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EVALUATING FISCAL REGIMES FOR RESOURCE PROJECTS:

AN EXAMPLE FROM OIL DEVELOPMENT

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ABSTRACT

This paper outlines, firstly, criteria that can be used to evaluate resourcetaxation systems, and, secondly, indicators that can be used in a practical project modeling framework to assess the regime against the criteria. Although much of the approach draws from standard procedures used by practitioners in the evaluation of petroleum projects and fiscal regimes for resources, this paper tries to relate these to concepts employed in wider analysis of tax systems and their incentive effects.

The application of the criteria and indicators is illustrated using a simulation for "Mozambique". The paper does not replicate any particular contract or field for that country, but uses the model exploration and production concession contract with possible bid or negotiated parameters added by the authors. The circumstances of a country such as Mozambique recur elsewhere: one major petroleum project is already operating, there are further discoveries but, as yet, no further development decisions, and exploration interest is significant but possibly not sufficient to permit an auction process to work properly. After considering fiscal regime issues for this "Mozambique", the paper locates the possible outcome in international comparisons. As with all such exercises, these have limitations and need to be carefully interpreted, taking account of things they do not show. An investment decision in any country will be determined by much more than a mechanical comparison of the effect of a fiscal regime on investor returns, simulating an identical field across a number of regimes.

INTRODUCTION

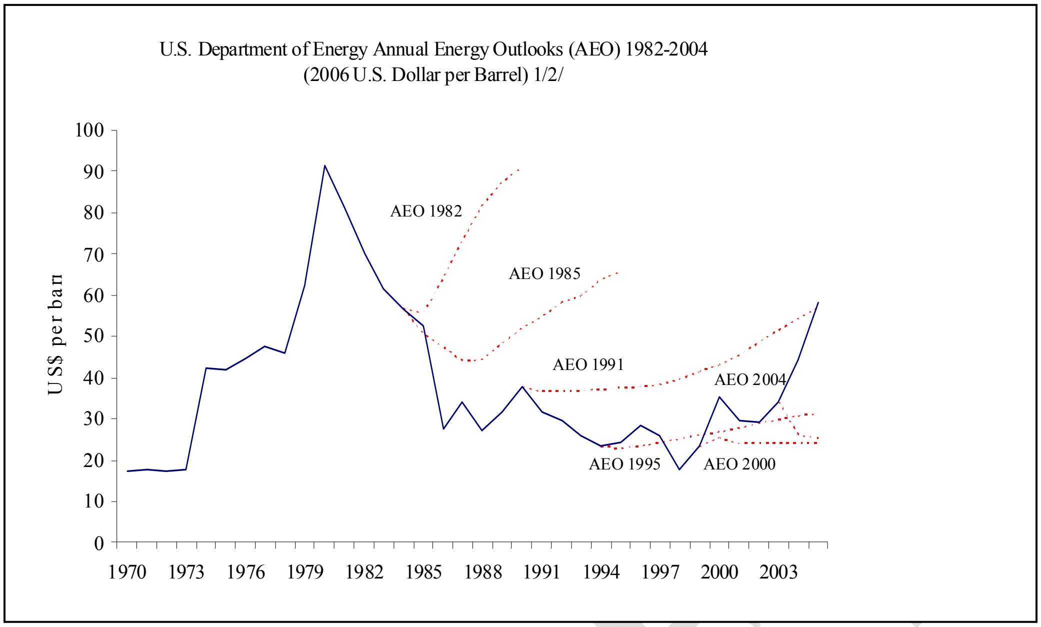
The unprecedented rises in the internationally traded prices of crude oil and natural gas (petroleum) between 2002 and 2008, and the sudden fall after July of 2008, have concentrated attention once again on how petroleum revenues are shared between owners of the resource in the ground (usually governments) and the companies that extract the petroleum. A large portion of world production is undertaken by companies owned by the governments that also own the resource—in some countries (for example, Iraq, Kuwait, Mexico, or Saudi Arabia) production is exclusively undertaken by national oil companies (NOCs) or even by the government itself, representing over 30 percent of world output.. Among member states of the OECD, on the other hand, production by NOCs is now much less common. Across most of the world, the pattern falls somewhere in between—often with the NOC participating alongside private investors in extraction under petroleum rights granted by the government. In these case, the NOC participation terms are part of the overall fiscal scheme (from the viewpoint of a private investor), and the NOC's net revenues form part of consolidated public sector revenues.

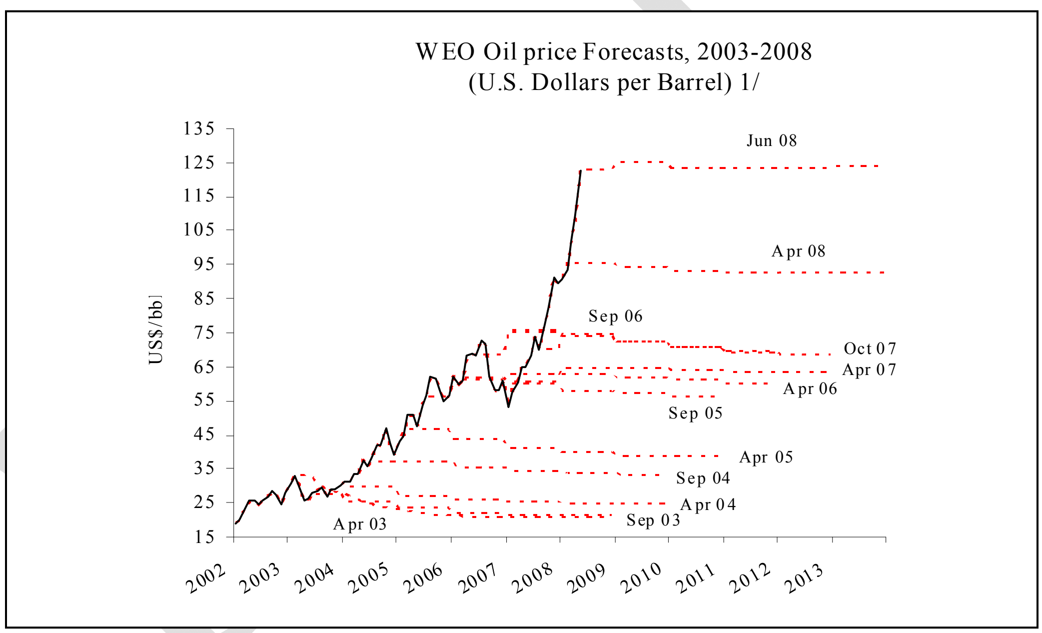
In the mining sector, exclusively state-owned production is less prevalent, though still important (in China and in Chile, for example, as well as many former Soviet Union countries. This paper is concerned with circumstances in which petroleum or minerals are developed with at least part of the capital provided by private investors, so that those investors participate in both the risks and rewards.

The strong rise in prices for petroleum and mineral commodities has occurred against great uncertainty (see Figure 1 for petroleum). Forecasters and forward markets have had a poor record of anticipating market developments. Fiscal regimes designed in earlier times, especially those with little built-in responsiveness to price, have come under strain, leading to renegotiation of agreements or unilateral imposition of new terms by governments.[2] The price boom has also caused a surge in demand for inputs to petroleum and mining production—whether specialized skills, plant and equipment, or supplies—which has sharply driven up the costs of exploration, development and production. For petroleum, it has also caused a revival in of exploration interest in areas thought previously to bear a relatively lower probability of success, and in recovery from high cost and technically challenging locations or sources—deep water and tar sands, for example. Earlier generations of petroleum fiscal regimes designed either from forecasts of field profitability, or with reliance on field size and rates of production as a proxy for potential economic return, have not worked well in the face of such change in market conditions. Mining regimes limited to a low royalty and corporate income tax have also come under strain.

[2] For surveys of changes in petroleum contact terms see Quiroz (2008), and Wood Mackenzie (2008).

Figure 1. Uncertainty in Prices and Price Forecasts





Sources: U.S. Department of Energy, Annual Energy Outlook (1982, 1985, 1991,1995, 2000 and 2004); and IMF World Economic Outlook.
Note: Charts are revised versions of Figure 2.3 in Ossowski et. al. (2008)
1/The solid lines are spot oil prices. The dashed lines are EIA price forecasts (top chart) and future prices (bottom chart)
2/ West Texas Intermediate (WTI) crude oil.

This paper outlines evaluation criteria and a modeling approach that can be used to analyze fiscal regimes for the petroleum and mining sectors from the perspective of a host government. We illustrate with the case of the impact of fiscal regimes at the point of the decision to develop a petroleum discovery. This is the core of evaluation of fiscal regimes, upon which evaluation at other decision margins (exploration, re-investment, abandonment) can be built. The basic approach to exploration evaluation (estimation of expected monetary value, or EMV) requires assignment of probabilities to an unsuccessful outcome and a variety of possible discoveries. The economics of the discovery cases will be like the development project cases studied here. The approach will be similar for mining projects—illustration is left for a subsequent paper.[3]

For many host governments, a key objective is attraction of exploration investment. Hence their interest in international comparisons. International comparison of fiscal regimes, however, has to interact with other factors—above all, the "prospectivity" (combined geological attractiveness and location) of an area. This paper makes no attempt at comparisons of prospectivity (at which oil companies themselves and consultants to the industry are expert, while staff of the IMF are not), except to the extent that differences in fiscal regimes may imply dfferences in prospectivity. Significant differences from country to country in the results of their fiscal regimes (for governments and investors) using identical project examples need to be explained by something—prospectivity as a combination of geological risk, physical location and political risk being the most likely. If they emerge, and are not explained, then an initial case for revision of a fiscal regime can be made.[4]

We outline, firstly, criteria that can be used to evaluate minerals taxation systems, and, secondly, indicators that can be used in a practical project modeling framework to assess the regime against the criteria. Although much of the approach draws from standard procedures used by practitioners in the evaluation of petroleum projects and fiscal regimes for resources,[5] this paper tries to relate these to concepts employed in wider analysis of tax systems and their incentive effects.

The task is different from, but a variant of, the process of project evaluation for investment decision-making by companies.[6] In particular, a government will typically have objectives for the efficiency of revenue-raising, preferences concerning the risk profile of outcomes, and about timing or delay in revenues, as well as objectives that it may hold in common with

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[3] See also the paper for this conference by Lindsay Hogan (2008)

[4] Daniel Johnston (2003: 108), "Tough terms usually correlate with good rocks," defines "prospectivity" broadly to include Adam Smith's notions of both "fertility" and "situation" in the case of land.

[5] For this perspective see for example Johnston (2003, 2007), van Meurs (1981, 2002), Lerche and Mackay (1999), Garnaut and Clunies Ross (1983), Wilson (1984), Hogan (2007), Conrad, Shalizi and Syme (1990).

[6] For a useful recent discussion of project evaluation measures relevant to companies and governments respectively, see Tordo (2007); see also Johnston (2003).

investors for a regime that maximizes investment and output over time. In this paper, the core building block for decision-making is analyzed—the profile of a petroleum project during development and production—from which a probability distribution of differing outcomes can be constructed to guide exploration decisions. The decision process itself works in the opposite direction (from exploration to development and production), with the higher risks usually at the earlier points, but each stage requires an assessment of the end and intermediate points.[7]

The application of the criteria and indicators is illustrated using a simulation for "Mozambique". The paper does not replicate any particular contract or field for that country, but uses the model exploration and production concession contract with possible bid or negotiated parameters added by the authors. The circumstances of a country such as Mozambique recur elsewhere: one major petroleum project is already operating, there are further discoveries but, as yet, no further development decisions, and exploration interest is significant but possibly not sufficient to permit an auction process to work properly. After considering fiscal regime issues for this "Mozambique", the paper locates the possible outcome in international comparisons. As with all such exercises, these have limitations and need to be carefully interpreted, taking account of things they do not show. An investment decision in any country will be determined by much more than a mechanical comparison of the effect of a fiscal regime on investor returns, simulating an identical field across a number of regimes.[8]

[7] See also the later discussion of decision trees.

[8] The risks in international comparisons include: misinterpretation of individual fiscal regimes, differences in treatment of indirect taxes, inconsistency of ring-fencing rules, issues of incremental investments, and interaction between host country tax systems and home country systems of invetsing companies.

I. Evaluating resource taxation systems

A. Criteria used in evaluating minerals taxation systems

Minerals taxation systems can be quantitatively evaluated for their neutrality, revenue raising potential, risk to government (stability and timing of government revenue), effects on investor perceptions of risk, and their adaptability and progressivity.[9]

Neutrality

Neutrality in public finance usage means that a tax instrument (or regime) causes the least possible unintended disturbance to private economic decisions that would be made in the absence of tax. A neutral tax is one that does not change marginal decisions about investment, production, or trade that would have been made in the absence of tax. There will be instances where the imposition of tax can enhance economic efficiency, by correcting for externalities that arise when private and social interests diverge—that is, when there is market failure. For example, governments may use tax policy to reduce environmental pollution when the market, left to itself, would have polluted in excess of a socially optimal amount.

Neutrality in taxation of mining and petroleum activities means that a tax does not, of itself, alter the order in which projects are undertaken; nor does it alter the speed of extraction, decisions about reinvestment, or the decision to abandon a petroleum field, or close a mine.

Revenue raising potential

The presence of natural resource rents makes resource industries major potential contributors to government revenues. Governments seek to tax as much of available resource rent as is compatible with the desired rate of investment in exploration and development, and of production. In most jurisdictions,[10] the government is the owner of the rights to mineral deposits in the ground. Thus, in addition to ensuring the resource sector makes its due contribution to public revenues in the same manner as other industries (through general taxation), fiscal arrangements are usually designed to secure a reward for ownership to the government. Government will usually receive a payment for this resource, separate from the

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[9] See Boadway and Keen (this conference), Conrad et al. (1990), Garnaut and Clunies Ross (1983), Wilson (1984), Hogan (2006).

[10] The USA is a prominent exception (except in the case of federal lands, and the offshore continental shelf).

regular income tax. This additional payment should be no greater than the value of resource rent—a return to the government as the resource owner which will not alter the behavior of the firm.[11] In this discussion, we abstract from the debate about whether resource rent should be broken down into components that include pure rent in the Ricardian sense, and the "user cost" or Hotelling rent—in the sense of the opportunity cost of exploiting a mineral deposit today rather than at some point in the future. The evaluation techniques described here are capable of encompassing both views: effective tax rates can be computed including the effect of a resource payment, or with resource payments treated as part of project costs.

Neutrality itself will be relevant to revenue-raising capacity across a country's mineral endowment as a whole. Efficient allocation of mineral investment implies higher real generation of rent over time, and thus greater taxable capacity.

The effect of the tax system upon the investor's perception of risk will also affect its revenue–raising capacity. If the fiscal terms tend to promote contract stability, or reduce the dispersion of expected outcomes, or avoid enhancing the prospect of negative returns then the size of taxable rent may be increased. Defining rent as the surplus over all necessary costs of extraction, including the minimum returns to capital needed to induce investment in the first place, the reduction of risk will reduce the premium for risk attached to the required minimum returns.

Revenue-raising capacity will also vary with the maximum marginal rate of tax[12] that can be levied on an additional dollar of income or cash flow, and still remain consistent with incentives to continued productive efficiency. it will not usually be feasible to aim to tax 100 percent of rent because there are problems of accurate estimation, possible presence of quasi-rents, and the need for sufficent incentive to continued efficient operation.

Finally, the adaptability of the tax system to the realized profit of a project will also determine its capacity to raise revenue. This is also the progressivity criterion, discussed below.

Risk to government

With given risk preferences on the part of government and investors, it should, in principle, be possible to apportion risks and expected returns in an efficient manner for an individual project. Gains may be made where the parties are prepared to trade mean expected value for

[11] Resource rents from mining can be defined as surplus revenues net of all costs of production, including the company's required rate of return. Economic rents, more generally, are present when there is a factor of production in fixed supply, or under imperfect competition.

[12] Not marginal effective tax rate (METR) in the sense discussed later.

risk.[13] The preferences of the government will vary with its underlying fiscal position, access to capital markets, and the extent of its portfolio of present and prospective resource projects.

Stability and timing of resource revenue is an important consideration for the design of the tax system where there is high government exposure to this volatile source of revenue. In principle, welfare will be maximized where a government can maintain a sustainable fiscal position and, using access to capital markets, mitigate the domestic effects of mineral revenue volatility. Even where this is not always possible, those governments with a diverse portfolio of mineral assets are likely to be better able to withstand volume and price fluctuations than a government dependent, for example, on just one or two large projects. Moreover, a medium term macroeconomic framework could be preferable as a stabilizer to sub-optimal tax system.

For those with large resource tax revenues, weak fiscal positions and a limited access to capital markets, or with a very restricted portfolio of projects, a stable revenue stream throughout the life of the project may be desirable—even if it results in some diminution of total revenues over time. The more a government prefers such stability, the more it will favor a fiscal regime weighted towards fiscal instruments such as royalties that are related to total volume or value of minerals produced, and less towards taxes based on profits or cash flow.

A risk-averse party will attach greater weight to outcomes falling below the mean of the probability distribution of expected outcomes,[14] whereas a risk-neutral party will attach the same weight to all outcomes whatever their location along the probability distribution. The usual assumption is that companies are risk averse, while governments are risk neutral. For a risk-neutral government, the variance of expected outcomes will be a reasonable measure of risk. A government may seek to reduce that variance, foregoing the prospect of exceptional revenues to reduce the risk of very poor outcomes. If it is argued that the opportunity cost to government of exploiting the particular resource is low, then companies and governments would face significantly different profile of potential outcomes—government would face the chance of a sub-optimal gain, while companies face risk of absolute financial loss.

The risk of deferral of government revenue is subject to the same considerations.[15]

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[13] See Conrad, Shalizi and Syme (1990) 45

[14] See the next section for a special adaptation of this concept in resource taxation problems: it is assumed that, in practice, investors associate risk with failure to attain a target rate of return.

[15] Specification of the risk preference (utility function) of any one government is beyond the scope of this paper. In practice the preference will tend to be revealed through choices between stable and variable sources of revenue, and early or later revenue, where the risk of overall reduction of revenue is greater with the risk averse choice.

Effects on investor perceptions of risk

Reduction of risks perceived by investors may reduce the required rate of return and raise the amount of rent available for collection. Risks face by resource investors include: substantial initial investment exposure before revenues are generated and the possibility of long payback period to recover this investment; uncertain commodity prices; and the political risk of unilateral alteration of fiscal terms by governments.[16]

Subjective expectations will play an important part in the determination of mineral rent—taken to mean the value of the product of a resource minus all the necessary costs of production, including the minimum return to capital that is require *ex ante* to induce the investment. Under uncertainty, expected return will be an assessment of the probability distribution of returns after tax. The supply price of capital to a project will be the probability distribution (or convenient summary measure of the distribution, loosely termed the "rate of return") required by the least demanding investor. Because this is a subjective assessment, government can influence it by measures to increase the security of investment, accelerate the recovery of investment (payback), and reduce the likelihood of those negative outcomes that add greater weight to the investor's perception of risk.

Assuming resource companies to be risk-averse, they will attach greater weight to outcomes falling below the mean of a probability distribution of expected outcomes. In analyzing resource taxation problems, however, it can be argued that, in practice, investors associate risk with failure to attain a target rate of return.[17] If so, the greater the value of outcomes below the target the greater the risk, and then risk can be measured as the expected value of outcomes with negative present value, discounting at the supply price of investment.

The assumption of risk aversion on the part of investors is very likely to hold where a significant part of the contribution to total investment funds is made by "bankers". This will occur where the finance for a project is not wholly a balance sheet liability of sponsoring companies, but where project lending is provided by financial institutions relying not on the guarantee of the sponsors (at least after completion) but on the cash flows and assets of the specific project.[18] Although "bankers" providing such finance may charge an interest rate

[16] In principle, the risks of this type in any individual project are diversified for a company that already has a significant portfolio of producing assets. This feature underpins the argument that a large oil or mining company is better able to assume certain risks than a fiscally-constrained developing country. Nevertheless, individual petroleum projects can represent a large portion of the total budgeted outlays even of major corporations.

[17] See Palmer (1980) , Wilson (1984)

[18] The circumstances known generally as "project finance", where the debt facilities are "non-recourse" to the balance sheets of the sponsor companies. A common arrangement in resource industries has been for sponsors

(continued)

margin above the cost of credit guaranteed by the sponsor companies, they still do not (usually) participate in the potential for equity-type returns when a project is especially successful. For a project financed in this way, therefore, the providers of capital as a collective have a strong preference *ex ant*e for the avoidance of negative outcomes. In loan calculations, this will be expressed as a requirement for the project to meet certain financial ratios, especially a debt cover ratio (ratio of free cash flow after taxes to obligations for principal and interest payments on debt.)

The contribution of any tax regime to expectations of stability in contract terms will be difficult to measure. The closest proxy is likely to be some measure of the responsiveness of the fiscal regimes to changed circumstances in output prices, costs, or volumes of production.

Adaptability and Progressivity

The adaptability of the tax system to realized profit will have a strong bearing on revenue-raising capacity, especially when the tax system is of general application across projects. Taking the realized profit, or "profitability", as the combined outcome of costs, output prices, and output volumes, the adaptability of the system will also influence investor perceptions of risk. A system that responds flexibly to changes in circumstances may be perceived as more stable. Depending upon the parameters set, it may also be less likely to increase risk, since it will take relatively less in conditions of low, or no, realized profit.

Adaptability can be measured by indicators of progressivity (discussed below), where progressivity means that a tax regime will yield a rising present value of government revenue as the pre-tax rate of return on a project increases. Conversely, a regressive regime will bear heavily on projects of low profitability, and the government share will decrease as intrinsic profitability rises.

Interaction among criteria

There are unavoidable trade-offs between neutrality, revenue-raising capacity, the risk and timing of the receipt of revenue, and the adaptability or progressivity of a fiscal system**.** A fiscal regime that is less reliant on income taxation and more on royalties will generate a relatively more stable and timely revenue stream, while imposition of import duties will yield a revenue stream during the investment phase. However, import duties will increase the cost of investment, and royalties may raise the marginal cost of extraction—discouraging

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to provide banks with a completion guarantee for the project facilities, which falls away after a period of commissioning and successful testing. At that point, the banks have recourse only to the cash flows and assets of the project itself. "Bankers" may in turn lay off some the risks on other parties or through insurance instruments.

development, at the margin, of otherwise economic projects or remaining resources. Similarly, an increase in the tax rate applicable to existing projects may raise revenue potential, but it will deter future investment (and, in the long run, reduce revenue). Administrative considerations are also important. For example, a royalty based on a transparent price formula may be easier to administer and monitor than a resource rent tax.[19] These trade-offs and administrative considerations call for political judgment—a unique best policy cannot be proposed.

B. Indicators for Measuring the Evaluation Criteria

We begin with consideration of indicators commonly used in general analysis of taxation, and then consider how these can be applied in the specific context of petroleum and mining.

Average effective tax rate

With mobile capital, neutrality of the tax system can be interpreted with respect to the decision on where to invest, and the decision on how much to invest.[20] For a given investment, without other locational differences, the discrete choice between two or more mutually exclusive locations depends on the average effective tax rate (AETR)—how much tax a firm will pay on an average investment. It can be proxied by the ratio of tax collections to a measure of the tax base, using either national accounts and other aggregate data (Mendoza, Razin and Tesar, 1994) or financial statement information (Collins and Shackelford, 1995). However, these measures have been criticized because they are backward looking in that they reflect taxes levied on income generated by past investment decisions. In response to such criticisms, Devereux and Griffith (2003) developed a framework for a forward-looking AETR. A forward-looking AETR is familiar in resource industries, calculated as the ratio of the NPV of tax payments to the NPV of the pre-tax net cash flow from a project that generates a return greater than that from a marginal investment.

Marginal effective tax rate

The location decision, however, depends upon evaluation of the optimal investment in each possible country, which will vary with the marginal effective tax rate (METR). The METR

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[19] A resource rent tax is imposed only if the accumulated net cash flow is positive. The net negative cash flow is accumulated at an interest rate equal to the company's cost of capital or discount rate. Thus, a resource rent tax provides the government with a share of returns once the company earns a certain minimum rate of return. See Nellor (1995) for a discussion on the merits of the resource rent tax and other fiscal instruments.

[20] This distinction is also made in Devereux and Griffith (1998a, 1998b and 2003) and in the Commission of the European Communities (2001).

is the ratio of the difference between the pre- and post-tax rate of return, for a marginal investment, to the pre-tax return.

The size of this "tax wedge" depends on a number of factors, in addition to the rate of tax on profit. The real after-tax rate of return on investment is affected by the tax treatment of the financing of the firm, and tax depreciation provisions. Inflation assumptions affect the calculation in that inflation erodes the value of future tax depreciation allowances, or losses carried forward, but increases the value of future interest deductions arising from debt financing. Indirect taxes, particularly import duties, may also be important, as will specific investment tax incentives, such as tax holidays, and the tax treatment of inventories. For investments that are domestically financed, the METR may also be affected by the personal income tax regime through its impact on the after-tax rate of return to saving. For example, the tax system may make a distinction between interest, dividends and capital gains, introducing distortions into an individual's choice of savings vehicle, or it may influence inter-temporal consumption preferences.

Application to resource projects

Some re-interpretation is required to apply these measures to the evaluation of resource taxation systems.

For all practical purposes, the interaction with personal income tax systems can be ignored. In the circumstances of petroleum investment in developing countries, the bulk of the inflow is from overseas and only the return at the corporate level needs to be considered.[21]

The investment decision concerns a resource whose dimensions are initially estimated and whose location is fixed,[22] and for which the techniques and scale of production are also largely fixed (with little or no substitutability among factors of production). The METR therefore does not serve as a determinant of scale of investment at the individual project level. If we conceive of petroleum investment in a country over time, over the whole of its possible petroleum deposits, then the METR would be an indicator of the deviation between the optimum level of investment to extract available resources, and the investment that will be forthcoming with a given fiscal regime.

[21] The interaction of home and host country tax systems remains important because of the foreign tax credit issue.

[22] Knowledge about the extent of any resource will nonetheless change as it is developed.

The METR can be viewed as an indicator of the neutrality or otherwise of the fiscal regime. Where there is a large tax-induced wedge between before and after-tax rates of return, then the range of otherwise feasible projects than can be developed will be narrowed. The ordering of projects may also be changed if the fiscal regime produces varying METR results for projects with differing cost and production profiles.[23]

A less formal expression of this concept (which we illustrate below) is estimation of the output price (strictly, a price path) at which a particular project will generate a post-tax rate of return that will just induce investment—a “breakeven” price. An alternative is the minimum size of resource required for viability, with given techniques and prices.

Given the fixed location of deposits, the METR applied to a petroleum project can be compared across countries. Ideally, it should be calculated separately for each fiscal regime with a field example appropriate to that regime, or at least to the country’s circumstances. Most international comparisons (including ours) examine the effects of different fiscal regimes on a suite of typical field examples, so that fiscal differences alone are captured.

The literature on estimating METRs is extensive with differences in the scope of tax ` treatment incorporated and assumptions made.[24] Most studies only include direct taxes in the METR calculations as the inclusion of indirect taxes, in particular withholding taxes and import duties, is complicated by their complex structure (multiple rates and exemptions), making their exact impact on a particular project difficult to determine.[25]

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[23] For those accustomed to estimation of METR for investment in manufacturing industry, a change of assumptions is necessary. For example, it is usually assumed that immediate expensing of capital investment for corporate tax purposes results in a zero METR for equity-financed investment. This holds only if *either* the firm has current income sufficient to deduct the investment expense in full, *or* unrecovered losses can be carried forward with interest at the firm’s discount rate. The first condition does not hold for the initial investment in a large petroleum project that is ring-fenced, and the second condition is a feature of only a very few petroleum tax systems (that of Norway now incorporates it).

[24] King and Fullerton (1984) and Boadway et.al. (1987) are seminal. These studies differ in a number of ways, including assumptions about the costs of debt and equity financing, and Boadway’s application of the model to a small and open economy. Boadway, Chua, and Flatters (1995) extended the standard model to consider firms operating under a tax holiday.

[25] Studies that do incorporate them typically have to make simplifying assumptions. Recent empirical applications include the analysis of corporate taxes in the EU (Commission of European Communities, 2001), the Canadian and US tax systems (Ruggeri and McMullin, 2004), sectoral incentives in Zambia (FIAS, 2004), and tax incentives and investment in the Eastern Caribbean (Sosa, 2005).

The AETR—better known as "government take" in the petroleum sector—is a familiar measure used in international comparison of fiscal regimes. It compares the share of petroleum rent taken by government across countries: the "government take" at a rate (or range of rates) of discount designed to simulate the risk adjusted return required *ex ante* by investors.

A major limitation of most AETR and METR estimates is that they ignore risk. In most cases, calculations are based on the assumption that all non-tax factors are the same in each jurisdiction being analyzed, including a common discount rate in NPV calculations. Such an approach ignores differences in risks across jurisdictions—both sovereign (political and regulatory stability, and reliability of infrastructure) and geological (uncertain reserve quantity and grade)—which may lead to erroneous country-attractiveness rankings. This issue is explored in depth in the following section.[26]

Stability and timing of government revenue

The stability and timing of government revenue can be assessed by analyzing the profile of estimated tax payments. Different tax regimes will create different tax profiles (a) through the effect on the timing of investment and production by altering incentives (non-neutrality), and (b) because different tax instruments will give rise to different profiles for a given pattern of depletion of mineral deposits. Stability can be assessed by calculating the variance in NPV of government cash flow, while timing can be assessed by constructing various summary measures, such as the proportion of the cash flow received in the first *n* years of the project.

C. Indicators of Investor Risk

The measures used to evaluate mineral taxation systems require the calculation of the NPV of before-tax and after-tax cash flows. This section examines a number of alternative methods for doing this that incorporate an investor's assessment of risk.

[26] Other limitations are that: the neoclassical model of investment behavior on which the METR is based is only one of a number of competing theories; it measures the distortion on investment through the tax system, not the actual responsiveness of the firm to the changed incentives; the financial structure of the firm is taken as given and is not endogenous to the tax provisions.

Variations of the discounted cash flow method

Using "hurdle" rates to estimate NPVs

The discounted cash flow (DCF) method is the traditional approach used by investors to calculate a project's NPV. In this approach, the expected values of future cash flows are discounted using a risk adjusted discount rate, or "hurdle" rate. If the cash flows are known with certainty, the discount rate only needs to account for the opportunity cost of capital to the firm—a "risk free" cost of capital. However, if the cash flows are uncertain, the discount rate will equal the sum of the cost of capital and the premium that is required to compensate the investor for risk. In resource projects, those risks can be project-specific and country-specific. A typical approach begins with the principle that the hurdle rate should equal the firm's cost of capital (see Appendix 2 for an approach to estimation of the cost of capital). This will reflect the firm's financial leverage, after-tax borrowing costs, and expected return on equity. Calculations are typically performed, first, on an all equity basis, so that financial leverage can be then be use to optimize returns to the firm's equity. For individual project appraisal, the hurdle rate might consist of the cost of capital, plus a premium for technical and commercial risks in the project, and a premium for sovereign risk related to the country in which the project is located.

This paper follows that approach in implicitly evaluating an assumed successful outcome, using a higher discount rate that is, in effect, adjusted upwards to take account of the probability of failure.

Internal rate of return

Some of the difficulties in estimating hurdle rates can be avoided by comparing internal rates of return (IRR). The IRR is the discount rate that equates the NPV of a project to zero. A common investment rule is to accept an investment project if the opportunity cost of capital is less than the IRR (in which case the NPV would be positive). The residuals from a cross-country regression analysis with IRRs as the dependent variable and proxies for various risks as independent variables would help assess the attractiveness of the project—positive residuals could be interpreted as above-average risk-adjusted returns from the project compared to other jurisdictions. In addition to avoiding the need explicitly to construct hurdle rates, this approach may also be more intuitive, especially if presented in a graphical form when the correction is needed for only one type of risk.[27] However, there are a number of pitfalls in using the IRR (Brealey and Myers, 2005). These include the possibility of there not being a unique IRR, difficulty in ranking projects where the upfront outlay is different, and

[27] Other known risk premia could be directly subtracted from IRR when there is more than one risk.

inability to account for an opportunity cost of capital (and, hence, discount rate) that varies over time.[28]

Criticisms of the discounted cash flow method

The risk-adjusted DCF method has been criticized for not properly accounting for cash flow uncertainty. In addition to the practical difficulty in choosing a risk-adjusted rate, the DCF method has been criticized for applying a single discount rate to both revenue and expenditure cash flows. Many argue that revenues and expenditures should instead be discounted separately, using rates that reflect the riskiness of each cash flow component.[29] Further, the use of a single discount rate assumes that the risk structure is stationary, which may not be the case, especially for long-life mining projects where risk tends to decline as the project develops.[30]

Another criticism of the DCF method is that it ignores managerial flexibility, though this is not inherent in the method. Specifically, the DCF method implicitly assumes that managers are passive once the binary decision on whether to invest has been made, regardless of how future events unfold (Smith and McCardle, 1998). However, in reality, managers respond to developments in output prices and other uncertain variables by expanding or abandoning production, or by varying the firm's output mix or its production methods. In some cases, managers may also have the option to wait before committing to investing. Options such as these are valuable and so the DCF method will understate the NPV of those projects that afford managerial flexibility.[31]

Alternative approaches

An alternative approach to accounting for risk is to discount certainty-equivalent cash flows using the risk-free interest rate. The certainty-equivalent cash flow is the amount that would make the investor indifferent between having that amount for certain or maintaining the rights to the uncertain cash flows from the project. (Box 1).

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[28] Multiple IRR's can come about when there is a large negative cash flow at the beginning and at the end of the project's life (e.g., a mining investment that entails significant clean up costs).

[29] See Jacoby and Laughton, 1992; Emhjellen and Alauoze, 2003; Samis, Davis, Laughton, Poulin, 2006.

[30] See (Jacoby and Laughton, 1992), and (Smith, 1998).

[31] Another criticism is that use of WACC assumes a constant corporate structure/gearing. Maybe reasonable assumption for large multinational.

Box 1. Certainty Equivalent Approach to Account for Risk

The certainty-equivalent method is closely related to the RADR method. However, instead of discounting expected cash flows using the RADR, certainty equivalent cash flows are discounted using the risk-free interest rate. In other words, the certainty equivalent approach adjusts for risks in the estimates of the cash flows, not through adjusting the discount rate. The certainty-equivalent and RADR approaches to calculating the NPV are both theoretically acceptable, with the preferred method dependent on practical considerations (Grinblatt and Titman, 2002).

Financial market information can often be used to construct certainty-equivalent cash flows for mining projects. For simplicity, it is often assumed that the only source of uncertainty is the commodity price, with production levels and costs known (or the risk assumed to be diversifiable). Certainty-equivalent cash flows can then be obtained relatively easily for those commodities whose forward (or futures) prices are quoted on commodity exchanges. The adjustment for risk takes place by using the forward price rather than the (higher) expected spot price, with the difference between the two a measure of the non-diversifiable risk of the commodity price. It will be necessary to extend the risk-adjusted price beyond the two-to-three year time frame that forward prices are typically available. One option is simply to extrapolate the price (McCarthy and Monkhouse, 2002), while another is to model the underlying stochastic process (see discussion below on real options).

Certainty-equivalent cash flows are more difficult to construct in the absence of financial market information. One option is to estimate the unobservable forward price (or the risk discount factor to be applied to the expected spot price to arrive at the forward price). This can be done econometrically or using financial models similar to the CAPM or arbitrage pricing theory (Grinblatt and Titman, 2002). Another approach is to attach probabilities to various cash flow projections and assume a utility function for the investor (e.g., Smith, 1998). A risk averse investor will have a certainty-equivalent net cash flow that is less than the project's expected net cash flow, with the size of the discount determined by the investor's attitude towards risk, as reflected in their utility function. The major disadvantage of the certainty-equivalent approach is that choosing the correct model to estimate forward prices or an investor's utility may not be any easier than choosing the hurdle rate.

The real option method recognizes that the methodology to value financial options can also be applied to value real assets. A basic call option gives the buyer the right, but not the obligation, to buy a security at a specified price in the future. Similarly, an investor can purchase the rights to undertake an investment project: the underlying asset is the present value of expected net cash flows from the project; the exercise price of the option is the required investment outlay; and the term of the option is the period for which the firm has the rights to the project. A similar framework can be applied to analyze other real options such as the flexibility to change levels of production in response to price movements (Box 2).

Box 2. Real Options

Brennan and Schwartz (1985) and McDonald and Siegel (1986) were among the first to apply financial option valuation techniques to real options (flexible production levels and the optimal timing of initial investment, respectively). The valuation methodology models the price of the underlying asset and does not require estimating a discount rate. Options are difficult to value directly because the asymmetric nature of the payoff implies that the risk and appropriate discount rate changes each time the price of the underlying asset changes. Black and Scholes (1973) proposed to value the option indirectly as part of a risk-free portfolio: it is possible to borrow money and take a long position in the option and a short position in the underlying asset such that the capital gains from one investment are completely offset by the loss from the other. Arbitrage will ensure that the two investments are priced equally, and because the portfolio is riskless the rate of return should equal the risk-free rate. To use the pricing formula it is necessary to assume that the price of the underlying asset follows a well-defined process. In the case of financial options, the stock price is typically assumed to follow geometric Brownian motion (prices are lognormally distributed). There is no need to assume a discount rate given that the pricing methodology relies on being able to construct a riskless portfolio.

Important differences complicate the use of the real options approach for resource investments. Resource investments are similar to a sequence of options (option to explore, followed by an option to develop, followed by an option to vary production) which increases complexity and requires a compound option formula. Modeling complexity is also increased if there is more than one source of uncertainty. As a result, it is typically assumed that there is only one real option to be considered, and only one source of uncertainty (Lander and Pinches, 1998). A further and more material difference between real and financial options is that the underlying asset of a real option (project value) is not traded. It is difficult to construct a portfolio of the underlying asset and the loan that has the same payoff as the option (the initial value of the asset is unknown, as is the underlying stochastic process).

The commodity price is typically assumed to be the only source of uncertainty; however, challenges remain even with this simplifying assumption. Mixed methods can be used to address the problem of projects not being tradeable assets with observable market prices (Smith and McCardle, 1998). This involves restricting option valuation techniques to situations where the underlying asset is tradeable (e.g., commodity price rather than entire project value) and using traditional methods to capture other risks. If the underlying asset is the commodity price, typical assumptions are that the price process follows geometric Brownian motion or mean reversion. Laughton and Jacoby (1995) and Smith and McCardle (1997) demonstrate that the valuation is highly sensitive to the assumed underlying stochastic process. Parameter estimation of the chosen functional form is also an issue. This can be done using historical data of market prices but the point estimates will not always be precise and may vary over time (McCarthy and Monkhouse, 2002).

1/ The payoff is asymmetric because gains are unlimited while losses are capped at the price of the option.

2/ See Paddock, Smith and Siegel (1988) for an example of an attempt to model project value directly, and Black and Roberts (2006) and Lund (1992) for attempts at modeling government tax claims as an option.

In view of some of the complications of these methods, they are not further pursued in this paper.[32] Despite its limitations, the DCF method survives and is widely understood.

[32] But see the paper by Lindsay Hogan (2008) for this conference, which uses certainty equivalence..

Modeling specific sources of uncertainty in the discounted cash flow framework

Sensitivity analysis

Sensitivity analysis is used to provide the investor with an assessment of the range and distribution of likely outcomes. The base case, and reference point for further analysis, is the NPV generated by estimating the expected value of each variable used in the DCF calculation. Investors will also be interested in the best and worst cases. These can be generated by using values of those variables with uncertain future values that at the the extremes of a probability distribution. Additional scenarios can also be run to isolate the impact of each source of uncertainty. For example, the effect of different commodity prices can be analyzed by holding input costs and other uncertain variables constant. Sensitivity analysis can also usefully highlight the impact that the choice of discount has on the NPV calculation (e.g., Otto, 2006). A key limitation of this approach is that gives little insight into the relative likelihood of different outcomes.

Monte Carlo simulations

This approach involves defining a probability distribution for each project variable that is uncertain, and using a computer program to sample from these distributions the cash flow for each period. After large numbers of samples, an estimate of the probability distribution of project NPV can be made. A number of useful summary statistics can then be calculated, including the expected NPV, standard deviation of NPV, and the probability of the NPV being less than a chosen threshold. Simplifying assumptions are typically needed to make the model computationally tractable, and most commonly involve assuming that some variables are deterministic and those that are stochastic are normally and independently distributed (e.g., Bohren and Schilbred, 1994).[33] To the extent that these assumptions are not valid, the estimated NPV distribution will deviate from the true (unknown) distribution.

In the illustrations for this paper, work of this type is confined to the price forecasting routine described in Box 3.

[33] In analyzing petroleum projects, Bohren and Schilbred (1980) assume that operating costs are normally and independently distributed and oil prices take one of two price outcomes with equal probability. However, for petroleum and other mineral projects, output and input costs tend to be positively correlated.

Box 3. Oil Price Simulation

This box explains the autoregressive model (i.e., the price today helps predicting the price tomorrow) used to generate the stochastic oil price simulations used in the paper.

Data used

The original data used are the annual simple average of three oil spot prices: Dated Brent, West Texas Intermediate, and the Dubai Fateh published in the WEO between 1960 and 2007. These prices were adjusted annually for U.S. inflation, using 2007 as the base year, and then normalized by taking natural logarithms.

Autoregressive (AR) model

It is assumed that real oil prices follow an autoregressive process given by

$$y_t = \alpha + \beta\, y_{t-1} + e_t \quad (1)$$

where y_t is the oil price in real terms defined above, α and β are parameters relating the current price to its past value, and e_t is a stochastic error term distributed normally with zero mean and variance σ^2. If $|\beta|<1$, $\alpha /(1 - \beta)$ is the mean of y_t, to which y_t will tend to revert in the long run. Parameters of the model are estimated by OLS, yielding the following estimated equation:

$$y_t = 0.28 + 0.92\, y_{t-1} + e_t \text{ where } e_t \sim N(0, 0.26) \qquad (2)$$

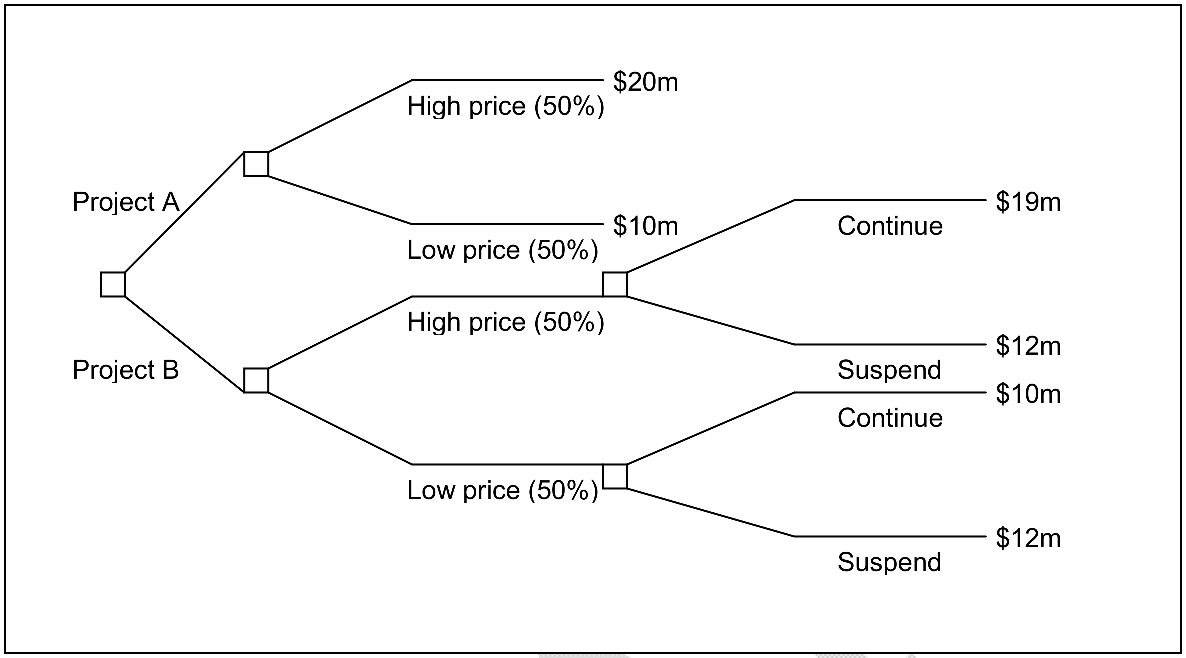
Stochastic simulations

In stochastic simulations, future oil prices are generated recursively using equation (2), starting again from the latest available price level (an average price of US$95/bbl was used for 2008), and with error terms randomly generated (using a normal distribution with parameters reported in (2)). Additionally, lower (US$20/bbl) and upper (US$200/bbl) bounds on oil prices are imposed to avoid extreme values. This exercise is repeated 500 times to construct a range of possible outcomes for future oil prices.

Incorporating managerial flexibility

The decision tree approach improves upon the DCF method by reflecting investors' decisions over time in an uncertain environment. Decision trees outline the available options embedded in projects. They also take into account uncertainty in important variables by attaching probabilities to discrete outcomes. A simplified decision tree for a resource project is presented in Figure 2. The decision tree has nodes which represents points of uncertainty (e.g., unknown commodity price) or decision (e.g., continue or suspend production), and branches which represent a range of possible alternatives at each node (e.g., commodity price is high or low). The project is valued at the end of each branch by discounting the cash flows arising along that branch. Similarly, the probability of an individual outcome can be determined by multiplying the probabilities at nodes along the branch. Thus, the method provides a range of possible project outcomes, and informs the investor of the relative merits of various decisions.

Figure 2: Decision Tree for a Project with an Option to Suspend Production



In the absence of flexibility, Project A is preferred as it has the higher expected NPV ($15m compared with $14.5m (=$0.5*$19+0.5*$10) for Project B). However, Project B enables the manager to suspend production, which he/she will do if the price is low. Taking this flexibility into account, the NPV of Project B of $15.5m (=0.5*$19m+0.5*$12m) exceeds that of Project A.

However, decision trees require a number of simplifying assumptions and do not address the difficulty in choosing the discount rate**.** The main advantage of decision trees is that they explicitly account for different managerial responses that are ignored in DCF methods. However, it requires probabilities to be determined at each node, and compared with Monte Carlo simulation, it gives a less complete picture of the distribution of possible project outcomes. Moreover, the decision tree method has even more difficulty in incorporating correlation between variables (Galli, Armstrong, and Jehl, 1999), and can quickly become very complex and intractably large unless limiting simplifying assumptions are made (Smith and McCardle, 1998). Perhaps most importantly, it inherits from the DCF method the practical difficulty of incorporating risk, either through choosing the discount rate or using certainty-equivalent methods.

A specific case of the decision tree is the assessment of expected monetary value (EMV) in the assessment of exploration economics. This paper is confined to decision-making at the development margin, but the project modeling apparatus can be straightforwardly adapted for the analysis of the effect of fiscal regimes on exploration decisions, using EMV analysis.

D. Summary of the Approach

Principles

Conventional DCF methods offer the simplest approach to evaluating minerals taxation systems on the criteria discussed here. There is little disagreement in the literature on the appropriate evaluation criteria. In contrast, there is much debate over the appropriate modeling methodology. After examining the criticisms of the traditional DCF method, this note analyzed three alternative approaches and found that each has significant implementation difficulties. The pros and cons of each method can be briefly summarized as follows.

- The **DCF** method is the traditional approach used by investors, is intuitively straightforward, and is well understood by all parties. In addition, Monte Carlo simulations can be used to construct an entire distribution of project outcomes, enabling a number of useful descriptive statistics to be calculated. The major criticism is the difficulty in choosing the RADR and that once chosen the same rate is applied to both revenue and expenditure cash flows.

- **Certainty-equivalent** methods offer an alternative approach to accounting for risk by adjusting the cash flows rather than the discount rate. This method holds particular appeal when forward prices are available. However, this will only be the case for commodity prices, and even then, difficult assumptions need to be made about forward prices beyond the maturity for which they are available. The assumptions required when there is no financial market information are problematic, and suggesting that this approach could only be used in conjunction with the DCF method.

- **Decision trees** are a useful device for exploring managerial flexibility. However, it requires a difficult assessment of the probability of discrete outcomes, can quickly become very complex unless limiting simplifying assumptions are made, and does not improve on the DCF approach to incorporating risk.

- **Real options** methods are becoming increasingly popular for project managers as they incorporate managerial flexibility as well as providing a more satisfactory way of accounting for risk. They are, however, difficult to apply in practice, and require a number of simplifying assumptions. These assumptions typically include that the commodity price is the only source of risk, again suggesting that this approach would need to be used in conjunction with the DCF method. In addition, the results are sensitive to the stochastic process that the commodity price is assumed to follow.

On balance, the DCF method remains the preferred tool, particularly as managerial flexibility is less of an issue in comparing fiscal regimes than it is for managers evaluating the merits of an individual investment project.

Measures of impact of the fiscal regime upon investors

The expected rate of return (IRR) on total funds outlaid in a discounted cash flow calculation, where "total funds" means equity, debt and retain earnings expended on project investment. In accounting terms, this return on total funds comprises operating profit less capital expenditure, change in working capital, and taxes. Interest is not deducted, except in tax calculations, so interest must be covered by positive cash flow (and is thus part of the expected return).

The present value of net cash flows (NPV) at a variety of discount rates. The key discount rate is the assumed risk-adjusted rate or "hurdle rate", consisting of the cost of capital, plus a project margin, and, in some circumstances, a premium for country risk. (Alternatively, the measure of country risk could be a target surplus of present value over zero at the project hurdle rate.)

Cost of capital estimates for integrated petroleum companies and petroleum producers in the USA currently seem to lie in a range of 8 to 9 percent in nominal terms.[34] An appropriate "project" margin over this may be 3 to 4 percentage points, bringing this discount rate conveniently close to 12.5 percent nominal or 10 percent in real terms. What then is the appropriate discount rate for an activity outside the investor's home country, incorporating country risk: on dollar denominated bond spreads, the additional margin is probably somewhere in the range of negligible to 10 percent, implying that a "worst case" discount rate (from a government viewpoint) would be 20 percent in real terms, with a "best case" at 10 percent real. In line with earlier discussion, this paper uses a hurdle rateabove the minimum for companies appraising a "success" case of 15 percent in real terms. The effects of varying this rate upwards, and the discount rate for government downwards, are also illustrated.

Average and marginal effective tax rates as discussed earlier.

Breakeven price required to achieve a target rate of return.

Payback period (in years) for recovery in real terms of initial investment outlay.

Sensitivity analysis can be performed over likely ranges of values for input and output variables. In this analysis, sensitivities are confined to oil prices, using the simulation model (Box 3). For each field example, the pretax outcomes are the same in each country, so post-tax variation is accounted for entirely by the impact of the fiscal regime.

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[34] From estimates by Aswath Damodaran (2008).

The investor's expected return is a weighted average of these outcomes: weighted both by the probability of occurrence and the investor's attitude to risk. We take both risk neutral and risk averse cases: (a) where equal weight is assigned to positive and negative outcomes, and (b) where the investor is solely concerned to minimize negative outcomes (those below the assumed target rate of return). The distribution of outcomes is measured both by summary statistics and by graphical representation of the cumulative probability distribution of outputs.

Additional measures of the impact of the fiscal regime upon government

Time profile of government revenue represents graphically the magnitude and timing of revenues, which can be easily compared from one case to another.

The tax (state) share of total benefits. The AETR is equivalent to the familiar notion of "government take", or state (plus national resource company) share of the present value of net cash flows to total funds outlaid at a given discount rate (for example, NPV15), or to "net benefits". When showing this as the state share of resource rent (see Figure XXX) the plotting of the line in cases of increasing profitability usually shows a declining state share as pretax net present value rises, until very high rates of pretax return are simulated. For almost all regimes, this occurs because the effect of royalty, or minimum production shares, or income tax with long depreciation periods, is significant as a proportion of net cash flow when pretax returns are low but falls as pretax returns rise. Virtually all fiscal schemes therefore appear regressive when graphed in this way, and the overall properties of the instruments within the fiscal regime are obscured (especially the progressive elements).

It is useful,in addition, to plot the state share of "total benefits"—revenues minus operating costs and replacement capital expenditure after start-up, expressed at a selected discount rate. These total benefits represent the cash generated by the project that is available to reward the providers of capital (to service both debt and equity, representing the initial capital outlays) and to meet all fiscal impositions, including state production shares and returns to concessional state participation. By this measure, the progressivity of any fiscal regime, with respect to revenues generated by the project, is clearly shown. The shape of the curve also provides another indicator of the extent to which the fiscal regime is likely to impede recovery of initial capital outlays.

The state share of "rent" is a graph of the AETR calculated for a range of present value outcomes, at a discount rate assumed to represent the investor's minimum required rate of return.

Variance of government revenue measured as the coefficient of variation of the present value of government revenues from a probability distribution of outcomes. This measures the dispersion of possible outcomes, and is a measure of risk to government (government may prefer a narrower range of potential outcomes).

Government share of total benefits in the first* n *years of project operation measures, when compared across cases, change in the timing of government revenue. In this analysis the period is 10 years, but could easily be any other desired period.

Table 1. Evaluation Criteria and Indicators

Evaluation Criterion	Key Indicators	Type of Sample or Output
Neutrality	Average effective tax rate (government take in profitable case)	Single case, international comparisons
	Marginal effective tax rate (wedge between pre and post tax IRR, as % of pretax)	Single case at investor's discount rate
	Breakeven price	Goal seek for price just yielding investor's discount rate
Revenue Raising Capacity	Time profile of revenue	Single case, graph
	Share of rent to government	Range of cases, graph
	Tax share of total benefits	Range of cases, graph
Risk to Government	Variance of NPV of revenues (coefficient of variation)	Probability distribution of cases
	Proportion of revenues in first *n* years	Single case (or mean of distribution)
Investor Perceptions of Risk	Dispersion of expected IRR (Coefficient of variation of IRR)	Probability distribution of cases
	Probability of below-target returns	Probability distribution of cases
	Value of negative returns	Probability distribution of cases
	Cumulative probability distribution of outcomes	Probability distribution of cases, graph
Relating Revenue Yield to Investor Risk	Compare expected yield index with expected risk index	Probability distribution of cases
"Prospectivity Gap"	Present value to equalize mean PV to investor	Probability distribution of cases
	Present value to equalize PV of negative returns	Probability distribution of cases

II. EVALUATION OF ECONOMICS OF FISCAL TERMS AND ALTERNATIVE REGIME

This section evaluates the economic terms for potential petroleum operations in "Mozambique" using three simulated oil fields. Stylized fiscal terms ("current terms"), working within the 2007 model EPCC of "Mozambique", are evaluated in terms of neutrality, revenue raising potential, risk to the government, adaptability, and progressivity, as discussed earlier in this paper. The "current terms" are then compared against an alternative fiscal package to illustrate potential benefits from regime refinements. Finally, the "current" and alternative terms are set in an international context, with an estimate of the "prospectivity gap" implied by the fiscal regimes.

A. Economics of "Current Terms" and Alternative Package

The simulated oil field examples are: (i) a medium-large onshore field, ii) a medium offshore shallow water (< 200 m) field, iii) and a large deep water field (1500 m). All exploration and appraisal[35], development, and operating costs reflect actual cost levels in the upstream industry[36]. Table 2 below lists projects and their costs.

Table 2. Project Examples

Onshore Oil Project		
Oil production	million bbl	100
Oil production	years	17
Finding and development costs	$ per bbl	5.5
Operating costs	$ per bbl	4.4
Decommissioning costs[37]	$ millions	20

Shallow Water Oil Project		
Oil production	million bbl	151
Oil production	years	18
Finding and development costs	$ per bbl	13.6
Operating costs	$ per bbl	6.8
Decommissioning costs	$ millions	80

[35] Exploration costs are assumed to be sunk costs. Therefore, they are not included as negative cash flows, but the sunk costs are included for cost recovery and depreciable tax purposes..

[36] The onshore and deep water field data were provided to FAD by Wood Mackenzie. The shallow water field is part of an FAD data bank of petroleum projects.

[37] Decommissioning costs are assumed to be spread out through the life of the project.

Deep water Oil Project		
Oil production	million bbl	1,000
Oil production	years	21
Finding and Development costs	$ per bbl	11.8
Operating costs	$ per bbl	4.8
Decommissioning costs	$ millions	1,000

The simulation of potential revenue generated by the projects uses WEO price projections at mid-September 2008. These extend until 2013, where prices decline modestly over the next year (Figure 3), and a constant price in real terms is assumed thereafter. The "current terms" applied in "Mozambique" are summarized in table 3 below.

Figure 3. WEO Oil Price Projection (as of September 2008)

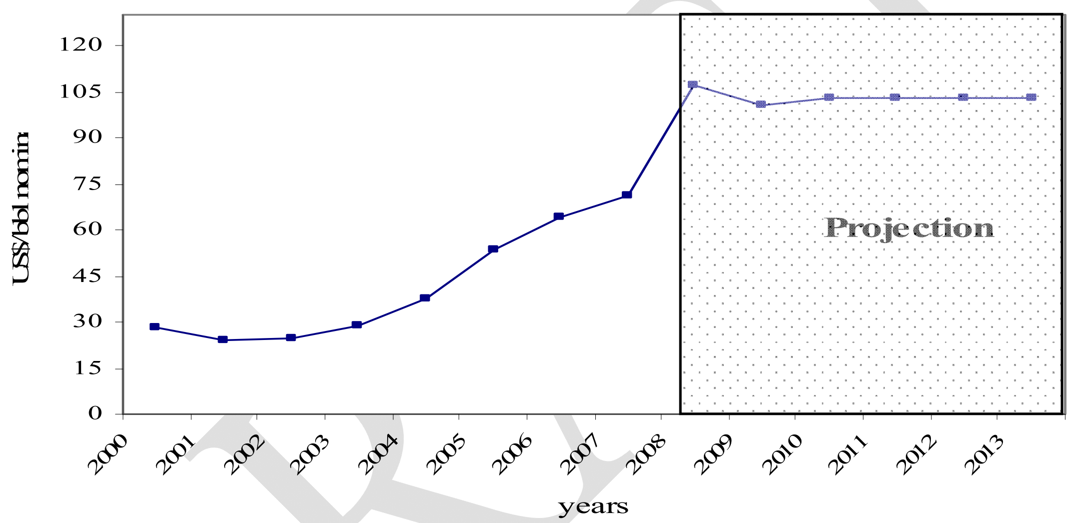


Table 3. Simulated "Current Terms"[38]

Royalty	10%
Cost Recovery Limit	65%
R-factor based profit petroleum sharing[39]	
R-factor <1	10%
1< R-factor <2	20%
2< R-factor <3	30%
3< R-factor <4	40%
R-factor > 4	50%
CIT rate	32%
Dividend and interest withholding tax (WT)	20%[40]
State equity participation	10%[41]

Revenue Raising Capacity

Time profile of revenue

The revenue pattern over the cycle of the projects mainly reflects the production profile. The onshore and shallow water fields have similar profiles, both reach peak production rates early in the life of the project with a subsequent steady decline in production. The deep water project also has high initial production, but reaches its peak production level later in time. While all three petroleum projects have substantial revenue potential, the magnitude will depend on price dynamics. The main source of government revenue, under the current fiscal regime, would be the share of profit oil, followed by corporate income tax (CIT) and royalty. Table 4 summarizes the main economic results for the three oil projects under the "current terms". All results, including revenue and rates of return are measured in real terms unless otherwise noted. The AETR is measured as the ratio of the NPV of tax payments[42] to the NPV of the pre-tax net cash

[38] The fiscal terms are assumptions by the authors, set in the framework of the Model Contract EPCC of 2005 and 2007 published by the "Mozambique" Institute of National Petroleum for its 2007 Licensing Round (http://www.inp-mz.com/).

[39] The R-factor is the "payback ratio". An R-factor = 1 indicates that costs and revenues of the contractor are equal (i.e., undiscounted real net cash flow = 0)

[40] For modeling purposes it is assumed that all investor cash flows after repayment of income tax and debt are remitted as dividends. In practice, however, the investor can reinvest profits, or arrange activities in a way that reduces dividend withholding taxes.

[41] State equity participation is assumed to be carried during exploration (repayable), but no premium is charged for the option to participate in a commercial discovery. This is concessional participation, and the net proceeds to the state are treated as part of the fiscal take.

[42] "Tax payments" are broadly defined to include royalty, state production shares and the revenues generated by concessional state equity participation in each project.

flow from the project at a given discount rate. The AETR represents the “government take” from net cash flow.

Figure 4. Time Path of Gross Revenues and Government Revenues Under “Current Terms” (WEO Prices)

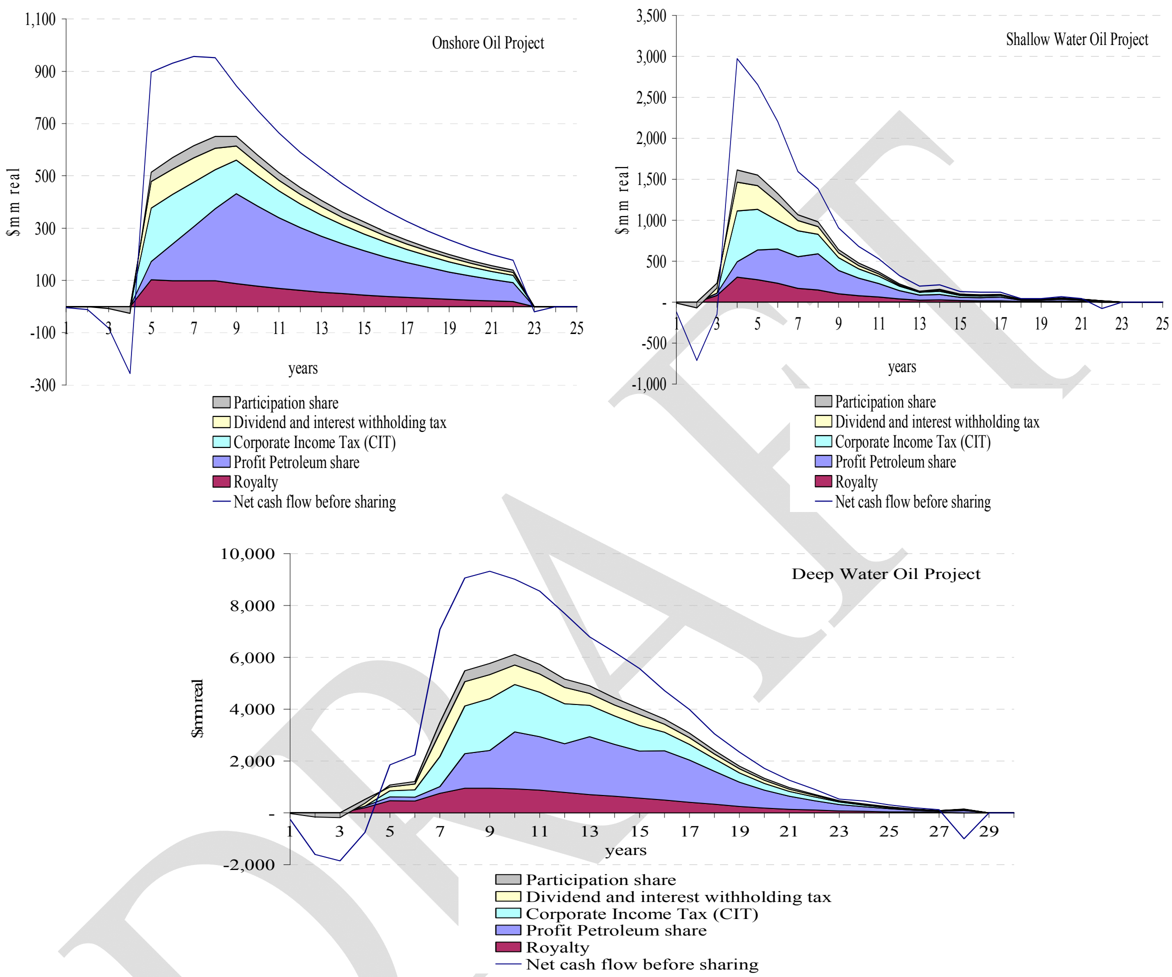


Table 4. Summary Results for the "Current Terms"

	"Mozambique" "Current" Fiscal Regime		
	Onshore	Shallow Water	Deep Water
Project pre-tax real IRR	152%	117%	54%
Post-tax real IRR to contractor	109%	87%	40%
Project pre-tax NPV at 10% ($mm)	3,883	7,390	30,793
Contractor NPV at 10% ($mm)	1,047	2,350	8,755
Payback period at 10% (years from start of production)	1.5	2.4	4.6
Government revenue NPV at 10% ($mm)	2,859	5,162	22,368
Government take (AETR) at 10%	74%	70%	73%
Project pre-tax NPV at 15% ($mm)	2,681	5,737	19,301
Contractor NPV at 15% ($mm)	740	1,857	5,393
Payback period at 15% (years from start of production)	1.6	2.4	4.8
Government revenue NPV at 15% ($mm)	1,974	4,068	14,459
Government take (AETR) at 15%	74%	71%	75%
Project pre-tax NPV at 20% ($mm)	1,918	4,528	12,360
Contractor NPV at 20% ($mm)	539	1,482	3,305
Payback period at 20% (years from start of production)	1.6	2.4	5.1
Government revenue NPV at 20% ($mm)	1,417	3,274	9,728
Government take (AETR) at 20%	74%	72%	79%

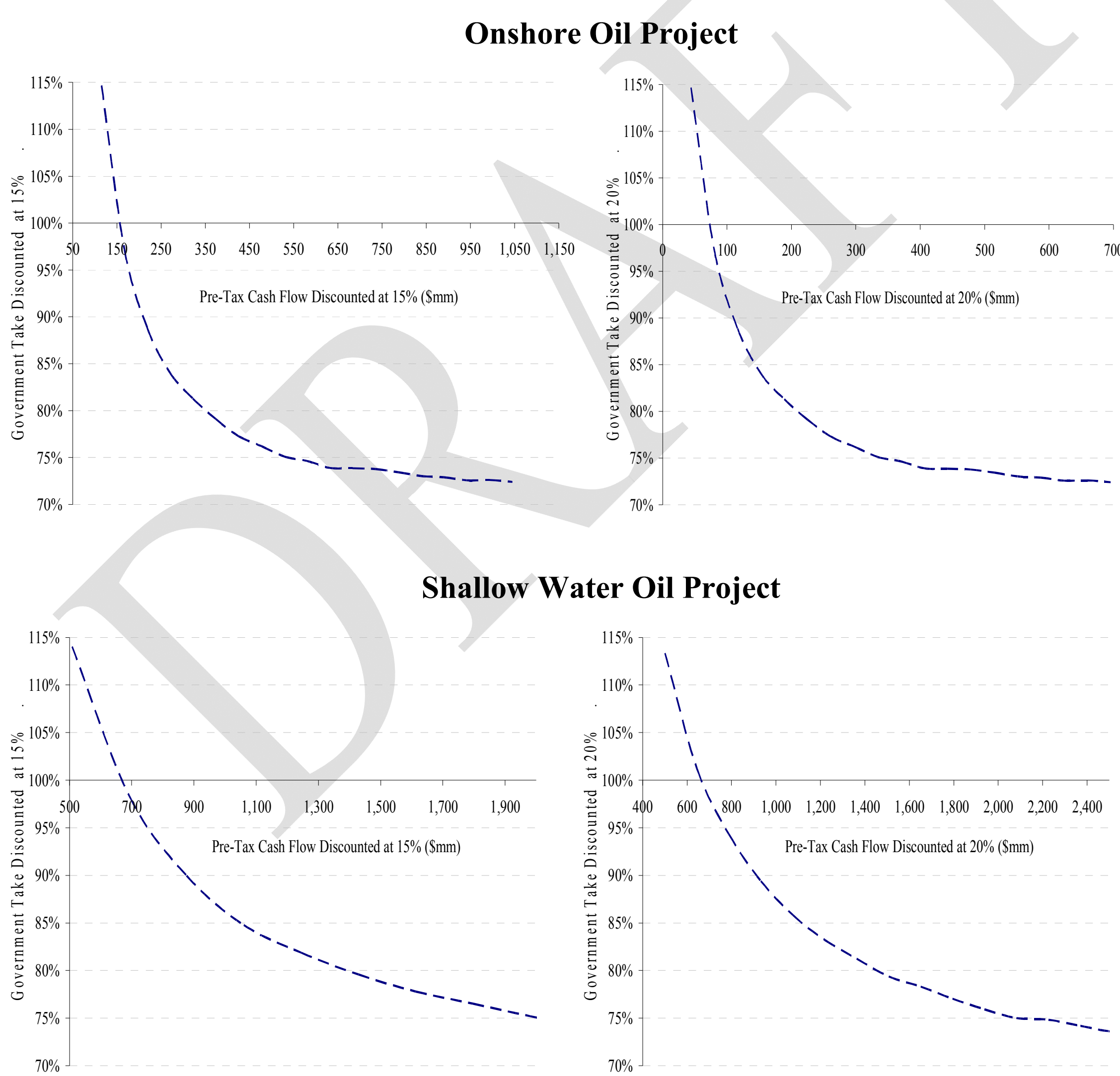
The onshore field has the highest pre-tax profitability because of the combination of a high initial production with the lowest development and operating costs per barrel among the three projects. In contrast, because of its capital cost structure and a more evenly distributed production profile, the deep water field is significantly less profitable than the other two projects.

The government take in the deep water project is higher than in the two other projects when using a rate of discount of 15 percent or higher. As the rate of discount increases, the difference in government take between the deep water field and the other two projects widens significantly, especially when compared to the onshore project. This result is explained by the combined effect of the royalty, the cost recovery limit, and the time value of money. The deep water project takes three times as much time to recover costs as the onshore field, and twice the time of the shallow water field (see payback periods above). Therefore, as the rate of discount increases, pre-tax positive cash flow, which occurs much later in the deep water project, is discounted proportionately more than in the onshore and shallow water projects. Thus, at higher discount rates pre-tax NPV falls at a faster rate in the deep water project, while in all cases early government revenues from royalty payments and first tiers of profit oil will be discounted proportionally. The same pattern is observable when comparing the onshore field to the shallow water project, which requires approximately one year more to recover costs. The government is initially assumed to have the same discount rate as the company of 15 percent in real terms.

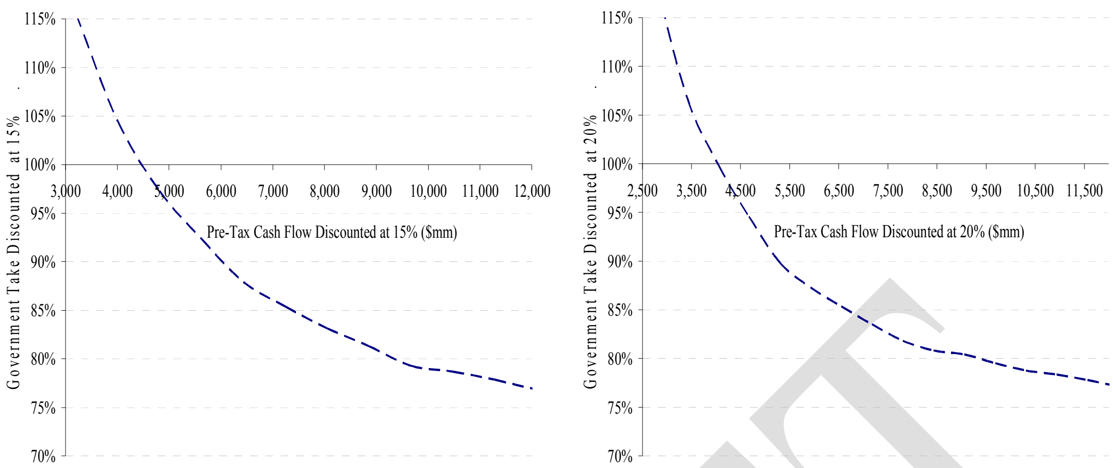
Government share of rent

The AETR is also used to examine the share of "rent" captured for government by the fiscal regime at different levels of profitability. Figure 5 illustrates the AETR over a range of pre-tax cash flow, for the each field, at rates of discount of 15 and 20 percent.

Figure 5. AETR over a Range of Pre-Tax Cash Flows discounted at 15 and 20 Percent



Deep Water Oil Project



Over the illustrated range of outcomes, the share of rent falls as the pre-tax present value of cash flows rises. Where the taxation share is above the horizontal axis, the government takes more than 100 percent of "rent" and the investor's ex-post return will be below the supply price of capital. Under conditions of certainty, investors would not undertake the project in these cases.

Introducing the Alternative Package

The alternative fiscal package offered in this paper is aimed especially at large oil projects with high cost structures, such as the one present in the deep water field described above. Although the parameters illustrated here perform relatively well in the other two projects, these could if necessary differ (for example, within a block-by-block bidding mechanism) to reflect the specific characteristics of other types of oil fields. The alternative package keeps the "current" royalty rate in "Mozambique", to secure early revenues for the government, but increases the cost recovery limit to 90 percent. In addition it introduces a rate of return based production sharing mechanism, and decreases the rate of interest and dividend withholding tax (WT) to rates common in recent bilateral double taxation treaties.[43]

[43] Not specifically those of Mozambique. Currently, "Mozambique" has treaties to reduce WT tax rates applicable to dividend, interest and royalty payments by "Mozambican" companies to non-residents with Italy, Mauritius, Portugal, and the United Arab Emirates.

Table 5. Alternative Package

Royalty	10%
Cost Recovery Limit	90%
IRR profit petroleum sharing (nominal ROR)	
IRR < 15%	25%
15% < IRR < 20%	35%
20% < IRR < 25%	45%
25% < IRR < 30%	55%
30% < IRR < 35%	65%
35% < IRR < 40%	75%
IRR > 40%	85%
CIT rate	32%
Dividend and interest WT	10%
State equity participation	10%

The fundamental difference between the rate of return and the R-factor mechanisms is that the rate of return takes into account the time value of money, while R-Factor does not. Figure 6 illustrates this important difference under the deep water oil project. The rate of return scheme gives a higher value to cash flows occurring earlier in the life of the project, thus, in the early years of the project the rate of return scheme increases at a higher rate than the R-factor. Later in the life of the project the rate at which the rate of return scheme increases is lower than in the R-factor.

Figure 6. R-factor and Cumulative IRR to the Investor for the Deep Water Oil Project

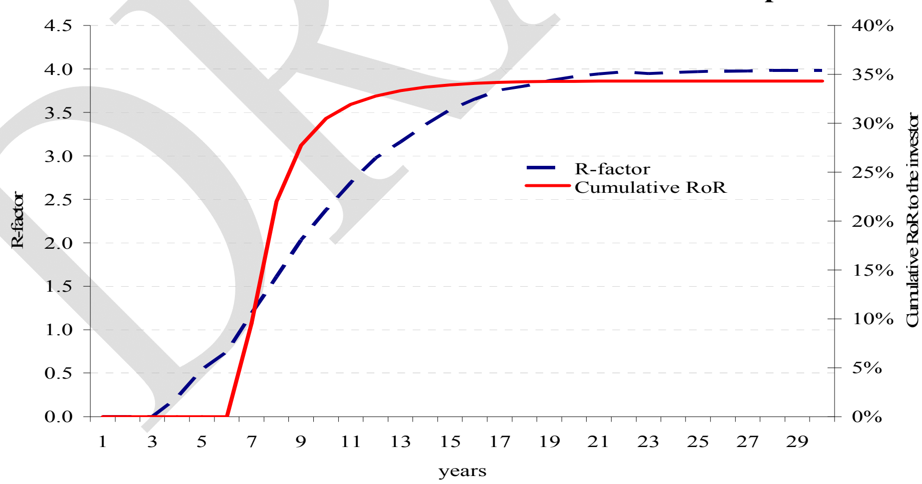
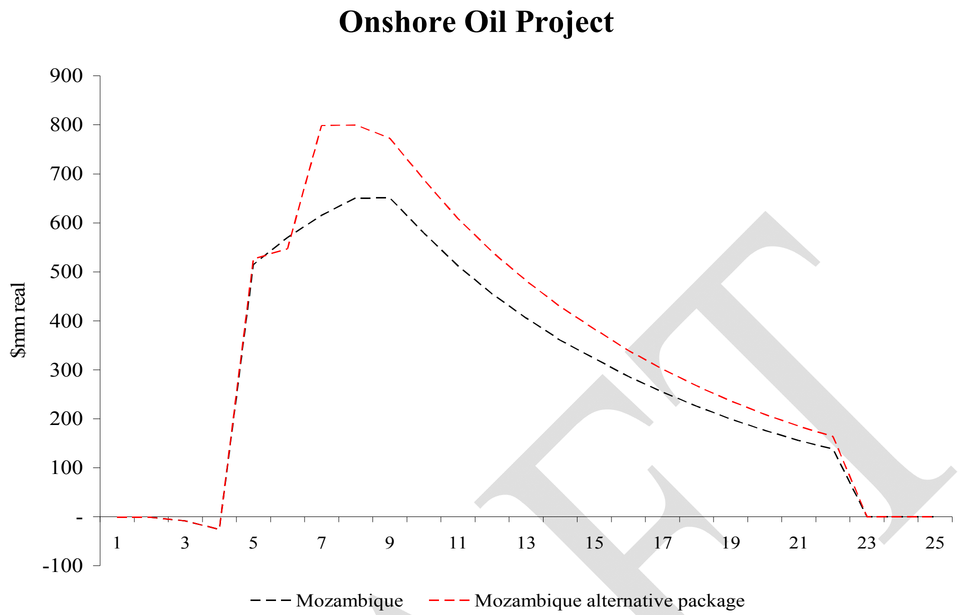
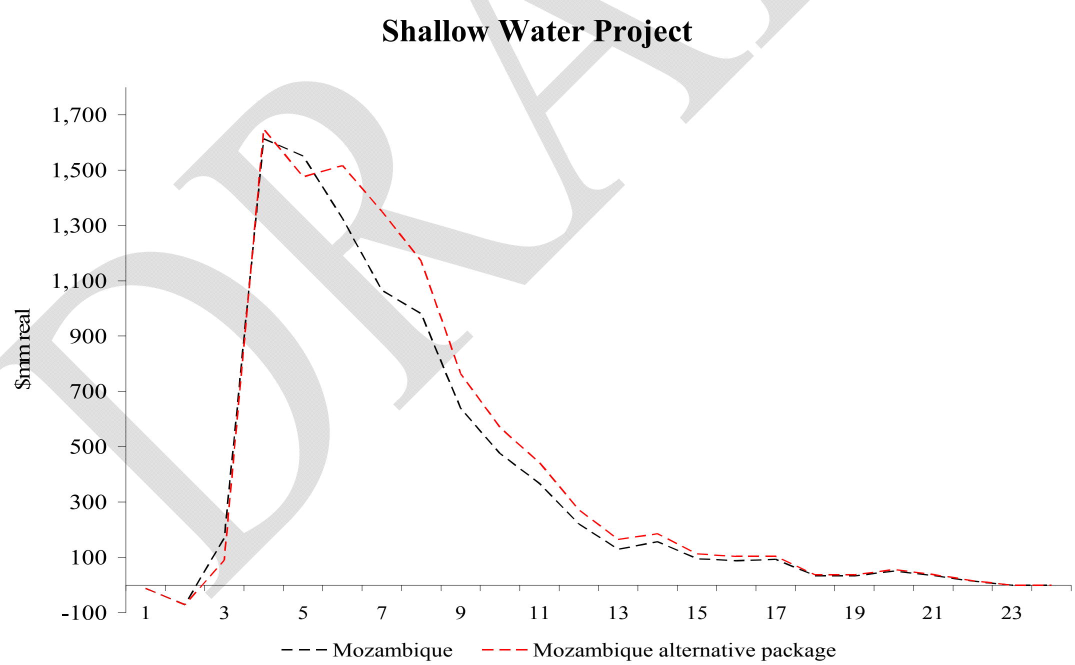


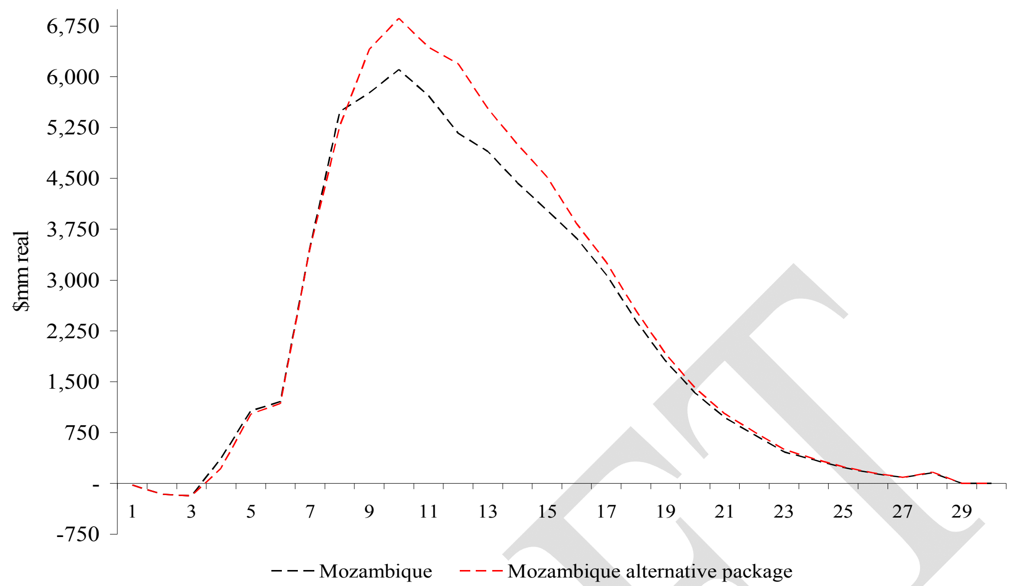
Figure 7 below illustrates the raising revenue superiority of the alternative package, over the "current terms" for each oil field project.

Figure 7. Government Revenues: Alternative Package vs. "Current Terms" (WEO Prices)





Deep Water Project



Neutrality

AETR, Breakeven Price and METR

Along with the AETR, the resource price at which a particular project will generate a post-tax IRR that will just induce investment (i.e., breakeven price) and the METR at that price are also evaluated under the two regimes. The AETR, discounted at 15 and 20 percent, is consistently higher under the alternative package than under the "current terms". In addition, when estimating the oil price at which each project will generate a post-tax IRR of 15 and 20 percent and the corresponding METR at those prices, the alternative package also fares better than the "current terms". Table 6 compares the AETR discounted at 15 and 20 percent at WEO prices, the price required to generate post-tax IRR of 15 and 20 percent and the METR at those prices between the two regimes for each oil field project. The alternative regime therefore appears to improve the trade-off between revenue-raising and investor risk (and would thus come closer to neutrality) but this result is dependent upon the price assumption used for the revenue-raising indicator.

Table 6. AETR, Breakeven Price, and METR

Onshore Oil Project	AETR at 15% (WEO prices)	AETR at 20% (WEO prices)	Price required to achieve 15% post-tax IRR	METR at 15% post-tax IRR	Price required to achieve 20% post-tax IRR	METR at 20% post-tax IRR
	%	%	$/bbl	%	$/bbl	%
Alternative package	85	85	20	44	23	43
"Mozambique"	74	74	21	49	25	47

Shallow Water Oil Project	AETR at 15% (WEO prices)	AETR at 20% (WEO prices)	Price required to achieve 15% post-tax IRR	METR at 15% post-tax IRR	Price required to achieve 20% post-tax IRR	METR at 20% post-tax IRR
	%	%	$/bbl	%	$/bbl	%
Alternative package	79	80	34	47	40	46
"Mozambique"	71	72	37	55	43	52

Deep Water Oil Project	AETR at 15% (WEO prices)	AETR at 20% (WEO prices)	Price required to achieve 15% post-tax IRR	METR at 15% post-tax IRR	Price required to achieve 20% post-tax IRR	METR at 20% post-tax IRR
	%	%	$/bbl	%	$/bbl	%
Alternative package	80	83	49	43	63	42
"Mozambique"	75	79	52	47	66	44

Progressivity

The progressivity of a fiscal regime can also be examined by comparing the government share of project total benefits[44] over a range of pre-tax IRR. In figure 8 below, the variation in pre-tax IRR (i.e., project profitability) is generated solely by varying oil prices. The share of total benefits represents the real NPV of government's revenues over the project life as a percentage of the real NPV of pre-tax total benefits. There are some advantages in the total benefits measure, as an indicator of profitability, over the AETR. First, it incorporates information on the relative tendency of each regime to allow investors to recover their costs. And second, it avoids the masking of relative progressivity of the regime, when presented graphically.

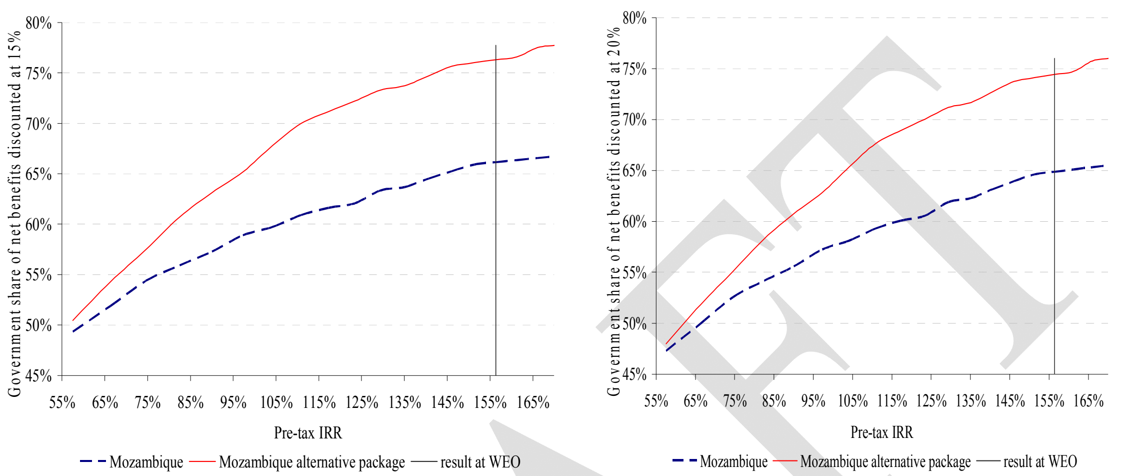
A more progressive regime allows the government to increase its share of revenue when the investment is highly profitable, while giving some relief to investors for projects with low rates of return. Moreover, a progressive regime could attract investment for marginal projects (increasing government revenue over time), just as a heavy early fiscal burden on a project

[44] Total benefits mean revenues minus operating costs and replacement capital investment, i.e., the "cake" from which taxes are paid, debt is serviced and equity providers are rewarded.

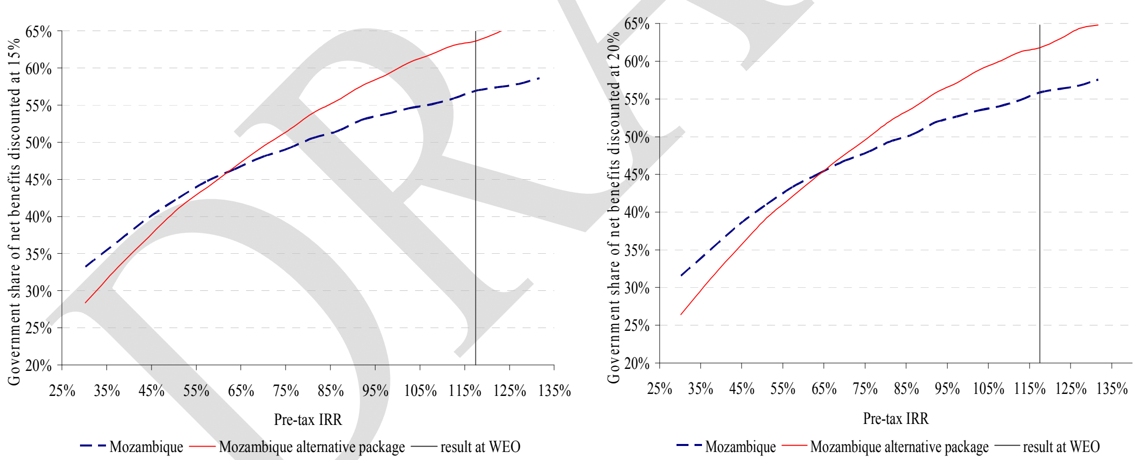
could deter investment altogether. The share of government revenues to total benefits over a range of pre-tax IRR is used, in Figure 8 below, to illustrate differences in progressivity between the alternative and "current" regimes.

Figure 8. Government Share of Total Benefits over a Range of Pre-Tax IRR

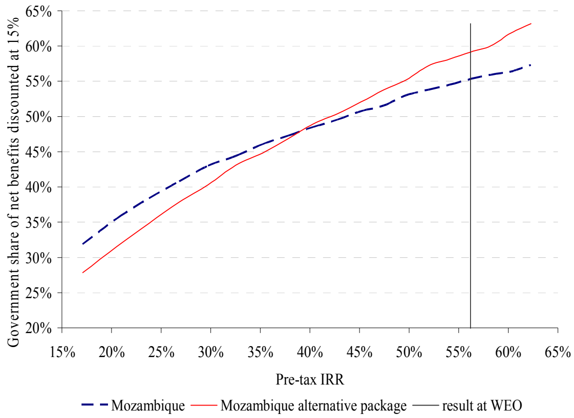
Onshore Oil Project



Shallow Water Project



Deep Water Project



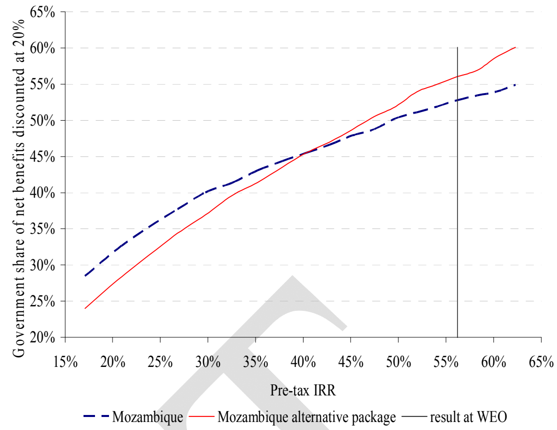


Figure 8 shows that the "current terms" tend to take relatively more from projects at lower levels of profitability. At the margin of viability (toward the left hand side of the graphs) the "current terms" place a heavier burden than the alternative package in each one of the projects. The alternative fiscal package lowers the government share for projects at low levels of profitability, improving "Mozambique" attractiveness for investment in exploration, while ensuring a significant government share for highly profitable commercial discoveries (right hand side of the graph).

Risk to Government

Table 7 below compares the expected tax payments, their coefficient of variation (CV) [45], and the government share of net benefits in the first ten years of the project, at discount rates of 15 and 20 percent. These results are calculated from the stochastic price simulations described in Box 3.

[45] The coefficient of variation is the standard deviation divided by the mean, and is a measure of the dispersion of returns.

Table 7. Mean Government NPV, CV, and Early Share of Total Benefits

Onshore Oil Project	Mean Government NPV at 15%	CV at 15%	Mean Government NPV at 20%	CV at 20%	Government share of net benefits at 15% during first ten years	Government share of net benefits at 20% during first ten years
	$mm	%	$mm	%	%	
Alternative package	1,193	52	734	58	40	42
“Mozambique”	899	56	667	55	38	40

Shallow Water Oil Project	Mean Government NPV at 15%	CV at 15%	Mean Government NPV at 20%	CV at 20%	Government share of net benefits at 15% during first ten years	Government share of net benefits at 20% during first ten years
	$mm	%	$mm	%	%	
Alternative package	1,985	64	1,620	65	36	36
“Mozambique”	1,845	56	1,524	57	37	38

Deep Water Oil Project	Mean Government NPV at 15%	CV at 15%	Mean Government NPV at 20%	CV at 20%	Government share of net benefits at 15% during first ten years	Government share of net benefits at 20% during first ten years
	$mm	%	$mm	%	%	
Alternative package	7,212	66	5,142	66	12	13
“Mozambique”	7,189	59	4,978	60	14	15

The alternative regime has generally a higher expected mean government NPV for the three oil projects, at both discount rates. In terms of capturing early revenues, the alternative regime takes a higher share of net benefits than the “current terms” during the first ten years of the onshore project. In the shallow water project, both regimes take approximately the same proportion of net benefits early in the life of the project, while in the deep water field the “current terms” take a slightly higher share of net benefits during the first ten years. These results are consistent with the progressivity measures illustrated above. For example, in the deep water field, which takes more time to recover costs, the burden of the alternative regime in the first ten years of the project is somewhat less heavy on investors than the “current terms”. However, as the pre-tax NPV of the project increases, this small difference in early government take of net benefits will be more than compensated later in the life of the project under the alternative package. Finally, when evaluating the dispersion of government revenues between the two regimes, the alternative package presents a modest increase in the CV of government revenue for all three projects. The small increase in risk to government, on this criterion, would have to be balanced against other gains from the alternative package.

Investor Perceptions of Risk

Investors perception of risks between the two regimes is evaluated by analyzing i) the mean expected post-tax IRR to the investor and the CV of investor returns, and ii) the cumulative probability distribution of post-tax NPV, discounted at 15 percent under each project. Table 8 below portrays the mean expected post-tax IRR and the CV of post-tax IRR for each project. While the mean expected post-tax IRR is very similar between the two regimes, the dispersion of returns to investors is reduced under the alternative package.

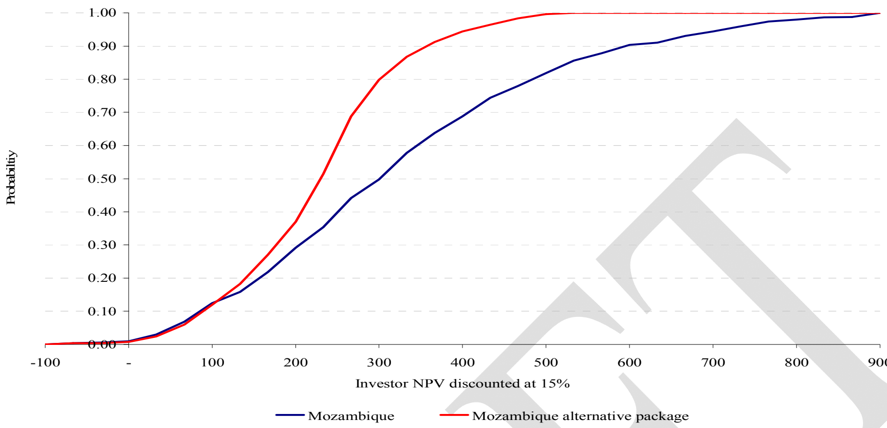
Table 8. Mean Expected Post-Tax IRR and CV

	Onshore Project		Shallow Water Project		Deep Water Project	
	Mean Expected post-tax IRR	CV of IRR	Mean Expected post-tax IRR	CV of IRR	Mean Expected post-tax IRR	CV of IRR
	%	%	%	%	%	%
Alternative package	47	31	41	35	20	46
"Mozambique"	50	36	41	42	19	49

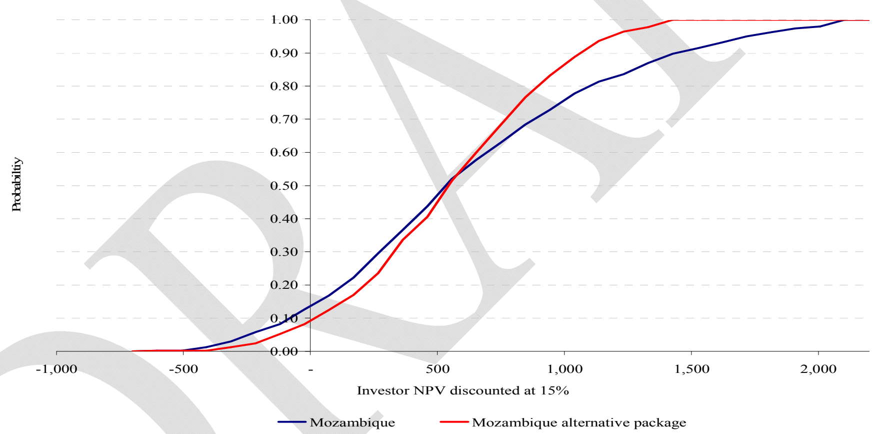
The lines in Figure 9 below show the cumulative probability distribution of the post-tax results under both fiscal regimes. All except the deep water project show a relatively low value of expected negative outcomes; this value is smaller under the alternative regime. The cumulative distribution van also be read to show the relative progresivity of the regimes. A fiscal regime designed to maximize the government's share of "rent" over a project life would have a low state share until the pre tax NPV of the project becomes positive, and would then increase rapidly to capture the majority of the economic "rent" created by the project. This pattern is better mirrored by the alternative package than by the "current terms".

Figure 9. Cumulative Probabilities of Post-Tax NPV, Discounted at 15 Percent

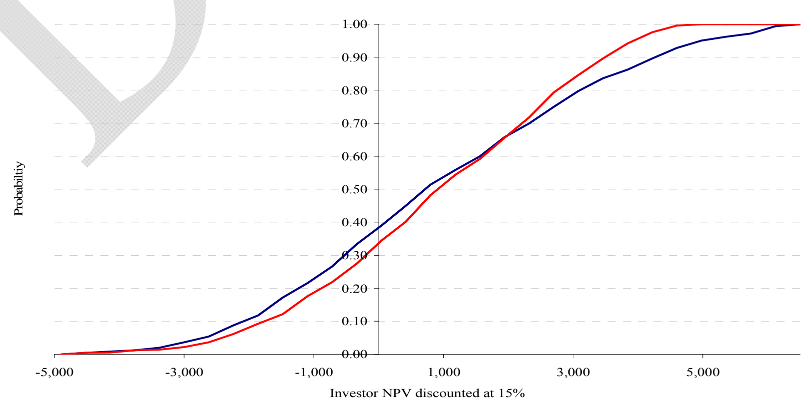
Onshore Oil Project



Shallow Water Oil Project



Deep Water Oil Project



B. "Current Terms" and Alternative Package in an International Context

In order to benchmark the "current terms" and the alternative package against international comparators, we evaluate the results from applying other countries' fiscal regimes to the deep water oil project. International comparators include deep-water petroleum producers and potential producers (i.e., countries with significant exploration activity) from Africa and elsewhere. Table 9 lists the international comparators in descending order of petroleum daily production as of 2007. The fiscal regimes of these countries are summarized in Appendix III. Four features of the fiscal regimes are compared: i) the overall tax burden (measured by AETR and breakeven price); ii) the risks to the government , iii) how the regime affects perceived risks for investing in the country; and iv) the "prospectivity gap" implied by each regime.

Table 9: Comparator Countries for Analysis

	Country	Fiscal regime	Oil production 2007[46] ('000 bpd)	Exploration Activity[47]
	African Comparators			
1	Nigeria	PSC	2,350	Offshore and onshore (less interest onshore due to recent militant unrest)
2	Angola	PSC	1,769	Offshore and onshore
3	Eq. Guinea	PSC	400	Offshore and onshore
4	Cameroon	PSC	83	Offshore and onshore
5	Mauritania	PSC	24	Offshore and onshore
6	Ghana	PSC	6	Offshore
7	Madagascar	PSC	0	Offshore and onshore
8	Mozambique	PSC	0	Offshore and onshore
9	Namibia	Tax & Royalty	0	Offshore and onshore
10	Sierra Leone	PSC	0	Offshore and onshore
	Non-African Comparators			
1	Norway	Tax & Royalty	2,270	Offshore
2	UK	Tax & Royalty	1,498	Onshore and offshore
3	Colombia	Tax & Royalty	531	Offshore and onshore
4	Australia	CIT and RRT	468	Onshore and offshore
5	Timor Leste	PSC	79	Offshore
6	Peru	Tax & Royalty	77	Onshore and offshore (not deep water)

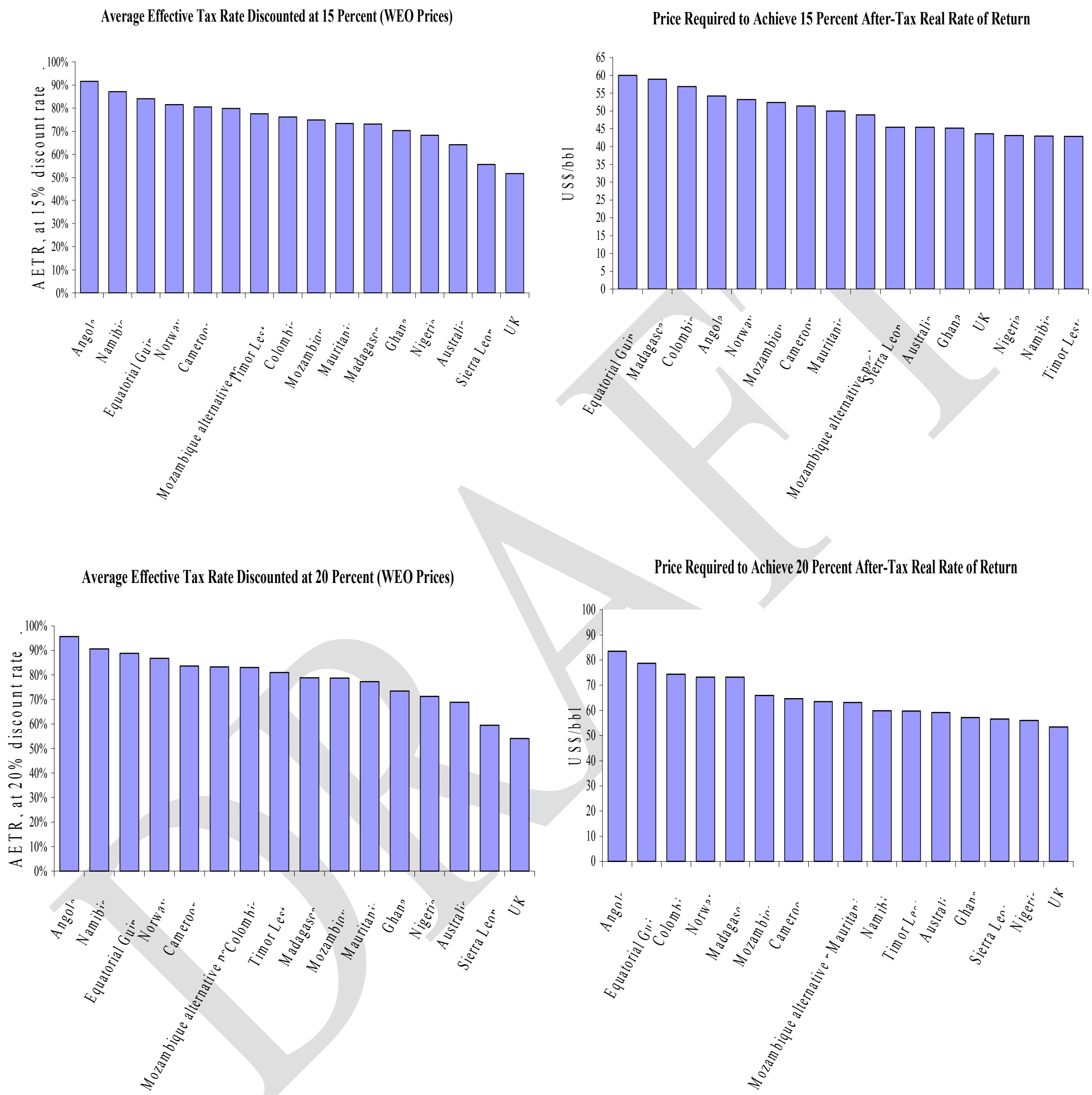
AETR and breakeven price

[46] Source: Energy Information Administration: World Crude Oil Production (including lease condensate) as of August 22, 2008.

[47] Source: IMF staff.

Figure 10 shows the AETR, discounted at 15 and 20 percent, for the "current terms" and alternative package against 15 international comparators, using WEO price projections; and the

Figure 10. AETR and Breakeven Price



price required to achieve a post-tax IRR of 15 and 20 percent (i.e., breakeven price). The results suggest that the alternative package captures a greater share of net cash flow than fiscal regimes in other countries with high activity in deep-water exploration, such as Ghana, Mauritania, Madagascar, Colombia and Timor Leste. Conversely, the alternative regime requires a lower price to achieve post-tax hurdle rates of 15 and 20 percent than most of the countries just mentioned (with the exception of Ghana and Timor Leste), and other medium and large oil producers such as Angola, Cameroon and Norway. A higher reported price indicates that a higher pre-tax IRR is needed to offset the effect of a heavier fiscal burden to achieve the targeted after-tax return. Fiscal regimes with lower required prices to just induce investment, such as the alternative package, represent a lower risk for investors, and may encourage exploration activities, especially in capital intensive environments such as deep water projects.

Risk to government and comparison with investor risk

The risk to government revenue is analyzed by evaluating the (i) the expected government receipts as a percentage of a baseline case, which is the "current terms" in "Mozambique"; and (ii) the CV of those government receipts. We compare these with an expected risk index for investors, where again "current terms" in "Mozambique" is our baseline case. Table 10 shows that the alternative regime would produce a small improvement in mean expected governmnet receipts, at the 'penalty" of some increase in variance. On the other hand, when compared to the "current terms" in "Mozambique", there is a large decrease in the expected risk index for investors—likely, as inteneded, to make the deep water play in the country more attractive.

Table 10. Index of Revenue Stability and Yield, with Expected Risk Index

	Deep Water Oil Project		
	Expected government receipts discounted at 15% as % of Mozambique	Investor expected risk index (at 15% discount rate) Mozambique =100	Coefficient of variation of government receipts %
UK	70	53	62
Nigeria	84	35	73
Sierra Leone	78	69	58
Ghana	88	65	69
Australia	86	57	65
Timor Leste	95	25	75
Alternative package	101	73	70
Mauritania	96	72	67
Namibia	103	42	78
Cameroon	101	62	71
Mozambique	100	100	63
Norway	106	89	68
Madagascar	107	183	54
Colombia	107	146	58
Angola	115	85	70
Equatorial Guinea	111	129	64

Investors Perception of Risk

An investor may be reluctant to accept possible returns below a required rate or may perceive high dispersion of expected outcomes as a strong risk factor. In order to assess the effect of the tax system on returns under a range of different price scenarios, a probability distribution of returns for a range of stochastically simulated oil prices was evaluated. Table 11 reports the mean expected post-tax IRR, CV of IRR, and the probability of tax-related returns below 15 percent for the investor. The countries are tabulated in descending order of the expected mean post-tax IRR. The alternative package increases the mean expected return to investors when compared to the "current terms" in "Mozambique". In an international context, the alternative package sits in the mid to upper section of the ranking. This indicates that on average, investments under the alternative terms will yield returns higher than the same investments under more than half of the fiscal terms in the comparator countries. The probability of generating returns below 15 percent is in the low to mid in level of the sample. In conclusion, the alternative package would improve the mean expected post-tax IRR for investment in "Mozambique" while reducing the volatility of potential returns. This will be an attractive advantage for investors considering investments in countries with high petroleum potential in deep-water environments, but yet without a significant commercial discovery of that kind.

Table 11. Mean Expected Post-Tax IRR, CV, and Probability of Returns Below 15 Percent

Deep Water Oil Project	Mean expected IRR %	Coefficient of variation of IRR %	Probability of expected return below 15% %
Project pre-tax	35	41	7
After-Tax			(Tax-related)
UK	26	48	12
Nigeria	23	39	14
Sierra Leone	23	47	19
Ghana	22	44	19
Australia	22	43	20
Timor Leste	21	38	16
Alternative package	20	46	24
Mauritania	20	47	23
Namibia	20	32	15
Cameroon	20	46	24
Mozambique	19	49	26
Norway	17	41	29
Madagascar	17	56	38
Colombia	17	47	36
Angola	16	39	31
Equatorial Guinea	16	49	39

"Prospectivity gap"

Objective measurement of the value assigned by investors to their perception of prospectivity risk can only be approached by an indirect route. It is possible to suggest what the value assigned to prospectivity risk would have to be in a particular country, given equal project risk, to equalize the attractiveness of the project under the different tax regimes surveyed. Table 12 reports: i) the excess over lowest mean expected NPV to investor, at a rate of discount of 15 percent; and ii) the excess over lowest expected negative NPV to investor, again at 15 percent discount rate.

Table 12. Prospectivity Gap[48]

	Deep Water Oil Project	
	Excess over lowest mean expected NPV15 to investor	Excess over lowest expected negative NPV15 to investor
	$mm	$mm
UK	2,877	21
Nigeria	1,895	299
Sierra Leone	2,359	(89)
Ghana	1,639	(8)
Australia	1,780	387
Timor Leste	1,141	1,108
Alternative package	804	200
Mauritania	1,044	472
Namibia	779	288
Cameroon	699	1,114
Mozambique	852	54
Norway	384	91
Madagascar	313	(963)
Colombia	371	(417)
Angola	(66)	660
Equatorial Guinea	-	-

According to the first column of table 12, if the attractiveness of the investment is to be equal as between "Mozambique" and Equatorial Guinea, the investor would have to assess prospectivity risk to be higher in "Mozambique", to the extent that an addition to expected NPV of $852 million is required. This is the relative addition to mean expected NPV on total

[48] Angola has the lowest expected mean to investor among the sample. However, because a variable cost recovery limit that increases after 5 years if the investor has not recover all costs, its lowest expected negative NPV to the investor is not consistent with the lowest expected mean measure. For this reason, Equatorial Guinea, which yielded what is otherwise the least favorable for investor, is chosen as the benchmark.

funds currently provided by the "current terms" in Mozambique. Under the alternative package, this difference narrows to $804 million.

In the second column of Table 12, prospectivity risk is measured as the change in tax-related expected negative NPV to investor necessary to equalize the expected value of negative returns among countries. Thus if the fiscal regimes are correctly specified, an investor will tolerate almost $54 million of total additional negative expected returns for a project located in Mozambique compared to one in Equatorial Guinea, while to go to Madagascar or Colombia, the expected value of negative returns would have to be much lower. Under the alternative package the gap from Mozambique to Equatorial Guinea widens to $200 million. Alternatively, if prospectivity is viewed as equal between, say, Nigeria and the UK, then the UK "sacrifices" just under $1 bn of potential mean expected receipts in this deep water case.

It is necessary to point out immediately that these figures cannot be taken as real prospectivity differences. They do, however, invite examination of significant differences in fiscal regimes.

Varying the discount rates

If the company's discount rate is set at 20 percent while the government's remains at 15 percent, or if the the government's rate is reduced to 10 percent, the broad conclusions from this choice of alternative regeimes are not altered (Appendix IV). In general, the lower the discount rate of government, relative to that of the company, the more the trade-off between investor risk and governmnet yield can be improved by targeting tax at high rates on realized rents (returns in excess of the investor's discount rate).

IV. CONCLUSIONS

This paper has attempted to set out evaluation criteria, and attach indicators or measures to them. The indicators are intended to be relatively easily calculated and interpreted. The aim is to provide a framework for numerical analysis of risk and reward trade-offs, as an aid to judgment in setting and revising fiscal regimes.

The paper shows how fiscal regimes can be assessed to pose questions about their relationship to both prospectivity and government objectives, as well as investor perceptions of risk. Mechanisms to adjust fiscal regimes (generally applicable legislation, standard contract terms, or auctions) are a separate policy question.

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Appendix I. Marginal Effective Tax Rate

The standard approach to estimating the METR is to consider an investment project that just earns the required after-tax rate of return—a marginal investment—and to calculate the impact of tax on the cost of capital. This can be understood more fully by reference to Figure 1.[49] [Figure to be added]. The figure depicts a downward sloping investment schedule with respect to the before-tax rate of return (r_g), and an upward sloping savings schedule with respect to the after-tax rate of return (r_n). Without taxes, a profit-maximizing firm will invest to the point where the marginal product of capital is just equal to the cost of using that capital—at point I*. Thus, while the required before-tax rate of return on a marginal investment is not directly observable, we can infer it by measuring the user cost of capital. Algebraically, the following condition must be satisfied:

$$R = [\beta i + (1-\beta)\rho] - \pi + \delta$$

where R is the return on investment (or marginal product of capital) and the cost of capital is comprised of: (1) the market rate of interest on debt financing, i, weighted by the proportion of investment financed by debt, β; (2) the cost of equity, ρ, similarly weighted; (3) the expected inflation rate, π; and, (4) real economic depreciation, δ.

With taxes, the firm undertakes the same optimization procedure but on an after-tax basis, giving rise to the following condition:

$$R(1-u) = \{[\beta i(1-u) + (1-\beta)\rho] - \pi + \delta\}(1-Z)$$

where *u* is the corporate tax rate and *Z* is the depreciation allowance for taxation purposes. Note that the above expression assumes that debt financing is tax deductible but equity is not. Returning to Figure 1, the before-tax rate of return to investment is net of depreciation, R-delta $\left(= r_g^e\right)$. At the after-tax equilibrium of $S^e=I^e$, there is a difference between this before-tax rate of return to investment and the after-tax real rate of return to savers $\left(= r_n^e\right)$. This tax wedge represents the tax revenue collected by government on the marginal investment, and when expressed as a proportion of the before-tax rate of return yields the METR:

[49] This discussion follows Boadway (1987) and Chua (1995) and is based on the neoclassical model of investment behavior.

$$METR = \frac{r_e^g - r_e^n}{r_e^g} = \frac{(R-\delta) - r_e^n}{(R-\delta)}$$

Appendix II. Cost of Capital

The capital asset pricing model (CAPM) is often used to estimate the cost of equity. The CAPM is based on the principle that equity holders will be compensated, in the form of a higher expected return, for holding non-diversifiable risk (also called systematic or market risk) but not for holding diversifiable risk (non-systematic or private risk). This is because equity holders can costlessly eliminate diversifiable risk by investing in a range of stocks (diversification is most effective the greater the negative correlation between individual stocks).[50] The optimal diversified portfolio will include every traded asset and the non-diversifiable risk of an individual stock will equal the contribution of that stock to the risk of the market portfolio. The CAPM for a stock can be expressed as:

$$E\left(R_j\right) = R_f + \beta\left(R_m - R_f\right)$$

where: $E\left(R_j\right)$ is the required return on the firm's equity; the risk premium (Rm-Rf) is comprised of the expected return to the optimal market portfolio, Rm, and the risk free rate, Rf; and beta is the correlation between the return on the firm's equity and that of the market,

$$\beta = \frac{\operatorname{cov}\left(R_j, R_m\right)}{\operatorname{var}\left(R_m\right)}.$$

The risk premium is most commonly estimated using historical data on the market return and the risk-free return. Limitations of this approach include the implicit assumptions that the risk aversion of investors has not changed, nor has the riskiness of the market portfolio. The risk premium can also be estimated by the implied premium in the stock price. However, this too has limitations, including that the model and inputs used to calculated the expected return on the market must be correct, and it implicitly assumes that the market is correctly valued. The standard procedure for estimating betas is to regress returns of an individual stock against market returns

$$R_j = a + bR_m$$

where the slope of the regression, b, is the estimate of beta. Estimated betas will not be good estimates of the true betas if the market portfolio is not properly defined or if the standard error of the estimate is large.

[50] Companies can also diversify by investing in a range of projects.

There are a number of problems in applying the CAPM to estimate the cost of capital for an individual resource project. The estimated beta reflects the entire company. Thus, this approach is only valid to the extent that the company's risk profile is the same as that of the individual project being evaluated (Brealey and Myers, 1991). Moreover, a number of the CAPM assumptions, such as returns being normally distributed and jointly normal with the returns of the market portfolio, may be satisfied at the company level, but are likely to be invalid when applied to mining projects (Smith and McCardle, 1998). A better approach is to estimate a beta based on firms or price indices that are similar in risk to the project. However, this tends to be difficult to do in practice, and will necessitate considerable judgment, including on classifying risks as either diversifiable or non-diversifiable.

A further complication is that the CAPM estimate of the RADR may not reflect all relevant risks. The appropriate RADR for an individual mining project includes a premium for the mineral project risk (commodity price, input cost and geological risks) and a premium for country risk. The CAPM estimate will need to be supplemented by an additional premium to the extent that it does not fully reflect all these risks. In many cases, it may even be necessary to use an alternative approach all together, such as relying on industry practice (Smith, 1995) or identifying each source of uncertainty and assessing (often qualitatively) a risk premium for each factor (Smith, 2000). Country risk (e.g., political and regulatory factors) could be added to the discount rate in order to accurately rank the attractiveness of country tax systems for a given investment project. Measures of country risk can be obtained from risk rating services[51], banks, or yields on government bonds[52]. However, it may not be straightforward to obtain a country risk figure expressed as an interest rate that can simply be added to the CAPM derived risk premium.

As noted in the text: (i) because economic analysis is usually applied to a project with a successful outcome; not all systematic risks are taken into account in economic analysis ; (ii) a resource company must make enough profit on successful projects to compensate for unsuccessful ones - particularly relevant in petroleum where there is low probability of success at the exploration stage.

[51] One example is the International Country Risk Index published by the PRS Group, Inc. Scores range from 0 to 100 and are updated monthly for 140 countries. Sub-indices are available for political, financial and economic risks.

[52] In many countries, government bond markets either do not exist or are too immature for yields to provide an accurate measure of country risk.

Appendix III. Summary of Fiscal Regimes 1/

	Angola Offshore	Angola Onshore	Cameroon	Equatorial Guinea	Ghana	Madagascar Onshore	Madagascar Offshore	Mauritania	Mozambique	Namibia
Royalty	-	-	-	Min 13%, Max 16%	12.5%	Min 8%, Max 20%	Min 8%, Max 20%	-	10%	5%
Basis	-	-	-	daily production rate	flat	daily production rate	daily production rate	-	flat	flat
Cost recovery limit	50%-65% (with uplift)	50%-65% (with uplift)	60%	70%	-	60%	65%	70%	65%	-
Profit share	Min 30%, Max 90%	Min 35%, Max 90%	Min 20%, Max 70%	Min 10%, Max 60%	Min 12%, Max 28%	Min 20%, Max 70%	Min 20%, Max 70%	Min 20%, Max 50%	Min 10%, Max 50%	-
Basis	ROR	cumulative production	R-factor	cumulative production	ROR	daily production rate	daily production rate	daily production rate	R-factor	-
CIT	50%	50%	40%	35%	30%	-	-	30%	32%	35%
ROR taxes	-	-	-	-	-	-	-	-	-	3 tiers Min 33%, Max 50%
State participation	15%	15%	25%	15%	10% and 3.75% (optional)	-	-	18%	10%	-
	State interest carried during exploration (exploration costs repayable)	State interest carried during exploration (exploration costs repayable)	State interest carried during exploration (exploration costs repayable)	State interest carried during exploration (exploration costs repayable)	The 10% State interest is carried during exploration and development (neither costs are repayable). The 3.75% State interest is carried during exploration only (exploration costs are not repayable)			State interest carried during exploration (exploration costs repayable)	State interest carried for exploration (exploration costs repayable at Libor + 1%)	

	Nigeria Onshore	Nigeria Offshore	Nigeria Deep Water	Sierra Leone	Australia	Timor-Leste	Colombia 1	Peru	Norway	UK
Royalty	10%	10%	-	10%	-	5%	Min 8%, Max 25%	Min 5%, Max 20%	-	-
Basis	flat	flat	-	flat	-	flat	daily production rate	daily production rate	-	-
Cost recovery limit	100% (with uplift)	100% (with uplift)	100% (with uplift)	-	100% (with uplift)	100% (with uplift)	-	-	-	-
Profit share	Min 52%, Max 60%	Min 60%, Max 65%	Min 20%, Max 50%	-	-	40%	-	-	-	-
Basis	daily production rate	daily production rate	cumulative production	-	-	fixed	-	-	-	-
Tax	50% (tax allowance on development costs)	50% (tax allowance on development costs)	50% (tax allowance on development costs)	37.5%	30%	30%	33%	30%	CIT 28%, ST 50% Special Tax (ST) base is the same as for CIT plus a 30% uplift on investment	CIT 30%, SC 20% the Supplementary Charge is an additional charge of 10% on a company's ring fence profits excluding finance costs
ROR taxes		-	-	-	1 tier 40%	1 tier 22.5%	-	-		
State participation	-	-	-	-	-	20% State interest carried during exploration (exploration costs not repayable)	-	-	-	-

1/ Colombia has a high price duty (up to 30% rate), which is triggered once cumulative production reaches 5 mmbbl and when prices are above US$34.77/bbl. There is also an exploitation duty of $0.1068 per bbl.

Appendix IV. Discount Rate Sensitivities

This Table 13 below presents the AETR for each project at WEO prices, discounted at 10, 15, and 20 percent; and the price required to achieve a post-tax IRR of 10, 15, and 20 percent along with the METR at those prices.

Table 13. AETR, Breakeven Price and METR, at various discount rates

Onshore Oil Project

	AETR at 10% (WEO prices)	Price Required to Achieve a 10% Post-Tax IRR	METR at 10% Post-Tax IRR
Alternative Package	85	16	48
"Mozambique"	74	17	54

	AETR at 15% (WEO prices)	Price Required to Achieve a 15% Post-Tax IRR	METR at 15% Post-Tax IRR
Alternative Package	85	20	44
"Mozambique"	74	21	49

	AETR at 20% (WEO prices)	Price Required to Achieve a 20% Post-Tax IRR	METR at 20% Post-Tax IRR
Alternative Package	85	23	43
"Mozambique"	74	25	47

Shallow Water Oil Project

	AETR at 10% (WEO prices)	Price Required to Achieve a 10% Post-Tax IRR	METR at 10% Post-Tax IRR
Alternative Package	79	29	52
"Mozambique"	70	32	61

	AETR at 15% (WEO prices)	Price Required to Achieve a 15% Post-Tax IRR	METR at 15% Post-Tax IRR
Alternative Package	79	34	47
"Mozambique"	71	37	55

	AETR at 20% (WEO prices)	Price Required to Achieve a 20% Post-Tax IRR	METR at 20% Post-Tax IRR
Alternative Package	80	40	46
"Mozambique"	72	43	52

Deep Water Oil Project

	AETR at 10% (WEO prices)	Price Required to Achieve a 10% Post-Tax IRR	METR at 10% Post-Tax IRR
Alternative Package	78	37	46
"Mozambique"	73	40	52

	AETR at 15% (WEO prices)	Price Required to Achieve a 15% Post-Tax IRR	METR at 15% Post-Tax IRR
Alternative Package	80	49	43
"Mozambique"	75	52	47

	AETR at 20% (WEO prices)	Price Required to Achieve a 20% Post-Tax IRR	METR at 20% Post-Tax IRR
Alternative Package	83	63	42
"Mozambique"	79	66	44

Table 14 shows the mean expected government NPV, CV and share of total benefits in the first ten years of the project, discounted at rates of 10 and 15 percent for all projects.

Table 14. Government NPV, CV and Early Share of Total Benefits

Onshore Oil Project

	Mean Government NPV at 10%	CV of Government Revenues at 10%	Government Share of Total Benefits at 10% during first 10 years
	$mm	%	%
Alternative Package	1,448	60	38
"Mozambique"	1,294	56	36

	Mean Government NPV at 15%	CV of Government Revenues at 15%	Government Share of Total Benefits at 15% during first 10years
	$mm	%	%
Alternative Package	1,193	52	40
"Mozambique"	899	56	38

Shallow Water Oil Project

	Mean Government NPV at 10%	CV of Government Revenues at 10%	Government Share of Total Benefits at 10% during first 10 years
	$mm	%	%
Alternative Package	2,324	67	34
"Mozambique"	2,241	59	36

	Mean Government NPV at 15%	CV of Government Revenues at 15%	Government Share of Total Benefits at 15% during first 10 years
	$mm	%	%
Alternative Package	1,985	64	36
"Mozambique"	1,845	56	37

Deep Water Oil Project

	Mean Government NPV at 10%	CV of Government Revenues at 10%	Government Share of Total Benefits at 10% during first 10 years
	$mm	%	%
Alternative Package	11,723	67	11
"Mozambique"	11,452	59	14

	Mean Government NPV at 15%	CV of Government Revenues at 15%	Government Share of Total Benefits at 15% during first 10 years
	$mm	%	%
Alternative Package	7,212	66	12
"Mozambique"	7,189	59	14

Finally, Table 15 presents the mean expected post-tax IRR, CV of IRR, and the probability of returns below 15 and 20 percent for the investors.

Table 15. Mean Expected Post-Tax IRR, CV, and Probability of Returns Below 15 and 20 Percent

Onshore Oil Project	Mean Expected Post-Tax IRR	CV of IRR	Probability of Returns below 15%	Probability of Returns below 20%
	$mm	%	%	
Alternative Package	47	31	1	3
"Mozambique"	50	36	1	4

Shallow Water Oil Project	Mean Expected Post-Tax IRR	CV of IRR	Probability of Returns below 15%	Probability of Returns below 20%
	$mm	%	%	
Alternative Package	41	35	7	14
"Mozambique"	41	42	12	20

Deep Water Oil Project	Mean Expected Post-Tax IRR	CV of IRR	Tax-related probability of Returns below 15%	Tax-related probability of Returns below 20%
	$mm	%	%	
Alternative Package	20	46	19	36
"Mozambique"	19	49	26	40