PROMOTING INVESTMENT INCENTIVES BY INTERNATIONAL FINANCIAL INSTITUTIONS: THE CASE OF FOSTERING NATURAL GAS INVESTMENTS IN DEVELOPING COUNTRIES

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1. Introduction

Few places are the old saying *It is costly to be poor* truer than when comparing the government share from extraction of natural resources in rich and poor countries. Rich countries can afford to take risk in their revenue regimes and may

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The Journal of Energy and Development, Vol. 50, Nos. 1-2

have negative cashflow for a period, at least for individual projects, while the poor cannot. The risk taken by the rich is rewarded by a high share of the net value from the extraction while the risk aversion among the poor leads to lower revenue collected. In the oil and gas sector, the rich resource state uses the Cash Flow regime or variations, while the poor state must resort to the Product Sharing Agreement often to participate in oil and gas activities through the National Oil Company (NOC), while limiting the risk they take.

The risk profile of the regime does not only affect the share of the net value from extraction, it also affects how much is extracted of the identified resources. However, business must be carried out under the tax regime in the country of activity. At least for something as linked to geography as extractives this intuitively looks true. But what if we borrow a page from the playbook of financial engineering and introduce the tax world equivalent of the Total Return Swap[1] and design its revenue sibling, the *Total Regime Swap*?

This paper specifies the elements relevant for risk and cashflow in the two mentioned natural resource regimes, the Cash Flow regime, and a standard Product Sharing Agreement (PSA). It uses a case and calculates the gap between the two regimes with the perspective of the extracting company. It then introduces the *Total Regime Swap* where a financial intermediary offers the extractor the cash flow equivalent of being under the Cash Flow regime with a tax rate which keeps the NPV for the extractor unchanged. The natural resource state does not need to be involved to make this happen. Finally, the paper calculates the IRR for the financial intermediary on the Total Regime Swap and offers conclusions.

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The authors gratefully acknowledge the helpful comments and suggestions received from Moses Misach Kajubi, Martin Lokanc, Magne Emhjellen, and Sindre Lorentzen. Dr. Osmundsen contributed to this paper in his capacity as an independent consultant, providing background research for a World Bank project. This paper is published under the names of the listed authors and should be cited accordingly. The findings, interpretations, and conclusions presented are solely those of the authors and do not necessarily reflect the views of the International Bank for Reconstruction and Development/World Bank, its affiliated organizations, the Executive Directors of the World Bank, or the governments they represent.

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[1] For information on the Total Return Swap, see https://www.investopedia.com/terms/t/totalreturnswap.asp.

2. *State Contingent Tax Design*

An ideal tax system works with the licensing system to attract the most efficient companies, ensures that all socially profitable deposits are exploited efficiently and maximizes the residual value the resource state can collect from its assets. An optimum system also shares the risk optimally between the government and the 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 transaction; see Osmundsen and Løvås (2013).

As for the contracting parties – host governments and 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 analyze two principal tax systems in the petroleum sector – licensing regimes and production sharing arrangements (PSAs) – in order to generate indications of the kinds of circumstances under which they are useful. Comparing licensing and PSAs is interesting because risk-sharing and the timing of revenue differ substantially in most cases.

3. *Two Tax Systems*

The discussion will be illuminated by a case. We will undertake a case analysis where the same project is evaluated under two tax systems – a Cash Flow tax regime under discretionary licensing (as used by Norway) and a hypothetical PSA/regime used in Africa. The two tax systems differ considerably in terms of risk sharing between international oil companies (IOCs) and host government and can be seen as polar cases. With direct tax refund of 78% of exploration and development expenses and a petroleum tax system without a ring fence, the Norwegian Government is carrying an exceptionally high level of risk and can afford to do so. The African government carries much less risk, because this is what it can afford, as is common for PSA regimes.

4. *The Cash Flow Tax System – The Norwegian Case*

The petroleum tax system is based on the Norwegian rules for ordinary corporate taxation. Because of the extraordinary returns from production of petroleum resources, the oil companies are subject to an additional special tax. The ordinary company tax rate is 22%. To ensure a neutral taxation system, paid company tax is written off when calculating the special tax base. This entails a special tax rate of 71.8% in order to maintain a combined marginal tax rate of 78%.[2] All investment can be deducted immediately against the special tax and over six years towards the

[2] https://www.norskpetroleum.no/en/economy/petroleum-tax/.

corporate tax. If the annual tax balance is negative, the company will receive a refund from the government. Consolidation between fields is permitted. There is no uplift.[3] The system is approximately neutral. The Norwegian petroleum tax system is also approximately linear, i.e., it is neither progressive nor regressive. A base case evaluation gives a reasonable description of project economics since the cash flow tax cuts the upside and the downside of the project in a symmetric manner.

5. The PSA Regime

PSA regimes are often hybrid revenue schemes, which contain PSA elements, a corporate income tax, and frequently additional revenue instruments. We analyze a relatively simple hybrid production sharing agreement/net income corporate tax (PSA/NIC) regime containing standard elements, including a sliding scale. The analysis does not include contractual and non-tax elements such as bidding and royalty. We would emphasize that PSA schemes vary from contract to contract and are confidential. However, model agreements often exist. The analysis must accordingly not be interpreted as a detailed analysis of a specific PSA contract, but rather as a system analysis of the general patterns inherent in these agreements. The objective is not to make a detailed comparison of the Norwegian and a developing/IDA country African petroleum tax system, but rather to illustrate and compare – through a particular case – the qualitative features of these two major classes of petroleum tax systems.

The specific PSA/NIC-scheme we analyze has the following features: the onshore activity has an ordinary net income tax system. In our hypothetical model, Capital Expenditure is depreciated is over the life of the asset, using the unit of production method. This configuration guarantees revenue to the government from the first year of production but implies front-end loading of investment for the IOC. The offshore regime is fairly complex. The main elements are 70% 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. If a NOC is involved, the same rules should apply to it as the holder of participating interests. There is no royalty payment. The profit oil not used to recover cost is split between the IOC and the government (represented by a national oil company, NOC) on the basis of a sliding scale. The profit split is production based, with 30% for the IOC for annual production below

[3] It is therefore the companies that are taxed, not the oil and gas fields. The companies are entitled to deduct all relevant costs from the tax basis. Deductions for investments (depreciation and an extra deduction from the special tax basis, called uplift), are designed to prevent the high tax rate from reducing the willingness of companies to invest on the Norwegian shelf. To ensure that companies are treated equally regardless of whether or not they are liable to pay tax, there is a system whereby companies can claim reimbursement of costs in the exploration phase as an alternative to deducting them from the tax base. https://www.norskpetroleum.no/en/framework/fundamental-regulatory-principles/.

1 billion Sm3, 40% for production between 1 and 2 billion Sm3, and 50% for production above 2 billion Sm3. The profit split generates revenue for the government from the first year of production, due to the limit on cost oil recovery. The thresholds in the profit oil split contribute to progressivity in the tax scheme. At the same time, they represent a distortive tax element. The tax scheme involves carrying of the NOC, i.e., the IOC funds the NOC investment This eliminates capital exposure for the government and reinforces the front-end exposure for the IOC. Overall payments to the resource country are estimated to be around 50%.

The 50% collected under this specific PSA is considerably lower than the 78% paid in the Norwegian cash flow tax. The latter is still preferred by the IOC due to a much more favorable timing of the tax payment and a high effective rate of return requirement. This creates a potential for value creation by the use of an International Financial Institution (IFI). We assume that 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 partly and immediately covered through the net income received by IOCs from other fields on the Norwegian Continental Shelf (NCS), thus adding to the difference in the time profile of tax payment.

Many PSA regimes will also include other elements, such as up-front payments in the form of either a bid for the license or bonus payments to the government, royalty as a gross take on total production and payable before cost recovery. In such regimes, there may be carrying of the national oil company in the exploration and development phase, and part of the production is regulated to be sold domestically at a low price. These additional features can in many cases shift more risk to the IOC and reinforce the front-end loading of IOC investments.[4] Unlike the cash-flow system, that is linear, the PSA system is non-linear, asymmetric, and the oil company carries all downside risk. Thus, a base case analysis is not sufficient to ascertain project economics. Expected value analysis, where different outcomes are weighted by their probability, is called for. Accordingly, the case analysis below will have a low, base, and a high case.

6. *Optimal Tax Design*

If tax contract design is suboptimal, it may be possible by redesign to achieve a win-win situation. The optimal characteristics and the closest to the theoretical ideal for a resource rent tax is found in a Cash Flow tax (Brown, 1948) with

[4] Some of these elements can also be found in discretionary licensing systems, they are not exclusive to PSAs.

pay-out of negative cash flow as described above. For oil companies that ration capital and are eager to get a low break-even price, they gain investment incentives and company NPV increases. The Government also is a winner with overall undiscounted tax payments for planned projects going up by eliminating the uplift in the previous tax system, and with new projects being developed sooner.

The fact that both company NPV and NPV of government revenue increased from the initial project portfolio is due to different effective rates of return requirements. The effective rate of return requirement is much higher for the companies, so there is a win-win situation of immediate tax depreciations instead of previously over six years. Government applies a real rate of 7% and companies approximately a real rate of 8% when calculating NPV. However, the sanctioning criteria of the oil companies often include a side-criteria linked to break-even price. Dependent on the view of the expected future oil/gas price, this may imply an effective rate of return requirement above 20%, see Osmundsen et al. (2022). So, there is a Pareto-improvement (win-win) by letting impatient oil companies get a shorter payback-time and the patient government get higher tax payments in the long term.

This successful tax system is not directly applicable to an African resource extraction country, since government in this case probably is not a patient player. A Cash Flow tax with pay-out requires a government with good liquidity and ability to take on risk, and the government needs to be a patient player. This is not the situation for most African resource extraction countries. With a cash flow tax, government becomes a silent partner in the project. It contributes to Capex with a fraction equal to the tax rate and receives the same fraction of revenue when it arrives. For a government that needs revenue now, and lacks liquidity and ability to carry risk, this regime is not an option. In a typical African PSA contract with ring fencing companies carry the initial investment and risk 100%. With more of the cost oil (or oil-equivalent in the case of gas) coming before government revenue, it is a reasonably good regime in terms of payback-time (auction fees and royalties are worse), but a cash flow tax in which Capex-burden is reduced immediately is preferrable from the company perspective.

We will analyze PSA contracts and a cash flow system as these two systems are representative of the general features of the petroleum tax system outside and inside the OECD area. It will serve the objective, which is not to make detailed comparisons, but through a case study analyzing the qualitative features of the two systems. Development projects are typically organized as license groups, consisting of several companies. For simplicity, we will in the text only refer to "the oil company."

7. *Participation from a Third Party*

What if we introduce a third party that is willing to take on the capital exposure and risk that IDA-countries cannot bear? The third party - an IFI - offers the oil company what we in the Introduction called the *Total Regime Swap* (TRS). The sum of the cash flow from the PSA regime and the financial TRS leaves the oil company economically in a situation as if it was under a Cash Flow regime. The TRS leaves the resource country economically and legally unaffected since it is a purely financial arrangement between the two parties of the TRS. The resource country can keep on relying on the PSA regime, that has long traditions and possibly is perceived as more trustworthy than a net income tax system. With this system, the oil company would be facing a cash flow system and the government would face the PSA. Both parties would be satisfied, and the investment would probably be sanctioned, if the arrangement was considered credible by both parties.

But what about the economics of the third-party contract? We started out saying there is a potential win-win situation, so potentially the third party could make a profit. However, that would not be without a risk. The third party would be exposed to risk related to, let us say, natural gas price, geology, cost developments, etc. A differential between two tax arrangements is an entirely new type of financial product with its own specific risk characteristics. These risk characteristics need to be analyzed in order to see if our TRS is a viable financial arrangement, and under which conditions. We will characterize the differential cash flow facing the third party in a representative model African LNG project. It should be noted that in principle such a TRS, if found sound, could be used in any situation where a government is monetizing its own natural resources.

8. Case Analysis

Let us study an African LNG project, subject to a PSA. Compared to an oil project, LNG projects have more costly transportation and processing, and production profiles are less steep and last longer. For normal natural gas prices, this typically means longer payback-time, which would make project sanctioning harder for international oil companies. Thus, in order to stimulate project sanctioning of a project that may bring considerable tax revenue to the resource extraction country, the tax system should be aligned to the decision metrics applied by the companies. There are several metrics that are relevant. Osmundsen et al. (2017) find they produce similar project rankings. We will analyze a model field and describe effects of our PSA on break-even price, payback-time, NPV, and IRR. In times of volatile prices of natural gas, the companies focus on break-even price (Osmundsen et al., 2022).

The field is to produce natural gas and condensate. Expected production of natural gas is 108 billion Sm3, of which 11.6 billion Sm3 is to be sold locally at a discount relative to the world market price, and the rest is sold on the global market. The local share of gas sales is around 10%. Expected production of condensates is 14 million barrels, which is to be sold on the global market. There is a ten-year development period, where most of the Capex is in the last four years. Capex is

22.9 billion USD and Opex is 25.8 billion USD, in nominal terms. Production lasts for thirty years, with fairly stable volumes.

The cash flow after tax for the oil company is displayed in Figure 1. To analyze the effect of the partial local sales provision, the figure also contains a line in which all the natural gas is sold on the global market. We see that the requirement of partial gas sales makes a considerable difference in the net cash flow, in spite of the percentage being as low as 10%. The reason is that with costs being unchanged, the tax subsidy is a one-to-one reduction on the net cash flow. Seen from the perspective of the oil company, the local price discount can be seen as an additional tax. It has similar properties as a royalty tax. It increases the risk as it has to be paid irrespective of the project economics, and the payment starts early, at production start.

The contractual arrangement with the IFI is as follows. The oil company receives a cash flow corresponding to a cash flow tax regime. This improves company project metrics and may secure project sanctioning. The African government receives payment on the agreed PSA terms. This is made possible by a third party, an IFI that goes in between the contracting parties. The cash flow of the IFI is thus the difference between project cash flow with PSA and project cash flow with a cash flow tax. The difference is depicted in Figure 2. As expected, we see from Figure 2 that the IFI starts off with a negative cash flow. The IFI is initially exposed to the difference in the company Capex share between the two tax systems. It means a negative cash flow because of immediate deduction with pay-out

Figure 1
AFTER TAX CASH FLOW FOR INTERNATIONAL OIL COMPANY FOR INVESTMENT IN AN AFRICAN MODEL LNG FIELD

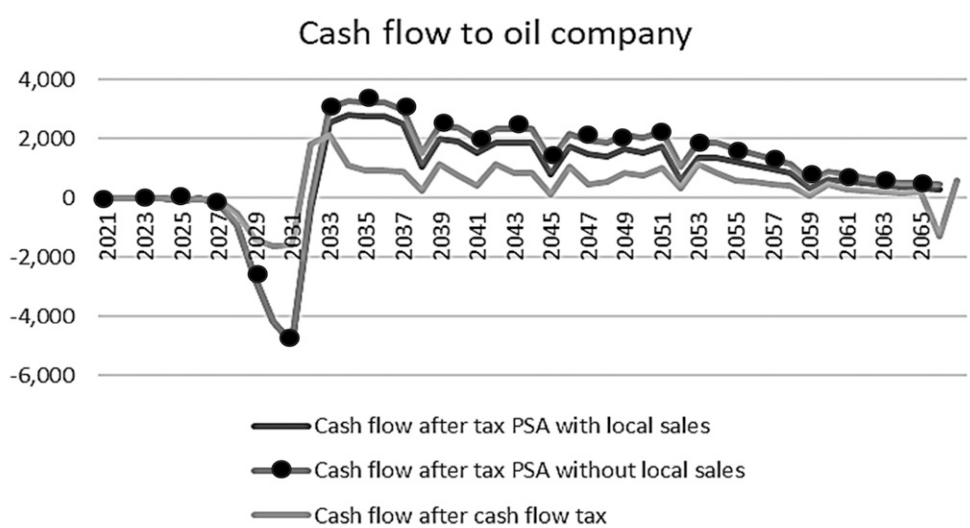


Figure 2
CASH FLOW FOR A THIRD PARTY IN AN AFRICAN MODEL LNG FIELD

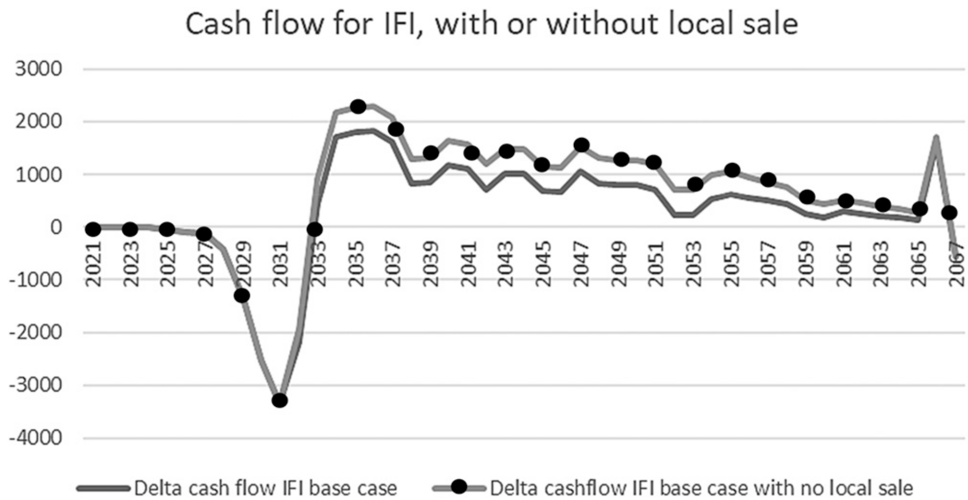


Figure Note: The cash flow is the difference between project cash flow with PSA and project cash flow with a cash flow tax. The figure displays the delta cash flow with and without provision for local sale at low price.

in the cash flow system. After production stars, the PSA is more favorable, and the cash flow is positive.

In Figure 2, we compare two situations for the cash flow of the IFI. One line depicts the situation where all production is sold at the international market and one where a fraction of the production is to be sold at the local market at a discount. We see from Figure 2 that local sales reduce the cash flow of the IFI that ends up paying for the price subsidy which has a similar effect as royalty. In the case analysis, the local sales provision is accounted for.

For modelling the cash flow tax system, we have chosen the Norwegian tax system. It is a net income tax system that allows for immediate deduction of investments and pay-out in case of a negative cash balance. The system is close to being a cash flow tax.[5] We are not aware of any other country with such a tax system. The UK tax system also has immediate deduction but does not have pay-out. Norwegian marginal tax rate is 78%. The case thus contains a comparison between an OECD type net income tax system and a hypothetical PSA regime, whereby the same LNG case is modelled for the two tax systems. The focus of this work, however, is on the potential involvement for a third financial party.

[5] IRR is approximately 1% lower after tax than before tax.

The project economics of the oil company and the IFI are displayed in Table 1. In addition to the base case, we have calculated a low and high case, corresponding to reserves 40% below and above the base case; alternatively natural gas and oil prices 40% below and above the base case. The cashflow tax does not entail local sales, as it does not come with this kind of provision. To obtain a relevant comparison, therefore, local sales must be included in the PSA calculations. Thus, partial local sales are accounted for in the table. Worth noting in the table is that for the base case, PSA implies a higher NPV than cashflow tax (2,696 versus 2,221). Nevertheless, the oil company prefers cashflow tax since the relevant decision metric, break-even price is considerably lower (45 versus 35.3). The reason is that the time profile for the cashflow tax is much better for the company. We can see that the IRR of the IFI is more volatile than for the company, although positive for all cases analyzed.

In contract design for the IFI, one would not like the IFI to be exposed to potential changes in two tax systems. The risk would be too high, Thus, the cash flow system in the contract should be kept constant at an agreed format and agreed tax rates. The tax rate thus gives a degree of freedom in designing the contract. The Norwegian tax system is merely applied in the paper for illustration purposes, and for a current comparison of two tax systems.

Table 1
RESULTS FROM MODEL FIELD CALCULATION
(The table displays project economics for oil company and IFI. Oil company PSA numbers include local sales. All numbers quoted are real 2021 USD)

	Breakeven price (in USD per barrel)	**NPV (8% real discount rate, USD millions)**	**IRR**	**Payback time (in years)**
Before tax, base case		9,098	17.7%	16
PSA, base case	45	2,696	12.2%	17
Cash flow tax, base case	35.3	2,221	16.7%	15
Before tax, high case		17,791	24.6%	15
PSA, high case	31.3	6,359	17.7%	16
Cash flow tax, high case	24.4	4,446	23.3%	14
Before tax, low case		405	8.5%	21
PSA, low case	72.8	−2,361	3.6%	27
Cash flow tax, low case	56.8	−4	8.0%	19
IFI, low case		−2,357	1.1%	46
IFI, base case		475	9.2%	20
IFI, high case		1,913	12.9%	18
IFI, base case, without local sales		2,796	14.3%	17

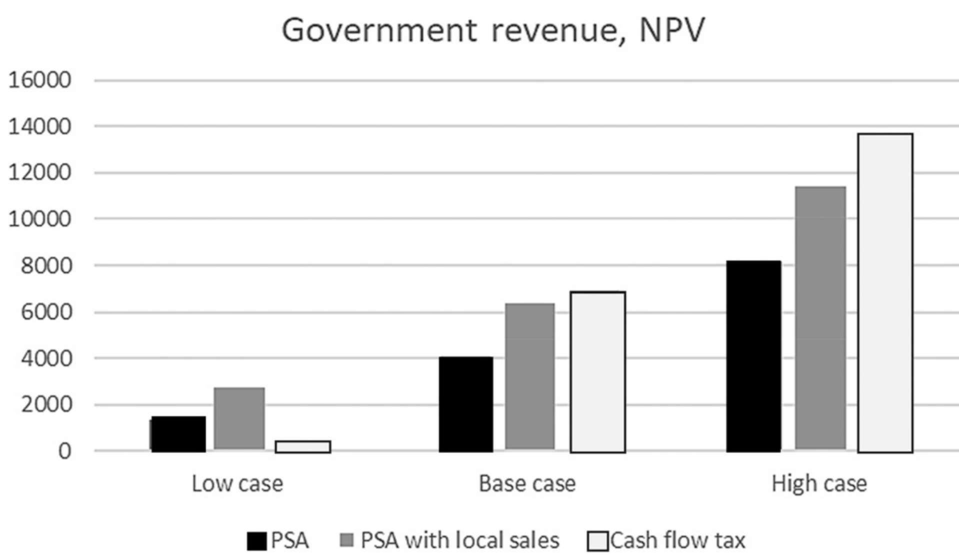
9. Government Revenue

An interesting finding in Table 1 is that with the cash flow tax, the companies pay more tax, but regardless, investment incentives are higher due to tax credits and symmetry in outcomes.

As can be seen in Figure 3, in the base case, NPV of tax payments over the project lifetime under PSA is 4.1 billion USD and 6.9 under the cash flow tax. However, we must account for the NPV loss of partial local gas sales, which amounted to 2.3. This adds up to a total effective PSA tax of 6.4, still below the cash flow tax. The differential NPV value before tax of a case with local sales have been added to the tax payment. This is how the company would look at it. Local government receives tax payments and in addition subsidized natural gas. From Table 1 we see that the companies actually prefer the cash flow tax system with higher NPV of effective tax payment. The explanation is that it has a more favorable time profile, with negative taxes initially, in the investment period, and higher tax payments later in the production period. The favorable time profile of tax payments makes this tax system better aligned with the companies' key decision metric – the breakeven price for natural gas.

Oil companies are risk averse with respect to price volatility, and the cash flow tax offers better downside protection. Whereas the cash flow tax is linear, the asymmetry in the PSA scheme is considered unfavorable by companies. The base

Figure 3
GOVERNMENT REVENUE FOR PSA, PSA WITH SUBSIDIZED GAS SALES, AND WITH A CASH FLOW TAX FOR THE CASE OF LOW, BASE, AND HIGH RESERVES
(Numbers in million 2021 USD)



case breakeven prices are 45 USD per barrel for the PSA regime and 35.3 USD per barrel for the cash flow system. The cash flow tax generates better ranking also on other decision metrics applied by the oil companies, but to a smaller extent. Base case IRR is 15.6% in the PSA regime and 16.7% with a cash flow tax. For payback-time we get 17 years for PSA and 15 years for the cash flow tax. This corroborates the finding in Emhjellen and Osmundsen (2017) that these metrics generate the same ranking of projects and tax systems. The misaligned incentives in the PSA regime represent a potential for improvement in terms of a third party, the IFI. The fact that NPV is higher for PSA than for the cash flow tax, indicates a potential for a profitable third-party arrangement. The question is whether the return is high enough to compensate for the risk.

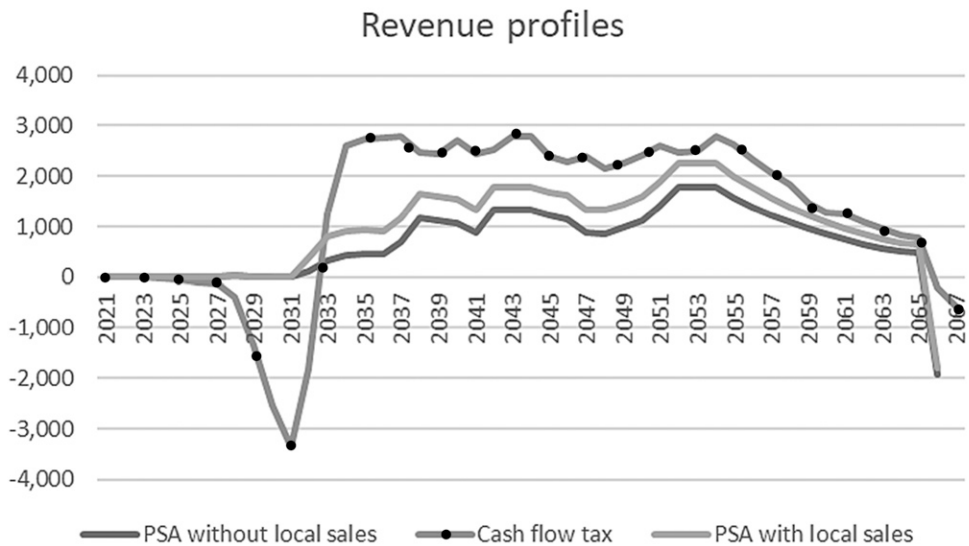
Comparing government revenue in PSA with cash flow tax, we see that PSA is better in the low case, but worse in the high case. Whereas the cash flow tax is linear, the PSA is non-linear. This distinction affects the risk facing investors. In a cash flow system, government is in effect a silent partner, and shares in the downside. This is not the case for the PSA contract, and thus the oil companies carry more risk. The upside and the downside are non-linear and therefore generates a reduction in the expected NPV for the IOC with the PSA regime that is not the case for the Norwegian tax system. Since the PSA system is non-linear, it is crucial to analyze upside and downside cases and calculate expected value.

The IFI will carry this risk of tax system asymmetry. The risk is clear from Table 1. If we assign equal probabilities to the low, base, and high case, we find that expected NPV for IFI is 10.3 million USD, which is considerably lower than the base case (475 million USD). Still, expected NPV is positive and there is a potential for the parties to enter into such a contract. The IFI receives an IRR of 9.2% in the base case. The NPV is calculated with a rate of return requirement of 8%, and the question is whether this is sufficient for the exposure by the IFI, or if external guarantees or other means of risk relieving are warranted.

Government revenue is depicted in Figure 4. Overall, the cash flow tax generates a higher revenue for government, but as clearly illustrated by Figure 4, the time profile of the revenue is considerably less favorable. With a cash flow tax, the government essentially becomes a silent partner in the project, thus taking part in the initial negative tax flow. With a PSA contract, the government has no initial payout, and revenue starts earlier than with a cash flow tax. The cash flow tax later surpasses the PSA contract in terms of revenue, recouping the initial capital outlays. This is demonstrated in the accumulated revenue stream, depicted in Figure 5. Please note that the darkest gray line in Figure 5 does not give the PSA contract full credit, since it in addition to tax revenue generates an additional national benefit in terms of subsidized natural gas. Accounting for this, see the lighter grey line, intersection of the cashflow schedule and the PSA schedule comes at a later year.

Looking at the accumulated revenue stream, we see that – compared to the neutral cash flow tax – international oil companies taking on PSA contracts provide

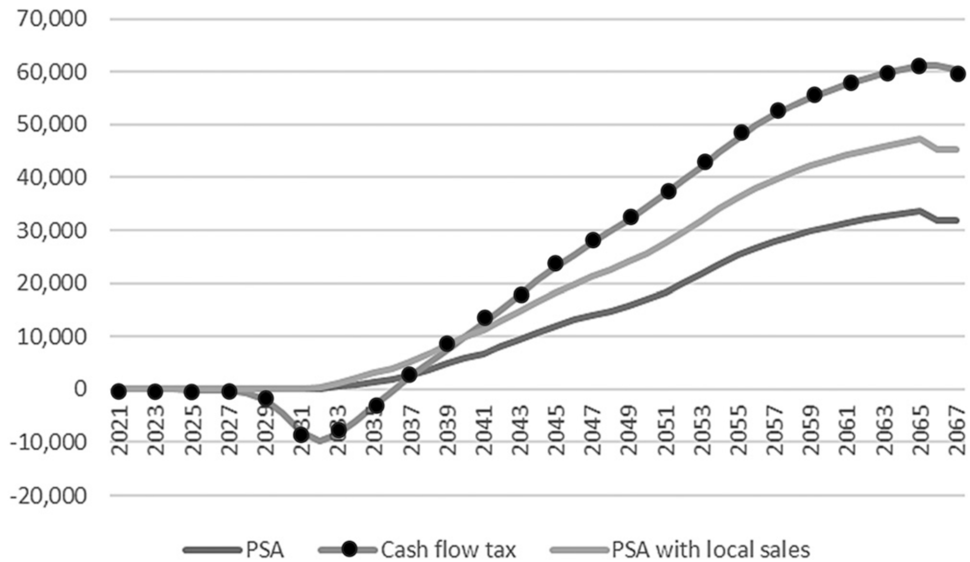
Figure 4
GOVERNMENT REVENUE STREAM FOR PSA AND CASH FLOW TAX, BASE CASE
(in million 2021 USD)



host governments with two services in addition to exploration, development, and production. They relieve the host government of initial cash payments, i.e., they serve as banks. Also, they accept a contract by which the host government only see the upside, i.e., they serve as an insurance company. Optimal risk sharing and allocation of cash flow over the project lifetime between host government in Africa and IOC calls for the latter to fund the initial investment. The high front-end loading of costs and the high level of risk borne by the IOC require them to retain a substantial part of the upside if the project is to be sanctioned. There is no free lunch, local government cannot both take on no downside and take a very high part of the upside. That limits the degree of progressivity which can be achieved. Whereas cash flow systems are linear, PSA contracts are regressive, even if they contain progressive elements.

In the accumulated revenue stream in Figure 5, we have in a separate line added the value of subsidized natural gas, defined as local sales obligation multiplied by the difference between global market price and local price. The project delivers tax revenue as additional local natural gas at a subsidized price. Supply security may be essential to local government. Again, there is no free lunch. The companies treat subsidized gas sales as tax payments. This means that if there were no local sales obligation, the government could demand extra tax revenue equivalent to the value of the subsidy. Maybe even more, if it is the case that the oil companies believe that local gas prices are subject to more political risk than other PSA terms.

Figure 5
ACCUMULATED REVENUE STREAM FOR PSA AND CASH FLOW TAX, BASE CASE
(in million 2021 USD, undiscounted)



Energy prices are politically sensitive and easy to use as political instruments in a "cost of living" crisis. Fearing this outcome, IOCs would in that case add an extra risk premium to this revenue stream. As a tax element, the gas subsidy is progressive, the higher the gas price, the higher the subsidy. The political risk and progressivity limit the fraction of production that it may be optimal for local government to dictate for local provision. The latter is valuable as far as it ensures access to domestic, affordable gas for energy security and financial reasons. Otherwise, the cost would be too high due to added risk premium and may outweigh the advantages.

To understand political preferences for IDA-countries versus OECD-countries, it is important to discuss discounting. Figure 5 of accumulated revenue displays undiscounted numbers. Whereas the PSA government has no explicit investment and receives revenue from the first year of production,[6] the cash flow government initially has a high payout, sharing in the Capex, and it is not cash positive until 17 years of production. If we account for the subsidized value of local sales, the two governments are on equal footing after 20 years, after which the cash flow country outperforms the PSA country. Thus, a patient and capital rich OECD

[6] The IOCs will most probably recover investment from the cost oil, so the investment will be de facto shared between government and IOCs through the tax system.

country selects a different tax system than an IDA country. This conclusion would be reinforced if we introduced discounting, with the IDA country applying a higher rate of return requirement.

Tax theory recommends a cash flow tax, because it does not distort the decision whether to sanction the project or not. The tax system also may affect decisions related to development and operation of petroleum projects, see Smith (2014). Hiorth and Osmundsen (2020) analyze the distortion in the decision on the number of infill wells, and Osmundsen and Wittemann (2024) analyze distortion in the development concept. In this case we address the decision on project sanctioning. In tax theory it is usually assumed that government and the company have the same rate of return requirement. From Figure 3 we see that NPV is positive for all cases analyzed if the oil companies accept projects with a positive NPV calculated with an 8% real discount rate. If this were the case, we would have a simple solution. The project would be developed both in the IDA and the OECD country and with different tax systems. The IDA project would be distorted in project design, execution, and operation, and would imply lower revenue, but this may be dominated by the government need for revenue early and the inability to carry downside risk.

If we allow for capital rationing, the picture may change. Capital rationing is addressed in Osmundsen et al. (2006), Kemp and Stephen (2018), and Bethmann et al. (2022). When oil and natural gas prices are volatile, oil companies ration capital by demanding a low break-even price from projects, see Osmundsen et al. (2022). The level of the break-even price may change over time but have for some years been 30 to 35 USD per barrel oil equivalent (oil is used as benchmark and natural gas revenue is converted to oil). This means that the project that we have analyzed would probably be sanctioned in the OECD country (break-even price 35) and not in the IDA country (break-even price of 45). Thus, the IDA country fails to attract investments from international oil companies.

10. The Potential Role of IFI

We will now discuss whether additional banking and insurance services implicitly provided by international oil companies to local governments in PSA contracts alternatively could be provided by a financial intermediary. With this approach, the companies would face a cash flow tax, and the government would still be renumerated according to the PSA contract. Apart from the fact that international oil companies currently claim high payment for their banking and insurance services and that an intermediary potentially could do it cheaper, there are other potential advantages. A problem with PSA contracts is that they may be distortive, in two dimensions. There may be profitable projects that would be sanctioned with a cash flow tax, but not with a PSA contract, and development projects that are sanctioned may have suboptimal concept choice and production efforts may be too low. The latter is not accounted for in the case analysis. By using a financial intermediary, both problems could potentially be remedied. Suboptimal development and operation are not modelled in this case; it comes as an additional benefit.

To illustrate the risk facing the IFI, we have calculated a low and a high case, defined by cases where production is 40% lower or 40% higher than expected. We see from Figure 6 that project risk is substantial. We would get the same effect if we kept volumes constant and changed output prices +/−40%. Thus, for this contractual arrangement to hold, the contracting parties would need to trust that the IFI will be able to carry the substantial risk. The unsystematic volume risk could be diversified by the IFI holding a portfolio of projects. Alternatively, risk sharing would be beneficial, by different IFIs sharing on the exposure in individual projects. The systematic price risk, however, cannot be diversified, as futures markets have limited liquidity beyond 12 months and the slope of the forward price curve is too unfavorable.

The IFI takes on high risk, with IRR going from 9.2% in the base case, to 12.9% in the high case and merely 1.1% in the low case.

Figure 6
CASH FLOW FOR A THIRD PARTY IN AN AFRICAN MODEL LNG FIELD

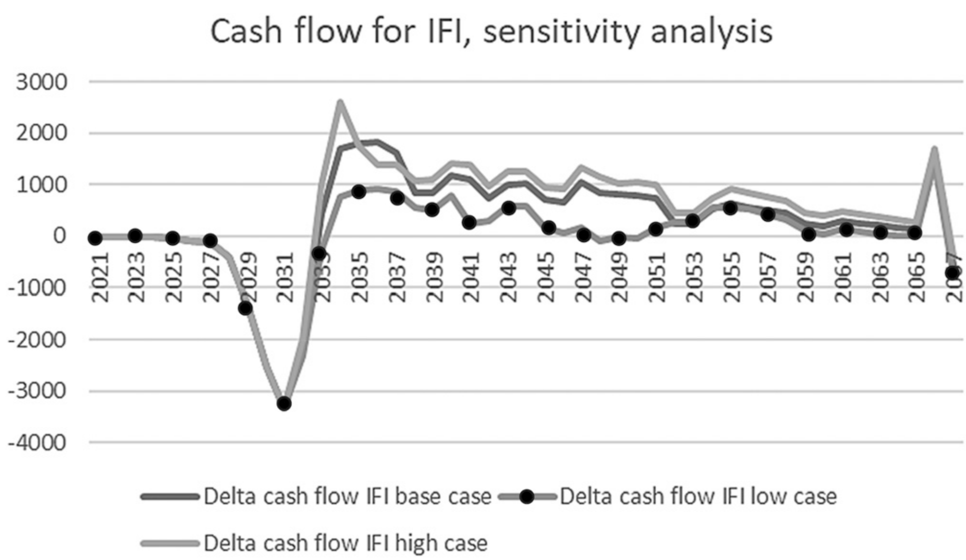


Figure Note: The cash flow is the difference between project cash flow with PSA and project cash flow with a cash flow tax. The figure displays a sensitivity analysis for a +/−40% change in production volume or output price.

11. Conclusion

In our model, IDA-countries use a simplified PSA for petroleum extraction. According to this simplified approach that mirrors the practice in this specific category of countries, the advantages are that governments are shielded from downside risk and that they receive revenue at an early stage. The downside is that they generate less overall value, and thus potentially lower overall revenue, as PSA contracts are not tax neutral as prescribed by taxation theory. This may lead to some profitable projects not being sanctioned or delayed, as well as suboptimal development concepts for sanctioned projects that have a lower extraction ratio. This is a particular problem since international oil companies ration capital, e.g., in terms of demanding a low breakeven price. Production sharing contracts imply a long payback time for the companies and thus a low score on this main financial indicator for project sanctioning. The paper proposes a novel solution to this dilemma, by which IDA-countries can have the best of the two tax systems. The solution is to let the additional banking and insurance services implicitly provided by international oil companies to local governments in PSA contracts, instead of being provided by a financial intermediary. With this arrangement the development country receives payment according to the PSA contract and the oil company is taxed according to a neutral tax system. The financial intermediary receives the differential cash flow. We demonstrate on an LNG investment case that this arrangement could secure project sanctioning as well as a positive net present value for the financial intermediary. The conclusion may not apply to all projects. However, the conflicting preference of extraction companies and IDA resource countries, where both parties want cash early, points to a potential intermediary role for a more patient player. This is a generic situation for extraction industries, e.g., it also applies to mining.

The case presented reveals a potential to improve tax revenue for an African country, by securing project sanctioning of a representative LNG-projects that may otherwise not have been developed. The project is profitable and has the potential to be profitable both to government and the company, but misaligned financial incentives and underlying risk perceptions may block the investment decision. The African government cannot share in the downside of the project, and they want revenue earlier. This is secured by a standard PSA contract. The terms of this contract are unfavorable in the oil companies' decision metric for ranking of projects, the break-even price, due to high front-end loading of investment and substantial downside risk. The paper has shown that this co-ordination failure could leave stranded a project that potentially is profitable to both parties.

This suboptimal outcome could potentially be solved by an international financial institution (IFI). Through correct contract design, the incentives of the government and the oil company can be aligned with the IFI bridging the risk perceptions of both parties. The arrangement demands that the IFI take on part of the initial investment and parts of the downside risk, with a reward of sharing in the production value. The case shows that the IFI involvement is expected to be profitable, but risky. The reason that it could be profitable is that the misaligned incentives make room for a win-win situation. The project can be sanctioned and the IFI shares the positive value of the project.

There are two additional positive effects from a potential IFI involvement that are not accounted for in the case analysis. Thus, the potential reward to the IFI could be higher. First, the project analysis does not account for country specific risk. The same company rate of return requirement is in the analysis applied whether the IFI participates or not. With a PSA contract the company would adjust for political risk, either by adjusting the rate of return requirement or by adjusting the cash flow. This would further reduce the probability for project sanctioning and increase the potential return for the IFI.

Second, the analysis does not account for the fact that the IFI arrangement will make the tax system neutral and that this may change project design and project operation so that the value before tax is increased. With an IFI involvement, the oil company is shielded from distortive elements in the PSA contract and may make additional investment increasing the resource recovery factor. This may generate higher values which may benefit all parties, including the IFI. IFI intermediation can help alleviate other types of political and country risks that hinder credible intertemporal commitments (World Bank, 2012) between investors and resource countries in the gas sector, but also in the mining of green minerals.

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