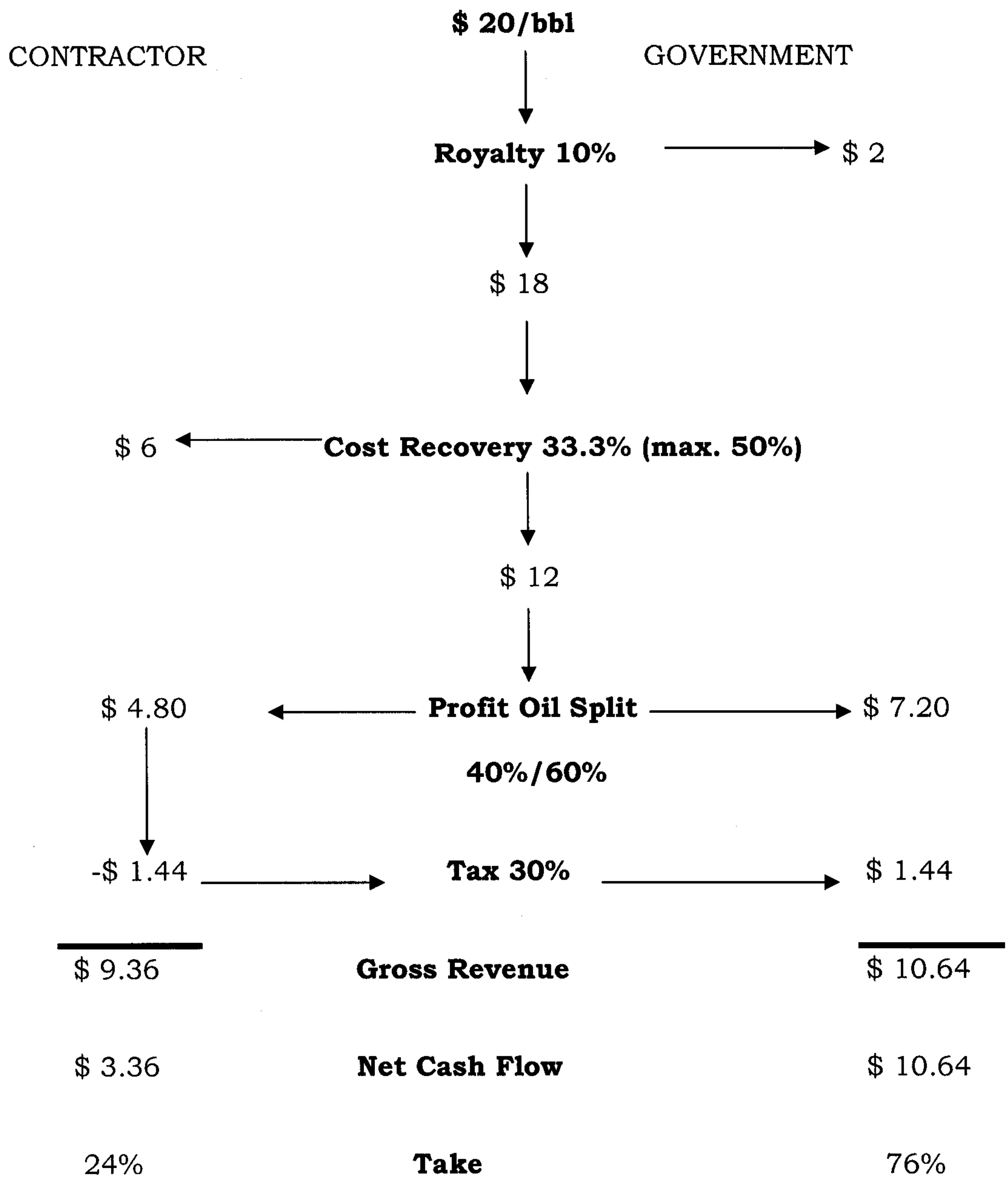
[10] Maximum cost oil here is 50 percent. However, on average the FOC did not need all available cost oil. Hence, the annual average of 33.3 percent.

[11] If the uplift is 20 per cent and capital expenditure is $100 million the FOC can recover $120 million.

associated gas, compensation, and arbitration. We will now discuss their relevance and potential impact on the contract partners.

The Fiscal System. The degree of taxation is largely determined by the terms of the contract. If the government receives high royalty payments and a large share of profit oil, common sense would suggest that little room is left for income taxation as this would provide a disincentive to the FOC. As the government take increases, the FOC's interest in the venture diminishes correspondingly. Generally speaking, if the only financial provision for the government is the payment of royalties, high income taxes will be levied.

Figure 3.2: PSA Flow Chart



However, given that under PSAs output is also shared[12] foreign companies are usually obliged to pay the generally applicable income tax, or none at all.[13] The latter case implies nearly always that the tax is not paid directly but is instead part of the government's profit-oil share. While income tax is related to the profitability of a venture, royalty is paid regardless of realised profits. It can be collected in cash or in kind. If the former is chosen, the price valuation of the oil produced is of utmost importance. The method of pricing will be outlined in the contract.

Tax Holidays. Some PSAs offer tax holidays for say the first five years of the contract.[14] They are intended as a further investment incentive. However, the timing of these periods is crucial. Income tax is only payable once production has begun. If the holiday starts when the contract starts and exploration takes three years the effective tax holiday is only two years. In order for the incentive to work the holiday would have to kick in no earlier than at the beginning of the production phase. It would then be attractive for the FOC to deplete its reserves as quickly as possible during the tax-free period.

Bonuses. Bonuses are another source of revenue for the host country. PSAs usually comprise signature and production bonuses, and in some instances discovery bonuses to be paid by the FOC. The terms are almost self-explanatory. A signature bonus is a one-off payment on signing a contract. It captures economic rent regardless of the success of exploration and production activities. In doing so it detracts from the economic attractiveness of the venture by loading the front end of the project into year zero and thereby reducing its present value. The less frequently applied discovery bonus is also a one-off fee. It is required after commercial discovery is declared and after the NOC has approved the FOC's development plan. Production bonuses, on the other hand, can be recurring. They are due when production reaches a certain level. For example $2 million have to be paid if average daily output during a specified period of time is 20,000 b/d. Another $2 million are requested at 40,000 b/d and so forth. Alternatively, or additionally, the government may insist on a production bonus once the x^{th} barrel has been produced. Neither bonus payment takes any account of profitability but most PSAs allow for bonuses to be tax deductible.

Domestic Market Obligation (DMO). If a government's priority is to satisfy domestic demand for oil it can impose a DMO on the FOC. As with most other contract terms this variable comes in different guises. The differences apply to both the amount requested and the price paid. Some contracts specify that a certain percentage of the FOC's production share has to be made available for the domestic market while others have a more general option stating that the NOC can request up to 100 percent of the contractor's profit oil should the domestic market require this. The pricing also varies. Under some PSAs the DMO has to be satisfied at a heavily discounted price. A further drawback for the FOC can arise if the DMO crude is paid for in local currency.

Export and Import Duties. Duties on equipment and material needed for exploration and development are very rare. If import duties are levied it is usually on goods such as foodstuffs that are available in the host country. The main reason for the

[12] As we will later, in most cases profit oil is shared in favour of the government.
[13] The FOC will not only be concerned with the tax treatment in the host country but also with the tax law in its country of origin.
[14] In some cases holidays for royalty payments also exist.

exemption is that the title to any equipment passes to the government either immediately or at the end of the contract.

Contract Duration and Commerciality. PSAs are exploration and production contracts. They will stipulate a minimum exploration period with possible extension for further periods. It is common practice that at the end of each phase the FOC has to relinquish a certain percentage of the total contract area. If commercial discovery is declared and a work programme has been agreed the production period starts. Some contracts stipulate a specific production duration while others set total contract times. For example, the relevant PSA clause could state that the minimum exploration period is three years with the possibility of two extensions of two years each, and a production period of 25 years with a possible five-year extension. It could, on the other hand, specify that the total contract duration is 30 years with a maximum exploration period of, say, seven years. One important aspect that should not be neglected here is the definition of commerciality, and who determines whether a field is economically viable or not. For the FOC exploration costs often mean large sunk costs which can only be recovered upon production through cost oil. If cost recovery is too great it represents a liability for the government as it may reduce its share of gross production. While some agreements allow the foreign contractor to decide whether development is feasible, it is common for the government to set a benchmark indicating the take that it regards as satisfactory. If the simulated take meets this target the FOC will get the go-ahead for development of the field. This issue becomes particularly crucial for PSAs without cost-recovery limit and with either no or low royalties.

Work Programme. The work programme outlines the FOC's commitments with regard to seismics, drilling, information dissemination, financial obligations, employment of local workforce and so forth. It has become quite common for this variable to be negotiable or biddable. The work commitment is a crucial negotiation factor. It contains most of the exploration risk since only a small number of exploration efforts are successful and lead to development of a field and thus to a stream of revenue which allows the FOC to at least recover its costs.

Participation. Most PSAs give the NOC an option to participate in the venture.[15] This, however, does not imply that the NOC shares in the costs and risks involved in the exploration period. Usually they have a carried interest which means the FOC bears the costs and the risk during exploration and carries the NOC through. If the field is declared commercial the NOC can (but does not have to) take up its option of working interest. Participation rates vary from 5 percent (some Indonesian PSAs) to up to and over 50 percent (Algeria 1991, China, some Indonesian PSAs) but 15 (Malaysia, Vietnam) and 25 percent (Angola, some Malaysian PSAs) appear to be rather common clauses. Apart from the extent of their involvement some issues that arise once the NOC decides to participate in the project are the point of entry, the kind of participation, the sharing of costs and the way in which the stake is financed. The NOC's financial contribution will usually come out of production. From the FOC's perspective any participation by the host country tends to be unattractive as the partner can interfere with the day-to-day management of the operation. Conflicting views may lead to a less efficient running of the project.

Fixed and Sliding Scales. Royalties, cost oil, profit oil and production bonuses can either be levied as fixed shares of production, such as a *n*-percent royalty that is

[15] PSAs without participation can be found e.g. in Egypt, Oman, Qatar, Yemen, the Philippines, Nigeria and Turkmenistan.

applied to all production, or on the basis of sliding scales. The latter method is becoming standard procedure. One can find many variations of sliding scales but the two most common ways of calculating payments using sliding scales are based on either average daily production or R-factors.

An example of a volume-based sliding scale is one of the Indonesian contracts which stipulates for profit oil that Pertamina receives at least 61.5385 percent of production and the FOC share will not drop below 19.2308 percent (Table 3.1). The R-factor, on the other hand, is the ratio of revenue to expenses. This means that the cumulative contract revenues earned by the FOC from cost recovery and profit oil are divided by the cumulative expenses incurred during a specified period. An example of this is one of the Azeri PSAs (Table 3.2).

Table 3.1: Profit Oil in Indonesia

Average Daily Production(bbl)	*Pertamina (%)*	*FOC (%)*
0-50,000	61.5385	38.4615
50,001-150,000	71.1538	28.8462
≥ 150,001	80.7692	19.2308

Table 3.2: Profit Oil in Azerbaijan

R-Factor	*SOCAR (%)*	*FOC (%)*
R < 1.50	50	50
1.50 ≤ R < 2.00	60	40
2.00 ≤ R < 2.25	62.5	37.5
2.25 ≤ R < 2.50	65	35
2.50 ≤ R < 2.75	70	30
2.75 ≤ R < 3.00	75	25
3.00 ≤ R < 3.25	80	20
3.25 ≤ R < 3.50	85	15
R ≥ 3.50	90	10

The design of the scale is usually based on the expected size of the discovery. Regardless of whether the contract is volume or R-factor based, caution needs to be applied to setting the rates. If they are too high, the scale loses most of its flexibility. Depending on the expected size of the deposit and its special characteristics, a threshold of say 50,000 b/d can be unprofitable. By the same token, if we have a 100-mb field which produces 20 per cent of reserves in the peak year of production (20 mb) the average daily production is 55,000 b/d. Thus, a sliding-scale tranche of, say, 100,000 b/d would be rather useless. Generally speaking, sliding scales add flexibility to a contract. The government take increases as the project profitability increases. In this system the former is a function of the latter whereas under a fixed system (e.g. the government always receives 60 per cent of available profit oil) profitability is a function of government take.

3.2 Some Simulations

The following computer simulations are based on a fictional, though not unrealistic, PSA. They will show how changes in one or more variables influence the two main measures used to evaluate the feasibility of a project, namely the net present value (NPV) and the internal rate of return (IRR). The latter measures the effective rate of return earned by an investment as though the money had been loaned at that rate.

It is the discount rate that equates the present value of revenues to the present value of costs:

$$\sum_t R_t (1+r)^{-1} = \sum_t C_t (1+r)^{-1}$$

where r is the IRR, R is revenue, and C is cost.

The NPV is the difference between the present value of revenues and costs at a given discount rate:

$$\sum_t R_t (1+d)^{-1} - \sum_t C_t (1+d)^{-1}$$

where d is the discount rate.

If the NPV is negative, the IRR is smaller than the discount rate and one would expect the project to be rejected. If the reverse is true for NPV and IRR, the venture would be approved unless an alternative scheme yields better results. On the other hand, if the NPV is equal to zero, the IRR equates the discount rate and indifference towards the project is likely.

For the original simulations presented in Table 3.4 we assume a medium oil price ($15/bbl), no royalty, cost oil of 40 percent, and a profit oil split of 60/40 in favour of the government. Income tax is initially zero. Multiplying production (column A) by the oil price (B) yields gross revenue (C). The deduction of royalty (I) from gross revenue results in net revenue (J). Available cost oil (M) is calculated as a percentage, here 40 percent, of gross revenue. However, whether all available cost oil or only a fraction is paid to the FOC depends on amortised cost (L). This in turn depends on the size of intangible capital expenditure (D), operating expenditure (F), and depreciation, depletion and amortisation (G). Capital expenditure is differentiated into intangible (D) and tangible (E) costs whereby the former refers to items such as patents and deferred charges.[16] Intangible costs and operating expenditure (F) are expensed[17] while tangible capital costs are capitalised.[18] The technique used for the depreciation of capital costs is a five-year straight line decline (G). If amortised costs are equal or less than available cost oil, the FOC will be paid the full amount. If, on the other hand, amortised costs exceed available cost oil, only the latter will be paid and the difference will be carried over to the next period when the whole process starts again. The profit oil shares for the government and the FOC are calculated on the basis of the remainder once cost oil (N) has been deducted from net revenue. Finally, net cash flows and takes are determined in the way explained in Figure 3.2.

The original assumptions as outlined above are then changed in several ways. We introduce a royalty, taxation, changes in cost and profit oil, and several combinations of these variables. This exercise is then repeated for different oil price scenarios, the outcomes of which are presented in Tables 3.7B3.9. In addition, Tables 3.4 and 3.6 present the case for sliding scales. The parameters are the same as before but we now vary the way in which profit oil is calculated. The volume-based sliding scale (Table 3.5) is taken from the 1987 Malaysian model contract while the R-factor scale (Table 3.6) can be found in one of the PSAs signed by

[16] For the accounting mechanics see Johnston (1994).

[17] In accounting terms, expensed refers to costs that are charged against revenue during the accounting period in which they were incurred.

[18] Capitalised refers to the periodic recovery of capital costs through depreciation or depletion.

Azerbaijan. Finally, in Table 3.10 we compare how different scales impact on NPV and IRR based on the original assumptions.

3.3 A Discussion of the Simulation Results

One of the most obvious observations is that variations in the division of profit oil between the two parties cause significant changes in IRR and NPV. If profit oil is altered from 60/40 (original assumption) to 50/50 and then to 40/60 the IRR increases from 25 to 32 and on to 38 for the low-price scenario (Table 3.7). Similarly, if taxes have to be paid by the FOC, a tax holiday leads to a substantial increase in the IRR. This increase becomes larger the higher the oil price.

A change in royalty can also have a notable impact. This can easily be illustrated with the royalty model presented by Mead (1994:6). In Figure 3.3 each curve represents a cost curve under a different royalty scheme. The straight horizontal line depicts incremental revenue. The vertical axis measures costs and revenues in dollars while the horizontal axis shows the time horizon. Wherever the cost curve crosses the revenue curve costs equal price and production will be abandoned. Not surprisingly, the higher the royalty to be paid by the FOC the earlier production will be stopped (at constant prices). However, as can be seen from Tables 3.7 to 3.9, if the oil price increases by $5bbl (all other parameters remaining constant) the IRR almost doubles, and the NPV increases manifold despite a royalty payment. As can be expected, the combination of royalty and tax has a significant impact on both IRR and NPV. Again, a price rise can yield a substantial improvement in profitability for the FOC while at the same time, of course, boosting government revenue. We also look at the case where the effect of royalty plus tax is mitigated through complete cost recovery (cost oil 100%). This combination of variables yields only a negligible effect which becomes even smaller with increasing oil prices and disappears altogether in the high-price scenario. However, this observation should be interpreted with caution as some of it might be explained through the specific data in our simulations where only in the low-price scenario the original 40 percent cost oil is not enough for full cost recovery.

Tables 3.7 to 3.9 show that for the FOC a tax levy is worse than a royalty payment. Obviously, were we to change the numbers for these two parameters we would get a different result (see Table 3.3). For example, a royalty of 15 percent yields both a lower IRR and NPV than a tax of 20 percent. Nonetheless, what this does indicate is that the often berated royalty[19] is not *necessarily* the worst of all worlds.

As one would expect a price increase results in major alterations of IRR and NPV. Projects that were either not at all or just feasible with a low oil price are now comfortably feasible. As mentioned earlier, in all three scenarios it appears that the worst case for the FOC is a change in profit oil in favour of the host country. This means that NOCs or governments that insist on a large portion of output have to create other investment incentives in order to make the project an attractive proposition for the FOC. Within the specified parameters, a PSA based on a R-factor scale leads to a higher IRR than one that calculates profit oil on a volume-based sliding scale. However, the impact of the latter depends to a large extent on the design of the different tranches. The scale used in Table 3.5 has only three steps. If

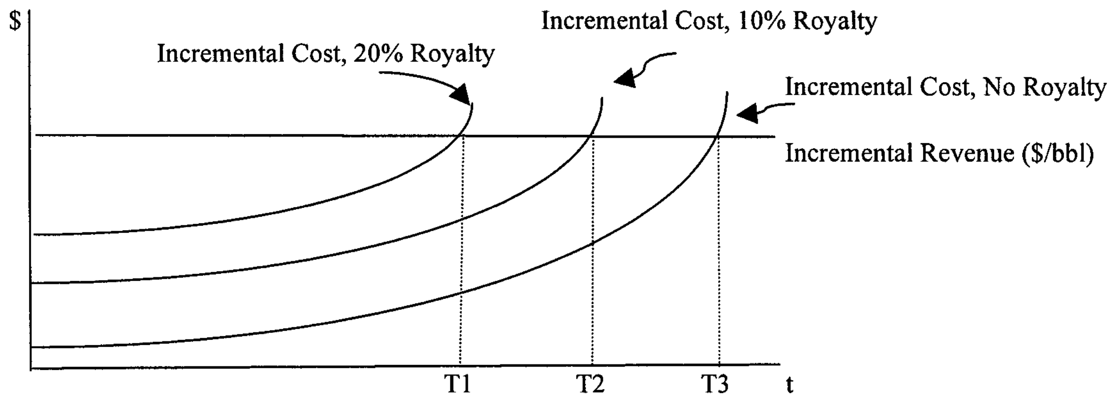
[19] As pointed out earlier, firms tend to be hostile towards royalties as they have to be paid regardless of profitability.

we increase this to five[20] both IRR and NPV decrease significantly (Table 3.10). The cash flows, on the other hand, change by very little. This suggests that in the case presented here the government might consider acceptance of a slightly lower cash flow if this provides an incentive for the FOC to sign the contract.

Table 3.3: A Comparison of Royalty and Tax

	Royalty			Tax	
%	NPV@12	IRR	%	NPV@12	IRR
5	42,466	40	15	36,681	37
8	39,302	38	18	34,469	35
10	37,194	37	20	32,995	35
12.5	34,557	35	22.5	31,151	34
15	31,920	34	25	29,308	33

Figure 3.3: The Impact of Royalties



[20] Daily Production (b/d) Gov/FOC

Daily Production (b/d)	Gov/FOC
0-5,000	40/60
5,001-10,000	50/50
10,001-15,000	60/40
15,001-20,000	70/30
>20,000	80/20.

Table 3.4: Sample PSA Cash Flow With Fixed Scale

Year	(A) Production ('000bbl)	(B) Oil Price ($/bbl)	(C) Gross Revenue ($m)	(D) IntangibleCapEx ($m)	(E) TangibleCapEx ($m)	(F) OpEx ($m)	(G) DD&A ($m)	(H) Royalty (%)	(I) Royalty ($m)	(J) Net Revenue ($m)	(K) Cost Oil (%)	(L) Cost Amort. ($m)	(M) Cost Oil Avail. ($m)	(N) Cost Oil ($m)
1	0	15	0	0	-10000	0	0	0	0	0	0	0	0	0
2	0	15	0	0	-8000	0	0	0	0	0	0	0	0	0
3	0	15	0	0	-15000	0	0	0	0	0	0	0	0	0
4	4500	15	67500	-15000	-10000	-11500	-8600	0	0	67500	40	35100	27000	27000
5	7000	15	105000	-2000	0	-14000	-8600	0	0	105000	40	32700	42000	32700
6	5600	15	84000	0	0	-12600	-8600	0	0	84000	40	21200	33600	21200
7	4760	15	71400	0	0	-11760	-8600	0	0	71400	40	20360	28560	20360
8	4046	15	60690	0	0	-11046	-8600	0	0	60690	40	19646	24276	19646
9	3439	15	51585	0	0	-10439	0	0	0	51585	40	10439	20634	10439
10	2923	15	43845	0	0	-9923	0	0	0	43845	40	9923	17538	9923
11	2485	15	37275	0	0	-9485	0	0	0	37275	40	9485	14910	9485
12	2087	15	31305	0	0	-9087	0	0	0	31305	40	9087	12522	9087
13	1732	15	25980	0	0	-8732	0	0	0	25980	40	8732	10392	8732
14	1427	15	21405	0	0	-8421	0	0	0	21405	40	8421	8562	8421
15	0	15	0	0	0	0	0					0		
Total	39999		599985	-17000	-43000	-116993	-43000		0	599985		185093	239994	176993

Year	(O) Remainder ($m)	(P) Profit Oil Gov (%)	(Q) Profit Oil FOC (%)	(R) Profti Oil Gov ($m)	(S) Profit Oil FOC($m)	(T) Tax (%)	(U) Tax ($m)	(V) NCF Gov ($m)	(W) NCF FOC($m)	(X) Gov Take (%)	(Y) FOC Take (%)
1											
2	0	0	0	0	0	0	0	0	-10000	0	0
3	0	0	0	0	0	0	0	0	-8000	0	0
4	0	0	0	0	0	0	0	0	-15000	0	0
5	40500	60	40	24300	16200	0	0	24300	16200	60	40
6	72300	60	40	43380	28920	0	0	43380	28920	60	40
7	62800	60	40	37680	25120	0	0	37680	25120	60	40
8	51040	60	40	30624	20416	0	0	30624	20416	60	40
9	41044	60	40	24626.4	16417.6	0	0	24626.4	16417.6	60	40
10	41146	60	40	24687.6	16458.4	0	0	24687.6	16458.4	60	40
11	33922	60	40	20353.2	13568.8	0	0	20353.2	13568.8	60	40
12	27790	60	40	16674	11116	0	0	16674	11116	60	40
13	22218	60	40	13330.8	8887.2	0	0	13330.8	8887.2	60	40
14	17248	60	40	10348.8	6899.2	0	0	10348.8	6899.2	60	40
15	12984	60	40	7790.4	5193.6	0	0	7790.4	5193.6	60	40
Total	422992			253795.2	169196.8		0	253795.2	136196.8	65.07702722	34.922973

(A), (D) - (G) based on Johnston, D (1994:50)
(C) = (A) x (B)
(D) Intangible Capital Costs [expensed]
(E) Tangible Capital Costs [capitalised, refer to (G)]
(F) Operating Expenditure [expensed]
(G) Depreciation, Depletion & Amortisation [5-year straight line decline]
(I) Percentage of (C)
(J) = (C) - (I)
(L) Cost Amortised:
[year 4: -((D)t + (F)t + (G)t); then: -((D)t + (F)t + (G)t) + (L)t-1 - (N)t-1]
(M) Cost Oil Available: (K) as a percentage of (C)
(N) = Cost Oil paid to FOC: If (L) > (M): (N) = (M); otherwise (N) = (L)
(O) = (J) - (N)
(R) = (P)% of (O)
(S) = (Q)% of (O)
(U) = (T)% of (S)
(V) Net Cash Flow Government: (I) + (R) + (U)
(W) Net Cash Flow FOC: If (K) = 0: (S) - (U) - (L); otherwise (W)=(S)-(U)
(X) = (V)/((V) + (W)) x 100
(Y) = 100 - (X)

Table 3.5: Sample PSA Cash Flow With Volume-Based Sliding Scale

Year	(A) Production ('000bbl)	(B) Oil Price ($/bbl)	(C) Gross Revenue ($m)	(D) IntangibleCapEx ($m)	(E) TangibleCapEx ($m)	(F) OpEx ($m)	(G) DD&A ($m)	(H) Royalty (%)	(I) Royalty ($m)	(J) Net Revenue ($m)	(K) Cost Oil (%)	(L) Cost Amort. ($m)	(M) Cost Oil Avail. ($m)	(N) Cost Oil ($m)
1	0	15	0	0	-10000	0	0	0	0	0	0	0	0	0
2	0	15	0	0	-8000	0	0	0	0	0	0	0	0	0
3	0	15	0	0	-15000	0	0	0	0	0	0	0	0	0
4	4500	15	67500	-15000	-10000	-11500	-8600	0	0	67500	40	35100	27000	27000
5	7000	15	105000	-2000	0	-14000	-8600	0	0	105000	40	32700	42000	32700
6	5600	15	84000	0	0	-12600	-8600	0	0	84000	40	21200	33600	21200
7	4760	15	71400	0	0	-11760	-8600	0	0	71400	40	20360	28560	20360
8	4046	15	60690	0	0	-11046	-8600	0	0	60690	40	19646	24276	19646
9	3439	15	51585	0	0	-10439	0	0	0	51585	40	10439	20634	10439
10	2923	15	43845	0	0	-9923	0	0	0	43845	40	9923	17538	9923
11	2485	15	37275	0	0	-9485	0	0	0	37275	40	9485	14910	9485
12	2087	15	31305	0	0	-9087	0	0	0	31305	40	9087	12522	9087
13	1732	15	25980	0	0	-8732	0	0	0	25980	40	8732	10392	8732
14	1427	15	21405	0	0	-8421	0	0	0	21405	40	8421	8562	8421
15	0	15	0	0	0	0	0					0		
Total	39999		599985	-17000	-43000	-116993	-43000		0	599985		185093	239994	176993

Year	(O) Remainder ($m)	(P) Profit Oil Gov (%)	(Q) Profit Oil FOC (%)	(R) Profti Oil Gov ($m)	(S) Profit Oil FOC($m)	(T) Tax (%)	(U) Tax ($m)	(V) NCF Gov ($m)	(W) NCF FOC($m)	(X) Gov Take (%)	(Y) FOC Take (%)
1	0	0	0	0	0	0	0	0	-10000	0	0
2	0	0	0	0	0	0	0	0	-8000	0	0
3	0	0	0	0	0	0	0	0	-15000	0	0
4	40500	60	40	24300	16200	0	0	24300	16200	60	40
5	72300	60	40	43380	28920	0	0	43380	28920	60	40
6	62800	60	40	37680	25120	0	0	37680	25120	60	40
7	51040	60	40	30624	20416	0	0	30624	20416	60	40
8	41044	60	40	24626.4	16417.6	0	0	24626.4	16417.6	60	40
9	41146	50	50	20573	20573	0	0	20573	20573	50	50
10	33922	50	50	16961	16961	0	0	16961	16961	50	50
11	27790	50	50	13895	13895	0	0	13895	13895	50	50
12	22218	50	50	11109	11109	0	0	11109	11109	50	50
13	17248	50	50	8624	8624	0	0	8624	8624	50	50
14	12984	50	50	6492	6492	0	0	6492	6492	50	50
15											
Total	422992			238264.4	184727.6		0	238264.4	151727.6	61.09468912	38.905311

Sliding Scale based on 1987 Malaysian Model PSA

Daily Production	Gov	FOC
0-10,000 b/d	50	50
10,001-20,000 b/d	60	40
>20,000 b/d	70	30

Daily Production: (A)/365

Table 3.6: Sample PSA Cash Flow With R-Factor Sliding Scale

Year	(A) Production ('000bbl)	(B) Oil Price ($/bbl)	(C) Gross Revenue ($m)	(D) IntangibleCapEx ($m)	(E) TangibleCapEx ($m)	(F) OpEx ($m)	(G) DD&A ($m)	(H) Royalty (%)	(I) Royalty ($m)	(J) Net Revenue ($m)	(K) Cost Oil (%)	(L) Cost Amort. ($m)	(M) Cost Oil Avail. ($m)	(N) Cost Oil ($m)
1	0	15	0	0	-10000	0	0	0	0	0	0	0	0	0
2	0	15	0	0	-8000	0	0	0	0	0	0	0	0	0
3	0	15	0	0	-15000	0	0	0	0	0	0	0	0	0
4	4500	15	67500	-15000	-10000	-11500	-8600	0	0	67500	40	35100	27000	27000
5	7000	15	105000	-2000	0	-14000	-8600	0	0	105000	40	32700	42000	32700
6	5600	15	84000	0	0	-12600	-8600	0	0	84000	40	21200	33600	21200
7	4760	15	71400	0	0	-11760	-8600	0	0	71400	40	20360	28560	20360
8	4046	15	60690	0	0	-11046	-8600	0	0	60690	40	19646	24276	19646
9	3439	15	51585	0	0	-10439	0	0	0	51585	40	10439	20634	10439
10	2923	15	43845	0	0	-9923	0	0	0	43845	40	9923	17538	9923
11	2485	15	37275	0	0	-9485	0	0	0	37275	40	9485	14910	9485
12	2087	15	31305	0	0	-9087	0	0	0	31305	40	9087	12522	9087
13	1732	15	25980	0	0	-8732	0	0	0	25980	40	8732	10392	8732
14	1427	15	21405	0	0	-8421	0	0	0	21405	40	8421	8562	8421
15	0	15	0	0	0	0	0					0		
Total	39999		599985	-17000	-43000	-116993	-43000		0	599985		185093	239994	176993

Year	(O) Remainder ($m)	(P) Profit Oil Gov (%)	(Q) Profit Oil FOC (%)	(R) Profti Oil Gov ($m)	(S) Profit Oil FOC($m)	(T) Tax (%)	(U) Tax ($m)	(V) NCF Gov ($m)	(W) NCF FOC($m)	(X) Gov Take (%)	(Y) FOC Take (%)
1	0	0	0	0	0	0	0	0	-10000	0	0
2	0	0	0	0	0	0	0	0	-8000	0	0
3	0	0	0	0	0	0	0	0	-15000	0	0
4	40500	50	50	20250	20250	0	0	20250	20250	50	50
5	72300	50	50	36150	36150	0	0	36150	36150	50	50
6	62800	60	40	37680	25120	0	0	37680	25120	60	40
7	51040	62.5	37.5	31900	19140	0	0	31900	19140	62.5	37.5
8	41044	62.5	37.5	25652.5	15391.5	0	0	25652.5	15391.5	62.5	37.5
9	41146	65	35	26744.9	14401.1	0	0	26744.9	14401.1	65	35
10	33922	65	35	22049.3	11872.7	0	0	22049.3	11872.7	65	35
11	27790	65	35	18063.5	9726.5	0	0	18063.5	9726.5	65	35
12	22218	65	35	14441.7	7776.3	0	0	14441.7	7776.3	65	35
13	17248	65	35	11211.2	6036.8	0	0	11211.2	6036.8	65	35
14	12984	65	35	8439.6	4544.4	0	0	8439.6	4544.4	65	35
15											
Total	422992			252582.7	170409.3		0	252582.7	137409.3	64.76612341	35.233877

Sliding Scale based on Azerbaijan PSA described in Table 3.2

Table 3.7: Scenario 1 - Fixed Scale with Low Oil Price ($10bbl)

Parameter Change	NPV@12	NPV@15	IRR	NCF_{GOV}	NCF_{FOC}
Original Assumptions	16,201	10,657	25	143,996	62,998
10% Royalty	9,170	4,780	20	159,996	46,998
No Cost Oil	-431,880	-336,847	n/a	239,994	-1,376,634
100% Cost Oil	12,366	7,244	21	133,798	56,199
10% Royalty, 100% Cost Oil	5,335	1,367	16	149,798	40,199
40/60 Profit Oil	37,293	28,290	38	95,998	110,996
50/50 Profit Oil	26,747	19,474	32	119,997	86,997
20% Tax	7,764	3,604	18	163,196	43,798
20% Tax with 5-year holiday	14,223	9,166	24	150,761	56,233
20% Tax, 10% Royalty	2,140	1,098	14	175,996	30,998
20% Tax, 10% Royalty,100% Cost Oil	-928	-3,828	11	164,438	25,559

Table 3.8: Scenario 2 - Fixed Scale with Medium Oil Price ($15bbl)

Parameter Change	NPV@12	NPV@15	IRR	NCF_{GOV}	NCF_{FOC}
Original Assumptions	47,740	36,874	42	253,795	136,197
10% Royalty	37,194	28,057	37	277,795	112,197
No Cost Oil	-396,727	-307,460	n/a	359,991	-1,296,636
100% Cost Oil	47,519	36,632	42	253,795	136,197
10% Royalty, 100% Cost Oil	36,973	27,816	36	277,795	112,197
40/60 Profit Oil	84,601	67,614	58	169,197	220,795
50/50 Profit Oil	66,170	52,244	51	211,496	178,496
20% Tax	32,995	24,577	35	287,635	102,357
20% Tax with 5-year holiday	44,055	34,086	42	266,220	123,772
20% Tax, 10% Royalty	24,558	17,524	30	306,834	83,158
20% Tax, 10% Royalty,100% Cost Oil	24,381	17,331	29	306,834	83,158

Table 3.9: Scenario 3 - Fixed Scale with High Oil Price ($20bbl)

Parameter Change	NPV@12	NPV@15	IRR	NCF_{GOV}	NCF_{FOC}
Original Assumptions	82,672	66,019	57	373,792	216,195
10% Royalty	68,611	54,264	52	405,791	184,196
No Cost Oil	-361,574	-278,072	n/a	479,988	-1,216,638
100% Cost Oil	82,672	66,019	57	373,792	216,195
10% Royalty, 100% Cost Oil	68,611	54,264	52	405,791	184,196
40/60 Profit Oil	136,999	111,333	76	249,195	340,792
50/50 Profit Oil	109,836	88,676	67	311,494	278,494
20% Tax	60,941	47,894	48	423,631	166,356
20% Tax with 5-year holiday	77,339	61,989	57	391,854	198,133
20% Tax, 10% Royalty	49,692	38,490	43	449,231	140,757
20% Tax, 10% Royalty,100% Cost Oil	49,692	38,490	43	449,231	140,757

Table 3.10: A Comparison of Fixed and Sliding Scales ($15bbl)

Type of Scale	NPV@12	NPV@15	IRR	NCF_{GOV}	NCF_{FOC}
Fixed Scale	47,740	36,874	42	253,795	136,197
Volume-Based Sliding Scale (3 Steps)	52,346	40,358	43	238,264	151,728
Volume-Based Sliding Scale (5 Steps)	45,722	34,512	39	248,751	141,241
R-Factor Sliding Scale	51,121	40,226	47	252,583	137,409

Part II: Some Theory

4 INCENTIVES, RISKS AND REWARDS

Oil exploration and development projects are characterised by large capital investments, long lead times, incomplete information, and in most cases significant differences in the abilities of the parties to bear the risks involved in the venture. Thus, contracts are potentially unstable and one or both signatories may want to renegotiate at some point in time. Furthermore, the inherent instability of contracts may result in some projects not being developed although they are economically attractive in general. The uncertainties over risk and reward-sharing prevent one or both parties from going ahead with the venture. When a government or its NOC enters into negotiations with a FOC which it expects to provide capital, technology and expertise it wants to ensure that it obtains the best possible deal given the country's specific circumstances. The NOC will take a number of elements (discussed in the following section) into account and evaluate them under different scenarios such as reserve discoveries, variations in oil prices, operating costs, and field development. The objective is to maximise revenue under each scenario.[21] However, given the existence of international competition for risk capital, technology and know-how trade-offs will occur. A further constraint is, of course, the fact that the FOC has the same aim of maximising its revenue. Although countries as well as the two parties to the contract are similar in the goals they pursue their relative success will be determined by their

- bargaining position
- negotiation skills
- country-specific circumstances.

The government therefore has to find the optimal, or efficient, contract form for its country. Efficiency can be, and indeed has been, defined in many different ways. Applying the definition of Pareto optimality from welfare economics to contract theory we can say that a contract is efficient when it is impossible to improve one party's terms without making the other party worse off. The efficient contract is then a non-zero sum game. Assume a contract is being renegotiated and is supposed to remain efficient. The renegotiation must either improve the positions of both parties or one partner improves its circumstances without the other one losing anything. In other words, neither party will be worse off. More specifically, assuming that the government can exploit its bargaining position it will try to offer terms that provide sufficient incentives for a FOC to sign the contract while at the same time ensuring that the foreign partner will not appropriate all incremental benefits. Incentives are therefore one of the main contract features. The second characteristic, which is closely linked to incentives, is the allocation of investment, geological and price risk. Finally, the contracting risk needs to be addressed. By this we mean the possibility, and probability, of non-performance by one or both parties.

4.1 RISK ALLOCATION AND CONTRACTING RISK

Investment decisions and strategic planning in general are carried out under uncertainty. The assessment of the risk involved in a project and the appraisal of

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[21] In order to avoid any confusion it should be stressed that the host country can have a wide range of objectives. Many of these, such as improvements in the health or education sector, are closely linked to the revenue maximising approach. Others, such as political influence and general strategic considerations, may be of equal importance.

whether potential rewards justify taking a particular risk are made by finding probability distributions of the measures concerned. Varying degrees of uncertainty that might affect the input variables will be taken into account. The main unknown factors in oil exploration and development are:

- discovery of new resources
- type of resource (oil or gas)
- size of deposit
- economic viability of development
- technological requirements
- future price developments
- general economic and political risks.

The allocation of these risks is a significant factor in the formulation of an efficient contract. Recall that for the contract to be efficient, or Pareto optimal, it has to be considered efficient by both partners. Let us illustrate this. It is conceivable that one party is more exposed to, say, price risk than the other.[22] Hence, the former is at a comparative disadvantage in carrying the price risk. Ideally, the two partners find a risk distribution that takes this into account. This process will inevitably involve a sharing of rewards that is related to the risk allocation. We can develop a similar argument with regard to the cost risk. Total expenditure on, say, an exploration operation depends on a large number of factors such as onshore, offshore or jungle location of the field, the use of two- or three-dimensional seismics, the depth of the deposit and so forth. Several million dollars may be spent on a venture that turns out to be unsuccessful because no commercial quantities of oil have been discovered. Thus, the successful projects must not only be profitable on their own terms but have to generate enough profit to make up for losses incurred elsewhere. The government will also have views on how the contract should be implemented, that is how the project should be managed. However, they depend on a foreign contractor to provide technology and expertise. Again there will be a trade-off between the way the government wants the operation to be run and the incentives it has to offer to its counterpart. The government will thus structure the contract so that the FOC finds it in its own interest to manage the project in the way the government itself would have chosen.

Contracting risk, on the other hand, is easier to contain since the non-performance of one party would very likely result in reduced rewards for both partners. If, say, the FOC takes the view that the potential for a future default by the host country exists,[23] it will insist on either incorporating a compensation clause into the contract or on a higher share of the gains from the project (or both). At the same time the government, too, will be concerned about the FOC breaking its commitment. It will warrant a penalty clause as part of the contract. Furthermore, under a PSA the government owns the resources even once they are produced and can therefore prevent any export of oil should the FOC default on its obligations. Two crucial points have to be taken into account here. First, compensation and penalty clauses are meaningless unless they are institutionally enforceable. In acknowledgement of this almost all PSAs provide for international arbitration should conflicts arise. Second, both partners have reputations to preserve. One partner's default will become known to the rest of the industry. FOCs would be very hesitant to enter into contracts with a country perceived as an unreliable partner.

[22] For instance, if a country is largely dependent on its oil revenues it will be more exposed to price changes than a FOC that is heavily diversified.
[23] Nationalisation would be an example here.

Governments, on the other hand would worry about the risk of doing business with a firm that has a history of either not finishing projects or trying to renegotiate its work and other obligations. Additionally, defaulting might make it difficult to obtain investment funds for future ventures.

The themes outlined in this section will now be investigated using two economic theory approaches: sharecropping and principal-agent theory.

4.2 SHARECROPPING

Like financial derivatives oil contracts can be traced back a few centuries to agricultural contracts. There are three main contract forms in agriculture; direct cultivation, fixed rent tenancy, and sharecropping. Their oil equivalents are national oil companies without foreign partners, the US bidding process, and production-sharing agreements. Joint ventures and concessions constitute bastard forms with the latter being closer to fixed rent contracts. Sharecropping forms the basis for a tool widely used in industrial economics: the principal-agent model.

While PSAs may only have been introduced to the oil industry in the 1960s, the concept of production sharing has been practised for much longer. It originates in agriculture where the landlord allows the tenant to use his land in exchange for a specified share of production. The terms of the agreement can vary widely. For example, the landlord can regulate in which way and for what purpose the land is used. He may also decide to bear part, or even all, of the costs which in turn will be reflected in the production share he receives. Sharecropping has been criticised as an inefficient arrangement since tenants receive less than their marginal product. If they produce an extra ten units they only gain x percent of this extra output because the landlord takes $1-x$. At the other end of the spectrum there exists the

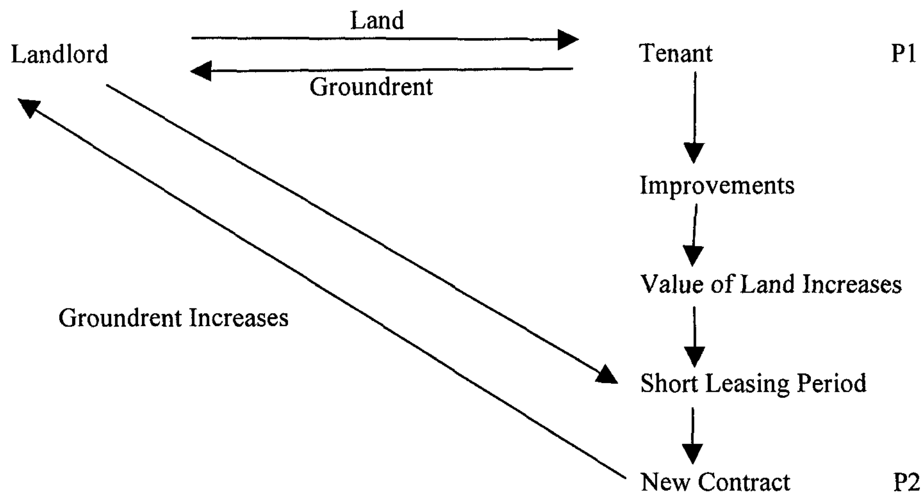
Table 4.1: Risk-Bearing under Different Contract Types

Contract	Landlord	Tenant
Fixed Wage	all	none
Fixed Rent	none	all
Sharecropping	some	some

view that considers this contract type as efficient in so far as it reflects the respective risks taken by the two parties. Assume bad weather destroys the crop. In this case neither the landlord nor the tenant receive any output. Under a rental contract the tenant would still be obliged to pay rent to the landlord whereas the sharecropping agreement reduces the risk for the tenant and increases that of the landlord. Hence, the share of production paid to the latter can be regarded as compensation for his risk-taking. By the same token if the chosen contract form were a wage contract, the landlord would carry all the risk as he would be required to pay wages even if output is zero.

Sharecropping is thus essentially a contract form which combines risk sharing and incentives. This is of particular importance when monitoring effort is costly. Stiglitz (1989) and Braverman/Stiglitz (1982) in their analysis outline two repercussions of this contract form. First, the landlord has an incentive to share the costs of the venture. In the case of agriculture contracts the landlord might for example want to encourage the tenant to use a fertiliser which will improve output. Thus both parties to the contract can increase their returns. Figure 4.1 shows one way of interaction between landlord and tenant. The former leases land to the latter who in turn pays a groundrent. The tenant then invests capital which may be labour and/or finance. If it is the latter the landlord can participate in providing the capital by acting as the lender or by investing jointly with the tenant. Either way it is likely that the value of the land increases.

Figure 4.1: A Landlord-Tenant Relationship



It is thus in the landlord's interest to keep the first leasing period, *P1*, short and write a new contract for *P2* which guarantees him a higher groundrent due to the improved condition of the land. By the same token the tenant is better off if he exploits the land as much as possible in *P1*. Second, credit markets and 'land markets' can be interlinked if the landlord is also the lender. If in the previous example costs are shared, meaning the tenant has to invest some capital, the landlord might provide these funds. Consequently the former is now indebted to the latter. One would expect that debt will affect both the tenant's effort and his attitude towards risk. This in turn has an impact on the landlord's return. Obviously, if costs are to be shared they have to be observable. Here the tenant might have an advantage as he is better informed about the conditions of the land and the required inputs. The contract therefore has to provide an incentive for the tenant to use this information asymmetry.

Another feature to be taken into account is the temptation for the tenant to take the entire output and disappear with it. The contract itself can incorporate an incentive that prevents this event from occurring. As long as the share the tenant receives is large enough both in absolute terms and relative to the landlord's allocation the former might be better off to stay. This is especially true if we introduce reputation. The tenant might plan to abscond with the entire production and settle elsewhere. However, as soon as his reputation for cheating is known to other landlords his chances of getting a new tenancy contract, and secure future income, are at best minimal. It is, of course, possible that his gain from cheating is large enough for him to buy his own land (in which case he himself can become a landlord) or set up a different kind of business which makes him independent of any landlord. From the landlord's point of view it is therefore first of all desirable that the incentive provided by the contract is good enough to prevent cheating. Failing that the penalty has to be so prohibitive that it deters any adverse actions. Finally, if this is still not sufficient the contract, and with it the penalty, has to be enforceable.

Up to this point we have explained how sharecropping works. The question that arises now is whether with regard to risk-sharing sharecropping contracts are superior to fixed-rent and wage contracts. Singh (1989) discusses this issue within the framework formalised by Newbery/Stiglitz (1979). Let α be the share the tenant holds in the sharecropping contract, r the rental rate, and w the wage rate. The agreed-upon amounts of land and labour are denoted by L and T respectively with a production function $Q(L, T, \theta)$ where the random variable θ stands for the state of the world. Newbery/Stiglitz specify that a fraction k of the land is rented out while the remainder is cultivated under a fixed-wage contract. Thus, the tenant's income is[24]

$$Q(kL, kT, \theta) - rkT + w(1 - k)L = kQ(L, T, \theta) - rkT + w(1 - k)L. \tag{1}$$

Next, if k^* is chosen such that

$$rk^*T - w(1 - k^*)L = 0 \tag{2}$$

the tenant's income is $k^*Q(L, T, \theta)$. This is the income the tenant with a fraction of land k^* receives in each state of the world. Let us further assume that markets for labour and land exist with prices w and r respectively. In this case a share contract only improves matters for the tenant if $\alpha > k^*$. Given the mix of wage and fixed-rent contracts the landlord's income is $(1 - k^*)\, Q(L, T, \theta)$. He prefers a share contract only if $1 - \alpha > 1 - k^*$ or $\alpha < k^*$. Considering that the tenant wants a share contract when $\alpha > k^*$ and the landlord wants it when $\alpha < k^*$, Newbery/Stiglitz conclude that no share contract exists that yields improvements for both landlord and tenant, and that the best outcome for both is a contract where $\alpha = k^*$. The authors thus *'demonstrate that [...] there will be a mix of wage and fixed-rent contracts on two subplots that gives the same pattern of returns [...] to the landlord and to the tenant as does a share contract for the whole plot'* (Singh 1989:39). Following this analysis, sharecropping does not provide superior risk-sharing.

Singh (1989) discusses some scenarios in which share contracts are preferable to fixed-rent and wage contracts. The first, again going back to work by Newbery/Stiglitz, considers the case where the tenant combines a fixed-rent contract, a share contract, a wage contract, and a fixed-rent contract with a share sublease. Provided the parameters are carefully chosen sharecropping here can lead to optimal risk-sharing. The second scenario concerns itself with non-tradable inputs. In the absence of a market for non-tradable inputs[25] and with a choice of only fixed-rent or wage contracts some potential tenants may only be willing to take wage contracts (which, as explained above, pass all risk on to the landlord). If in addition share contracts are offered, some potential tenants may be induced to accept them. They can now use their endowments of non-tradable inputs without being exposed to the risk inherent in a fixed-rent contract. The advantage to the landlord is obvious B he can share the risk with the tenant. A third area that favours sharecropping over other contract forms is the issue of labour market

[24] This assumes constant returns to scale in production and no indivisibilities. However, Allen (1985) has shown that the overall result is the same even if these assumptions are relaxed.

[25] Singh (1989) cites managerial and supervisory labour as well as the service of draught animals as examples.

imperfections other than wage uncertainty. If labour input is not observable the wage contract provides no incentive for high levels of effort. Sharecropping, on the other hand, does provide such an incentive.

The common theme that has emerged from this discussion so far is that sharecropping is a response to uncertainty and asymmetric information, and that it addresses market failures in the markets for labour, insurance, credit and capital. We will now further develop the main issues, namely screening (finding the 'right' tenant), incentives (inducing the 'correct' level of effort), and cost-sharing (sharing of input costs between landlord and tenant).

The *screening* problem arises from the inability of the landlord to directly observe certain characteristics of a potential tenant which can influence productivity (e.g. entrepreneurial ability). Economic theory assumes that by offering different types of contract the landlord attracts the 'right' type of tenant for each contract. Tenants select contracts according to ability which in turn provides a screening mechanism for the landlord. The screening model thus explains the co-existence of different contract types. Moreover, it fits the observation that sharecropping frequently yields lower productivity than fixed-rent tenancy (Singh 1989). The ramification of this is that low-ability tenants choose the former and high-ability tenants the latter contract form. In addition, Singh (1989:56) points towards the agricultural ladder hypothesis which states that the accumulation of physical and human capital induces tenants to progress from wage contracts over sharecropping to rental contracts and finally to ownership of land.

The issue of *incentives* and sharecropping is based on the argument that the latter leads to an inefficient labour input because the tenant receives only a fraction of his marginal product. Labour input here does not mean the hours worked (which would be observable and thus enforceable) but refers to the effort level chosen by the tenant. We can identify three elementary approaches to this problem that are all driven by the assumption that effort is not fully observable. First, if the tenant is risk averse and there is no insurance market the landlord supplies both land and insurance. Hence, he will be looking for a contract that provides the optimal trade-off between insurance and incentives. This is exactly the function a share contract fulfils.

The second approach deals with a two-sided incentive problem where both landlord and tenant provide labour inputs. The underlying assumptions here are that the landlord is better at management (due to superior access to information, markets and institutions) and the tenant is better at supervising labour. A share contract offers each agent the opportunity to specialise in their strength.[26] However, there are several caveats attached to this notion. If the landlord's managerial input is high, his expected payoff from the contract is low and he would thus prefer a fixed-rent contract.[27] If the tenant's supervisory input is high, his expected payoff is low and he would prefer a wage contract. If both inputs are low sharecropping is the favoured option.[28] The virtue of this approach is the incorporation of active landlord participation. Landlord and tenant each provide inputs of which they have different

[26] A wage contract would put the onus of management and supervision on the landlord whereas a fixed-rent contract would require the tenant to provide both management and supervision.
[27] It should be pointed out that this holds only if there exists a landlord-tenant relationship. Otherwise direct cultivation would be preferable for the landlord.
[28] A formal treatment can be found in Singh (1989).

endowments. Hence, a wage or fixed-rent contract may not be optimal, and a further justification for the existence of share contracts is given.

The third model in the context of sharecropping and incentives assumes that the tenant has a wealth or income constraint. His income can therefore not be negative which rules out a fixed-rent contract. The choice is then between wage and share contracts. If in addition the landlord aims to minimise regret rather than maximise expected utility a share contract with a 50B50 split is the optimal contract form.[29] On the other hand one could also argue that the wealth constraint implies that rich tenants obtain fixed-rent contracts and less well-off tenants take out share contracts. A poor tenant may then prefer a wage contract. The landlord would, however, object to the latter if he believes that the tenant might default. In that case, once again, a share contract would be favoured over other contract types.

We have thus shown how sharecropping works and under what circumstances share contracts are preferable to wage and fixed-rent contracts. What remains to be explained is why in a number of share contracts the landlord shares the input costs. The intuitive argument for cost-sharing in sharecropping is that not only the tenant but the landlord, too, faces a wealth constraint which prevents him from offering a wage contract.[30] At the same time the cost-share provides the landlord with a justification for monitoring the tenant who, aware that he is being monitored, is more likely to choose a high effort level. The tricky bit is to find the equilibrium that induces the worker to choose the effort level which maximises output for both himself and the landlord. We work through this problem in the following section where the sharecropping model is extended to a simple form of the principal-agent theory which can be regarded as a modern development of the former. As Stiglitz (1989:308) points out *'the sharecropping model has served as the basic paradigm for a wider class of relationships known as principal-agent relationships'*.

4.3 PRINCIPAL-AGENT RELATIONSHIPS

As the name suggests, principal-agent theory deals with the actions of a principal (landlord), who owns an asset, and an agent (tenant), who works with that asset and/or makes decisions which will affect the value of the asset.[31] The theory focuses on the optimal design of contracts between the two parties whereby it is possible to have more than one agent. Applied to PSAs this means that the state or the NOC is the principal and the foreign contractor is the agent. If the foreign contractor is a consortium this could be regarded as a principal-agent problem with many agents.

Modern contract theory[32] tells us that contracts are by definition incomplete. If we had only two states of nature, say rain and sunshine, we could foresee that tomorrow we will have either rain or sunshine or a combination of the two. What we do not know is which of the three it will be. A contract based on the possibility of these three events occurring could simply specify that if 'rain' clause x applies, if 'sunshine' clause y applies and so forth. However, in reality there are infinite events that can occur. Some may be more likely than others, and some will be regarded as

[29] The proof for this result is somewhat longwinded. A summary and evaluation of the analysis is offered in Singh (1989).
[30] As outlined before, the tenant's wealth constraint may make a fixed-rent contract impossible.
[31] The principal is the landlord in the sharecropping model, while the agent is the tenant.
[32] See e.g. Hart (1995).

being more relevant than others. Assume we are an oil company negotiating a contract in a foreign country. Surely we would be more concerned about say the likelihood of a nationalist terrorist group attacking our oilfield than the likelihood of a plane crashing in the car park. Therefore, the best we can hope for is the formulation of a comprehensive contract. We try to take all possible, relevant future events into consideration and make provisions for those events that we cannot foresee.

The main concern is the relationship between ownership and control when writing a contract within this framework. Recall that the two parties to the contract are a principal and an agent. The principal will want to design a contract such that his interest will be advanced by the agent despite the fact that the interest of the latter may diverge from that of the former. Thus, the principal needs to provide an incentive to the agent that will induce him to act in the principal's interest. At the same time the principal has to develop a monitoring system that allows him to measure the agent's performance, and that avoids moral hazard. In other words, the principal wants to establish a scheme whereby the agent is induced to maximise his efforts in order to get a maximum reward which in turn will also yield maximum profit to the principal. As mentioned before the agent can be a team. This makes the control of moral hazard more difficult as it is harder to detect the source of shirking. One way to control moral hazard is for the principal to pay the agent a salary and bonus based on the performance of the company. The better the agent performs the higher his income. However, if we have many agents they may have different utilities of leisure. That is to say somebody may be prepared to accept a lower income if that means he can work less hard and has more leisure. In this case shirking can still persist unless group pressure and/or social cohesion make it unacceptable to each individual agent. The issue just discussed implies another way to prevent moral hazard. The problem can be avoided if the principal develops a mechanism that enables him to monitor the performance of each individual agent. Also in conjunction with the first scenario is the possibility of incentive contracts which reward agents only on the basis of individual results. One could imagine a scheme whereby the agent has to pay the principal a specified sum in case of underachievement. The most obvious solution to the principal-agent problem is of course for the principal to become his own agent.

4.4 An Application of the Principal-Agent Model[33]

We start with the simple case where there is only one principal and one agent. The principal (landlord) is a state who owns the oil, and the agent (tenant) is a FOC who is willing to provide finance and expertise in order to explore and exploit the resource. The state has to offer contract terms that are attractive enough for the FOC to enter into an agreement. In other words, the reservation utility of the FOC has to be known and, at the very least, matched. In the example above the reservation utility is the outside wage, here it can be replaced by the rate of return the FOC anticipates from a comparable project elsewhere. This is the participation constraint. At the same time the state has to solve the incentive constraint since it will want to ensure that it receives maximum revenue from the venture. Thus the utility from working hard (fulfilling the contract) should be no less than the utility from shirking (cutting corners). This implies that the profit in the former has to be greater than in the latter case. In the previous section we have shown that the principal has to pay the agent x units above his reservation utility for the contract

[33] A formal treatment of the principal-agent model is provided in Appendix 4.1.

to be optimal. If this is true then the state has to compare its own contracts to those offered by other countries and add some kind of improvement to them. This, of course, only applies to *ceteris paribus* conditions. If, say, the geological characteristics or the size of the deposit are favourable the state can still attract the FOC even with a contract that is comparatively less attractive.

Recall that in the previous section we distinguished between incentives under certainty and uncertainty. A PSA is signed before the FOC has had the opportunity to explore the oilfield on offer. It therefore faces the following uncertainties in the exploration period:

- No discovery
- Discovery is not commercial
- Cost increase

The latter can be due to several factors. Previously unknown characteristics of the deposit may require the use of more expensive technologies. The same reason can lead to the necessity for an extension of the initial exploration period. This has knock-on effects. The longer it takes to explore the field the later production starts. Only once oil is produced can costs be recovered. Financial circumstances might change and make borrowing more costly. The state, on the other hand, has no direct financial risk in this phase. However, it has to monitor that the FOC complies with the work obligations specified in the contract (number of wells to be drilled, depth, technology etc). Our general discussion of principal-agent relationships has revealed that under certainty effort can be observed through output and thus requires no special monitoring. The same result can be achieved under uncertainty if the agent's state-contingent wages are correctly specified. Given that under a PSA the FOC can only recoup its exploration expenditure if oil is produced, it can generally be assumed that the FOC has no incentive to artificially prolong the exploration phase or to use inadequate means in the process. Since the FOC bears the entire exploration risk[34] it will try to ensure that the contract terms allow for sufficient rewards in the development phase of the project. The two main uncertainties encountered by the FOC during production are

- Cost increase
- Price decrease.

The first point also includes protection payments in case of civil wars or terrorist activities. However, contrary to the exploration uncertainties, risks in the development period are shared by the FOC and its host government or NOC. What differs is the extent to which these uncertainties affect the partners. Let us start with the cost risk. Assuming that the NOC refrains from taking up its participation option, a cost increase is largely but not entirely borne by the FOC. Say the cost recovery limit is 50 percent. A rise in costs then means that the FOC needs more time to recoup its expenditure. The longer it requires the maximum cost oil the longer both the FOC and the government have to wait before they can realise their take. Considering the definition of profits as being equal to the difference between total revenue and total cost, $\pi = TR - TC$, we can thus state that costs have a

[34] There are two exceptions to this. The FOC and the NOC can enter into a joint venture in which costs are shared in accordance with the stake each partner has in the venture. Alternatively, the NOC can take up its participation option during exploration rather than in the development phase. While the latter is highly unusual the former becomes more common especially in the FSU countries.

significantly bigger impact on the FOC's profit than on the government's. Next we are concerned with revenue. The government's revenue can come from royalties, its profit-oil share, taxes, bonuses, customs duties, price caps, and DMOs. The FOC's sources of revenue are cost oil and its share of profit oil. Profit is also a function of price and output, $\pi = PY$. Algebraically this implies that if price and/or output increase profit will go up, too. However, as we have seen again in the recent past, if price falls an increase in output is not necessarily the answer. Thus, to make the principal-agent model workable the incentives, or rewards, offered to the agent, the FOC, have to take into account all the factors discussed above and balance them in a way that induces maximum effort from the FOC while at the same time ensuring an adequate government take.

Going back to the theoretical discussion of the principal-agent model in the previous section, recall the major insights and their relevance for PSAs. We know that the agent has a reservation utility stipulating what return he can earn from an alternative investment. Under certainty, the principal has to compensate him by paying x units above that reservation utility. Under uncertainty x is greater than it is under certainty if maximum effort is to be induced. However, the expected compensation to the agent is the same in both cases. For PSAs we can ignore the differentiation between these two states. As we have demonstrated there is always uncertainty. Some of these risks are encountered under any contract form while others are PSA specific. Finally, we distinguished attitudes towards risk. The larger the FOC, and this is particularly valid for multinationals, the less risk averse we expect them to be. They have diversified portfolios which allow them to offset losses from one venture against gains from others. In addition they are active in most or even all oil- producing regions. How risk averse the government is depends on several factors such as its dependency on oil revenue, oil reserves, its standing in the producers table and so forth. Therefore, it seems more likely that if one of the partners needs compensation in order to overcome risk aversion it will be the government rather than the FOC.

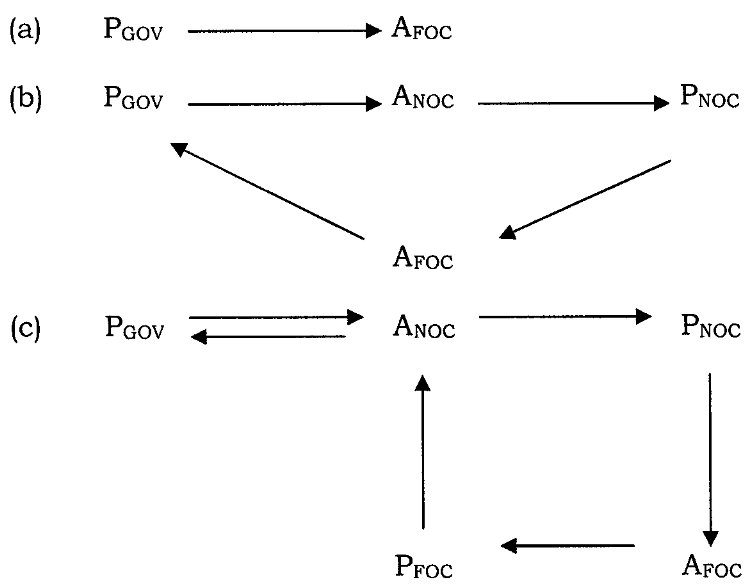
So far we have only considered a situation with one principal, the government, and one agent, the FOC. Figure 4.3[35] shows some more constellations that are possible under PSAs.[36] Part (a) depicts the case discussed so far. Parts (b) and (c) add the NOC to the scenario. The role of the NOC has been analysed in detail by Noreng (nd) and we do not intend to reproduce his work here. Hence we will limit ourselves to some brief remarks on the reasons for the establishment of NOCs and their interaction with both governments and FOCs. NOCs were created to counterbalance the influence of the major oil companies. The latter were perceived as maximising their benefits and thereby often acting to the detriment of the host country's objectives. The purpose of NOCs, however, went beyond mitigation of the FOCs' practices. Setting up a NOC was regarded as a way of accumulating knowledge and expertise which would improve the country's bargaining position in future negotiations.

Furthermore, during conflicts the FOC would have to deal with the NOC. The government would thus be enabled to rise, at least officially, above the hurly-burly of controversies and at the same time protect its position vis-à-vis foreign governments. Once the NOC is sufficiently experienced it can either become an equal partner with a FOC or even venture abroad in its own right. A crucial point is, of course, the relationship between the NOC and government. There are various

[35] P denotes the principal, and A denotes the agent.
[36] This is by no means a complete list of principal-agent relationships.

possibilities. The NOC can be completely independent of the government and direct its operations like any other company. At the other end of the spectrum the NOC might simply be another government department. Parts (b) and (c) in Figure 4.2 refer to these cases. In (b) the government, representing the state as the owner of the oil, puts the NOC in charge of oil operations.

Figure 4.2: Some Principal-Agent Relationships



The latter becomes thereby a principal delegating the exploration and exploitation of oilfields to FOCs. The arrow from the FOC to the government indicates that in this particular instance the firm pays taxes directly to the government. Part (c) demonstrates for example that the NOC pays taxes out of its profit oil on behalf of the FOC and thus becomes not only the government's but also the FOC's agent. These multi-level principal-agent problems highlight a further complication. The more players that are involved in an operation the more scope there is for cheating and the greater the need for monitoring. For instance, the FOC and the NOC could collude and cheat the government of some of its tax revenue. The government can incorporate a control mechanism by, say, appointing one of its ministers as president of the NOC. This would then lead to additional opportunities for cheating. However, the debate of these issues is not unique to PSAs and will therefore not be extended.

APPENDIX 4.1 THE PRINCIPAL-AGENT MODEL

In this appendix we present some simple economics with a view to design an optimal incentive scheme.[37] We start with incentives under certainty. Here the agent's effort e can be observed through output Y. We further assume that there are two degrees of effort e, a high degree with $e=2$, and a low degree with $e=0$. The latter represents shirking. The agent is paid a wage w, and has a reservation utility of $U=10$. The existence of a reservation utility implies that the agent has an outside opportunity which would yield him $U=10$. There is only one principal and one agent. This information allows us to formulate the agent's utility function which is

$$U = \begin{cases} w-e \\ 10 \end{cases} \tag{1}$$

Output Y depends on effort e so that $Y(e) \Rightarrow Y(2)$ presents high output and $Y(e) \Rightarrow Y(0)$ presents low output. Thus

$$Y(e) = \begin{cases} H \\ L \end{cases} \tag{2}$$

Profit π is defined as output minus the wage paid by the principal to the agent which yields the profit function

$$\pi = R(e) - w. \tag{3}$$

The objective of the principal is to maximise his profits, that is equation (3) through minimising the expected wage bill Ew and induce the agent to choose the high effort level $e=2$. He would therefore want to formulate a contract that stipulates a high wage w_H when a high level of output Y_H is achieved and a low wage w_L in the case of low output Y_L. His difficulty is to determine the values of w_H and w_L that will result in maximum profit subject to the provision of incentives for the agent to opt for $e=2$. Here the principal encounters two constraints. The first is the participation constraint which arises from the existence of the agent's reservation utility $U=10$. In order to induce $e=2$ the contract should specify values for w_H if $Y(2)=H$ and for w_L if $Y(2)=L$ that provide the agent with at least $U=10$. This can be written as

$$w_H - 2 \geq 10. \tag{4}$$

The second constraint is the incentive constraint. It postulates that the utility level from working hard should be no less than the utility from shirking so that

$$w_H - 2 \geq w_L - 0. \tag{5}$$

Solving (4) we obtain $w_H=12$. Substituting this into (5) yields $w_L=10$. The profit that results from a high effort level is then

$$\pi_H = H - w_H = H - 12$$

while the profit from shirking is

$$\pi_L = L - w_L = L - 10.$$

---

[37] This is based on the treatment of the concept in most standard economics textbooks.

Hence for the contract to be optimal for the principal $\pi_H \geq \pi_L$ or $H \geq L+2$. This means that the principal has to pay the agent at least two units above his reservation utility to induce a high effort.

Consider now how the incentive scheme has to change under uncertainty. The latter is defined as different states of nature beyond the control of either principal or agent. Referring to the introductory remarks of the section this means we know there is a possibility for it to rain tomorrow but we cannot be certain that it will actually rain. Within the framework of our analysis it implies that $e=2$ will not necessarily ensure $Y=H$. Under certainty effort could be observed through output. The principal therefore had no need to monitor the agent. In the case of uncertainty the level of output can but may not be directly related to the level of effort. The output of a shop selling clothes may decrease because the shop assistant is unfriendly ($e=0$). On the other hand he or she may be very friendly and competent ($e=2$) but people instead of buying clothes prefer to watch the football World Cup. Therefore, an increase in e only increases the probability of $Y(e)=H$. If nature determines $Y(2)$ and $Y(0)$ according to

$$Y(2) = \begin{cases} H prob 0.8 \\ L prob 0.2 \end{cases} \qquad Y(0) = \begin{cases} H prob 0.4 \\ L prob 0.6 \end{cases} \tag{6}$$

then by choosing $e=2$ the probability of high output increases from 0.4 to 0.8. In order to incorporate uncertainty into the model the agent's utility function (1) needs to be modified. Assuming that the agent wants to maximise his expected wage Ew minus the effort he put into his work we obtain

$$U = \begin{cases} Ew-e \\ 10 \end{cases} \tag{7}$$

with

$$Ew = 0.8w_H + 0.2w_L \qquad \text{for } e=2$$

and

$$Ew = 0.4w_H + 0.6w_L \qquad \text{for } e=0.$$

The new participation constraint becomes

$$0.8w_H + 0.2w_L - 2 \geq 10. \tag{8}$$

Despite $e=2$ uncertainty may yield L rather than H. Thus the incentive constraint changes to

$$0.8w_H + 0.2w_L - 2 \geq 0.4w_H + 0.6w_L. \tag{9}$$

The contract has to specify the agent's state-contingent wages (w_H for $Y(2)=H$ and w_L for $Y(2)=L$) that would result in a higher expected utility under $e=2$ than under $e=0$. Since (8) implies that

$$w_L = 60 - 4w_H$$

and (9) implies that

$$w_L = w_H - 5$$

the optimal contract would be the one that sets $w_H=13$ and $w_L=8$.

Both examples show that the principal can control the agent without extra monitoring. Under certainty effort can be observed through output, under uncertainty a high level of effort can be induced through the right specification of the agent's state-contingent wages. The wage bill for the principal is $w_H=12$ and $w_L=10$ in the first case and $w_H=13$ and $w_L=8$ in the second case. The expected wage bill, however, is the same in both examples. Under certainty $Ew=w_H$, under uncertainty $Ew=0.8w_H+0.2w_L$. We can therefore conclude that the economic incentive mechanism is not costly to implement. The result that the expected wage bills are the same under certainty and uncertainty only holds as long as both principal and agent have the same attitude towards risk. The structure of the contract will change if one of them is risk averse. Hence we have to introduce subjective probabilities which measure the likelihood each of the two attaches to the realisation of the two states of nature, *H* and *L*. For the principal, *P,* we then get

$$Y_P(2) = \begin{cases} Hprob0.8 \\ Lprob0.2 \end{cases} \qquad Y_P(0) = \begin{cases} Hprob0.4 \\ Lprob0.6 \end{cases} \tag{10}$$

whereas the agent, *A*, assumes that

$$Y_A(2) = \begin{cases} Hprob0.7 \\ Lprob0.3 \end{cases} \qquad Y_A(0) = Y_P(0). \tag{11}$$

In this example the agent is more risk averse than the principal and can therefore be expected to require greater compensation than in the previous cases. This point is reinforced when comparing wage expectations. The equation

$$Ew_P = 0.8w_H + 0.2w_L > 0.7w_H + 0.3w_L = Ew_A$$

shows that the wage bill expected by the principal is higher than that expected by the agent. From (11) we know that

$$Ew_A = 0.7w_H + 0.3w_L \qquad \text{for } e=2$$

and

$$Ew_A = 0.4w_H + 0.6w_L \qquad \text{for } e=0.$$

From this we can construct the new participation constraint.

$$0.7w_H + 0.3w_L - 2 \geq 10 \qquad \text{or} \qquad w_H = (12-0.3w_L)/0.7 \tag{12}$$

and the new incentive constraint

$$0.7w_H + 0.3w_L - 2 \geq 0.4w_H + 0.6w \quad \text{or} \quad w_H = 2/(0.3+w_L). \tag{13}$$

The graphical presentation in Figure 4.3 shows the combinations of w_H and w_L that maximise *e* (to the left of (13)) and are acceptable contracts for the agent (above (12)) as well as the optimal contract (triangle above point *E*). The line labelled (14) represents the principal's choice of w_H and w_L that will minimise his expected wage bill Ew_P, that is

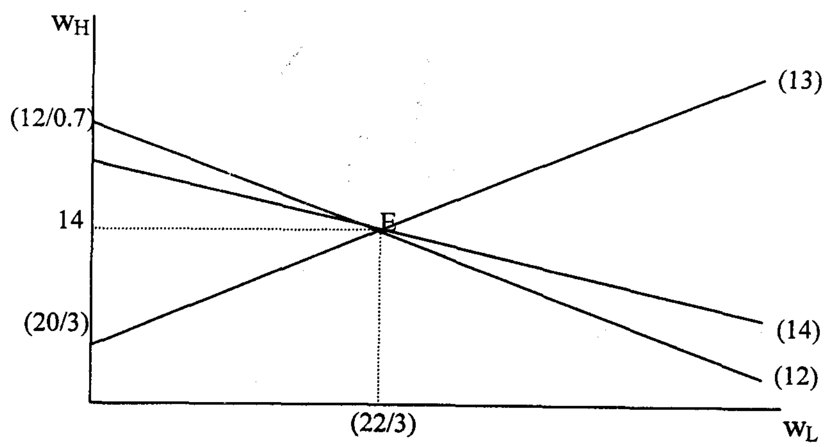
$$\min Ew_P = 0.8w_H + 0.2w_L. \tag{14}$$

In Figure 4.3 Ew_P is minimised at point E. The principal would thus choose a contract with w_H=14 and w_L=22/3. Hence

$$Ew_P = 0.8w_H + 0.2w_L = 12.66 > 10 + 2.$$

Let us recall that the agent's reservation utility is *10* and his high effort level is *2*. Under certainty where effort is perfectly correlated with output the principal has to pay the agent *10+2* in order to induce maximum effort. This is at the same time the principal's expected wage bill. In the case of uncertainty Ew_P is the same; *12* in our example. *12.66* tells us that the principal's Ew exceeds the agent's reservation utility plus his effort. The intuition behind this is that the agent is risk averse and therefore requires compensation for taking a random wage contract. This compensation is reflected in the difference *12.66-12* which in turn can be interpreted as the premium for being relatively more risk averse. To sum up then, this simple principal-agent model shows that problems arise when effort is not perfectly correlated with output.

Figure 4.3: The Optimal Incentive Structure



Part III: An Empirical Analysis

5 PRODUCTION-SHARING AGREEMENTS 1966B98

5.1 THE DATASET

The empirical analysis that follows is based on 268 PSAs signed by 74 countries during the period 1966 to 1998. Out of the total number of contracts 83 represent the model contracts of 42 countries. The regional breakdown of the sample is shown in Table 5.1, a more detailed list can be found in Appendix 5.1. For the purpose of this research we only consider contracts that are explicitly called PSAs. In addition to the global and regional analysis we distinguish between exporting and importing countries as well as OPEC members, and between onshore and offshore terms and conditions. The regional analysis will then be further disaggregated into case studies where the contracts of selected countries are analysed (Chapter 6). The individual countries considered are Indonesia as the country that first introduced PSAs, Angola, India, Iran, Peru, and Azerbaijan as a representative of the FSU. The latter three are chosen due to recent developments in their oil sectors, especially the opening, in some cases re-opening, of the industry to foreign companies.

The variables under consideration can be grouped into six categories detailed in Table 5.2. First, basic information is given such as the parties to the contract, the year the contract was signed, and the area which in this context refers to the location of the oilfield B that is whether it is onshore, offshore, marginal, in the jungle and so forth. The second category is labelled PSA elements which, strictly speaking, is not quite correct as all parameters listed are contract elements. It contains the basic contract elements. The third category, exploration and production, also includes relinquishment clauses which refer to the percentage of the contract area that has to be surrendered at the end of the first exploration period. Acreage, here, means the size of the area. The fourth category includes the various bonuses that the FOC may or may not have to pay to the government. Under the fifth category, taxation, we classify not only the tax, usually income tax, that has to be paid but also other financial obligations such as export and import duties, price caps, and domestic market obligations. Strictly speaking, the latter have nothing to do with taxation. However, they can be regarded as a financial obligation since the FOC will usually only receive a heavily discounted price. Finally, the legal framework is a somewhat crude description for the different forms of arbitration, work obligation for the FOC, and possible participation by the NOC.

Table 5.1: The Regions

Region	Number of Contracts	Largest Number of Contracts
Asia & Australasia	80	Indonesia (37)
Central America & Caribbean	21	Guatemala (7)
Eastern Europe	28	Azerbaijan (7)
Europe	2	Malta (2)
Middle East	41	Yemen (17)
North Africa	15	Egypt (6)/Libya (6)
South & Central Africa	69	Nigeria (10)
South America	14	Peru (4)

Before presenting the results of the empirical analysis a word of caution might be appropriate. First, there is no information on the exact number of PSAs signed between 1966 and 1998. It is thus difficult to evaluate how representative the sample in this study is in a quantitative sense. However, all the major oil countries have been considered. Indeed every attempt has been made to include all countries that offer PSAs. We are not aware of any other study that is quantitatively as extensive as the present one. The closest is Barrows (1994) which compares the conditions provided by 226 concessions, production-sharing and other contracts. Second, the data set has a somewhat uneven distribution of contracts among regions as well as among countries within regions. This is usually due to the relative size of the oil sector and/or the relative dominance of one contract form over others. Third, we rely largely on publicly available material from news services and consultants such as Barrows which publish either original contracts or a summary of the terms and conditions. Not all information regarding the various contract parameters is necessarily made available, and occasionally there are significant timelags between the signing of a contract and its publication. Nonetheless, the analysis should give a good approximation of how PSAs have developed over time both globally and regionally.

Table 5.2: The Parameters

Basics	PSA Elements	E&P	Bonuses	Taxation	Legal Framework
Country	Royalty/FTP	Exploration	Signature	Tax	Work Obligation
Year	Cost Oil	Production	Discovery	Export Duty	Participation
Domestic Partner	Profit Oil	Acreage	Production	Import Duty	Arbitration
Foreign Partner		Relinquishment		Price Cap	
Area				DMO	

5.2 CONTRACT DEVELOPMENT OVER TIME

Royalties. Royalties here refer to the maximum rate payable. While most PSAs levy fixed royalties, some contracts incorporate sliding scales. Since this research is based on the contract terms rather than the productivity of the fields in question we do not know the actual royalty rate if a sliding scale is applied. Therefore, the maximum possible rate is taken for the purpose of comparison. In most cases, the maximum is also the actual rate. Among the countries that offer sliding scale royalties are China, Turkmenistan, Syria, Yemen, Algeria, Egypt, Chile, Ethiopia, Gabon, and Nigeria.

During the period 1966 to 1998 royalties in Asia and Eastern Europe have on average been much lower than those in other regions. The average royalty rates in Asia and Eastern Europe were below 4 percent and 5 percent respectively whereas one could observe average royalties between 7 and 9 percent in the rest of the world. One explanation for this divergence is the absence of royalties in many Asian PSAs and in particular in the Indonesian contracts. Indonesia accounts for almost half of all Asian agreements under consideration. In place of royalties Indonesian contracts provide for first tranche petroleum (FTP) of 20 percent.[38] This is shared between the two contracting parties according to the agreed profit-oil split but works otherwise in the same way as a royalty payment. The picture is thus

[38] A detailed explanation of FTP can be found in Chapter 6 (Indonesia case study).

somewhat distorted. Given profit-oil shares that vary between 50 and 90 percent in favour of the government, the latter will receive between 10 and 18 percent of the initial 20 percent of production. This, of course, does not translate into a royalty of 10 to 18 percent since we are only considering a fifth of crude output rather than total production as in the case of royalties. Nonetheless, it is safe to conclude that actual royalties in Asia are higher than observed royalties.

Furthermore, 30 percent of the Asian PSAs in our dataset are model contracts (or revised model contracts). Like most other parameters royalties are occasionally negotiable or biddable[39] which means that for some agreements we have no information on payments. Another contributing factor to the divergence of royalty rates is the spread between the highest and lowest rates levied within regions. In Asia royalties vary between zero and 12.5 percent, in Eastern Europe between zero and 17.5 percent. In all other regions the variation is at least 20 percent. In South America the gap between highest and lowest royalty is 45 percent. This, however, is due to one of the Chilean contracts that allows for a maximum of 45 percent. If we deduct this extreme value, the region conforms to the 20 percent variation. At present royalty rates show a tendency to increase everywhere but especially in Eastern Europe and North Africa. The latter, together with Central America and the Caribbean, displays the highest average royalty rate with 10 percent and a trend to rise further. Net exporters charge significantly higher royalties than net importers, and, not surprisingly, onshore contracts are relatively tougher for FOCs than offshore agreements.

Figure 5.1A highlights the cluster of contracts without royalties. They constitute 63 percent of all PSAs in the dataset. In fact 91 percent of all contracts fall in the four categories of zero, 10, 12.5, and 20 percent royalty. Most of the remaining 9 percent of PSAs require royalties between 12.5 and 20 percent. Only one contract has a royalty payment of more than 20 percent (Chile with 45 percent), and only five are below 10 percent.

Cost Oil. Approximately one-third of PSAs under consideration specify annual cost oil allowances either on a sliding scale or, with regard to model contracts, state that this variable is biddable or negotiable up to a certain maximum value. Cost oil allowances vary from zero in some Libyan, Peruvian, Romanian, and Trinidadian contracts to 100 percent in countries such as Indonesia, Liberia, Bahrain, Guatemala, Algeria, India, Azerbaijan, and Nigeria. Two points should be noted here. First, not all PSAs in the countries concerned carry a zero or 100 percent cost-oil clause. Second, full cost recovery occasionally comes with a time limit attached to it. The share of production set aside for cost oil will decline after, say, five years. In this sense it works similar to a tax holiday.

The following observations are based on maximum rates. Since 1966, cost oil has on average been lowest in the Middle East with 37 percent, and South America and North Africa with 45 and 49 percent respectively. The most generous treatment of cost recovery could be found in Asia with 66 and in Central America with 69 percent. Both Eastern Europe and Southern/central Africa have cost-oil rates that are close to the world average. As with royalties, there are significant variations in cost recovery limits within regions. The gap between highest and lowest maximum cost oil during the period 1966 to 1998 is 100 percentage points in Central America, Eastern Europe, North Africa, and South America. In Asia cost recovery levels range from 20 to 100 percent. Variations in the Middle East and

[39] This is the case with several of the Philippine and Mongolian contracts.

Southern/central Africa contracts are similar with 25 to 100 and 30 to 100 percent respectively. The current trend is for cost oil to increase in all regions with the sole exception of the Middle East where it is slightly decreasing from its average 40 percent which is by far the lowest rate. Given the number of PSAs with maximum cost oil of 100 percent, and recalling that this optimum rate[40] often only applies to a specified number of years, the percentage of production paid as cost oil over the lifetime of a contract will be substantially lower than the current global average of 70 percent.

Two somewhat surprising results are that overall onshore cost oil is more generous than the offshore rate, and that there appears to be no difference between exporters and importers. The onshore-offshore result can be explained by taking two factors into account. First, the number of onshore contracts contained in the dataset is significantly greater than the number of offshore contracts. Thus, it takes only a few low cost recovery offshore PSAs to drag down the entire offshore sample. Countries such as Qatar, Côte d'Ivoire, Vietnam, Angola, and Myanmar fall into this category. Second, some of the onshore fields are either marginal or in mountainous and frontier areas. These fields usually offer relatively better terms. The similarity between exporters and importers might be due to the comparatively large number of model contracts in the latter group that allow for cost recovery to be negotiated or to be biddable. Furthermore, the exporting countries comprise both Indonesia and Nigeria with several 100 percent cost recovery contracts. Considering the comparatively large number of PSAs from the two countries this would push up the average cost oil granted by exporters.

Figure 5.2A shows the most common cost-oil allowances. Almost half of all contracts specify cost oil at either 40 or 100 percent, while almost one-third are at 30 or 50 percent. At the other end of the scale, zero-percent cost oil features in only 2.5 percent of PSAs. The remaining 20.5 percent of contracts are concentrated in the 20 to 29 percent bracket (11 PSAs, mainly at 25 percent) and the 51 to 99 percent bracket (22 contracts, mainly at 70 or 80 percent). Apart from a high concentration on only a few allowances, there appears to be a preference for round numbers. We are more likely to find cost oil specified at 40 percent than at, say, 45 percent.

Profit Oil. Only 45 of the 268 PSAs in our dataset have fixed profit-oil shares, all others have some kind of sliding scale which is either based on output or rate of return. Given this bias in favour of sliding scales we consider the maximum and minimum values for the following analysis. The figures are based on the FOC share but the government or NOC share can easily be calculated by deducting the FOC share from 100. During 1966 to 1998 the highest maximum profit-oil share for FOCs could be found in Central America with 65 percent and by far the lowest in the Middle East with 28 percent (Table 5.3). The latter also offered the lowest minimum share with 16 percent, whereas Central America, Eastern Europe, and South America with up to 39 percent granted the most generous minimum shares to FOCs. Again, the reader should be reminded that we consider contracts rather than production levels and thus have no information on the actual profit oil distribution. Nonetheless, we obtain a good approximation of how output might be divided. The spread between highest and lowest maximum varies from 10 percentage points in South America to 85 in Asia and Southern/central Africa. This is not surprising since the maximum profit oil for FOCs in South America is only 50 percent compared to 100 percent in the latter two regions.

[40] From the viewpoint of the FOC.

Table 5.3: Profit Oil for FOCs						
	Average Profit Oil		*Max Profit Oil*		*Min Profit Oil*	
	Max	*Min*	*Highest*	*Lowest*	*Highest*	*Lowest*
Asia	44.15	28.21	100	15	60	10
Central America	64.71	36.57	95	40	85	20
South America	48.00	38.80	50	40	50	30
Eastern Europe	51.93	37.00	80	40	60	10
Middle East	27.80	15.75	60	11.8	40	7.5
North Africa	38.67	18.00	100	19	50	10
South Central Africa	55.69	29.17	100	15	75	5

Currently maximum profit oil tends to increase in all regions with the exception of the Middle East where it is declining from its 25 percent average which is significantly lower than elsewhere. South America, too, shows a very slight decreasing trend from its present 45 percent level. The regions with the highest average maximum are at the same time the ones that have a tendency to strongly increase the FOCs' share of profit oil. These are Central America and North Africa with 90 percent and 72 percent respectively. While the difference between the highest and lowest maximum profit oil is relatively large, the minimum shares are closer together. The Middle East again is at the bottom end of the scale with 16 percent and Central America offers the highest minimum profit oil with 50 percent on average. This is also reflected in the 1966B98 time series. At present there appears to be little variation between onshore and offshore contracts with regard to minimum shares but a substantial difference in maximum entitlements. The trend also indicates that profit oil will increase more in offshore than in onshore contracts. It is noticeable that offshore sliding scales are usually volume rather than rate-of-return based. For both variables exporters offer less favourable conditions to FOCs than importers.

As with royalties and cost oil both minimum and maximum profit-oil shares tend to cluster around certain values (Figures 5.3A and 5.4A). More than one-third of contracts have a minimum profit-oil share for the FOC of either 10 or 30 percent. Altogether two-thirds specify minimum profit oil between 5 and 30 percent (inclusive). A similar picture emerges with regard to maximum profit oil. A quarter of all contracts specify this at either 40 or 50 percent. Only eight PSAs set the maximum at less than 20 percent, but almost 30 percent of contracts opt for a maximum of more than 50 percent. Again, there seems to be a tendency to adopt round numbers. Hence, the difference between minimum and maximum profit oil (Figure 5.5A) tends to be clustered around zero, 10, 20, 30, and 40 percentage points. There are, however, 18 contracts that display gaps of more than 40 percentage points (up to 85 points). No difference means profit oil is calculated on a fixed scale such as 65/35. Differences in excess of zero indicate the scope of sliding scales. In most cases a gap of 40 percentage points between maximum and minimum profit oil testifies to more steps on the scale than a gap of, say, 10 points. For all variables considered so far, we observe that there are many small steps at the lower end of the respective scales, and only a few big steps at the upper end of the scales. This can be read of the curves in Figures 5.1A to 5.5A where the intervals between peaks are smaller on the left hand side of the diagrams than they are on the right hand side.

Duration of Contract. Although over time both minimum and maximum exploration periods have varied substantially between regions a relatively high degree of convergence can be observed at present. The only notable exceptions are the Middle

East and South America who both offer shorter than average exploration times as well as Southern/central Africa with well above average duration. Trends, however, differ widely. While some regions such as Southern/central Africa and Eastern Europe show tendencies to increase exploration times, others such as Asia and the Middle East tend towards further shortening this period of the contract. Maximum production periods reveal greater divergence and range from 23 years in the Middle East to 30 years in South America with an overall trend to decrease. It should be pointed out that both exploration and production periods show a great variance within regions. This result is especially striking in Asia and Southern/central Africa.

The percentage of the contract area that has to be relinquished at the end of the first exploration period ranges from 20 percent in Asia to 35 percent in Southern/central Africa and Eastern Europe. Again, the trend to increase or decrease relinquishment requirements varies widely between regions. Similar to the variance in contract duration within regions, there appears to be a great deal of divergence between countries with regard to relinquishment. The difference between the highest and lowest percentage of the total contract area that has to be relinquished is only ten in North Africa but 50 in Asia. Onshore and offshore PSAs are similar as are the terms offered by exporters and importers.

Bonuses. Only very few PSAs in our sample demand the payment of, usually very small, discovery bonuses. We therefore ignore this variable and only consider signature and production bonuses. Both display a strong divergence between regions. Generally, Eastern Europe tends to be at the lower end of the scale and the Middle East at the upper end. While production bonuses are similar for onshore and offshore contracts, the former require notably higher signature bonuses than the latter. By the same token, exporters charge higher bonuses than importers with some OPEC countries behaving like an importer with regard to signature bonuses and like an exporter with regard to production bonuses. Signature bonuses show a tendency to increase strongly in the regions that are at the lower and the upper end of the scale, while remaining unchanged or decrease slightly in all other regions.

The trend is for production bonuses to increase in those areas that at present request the lowest payments. Over time signature bonuses have been lowest in Eastern Europe and Asia, and highest in the Middle East and Central America. Production bonuses, on the other hand, were on average lowest in Eastern Europe and Central America, and highest in the Middle East and Asia as well as in Southern/central Africa. Within regions the spread between maximum and minimum signature bonuses has been lowest in Eastern Europe, and highest in the Middle East and Southern/central Africa. For production bonuses we observe the lowest spread in Eastern Europe and North Africa and the highest in Asia and Southern/central Africa.

Figure 5.1: Maximum PSA Royalty (% of gross production)

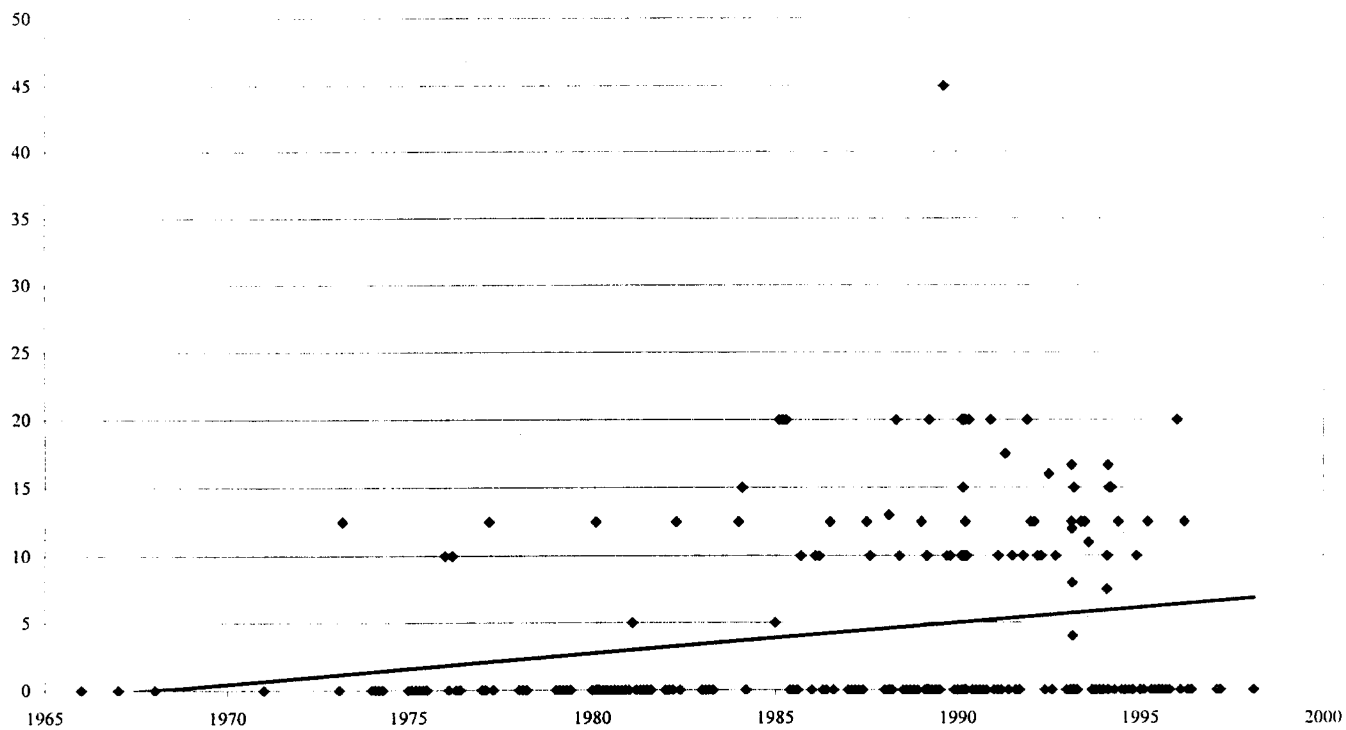


Figure 5.1A: Distribution of Maximum Royalty

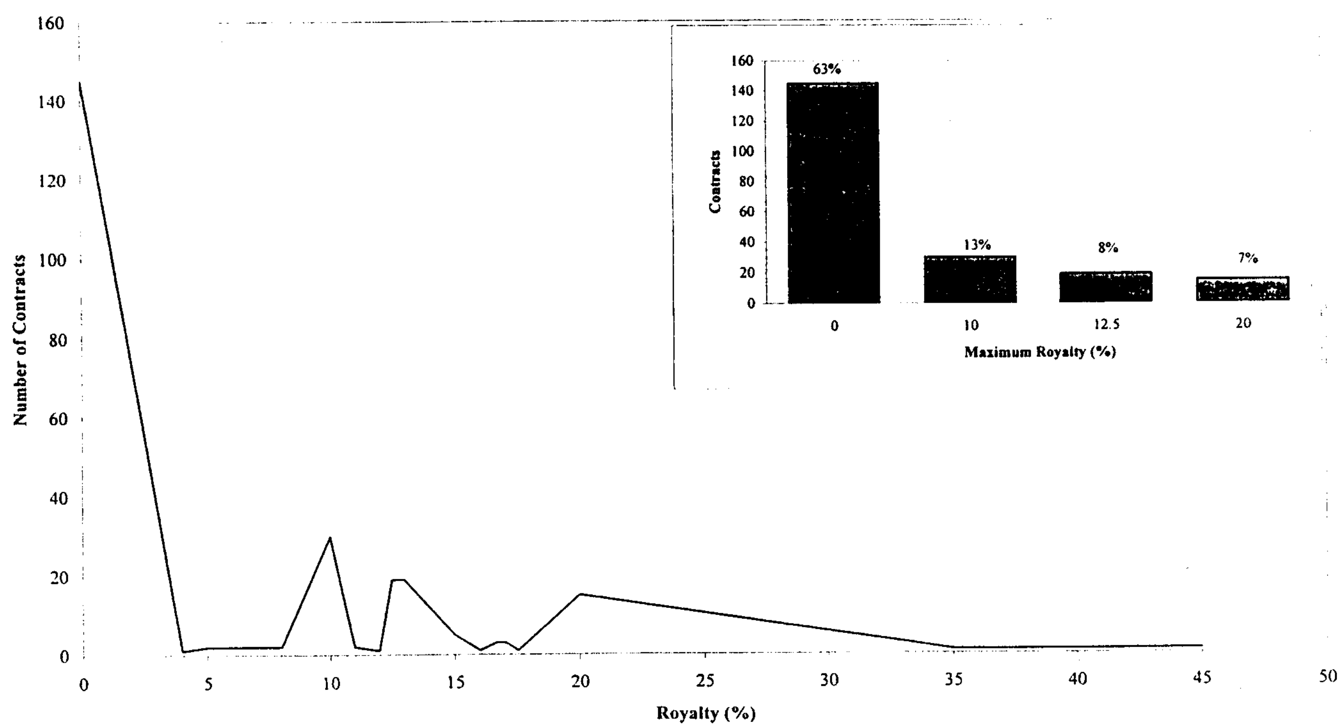


Figure 5.2: Maximum Cost Oil (% of gross production)

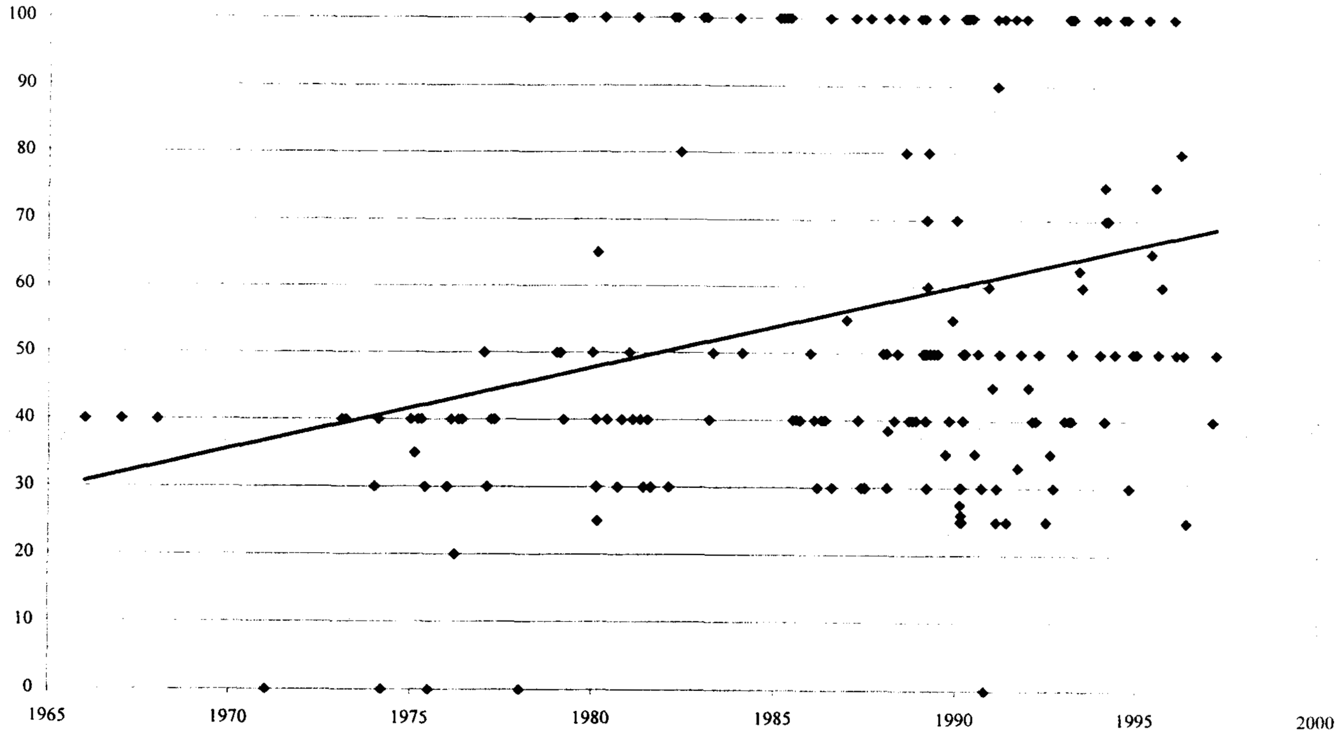


Figure 5.2A: Distribution of Maximum Cost Oil

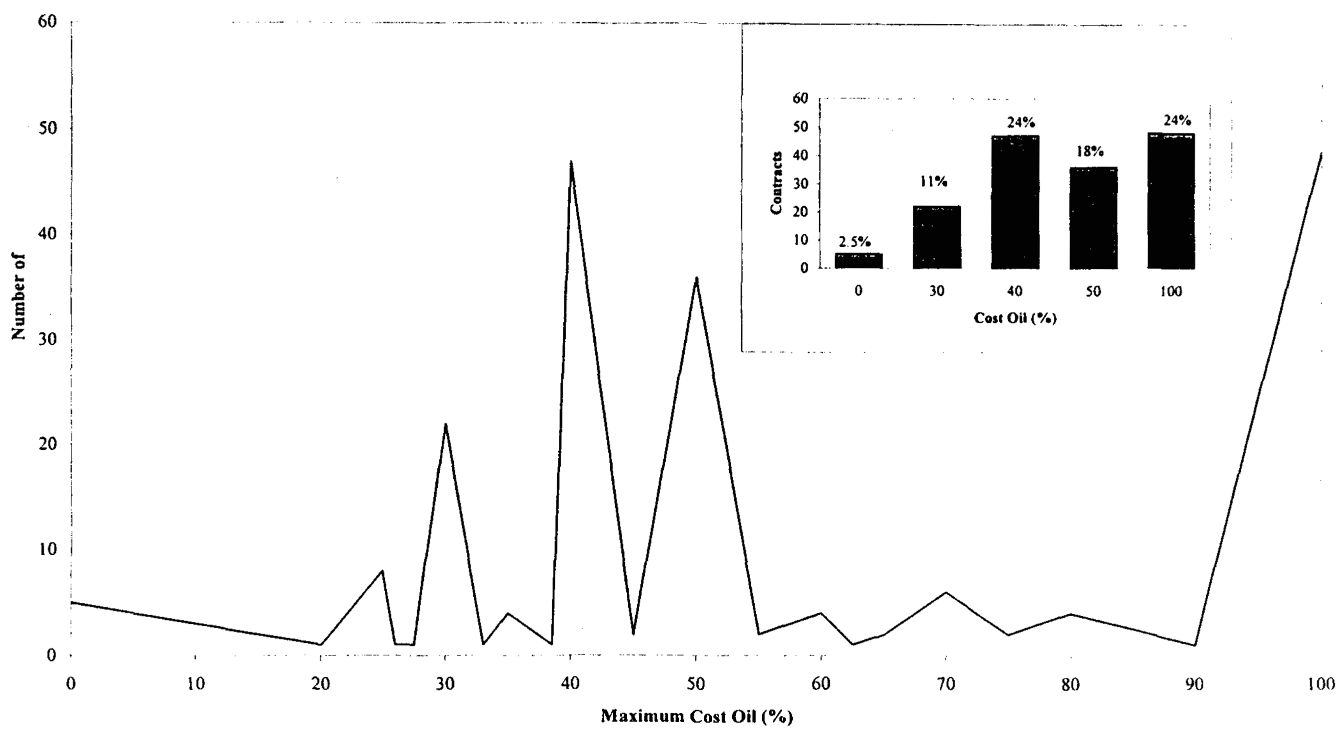


Figure 5.3: Minimum Profit Oil for FOC (% of total profit oil)

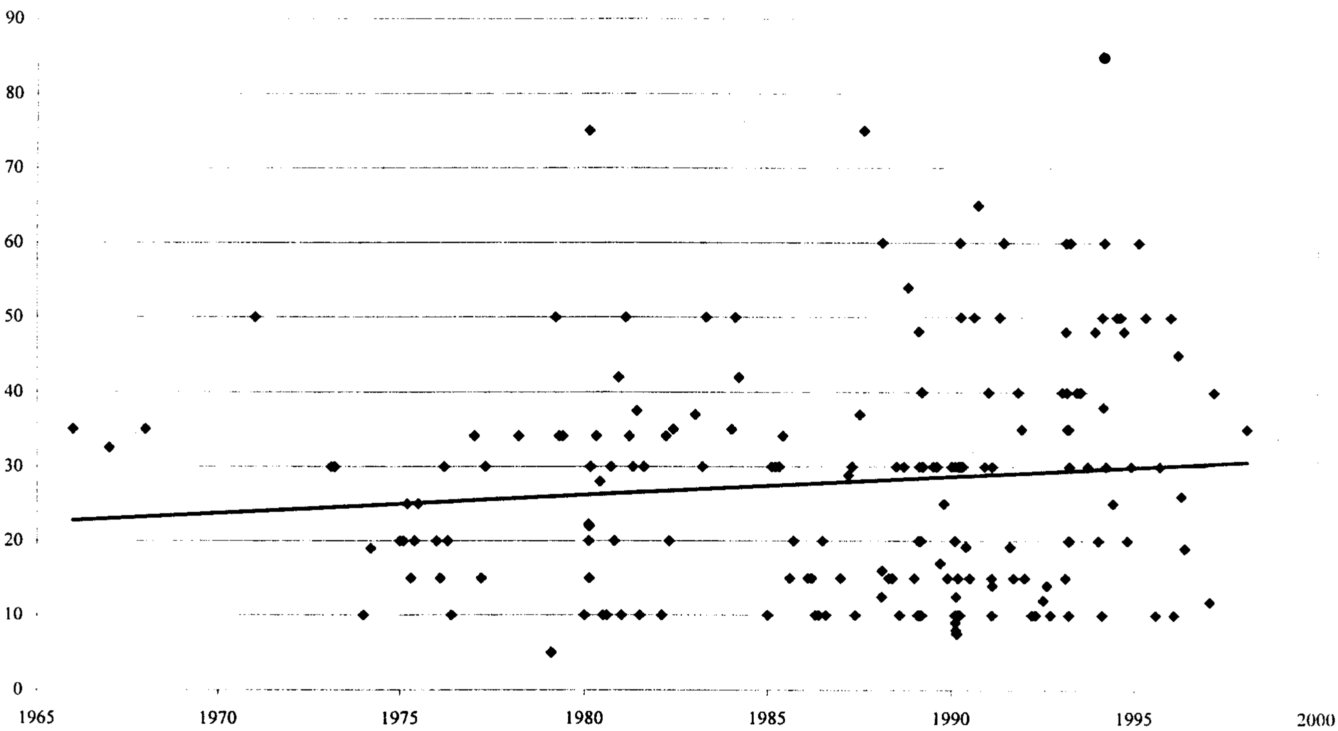


Figure 5.3A: Distribution of Minimum Profit Oil for FOC (% of total profit oil)

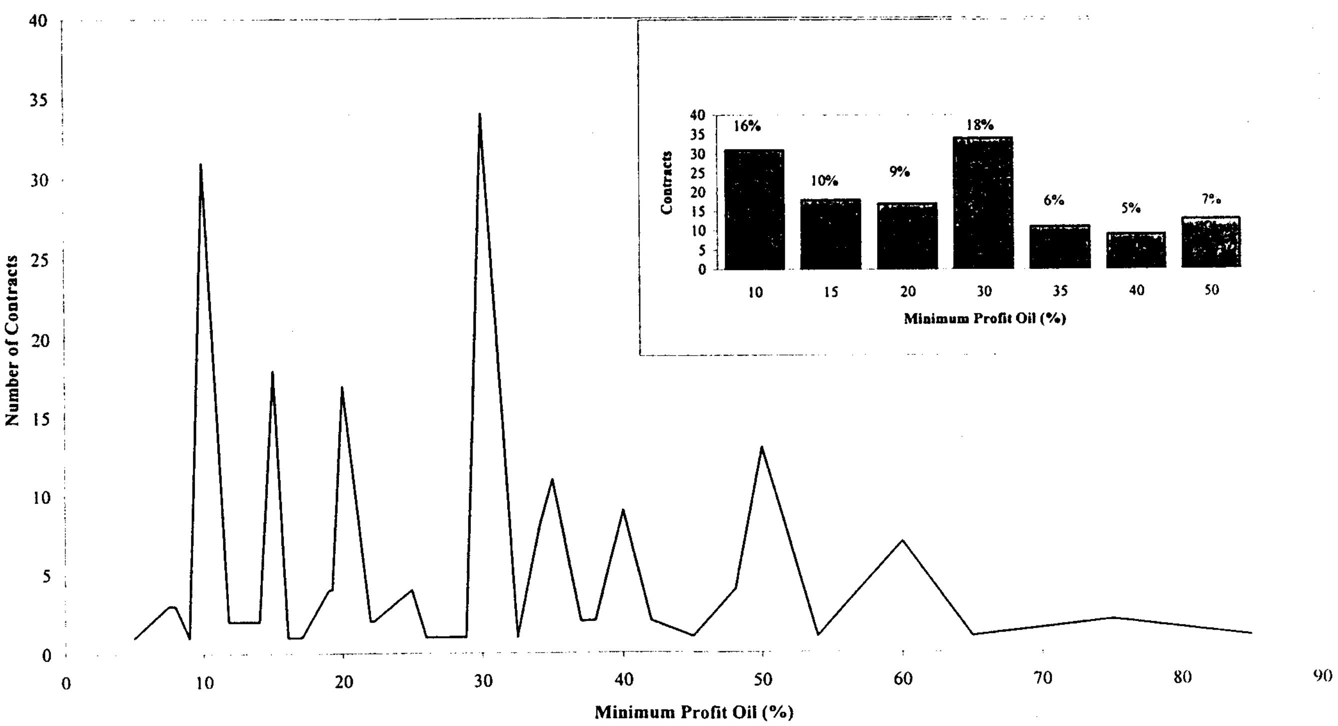


Figure 5.4: Maximum Profit Oil for FOC (% of total profit oil)

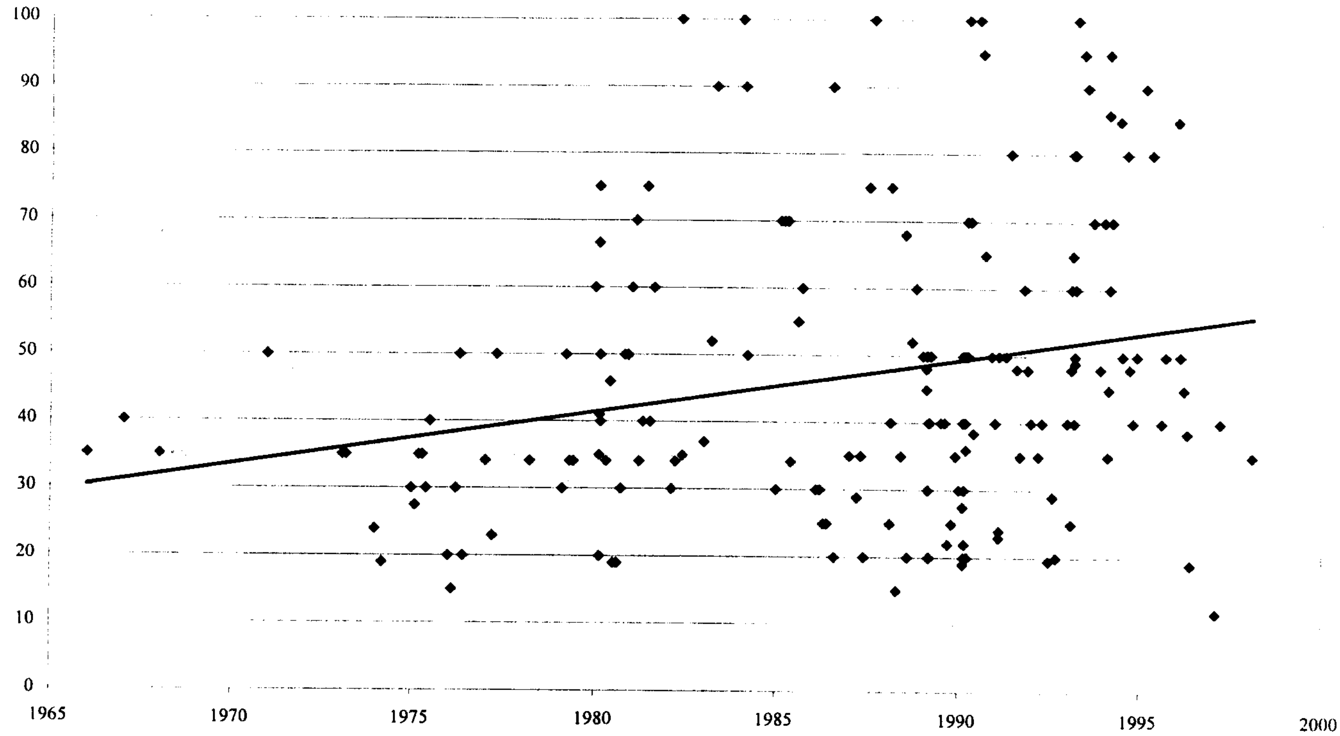


Figure 5.4A: Distribution of Maximum Profit Oil for FOC (% of total profit oil)

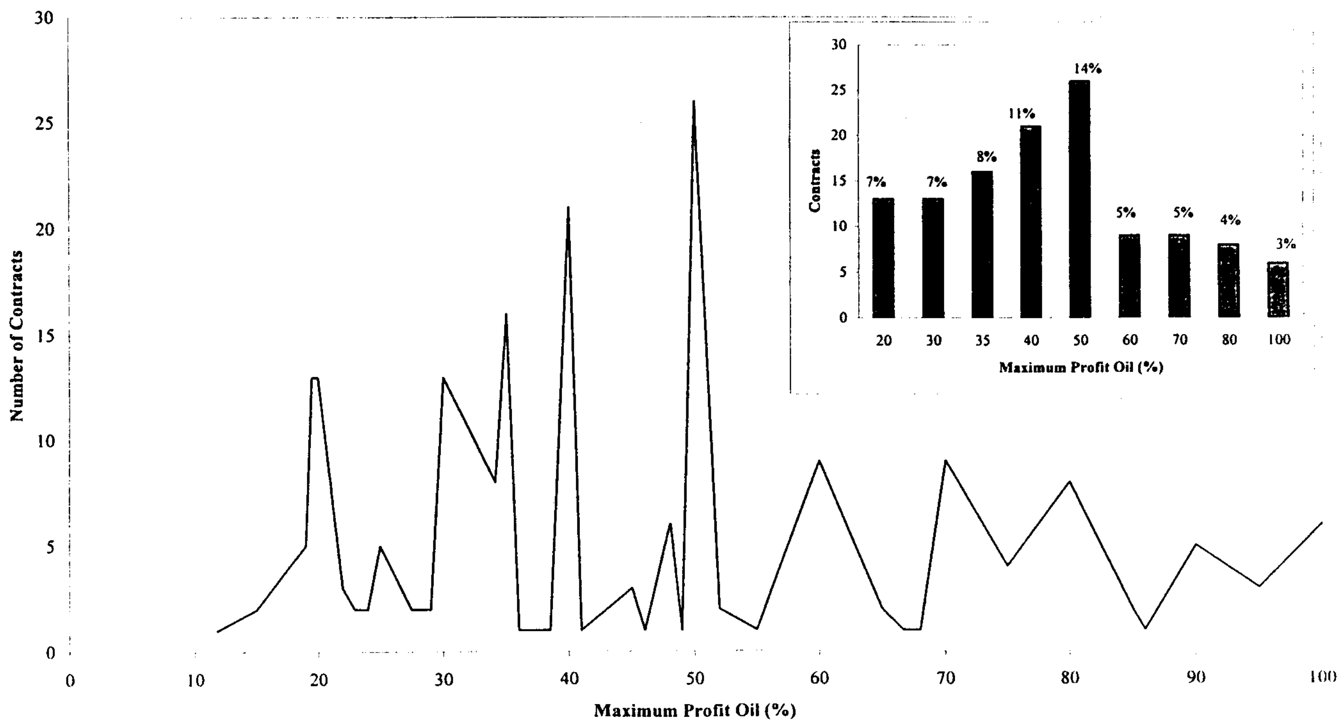


Figure 5.5: Difference Maximum-Minimum Profit Oil for FOC

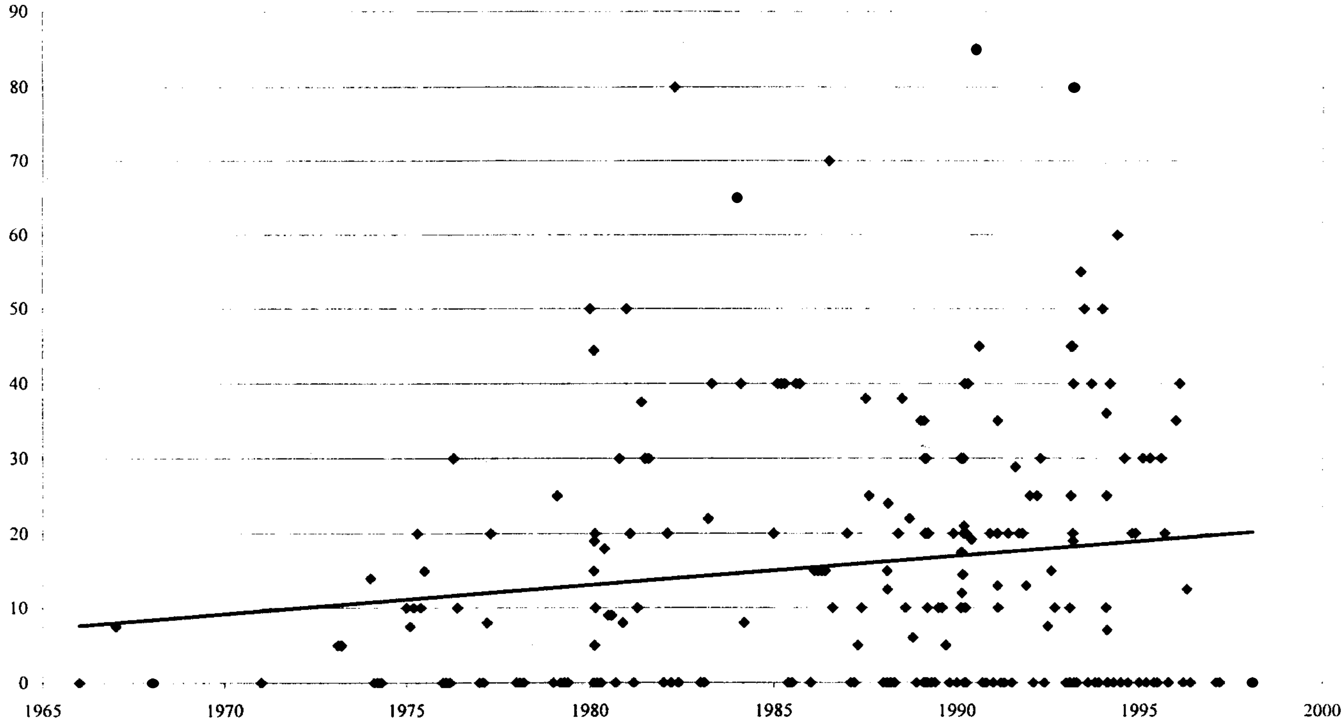
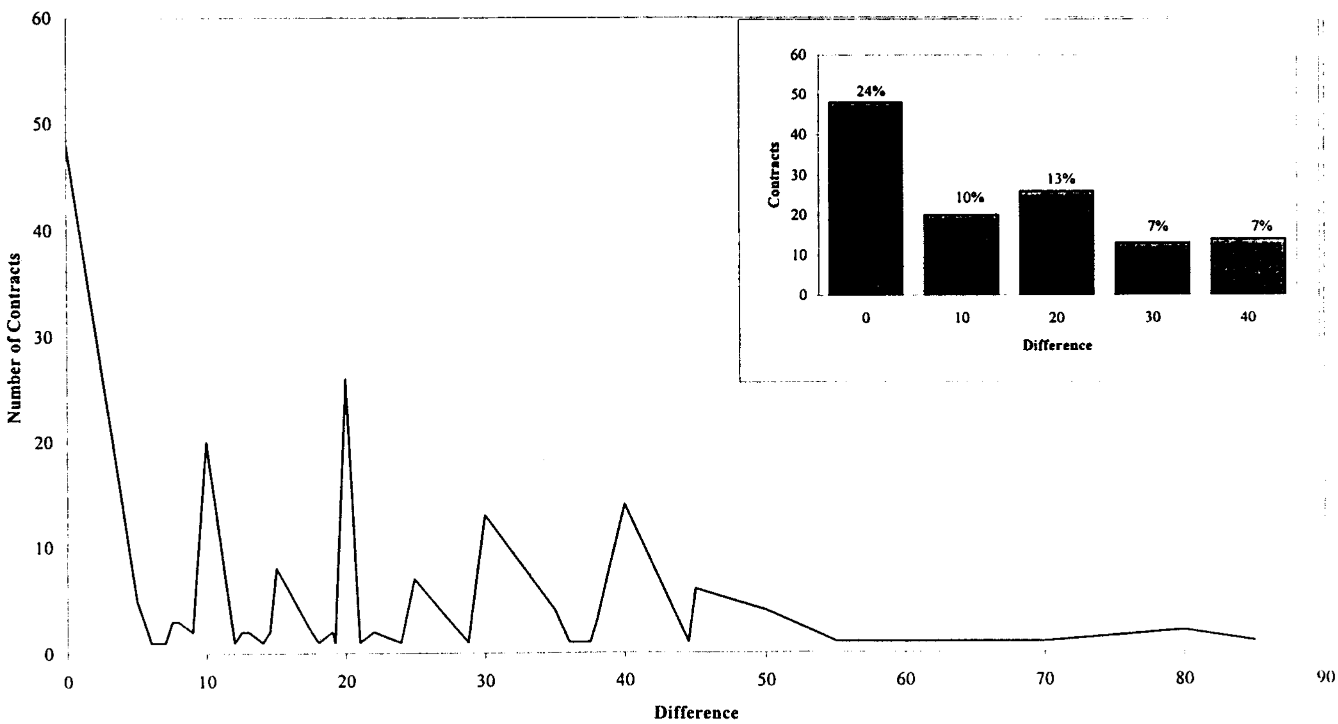


Figure 5.5A: Distribution of Difference Maximum-Minimum Profit Oil for FOC



Taxation. For the purpose of this study we are not so much concerned with the tax rate, which varies from zero to 60 percent, but with the payee. In about one-third of all contracts contained in the dataset the tax is paid by the FOC. Almost 20 percent of PSAs specify that the NOC has to settle the tax bill on behalf of the FOC. A further 20 percent of contracts waive any tax liabilities. In the remaining cases income tax is either negotiable, or, for the reasons outlined at the beginning of this chapter, we have no information on this parameter. The average income tax in the contracts which specify the exact rate to be paid by either the NOC or the FOC is 45 percent. This has been relatively stable over time. There is presumably a rather simple explanation for this stability. Income tax rates are usually not contract specific elements but are based on the generally applicable tax laws of a country. Tax legislation tends to change very rarely. If it is altered this happens mostly on a small scale.

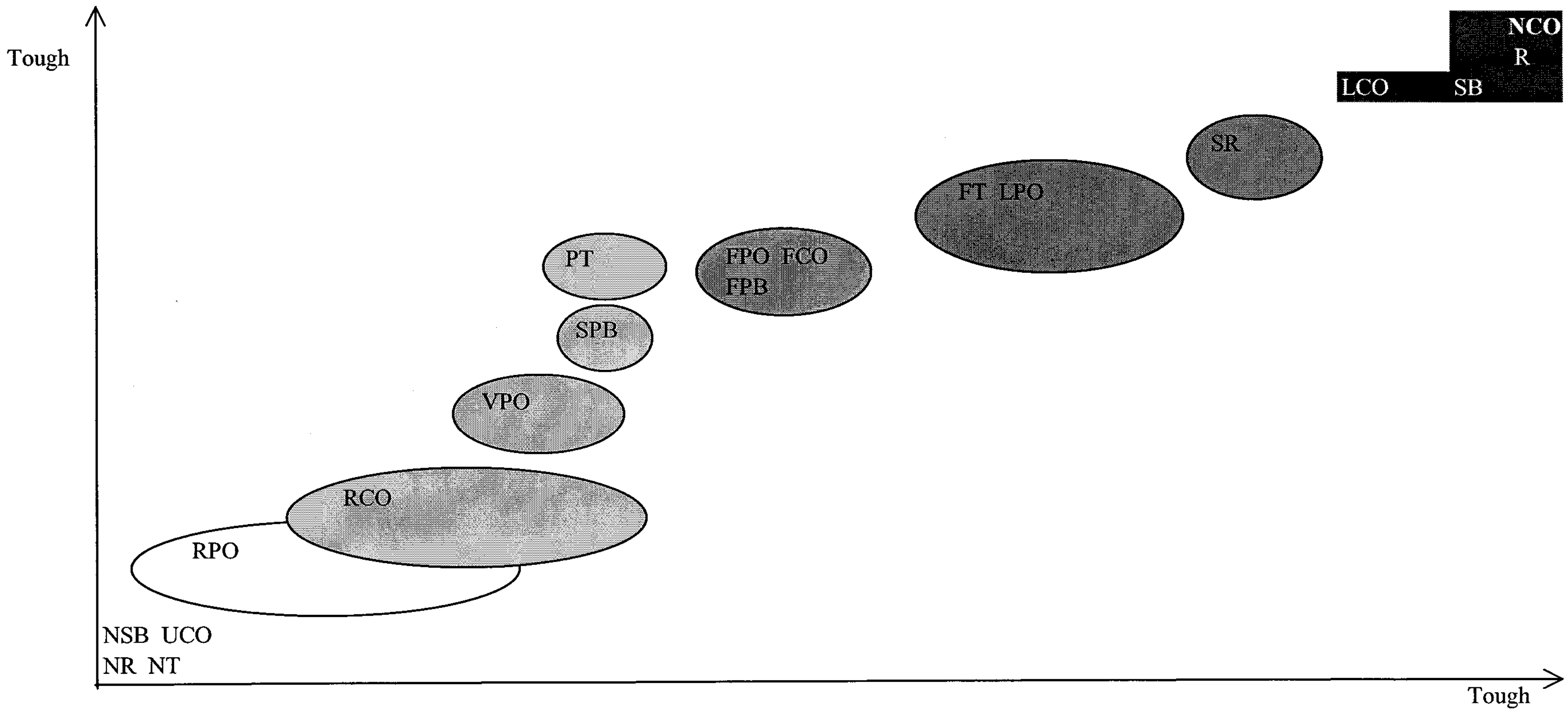
Global Development. Considering all contracts in the dataset, royalty rates have remained almost unchanged since the introduction of PSAs but we can observe greater divergence since the mid 1980s (Figure 5.1). Cost oil has increased significantly largely due to the spread of no-limit contracts (Figure 5.2). As with royalties we presently find a greater diversity for cost recovery. Up to the late 1970s the range for this variable was zero to 40 percent whereas it is now zero to 100 percent.[41] Until the late 1970s the FOCs' minimum profit-oil share was no higher than 50 percent. Since then some PSAs offer the foreign contractor a minimum share of up to 85 percent, and quite a few contracts stipulate that the said minimum will not fall below 50 percent (Figure 5.3). The maximum profit oil to which the FOC is entitled has increased accordingly; a development which can mainly be attributed to some PSAs with maximum shares of up to 100 percent (Figure 5.4).[42] This in turn can be explained through the ascendancy of sliding scales. The spread between the lowest and highest profit-oil shares for the FOC has also increased over time (Figure 5.5). In addition to the before mentioned predominance of sliding scales this is accounted for by the relatively larger increase in maximum profit oil as compared to the increase in minimum shares.

Both minimum and maximum exploration times have decreased with the former displaying a stronger decline than the latter. The reduction of the first exploration period allows the host country greater control over the venture since subsequent phases need government, or NOC, approval. However, the overall decrease should be due to advances in technology. In this context, the first relinquishment, which usually takes place at the end of the initial exploration period, has also been reduced. That is to say that the percentage of acreage to be given up has become smaller. At the same time a greater divergence between contracts can be observed. While the relinquishment varied between zero and 50 percent in the early PSAs it was reduced to 15 and 25 percent in the mid 1970s. It should be noted, though, that the current trend is a slight increase in the percentage to be relinquished.

It is difficult to make any firm assertions concerning the various bonuses. One clear feature is the strong divergence between minimum and maximum bonuses payable under different PSAs. As pointed out before, discovery bonuses are negligible. Production bonuses have increased slightly while the opposite is true for signature bonuses. The former are almost always calculated using sliding scales, and we refer to the maximum payable. As explained earlier in the case of profit oil, sliding scales

[41] Countries that offer PSAs with cost oil up to 100 percent include Algeria, Azerbaijan, Chile, Guatemala, India, Indonesia, Liberia, and Nigeria.
[42] Some of these contracts can be found in India, Liberia, Libya, Uganda, and Zaire.

Figure 5.6: Characteristics of PSA Elements



R Royalty	NT No Tax	FPB Fixed Production Bonus	NCO No Cost Oil
NR No Royalty	PT Progressive Tax	SPB Sliding-Scale Production Bonus	LCO Low Cost Oil
SR Sliding-Scale Royalty	FT Fixed Tax		FCO Fixed Cost Oil
			RCO R-factor based Cost Oil
LPO Low Profit Oil	VPO Volume-based Profit Oil	SB Signature Bonus	UCO Unlimited Cost Oil
FPO Fixed Profit Oil	RPO R-factor based Profit Oil	NSB No Signature Bonus	

make it impossible to evaluate the actual share received or paid. For this we would need to move beyond the contracts and analyse the performance of the various oilfields. This, however, is outside the scope of the present study.

The remaining PSA parameters vary so widely between contracts that they render a global comparison meaningless. Thus, all that needs to be said is that only very few countries levy export and import duties, and impose price caps. DMOs have changed in so far as the price used for the calculation of the payment is less discounted than it used to be, and that it has become quite common to apply the market rather than a posted price. Work obligations have become more flexible over time. They are frequently either biddable or negotiable or can be reviewed at the end of each exploration phase. Participation by the NOC has always varied strongly. For our sample the average participation rate is 23 percent with a range from 5 to 51 percent. In most contracts the NOC has the option but no obligation to participate.

5.3 Some Further Evidence

In the preceding section we have shown that most PSA parameters have changed, sometimes substantially, since their introduction in 1966 and that the main changes occurred in the mid 1970s at a time when the oil price increased dramatically. Whether the alteration of the contract elements was a response to changes in the oil price or whether it was due to the maturity of PSAs as an accepted contract form is debatable. However, in the remainder of this chapter we address the following questions:

- Are contract variables correlated?
- Is there a tendency for countries with significant alternatives to oil to offer more generous or tougher terms?
- Have PSA terms and conditions changed in response to the 'new players', i.e. the Caspian countries?

Correlations. If one were to classify PSAs the obvious categories are contracts that are tough, average, and favourable for the FOC. This classification is, of course, relative, and a tough contract can still be highly profitable. The simulations in Chapter 3 have shown that for example an increase in the price of oil can turn a previously unfeasible project into a desirable one. By the same token, terms that would be considered tough for one field might be looked upon as favourable for another field due to, say, different geological conditions. Several other factors such as the PSA terms offered elsewhere and the cost of risk capital can play a crucial part in the evaluation of a particular contract.

Figure 5.6 displays a, somewhat crude, categorisation of the main PSA elements. Generally speaking, a tough contract is one that requires a high signature bonus and royalty payment, and offers only a low profit-oil share possibly in connection with a low cost-recovery limit. The first two variables are tough because they have to be paid regardless of the profitability of the venture, in the case of signature bonuses even before production starts. Low cost recovery indicates that it may well take some time before the FOC has recovered its start-up costs. The impact of the profit-oil split depends largely on the way in which it is calculated: fixed, volume-based or R-factor scale. Depending on the starting point, a progressive income tax may be better than a fixed tax but it is nowhere near as good as no tax at all. The same can be said for cost oil. If the cost-recovery percentage is fixed then a high ceiling is obviously more favourable than a low one, and a sliding scale will (though does not have to) usually lead to a faster recouping of costs. However, for the FOC the most desirable case is one with unlimited cost oil. In this case one would expect that the FOC has to pay a price in the form of royalty. After all 100 percent cost oil can mean that for a number of years no production is left for profit oil. Hence the government would receive no revenue unless it charges royalty. Similar rankings can be developed for other parameters.

In terms of correlations we would then expect for example that a high royalty comes with a high signature bonus as the host country appears to be concerned to receive a guaranteed cashflow regardless of profitability. If furthermore it sees the necessity to provide incentives elsewhere in the contract which are supposed to balance the tough elements it could opt for a high cost-recovery limit and R-factor based profit oil. Needless to say, if the government for whatever reason feels in a position that does not necessitate any contractual concessions the latter elements will be low and fixed. Accordingly, a favourable PSA that is based on the profitability of the operation will forego royalties, offer R-factor based profit oil and implement a progressive income tax or no tax at all. There are many variations of this theme, and the two scenarios outlined above should only serve as an illustration of the general principle.

Table 5.4 displays the regional correlations for the main PSA elements. The values are between 1 and -1. The closer the coefficient is to 1 the stronger is the positive relationship between the two variables. This means they move in the same direction. The closer the coefficient is to -1 the clearer is the indication of an inverse relationship where the value of one variable declines as that of the other increases.[43] The gaps indicate an insufficient number of observations which makes correlations impossible or meaningless.

As we can see, the parameters under consideration are either weakly or not at all correlated for Asia and Southern/central Africa. In the other regions, particularly in North Africa, South America and Central America we find some strong correlations. This is especially true for South America where royalty and maximum profit oil show a perfect negative correlation indicating that PSAs with high royalties have low profit-oil shares for the FOC and vice versa. Royalty and cost oil, on the other hand, are almost perfectly and positively correlated. As one increases so does the other. The other two strong relationships in South American PSAs are inverse ones between cost oil and maximum as well as minimum profit oil. Whereas the royaltyBcost oil correlation indicates that contracts offer an incentive to balance royalty payments, the remaining three relationships point towards tough contracts. For example, if royalty increases the profit-oil share decreases which is a double negative for the FOC. We will not discuss all correlations presented in Table 5.4 in detail. However. it is easy to see that the strong correlations in North African and Central American PSAs are relatively favourable for the FOC while the Middle East results send mixed signals. The non-existing correlations are probably as interesting as the existing ones. Following the analysis in this and previous chapters one might have expected strong, positive or negative, relationships between royalty and tax, royalty and signature bonus, minimum and maximum profit oil as well as cost oil and profit oil. With very few exceptions we have not found any such correlations in our dataset. Furthermore, although not presented in Table 5.4 it should be noted that minimum and maximum exploration periods, and

[43] Econometricians worth their money would, of course, pull their hair on seeing this simplistic approach. However, for the purpose of this study an approximation of how various contract elements behave is sufficient.

minimum exploration phases and minimum relinquishment requirements are also uncorrelated. Coming back to a point raised earlier, the data analysis also yields the result that 60 percent of PSAs with unlimited cost recovery levy royalties or, in the case of Indonesia, FTP. Almost all these contracts require the FOC to pay income tax.[44] The two main inferences from these findings are that with regard to PSA terms there is competition between regions but even greater competition within regions. Based on this realisation we cannot refer to, say, a typical Asian or Eastern European contract.

New Players. Since the early 1990s several countries have begun to open or reopen their oil sectors to foreign firms. The most spectacular newcomers to the international scene were the Caspian countries. At the end of 1997 their proven oil reserves stood for 15 percent of total world reserves. The earliest Caspian PSA in our dataset is one signed by Azerbaijan in 1993. Azerbaijan is also one of the most active countries with regard to tendering PSAs. New and numerous investment opportunities such as these will inevitably lead to increased competition for risk capital. A simple view of the world would thus suggest that in order to continue to attract foreign investment the 'old players' will have to adjust their PSA terms. Adjustment here means offering more favourable exploration and production conditions to FOCs. If this argument were to hold the dataset should indicate a change in the main PSA elements during the 1990s. Contract parameters in Asia and Central America changed in the early 1990s before the first Caspian PSAs were signed. The same is true for North Africa with the exception of changes in the minimum profit-oil share (increased), maximum and minimum exploration periods (decreased and increased respectively), minimum relinquishment (decreased) and bonuses (decreased) which occurred in the second half of the 1990s. There were hardly any alterations in the South American contract terms since the mid-1990s. Royalties and cost oil went slightly up, with profit oil showing a rather insignificant downturn. The Middle East and Southern/central Africa display various modifications to their PSAs since 1993/4. However, they tend to move in opposite directions. Cost-recovery limits, for instance, increased in the Middle East but decreased in Southern/central Africa. The changes, especially in the latter region, are not necessarily to the advantage of the FOC. Hence, while we can show that PSAs have undergone changes in the 1990s it is not possible to pinpoint these alterations in the contract parameters as a response to increased competition.

[44] Which reinforces the old wisdom that there really is no free lunch.

Table 5.4: Regional Correlations

Parameter 1	Parameter 2	Asia	S/C Africa	N Africa	S America	C America	Middle East	E Europe/FSU
Royalty	Cost Oil	-0.468	0.286	0.746	0.954	0.866	-0.685	0.376
	Max Profit Oil	0.376	0.147	0.190	-1	0.576	-0.031	-0.082
	Min Profit Oil	-0.038	0.197	0.644		-0.093	-0.419	-0.262
	Signature Bonus	0.335	-0.208	-0.415		-0.333	0.156	-0.318
	Production Bonus	0.131	-0.442			-0.339	0.342	0.930
	Income Tax	0.155	-0.126		0.359		-0.023	0.247
Cost Oil	Max Profit Oil	0.220	0.555	0.507	-0.768	0.805	0.248	0.086
	Min Profit Oil	0.318	0.192	0.403	-0.939	0.207	0.715	0.295
	Signature Bonus	-0.098	-0.405	-0.690			-0.303	0.142
	Production Bonus	0.243	-0.247	-0.509		-0.505	-0.343	0.641
Max Profit Oil	Min Profit Oil	0.573	0.538	0.504	0.567	0.716	0.624	0.449
	Signature Bonus	-0.328	-0.365	0.410		-0.680	-0.210	-0.503
	Production Bonus	-0.282	-0.129	0.731		-0.677	-0.337	0.046
Min Profit Oil	Signature Bonus	-0.381	-0.356	0.793		-0.525	-0.250	-0.345
	Production Bonus	-0.092	0.136	0.825		-0.524	-0.380	0.046

APPENDIX 5.1 DATASET INFORMATION

Table 5.5: Production-Sharing Agreements 1966–98 (Number of Contracts in Brackets)

Asia & Australasia (80)	Bangladesh (5) China (4) India (5) Indonesia (37) Laos (1) Malaysia (8) Mongolia (2) Myanmar (7) Nepal (1) Philippines (3) Sri Lanka (2) Timor Gap (2) Vietnam (2)
Central America & Caribbean(21)	Antigua (1) Belize (3) Cuba (1) Guatemala (7) Haiti (1) Honduras (1) Netherlands Antilles (2) Trinidad & Tobago (5)
Eastern Europe (28)	Albania (3) Azerbaijan (7) Bulgaria (1) Croatia (1) Georgia (3) Kazakhstan (3) Kyrgyzstan (10) Romania (2) Russia (1) Serbia (1) Turkmenistan (4) Ukraine (1)
Europe (2)	Malta (2)
Middle East (41)	Bahrain (3) Iraq (2) Jordan (6) Oman (3) Qatar (7) Syria (3) Yemen (17)

North Africa (15)

Algeria (3)
Egypt (6)
Libya (6)

South America (13)

Bolivia (2)
Chile (1)
Ecuador (1)
Guyana (2)
Peru (4)
Uruguay (1)

South & Central Africa (69)

Angola (9)
Benin (1)
Cameroon (1)
Congo (1)
Cote D'Ivoire (8)
Equatorial Guinea (2)
Eritrea (1)
Ethiopia (3)
Gabon (8)
Ghana (1)
Guinea (2)
Kenya (1)
Liberia (2)
Madagascar (1)
Mauritania (1)
Mozambique (3)
Nigeria (10)
Sudan (5)
Tanzania (5)
Togo (2)
Uganda (1)
Zambia (1)

Table 5.6: Current Trends[1]

	Royalty	Max Cost Oil	Profit Oil FOC Max	Profit Oil FOC Min	Duration of Contract[2] Max Prod	Duration of Contract[2] Max Expl	Duration of Contract[2] Min Expl	Relinq[3]	Signature	Bonus Discovery	Bonus Production
onshore	9+[4]	70+++	53+	30+/-	25-	6.5-	3.2--	27+/-	4+/-	na	5--
offshore	7+++	68+	61++	33++	25+/-	6-	3+/-	27+/-	1.25-	na	6+/-
exporters	10+++	69++	50++	27+	25-	6-	3--	25+/-	4.5+	0.8+	8+/-
importers	5+/-	69++	60+	38+	25--	7-	3--	25--	1.8+	0.2+/-	4.6--
OPEC	5++	100+++	55++	30+	25--	6--	3.8-	23+/-	1.1--	0.1+/-	10+
South/Central Africa	8+	70+++	62+	32+	25--	8++	3.1-	35+/-	2.5+/-	na	5-
Eastern Europe	6+++	62+++	58+	38-	28+	7++	4++	35++	0.75+++	na	2++
Asia/Australasia	5.5++	76+	55++	28+/-	24--	6--	3.5--	20-	1.8-	0.3-	5--
Central America/Caribbean	10+	100+++	90+++	50+++	27+/-	6.5-	2.5--	24+/-	na	na	na
Middle East	8.5+	40-	25--	16+/-	23--	5.5--	2.9+/-	25--	6+++	0.002+	8+/-
North Africa	10+++	85+++	72+++	27++	25+/-	7++	3--	28++	3+++	na	6+++
South America	8.5+	60+++	45-	30--	30+	5.3+/-	2.5---	25---	na	na	10+

[1] The figures are current averages (that is the average of the 1997/98 contracts) as opposed to averages over time. Royalty, cost oil, profit oil, and relinquishment in percent; duration of contract in years; bonuses in US$m.
[2]Production and exploration duration.
[3]Minimum relinquishment at end of first exploration period.
[4]+(-) slight increase (decrease); ++(--) increase (decrease); +++(---) strong increase (decrease); +/- no change.

6 CASE STUDIES

The profiles presented in this chapter provide an analysis of the development of PSAs in selected countries. They are not intended as socio-economic studies. Another feature not to be found in this chapter is the discussion of sanctions and the impact of civil and other wars. There are two reasons for this. First, we are interested in the contract terms, their evolution over time, and how they compare to other agreements in the region as well as globally. Second, it is our firm belief that FOCs explore and develop wherever they expect to make profits. If it serves their financial and strategic goals they are well prepared to negotiate with different warring parties, pay protection money and so forth. An additional motive for proceeding in this fashion is that a sophisticated country analysis justifies a paper in its own right rather than a few pages.

Indonesia was chosen because it is the country first to introduce PSAs. In addition, apart from very few service agreements, all contracts for oil exploration and development in Indonesia are PSAs. Angola is of interest due to its recent bonanza of large oil discoveries. The FSU is one of the major players in terms of both production and reserves. In order to avoid repetition by analysing all member states we have chosen Azerbaijan as the country that has showed the highest level of activity in the region and, perhaps as a consequence, is best documented with regard to PSAs. India is widely regarded as one of the more immature[45] oil sectors in a country with potential. Iran has been included as one of the most intriguing openings of a national industry. As we will see later, Iran's oil contracts combine PSA features with those of traditional service contracts. The chapter is rounded off by a case study of Peru as a representative of Latin America. Venezuela and Columbia which can be considered the main protagonists in the region are not discussed here since neither of the two countries is in our dataset.[46]

6.1 THE DEVELOPMENT OF PSAS IN INDONESIA

Discussing PSAs in Indonesia in order to illustrate how they have evolved and how they work in practice makes sense for several reasons. Indonesia was the first country to offer PSAs. Second, they have been one of the most active countries with regard to this contract form not only in Asia but worldwide. Third, a large number of FOCs have at one stage or other been involved in oil operations in Indonesia. Finally, individual Indonesian PSAs are based on model contracts. The three generations of contracts so far enable us to analyse how the contracts have adapted to changing circumstances.

When Indonesia gained independence from the Netherlands nationalistic feelings were running high. Foreign firms operating under the concession system became the target of increasing hostility. Their concessions were regarded as being far too generous to the foreign companies at the expense of the country. The government responded by freezing all new concessions. The ensuing stagnation in oil development was a disadvantage for both Indonesia and the foreign oil companies. The latter lost access to their investment and to good quality crude deposits, while the country forfeited a large part of its potential revenue. The government wanted to

[45] Immature here refers to the oil industry and not to the state of development of the country.

[46] Recall that we defined a PSA as one that is explicitly called just that. This is not the case in either of the two countries.

develop and control its oil resources but had neither the necessary finance nor the technology and know-how. In order to readdress the situation new legislation was passed. At first the old concessions were converted into contracts of work. This, however, was considered by many Indonesians as old wine in new bottles. The issue was finally resolved through the introduction of production-sharing agreements. PSAs were deemed acceptable because the government was able to uphold the national ownership of its resources while the foreign company had no equity share in the venture, and the NOC had full managerial control. A state company was established for this purpose.[47]

The main features of this new contract form distinguish it clearly from concessions. As the name implies, production not profit is shared under a PSA. The contractor bears the pre-production risk, and can recover its costs up to a specified limit of annual production (cost oil). The remaining output is shared between FOC and NOC at a pre-agreed production split in favour of the state company (profit oil). The title to any equipment purchased by the contractor passed to the NOC upon entry into Indonesia. The FOC was under a domestic market obligation which meant it had to sell part of its profit oil to the NOC at a contractually agreed price. Given that this was usually a heavily discounted market price this practice arguably decreased the FOC's profit-oil share. PSAs were awarded for a total duration of 30 years with six to ten years for exploration.

The major oil companies were initially not very keen on PSAs. They were reluctant to invest capital into a venture which they were not allowed to own or even to manage. There was also concern about setting a precedent that might affect their operations elsewhere. Thus, the first foreign firms to enter into PSAs were independent oil companies.[48] They were more willing to compromise on the contract terms that had been turned down by the majors as they considered this an opportunity to break the dominance of the big FOCs, and gain access to good quality crude. In addition they were eager to enter into overseas production in order to increase supply for their refineries. The majors, worried about losing too much territory to the independents, finally bit the bullet and accepted PSA terms.

The earliest PSAs were approved in 1960. However, the first significant contract was signed in 1966 with a US consortium known as IIAPCO. These first generation PSAs allowed for up to 40 percent of exploration and operation costs to be recovered each year. The profit-oil split was 65/35 in favour of the NOC. Profit oil provided guaranteed revenue regardless of the profitability of the project or the market price. The FOC had to sell 25 percent of its profit oil to the NOC under the DMO. This was done at 15 percent of market price, and increased the country's take of annual production from 39 to approximately 46 percent. The government owned all production inclusive of crude stored at the export terminals. It had the ability to deny export. There was no royalty and no taxation. In 1976 the second generation PSA came into operation. Cost oil had already been altered in 1974 to the extent that difficult areas had no cost recovery limit. The profit-oil split was changed to 85/15, FOCs now had to pay tax, and the DMO was reimbursed at full market price for the first five years of production. The new conditions applied also to contracts signed under previous PSA terms. These changes were made in response to two events. First, the government reacted to the 1973 increase in oil prices and the

[47] Initially, three companies were created: Permina, Pertamin, and Permigan. The latter was dissolved in 1965, while the other two were merged into one all-embracing state company, Pertamina, in 1968 (Barnes 1995).
[48] IIAPCO in 1966 and Phillips Petroleum Co in 1968.

expectation that this increase would continue.[49] It therefore increased its share of profit oil. Second, under the rules of the Internal Revenue Service, US firms were not eligible for foreign tax credit. The first generation PSAs provided for tax payments to be made by the NOC to the government. The NOC's profit oil and the DMO were not deemed tax deductible in the USA. In order to help US companies to gain tax exemptions it was decided to introduce a tax that had to be paid directly by the FOC to the government. The contractor's profit oil was grossed up to balance the tax payment.

The third generation PSAs, introduced in 1988, showed increased flexibility. They were legislated at a time of declining oil prices, increasing production costs, and tightened international competition for scarce risk capital. As a consequence Indonesia now offered a more favourable production share for companies exploring marginal fields. The main innovation was the so-called first tranche petroleum (FTP). With FTP the first 20 percent of production is split between NOC and FOC at the same rate as profit oil. The NOC is thus guaranteed a minimum share of output, and even when cost oil is unlimited costs can now only be recovered from 80 rather than 100 percent of output. In this sense FTP works as a cap on cost recovery. Furthermore, the third generation contracts introduced improved incentives for marginal fields in the form of changed profit-oil shares, and for new fields in the form of higher prices for oil sold under the DMO. Profit oil for conventional oilfields was set at 80/20 and for marginal fields at 75/25. The latter was revised in 1994 to 65/35. In addition, the 1992 'new package' presented changes to gas contracts, with the FOCs profit oil being increased from 70/30 to 65/35 for conventional fields and 60/40 for marginal deposits. Gas contracts have no ceiling on cost recovery as a consequence of which the government has no guaranteed minimum revenue. This concession was deemed necessary in order to induce firms to incur high capital costs needed to start up gas development. Different terms were offered for offshore development at depths of more than 1,500m with profit shares at 70/30[50] for oil and 55/45 for gas. The amendments were intended as incentives for exploration and production in high risk and remote areas with the aim to maintain production at 1mb/d for the next 25 years and delay net oil imports until at least 2010.

It should be pointed out that these model terms have not been slavishly applied to individual contracts. In the early contracts, before the introduction of unlimited cost recovery, cost oil varied between 35 and 50 percent. Pertamina usually receives at least 60 percent of profit oil with the exception of several PSAs in the late 1980s and early 1990s when its share declined to 51.9231 percent. Although the country signed a contract with sliding scale profit oil as early as 1967 (with Continental) many PSAs still have fixed production shares. Indonesia usually requires the payment of both signature and production bonuses but very seldom discovery bonuses. Contracts tend to last for 30 years with an exploration period of 3 to 16 years depending on the size and the specific conditions of the field. The percentage of acreage to be relinquished after each exploration phase has varied over time and between contracts. There are no special export and import duties, and no price caps. Pertamina has usually a 10 percent option to participate in the venture. As with most PSAs, arbitration is at the international level, in this case with the International Chamber of Commerce in Paris.

[49] At one stage it was expected that the oil price would reach US$50B60/bbl.
[50] Revised to 65/35 in 1994.

6.2 ANGOLA: TOUGH PSA TERMS ARE NO DETERRENT

In April 1996 Elf in partnership with Exxon, BP/Statoil, Norsk Hydro and Fina completed the Girassol discovery well. Girassol, it turned out, holds 1bn barrels of recoverable oil. Not surprisingly such a huge find worked as a catalyst to attract other oil firms keen to explore offshore Angola. By summer 1998 eight more large deepwater fields had been discovered with reserves ranging from 250m to 1.5bn barrels. This is as well given that oil accounts for 80 percent of the country's revenues. Once Girassol goes onstream it is hoped to increase daily production from currently 750,000 barrels to one million barrels.[51]

The Contract Terms Since 1979. Most Angolan contracts are offshore PSAs. They forego any royalty payment but levy a 50 percent income tax. However, in the 1991 model contract for deep water exploration and development the government indicated that it will favourably consider any problems arising with regard to international double taxation. Cost oil has been fixed at 50 percent but the calculation of profit oil reveals some changes over time. While the 1979 PSA with Texaco allowed for a government share of between 70 and 95 percent, subsequent agreements reduced the minimum share to between 40 and 55 percent with the upper end down to 90 percent. Contracts signed during the 1990s have a rate-of-return sliding scale as opposed to the earlier volume-based scale for profit oil. Both the R-factor bands and the allocated shares are negotiable. The exploration period used to consist of an initial three-year phase with the option of two one-year extensions. The 1991 model PSA altered this to four years with a possible extension of two years. Recent experience, not least with Girassol, has shown that even deepwater fields are being developed ever quicker in an attempt to recover costs at an early stage. The development period has increased from 20 to 25 years with a possible, negotiable, extension. The model PSA specifies the kind of work to be conducted; the extent, however, is to be agreed between the partners for individual contracts. FOCs have to pay a signature bonus and fulfil, at Sonangol's request, their marketing obligation of the NOC's production share. One of the toughest features of the Angolan contracts used to be the, meanwhile abolished, price cap which varied from $13 per barrel in 1980 to $32 per barrel in 1988. Under the price cap formula the government was guaranteed 100 percent of any revenue received over a certain price per barrel. For example, if the world price was $15 per barrel and the price cap was set at $13 per barrel the FOC would be liable to pay $2 per barrel to the government. The revision of the price cap to $20 and over was, however, not much of an incentive at a time when oil prices were declining sharply. By the same token the alteration of profit-oil shares for marginal fields in favour of the FOCs during the 1980s was of little interest to companies who were looking for major discoveries which still fell into the lower production-share brackets. Thus, it is no surprise that Barrows (1994) evaluated the country's oil regime as very tough.

Less Tough But Still Not Easy. In some respects Angola is a typical Southern/central African oil producer while in other areas it differs markedly from its neighbours. Most PSAs in the region apply to offshore areas. Signature bonuses are common, and wherever the FOC has to pay income tax 50 percent is the average rate. Angola's cost oil is with 50 percent below average. Although Gabon, for example, only allows for 30 percent of production to be used for cost recovery, several countries impose no limit, among them Nigeria. Angola has potentially two comparative advantages. First, most countries in the region impose royalties which

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[51] It should not be ignored that even in Angola not every project proves to be the envisaged success. Shell for example had to reappraise the estimated reserves at the Bengo offshore oilfield from 200mbl to 100mbl.

in some cases reach 20 percent. Second, while the calculation of profit oil on a sliding scale has been adopted by the majority of countries, Angola is one of the few offering a rate-of-return based scale. Provided both the bands and the shares are appropriately set this should help to make Angolan PSAs more attractive to FOCs than the contracts offered by some of its neighbours. Globally, Angola looks good with regard to royalty payments and profit oil calculations. It is comparatively tough on cost recovery and average on most other contract parameters. The Angolan PSAs are in many respects similar to those signed by Azerbaijan. Neither country requests royalties, they both have adopted R-factor based profit-oil scales and treat cost recovery in a similar way. There are also some similarities with the Indian contracts, especially with regard to royalties, profit oil and income tax. In comparison with other offshore projects Angola behaves typically as far as royalties are concerned. The one notable exception to zero royalty among the offshore participants is Nigeria. A 50 percent limit on cost recovery is about average although it should not be overlooked that several countries, such as Indonesia and Nigeria, put no limit on cost oil. On the other hand PSAs in Qatar and Côte d'Ivoire specify much lower cost oil. Almost all offshore countries display sliding scales for profit oil but Angola is the only major producer with rate-of-return based scales. The Angolan PSAs are in line with India and Nigeria in their treatment of income tax which is slightly on the high side when looking at all offshore contracts in the dataset.

Overall we can conclude that the label 'very tough' which was justifiably attached to Angolan PSAs in the 1980s has been softened to 'tough'. The tough components, relatively low and fixed cost oil as well as high income tax, are somewhat balanced by the absence of royalties and an R-factor based sliding scale for profit oil. Most importantly, however, Angola promises large discoveries in its until recently underexplored offshore areas. Evaluations such as 'tough' or 'very tough' are relatively meaningless if one does not discuss profitability at the same time. As long as FOCs realise an expected rate of return on their investment there appears very little reason for the Angolan government to soften its terms.

6.3 AZERBAIJAN: THE NEXT BIG OIL PLAY?

In mid-1998 the Energy Intelligence Group published a special report on Azerbaijan. In it they made the following observation. *'Since 1994 Azerbaijan has secured over $30 billion in long-term oil investment [...]. Dozens of new contracts are under negotiation, with Western companies still bending over backwards to acquire a slice of the action. State oil company Socar has taken full advantage, demanding higher equity and fatter bonuses'* (Energy Intelligence Group 1998:1).

Figure 6.1 shows the demographics of the 16 PSAs signed by the end of 1998.[52] In addition to Socar they involve 28 companies some of which have formed joint ventures for individual contracts such as the Amerada Hess/Delta joint venture for the Kyursangi-Karabagly PSA signed in December 1998. The figures in the diagram have been calculated in the following way. For each company we have summed up all its participation shares in Azerbaijan. Next, we added up all participation shares from all PSAs. Finally, each company's share is expressed as a percentage of the total. Take BP/Amoco as an example. By the end of 1998 the company had signed five PSAs in Azerbaijan. Its participation rates for those contracts are 34.1; 25.5; 30; 25 and 15 percent which yield 129.6. If we do this for each company and add

[52] Based on EIA data.

all the outcomes we get 1590. BP/Amoco's 129.6 expressed as a percentage of 1590 results in 8.15 percent. Hence, the diagram reveals that BP/Amoco is by far the most active FOC in Azeri oil exploration and production. The company's position will be strengthened further should the proposed merger with Arco get the go-ahead from the European Union. Total participation would then be over 12 percent. This is far ahead of the next most active companies in the country, Lukoil (3.77 percent) and Exxon (3.65 percent). Nonetheless, the overall picture is one of rather smooth distribution of participation shares across many companies. Furthermore, Socar's insistence on larger equity shares in the contracts will increase the NOC's total share from its 1998 level of 36.64 percent and thereby reduce the share available to FOCs. Socar settled initially for participation rates as low as 7.5 percent. However, with one exception,[53] all PSAs signed since November 1997 specify a 50 percent equity share by the NOC.

Each contract has the force of law which can slow down the decision-making process. The foreign partner, which in Azerbaijan usually means an international consortium, negotiates the PSA terms with Socar. The latter then passes it on to various government departments who may implement some changes. Next the contract has to be ratified by parliament. The final consent has to come from the president. While this is a rather cumbersome procedure it does not appear to be a deterrent for potential investors.

Azeri PSAs do not require a royalty payment but the FOC has to pay a tax of between 10 and 35 percent. The tax rate depends on the participation share held by the FOC. It is 30 percent for shares exceeding 30 percent. If the PSA covers a mountainous area the FOC is taxed with 10 percent. For lower equity shares the tax rates are 25 percent on profits of up to 200,000 rubles, increasing on over 500,000 to 35 percent. This is a profit tax which takes into account the contractor's rate of return. Profits reinvested are exempt from taxation.

For cost recovery the Azeri contracts distinguish between operating and capital costs. Cost oil available for operating costs is 100 percent. Capital costs can be recovered from between 50 and 60 percent of the remaining total production. Profit oil is calculated according to R-factor based sliding scales. The government share varies between 20 and 90 percent of total profit oil. The country's first PSA for the Chiraq, and Gyuneshi fields stipulated in addition that the scale should be dependent on transport costs and whether the contractor achieves early oil. However, this very elaborate way of allocating crude shares was dropped in later contracts. Instead the original three-step scale was extended to up to nine steps.[54] In contrast to most contracts, bonus payments in Azerbaijan's PSAs can be substantial. The Ashrafi/Dan-Ulduzu contract for example requires bonus payments of up to US$75 million depending on production thresholds.

So far we have seen that the Azeri contracts offer above average cost oil with operating costs being recoverable immediately. There is no royalty but FOCs have to pay taxes on a rate-of-return basis. Profit oil is calculated on a sliding scale which has been extended from three to nine steps. All PSAs require bonus payments which can be substantial. The trade press has on occasion labelled the Azeri contracts as being tough. This is not necessarily true. FOCs would of course prefer to pay neither taxes nor royalties. However, while royalties are levied regardless of

[53] Socar only holds a 20 percent share in the Gobustan contract which was ratified in Nov 1998 and covers one of the smaller fields (in terms of estimated oil reserves).

[54] Refer to chapter 3 for an example of the current Azeri scale.

the profitability of an operation, taxes take profits into account. Hence, the tax element does not make Azerbaijan's PSAs especially tough. The same applies to profit oil where a very detailed sliding scale offers flexibility in case of price changes. Cost oil treatment is on the generous side in line with many Asian contracts. This leaves bonus payments. They tend to be above average and of similar magnitude to those in many Middle East contracts.

6.4 INDIA'S PSA INCENTIVES IN A GLOBAL CONTEXT

In 1998, after four years the Indian government has finally signed off 18 blocks for oil exploration and development under production-sharing agreements. Four of the fields are offshore. The three blocks on the western coast cover an area of 9,865 sq km, the acreage for the eastern offshore field is 7,000 sq km. Onshore the size of the exploration areas ranges from 400 sq km to 7,390 sq km. Total acreage for the 18 contracts is 53,040 sq km. About 60 percent of the total contract area involves US companies with Okland being engaged in two-thirds of that zone. Unlike contracts signed in the early 1990s no major oil companies are involved in the present agreements. In the first phase the PSAs are expected to induce investment totalling $40m which includes $25m of foreign investment.

The Bidding Terms. The contract terms were first outlined in the Eighth Round Bid Announcement in 1994. The incentives for foreign oil companies were manifold. The Announcement stipulated that there would be no minimum expenditure requirement during exploration nor would signature or production bonuses be levied. As with previous PSAs the government renounced any entitlement to royalty payments[55] but foreign firms have to pay 50 percent income tax. Profit oil would be calculated on an after-tax R-factor based sliding scale. Oil purchased by the government from the foreign oil company for the satisfaction of domestic demand would be valued at the international market price. The contract duration was specified at 25 years and a possible extension of five years. 25 percent of the original area has to be relinquished at the end of the first exploration period. The government or one of its agents has a 30 percent carried interest which can be converted into a working interest once commercial production starts. In addition the government has the option to a 10 percent working interest during exploration, thereby contributing to 10 percent of the exploration cost. Profit oil, cost oil, exploration period (up to seven years), and work commitments during each phase of exploration were biddable. Individual contracts would provide for the exploitation of associated and non-associated gas with priority to the development of natural gas for the domestic market.

Model Contract Amendments. The bid announcement was followed by a model PSA in 1995 which made only very few changes to the terms set out the year before. The maximum exploration period was reduced to six years and mandatory relinquishment after the first exploration phase increased to 30 percent. The latter, however, was scaled back to 25 percent in the 1997 Review of Petroleum Regulation. Some amendments to government participation were also incorporated. ONGC or Oil India would have a participating interest between 25 and 40 percent and thereby share exploration costs in proportion to their participating interest.

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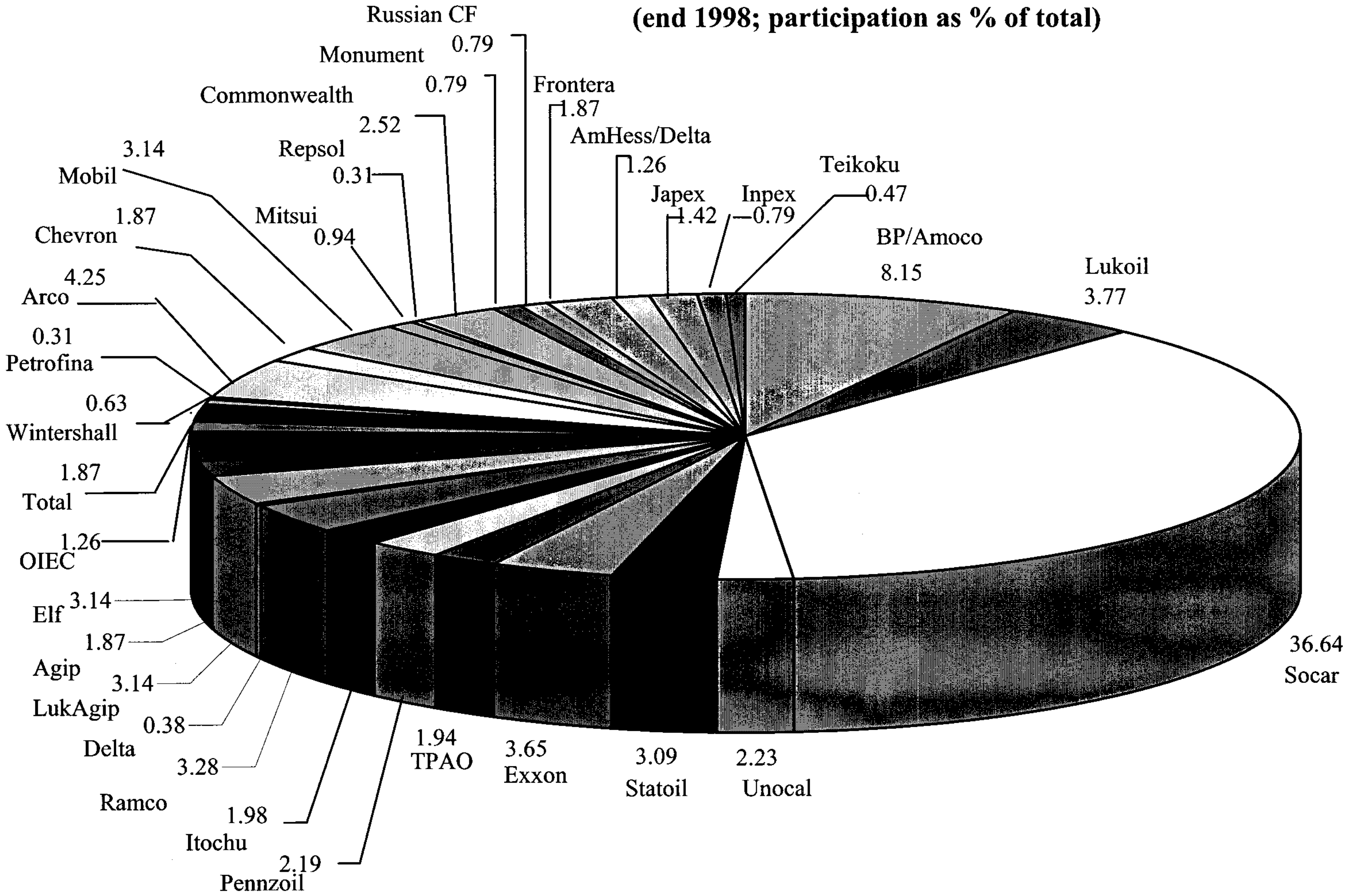
[55] In September 1998 it was announced that the Indian government planned a *New Exploration Licensing Policy*. Royalties under the new scheme will be 12.5 percent of the sale price of crude oil for onshore fields, 10 percent for offshore and 5 percent for deepwater fields.

Figure 6.1: PSA Partners in Azerbaijan (end 1998; participation as % of total)



A Comparison. India's PSAs levy higher taxes than the average Asian PSA, and the minimum area that has to be relinquished at the end of the first exploration period tends to be proportionally larger. However, taxation is not necessarily a disincentive. While royalty payments are based on gross production regardless of the profitability of the field, taxes are paid on the foreign oil company's share of profit oil and thereby take profitability into account. For several other contract variables the country offers relatively better terms than the rest of the region. Two features in particular stand out. PSAs in India request no royalty payment, and the profit-oil share is calculated on an after-tax sliding scale which is based on the rate of return rather than volume. The findings presented in Table 6.1 indicate that with regard to PSAs India is not a typical Asian oil producer. By the same token its contracts also differ from the average PSA offered by net oil importers. While during the late 1980s and early 1990s most importing countries introduced sliding scales for profit and indeed cost oil, only a comparatively small number have opted for R-factor based scales. The average net importer imposes royalties of 5 percent and charges lower income tax than the Indian government. In fact, quite a few PSAs of importing countries forfeit taxation of foreign oil companies altogether.

In 1997 India's oil production was about the same as that of Angola and Malaysia. With regard to PSAs India appears to be similar to Angola. The latter requires no royalties, income tax of 50 percent, and calculates profit oil on an after-tax R-factor based scale. Malaysia in comparison has set a royalty rate of 10 percent for its contracts. It has, however, in the late 1990s turned to R-factor rather than volume-based sliding scales. The tax rate in Malaysian PSAs is at 45 percent only slightly below that of the other two countries. Considering oil reserves in million barrels, India is in a position similar to Qatar, Yemen, Egypt, and Malaysia. We have already compared it to the latter. As for the other three producers, their PSAs display some marked differences to those signed by India. In all three countries income tax is usually paid by the respective national oil companies, and they all claim signature and production bonuses. Yemen in addition levies a royalty (the Egyptian royalty is commonly borne by EGPC). While Qatar has moved to R-factor based sliding scales, Egypt and Yemen both still largely rely on volume-based scales, and in some cases on fixed cost-oil percentages.

Table 6.1: Main Features of Asian PSAs

	India	**Average Asia**
Duration of Contract	25+5 years	24 years
Exploration Period	max 6 years	max 6 years
Relinquishment	25%	20%
Royalty	0	5.5%
Cost Oil	biddable	max 60%
Profit Oil	after-tax R-factor	min 28% - max 55%
Taxation	50%	41% (during 1990s)
Signature Bonus	0	US$ 1.8m
Production Bonus	0	US$ 5m
Domestic Market Obligation	international market price	varies but usually at discount
State Participation	25%-40%	18% but strong variations

In conclusion we can say that with regard to its PSAs India is an atypical Asian oil producer and an atypical net importer. It charges higher than average income tax rates but the other contract parameters make up for this. Opting for tax rather than royalty and for after-tax R-factor based profit oil the contracts are strictly profitability oriented. In this sense India behaves more like countries with similar oil production volumes. The Indian PSAs appear to be closely related to those of Malaysia and in particular Angola.

6.5 Iran's Buy-Back Tender: Production-Sharing or Service Agreements?[56]

In July 1998, amid much hullabaloo Iran finally started its tender for 24 oil and gas development projects, 17 exploration blocks, and assorted downstream schemes. The development offer consists of 15 onshore and nine offshore blocks, while exploration can be conducted in eleven onshore and six offshore areas. The contractual form is called a buy-back agreement which appears to be a hybrid of a production-sharing agreement (PSA) and a service contract although it is much closer to the latter. Despite some confusion about the exact nature of the buy-backs Iran's road show in London revealed great interest by the industry with 450 conference delegates from 150 companies and organisations.

Setting the Scene. Despite the 1996 sanctions Iran is still the world's fourth and OPEC's second largest oil producer.[57] It accounts for about 5 percent of global oil production. The country is ranked tenth with a 1.7 percent share of worldwide natural gas production. Iran is also among the major reserve countries with R/P ratios of 69 percent for oil and over 100 for natural gas. It is estimated that it holds nine percent of the world's proven oil reserves. Oil export revenues were US$ 18bn in 1996 and thus accounted for 81 percent of total export revenues. In 1997 the main customers for Iranian crude were Japan, South Korea and the UK.

Experience with Previous Buy-Back Contracts. The first buy-back was signed between NIOC and Total in 1995. The contract covered the Sirri A and E offshore oilfield with expected rates of return of 20 and 23 percent respectively. Since then two more contracts have been awarded: one to Bow Valley for the Balal offshore oilfield with an expected rate of return of 24 percent, the other to Total for the second and third phase of the giant South Pars gasfield. The expected return for the latter is 18 percent. Furthermore NIOC is negotiating with Elf Aquitaine and Agip for a major gas and water injection project at the offshore Doroud oilfield. Additionally, a consortium consisting of Shell, Petronas, Gaz de France and British Gas, is in pursuit of a venture to develop phase four and five of the South Pars field with the aim of exporting gas to Pakistan. They are in competition with BHP who also want to pipe Iranian gas to Pakistan and are considering a link-up with Gazprom for this purpose. Finally, NIOC has drawn up a shortlist of three companies for exploration activities in the Caspian sector. The companies are BP, Shell and Lasmo.

The Present Tender. FOCs on entering a buy-back agreement have to provide all investment capital necessary to finance exploration or development of the field. Capital expenditure, interest charges, and the pre-agreed share of production is then repaid through the sale of the produced oil or gas. NIOC has a supervisory role. The respective shares for the two parties are calculated by translating gross production into gross revenue and deducting operating costs. Net revenue is then split according to an agreed formula.

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[56] The figures for Iran are based on various issues of MEES, OGJ, PR, Euroil, and Energy Day.
[57] All figures are based on BP's Energy Statistics.

Table 6.2: Onshore Oil and Gas Development

Field	Project	Original Oil/Gas	Recoverable Reserves	API Gravity	Current Production	Depletion	Capacity Objective
Agha Jari	Gas injection/pipeline	28bn bbl	9.5bn bbl		200,000b/d	8.7bn bbl	
Ahwaz Area: Ahwaz	Gas injection/pipeline	31.5bn bbl	3.4bn bbl		Yes	520mn bbl	
Abteymur	Gas injection/pipeline	14bn bbl	1.27bn bbl		Yes	85mn bbl	
Mansouri	Gas injection/pipeline	19.3bn bbl	1.16bn bbl		Yes	85mn bbl	
Central Zargos: Rig	Production facilities/pipeline	350mn bbl	110mn bbl	34-36			
Shuroum	Production facilities/pipeline	811mn bbl	154mn bbl	21-27			
Dudrou	Production facilities/pipeline	92mn bbl	10mn bbl	46			
Cheshmeh-Khosh	Gas injection	1.513bn bbl	287mn bbl		Yes	120mn bbl	80,000b/d
Darquain	IOR/EOR	2.894bn bbl	289mn bbl	38-39	Testing		30,000b/d
Dehluran	IOR/EOR	3.693bn bbl	555mn bbl	33-40	Yes		20,000b/d
Jufeyr	IOR/EOR	2.727bn bbl	137mn bbl	22-39			
Masjed-e-Suleyman	IOR/EOR/production facilities	6.58bn bbl			1,500b/d	97%	
North Pars	Development/infrastructure	106TCF	47TCF		Appraisal		2.4bn cfd
Paydar	IOR/EOR	816mn bbl		13	910b/d (summer)		10,000b/d
Saadat Abad	IOR/EOR	372mn bbl	41mn bbl	41.5	No		
Sarvestan	IOR/EOR/production facilities	848mn bbl	136mn bbl	28-31	No		20,000b/d
Tang-e-Bijar	Development/treatment	5TCF					350mn cfd
West Assaluyeh	Development	1.715-5.772TCF					500mn cfd
West Paydar	IOR/EOR	1.9bn bbl	189.7mn bbl		3,000b/d		

Table 6.3: Offshore Oil and Gas Development

Field	Project	Original Oil/Gas	Recoverable Reserves	API Gravity	Current Production	Depletion	Capacity Objective
Esfandiar	IOR			31	No		6,000-70,000b/d
Foroozan	EOR		890.4mn bbl	29-30	50,000b/d		90,000b/d
Hendijan	IOR/EOR			27-32	8,000b/d		25,000b/d
Nowrooz	EOR/production facilities	1.729bn bbl	705mn bbl	20-21	Interrupted by war		90,000b/d
Salman	EOR		430mn bbl (remaining)		100,000b/d	1,228.5mn bbl	
Sirri: Sirri C	EOR	486mn bbl			14,000b/d	51mn bbl	35,000b/d
Sirri D	EOR	693mn bbl			14,000b/d	103mn bbl	35,000b/d
Soroush	EOR/production facilities	9.1bn bbl		19			60,000-150,000b/d
South Pars Gas	Further development	280TCF			3bn cfd		5bn cfd
South Pars Oil	NO DATA RELEASED						

There are two stages to this process. In the first stage the FOC explores a field. At the end of the exploration period the operation is either declared commercial or non-commercial. In the latter case the FOC bears all the risk and all the costs and the contract is terminated. NIOC will declare a commercial discovery if the projected output results in a minimum rate of return for NIOC after deduction of all capital costs, bank charges, operating costs and fees to the FOC. However, the FOC that conducted the exploration work will not necessarily obtain approval for the development of the field. It has merely the right of first negotiation with NIOC for the development contract. If the negotiations are successful a development contract is awarded. If NIOC and the stage-one FOC fail to reach an agreement the contract will be tendered. The latter will then receive its expenditure plus an agreed fee. Payment is made either directly by NIOC or by the FOC which succeeds in stage two. They in turn are entitled to recoup these costs within the scope of their contract.

Onshore Oil and Gas Development Projects. The onshore blocks are mostly located along the border to Iraq, and in the oil-rich Zagros mountains with a few fields being situated further south. Three fields are for gas development: Tang-e-Bijar in northern Iran close to the Iraqi border as well as North Pars and West Assaluyah fields in coastal areas in the south. Tang-e-Bijar has estimated reserves of 5TCF and it is hoped that it will eventually produce 350mn cfd. The corresponding figures for North Pars are 47TCF and 4bn cfd while estimates for West Assaluyah vary between 1.715 TCF and 5.772 TCF. The objective for the latter is a production rate of 500mn cfd. Although North Pars could produce 4bn cfd it is currently only aimed at 2.4bn cfd of dehydrated sour gas for injection at Agha Jari and other oilfields. All gas produced is intended for domestic use. This leads us to the gas injection projects. These are Agha Jari, Ahwaz, Abteymur, and Mansouri in the greater Ahwaz region, and Cheshmeh-Khosh which has a northerly location close to the Iraqi border. All blocks are presently producing, and secondary recovery methods, i.e. gas injection, are required to improve recovery from the fields. Agha Jari produced 1mn b/d at its peak in 1974 and has a current output of 200,000 b/d. Its primary reserve was estimated to be about 9.5bn barrels of which more than 90 percent has already been produced. Simulations have shown that an additional 5bn barrels of oil are recoverable if the reservoir pressure can be increased. For this to happen, a total gas injection of 20 TCF is required. The gas would mainly come from the North Pars and Assaluyah fields. Thus, part of the work programme is the construction of a gas transmission pipeline of 500 km for this purpose. The Cheshmeh-Khosh gas injection project requires 120mn cfd of gas in order to increase production capacity to 80,000 b/d. One-third of it will be associated gas from the field itself, the remainder will come from nearby Qaleh-Nar gas reservoir. The three blocks in the direct vicinity of Ahwaz town need gas injections of 360mn cfd (Ahwaz) and 120mn cfd (Abteymur and Mansouri each) respectively to maintain reservoir pressure. The gas is supposed to come from Kabir-Kuh and thus, as in the case of Agha Jari, a pipeline of 350 km has to be installed as part of the work programme.

Several of the remaining blocks on offer are already producing oilfields with the objective to improve development by applying enhanced recovery (EOR) methods and, in the case of not-yet producing fields, initial oil recovery (IOR) methods. The Dehluran oilfield, for instance, which is located near the IranBIraq border and has a production capacity of 75,000 b/d is in need of a desalting plant. Masjed-e-Suleyman in the Zargos mountain area has depleted its recoverable reserves by 97 percent and not only requires EOR methods but also an expansion of its existing production facilities. The tender for the Sarvestan oilfield in south-east Iran also includes the design and construction of a production unit to process crude from this field and nearby Saadat Abad and to convey this production to the refinery in Shiraz. This field and others have yet to be developed. The Paydar oilfield also falls into the latter category. It is close to the Iraqi border, and so far only one well has been drilled. Average output is 910 b/d during summer. Production has to be stopped during winter as the crude is too viscous and the well is unable to flow in cold weather. The objective is for production to reach 10,000 b/d.

Offshore Oil and Gas Development Projects. The offshore oil projects tend to be in the upper Gulf region with the exception of Sirri C and D and Salman. Initial and/or enhanced oil recovery methods are mainly required. In addition, Nowrooz and Soroush also need work on production facilities. Most fields are currently producing but it is hoped to increase output substantially. The objective for Esfandiar for example is to lift 6,000 b/d initially and increase this to up to 70,000 b/d eventually. The plan for Soroush is to produce 60,000 b/d by 2001, then 100,000 b/d in a second stage and finally reach 150,000 b/d. The South Pars gasfield which is already under operation by Total is tendered for further development which should push its production from currently 3bn cfd to 5bn cfd.

Figure 6.2: Legal Structure for Buy-Backs

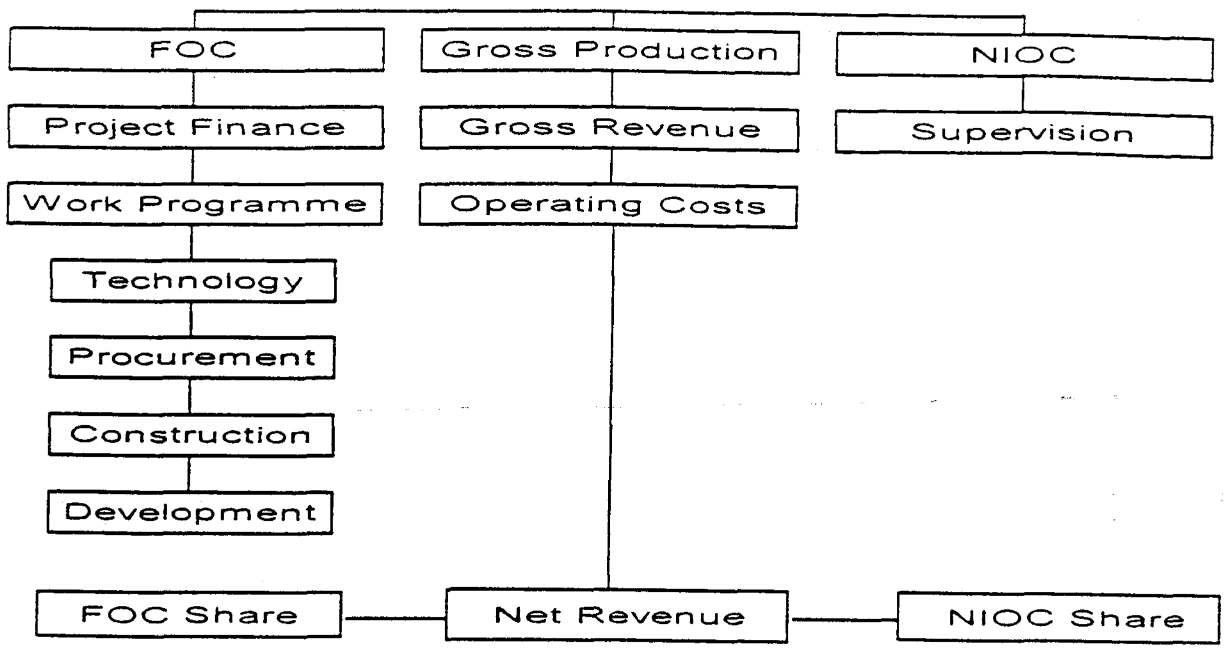
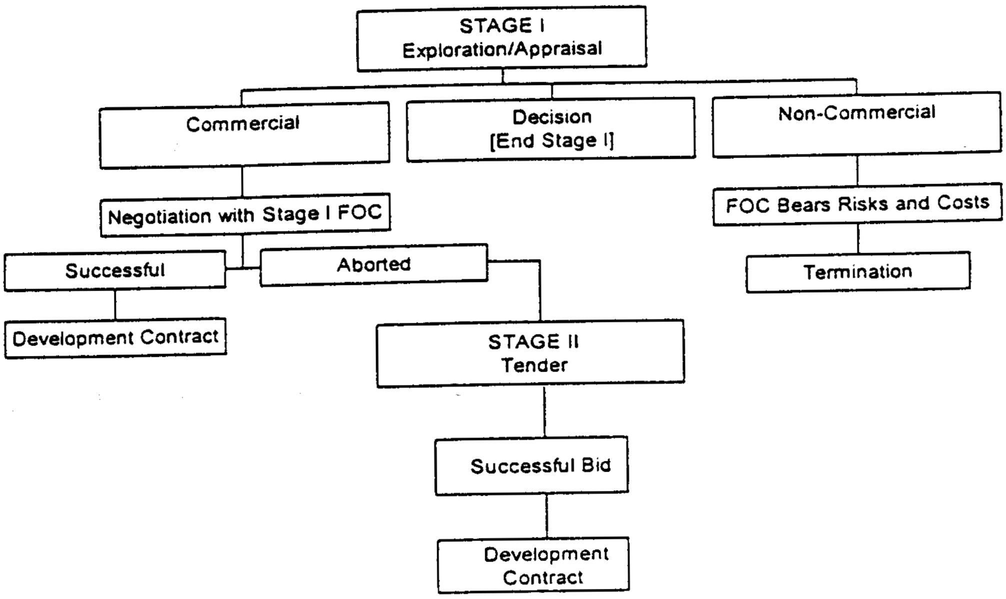


Figure 6.3: Buy-Back Procedure



Exploration Projects. The location of the 17 exploration blocks ranges from northern Iran, where one block is near the Caspian Sea and two more blocks are close to Azerbaijan, along the border with Iraq all the way down to the Lower Gulf area where most offshore projects can be found. Several onshore blocks are in the vicinity of already producing oilfields. In addition there are two exploration areas in central Iran. The Tabas Block is located near Tabas town in salt flats terrain while the Kashan-Zavareh Block is in the Alborz region just south of Tehran. The blocks vary widely in size. The offshore Dara Block near Abadan is the largest with 12,000 sq km. Other large blocks are West Kish which is also offshore and covers an acreage of 9,600 sq km, the nearby East Kish Block with 6,290 sq km, and the onshore Makran Block which measures 8,000 sq km and is located in south-eastern Iran. Among the smaller exploration projects are the Semirome Block with 1,200 sq km in the Zagros mountains, and the two Moghan blocks near the border with Azerbaijan. They cover an area of 1,000 sq km and 1,500 sq km respectively.

A Comparison to PSAs. Unlike a PSA a buy-back offers the FOC only an exploration contract which will not necessarily be converted into a development contract even if commercial discovery is declared. The agreements have a relatively short duration of between five and seven years. Capital cost ceilings can only be exceeded for new additional work approved by NIOC. The extra expenditure is then added to the initial capital costs and repaid under the amortisation period of the contract. The FOC receives its project expenditure plus a fee. The latter is some percentage of total capital costs excluding bank charges and operating costs. In the existing contracts Bow Valley receives 47 percent of capital costs for the Balal field. Total's fee is 39 percent and 60 percent respectively for Sirri A and E, and 70 percent for South Pars two and three. This way of calculating 'profit oil' differs sharply from PSAs where the FOC receives a share of gross production. Another important feature of the buy-back agreements is the treatment of price risk. If the oil price drops significantly resulting in a low level of revenue that is not sufficient to cover the FOC's monthly entitlement, NIOC may reduce its share of net revenue. Obviously the latter will not allow its share to fall below a certain 'critical' level. If this sacrifice is still not enough to meet the FOC's requirement the amortisation

period will be extended. At present these repayment periods range from three years for Balal to five and a half years for South Pars.
It appears that although the interest in the Iranian tender was very great the response so far has been disappointing. The main stumbling blocks are:

• Exploration contracts will not automatically lead to *development contracts*; there is no guarantee that NIOC will negotiate in good faith with the stage-one FOC.

• The *contract duration* is comparatively short. The Iranian government considers long-term supply contracts for FOCs to balance this factor.

• With regard to *price risk* it is not clear whether NIOC has an obligation to reduce its share of net revenue if the oil price drops nor is it known by how much its share will be reduced.

• A final point concerns *cost recovery*. FOCs have indicated that they would prefer the option of utilising alternative oil or gas if the output of a field is not sufficient to cover cost recovery. NIOC has responded by hinting at the possibility of packaging North Pars with an onshore oilfield that falls into the category of gas-injection projects.

On the positive side it can be argued that Iranian buy-backs are low cost, low risk contracts with a reasonable rate of return.[58] In conclusion we find that although buy-backs display some PSA features such as cost and profit oil this contract form is much closer to traditional service contracts than to PSAs.

6.6 PERU: PSAs WITH A DIFFERENCE

Peru signed its first PSAs in 1971. The initial contracts were closely modelled on the Indonesian PSAs and, like their Asian counterparts, underwent substantial changes over time. In the 1971 model contract profit oil was split according to a fixed scale. The FOC was entitled to a share of between 44 and 50 percent depending on risk assessment, estimated development costs, and projected production volume. The contracts made no cost recovery provision, and levied no royalty. Tax had to be paid by the NOC, Petroperu.[59] The major problem for the FOCs was the Peruvian insistence that a specified number of wells had to be drilled even when seismics and other tests have already indicated that oil was unlikely to be discovered.

The second generation model PSA in 1978 revealed some significant changes. Profit oil was now calculated on a sliding scale which guaranteed the NOC at least 50 percent of production. In addition, the drilling requirement was modified. Most importantly, however, changes in the US tax law brought about a change in the way Peru's PSAs dealt with the tax issue. The USA required that companies had to pay tax on their foreign operations directly to the host government if they wanted it to be credited against US tax obligations. Hence, the tax burden for the PSAs was shifted from the NOC to the FOCs.

Throughout the 1980s and 90s the contract structure changed several times. The two main alterations are the introduction of bonuses and, usually biddable, royalties. According to the 1980 PSA with Occidental, Petroperu was entitled to an

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[58] Estimates set the rate of return for the present tender close to 20 percent.
[59] Petroperu was partially privatised in 1993. Its role has been assumed by Perupetro.

annual bonus of 1.9 billion soles. This bonus had to be paid by Occidental for 20 years. In the case of contract termination before the end of the 20-year period, the FOC was obliged to pay the remainder immediately. While the bonus is tax deductible it has to be paid regardless of profitability. However, it should be pointed out that not all Peruvian PSAs require bonus payments. Considering that royalties are biddable it is not surprising that they vary across contracts. Chevron's 1996 contract is based on a bid containing a minimum royalty of 45.4 percent for low production at $15 per barrel which increases to a maximum of 63.2 percent for high production at $35 per barrel. This is an indication of the company's determination to win the contract. Most bids start with royalties of 18 to 20 percent. Enterprise, for instance, signed a PSA in 1998 which committed them to royalties of 18 to 45 percent depending on R-factor and oil price.

Overall, the lower royalty of 18 to 20 percent is the average rate in South America. Zero cost oil is rare and is only found in very few contracts worldwide. The NOC's minimum profit-oil share is relatively high with 50 percent while the maximum share of 58 percent is on the low side. Bonus payments are common. However, the way the Peruvian bonus is levied is rather unusual.

Part IV: Conclusions

7 THE MAIN FINDINGS AND CONCLUSIONS

When designing a fiscal system a government aims to maximise revenue from its natural resources while at the same time providing sufficient incentives to foreign investors. The oil industry relies on many different contract forms. One of the most widespread types is the production-sharing agreement.

Under a PSA the FOC receives a share of production as a reward for its investment and operating costs and the work performed. It usually bears the entire exploration cost risk and shares the revenue risk with the host country. The contract is signed before exploration begins and the foreign partner will therefore expect significant rewards later on in the life of the contract. The FOC's revenue is made up of cost oil and profit oil, while the direct sources of revenue for the government can comprise royalties, profit oil, bonuses, taxes, customs duties, and indirect benefits that arise from price caps and DMOs. PSAs do not divide profits out of market proceeds but instead divide the physical production after allowing a portion of output to be retained by the FOC for the recovery of pre-production and production costs. This means that costs can only be recovered once oil is produced. A source of disagreement at this point can be the definition of costs. This is the basis for the determination of the profit-oil volume that is the part of production remaining after costs in the form of oil have been deducted. The sharing of production follows a pre-agreed split between the FOC and the state or its NOC. In theory the state controls the operation but de facto the risk-taking private partner manages the project unless the NOC takes up its option to participate in the venture, which has become more common over time.

PSAs address the important issue of ownership of oil reserves which has made this contract form politically acceptable in most developing countries. Before the introduction of PSAs the concession agreement vested, for all intents and purposes, the ownership with the foreign company at the wellhead. Under PSAs reserves and all installations and plants built by the FOC are government property. The PSA is attractive to foreign firms, particularly those based in the USA, because they can book the reserves in their balance sheets notwithstanding the fact that they do not own them. It seems that the rationale is that the company is entitled to produce for a long period of time, in many cases for as long as the field is alive. During this time it can book the reserves because of access rather than legal title.

A PSA does not allow for up- or downgrading of the contract terms once the exploration period comes to an end and information about the exact size and characteristics of the deposit is available. The same problem arises at the start of exploration because the work obligation during this phase is finalised before work begins. It would appear that it is in the FOC's interest to have a short initial exploration period and then negotiate the work programme for subsequent phases if these are needed. Once development commences cost oil enables the FOC to recover its costs even if the project is not profitable. Under different contract forms costs are often deductible from taxable income which in the case of PSAs is the FOC's profit oil. If the project does not realise any profit then there might not be a taxable income against which to deduct costs. With cost oil, however, at least part of the expenditure can be recovered provided there is some cash flow. Not surprisingly, FOCs are therefore keen on high cost recovery limits and some PSAs indeed set the maximum cost oil at 100 percent. The problem for the government is that the higher the cost recovery the lower the nominal profit oil to be shared between the parties. One way around this dilemma is to impose royalties thereby generating a guaranteed minimum revenue stream.

Depending on the discount rate marginal projects might not be profitable if the fiscal system is not sufficiently geared towards economic rents. Governments have recognised that this kind of rigidity can work detrimentally to their goal of maximising revenue. Thus, most PSAs now offer sliding scales for the calculation of profit oil. We have shown that such a sliding scale is particularly effective if it is based on the FOC's rate of return. These so called R-factor sliding scales indicate that contracts have become more profit related. However, if the contract parameters are badly structured they can still work as disincentives in a low oil price scenario. If the oil price is high economic rent is large. Even if the government take is great the project is likely to be profitable for the FOC in which case a badly structured scheme is not a disincentive.

Figure 7.1 summarises how PSAs deal with risks and rewards. The first column displays the various uncertainties encountered during the lifetime of a PSA. Next, in column two we consider who bears a particular risk, the government and/or the FOC, and then specify that risk. The third column shows how each party tries to control their risks, while column four discloses how the PSA addresses these issues. The first uncertainty concerns reserves both during exploration and production. The main risk for the FOC is that reserves are not large enough to be commercially viable. Hence, if the contract never enters into its production stage, the FOC has no way of recovering its exploration costs. However, if commerciality is declared and production begins, the FOC will want to recover its costs as early as possible. This is done through the cost oil allowance which is specified in the PSA. The government's main concern in this context is that the FOC applies best-practice methods during both stages in order to maximise total production. They can ensure this by monitoring the operation and by taking up their participation option.

The second row of Figure 7.1 deals with price uncertainty. Both parties to the contract will be concerned about the give-away of revenues if, during the production period, the oil price changes substantially and the contract is not sufficiently flexible to accommodate this change. In addition, a low-price environment may result in the non-exploration of some oilfields, and the non-profitability of existing operations. The aim for the contract partners is therefore to provide for an upside-downside trade-off. Sliding scales, especially those for profit-oil shares, achieve this objective.

A further concern is the uncertainty regarding costs during development and production. The government's risk depends largely on its participation. However, if costs change significantly this will affect the amount of cost oil and/or the length of time during which the FOC requires the maximum cost-oil allowance. This in turn has an impact on the volume of production available for profit oil and thus on the government's profit oil. The FOC, in order to minimise its risk with regard to operation and capital costs, will have two aims. First, they want to recover their costs as early as possible. Second, they prefer contracts to display a degree of flexibility, possibly in the form of contract elements being linked to rates of return. The PSA takes care of these issues through cost oil allowances and sliding scales.

Row four of Figure 7.1 addresses the uncertainties arising from specific prices and markets. The former refers to items such as posted prices and the latter to the market in which production will be sold which includes DMOs. Potential problems here are access to markets and profitability. The common solution is for the PSA to provide a link to world-market prices. For example, if the government requires the FOC to fulfil its DMO the price paid for the crude oil is *n* percent of the world-market price with *n* being specified in the contract.

The last two rows raise the issues of infrastructure such as building roads or export terminals, and sovereignty. For the government both these areas are risk-free. The FOC is mainly concerned with costs, profitability, and expropriation. In addition they may fear that the government as the sovereign may impose adverse tax changes or price controls. In both cases it is in the FOC's interest to recover its costs as soon as possible, and for the payback to set in at an early stage. While infrastructure and transport requirements vary widely and are contract-specific, the most common PSA response to sovereign risk is international arbitration.

The empirical analysis in Chapter 5 which includes 268 contracts shows that most PSA parameters have changed substantially over time, and that the main changes occurred in the mid 1970s. The attempt to classify contracts as either tough or favourable or as balancing parameters yields mixed results. We correlated contract variables with each other in order to see whether, say, a high royalty was balanced elsewhere in the contract, for example through high cost oil. Conducting this exercise for the main parameters, we find that PSA variables are either weakly or not at all correlated for Asia and Southern/central Africa. In the other regions, particularly in North Africa, South America and Central America we find some strong correlations. This is especially true for South America where royalty and maximum profit oil show a perfect negative correlation indicating that PSAs with high royalties have low profit-oil shares for the FOC and vice versa. Royalty and cost oil, on the other hand, are almost perfectly and positively correlated. As one increases so does the other. The other two strong relationships in South American PSAs are inverse ones between cost oil and maximum as well as minimum profit oil. Whereas the royaltyBcost oil correlation indicates that contracts offer an incentive to balance royalty payments, the remaining three relationships point towards tough contracts. For example, if royalty increases the profit-oil share decreases which is a double negative for the FOC.

With regard to PSA terms we find that there is competition among governments between regions but even greater competition within regions. This implies that one cannot refer to, say, a typical Asian or a typical Eastern European contract. Overall, offshore PSAs are more favourable for the FOC than onshore agreements. The difference is, however, not quite as marked as one might have expected. There is a much clearer distinction between exporting and importing countries with the former generally offering tougher conditions. While we can show that PSAs have undergone changes in the 1990s it is not possible to pinpoint these alterations in the contract parameters as a response to increased competition from new players such as the Caspian countries. Furthermore, there is no clear-cut evidence that countries with large reserves of crude oil offer tougher contract terms. A further significant factor is the observed dispersion of variables across contracts over time. The time series analysis presented in Figures 5.1 to 5.5 indicates a wide range for each variable; for example royalties vary between zero and 45 percent. However, considering Figures 5.1A to 5.5A we find that for most parameters there exist preferences for certain values; for instance, despite the wide range, 91 percent of PSAs in the dataset have royalties of either zero, ten, 12.5 or 20 percent.

PSAs are the oil industry's equivalent of sharecropping contracts. As with the latter, economic theory suggests that PSAs are inefficient contract forms because the FOC does not receive its marginal product. Thus, the question arises how and why this inefficient form of an oil contract flourishes. Principal-agent theory helps to explain how risks and rewards have to be balanced in order to nonetheless let this type of arrangement prosper. The fact that PSAs are one of the dominant exploration and development agreements points towards their efficiency as an institutional arrangement for risk sharing even if they are inefficient in terms of economic theory. In that sense it can be argued that a PSA is a political rather than an economic contract.

Figure 7.1: PSA Risks And Rewards[1]

UNCERTAINTY	RISK: Gov	RISK: FOC	OBJECTIVE: Gov	OBJECTIVE: FOC	PSA RESPONSE
Reserves – **Exploration Stage**	•Not best practice	•Non-Commerciality	•Monitor operations	•Cost recovery	•Cost oil •Participation Clause
Reserves – **Production Stage**	•Not best practice		•Participation		
Oil Price – **High**	•Giveaway of revenue		•Trade off upside for downside		•Sliding scales
Oil Price – **Low**	•Non-exploration	•Profitability			
Costs (Develop&Prod)	•Depending on participation	•Operation costs •Capital costs	•Flexibility	•Link to rate of return	•Cost oil •Sliding scales
Specific Price/Market	•Posted price •Price definition	•Price controls •Posted price •DMO	•Secure revenue •Access	•Profitability	•Link to world market price
Infrastructure/Transport	•None	•Costs •Expropriation •Non-Commerciality		•Cost recovery	•Contract specific
Sovereign Risk	•None	•Expropriation •Tax changes •Price controls		•Early payback	•International Arbitration

[1] I am especially grateful to John Mitchell for suggesting this matrix.

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OXFORD INSTITUTE FOR ENERGY STUDIES
57 WOODSTOCK ROAD, OXFORD OX2 6FA ENGLAND
TELEPHONE (01865) 311377
FAX (01865) 310527
E-mail: publications@oxfordenergy.org
http://www.oxfordenergy.org