Statistics Norway
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Documents

The petroleum business environment
A reader's digest

Statistics Norway
Statistisk sentralbyrå

Contents

1. Introduction

This document presents some of the backdrop for building a global model of the oil market with particular emphasis on the supply side. The main issue has been: What are the company incentives for investments and how do companies of various kinds approach their opportunities? First we present the main characteristics of petroleum companies and define company segments that may be driven by similar preferences and face roughly the same set of investment opportunities. In addition to the vertically integrated supermajors and other private petroleum companies, we consider the position of state oil companies, in particular of Saudi Arabia. Further, the document provides an overview of the main contract arrangements between an oil resource owning nation and petroleum companies. The three most common contract arrangements are licence, production sharing agreement and service contract. The pay-off structure of these contract arrangements is illustrated, and some implications of tax design were considered. Finally, the internal rat of return is calculated for an identical model field in 7 countries with different tax regimes.

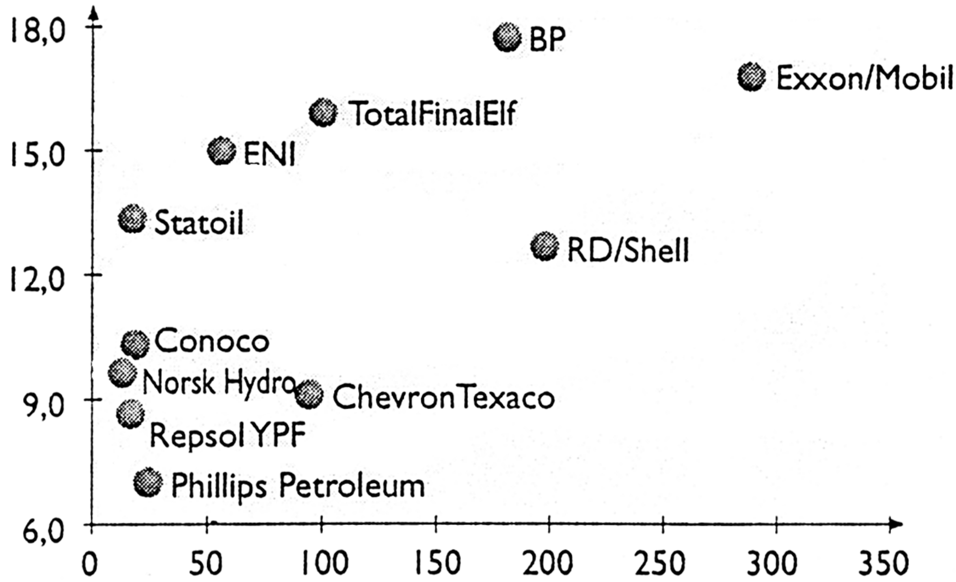
The material brought together in this note is intended as guidelines for modelling of petroleum supply, design of relevant scenarios and as background for defining research topics. The work has been part of a project financed by the Petropol programme of the Norwegian Research Council. Within this project, econometric studies have been carried out to identify characteristics of demand for energy products (Liu, 2004), look for market power in the oil market (Hansen and Lindholt, 2004) and also study a possible relation between oil prices and drilling activity via adaptive oil price expectations (Ringlund et al., 2004).

2. To invest or not to invest in oil production?

While there is a basic understanding that petroleum companies pursue the highest possible return, it is considerably more complicated to grasp the incentive structure of petroleum investments in its more realistic dimensions. Modelling such investment decisions naturally involves simplified depictions of a very complex decision process. However, even in a simple recipe there are possibilities to mirror some basic behavioural characteristics that are essential to the modelling of petroleum supply. To do so, it is useful to classify petroleum companies.

There are different types of oil companies, private or state owned, national or multinational (in their operations), large and small, vertically integrated or companies just concentrating on exploration and production. In this note we focus three types of oil companies, i.e. private, vertically integrated supermajors ("majors"), other private oil companies ("non-majors") and state owned companies (SOCs).

Figure 1. Petroleum company value (bill. USD) and return on average capital employed



Source: Magma-no 5 /UBS Warburg

The majors in our context include ExxonMobil, Royal Dutch/Shell, BP-Amoco, Total-Fina-Elf and ChevronTexaco. Figure 1 illustrates the magnitudes of these supermajors in relation to the magnitude of a number of other international oil companies, as measured in company market value. (ROACE, i.e. return on average capital employed on the vertical axis).

Although majors grow, their playground has been drastically reduced in the last decades. Table 1 shows the ranking of oil companies according to size of production - in 1972 and in 2000. In 1972, there were 6 private companies among the 7 biggest companies world wide. In 2000 there were only two private companies (ranked as number 6 and 7) among the 7 biggest companies. Fully state owned companies now make up for about 50 percent of global production. Outside OPEC the share is 22 percent. There is good reason to assume that ownership and framework conditions have an effect on the investment priorities of the various company segments.

Table 1. Largest oil-producing companies ranked by estimated oil production (mb/d)

	1972			*2000*		
Rank	*Company*	*Produc-tion*	*Share*	*Company*	*Produc-tion*	*Share*
1	Exxon	5.0	10.8%	**Saudi Aramco**	8.8	11.7%
2	**BP**	4.7	10.1%	**NIOC (Iran)**	3.8	5.0%
3	Shell	4.2	9.0%	**PEMEX (Mexico)**	3.5	4.6%
4	Texaco	3.8	8.2%	**PDVSA (Venezuela)**	2.9	3.9%
5	Chevron	3.2	7.0%	**INOC (Iraq)**	2.6	3.4%
6	Gulf	3.2	7.0%	ExxonMobil	2.6	3.4%
7	Mobil	2.3	5.0%	Shell	2.3	3.0%
8	**Former Planned Economies**	1.3	2.8%	**CNPC (China)**	2.1	2.8%
9	**CFP (Total)**	1.0	2.1%	BP	1.9	2.6%
10	**Sonatrach (Algeria)**	0.9	2.0%	**KPC (Kuwait)**	1.9	2.5%
11	Amoco	0.8	1.8%	**ADNOC (Abu Dhabi)**	1.8	2.4%
12	Arco	0.7	1.4%	Lukoil	1.5	2.1%
13	Du Pont	0.6	1.3%	**NOC (Libya)**	1.5	2.0%
14	USX (Marathon)	0.5	1.0%	TotalFinaElf	1.4	1.9%
15	**PEMEX (Mexico)**	0.4	1.0%	**Petrobras**	1.3	1.8%
16	Occidental	0.4	1.0%	**Pertamina (Indonesia)**	1.2	1.6%
17	Getty	0.4	1.0%	**NNPC (Nigeria)**	1.2	1.6%
18	Sun	0.4	0.8%	Chevron	1.2	1.5%
19	Unocal	0.4	0.8%	**Sonatrach (Algeria)**	1.0	1.3%
20	Phillips	0.3	0.7%	Yukos	1.0	1.3%

Note: Companies with state participation are in bold.

Source: IEA World Energy Outlook, 2001 Insights.

Among state oil companies, there is reason to focus investment strategies of Saudi Arabia/OPEC core. Saudi Arabia in particular is in a unique resource situation but constrained by restrictions on financial operations and burdened by a need for government revenue. These factors might in a medium term perspective give reasons for investment priorities that differ from other state owned companies as Saudi Arabia plays an influential role in the oil market as dominant producer and resource owner.

Companies that are partly state owned, partly private owned are generally stock market sensitive and may possibly best be grouped together with the private companies in a modelling context. Statoil and Norsk Hydro would thus be assumed to behave like fully private oil companies. On the other hand, Petrochina and Sinopec are partly privately owned, but Chinese government's control dominates over private investors' preferences. Hence these companies should be included among state oil companies. Private companies that are only engaged in domestic reserves can be grouped together with international private companies. This would ignore the possibility that national (but private) oil companies may have preferential access to resources or otherwise different framework conditions than foreign companies (such privileges seems to be in decline). It is important to be aware that the term national company sometimes is used for private, domestically engaged companies, sometimes as a synonym for state owned companies in the business and research terminology.

The three company segments differ with respect to their capacities to invest and their preferences with respect to choice of provinces, scale of projects, activity level and terms of operation. Some available evidence that indicate different framework conditions and behaviour among private oil companies will be commented on below.

Table 2. Share of production by company segment[1]. Percent

	Production mb/d	State-owned	Private oil companies	
			International[2]	National
OPEC-CORE	22,5	96,9	3,1[3]	
REST-OPEC	5,5	69,1	27,3	3,6
LA	7,25	55,1	14,9	29,9
CHINA	3,23	100[4]		
REST-ASIA	4,46	20,2	79,8	
RUSSIA/UKRAINE/BELARUS	6,5	0	100[5]	
CASPIAN REG.	1,42	75	25	
WESTERN EUR.	6,78	0	100	
AFRICA	2,83	28,6	66,1	5,3
CANADA	2,74		100	
USA	8,11		100	
OECD-PACIFIC	0,84		100	
EASTERN EUR.	0,18	50	50	

[1] Information from Oil and Gas Journal (2001), Petroleum Intelligence Weekly (2000-2004), IEA (2001).
[2] Petrobras (Brazil), Statoil (Norway) and Sonangol (Angola) are categorised as private, even though they are partially state-owned.
[3] The Abu Dhabi National Oil Company seems to plan a limited opening of UAE upstream oil production to foreign firms. Petroleo di Venezuela opens for joint ventures in crude oil in Venezuela (foreign companies already have licenses in the heavy crude oil sector). To what extent private oil companies will enter Iraq remains uncertain.
[4] Although Petrochina and Sinopec are not fully state-owned (and have been acquiring interest in exploring and production round the world), it seems that private/foreign investors do not have the influence which is customary in partially state-owned companies elsewhere.
[5] Recent legal action by the Russian government towards Yukos Oil may indicate a stronger state control in some companies.

2.1 Private companies' investment decisions

A dominating attitude has been that cash flow (CF) is a major determinant of investments in the upstream petroleum sector. Cash flow is the current gross sales minus operational costs and current capital outlays (as if immediately depreciated). That (post-tax) cash flow is a major determinant of investments would be consistent with a view that profitability in petroleum investments is higher than the return to alternative investments. The higher profits are generally related to the opportunity to earn parts of the petroleum resource rent and to the barriers to entry in effect due to discriminatory tax rules, economies of scale, technology. Logically, if so is the case, those who are within the industry seek to reinvest. However, the cash flow as an "investment drive" does not necessarily mean that all the cash flow is reinvested. A share is diverted to other activities for strategic purposes or risk management.

One strategic issue relates to the possible benefits of vertical integration by diverting investments to refining and distribution (downstream). Industry arguments for vertical integration concerns security of supply and markets. An interesting implication of vertical integration is pointed out by Bain (1956) as cited in Barrera-Rey (1995): vertical integration may imply barriers to entry as competitors must invest in two production stages at the same time and thus increase the capital requirements of entry. Arrow (1975) introduced random output and information in advance as reason for downstream companies for backward integration. Barrera-Rey (op.cit.) provides a further theoretical and empirical overview and discussion of vertical integration, including transaction costs and asset specificity, concluding that there are both benefits and costs of vertical integration. The incentive to integrate may thus be company specific and empirical evidence is necessary to draw conclusions. There is a brief overview of arguments of the discussion in Antill and Arnott (2003), who consider vertical integration as profitable. They point to the currents state where financial integration has replaced operational integration to harvest those benefits. The improved working of the oil market in recent decades has made financial integration an option to replace operational with finacial intagration and thus possibly avoiding inefficiencies in joisnt operations. For an overview of research in this field, see Bindemann (1999).

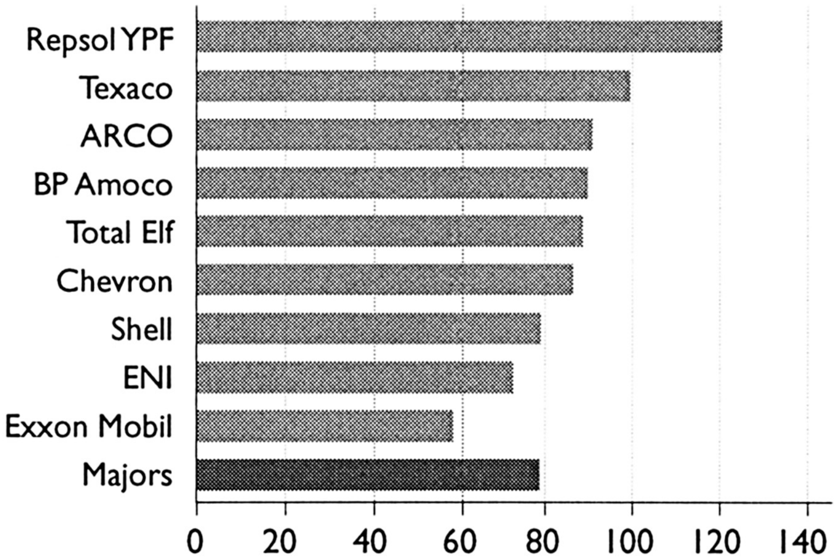
Although it is difficult to pin point strategic aspects behind investment priorities, a model approach might preferably distinguish between majors and non-majors to open up for different assumptions among company segments. Below we discuss some of the floating characteristics and information about petroleum company investments.

Vertically integrated supermajors (majors)

The environment of oil giants has changed considerably since the days of the Seven Sisters in the 1960's (Sampson, 1975). The sisters are now reduced to 4 supermajors that are outstanding in scale, value and capacity. A significant difference between then and now is that considerable reserves no longer are in the control of the international private oil giants, but are nationalised. Hence, the 4 supermajors Exxon Mobile, Royal Dutch/Shell, BP and Total Fina Elf, only contributed about 11 percent to global oil production in 2000. The majors have effectively become price takers in the oil market according to Antill and Arnott (2003). With a working crude oil market, the benefits of being operationally integrated have become of less importance. Rather, the majors are now financially integrated and operate various business units that report financial results to senior management, i.e. they operate like in a fund setting.

To judge from Simmons (2001) the mega majors have “lots of spare cash and solid dividends”. With such high dividends, it seems natural to reinvest and expand. There might however, be barriers to growth - like human capital constraints. However, in a medium to long term perspective it seems unreasonable to assume that the majors are unable to build up sufficient expertise for a growth strategy. Figure 2 shows, however, that there has been less than full reinvestment of the big international oil companies’ cash flow in recent years. The capital expenditure (capex) to cash flow-rate of majors was about 80 percent during 1995-1999.

Figure 2. Percentage share of cash flow reinvested (capex/cash earnings), 1995-99

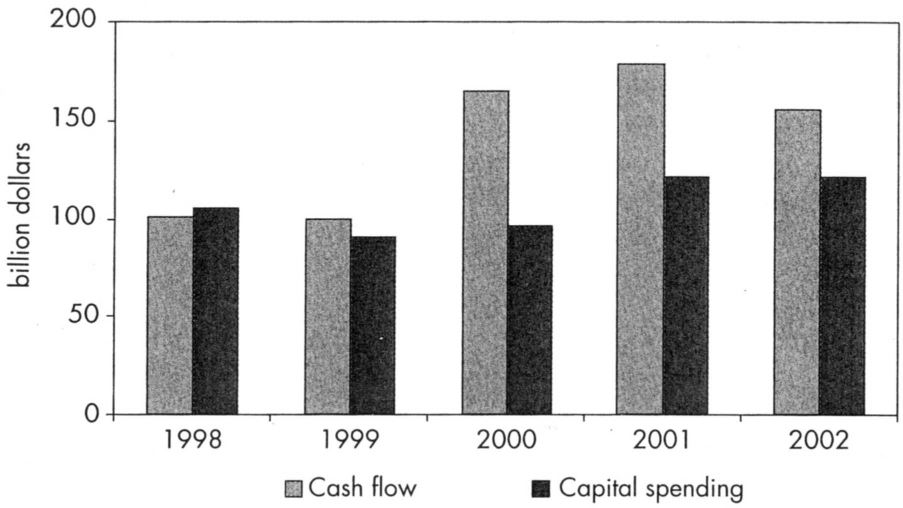


Source: HSBC, Secotr Report, Integrated Oil and Gas, February 2001.

In more recent years with a high oil price, the capital expenditure as share of cash flow has been even lower (figure 3). The years 1995-1999 was a period of mergers and acquisitions. Mergers are reorganisations of companies with expected synergy effects on return or company value without new production capital into operations. In acquisitions, the purchasing party makes an investment as good as any other purchase of production capital - whereas the other party makes an identical disinvestment in petroleum, i.e. an act of diversification

Further, companies have been busy buying up their own shares (Osmundsen et al. 2002, Antill and Arnott, 2003) - a kind of reinvestment in petroleum without bringing in new capacity. This seems like a logical solution if expected profit is higher than in other sectors, but cash flow too high to invest given a limited company capacity and project portfolio. This might help to explain why capital expenditure is lower as a share of cash flow in spite of the solid dividends in recent years with high oil price. One may conclude that big oil companies see petroleum investment projects as preferable in the long run and thus that a considerable share of cash flow will be reinvested in the long run as well. The purchase of own shares invite to confidence in the company.

Figure 3. Oil Company* capital spending and Operation Cash Flow



* Covers a sample of 36 integrated and independent exploration and development firms with av combinded production of 36 mboe/d.
Source: Merrill lynch (2000)/ IEA World Energy Investment Outlook 2003.

Snakes might, however, join in and question if own shares have been bought up with "Enron" intentions. It has been a dominant attitude, though, that the petroleum sector is more "real" and transparent than for instance the IT sector, hence the inward investments are regarded as good signs rather than bad. But the recent development might indicate that oil companies have books in slight disorder, by having accounted for higher reserves than economically sustainable. Shell downgraded 20 percent of "proven reserves" to "probable" or even lower graded reserves in early 2004. The value of company reserves were depreciated 40 percent and the price of shares fell immediately by about 7 percent (The Economist, 2004). The reserves (partly Ormen Lange) were further down-graded in March 2004. How transparent the petroleum industry really is, is a somewhat open question.

Some attention should be paid to the possibility that limited rate of investments lately might reflect a genuine decline in expected return. There are circumstances around future framework conditions that might signal lower return. Company projects portfolios consist according to Antill and Arnott (2003) of two parts that are unequally profitable. One part consists of old projects with depreciated, but clearly profitable production capital that contribute significantly to company earnings. The other part consists of recent investments with high capital costs and a significant lower return. New investments may involve highly capital intensive projects (deepwater, sub-sea etc) in this latter category. The combination of high capital costs and increased transparency around government take in developing countries may work together to clarify the real profitability of new investments.

The resource owners and petroleum companies are increasingly forced to disclose all transactions related to oil and gas production. Governments in developing countries are now cooperating with IMF to establish complete state accounts, with the possible outcome that resource-owning nations will strengthen resource regulation and secure a higher share of the resource rent for national development. A side effect is possibly an upward shift in government take and increased transparency with respect to genuine return on investments.

Climate policy and climate initiatives are increasingly framing the working conditions for petroleum companies. The EU carbon trade will start working in 2005. Although US have not ratified the Kyoto Protocol, a US policy is being created bottom up. An important step is a 10 state initiative to develop a cap and trade system among power plants and requirements to supply renewable energy in 13 states. Although this action mainly will have a direct effect on the coal market, it signals with some strength the upcoming effort to reduce carbon emissions. In November 2003 carbon was traded at around 11 – 12 ECU per tonne of CO_2 (Petroleum Economist, 2003a). Climate change is increasingly understood as a big environmental challenge to the petroleum industry, more so for oil than gas. Taxation and regulation, innovations, shifts in demand and changes in weather patterns are seen as major factors behind future petroleum company value. Climate change enters as a "key long-term investment theme". An investor survey under the Carbon Disclosure Project reveals differences among petroleum companies concerning emission intensity and costs of cutting company emissions. The cost of emission reductions varied between 0.5 percent and more than 2 percent of annual company cash flow for a 10 percent cut in GHG emissions from 2001 levels.

There is reason to assume that the major's share of external finance is more formal than real. Antill and Arnott (2003) refer to the financial means and financial capacity as the number one activity where petroleum companies have comparative advantages. Provinces with license systems are tax based, allowing companies to deduct interest expenditures from the tax base. To benefit from these tax rules, companies would tend to let the cash flow make a round-trip and become "external" to fully use the deduction rules. US and the North Sea provinces are both tax-based regimes with incentives to fill up the “quota” for interest expenditure deductions. A relative decline in activity in these provinces would imply a cost in terms of reduced possibilities to downgrade capital costs. Reduced activity and matured potential in US and the North Sea in recent years may be part of the explanation why at company level the average share of external finance is reduced from 25 to 5 percent in recent years (Osmundsen, 2002).

Investment behaviour of majors

Three main alternatives may seem relevant in a simplified modelling framework:

1) Exogenous share of cash flow (CF) reinvested in oil.

The share of total cash flow that is reinvested in oil production is set exogenously, based on recent years’ practice and possibly adjusted for price expectations. The residual CF is diversification and covers capital flow to other industries, including the gas sector and finance and insurance. Among financial investments we include purchase of company shares, which increases company value (to the benefit of all shareholders).

2) Exogenous and moderate growth in production volume (1-2 percent).

Limited growth rate has characterised the supermajors in recent years (Simmons, 2001). A specific assumption could be that growth in volume parallels growth in global demand of transportation oils. This assumption would reflect the tendency of majors to focus investments in emerging markets (China, Russia), where oil is too expensive for heating and consequently is reserved for transportation which is increasingly in demand. In China, which generates about a third of the increase in world oil demand, coal will hardly be replaced by oil in manufacturing industries due to large cost differential.

3) Profit target.

It is frequently stated that supermajors only engage in projects that are big and promising enough to deliver about 15 percent internal rate of return (IRR). There seems to be widespread agreement about the fact that supermajors are preferred as operators for large, demanding projects with a potential for high return. However, there is less trust in that supermajors actually achieve this high rate of return of 15 percent. According to Antill and Arnott (2002) the true rate of return of the 5 supermajors has been as low as 9-10 percent IRR over the years 1997-2001, or just 1-2 percent above normal risk adjusted return. A modelling approach could be to limit investments by super-majors to a level where 10 percent of return is achieved. In Kemp and Stephen (2004), a 10 percent rate of return is used as investment criteria for a study of future investment scenarios on the British continental shelf.

Depending on the regional dispersion of investment by different types of companies, supermajors would be in competition with other investments. Due to the superior capacity of supermajors to implement large projects within budget and time could technically be implemented as if supermajors' production function reflect a higher productivity than non-majors in every region. How far majors would go in their investments depends on the scale of investments by independent exploration and production companies that are financially constrained.

Non-majors

This group of oil companies is clearly quite heterogeneous. However, they share some characteristics that make it useful to distinguish them from the majors. Transnational and more provincially based private oil companies are less vertically integrated than majors. They have shown higher growth rates than majors and tend to be capital constrained. When industry representatives and analysts characterize the investment by non-majors in upstream, there are rules of thumb that the loan finance share in company value can be up to 50 percent for the larger companies that mainly are engaged in production, and 30 percent for the smaller independents that are engaged in exploration as well (Oil and Gas Journal, 2002b) The share of loan finance in company value is kept under control by shareholder response. According to Oil&Gas Journal (op.cit) the external finance of the non-majors has recently been limited by their company value at the stock exchange rather than by the interest rate or oil price. Non-majors have a higher capital cost than majors, as the majors benefit by internalising the earnings on financial services (Antill and Arnott, 2002). In a modelling context this might be reflected in different productivity between majors and non-majors.

Investment behaviour of non-majors

To start with, a working hypothesis could be that the total level of investments by the non-majors is determined by their cash flow and in addition, an exogenous share of external finance. Oil and Gas Journal (2002) indicate that independent exploration and production companies typically have 30 percent loan finance in capital stock, while the bigger companies have about 40 percent shares of loans and equity.

2.2 State owned companies

Table 1 above illustrated the current situation that state oil companies (SOCs) control a major share of oil production. The SOCs are now said to be less favoured by their national owners concerning access to resources than was the case earlier. State oil companies are still less efficient than private companies, but according to Simmons (2001) many state owned companies now apply world class technology through outsourcing. There is an on-going transformation of state oil companies towards more commercial agents stopped of national privileges and regulation power is described in Petroleum Economist (2003b).

As extractive industries with a resource rent potential, it is probably a preferred strategy of SOCs to invest in petroleum rather than in other industries. Thus their CF is likely to be recycled, except for government take for financing public expenditure. In developing countries with large populations, government take can be in strong competition with investment interest -or with rent-seeking leadership.

As a default, one may assume that government take is somewhat higher than the return to shareholders in private companies and that the residual is reinvested. However, in Saudi Arabia, Kuwait and Venezuela one may consider linking the government take to forecasted growth in public expenditure, based on population growth scenarios. Below we have considered such a link for Saudi Arabia. However, the method can be adapted to other countries as well. However, the situation in Saudi Arabia is of special interest since their role in the oil market will have significant effect.

Investment behaviour of Saudi Arabia

As Saudi Arabia is a dominant oil producer, the regime will face price reductions as a consequence of increasing supply. To increase oil revenues has both short term and long term implications on oil price and market share. Cappelen and Choudry (2000) present various macroeconomic scenarios for Saudi Arabia. The overall picture is that Saudi Arabia will remain in a capital deficit for the next decade. Due to a high population growth of about 3.5 percent per year and low forecasted growth in non-oil private sector, the demand for finance of public expenditure might limit the possibility to invest in the petroleum sector. By reserving funding for public expenditure in line with the population demand, an upper limit to Saudi Arabia's investments may be identified.

If Saudi Arabia must rely on external capital to further develop the petroleum sector, it seems reasonable to assume that this will be implemented in joint ventures with big international oil companies. This kind of arrangement is expected to take place in gas development, however, the option may over time be realized in the oil sector as well. New private investment opportunities in the Saudi Arabia would probably originate in the cash flow of majors, possibly reorienting their investment flows to petroleum provinces considerably.

As an illustration of the situation, we will consider various strategies for allocating the cash flow to domestic government consumption versus investments in oil production capacity. In all alternatives it is assumed that oil investments by OPEC CORE are made within the region. In this context, investment in an emerging gas sector is regarded as exogenous or determined in other parts of the model, hence they are not made explicit here.

a) *Saudi oil investments are limited by the need for government income to cover expenditures driven by the rapid population growth.*

A submodel may determine the share of Saudi Arabian cash flow that is absorbed by the government. The remaining share of the cash flow can be regarded as an upper limit to investments in oil. If domestic budget needs are limiting investments, the upper limit can be calculated as follows:

(1) $$RI_{SA}^t = CF_{SA}^t - BUD^t$$

(2) $$NNP_0^t = NNP_0^{t-1}\left(1+0.015\right)$$

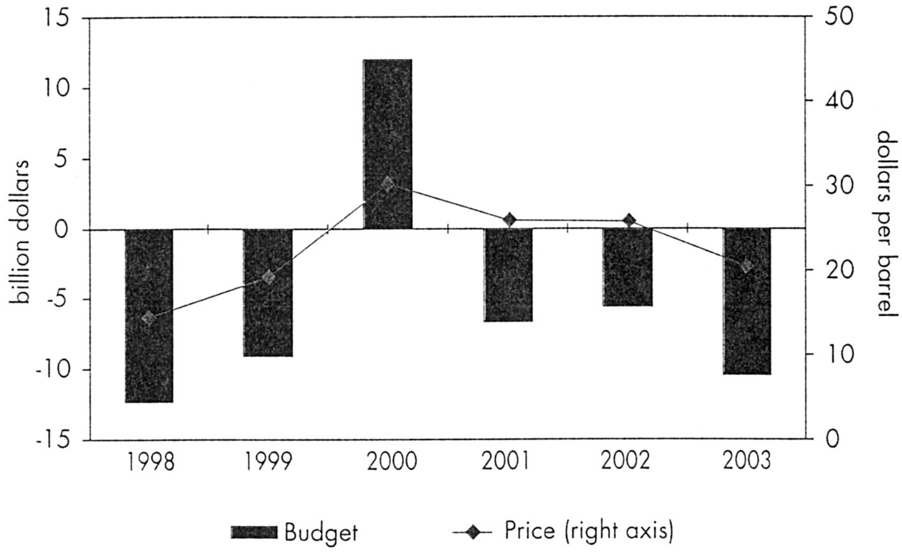
(3) $$GOV^t = T_0 \cdot NNP_0^t + BUD^t$$

(4) $$GOV^t = GOV^{t-1}\left(1+0.035\right)$$

RI_{SA}	Total oil revenue available for reinvestment in oil production
CF_{SA}^t	Cash flow generated of Saudi Arabia
$BUD =$	Share of Saudi cash flow diverted to non-oil use, is implicitly determined above.
$NNP_{SAO}^t =$	Net product in other sectors than oil, assumed to grow 1.5 percent p.a.
$GOV^t =$	Public expenditure period *t,* (assumed to increase with the same rate as the population (3.5 percent per year))
$T_0 =$	Tax rate, non-petroleum sector

Figure 4 presents the recent development in Saudi Arabia's budget deficit in relation to the oil price. The 2003 figure is based on an oil proce forecast of 20.5 USD/barrel. However, recent high oil prices lead to a considerable 2003 surplus of 85 billion USD, which is the the highest since 1981 (Petroleum Economist, 2003c). Judged form Figure 4, an oil price below USD 25 per barrel may lead to a budget deficit.

Figure 4. Saudi Arabia budget surplus/deficit and crude oil price



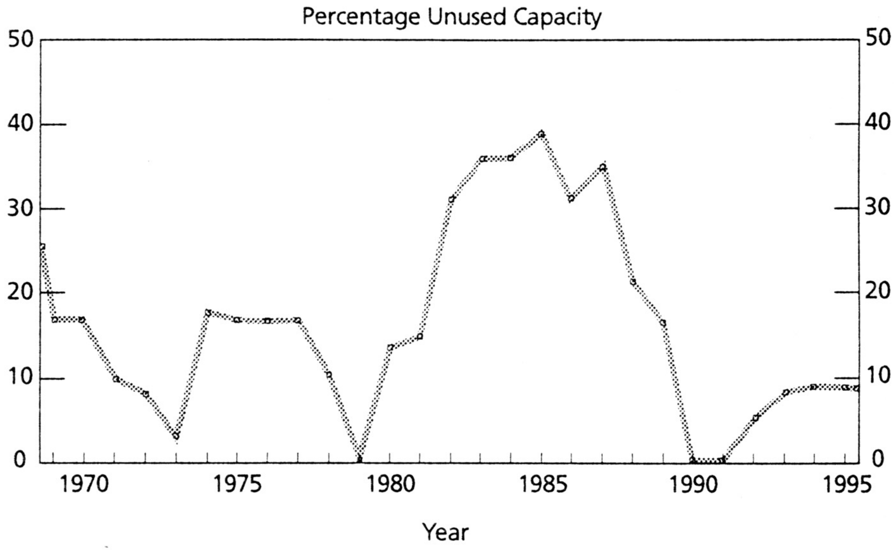
Note: The oil price is spot WTI. The price for 2003 of $20.5/barrel is that used in the budget.

Source: Merrill Lynch (2003).

b) Saudi production capacity concerns

SA will maintain capacity sufficiently above the production level to pose a valid threat behind cartel power. Saudi Arabia is the dominant producer within the OPEC cartel. To exert market power, OPEC restricts supply and Saudi Arabia supports the price with excess capacity to discourage new entrants in the market. Figure 5 shows the development of OPEC excess capacity over the last decades. The cost of keeping spare capacity is low in Saudi Arabia since the cost of production is very low.

Figure 5. OPEC Excess capacity to produce crude oil 1968-1996



Source: Capacity-CIA, Production, BP

Around year 2000 the excess capacity was estimated to about 20 percent. In earlier years the overcapacity has been higher, but due to increasing financial constraints we may assume 20 percent overcapacity to be a suitable dimension of threat for the future in a model context. This means that capacity growth is proportional to production growth.

(5) $$\frac{C^t}{C^{t-1}} = \frac{X_t}{X_{t-1}}$$

(6) $$RI_{SA} = C^t - C^{t-1} = C^{t-1}\left(\frac{X_t}{X_{t-1}}\right) - C^{t-1}$$

(7) $$\Rightarrow \quad RI_{SA,SA} = C^{t-1}\left(\frac{X_t}{X_{t-1}} - 1\right)$$

C_t = capacity in year t

X_t = production in year t

RI_{SA} = necessary investments in Saudi Arabia to exert market power

In a model approach the capacity growth can be implemented with a lag. Subordinated the capacity growth, the Saudi Arabia (OPEC CORE) decides how much to produce based on the current market. With "fixed" capacity, the deviation of production from full capacity will represent a cost in terms of lost pressure.

Income targets, oil price and market share goes together. It may be considered to include a long-term optimisation criteria as background for evaluating myopic behaviour - or as a regular investment criteria.

Kuwait is a country that is close to experiencing the dilemma of Saudu Arabia. According to an IMF survey (Oil &Gas Journal 2003a), Kuwait's economy is currently in a "balanced" situation, but faces the long term challenge similar to Saudi Arabia with high population growth and a small private sector. Hence, an income target for Kuwait similar to Saudi Arabia could be relevant for future petroleum analysis. If 2003 represents a genuine balance with respect to state petroleum revenue, the future needs for petroleum revenue must compensate for population growth and for change in revenue from non-petroleum sectors as in Saudi Arabia.

3. Allocation of total investments upon regions

When discussing regional allocation of oil investments, the modelling approach in mind is dimensioned for 13 petroleum provinces and 4 types of fields. The model will allocate capital from various company segments to these 52 investment opportunities. Model parameters can obviously never precisely mimic the thinking of petroleum companies when they allocate their capital on these 52 investment opportunities. Still it makes sense to deal systematically with the allocation mechanism, because provinces differ with respect to reserves, economic potential and political framework conditions. These factors can be dealt with in a transparent way in a quantitative model so that impacts of investment strategies can be traced all the way to the global market and back to companies and resource owners.

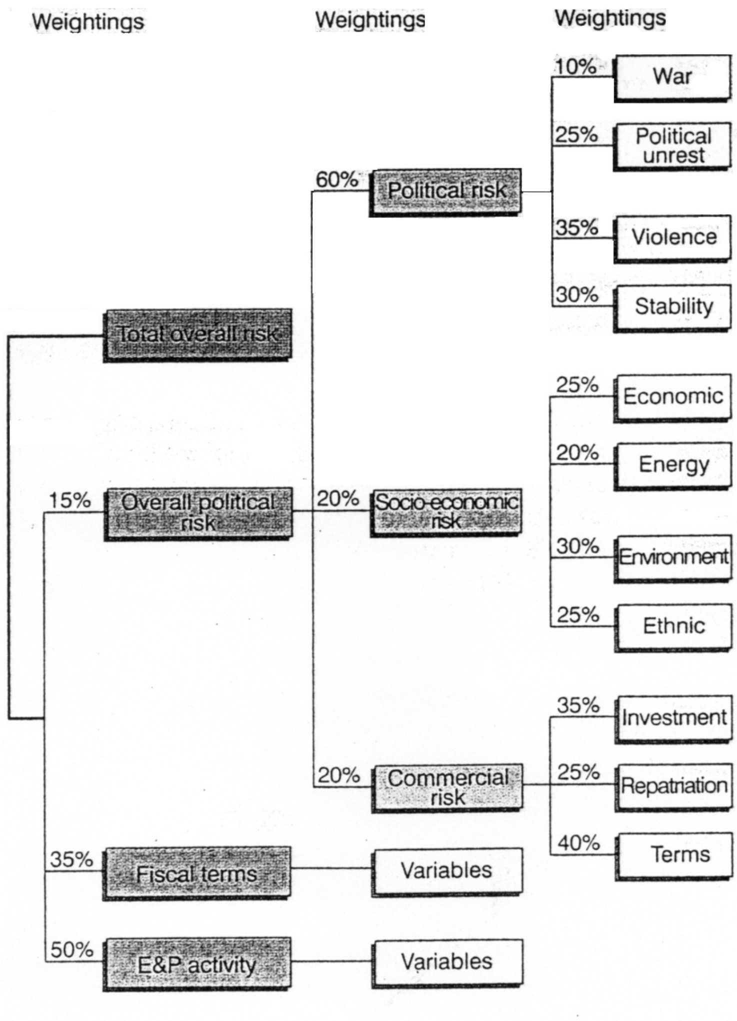
When approaching the investment allocation mechanism, there has to be some basic principles , and on top of that a set of factors that adjust decisions according to specific trends and hypothesis that need to be investigated. No simple mechanism will be able to express all conditions behind the investment decisions in a modelling context. The fundamental drive is that investments do flow to maximize profits. Each year's investments in a region/field type is treated as a separate project with the typical development phase, plateau phase and decline phase for that undertaking. The criteria for making investment is the net present values (NPV) over the project lifetime. The NPV is estimated with an expected future oil price and 6 years depreciation of capital. The expected oil price is of course not an easy figure to identify, but can be linked to historic prices or controlled by the model user to illustrate specific implications for oil market development. As a result, there will be equal marginal revenue among all regions and field types - as long as there are no restrictions on investments or other exogenous aspects taken into account.

However, the base year allocation of capital may generally show a clear deviation from such a perfect approach under full certainty, as the observed marginal rates of return export differ among field types and regions. Expected returns depend on a lot of factors that remain behind the veil in a planning process. Political and technical risks are obviously present in considerable amount in the investment decision, together with market strategic considerations. Finally of course, due to long lead time of projects, the world may have turned out differently from expectations. As a consequence, regions/fields currently produce in parallel while offering different rates of return on further investments, as seen from a simple model profit max point of view. Below we consider how various elements behind such a deviation might bear relevance to future investment decisions.

Risk

The IHS Energy Group has developed a database for systematic studies of political risk in world petroleum production (Petroleum Economist, 2002). Risk has been divided in three main categories: general political risk, fiscal risk and exploration and production risk with the weights 15, 35 and 50 percent in the risk aggregate. The risk aggregate assigns the same total risk to operations in Norway and Nigeria, whereas the composition of risk clearly differs. Norway ranks high on legal/fiscal risk, and Nigeria ranks high on political risk.

Figure 6. IHS Energy Group – petroleum risk weightings



Source: IHS Energy Group

Modelling the investment decision could include a risk premium on allocation decisions based on this kind of indicators. There is reason to take into account that company segments respond differently to risk. The fact that the modelling approach in mind distinguishes between field categories (on-shore, off-shore shallow, deep sea) may provide some relevant basis for implementation of risk indicators if available.

Strategic considerations
It is expected that considerable investments will flow downstream to emerging giant markets for transportation oil in the coming decades. Majors with huge cash flows are better positioned than capital constrained non-majors for investing downstream in such market with high growth potential, like China, Russia and India. The vertically integrated majors have investment capacity to obtain market power in these upcoming, vast retail markets.

Further, majors are more likely to get access to Saudi Arabian projects because they enjoy a higher level of confidence regarding project development and cost control.

Efficiency considerations not accounted for in the model profit function
According to Stevens (1998) there are large technical economies of scale in oil. In tanks and pipelines, capital costs are a function of surface area, while output is a function of volume.

Companies may tend to stay in areas where they have obtained substantial experience and knowledge (geological and institutional) or companies may tend to stay to exploit a scale factor in a region (fixed costs, materiality, clusters generating positive externalities). The cost of a project may shift downwards as the total industry capacity in the region is increasing. This corresponds to the hypothesis of cluster externalities, i.e. that concentration of activity expands the set of options for technical solutions and increases the competition among suppliers, thus avoiding cartel prices from subcontractors.

Resource owners tend to prefer majors as partners in development of large projects, because majors have a high success rate concerning time and budget. Hence, majors may be stronger represented in provinces with expected high average field size: i.e. getting access to the most attractive reserves and to be operators in areas demanding frontier technology - like in very deep water fields.

On the other hand, independent exploration and production companies are assumed to be better qualified for mature provinces, they are said to be more entrepreneurial and able to increase the production to reserve ratio in mature fields/provinces. This is what is seen in the North Sea at the time being.

Independents are relying on external finance (limited) and might concentrate in tax regimes with interest expenditure deduction.

State companies may concentrate on national reserves to secure tax revenues/resource rent.

The cost level can be expected to depend on the tax regime. Hence it may be useful to distinguish between tax based provinces and production sharing agreement (PSA) provinces (regimes).

Some countries' tax system favours loan finance, as currently in the US (Oil &Gas Journal 2003b), others not. If debt finance is favoured by the tax system, it is likely to be chosen to the extent allowed by the tax authorities. According to Lund (2002) the oil companies are known to approach these limits. In practice this means that the model should be realistic with respect to the rules governing the possibility to deduct interest rates.

The IEA World Energy Investment Outlook 2003 forecasts how investments will flow to regions over the next decades. Table 3 shows the total amount of oil investments needed to increase global supply from 77million barrels per day (mbd) in 2002 to 120 mbd in 2030, that is 56 percent. Offshore fields will account for almost a third of this increase in production.

Non-conventional oil and refining will altogether take 21.7 percent of total investments in the oil sector. Hence, conventional upstream oil investments including exploration will account for almost 80 percent of total investments up to 2030 according to IEA. Further, an increasing share of oil is expected to come from the low cost provinces (Middle East), and the developing countries will account for nearly 55 percent of global upstream oil investments in the period until 2030.

Table 3. Global oil cumulative investment by region and activity, 2001-2030* (billion dollars)

	Exploration & development	Non-conventional oil	Refining	Total
OECD North America	466	114	43	622
OECD Europe	199	1	22	222
OECD Pacific	19	1	24	44
Total OECD	**684**	**115**	**89**	**888**
Russia	308	0	20	328
Other transition economies	113	0	7	120
Total transition economies	**422**	**0**	**26**	**448**
China	69	0	50	119
South and East Asia	87	7	69	163
Middle East	408	16	99	523
Africa	311	7	42	360
Latin America	241	59	37	336
Total developing countries	**1,116**	**89**	**297**	**1,502**
Total non-OECD	**1,538**	**89**	**323**	**1,950**
Total world	**2,222**	**205**	**412**	**2,839**

* Not including global transportation investment of $257 billion.

4. Cash flow target

When allocation of investments on projects and regions is based on genuine profitability, the time profile of the cash flow is no issue.

According to Antill and Arnott (2003) most corporations take investment decisions based on discounted cash flow techniques, which should correspond to profit maximization at project level under certain conditions. However, if companies head for a fixed growth in cash flow, the ranking of investment opportunities might differ from under the profit-max criteria. Projects with delayed returns would tend to be by-passed by equally or less profitable projects on the ranking list of attractive investment opportunities that have a less suitable time profile of the cash flow. Such a selection of projects might lead to cycles in the investment path of companies. A cash flow bias in investment allocation could tend to keep costs higher and supply lower than in a profit max scenario. A higher oil price would then be the result and finally high enough to relax the cash flow stress and open up for more profitable projects with delayed earnings. The interaction between cash flow target and investment in tax regimes versus production sharing regimes if tax regimes and PSA regimes have systematic differences in time profiles of their cash flows.

Why should companies head for a cash flow target? A possible explanation could be that management is under scrutiny from relatively myopic shareholders.

In modeling oil supply one might possibly let a cash flow target determine the allocation of investments upon project opportunities and thus study the effect on investments and supply.

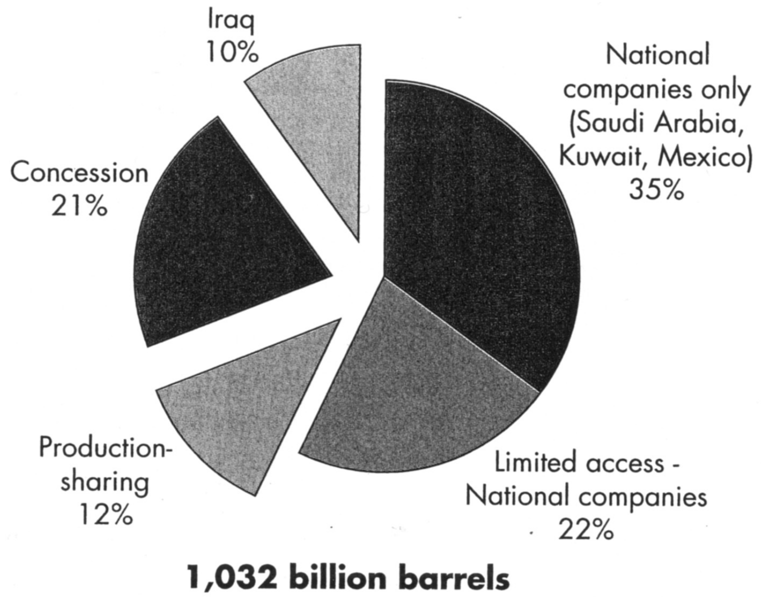
5. Contracts and cash flow

Petroleum projects are large and unique. Because of imperfect markets and costly information markets for access to reserves clear through contracts based on more than just a price. The two parties strongly depend upon each other's performance over several years and the responsibilities and rights of the reserve owner and company are regulated in various ways through specific contracts. One reason is that taxes and incentives are designed specifically to secure the owner the scarcity rent of natural capital. Another is to take account of the high risk involved in huge capital-intensive projects. A list of various frequently used contract elements is found in the appendix A and table A1, and appendix A, table A2-A5 provides an overview of the tax systems in the US, the UK, Angola and Iran. Further, contracts are embedding government concern about how to avoid drainage of the tax base to other countries by multinationals (see Gresik, 2001). Contracts and tax systems in operations are complex, but most regimes either have a mix of gross and (a lower) net revenue tax or only (a higher) net profit tax. It is generally so that 100 percent oil resource rent taxation is not imposed (Stiglitz and Dasgupta, 1971), even though rent taxation has long been seen as a non-distorting tax (Henry George) and net taxes are considered less distortive than gross taxes.

Below we stylise the main properties of various contracts and tax regimes. There are three main categories of contracts between reserve owner and the petroleum company. These are licences, production sharing agreements and service contracts. Below we present main features of these kinds of agreements and in which context they usually are applied. This information is from Petroleum Intelligence Weekly (2000-2004), Oil and Gas Journal (2000-2004), EIA (2001-2003), IEA (1993), Ministry of Finance (2000) and Mommer (2001). Appendix A indicates the overall setting of conditions frequently surrounding the various contract types. In addition we list som specific features of the tax regimes in the US, Angola, Iran and UK as of 2000/2001.

Figure 7 below shows the use of licensing and production sharing worldwide in terms of their access to oil reserves. Licences (concessions) regulate access to 21 percent of global oil reserves, and production sharing agreements 12 percent. State oil companies rule over roughly two thirds of total reserves when Iraq is included. Service contracts are not included in this table, because it is subordinated the reserve/production owner.

Figure 7. Access to oil reserves



Source: IFP (2002); *Oil and Gas Journal* (24 December 2001); IEA analysis.

5.1 Auction or discretionary licensing

Licenses are named concessions, permits or leases. A licence gives the oil company (the concessionaire/licensee) the right to all oil produced, while imposing net tax and/or royalty (a gross tax on production value). The oil company is given the right to explore and produce on a specific reserve/field, and is usually also given the right to export the oil. All equipment and production facilities belong to the company.

Royalty is sometimes levied on the production value at wellhead. In addition to the gross tax, companies pay net income tax (corporate tax and special taxes). In other tax regimes the oil companies only pay a net tax. Under the licensing regime we get the net return:

$$
\begin{aligned}
\pi_t &= p_t q_t - C_t^{INV} - C(q_t, R_{t-1}) - w_t x_t - B \\
&\quad - \left\{ \tau_{Gt} p_t q_t + \tau_{Nt} \left[p_t q_t - \beta_{INVt} C_t^{INV} - \beta_{EXTt} C(q_t, R_{t-1}) - up w_t x_t \right] \right\}
\end{aligned}
\tag{8}
$$

where q_t is the rate of extraction and p_t is the oil price. C_t^{INV} is the development or capital cost, while $C(q_t, R_{t-1})$ implies that the extraction costs is assumed to vary (positively) with the rate of extraction and (negatively) with the level of remaining reserves. x_t represents the rate of exploratory effort at unit cost w_t. B is the bonus bid in auction licensing or a signature bonus in discretionary licensing. Royalty is τ_{Gt} and τ_{Nt} is the net income tax (including corporate tax, special petroleum tax, petroleum revenue tax, resource rent tax etc.). *up* is (1+ an uplift) on exploration costs, so that more than 100 percent of the exploration costs can be offset against taxable profits.

β_{INVt}, β_{EXTt} are correction factors expressing different fiscal conditions. If $\beta_{INVt} = \beta_{EXTt} = 1$ the tax relief is immediately given for the costs incurred. The advantage of deducting costs (β_{INVt}, β_{EXTt}) depends on whether the company has sufficient taxable profits to offset these capital allowances and relieves on operating expenditure. Since early income is low, it makes a big difference to the tax burden if capital allowances can be offset against income from other fields. Reducing the value of the *β's* is referred to as increasing tax distortions (as is increased gross taxation by royalty payment). Tax distortions in this context means deviation from a full and immediate deduction of variable and fixed costs – whereas the usual meaning is a deviation from an efficient tax.

A limitation to tax allowances is introduced through ring-fencing. Ring-fencing entails that the expenditure can be relieved only against profits from the same field, thus allowing no relief against profits generated elsewhere. If the company does not have sufficiently taxable profits within a license, the costs are not available for relief until the field itself comes into profit. Usually the company may carry the losses forward until profits give room for the capital cost allowances. Norway practices that allowances can be carried forward with an interest in order not to discriminate against new entrants. Capital is typically not 100 percent allowable in the year that it is incurred, but is depreciated over a number of years (affecting β_{INVt}). There might also be an additional uplift on capital expenditure (affecting β_{INVt}). Ring-fence systems are rarely used under petroleum licensing (as opposed to production sharing contracts, se below). In addition, interest expenses might be an allowable expense against taxable profits.

5.2 Production Sharing Agreements/Contracts (PSA/PSC)

A production sharing contract divides production between the government and the contractor, after allowing a portion for cost recovery on behalf of the oil company. It usually also imposes an income tax. A PSA is established with the resource owning government, usually through its state oil company. The contractor is operator and works under the supervision by the host country usually represented by the State Oil Company. The contractor provides all the funds for the operations. A PSA gives the host country more control over both project operations and ownership of production than does a licence regime. Equipment and facilities used for petroleum operations belong to the host country.

Production sharing agreements in petroleum production was first introduced in Indonesia (OECD, 1993). It is perhaps not surprising that this type of contract was selected in a developing country where production sharing under the name of sharecropping has been a traditional way of subcontracting in agriculture. Sharecropping is still widely used in agricultural sector of developing countries. Seen in a simplistic way, the production sharing contracts incorporate incentives to under-invest in production as pointed out by Marshall (1920). For, "when the cultivator has to give his landlord half of the returns to each dose of capital that he applies to the land, it will not be in his interest to apply any doses the total return to which is less than twice enough to reward him". As with the agricultural tenant, the operating petroleum company would only receive a share of marginal product and thus limit the efforts in production in comparison to the optimal level. The Marshallian critique made a paradox of the fact that sharecropping systems sustained in most poor agricultural economies until Stiglitz (1974) explained sharecropping as a Pareto-efficient contract between the principal (landlord) and the agent (agricultural worker) when risk markets are absent and effort is difficult to monitor. Thus, production sharing might serve both parties in terms of spreading risk and reducing the monitoring costs in relation to moral hazard under operations.

Since first used in Indonesia in 1966, production sharing agreements have been widely used in the petroleum industry, creating enclaves of stability in unstable economies. In a country with non-convertible currency, PSAs will serve as a vehicle for repatriation of profits through export of a fungible product like oil ((Oil and Gas Journal, 2002b).

Russia introduced PSA in 1995 as an alternative to the existing licensing system. Negotiable terms of each field development and stable terms over the project lifetime were seen as important preconditions for inflow of foreign capital and company involvement. However, the PSA legal and financial framework is so far not fully defined and no PSA has been implemented recently. However, improved legal and fiscal terms in recent years have made investors more confident in the license based investment opportunities. In particular a shortening of the depreciation period from 15 to 5 years has made remote offshore projects more attractive under the normal tax regime.

A particular feature of the PSA is that the host country receives income from the very beginning of the production period (as is the case with a gross tax in a licensing regime), whereas under a tax system the early capital allowances would be huge and leave the taxable income relative low.

We get the net return:

$$\begin{aligned}(9)\qquad &\pi_t = \beta_{COt} p_t q_t - C_t^{INV} - C(q_t, R_{t-1}) - w_t x_t - B + \beta_{POt}(p_t q_t - \beta_{COt} p_t q)\\ &- \tau_{Nt}\left\{\beta_{POt}(p_t q_t - \beta_{COt} p_t q_t) + \beta_{COt} p_t q_t - \beta_{INVt} C_t^{INV} - \beta_{EXTt} C(q_t, R_{t-1}) - upw_t x_t\right\}\end{aligned}$$

β_{COt} is the share of the production that goes to the contractor to cover costs (e.g. , 50 percent in each year). $\beta_{COt} p_t q_t$ is referred to as "cost oil". B is a signature bonus. β_{POt} is the contractor's part of "profit oil", i.e. is the share of production value left after the cost oil is covered (often connected to the post-tax return in the sense that a higher rate of return for the contractor means a smaller share of the profit oil). If true costs are less than the cost oil in any year, the unused balance is added to the profit oil and divided according to the relevant shares of production value. Costs that are not covered in one year can generally be carried forward for recovery in later years (sometimes with interest).

τ_{Nt} is the net income tax rate (petroleum income tax). If the accrued costs are equal to the "cost oil", the net income tax is simply levied on the contractor's share of profit oil (disregarding exploration costs)

β_{INVt}, β_{EXTt} are correction factors for different fiscal conditions. There are usually ring-fence systems in production sharing agreements, i.e. the expenditure on the field can only be relieved against same field's profits, and not against profits generated elsewhere.

Sometimes commercially hired in exploration costs and administration costs connected to the specific PSA-area are deductible in addition to development and operating costs. It seems that interest expenses never are deductible in the basis for petroleum taxation in PSAs. Capital is typically not 100 percent allowable in the year that it is incurred, but is depreciated over a number of years (affecting β_{INVt}). There might also be an additional uplift on capital expenditure (affecting β_{INVt}).

In countries like Angola and Azerbaijan (and Iran, see below) there is some compensation for not offsetting the financial costs like interest expenditures either as an uplift on capital expenditure or by allowing interest on the balance of unrecovered costs to be recovered in subsequent years. up is (1+uplift) on exploration costs.

5.3 Service Contracts

Service contacts are frequently practiced in Iran under the name of "buy-back" contracts, but are used also in other countries. In the case of service contracts, an investment budget is negotiated between the international oil company and the resource owner (which may be a government or state oil company) for developing a specified field. The international oil company finances the entire cost of upstream development and recovers development costs plus an agreed rate of return. The sub-contracting oil company takes over field development after exploration has been completed and returns the operatorship to the state oil company after development is completed and the production phase begins. It leaves no output oil to the contractor, but pays him a flat fee (interest) for his capital and expertise. The oil company may, however, have the right to buy a certain amount of the production. A corporate income tax is usually imposed.

The service contract is different from the other petroleum arrangements because when the contractors have completed the development, the contractors must hand over the operatorship to the state oil company/resource owner. In some service contracts where the international oil companies takes the exploration risk, the contractor may be paid both an interest (the remuneration fee) and a risk fee. Some international oil companies expressed concerns in 1998 when Iran introduced a separate service contract limited to exploration projects. In case of discovery the contractor would get the service contract, otherwise the National Iranian Oil Company may transfer the contract to another company, possibly learning the exploration costs of the first contractor partly uncompensated.

The net return of a service contractor is:

$$(10) \qquad \pi_t = \left\{C_t^{RECOVERY} - C_t^{INV} - C(q_t, R_{t-1})\right\} + (1-\tau_{Nt}) \cdot \beta_{FEEt} C^{INV}$$

where $C_t^{RECOVERY}$ is the cost recovery. The investment and extraction costs of the contractor are covered within the limits of the specified budget. The costs are covered when the production period starts. Costs that are not specified by the contractor, must be covered by the contractor, but this is, however, open for negotiations. If costs are lower than specified, the cost recovery will be based on the revised cost budget, but the remuneration fee β_{FEEt} (as percentage of the investment budget) will not be changed. Usually the remuneration fee is about 35 - 70 percent of the capital costs.

β_{GPOt} represents the share of the production value, called government "priority oil", which the state will take before the company is paid. If $p_t q_t - \beta_{GPOt} p_t q_t < (1-\tau_{Nt})\beta_{FEEt} C^{INV}$ i.e. if government oil income beyond the priority oil is too small to compensate the contractor properly, the payment that is not covered will be carried forward and covered in the next period with interest compensation (although the share of priority oil may be negotiable).

In appendix B we indicate the regional differences in net and gross tax rates, where the gross tax rates is either a royalty in a license system or the size of the government's take of oil in a PSA.

5.4 Contracts, taxes and revenue

In the following, some characteristics of various contract and tax regimes are discussed in light of how they affect net present value (NPV) and internal rate of return (IRR).

The net present value of a project is the discounted future stream of net income conditional on the information set I_{t-1} , which includes the taxation system in force at time *t-1*.

Let $NPV = \sum_{s=t}^{\infty} (\frac{1}{1+r})^{s-t} (\pi_s)$, where r is the discount rate and π_s is the producer profit *net of taxes*.

The internal rate of return (IRR) is the discount rate for which the NPV is equal to zero. Below we compare the NPV and the IRR under different tax regimes. We consider a hypothetical 250 million barrels model field in seven countries with different fiscal terms, in order to isolate the effects of the fiscal regimes while ignoring other conditions being important as field size, success rates, relative costs etc. Exploration costs are not included. We assume that the tax and discount rates are constant over time. *The pre-tax economies are therefore the same* for each field in each regime with identical production profiles and costs.

It is assumed no ring-fencing and that the company has sufficiently taxable profits elsewhere to offset initial losses (which is not the case for a new entrant). Signature bonuses are disregarded, and we therefore underestimate the level of government take in countries where contracts are paid up front.

Before we present the results of the comparison between different tax regimes, we briefly look at the impact on the NPV of a change in the tax rules and oil price in a single year, assuming that the impact in one year is representative for the overall change in these factors.

License regime

With these assumptions we get the single year net income under the licensing regime from equation (8):

(8a) $$NPV = (1-\tau_G - \tau_N)pq - (1-\tau_N \beta_{INV})C^{INV} - (1-\tau_N \beta_{EXT})C(q, R_{-1})$$

This form of the equation highlights the net and gross tax burden associated with gross sales, capital costs and extraction costs. We are now interested in the effects of a change in net income tax rate and a change in oil price on net present value:

(8a') $$\frac{\partial NPV}{\partial \tau_N} = -pq + \beta C < 0$$ *and* (8a'') $$\frac{\partial NPV}{\partial p} = (1-\tau_G - \tau_N)q > 0$$

where C by simplification represents total costs and β is an average tax correction. When $\beta<1$ and the pre-tax profit is positive, we see that an increased net tax rate leads to a reduction in NPV that is larger (in absolute value) when the tax distortions are greater (β is smaller). An increase in tax distortions β_{INV} and β_{EXT} may be caused by a longer depreciation period, a smaller uplift on capital, and/or if less interest expenses are allowable and if a more stringent ring-fence system is introduced. From equation (8a'') we see that increased oil price leads to an increase in NPV. However, changes in the oil price have less effect on the NPV the higher the (gross or net) tax rate. Hence, in a high-tax regime the oil company will not lose much of the NPV from a reduction in oil price, and not gain so much from an oil-price increase.

Production sharing agreement (PSA)

Following the same assumptions as above, we get from equation (9) under the PSA-regime:

(9a) $$NPV = (1-\tau_N)(\beta_{CO} + \beta_{PO} - \beta_{PO}\beta_{CO})pq - (1-\tau_N \beta)C$$

(9a')

$$\frac{\partial NPV}{\partial \tau_N} = -pq(\beta_{CO} + \beta_{PO} - \beta_{PO}\beta_{CO}) + \beta C < 0 \quad and \quad (9a'')\frac{\partial NPV}{\partial p} = (1-\tau_N)(\beta_{CO} + \beta_{PO} - \beta_{PO}\beta_{CO})q > 0$$

Again, increasing the net tax rate leads to a smaller NPV and an increase in the oil price results in higher net present value as expected. The change in NPV from a change in the oil price is smaller the higher the tax rate and the lower the (share of) cost oil and profit oil.

License

Let us look at the general internal rate of return. When we derive the effects on the IRR we assume that there are only two periods, and that costs only accrue to the first period whereas revenue only accrues to the last period:

(8b) $$NPV = -(1-\tau_N \beta)C + \frac{(1-\tau_G - \tau_N)pq}{1+r^*}$$

where r^* is the rate of return (discount rate) which represents the IRR when the NPV is set equal to zero.

(8b') $$IRR = \frac{(1-\tau_G - \tau_N)pq}{(1-\tau_N \beta)C} - 1$$

We see that if $\beta=1$ and $\tau_G=0$, the net income tax has no effect on the internal rate of return. That is, if there is no royalty element and if immediate relief was available for the capital as well as operating costs there would be no difference between the post-tax and the pre-tax rate of return at the prevailing level of government take. The rate of return will not vary because in effect the company will invest only (*1- tax rate*) on a post-tax basis and receive (*1- tax rate*) of the profits.

The effect of changes in the taxes and the oil price on IRR is presented below.

License

(8b'') $\dfrac{\partial IRR}{\partial \tau_N} = \dfrac{pq[\beta(1-\tau_G)-1]}{C(1-\beta\tau_N)^2} \le 0$ and (8b''') $\dfrac{\partial IRR}{\partial p} = \dfrac{q[(1-\tau_G-\tau_N]}{C(1-\beta\tau_N)} > 0$ (assuming $\tau_N - \tau_G < 1$)

An increase in the tax rate results in lower IRR. If the oil price rises, the IRR increases. However, if $\beta<1$ changes in the rate of return from changes in the oil price are smaller with higher tax rates. Further,

(8b'''') $\dfrac{\partial IRR}{\partial \beta} = \dfrac{\tau_N(1-\tau_G-\tau_N)pq}{C(1-\beta\tau_N)^2} > 0$

Hence, reducing the tax distortions (higher β) by allowing more (immediate) relief of costs leads to increased IRR.

Production sharing agreement

When we study the effects on the IRR under the regime with PSA, we rewrite (8b) as:

(9b) $$NPV = -(1-\tau_N\beta)C + \frac{(1-\tau_N)(\beta_{CO}+\beta_{PO}-\beta_{CO}\beta_{PO})pq}{1+r^*}$$

and get

(9b') $$IRR = \frac{(1-\tau_N)(\beta_{CO}+\beta_{PO}-\beta_{CO}\beta_{PO})pq}{(1-\tau_N\beta)C} - 1$$

Changes in the net tax rate affect the IRR as follows:

(9b'') $\dfrac{\partial IRR}{\partial \tau_N} = \dfrac{pq(\beta_{CO}+\beta_{PO}-\beta_{CO}\beta_{PO})(\beta-1)}{(1-\beta\tau_N)^2 C} \le 0$ and (9b''') $\dfrac{\partial IRR}{\partial p} = \dfrac{(1-\tau_N)(\beta_{CO}+\beta_{PO}-\beta_{CO}\beta_{PO})q}{(1-\beta\tau_N)C} > 0$

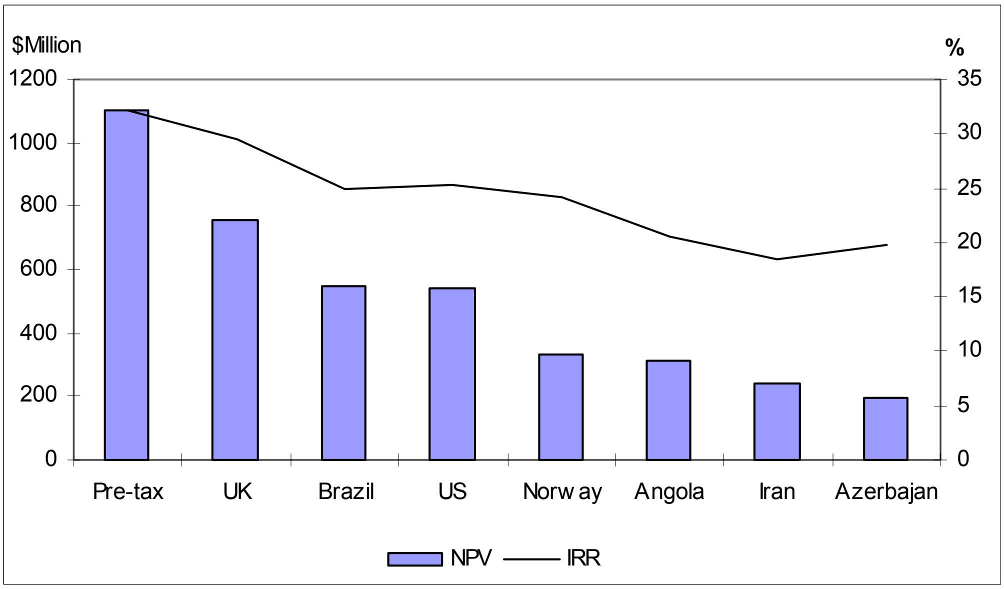
This is in accordance with the results above under licensing (equation 8b'' and 8b'''). In addition, changes in the rate of return from changes in the oil price are smaller the higher net tax rate and the lower the (share of) cost oil and profit oil.

(9b'''') $\dfrac{\partial IRR}{\partial \beta} = \dfrac{\tau_N(1-\tau_N)pq(\beta_{CO}+\beta_{PO}-\beta_{CO}\beta_{PO})}{(1-\beta\tau_N)^2 C} > 0$

Again, an increase in the distortions leads to lower IRR (as in 8b'''). Hence, any element of fiscal regime that acts to delay immediate relief for expenditure (smaller β) will reduce the IRR; as is the case with ring fencing and depreciation. The same effect has (front-loaded) non-profit related elements of government take have (as cost oil/signature bonuses/profit oil caps).

In figure 8 below we present calculated NPV and IRR in the model fields of seven different countries. The net present value (NPV) of the contractor's cash flow is calculated with a 10 percent discount rate. The internal rate of return (IRR) is calculated on the post-tax contractor's cash flow. Oil price is set to \$20 per barrel. Oil price rise and cost inflation are assumed to be 2,5 percent per year.

Figure 8. NPV and IRR of a 250 million barrels model oil field with oil price of \$20



UK has the highest NPV among the seven tax regimes (and this is true also at a low oil price of \$10 per barrel). This is due to the fact that the level of government take in the UK is as low as 30 percent (as of 2001) and is entirely profit related.

The US (Golf of Mexico) and Brazil have roughly similar NPVs (over low oil prices also) as they have comparable fiscal regimes with slightly higher royalty in the US being offset by a higher effective corporate income tax rate in Brazil. Total government take amounts to around 47 percent in Brazil and US.

Norway has a lower NPV than the former three regions due to the high level of government take (78 percent profit tax). As illustrated above a fall in the oil prices will have less effect on the total value of a project in a country with a high level of government take as the majority of the decrease will be absorbed by a reduction in the taxes. As a consequence, with a lower price of $10, Norway's NPV ranks as number three after UK and Iran.

The Angolan NPV is roughly equal to the Norwegian level. The net tax rate of Angola is lower than in Norway and the sum of the "cost oil" and "profit oil" is reasonably high with a relatively high oil price. In addition the NPV in Angola is somewhat higher than in Azerbaijan because of a higher cost and profit oil-share[1] (and through an uplift of 40 percent of the capital costs). With lower oil prices the NPV is lowest in Angola, because the sum of the cost and profit oil is higher in Angola than in Azerbaijan (although the distortions are lower and the net tax higher).

The Iranian NPV is relatively low because of the fixed remuneration fee as a percentage of the remuneration fee (investment budget). For the same reason the NPV is relatively high under the low oil price scenario (the second largest after UK). The Iranian NPV responds only moderately to changes in the oil price.

As for the effects on the IRR, the IRR in the UK shows the least change from the pre-tax level as shown in figure 8, because of a lack of ring fencing, no revenue based element of government take and the generally low government take.

We see from equation (8b') that with little distortions in the tax system, the size of the net tax is not so important in determining the IRR. This is the reason why Norway exhibits relatively high IRR. The distortions in the Norwegian fiscal regime are limited to the effects of depreciation and compared to in the UK these distortions are offset by a positive effect of the uplift on capital expenses. However, the distortions have a greater effect on the IRR because of the higher tax rate in Norway. Norway exhibits the same IRR as UK with low oil prices (again due to the higher tax rate). In 2002 the UK increased the corporate tax with 10 percent in the North Sea. After the tax increase, government take in the UK was estimated to 38 percent compared with 68 percent for the Norwegian continental shelf. However, the depreciation rules and lack of ring-fencing are somehow making the NCS more attractive, for investments as indicated by the higher presence of big companies in Norwegian areas. (Petroleum Economist, 2003d).

The US has similar IRR as Norway. Again there is no ring fencing so the main distortion in the fiscal regime, apart from the royalty payment, is introduced through depreciation.

[1] Cost and profit oil are calculated differently in the two countries.

The Brazilian IRR is at the level with Norway and US. The Brazilian tax system is similar to the US regime.

Angola and Azerbaijan have similar IRR and the main distortion in the tax-regimes is the system of ring fencing, besides the upfront government takes through cost and profit oil. The IRR is lowest in Angola with a low oil price of $10. This is due to the higher share of cost and profit oil in Angola (even if the distortions are smaller and the net tax rate is higher) The IRR in Iran is relatively unchanged over different oil prices. This reflects the fact that the contractor's remuneration is a fixed percentage of the investment budget and the cost cap. The IRR neither increases a lot with higher price, nor declines much due to lower prices.

It should be stressed that the impact of the tax regime alone does not motivate an investment. *Exploration success rates, costs and average field size* will also have considerable impact on a company's investment decisions. In the calculations carried out here, we have disregarded that there are different fiscal rules for covering of the exploration expenditures.

Tables A1-A5 provides some more details about tax elements and the tax systems of the US, Angola, Iran, and the UK. Appendix B indicates tax rates averaged across countries.

6. Final Comments

This paper gathers some of the less stringent information about the petroleum industry - a kind of "back to office" report after visiting various petroleum related journals, available research and reports of various kinds. Research in this area does not abound in the open. There seems to be high barriers of entry to open research on the petroleum industry, as a considerable share of data and research are at private hands and only available at high costs. Most academic institutions and non-commercial research institutes generally have no access to all basic data of relevance.

The petroleum industry contains companies that are overwhelmingly large and powerful. As a consequence they behave strategically in most contexts, also in the field of data and research. Petroleum companies have resources to purchase the information that they want, so have many resource owning governments, and their willingness to share the information is limited. It is somewhat uncomfortable to observe that much of the analytical work carried out upon paid request cannot be tested in the open. In research it is fundamental that methods and results can be controlled and repeated. Rather, much of the information flow surrounding the petroleum industry more resembles "rules of thumb" than statistically and methodically qualified research. When information producing consultancy firms present their studies the information comes in bits and pieces - sufficient to encourage commercial demand, but insufficient as genuine public information.

This situation raises two important questions. One is the question about quality of research that is not under peer review by independent researchers, research that is heavily relied upon by companies and resource owning governments. Another is if it is well considered by the Norwegian government to limit public funding for social science petroleum research to only a minor fraction of basic data costs.

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Appendix A

Rights and responsibilities in contracts between resource owner and petroleum company frequently included in the contracts (see also table A1):

Duration

1) Reconnaissance

Non-exclusive right to conduct geological/geophysical surface work (entailing only shallow drilling) and of short duration (1-2 years).

2) Exploration

Exclusive right to explore and drill for oil (usually 3-10 years, and may be renewed or extended if oil is found and if various other obligations are met).

Considerable variation in the obligations to relinquish (a certain portion of) the exploration area within stated time limits.

3) Exploitation

Long-term right to extract oil (usually 20-30 years)

Cash bonuses

1) Signature bonus

Payable upon signing of the agreement with the government.

2) Discovery bonus

Payable when a commercial discovery is made.

3) Production bonus

Payable as an agreed amount upon the achievement of a stated level of production.

4) Bid bonuses

The winner of an auction pays the amount that was offered (first- or second-price, sealed- or open-bid auction). The setting up of the auction is crucial in determining the actual (expected) result. The bid in an auction is sometimes referred to as a signature bonus.

Royalty

The royalty is stated as a certain percentage of the production or the production (well-head) value, and the government often has the option to take the royalty in cash. Different systems are applied:

1) Sliding scale system

The royalty increases in steps in accordance with certain stated levels of production.

2) Onshore-/offshore systems
3) Water depths-/distance from shore systems.
4) Oil quality systems

Following the oil price crash in 1986 many countries reduced or eliminated the royalty.

Cost recovery in PSA

The contractor bears all the costs and these are recovered out of a percentage of production. The first 20-50 percent of the production may go to the contractor to cover costs. The part of the production that is used for cost recovery is called "cost oil".

Production split in PSA

Following the deduction of the cost recovery, the production is divided between the oil company and the state. The available amount of production, called "profit oil", which is what remains of the production after deduction of the "cost oil", is shared between the NOC and the contractor. Sometimes a higher post-tax return will give a lower share of profit oil. A higher share of production may also increase the income tax. (Seems that in the late 1990s, when oil prices were low, the PSC would give the IOC larger volumes, but as oil price started to rise from 1999 - this would entail relatively smaller volumes for the IOC.)

Income tax

The income tax may be
1) A general corporate tax
2) A special petroleum tax rate (In 1992 OPEC countries had a uniform petroleum income tax rate of 85 percent, in 2004 Norway has a corporate income tax rate of 28 percent and a special petroleum tax rate of 50 percent) or
-or a Petroleum Revenue Tax (on older fields in UK)
-or a Resource Rent Tax (Australia).

3) Tax paid by government
Used in the PSC where the government imposes a tax and then pays the tax on the contractor’s behalf. For this the government receives a higher share of production. The contractor receives a tax receipt which he can present to his home country and receive a tax credit. In general, an oil company will be able to get a tax credit in its home country for taxes paid abroad (but not for royalty paid).

4) Tax bid (profit share) in auctions

Ring face system and capital allowances

Different "ring-faced" systems may be implemented to prevent that costs from one block is deducted from another block (and is often applied in PSC). The aim may also be to prevent that costs from other activities, e.g. refining and marketing, is deducted from production costs of all fields/upstream activity.

Capital allowances in the form of depreciation and amortisation is granted at different rates in various countries. Typically, the write-off period for fixed assets seems to be in the range of six to ten years, although in some countries assets may be written off the year in which they are required.

State participation/Joint venture

May accompany both licenses and PSC, and is a partnership between the oil company and another company (which frequently is the government company) by which they agree to jointly operate the venture.

Under some concessions or contractual agreements the state or the national company will have its influence through its representation in a joint management committee. In a joint venture arrangement where the national oil company has agreed to put up some share of the investment costs, it will normally be expected that it has a vote in the management committee, which is at least commensurate with its share in the joint venture's costs. Frequently the government only participates after discovery, thus transferring exploration risk to the oil company. The corporate profits after taxes are divided between the oil company and the government.

In 2001 Nigeria has licenses for most of its producing companies, production sharing for one and joint venture in most through 60 percent government participation.

Various other obligations:

1) Work program

An obligatory work program will require a minimum investment level in the exploratory period, as the amount invested or wells drilled or the number of seismic lines performed within a specified time limit.

2) Conservation obligation

Through legislation or agreements the government regulate production based on sound conservation principles.

3) Environmental obligations

The government want to avoid pollution, impose restrictions on gas flaring, remittance of platforms and production facilities.

4) Crude oil marketing

The oil company may be obliged to purchase the state's share of the production, based on clearly defined terms. This type of obligation may be valuable for oil companies that are anxious to obtain crude oil for their marketing systems.

5) Title to assets.

If the oil company owns the production facilities, agreements may provide that the ownership of these assets will revert to the state on expiry of the contract/license.

6) Guarantees of performance

The oil company must guarantee its performance, e.g. through a bank guarantee or an unconditional guarantee from the parent company.

7) Domestic demand

Requirement for the oil company to supply some of the demand in host country (In 1992 Indonesia had a requirement that crude oil for national needs be supplied.)

8) Refining obligation

A requirement that the oil company must establish a refinery or other plants to process petroleum.

9) Preference for the use of domestic goods and services

Legislation may oblige the oil company to purchase domestically produced goods and services.

10) Training programs

Some licenses and contracts contain provisions obliging the oil companies to provide training of nationals of the host country.

11) Transfers of technology

A certain share of the research and development work, which is needed to bring an offshore field into production, must be carried out in the host country.

12) Negotiable fiscal terms

13) Other

- a) Employee health and safety provisions
- b) Procedures for the settlement of disputes

Table A1. General features of a tax regime

Petroleum Arrangement	Cash bonuses 1) Signature 2) Discovery 3) Production 4) Bonus bid in auctions (sometimes referred to as signature bonus)	Royalties (Gross) 1) Sliding scaled 2) Off-/on-shore 3) Water depths 4) Oil quality 5) Royalty bid in auctions	Cost recovery	Prod. Split (state vs. int. oil company)	Net Income tax (field or comp. based) 1) Corporate tax 2) Special petroleum tax/ Petroleum Revenue Tax/ Resource Rent Tax 3) Tax bid (profit share) in auctions	Tax Distortions Ring fence system of deductible costs Capital allowances	State participation Joint venture (and joint management committee)	Various other obligations: 1) Work program 2) Conservation conditions 3) Environmental conditions 4) Crude oil marketing 5) Title to assets 6) Guarantees of performance 7) Domestic demand 8)Refining obligations 9) Preference for the use of domestic goods and services 10) Training 11) Transfers of technology 12) Negotiable fiscal terms 13) Duration
License-Discretionary	x (1+2+3)	x (1+2+3+4)	0	0	x (1+2)	x	x	x
License-Auction	x (4)	x (1-5)	0	0	x (1+2 +3)	x	x	x
Production Sharing Contract	x (1+2+3)	rarely	x	x	x (1+2)	x often ring-fencing	x	x
Service Contract	?	0	x	No oil, but a flat fee for services (some contries may involve a risk-fee)	x (1)	x	x	x

Note: x = relevant for the corresponding petroleum arrangement in the left column, 0 = not relevant

Table A2. Tax regime in the US

UNITED STATES **Mexican Gulf** Petroleum Arrangement	Duration 1) Reconnaissance 2) Exploration (With relinquishment obligations) 3) Exploitation	Cash bonuses 1) Signature 2) Discovery 3) Production 4) Bonus bid in auctions (sometimes referred to as signature bonus)	Royalties (Gross) 1) Sliding scaled 2) Off-/on-shore 3) Water depths 4) Oil quality 5) Royalty bid in auctions	Other fees and taxes	Net Income tax (Field or company based) 1) Corporate tax 2) Special petroleum tax/ Petroleum Revenue Tax/ Resource Rent Tax 3) Tax paid by host in PSC 4) Tax bid (profit share) in auctions	Ring fence system of deductible costs Capital allowances	State participation Joint venture (and joint management committee)	Various other obligations:
Auction of licenses		4)	3) Field based royalty on well-head value; 12,5% for over 400m, 16,67% for less than 400m (as from nov. 1995 are fields deeper than 200m for specified prod. levels and water depths exempt from royalty)	After the Exxon Valdez disaster a small Environ-mental Tax was introduced	Company based Federal 1): 35%	No ring fence system for upstream activity. Ordinary costs can be deducted from the tax base for Corporate Tax: Operating costs, depreciated capital costs, royalty payments and interest expenses.	No direct or indirect state activity through state oil companies	Bonus bid is the only condition that can be affected by the company

Table A3. Tax regime in Angola

ANGOLA Petroleum arrangement	Duration 1)Reconnais-sance 2)Exploration (with relinquishment obligations) 3)Exploitation	Cash bonuses 1)Signature 2)Discovery 3)Production 4) Bonus bid in auctions (sometimes referred to as signature bonus)	Royalties (Gross) 1) Sliding scaled 2)Off-/on-shore 3)Water depths 4)Oil quality 5) Royalty bid in auctions	Cost recovery	Prod. Split (state vs. int. oil company-IOC)	Net Income tax (field or comp. based) 1) Corporate tax 2) Special petroleum tax/ Petroleum Revenue Tax/ Resource Rent Tax 3) Tax paid by host 4) Tax bid (profit share) in auctions	Ring fence system of deductible costs Capital allowances	State participation Joint venture (and joint management committee)	Various other obligations:
Production Sharing Contract (PSC): A) For depths over 200m (the conditions are as for all offshore contracts after 1991)		1) Signature bonus (can have significant effect on the economy of a project)		"Cost oil" limited to 50% of the production (as high as 55% for some deepwater blocks). Costs that are not covered in one year can be carried forward for recovery in later years (without interest compensation). If costs are less than the maximum available cost recovery in any year, any unused balance is added to profit oil (and divided according to the relevant production splits). (cost of abandonment are recoverable after certain rules)	The rest of the oil is "profit oil". The take of the state is higher when the IRR increases (IOC gets 75% when IRR is less than 15%, if IRR is less than 30% the IOC gets 45%). The Internal Rate of Return (IRR) is estimated from the cash flow after tax exclusive of exploration costs. (Cash Flow=cost oil +profit oil -petroleum income tax -development and operating costs (but not exploration expenditure; only expenditure after the date of commercial discovery is included)	2) 50% Petroleum Income Tax on the profit from extraction (in effect it is levied on the contractor's share of profit oil)	Ring fence system for fields. Costs deductible through cost oil are investment and operating costs and in addition exploration and adm. costs connected to the specific PSC-area (exploration costs that are not commercial are not deductible). Interest and petroleum tax are not deductible through the cost oil. Sign. bonus can neither be deducted through cost oil or in the basis for petroleum taxation. An uplift of 40% is applied to development (capital) costs for cost recovery purposes, and is recoverable in equal instalments over 4 years.	Usually an implicit state (Sonangol) participation of 20% in each license (supported by the other companies through the exploration phase, but repaid with interest)	12) The relation between IRR and profit oil and the size of the signature bonus is negotiable (biddable items when applying for a contract).
B) For depths less than 200m (as of 1979) -differences from deep water contracts				If oil price exceeds a price cap then the contractor pay an excess fee (in practise almost not implemented prior to May 1999)	Production split vary with cumulative production in the development area		Exploration costs are partly recoverable through cost oil		

Discretionary licensing Onshore, post-January 1982 terms			Royalty of 20%			Petroleum Transaction Tax (PTT) of 70% (determined in the same manner as corporate tax except that royalty and interest are not deducted) + Petroleum Revenue Tax (PRT) of 65,75% of final profit	Investment allowance (uplift) of 50% on amounts invested and capitalized each year, Production allowance of $4 per boe in 1982 escalating at 7% per year thereafter; PRT is gross annual income minus depreciated exploration costs, depreciated operating costs, depreciated capital costs, royalty payments, PTT and surface rental charges		

Table A4. Tax regime in Iran

IRAN Petroleum Arrangement	Duration 1) Reconnais-sance 2) Exploration (With relinquishment obligations) 3) Exploitation	Cash bonuses 1) Signature 2) Discovery 3) Production 4) Bonus bid in auctions (sometimes referred to as signature bonus)	Royalties (Gross) 1) Sliding scaled 2) Off-/on-shore 3) Water depths 4) Oil quality 5) Royalty bid in auctions	Costs and payment conditions	Ring fence system of deductible costs Capital allowances	State participation Joint venture (and joint management committee)	Various other obligations:
Service Contract (as from 1995, called buy-back contracts in Iran) The contactor agrees to undertake a specified field development programme, and a specified inv. budget (for exploration and development) is negotiated				Within the specified budget the costs of the IOC is covered + a remuneration fee based on a percentage of the inv. budget (The remuneration fee usually seem to be in the region of 35-70% of the capital costs; the nominal IRR is usually 15-20%, although early contracts could be in excess of 20%). The cost is recovered and fee paid over a certain time period (e.g. 5 years) and is paid to the company on a monthly basis from the start of the prod. period. Usually around 30% of the oil is "priority oil" which the state will take before the company will be paid; but payment that is not covered by the remaining 70% will be carried forward and covered in the next period with interest compensation (but the share of priority oil can be negotiated if e.g. the oil prices are low). Costs not specified must be covered by the contractor (can be sanctioned by the NIOC if a change in e.g. field characteristics). If costs are lower than specified the remuneration fee will not be reduced (but inv. costs will be based on the new budget).	Income and costs are limited to each project	The National Iranian Oil Company (NIOC) has effective control over the whole project. When the development is finished, the operator command is transferred to the NIOC.	12) Inv. budget, remuneration fee and the period over which they are amortised are all open for negotiation.

Table A5. Tax regime in the UK

UNITED KINGDOM Petroleum Arrangement	Duration 1) Reconnais-sance 2) Exploration (With relinquishment obligations) 3) Exploitation	Cash bonuses 1) Signature 2) Discovery 3) Production 4) Bonus bid in auctions (sometimes referred to as signature bonus)	Royalties (Gross) 1) Sliding scaled 2) Off-/on-shore 3) Water depths 4) Oil quality 5) Royalty bid in auctions	Other fees and taxes	Net Income tax (Field or company based) 1) Corporate tax 2) Special petroleum tax/ Petroleum Revenue Tax/ Resource Rent Tax 3) Tax paid by host in PSC 4) Tax bid (profit share) in auctions	Ring fence system of deductible costs Capital allowances	State participation Joint venture (And joint management committee)	Various other obligations:
Discretionary licensing: New fields (after March 1993)					Company based 1): 30% for new fields (up to 1997:33%, 1997: 31%, 1998:30%) Production Revenue Tax (PRT) removed for new fields as from march 1993.	No ring fence system for upstream activity within the company (losses outside the upstream sector cannot be offset against upstream profits- expenses can be consolidated against other extraction income.) Ordinary costs can be deducted from the tax base for Corporate tax: Operating costs, depreciated capital costs (25% of a declining balance) and interests expenses (+any royalty and PRT). Losses can be brought forward from previous years (if not in a tax-paying position). There is an uplift of 35% on capital expenditure.	No direct or indirect state activity through a state oil companies	1) Work program, e.g. wells drilled 12) None of the fiscal terms is negotiable
Older fields (up to March 1993)			Some older fields prior to April 1982 in addition pay a 12,5% royalty (of the landed value less an allowance for the cost of transportation and processing)		Company based I) + Field based PRT of 50% which is estimated from assessable profits	Ring fence system for fields with PRT where only field-based costs are deductible, in addition to ordinary costs above are an oil allowance based on production volume, but interest is not deductible. The system with allowances for expenses on exploration against the PRT was removed in March 1993 *(the rules for both taxes and field-deductible costs have changed considerably over the years)*		

Appendix B

Table B1. Tax rates by region (average across countries[1]). Percent

Region	Production mb/d	Gross tax	Net tax
OPEC-CORE	22,5	35	40
REST-OPEC	5,5	35	40
LA	7,25	12,5	35
CHINA	3,23		
REST-ASIA	4,46	8	62
RUSSIA/UKRAINE/BELARUS	6,5		50
CASPIAN REG.	7,92	30	50
WESTERN EUR.	6,38		60
AFRICA	0,81	12	60
CANADA	2,74	4	50
USA	8,11	15	35
OECD-PACIFIC	0,84	15	45
EASTERN EUR.	0,18		60

[1] The figures must be seen as average levels over countries with different tax regimes, weighted with production. The figures are based on accurate information for most countries and on assumptions for others. For example, the tax system in Western Europe is dominated by UK and Norway where only net taxes are used. As UK only has a net tax of 30 percent (on fields after 1993; see appendix B) and Norway has a net tax of 78 percent, a production-weighted average leads to a tax rate of around 60 percent in this region.

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