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Trends and trade-offs in petroleum tax design[1]

by

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Abstract

How should tax systems be designed to account for the characteristics of the government, the oil companies and the projects in order to maximise welfare for the country's inhabitants? How should vital government characteristics reflected in parameters such as impatience to obtain tax revenue – the discount rate – and the willingness and ability to carry risk be accounted for in tax design? These basic issues in petroleum tax design are discussed by means of a tax model for a discretionary licensing regime (Norway) and a production sharing agreement regime (Angola). The analysis covers the entire life cycle of a typical petroleum project, i.e., including the exploration decision. We discuss the trade-off between progressivity on the one hand and the incentive for the oil companies and the host government to carry risk and investment on the

[1] We would like to express our thanks for rewarding conversations with and comments on the article itself from a number of key specialists in the oil sector and academia, in particular Flemming Helgeland, Michael Keen, Per Kårstad, Morten Lindbäck, and Knut Einar Rosendahl. We are grateful for constructive comments from the editor and the referees. We are also thankful for comments and suggestions at *IMF Resource Tax Conference*,Washington D.C., September 25, 2008, and at the 20th International Petroleum Tax Conference, Oslo, October 4., 2009. Osmundsen is grateful to Norwegian Research Council for funding. Address for correspondence: Petter Osmundsen, Department of industrial economics and risk management, University of Stavanger, NO-4036 Stavanger, Norway. Tel: +47 51 83 15 68. Mobile: +47 99 62 51 43. E-mail: Petter.Osmundsen@uis.no. Home page: WWW.UiS.no/Osmundsen

other. Thus, we provide basic elements in a state contingent tax design. The paper also surveys trends in petroleum taxation, and discusses how tax elements vary over the business cycle.

Keywords: taxation; petroleum; PSA; discretionary licensing regime

1. Introduction

Much variation exists in petroleum tax systems. The purpose of this paper is to analyse such variation by identifying basic drivers for differences in tax design. Relevant factors are the ability and willingness of oil companies versus government to carry risk and how far the government needs revenue immediately (i.e., has a high discount rate). To obtain a high level of government revenue, tax design has to accommodate vital differences between governments, oil companies and projects. This design is important to the inhabitants of the resource countries, since it will generate a higher level of welfare. An optimised tax design may also benefit the oil companies, since such a tax system will be more predictable and less prone to changes once investments have been sunk.[2]

Tax theory generates recommendations for optimum design of revenue instruments, e.g., the resource rent tax. However, most observed tax systems deviate from theoretical recommendations, and vary a great deal. Our working hypothesis is that this variation reflects different characteristics of projects, host governments and international oil companies (IOCs), and that the number of relevant parameters is larger than the ones accommodated in traditional tax analysis. By simple project analysis of the features of discretionary licensing contra production sharing agreement (PSA) regimes, we attempt to illuminate these additional

[2] Kydland and Prescott (1977) and Osmundsen (2010).

parameters. We also make careful attempts to indicate optimum state contingent tax design. To make this comparison relevant, we analyse two particular tax systems – the Norwegian discretionary licensing regime and the PSA regime for deepwater Angola. We believe that these two systems are representative for the general features of petroleum tax systems inside and outside the OECD area. Our objective is not to make a detailed comparison of the Norwegian and the Angolan petroleum tax systems, but rather to illustrate and compare – through a particular case – the qualitative features of these two major classes of such systems.

Many tax analyses consider exploration expenses to be a sunk cost, and focus only on the development and production stages. To achieve sustainable operation, however, an oil company needs to consider the entire life cycle of the projects it enters into. Accordingly, we undertake an expected monetary value (EMV) analysis, i.e., we include the exploration decision. EMV is the expected net present value (NPV) of a life-cycle oil project, including exploration expenses.

Our focus is on trends and practical issues in the design of petroleum taxation. For more theoretical and general approaches to the taxation of non-renewable natural resources, see Daniel et al (2010) and Lund (2009).

Optimum tax theory and principal/agent theory make it possible to develop optimum tax systems and regulatory regimes by maximising a social welfare function subject to constraints.[3] An insight from the analysis in this article, allowing for more constraints, is that no *one* optimum tax system exists. Rather, optimum tax design is state contingent. It needs to be customised to the parties involved. Which is the more risk averse – the government or the oil companies? Which is able and willing to carry downside risk? Which is able to wait for revenue? The design of the tax system must also be adjusted to the prospectivity of the projects to hand – a high effective tax rate is only appropriate for highly prospective projects. Optimum risk sharing and allocation of cash flow over the project lifetime between host government and IOC often call for the latter to

[3] Osmundsen (2005) and Lund (2009).

fund the initial investment. The high front-end loading of costs and the high level of risk borne by the IOC require it to retain a substantial part of the upside if the project is successful. That limits the degree of progressivity which can be achieved.

The remainder of this paper is organised as follows. The analytical framework for the tax analysis is introduced in section 2. Section 3 discusses trends in petroleum taxation. Sections 4 and 5 present the two tax systems to be analysed in detail – the Norwegian and Angolan fiscal regimes. The tax analysis is presented in section 6 and results are provided in section 7. Section 8 concludes.

2. Analytical framework

The design of petroleum taxation can be illustrated by principal/agent theory.[4] Petroleum deposits are in many cases a common resource whose ownership is shared by all inhabitants. Accordingly, the government's main objective is to maximise its net total take from the industry, i.e., the sum of corporate tax, royalties, dividends and so forth, and to use this revenue for public expenditure and investments.[5] An optimum division of labour implies the participation of private companies in petroleum extraction. On behalf of the inhabitants, the government acts as a principal and gives such private companies (agents) the extraction right through a discretionary licensing system. In return, the private companies pay taxes. An ideal tax and licensing system captures the petroleum rent, attracts the most efficient companies, and ensures that all socially profitable fields are exploited efficiently. An optimum regulatory system also shares the risk optimally between the government and the petroleum companies.

A basic insight from principal/agent theory is that no one universal optimum contract or tax system exists. Instead, contracts must be tailored to the position of the contracting parties and the

[4] See, e.g., Laffont (1989) for a general exposition of principal/agent theory, and Osmundsen (1998, 2002) for applications to exhaustible natural resources.
[5] The government may also seek to increase the number of local jobs and enhance local investment.

transaction. A state contingent tax policy can thereby be derived. Where the transaction is concerned, relevant characteristics for petroleum deposits are the prospectivity (economic attractiveness) of a given field and geological area, the oil price, the state of the business cycle, and the presence of adequate infrastructure and competent suppliers. As for the contracting parties – host governments and oil companies – relevant characteristics are the ability and willingness to carry risk, and the degree of impatience for revenue (reflected in the discount rate).

In this paper, we analyse two principal tax systems in the petroleum sector – discretionary licensing regimes and PSAs – in order to generate indications of the kinds of circumstances (characteristics of petroleum deposits and contracting parties) under which they are useful.

Other fiscal regimes available in the petroleum sector, e.g., for developments on land and for service contracts, are not addressed in this paper. However, these can still involve either discretionary licensing or PSAs. Comparing discretionary licensing and PSAs is interesting because risk sharing and the timing of revenue are often perceived to differ substantially between them. However, that is not necessarily true, especially where the timing of revenue is concerned.[6]

3. Trends in petroleum taxation

One trend which makes comparison of tax systems over time challenging should be noted – fiscal elements are becoming much more sophisticated. Oil tax systems need to cope with fluctuations in the oil price, for example. In 2008, the oil price (Brent Platts dated) varied between USD 37 and USD 144 per barrel. Access to acreage for IOCs and petroleum taxation

6 However, everything depends on the terms and design of the fiscal regime. See Baunsgaard (2001), Bindemann (2009) and Duval et al (2009).

are changing with the oil price. We can view this as the outcome of varying bargaining positions between host governments and IOCs. When oil prices are high, host governments have a strong bargaining position. Their finances are sound, so they can afford to be more patient. They can ration available acreage and give priority to national oil companies (NOCs). They are also in a position to increase taxes, since a number of IOCs are eager to compete for the limited acreage available. The opposite prevails when oil prices fall. Host governments – if they have not developed a buffer fund – are in a weak financial position, unable to finance large investments by NOCs, and dependent on IOC spending. At the same time, IOCs typically cut back on their investment budgets. To attract sufficient investment, host governments therefore increase available acreage and cut taxes.

In the following description of petroleum tax system developments, we benefit from Van Meurs (2008) and Johnston (2008). Three phases have occurred in petroleum taxation since 1974, where general tax trends (though not without exceptions) follow the development of the oil price:

1974-1984

- Sharp increases in government take
    - high oil prices
    - tax increases
    - reduction of acreage.

The sharp increase in oil prices in this period put host governments in a strong fiscal position and consequently gave them a strong bargaining position towards IOCs. This shift in relative bargaining power led to tax rises and a reduction in available acreage for IOCs, e.g., through nationalisations.

1984-2003

- Decreases in government take
    - low oil prices
    - tax reductions
    - expansion of acreage.

As a response to falling oil prices and a reduced take, many host governments (e.g., Canada, the UK, Malaysia, Algeria and Egypt) made new acreage available in this period. The role of NOCs also changed significantly. More of them (Azerbaijan, Mexico and Iran) began to enter into contracts with IOCs. Some NOCs lost their monopoly, and governments (Brazil, Argentina, Saudi Arabia and Bolivia) dealt directly with IOCs through licensing. Carried interest provisions for NOCs were reduced or eliminated (Norway, the Netherlands and Colombia)

2003-2008

- Increases in government take
    - increase in oil prices
    - tax increases
    - no new acreage.

Prices were rising and government take was increasing. This occurred along several different paths. Progressive elements in some systems generated an automatic upward adjustment (Angola, Malaysia, Trinidad and Tobago, Russia and India).[7] Host governments introduced stricter fiscal terms (the UK, Alaska, Alberta, Algeria, Bolivia and Kazakhstan). Government take was increased by the oil companies themselves in bid rounds (Libya and India). Greater state participation was also seen, directly by the state (Venezuela and Algeria) or through NOCs (Russia with Gazprom).

A topical issue pertaining to long-term trends in the petroleum sector is whether private petroleum companies may gain access to large resources through political change, e.g., in the Middle East, and whether service contracts will be replaced by discretionaly licencing or production sharing arrangements.. Will we also see an extension to the current trend of re-nationalisation (Venezuela, Bolivia, Russia and Algeria)? As noted above, oil price developments are likely to be decisive is these matters.

[7] Although taxes may increase with higher oil prices, the relevant tax system is not necessarily progressive. Progressivity is defined as a tax system where tax rates increase as a fraction of revenue when income increases.

Political pressure for transparency might support a trend towards simplification of conditions – less diverse fiscal terms, standardisation of PSAs, and more legislation at the expense of negotiation.

We also see indications of trends in the direction of differentiated taxation for various petroleum grades. We already see that, in order to stimulate gas production, tax terms for gas are often more favourable than for oil.[8] In the same manner, we may see preferential tax conditions for LNG, gas to liquid (GTL), heavy oils, oil sands, oil shales, coal bed methane, gas hydrates, frontier areas, deep water and enhanced oil recovery. These tax differentials are likely to reflect the difference in resource rent. The latter is highest for oil.

Great attention has been paid lately to sluggish development of petroleum reserves. Such development depends not only on the change in licensed acreage but also on technological progress. We see many technological advances. Accessible acreage has been extended to water depths of 2 000 metres. Improved pipeline technology is opening up inland and Arctic basins (Bolivia, Siberia, Sudan and Alaska), and improved LNG technology is contributing to a globalisation of the gas market.

As a preliminary introduction to our project analysis, we first describe the two particular tax systems under analysis – the Norwegian discretionary licensing regime and the PSA regime used in Angola for deepwater projects. Norway and Angola have been chosen because they represent polar cases in terms of risk sharing between IOCs and host government. With the 2004 rules for a direct tax refund of 78 per cent of exploration expenses and a petroleum tax system without a ring fence, the Norwegian government is carrying an exceptionally high level of risk. The Angolan government carries much less risk, as is common for PSA regimes. Large Angolan signature bonuses from auctions on top of the PSA regime imply that IOCs are carrying a very high level of risk. Another feature of the Norwegian and Angolan regimes which makes them

[8] In some contracts in Malaysia, for instance, the cost oil limit is 50 per cent for oil and 60 per cent for gas. In order to be able to calculate cost oil and cost gas separately, a cost allocation procedure has to be established – usually based on gross revenue from each source.

interesting for analysis is that they are among the very few systems to remain stable despite substantial oil price increases.

4. The Norwegian petroleum tax system[9]

Norway has a discretionary licensing system. The government receives a large share of the value created through

- taxation of oil and gas activities
- direct ownership in fields on the Norwegian continental shelf (NCS) through the State's Direct Financial Interest (SDFI)
- dividends from its shareholdings in Statoil.

Petroleum taxation is based on the Norwegian rules for ordinary corporation tax. Petroleum resources are scarce, generating a resource rent for inframarginal deposits. Owing to the profitability associated with producing petroleum resources, a special tax is also levied on income from these activities. The corporate tax rate is the same 28 per cent levied for land-based activities, while the additional special tax rate is 50 per cent. When calculating taxable income for both ordinary and special taxes, an investment is subject to depreciation on a straight line basis over six years from the date it was made. Companies may deduct all relevant expenses for exploration, research and development, net finance, operation, decommissioning and so forth. Consolidation between fields is permitted.

In order to shield normal return from the special tax, an extra deduction – the uplift – is allowed in the calculation base for special tax. This amounts to 30 per cent of investment (7.5 per cent per annum for four years from the year the investment was made). Companies which are not in a tax position may carry forward, with interest, their losses on development and operations as well as the uplift. Losses can also be sold as a tax position to other companies with offshore

[9] This section is based on the *Facts 2010* publication from the government. For a detailed analysis of the Norwegian petroleum tax system, see Bjerkedal and Johnsen (2005) and Lund (2002).

income. Oil companies receive a refund of the fiscal value of exploration costs. Thus, the Norwegian petroleum tax system is close to being linear, i.e., it is neither progressive nor regressive – the same effective tax rate applies to all companies.

The petroleum tax system has been designed to provide neutrality, so that an investment project profitable for an investor before tax will remain profitable after tax. Neutrality is achieved by imposing an uplift, which ensures that the government carries the same fraction of costs as it captures of revenue. Neutrality makes it possible to harmonise the desire to secure significant revenues for the community with the requirement to provide sufficient post-tax profitability for the companies.

5. The Angolan PSA/NIC deepwater regime

PSA regimes are often hybrid revenue schemes, which contain PSA elements, a corporate income tax, and frequently additional revenue instruments. We analyse a fairly simple hybrid production sharing/net income tax (PSA/NIC) regime containing standard elements, including a rate of return (ROR) scheme which we believe will become more common. Our analysis does not include contractual and fiscal elements such as bidding and carried interest. We would emphasise that PSA schemes vary from contract to contract, and are confidential.[10] Our analysis must accordingly not be interpreted as a detailed analysis of a specific Angolan PSA contract, but rather as a system analysis of the general patterns inherent in these agreements. Our objective is not to make a detailed comparison of the Norwegian and Angolan petroleum tax systems, but rather to illustrate and compare – through a particular case – the qualitative features of these two major classes of petroleum tax systems.

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[10] But model agreements often exist.

The specific Angolan PSA/NIC scheme we analyse has the following features: the main elements are cost recovery for the IOC, a profit split of the oil not used for cost recovery, and a tax on profit from oil for the IOC. Cost recovery is limited in two ways. First, only 50 per cent of the oil produced can be used for cost recovery[11] and, second, the capital expenditure (Capex) must be depreciated over four years from production start. But a high uplift of 10 per cent in four years is also provided, which gives a 140 per cent cost recovery of Capex. Capex is recovered first, then operating costs. In this PSA/NIC scheme, the IOCs cover all initial investment and this is only recovered when the project begins to generate income. Taxation is project-based. The Norwegian system does not feature this ring-fence system for individual projects, either for corporate income tax or the special tax. Thus, initial investments are – through tax depreciation and uplift – partly and immediately covered through the net income received by IOCs from other fields on the NCS.

The oil not used to recover cost is split between the IOC and the government (represented by an NOC) on the basis of a sliding scale related to the return on invested capital for the IOC. This ROR is calculated on the cash flow for the IOC in the years leading up to the profit split. The sliding scale we use is shown in the table below.[12]

ROR	IOC profit oil share
0-10%	80%
10-20%	70%
20-30%	60%
30-50%	30%
Above 50%	15%

[11] In many PSAs, the fraction of cost oil can vary on the basis of predefined triggers in the contract. If a project has not covered its year zero costs by year four, for example, the cost fraction in year five increases above 50 per cent until all costs from year zero are covered.

[12] Examples exist where the investors' share of profit oil could be as low as 10 per cent.

The IOC is thereafter taxed at 50 per cent on the profit oil it receives.

Many PSA regimes will also include other elements, such as up-front payments in the form of either a bid for the licence or bonus payments to the government, royalty as a gross take on total production and payable before cost recovery, carrying the national oil company in the exploration phase, part of the production to be sold domestically at a low price, and a price cap on possible profit oil income. These additional tax features shift more risk to the IOC and reinforce the front-end loading of IOC investments. Since many of these elements can also be found in discretionary licensing systems, they are not exclusive to PSAs.

We now turn to describing the model project we will use in our project analysis.

6. Tax analysis

The two tax systems – Norwegian and Angola – are applied to the same oil project. We use a standard type of petroleum project, with the following details.

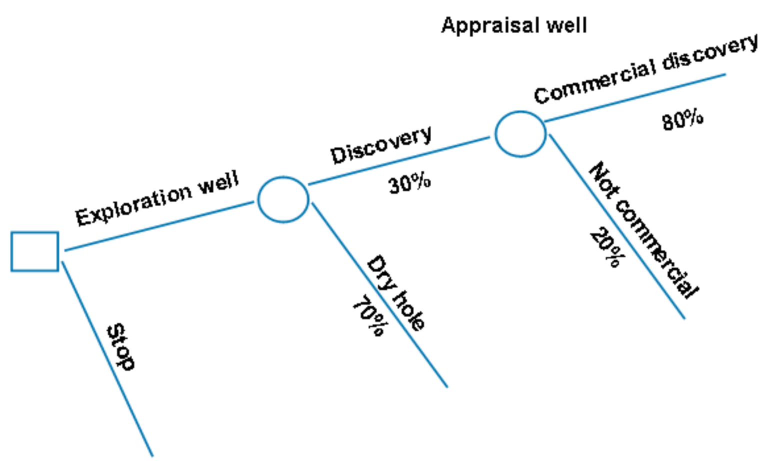

Figure 1: Decision tree for the project example, with an exploration well and an appraisal well.

Exploration begins in 2009. The probability of finding oil is 30 per cent, whereas the ex ante probability of the project being commercial, given that oil is found, is 80 per cent. The discount rate for company and society is 10 per cent in real terms. According to the Boston Consulting Group (2005), this is representative over time for the petroleum industry. The decision tree is depicted in Figure 1.

Upstream project	2009	2010	2011	2012	2013	2014	2015	2016
Front-end costs								
Exploration Opex	150							
Appraisal Opex		75	150	75				
Opex								
Investment								
New facilities					200	1500	2000	3000

Table 1: Front- end costs for the model project, in USD million.

Table 1 depicts the initial costs of the project, divided between operational expenditure (Opex) for exploration, appraisal and development of the field, and capital expenditure (Capex) on new facilities. All numbers are in real values. From the start of production in 2017 until close-down in 2031, annual operating costs of USD 400 million are incurred.

Upstream	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Oil production	20	40	40	40	40	40	37	33	27	22	18	15	12	9	7

Table 2: Production profile for the model project, in million barrels per year.

The production profile is presented in Table 2. The oil company and the government have a common price distribution: base case USD 80 (40 per cent), USD 40 (30 per cent), and USD 120 (30 per cent) per barrel. All the numbers are in real terms.

7. Results

We find that the Norwegian tax system performs better than the PSA regime on a number of decision criteria and on system properties such as minimising distortions. PSA systems are nevertheless widely used because they provide host governments with revenue at an early stage[13] and shield it from downside risk in the project.

When the oil price increases, the focus is on tax adjustments to capture additional resource rents. Should oil prices fall, the relevant issue is how to cut taxes to attract foreign investment. The current regulatory model in many resource-rich countries relies very much on heavy funding by the NOCs, which is a vulnerable strategy when prices fall. Thus, it is vital to examine how different types of petroleum tax systems cope with large fluctuations in the oil price.

A large variety of PSA regimes exist. According to Johnston (2008), most of them were not adequately constructed to handle an increase in oil prices efficiently, because most are regressive, i.e., the government's percentage share of profits goes down when oil prices go up. This is the main reason why we have seen a large number of ad hoc changes to petroleum tax systems over the past couple of years. Petroleum tax systems with progressive government take elements, such as ROR schemes, have been under less pressure to change.

Below, we illustrate company EMV and government take for different oil prices, and for Norway and Angola. The base year for the calculations is 2008. A few results are worth mentioning. First, even though the Angolan regime includes a progressive ROR scheme, the country's overall tax burden is actually regressive. This is also the case for most existing petroleum tax systems, as noted by Johnston (2008). The reason is portrayed in Figure 2 below – the Angolan government carries no downside risk. Unlike the Norwegian regime, where the government continuously shares in investment through tax depreciation and uplift, the IOCs carry all initial capital exposure in Angola. Since it is carrying all the downside risk, an IOC must be allowed to keep a significant part of the upside to be willing to participate. Second, we

[13] Note that this is not unique to the PSA system. Signature bonus, competitive bidding terms, royalty and so forth all achieve the same target of early revenues and can be found in both PSA and discretionary licensing regimes.

can identify a state contingent optimum tax design from the simulations. The PSA regime is beneficial to the host government if it is risk averse (unable or unwilling to carry downside risk). For governments which can wait to receive revenue and are able and willing to carry downside risk, a neutral net income system (i.e., one with no distortions) – such as the Norwegian tax system described here – is to be recommended since it maximises overall project value.

This fits pretty much with real-world observations. Host governments in OECD countries generally carry more risk, get the revenue later,[14] and have less distorting petroleum tax systems than those outside the OECD area. These tax systems have two advantages in terms of revenue potential. First, by avoiding distortions, the tax base is higher. Second, the potential for taxation is higher – the risk premiums for the companies are lower since the government is carrying much of the risk. We now go into our analysis in more detail.

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14 An exception is the US system, which raises early revenue through auctions of drilling leases.

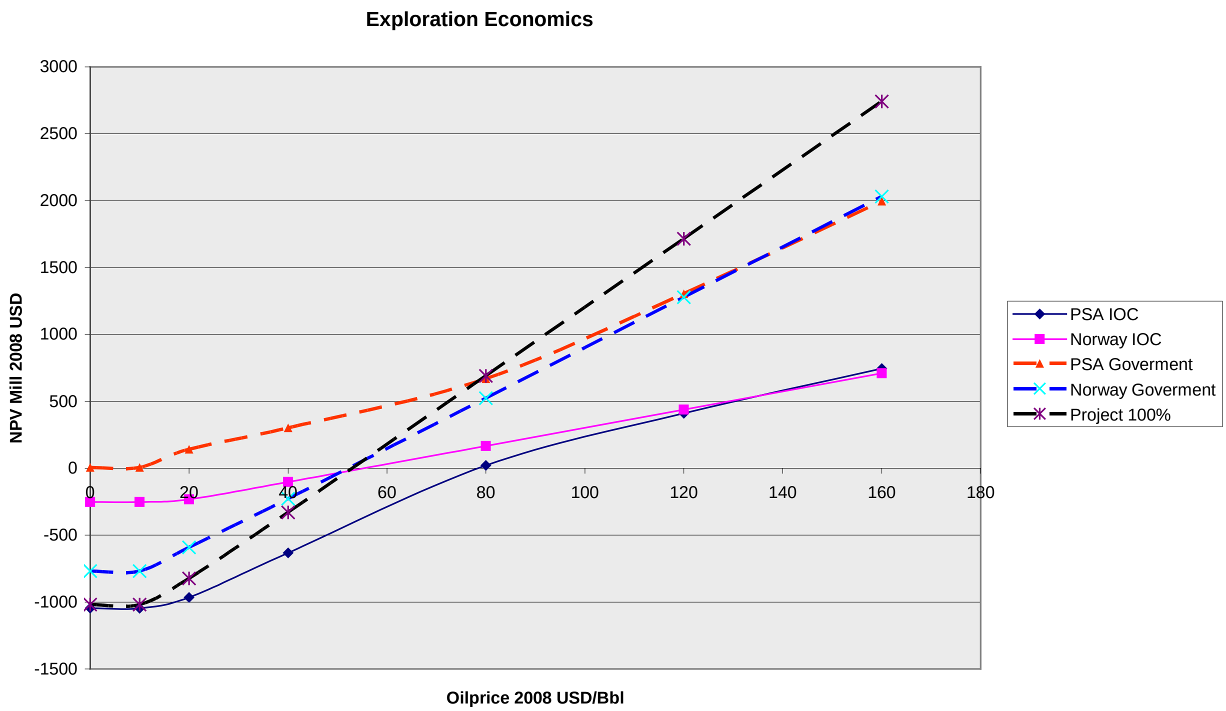

Figure 2: Life cycle calculation for a model field under two tax systems – Norwegian petroleum tax and Angolan PSA/NIC scheme. For different oil prices, the curves illustrate (in NPV terms) the before-tax return on the project (100 per cent project), the after-tax return to the IOC in the two tax regimes, and the revenue for the two governments. The black line illustrates the before-tax NPV of the project.

Figure 2 shows the NPV calculations for the IOC and the government under Angolan PSA scheme and a neutral Norwegian net income tax system, and under different oil prices. The calculations are made prior to the exploration decision. In other words, we focus on the life cycle perspective of the field. EMV is the term used for such NPV calculations. This is an expected value because it is contingent on the outcome of the exploration activity.

The diagram clearly illustrates the linearity of the Norwegian petroleum tax system, and the non-linearity of the Angolan PSA regime. Given the uncertainty of the exploration outcome – which differs between the IOCs – the Angolan fiscal system involves a clear regressive element, i.e., the effective tax rate decreases when the oil price goes up. At low oil prices – e.g., USD 40 per barrel – the IOC has a negative outcome from the project (negative NPV before tax) in the Angolan regime, but still has to pay a considerable amount of tax. The IOC here faces a tax rate above 100 per cent. Thus, the government has a positive NPV even at a low oil price. However, the IOC takes a double hit, and considerable upside must be present to compensate for this negative outcome. At an oil price of USD 80 per barrel, the tax burden falls below 100 per cent and the IOC obtains a positive EMV. We see from Figure 2 that the Norwegian government captures a smaller fraction of the EMV than the Angolan government at oil prices below USD 140 per barrel. For prices above this level, the two tax systems generate about the same revenue.

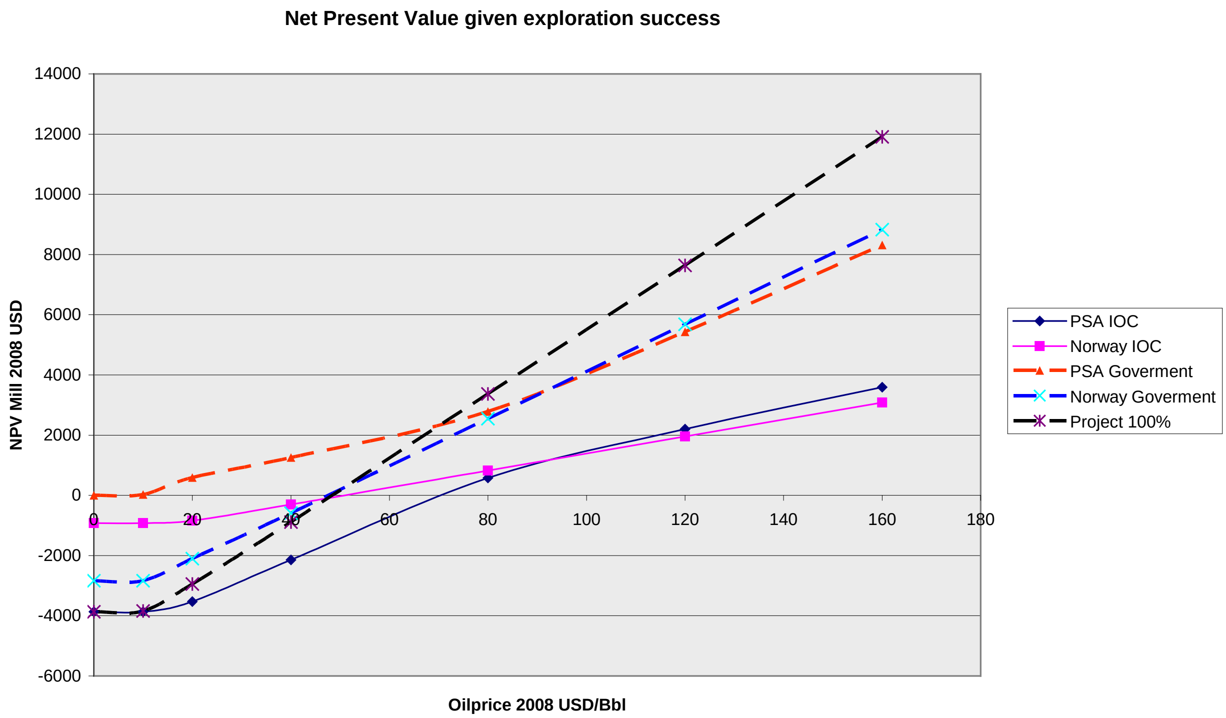

Figure 3: Field development calculations for a model field under two tax systems: Norwegian petroleum tax and an Angolan PSA/NIC scheme. Exploration costs are treated as sunk. For different oil prices, the curves illustrate (in NPV terms) the before-tax return from the development project, the after-tax return to the IOC in the two tax regimes, and the revenue to the two governments.

Figure 3 illustrates calculations similar to those in Figure 2, but confined to the development phase of the project. Thus, we undertake ex post calculations after exploration has proved successful. We see that the Angolan government has higher revenue than the Norwegian government at prices below USD 95 per barrel, while the Norwegian system generates a marginally higher revenue at prices above this level.

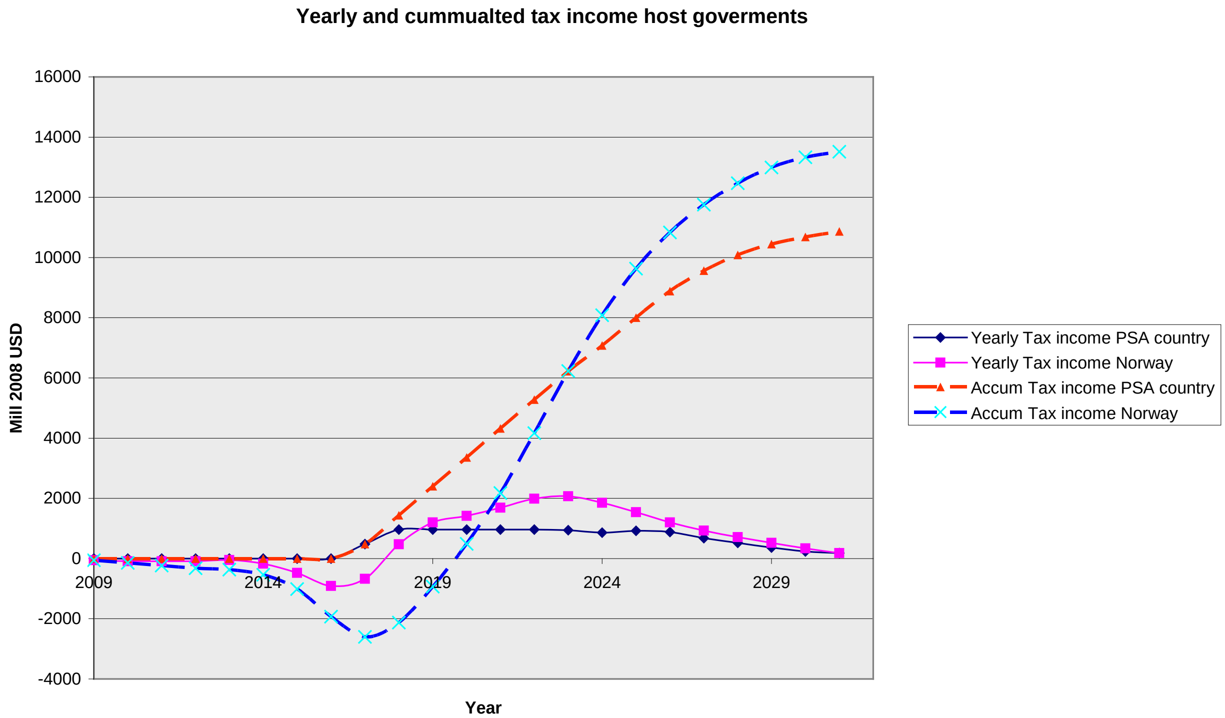

Figure 4: Revenue streams for an oil price of USD 80 per barrel. Life cycle calculation for a model field under two tax systems: Norwegian petroleum tax and an Angolan PSA/NIC scheme. The curves illustrate the annual and the accumulated revenue for the two tax systems.

Figure 4 illustrates annual and accumulated revenues in the two tax systems for the base case with an oil price of USD 80 per barrel. Unlike the previous figures, which show NPV calculations, the numbers in Figure 4 are not discounted. The diagram is a pedagogic reference case of no discounting, illustrating the point that a difference in discount rates is one factor which explains why different countries opt for different tax systems. Abstracting from discounting, we see that Norway overall gets a higher tax revenue, but with a considerably less favourable time profile. To provide a better grasp of the tax system comparison, we now display specific numbers from our calculations.

Oil Price	40	**80**	120	**Weighted**
IOC PSA	-2 147	**580**	2 203	**249**
IOC Norway	-301	**821**	1 953	**824**
Goverment PSA	1 259	**2 788**	5 436	**3123**
Goverment Norway	-587	**2 545**	5 685	**2548**

Table 3: NPV for the IOC and the governments
for different oil prices, given exploration success.

Table 3 shows the NPV of the project given successful exploration for oil prices of USD 40, 80 and 120 per barrel, i.e., some of the numbers in Figure 3. The values in the table are for the IOC and for the government in Angola (PSA) and Norway (discretionary licensing). We also show the expected NPV, with oil price probabilities of 30 per cent for USD 40 per barrel, 40 per cent probability for USD 80, and 30 per cent probability for USD 120. The results are reported for the IOC and the two governments. We see that the IOC gets a marginally better expected payoff in Angola at high oil prices, but that the position is reversed for low prices. The reason is that the Norwegian government shares the downside risk by means of tax deductions, whereas this is not the case in Angola.

Oil Price	40	**80**	120	**Weighted**
IOC PSA	-632	**22**	412	**-57**
IOC Norway	-103	**166**	438	**167**
Goverment PSA	302	**669**	1 305	**750**
Goverment Norway	-227	**524**	1 278	**525**

Table 4: EMV of the exploration project
for the governments and the IOC, at different oil prices.

Table 4 shows the corresponding expected exploration economics. Note that the NPV of the project is much lower when we account for exploration uncertainty, exploration expenses and lead times. When we account for the exploration phase, the differences between the two tax regimes are reinforced. The EMV is better for the IOC in Norway than in Angola at all the oil prices we analyse. Note that the weighted EMV is negative in Angola, so the IOC will not undertake this project under the PSA terms even if it is profitable on a before-tax basis.[15] This is an illustration of the fact that this PSA regime is non-neutral when we account for uncertainty, and that investment decisions can be distorted. The Norwegian tax regime is neutral by design, so the decision can be made in this regime by calculating EMV for the base price of USD 80 – price weighting is not necessary. The neutrality of the Norwegian system lies in the fact that the fraction of costs – on an NPV basis – carried by the government is equal to the fraction of the income it captures. This symmetry implies a cash flow tax system, which does not distort economic decisions by the oil companies.[16] The distortive property of the Angolan PSA system lies in its asymmetry – while the government carries none of the downside risk, it captures a large fraction of the upside. Thus, the non-linear tax system discriminates against risky investment. In this particular case, the Angolan government will have incentives to change the fiscal terms so that this profitable project can be developed. Since PSA terms are project-based, such adjustments can be made.

PSA schemes are non-neutral, and are known to cause distortions of the investment level, the trade-off between Capex and Opex, and production profiles.[17] Despite the deadweight losses, PSA schemes are widespread among resource-rich host governments outside the OECD. Reasons include the fact that the host government does not have to carry downside risk, and that the revenue comes early.

Oil Price	40	**80**	120
PSA	-142 %	**83 %**	71 %
Norway	66 %	**76 %**	76 %

Table 5: Tax progression for different oil prices for the two fiscal regimes.

15 Thus, it does not help that the government revenue calculated for the PSA regime in Table 4 is higher than for the Norwegian tax regime, as long as the project will not be implemented. In technical terms, the PSA conditions in this particular case violate the IOC's participation constraint.

16 As capital expenditure cannot be written off immediately, the Norwegian tax system is not identical to conventional cash flow tax systems. The NPV loss of depreciation, however, is compensated by an uplift designed to generate neutrality.

17 Note that the resulting deadweight losses are not captured by our project example. For the sake of simplicity, we have assumed that the IOC has the same costs and revenues under the two tax regimes.

The Angolan PSA scheme we analysed had a progressive element in the ROR-based sliding scale. Nevertheless, the overall tax system is regressive. See Table 5. A progressive tax system would not be possible, since it would not allow the IOC to recoup all the costs it bore up front.[18] To recoup its initial costs, the IOC needs to keep a significant part of the revenue if the project is successful. The Norwegian tax system, by comparison, is close to linear.

We will now explore a few supplementary decision criteria which IOCs use in selecting projects.

Oil Price	40	**80**	120	**Weighted**
IOC PSA	-0,63	**0,17**	0,65	**0,07**
IOC Norway	-0,09	**0,24**	0,58	**0,24**

Table 6: NPV index at different oil prices for the two fiscal regimes.

When capital, personnel or other inputs are scarce, IOCs make use of an NPV index to rank projects. This is defined as NPV after tax divided by Capex before tax. If capital is the limiting factor, or if the latter is correlated with capital, this ranking criteria maximises value for the IOC. From Table 6, we see that the Norwegian tax system outperforms the Angolan PSA scheme on this indicator when all price outcomes are considered, because of a much better outcome at low prices.

	Given explor. success	Exploration economics
IOC PSA	70	78
IOC Norway	52	55

Table 7: Break-even prices for the two fiscal regimes.

Yet another input to investment decisions is the break-even price, i.e., the critical oil price at which NPV after tax is zero. For both countries, break-even prices after tax are a function of the level of NPV. However, Table 7 shows that the break-even price is much lower with the Norwegian tax regime, since the government in this case shares in the negative outcomes.

[18] In technical terms, it would violate the IOC's participation constraint. See Osmundsen (2006).

Oil Price	40	**80**	120
IOC PSA	n.a.	**2021**	2019
IOC Norway	2020	**2019**	2018

Table 8: Pay-back times at different oil prices for the two fiscal regimes.

Finally, one might consider pay-back times. This criterion may be relevant if the political risk is perceived to increase over time, for example. The Norwegian regime scores slightly better on this indicator. See Table 8. Note that with an oil price of USD 40 per barrel, the IOC never reaches pay-back in the PSA regime.

8. Conclusion

Our analysis is too specific to provide any precise and general conclusions, but illuminates the basic trade-offs in petroleum tax design. Optimum risk sharing and cash flow allocation over the project lifetime between host government and IOC often call for the latter to fund the initial investments. The high front-end loading of costs and the high level of risk borne by the IOC call for it to retain a substantial part of the upside if the project is successful. This limits the degree of progressivity which can be achieved. Thus, optimum tax design is contingent on the relative characteristics of the host government and the IOCs – which of them is better able to carry downside risk and which can wait for revenue.

We find that the Norwegian tax system performs better than the PSA regime on a number of decision criteria, and on system properties such as minimising distortions. PSA systems are nevertheless widely used because they provide host governments with revenue at an early stage and shield them from downside risk in the project. At very high prices – or alternatively with a more prospective project – revenue under the Norwegian tax system exceeds that in Angolan. However, this could be adequately remedied, e.g., through the use of signature bonuses determined by bidding or negotiation. In general, we observe that the more attractive the resource base, the tougher are the fiscal terms. This is the result of fiscal competition.[19] Even though the petroleum resources are immobile, resource countries compete to attract the most competent companies, personnel and equipment. Such competition takes place either in a free market (bidding or negotiation over terms) or on the basis of legislative tax design based on comparative analysis.

Comparing discretionary licensing regimes with PSA schemes leaves a general impression that the government carries more risk in the former. It should be emphasised, however, that this is not inherent in the revenue system. Different types of risk sharing can be implemented in both systems. Thus, the Angolan government is exposed to less risk and generates earlier revenues than its Norwegian counterpart not because it has a PSA regime, but because of the way this system is designed. The same outcome as the cost recovery mechanism could have been achieved, for example, with the imposition of royalty in Norway. Note that Norway used to levy a royalty but abolished it. Thus, the maturity of the petroleum sector and macroeconomic conditions play major roles in tax design.

From the company perspective, the Norwegian petroleum tax system is much more favourable than the particular PSA regime analysed. However, it should be emphasised that our implicit assumption that all other features are the same in the two countries may not be valid. The most crucial element in this setting is prospectivity. A harsher tax system may be justified if prospectivity – in terms of volumes in place, reservoir characteristics and costs – is more favourable. On the other hand, our analysis does not include contractual and fiscal elements such as bidding and carried interest. These elements, prevalent in highly prospective resource countries, entail even higher front-end loading, higher downside risk, and greater progressivity for the IOCs.

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[19] See Osmundsen (2006) and Nakhle (2007).

Our analysis assumes that the IOC and the government have the same discount rate. The Norwegian government usually has a lower discount rate than the companies. Norway is well funded, with about USD130 000 per capita in a sovereign fund in 2012. Accordingly, the Norwegian government is a patient player with a low discount rate. Carrying a large fraction of the front-end investment – and getting correspondingly higher tax revenue later – may therefore make good sense for it. That probably represents the optimum intertemporal allocation of funds between government and companies for Norway. This may not be a good system for other resource-rich countries. Many of these are in acute need of public revenues, i.e., the discount rate for the government is high. In such cases, investment is typically borne by the IOCs (carried interest) and additional gross tax elements – such as royalties – secure early revenues for the government. Such fiscal instruments were also used by Norway when its petroleum operations began more than 40 years ago.

Much attention is being paid these days to the revenue system Brazil will select. After several gigantic discoveries in recent years, this country stopped further licensing rounds because the government was not assured that signature bonuses from auctions would ensure that it captured a significant part of the resource rent. One model discussed by the Brazilian government is a PSA scheme, on the grounds that this system guarantees revenues for the government from day one of production (instead of waiting for the IOCs to reach a tax-paying position), while the presumed inherent progressivity provides better assurance that the IOCs will not capture an unreasonable part of the return in the event of high oil prices or unexpectedly large reservoirs.

Our simple analysis cannot be used to derive very specific advice on petroleum tax design. But we believe it can be used as a basis for general remarks. One insight is that no *one* optimum tax system exists. Rather, optimum tax design is state contingent. It needs to be customised to the parties involved: which of them – government or companies – is the more risk averse? Which is able and willing to carry downside risk? Which is able to wait for revenue? The design of the tax system has also to be adjusted to the prospectivity of the projects to hand – a harsh tax system is only appropriate for highly prospective projects.

We also demonstrate that a sustainable tax policy needs to take the entire life cycle of the project into account. Several of the recent tax increases in petroleum-producing countries clearly violate this requirement. In many cases, they have been based solely on analysis of development projects and treat exploration costs and risk as sunk. In such cases, the life-cycle calculation may become negative and deter future investment. This is particularly the case if tax adjustments are asymmetric – i.e., taxes are adjusted more quickly upwards when prices rise than downwards when they fall. If IOCs anticipate this type of government tax behaviour, exploration decisions are likely to be deterred even if the projects are profitable.

In our project example, we have assumed that the IOC can deduct a correct amount of costs in the tax calculations. This is not a trivial assumption. If deductible costs deviate from actual costs, the effective tax rate may deviate from our calculations. In PSA models, the NOC usually plays two roles. First, it acts as an investor, facing the same commercial terms as the IOCs. Second, it serves as a licensing authority and, in that capacity, determines whether to accept the costs which can be covered by cost oil. One should bear in mind that the NOC may have incentives to pursue a cyclical pattern on accepting costs – deductions are denied to a greater extent at times when oil prices are high. This adds to the progressivity of the effective taxation.[20]

The rise in oil prices up to mid-2008 prompted tax increases in most resource countries. However, a few notable exceptions can be seen. The Norwegian tax system has remained stable throughout the period of rising prices. (Actually, tax breaks for exploration costs have been given to companies without taxable income.) The explanation is two-fold. First, unlike the British petroleum tax, for example, the effective tax was high at the outset. Second, like the UK, the

[20] As a licensing authority, NOCs often also have the right to approve all contracts which incur costs. They often make sure that these contracts are awarded to companies with which they have a joint venture. This type of intervention is also reported to be more prevalent at when oil prices are high.

Norwegian system is close to a cash flow tax and therefore automatically accommodates price changes. Another country with a stable tax system during this period is Angola. It also started out with a high level of effective taxation before the increase in oil prices. Another stabilising element may be the signature bonus system. This has represented a very potent revenue instrument for Angola, effectively accommodating the oil price rise. High signature bonuses will depend to a large extent on the credibility of the remaining tax instruments, and Angola has thus had a credible commitment structure. It is always the case that excessive short-term tax increases may hurt future investments and revenues. With new exploration acreage being continuously awarded, however, the cost of a country's lost reputation, in the form of a drastic decrease in signature bonuses, would be incurred immediately.

Our analysis is richer than traditional tax analyses. Nevertheless, our comparison of tax systems omits several relevant elements of project analysis for tractability reasons. Our intention has not been to make an accurate comparison of tax payments, but rather to illustrate general features of different tax systems. This may justify simplifications, but readers should bear in mind that we do not make a fully fledged comparison. We will now discuss some of the omitted elements. From a strict tax perspective, non-neutral tax systems (e.g., PSA schemes) are more prone to change because distortions are enhanced when the oil price fluctuates. Oil companies may let this fiscal uncertainty be reflected in cash flows, accounting for an expected tax increase in the event of higher oil prices. This will weaken their investment incentives, thus illustrating the benefits of a credible tax policy for the resource country. Nor have we accounted for signature bonuses, which are often one of the supplementary elements in PSA regimes. The front-end-loading structure of signature bonuses, combined with lack of consolidation, leads to a significant reduction in the project's expected monetary value for the IOC. Accordingly, international comparisons of petroleum tax systems which fail to take account of signature bonuses can be seriously misleading.

In our study of different petroleum tax systems internationally, we find evidence of Van Meurs' rule: the administrative complexity of a fiscal system is inversely proportional to the government's administrative capacity. See Van Meurs (2008). According to Van Meurs, the straightforward systems are found in countries such as the UK, the USA and Norway, while complex systems prevail in countries like Liberia, Burundi and Senegal. On a general basis, we believe the design of simple and transparent tax systems is to be recommended. These are easier to administer and reduce the risk premiums of the IOCs.

Several topics not addressed by our paper could provide relevant extensions of our analysis, including to service contracts and oil projects on land.

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