TECHNICAL NOTES AND MANUALS

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Fiscal Affairs Department

INTERNATIONAL MONETARY FUND

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Authorized for distribution by Michael Keen

February 2016

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JEL Classification Numbers:	E62, H20, H25, L71, L72
Keywords:	Mining taxation, petroleum taxation, fiscal regime design
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[1] The authors would like to express their gratitude to Philip Daniel, Michael Keen, Peter Mullins and Victoria Perry for encouragement and detailed comments and suggestions. The authors would also like to thank Nate Vernon for outstanding assistance in preparing the models accompanying this technical note. Finally, the authors would also like to acknowledge the work of current and former FAD colleagues that have contributed to the development of the FARI modelling framework over the years.

TECHNICAL NOTES AND MANUALS

Fiscal Analysis of Resource Industries (FARI) Methodology

Executive Summary

This manual introduces key concepts and methodology used by the Fiscal Affairs Department (FAD) in its fiscal analysis of resource industries (FARI) framework. Proper evaluation of fiscal regimes for extractive industries (EI) requires economic and financial analysis at the project level, and FARI is an analytical tool that allows such fiscal regime design and evaluation. The FARI framework has been primarily used in FAD's advisory work on fiscal regime design: it supports calibration of fiscal parameters, sensitivity analysis, and international comparisons. In parallel to that, FARI has also evolved into a revenue forecasting tool, allowing IMF economists and government officials to estimate the composition and timing of expected revenue streams from the EI sector, analyze revenue management issues (including quantification of fiscal rules), and better integrate the EI sector in the country macroeconomic frameworks. Looking forward, the model presents a useful tool for revenue administration practitioners, allowing them to compare actual, realized revenues with model results in tax gap analysis.

I. Background

Mining and petroleum projects share several characteristics that distinguish them from other sectors of the economy, due either to their mere scale or to the intrinsic properties of the resources themselves.[2] Over time, countries have tailored their fiscal regimes to address challenges associated with the inherent characteristics of EI and existing market conditions. These fiscal regimes (Box 1) usually diverge from the general tax system applicable to the rest of the economy and vary widely in structure, choice of fiscal instruments and rates, as well as in the way fiscal instruments interact with each other.

In practice, the interaction between different fiscal instruments and individual EI projects can produce effects that cannot be easily inferred from headline tax parameters. Moreover, comparing fiscal instruments individually is often not sufficient: they have to be evaluated as a package. Without some quantification, it is difficult to tell how two fiscal packages with otherwise identical terms compare with each other when all that differs is one item – for example, the rate at which capital costs can be

[2] These include the presence of high sunk costs, long production periods, pervasive uncertainty, and resource exhaustibility. Their relevance for tax policy is discussed in the resource literature and various IMF publications. See for example Boadway and Keen (2010) or IMF (2012).

Box 1. Defining the EI Fiscal Regime

The fiscal regime for mining and petroleum (oil and gas) is the combined system of tax and non-tax instruments used to raise government revenue from natural resource extraction activity. It includes not only conventional instruments such as royalty and CIT, but also contractual schemes such as production-sharing or risk service contracts. Lump sum payments required upon granting of rights (commonly referred to as "signature bonus") and production bonuses payable upon reaching a predetermined production level are also common.

The fiscal regime can further include instruments of state participation which have fiscal effect on the division of revenues even where held by a commercially operating state-owned enterprise. The fiscal regime may also comprise taxes, fees, levies and charges which accrue to the state by way of additions to input costs.

Mandated requirements that do not directly add to fiscal revenues may form part of the fiscal regime. These can include, for example, obligations to supply product to the domestic market at prices below export parity, or obligations to support acquisition of equity interests by designated citizens. Finally, the fiscal regime may be project-specific if some of its components are set in a contract, or sector-specific if it applies uniformly to all extractive projects.

deducted in calculating taxable income for corporate income tax (CIT) purposes; or, how these differences are amplified or diminished by variations in the underlying project profitability in reaction to changes in prices or costs.

Because of such interactions, the design and evaluation of fiscal regimes require detailed economic and financial analysis at the project level. To support its technical assistance (TA) work over the years, FAD has developed an analytical tool that allows project-based modeling and fiscal regime evaluation known as FARI.[3] The FARI framework consists of a detailed, Excel-based discounted cash flow (DCF) model that operates on a project by project basis. The model inputs include production and cost profiles over the life of resource projects, economic assumptions such as prices, inflation and discount rates, financing arrangements, and the terms of the fiscal regime to be evaluated.

The analysis performed in FARI is done from the perspective of an investor from abroad, a normal situation for many resource-rich developing countries which depend on foreign investment to develop their EI sectors. The model helps determine how the net cash flows generated over the full life cycle of a project are divided between such an investor and the host government according to the terms of the fiscal regime. The government's revenue arising from a project usually comes in

[3] The economic principles underlying the FARI model are the same as those used in models developed by the industry. The fiscal analysis, however, draws on public finance and economic theory to reflect the government's perspective.

the form of tax and non-tax instruments such as royalties, CIT, additional profit sharing mechanisms, final withholding taxes, state participation, and / or other EI related levies.[4]

FARI uses a suite of indicators to evaluate how different combinations of fiscal terms compare along relevant economic criteria (such as neutrality, revenue raising capacity, time profile of government revenue and progressivity), and against fiscal regimes in other jurisdictions—the calculations of which are discussed in detail in this manual. While FARI was originally designed as a tool for EI fiscal regime design and evaluation, it can also be adapted for revenue forecasting and tax gap analysis. Nevertheless, as any model, FARI represents a simplification of the reality and the results need to be interpreted with care. In particular, the model assumes full efficiency of revenue collection, no international tax planning, and no opportunity to deduct costs from one project against revenues from another in the absence of a well-defined fiscal boundary (or ring-fence) around the project.

This technical note offers a description of the FARI methodology as a quick reference guide for practitioners and country authorities dealing with EI taxation. The purpose is not to provide a detailed user guide to the model used in FAD advisory work, but to discuss the underlying thinking behind FARI's main concepts and methodology. To this end, the manual is accompanied by a "stylized" version of the FARI model containing illustrative project examples, main fiscal calculations, and key economic indicators. The theory and principles behind the model's fiscal analysis and indicators are discussed in detail in Daniel, Keen and McPherson (2010).

II. Fiscal Modeling of Resource Projects

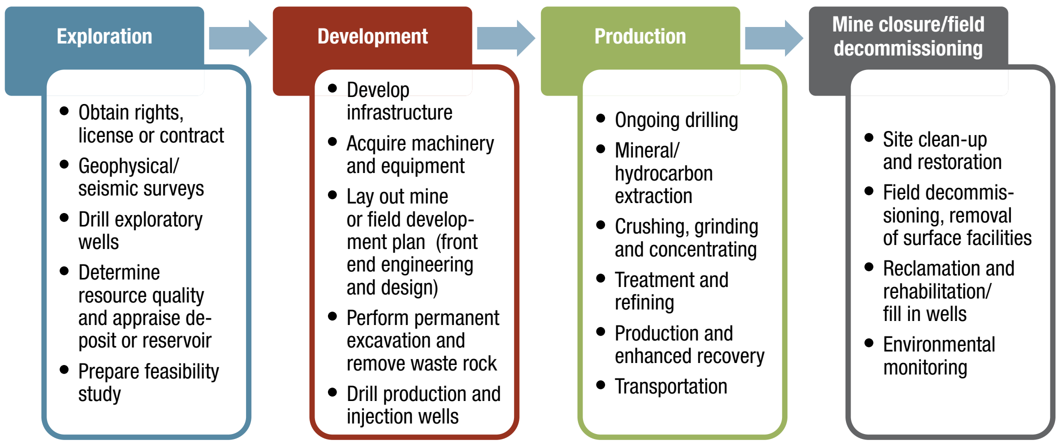
In FARI, a project is defined as all necessary activities to commercially develop and exploit a mineral deposit or a petroleum field, collectively referred to as "upstream activities". These activities span from exploration work undertaken to identify reserves, to the development and extraction of resources, to closure and rehabilitation of the production site once the resource has been depleted.

Economic modeling for fiscal regime design and evaluation is primarily concerned with upstream activities.[5] However, FARI may also be adjusted to incorporate activities related to the enhancement of the extracted product through further processing and refining, beyond the upstream border. The project costs included are usually those directly related to the extraction process, but a facility to add estimated externalities, such as resource depletion or environmental costs, could be added when needed.

[4] The exact resource revenue definition (that is, what government payments are classified as resource revenue) can be narrow or wide. That is a policy reporting choice outside FARI. For further discussion see STA Template for government resource revenue statistics (IMF 2014).

[5] Physically speaking, upstream activities end at the point where the resource is first sold or delivered. This can be the inlet point of a pipeline, or a refinery or processing plant.

Figure 1. Lifecycle of a resource project



A. Stages in the Life of a Resource Project

The lifecycle of a resource (both mining and petroleum) project can be divided into four main phases: (i) exploration; (ii) development; (iii) production; and (iv) mine closure or field decommissioning (Figure 1).

During the *exploration phase*, companies aim to identify and assess the geology of the areas of interest to determine the extent and nature of the resource in place. In mining, most of the costs are associated with conducting geophysical surveys, geological mapping to assess the potential for mineralization, and initial drilling to better understand the contents of the mineral deposit. If initial exploration is successful, further work is conducted to define the quality and quantity of the potential ore deposit, and to determine the mining method to extract the ore. This additional exploratory work, or "advanced exploration" as it is referred to in the industry, provides the first inputs to start planning the mine layout and to produce initial estimates to develop the resource project. In petroleum, after acquiring acreage and rights to explore for oil and gas, companies conduct seismic surveys to understand the geological and geophysical characteristics of the area. This process can take between three to five years, and if results are promising exploration drilling takes place. If petroleum is discovered, the company carries out an appraisal work program to assess the commerciality of the reservoir. It may take between four to 10 years, sometimes longer, from the time hydrocarbons are discovered to the time commercial production begins.[6]

Once commercially recoverable reserves are proven, the project advances to the *development phase*. For a mine, the development phase comprises all the activities required to establish permanent access to the ore body and carry out commercial production. During this phase the mine site is prepared, infrastructure is developed, mine construction – whether underground or on surface – takes place, and ore processing facilities are built. The development phase is the most capital

[6] Each of the phases will involve rights and obligations under the legal regime: those topics are discussed at length in Duval, LeLeuch, Pertuzio, and Weaver (2009).

intensive of all phases, and, depending on the size of the reserves, usually lasts between two to five years. For petroleum projects, development comprises the drilling of production and injection wells, as well as the building of surface facilities to transport, store, and measure the petroleum extracted. The development of an onshore field normally takes about a year, while offshore fields may take up to seven years depending on their size. During this phase, companies also need to prepare a field development plan (FDP) and submit it to the government for approval. The FDP describes the process by which petroleum will be extracted and produced, including expected production rates and solutions for the transportation of petroleum products (for example, the use of existing pipelines, construction of new flow lines, or an offshore terminal).

The ***production phase*** commences when the resource in the ground can be extracted and processed into a commercial product on a continuous basis, and can span over 20 years depending on the size of the reserves. In mining, this phase includes ore extraction, processing, and transportation. Production levels may be sustained over several years or even decades. However, there may be instances in which mining projects enter into periods of inactivity (also referred to as "care and maintenance") due to changes in market conditions, operational problems, or as a result of political or social instability. In petroleum, this phase includes the different processes to extract oil and gas from reservoirs to the surface, separate crude oil from natural gas (if they occur together), and transport it to a pipeline network or a processing facility. Regardless of the production horizon of a petroleum field or mine, extraction rights are generally granted for a finite period of time, albeit with extension options in some places.

Finally, when reserves are depleted or production is no longer profitable mines are ***closed*** and petroleum fields are ***decommissioned***. Depending on the legal dispositions of the jurisdiction where the project is located, companies may be required to restore the site to its original state. This process can be very expensive, and companies sometimes start to set aside funds to cover these costs when a certain percentage of reserves has been depleted.

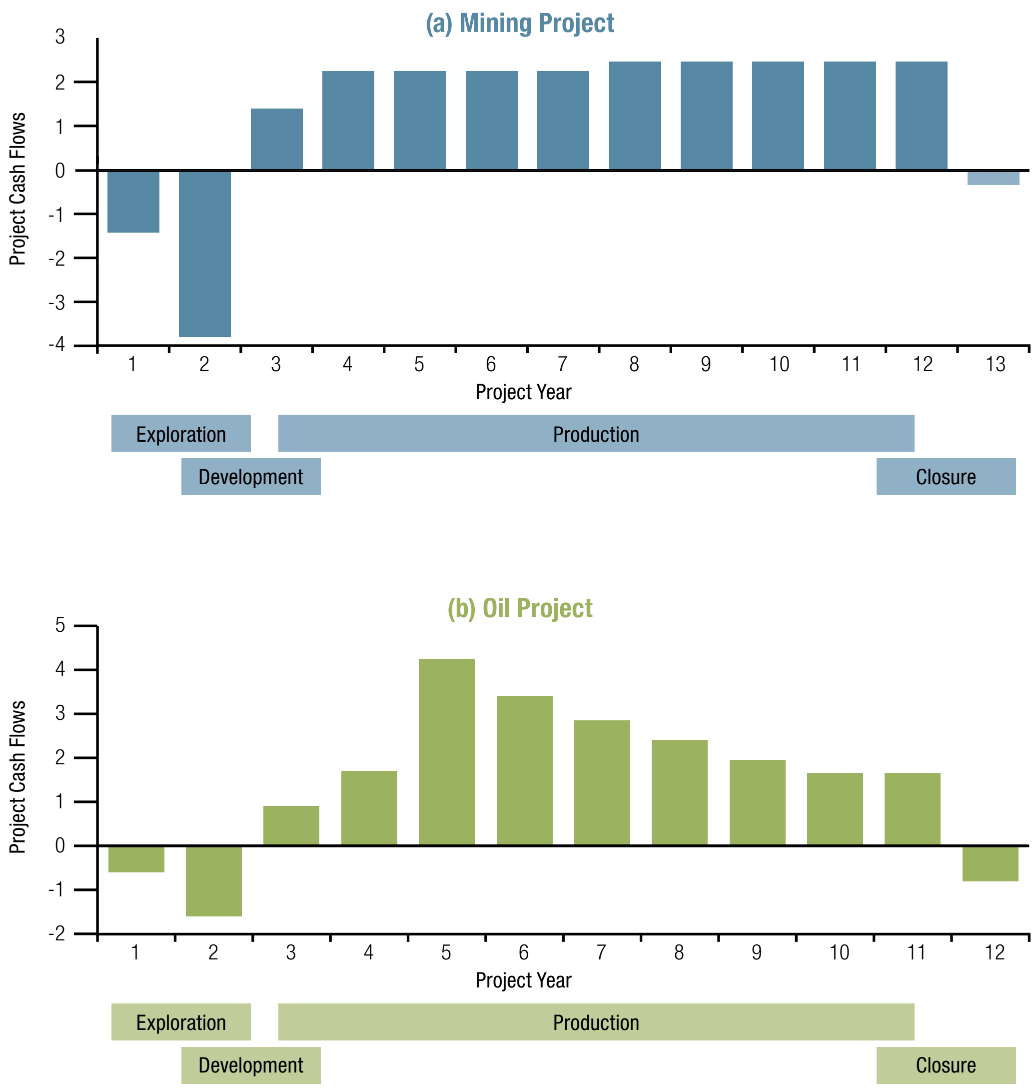
The cash flows of a resource project mainly reflect the costs associated with the different phases described above and the production profile. While each mine has unique production and cost characteristics, it is not uncommon for mining projects to reach a peak production level early in the project life, and maintain this level until the end of the project (Figure 2a). This is because the rate of production is limited by the nameplate capacity[7] of the processing plant. A mine cannot produce above this limit, unless additional capacity is built later on. Conventional gas projects also exhibit this relatively stable production profile, as gas processing facilities have limited capacity.

In contrast to the stable production rates usually found in mining and conventional gas projects, oil fields tend to have a bell-shaped production profile. After a production ramp-up period in the early years of the project, oil fields tend to reach peak production towards the middle of

[7] Nameplate capacity refers to the maximum output of processed or refined products that a processing plant or refinery can produce in a given year.

the project life, and then sustain a declining rate of production until the end of the project (Figure 2b). This profile is directly related to the intrinsic characteristics of petroleum reservoirs: in the beginning, pressure in the reservoir will sustain higher production rates, but as the resource in the reservoir gets depleted and pressure subsides, production rates also fall unless enhanced oil recovery is done (for example, by injecting gas back in the reservoir).[8]

Figure 2. Illustrative Cash Flows: Resource Projects



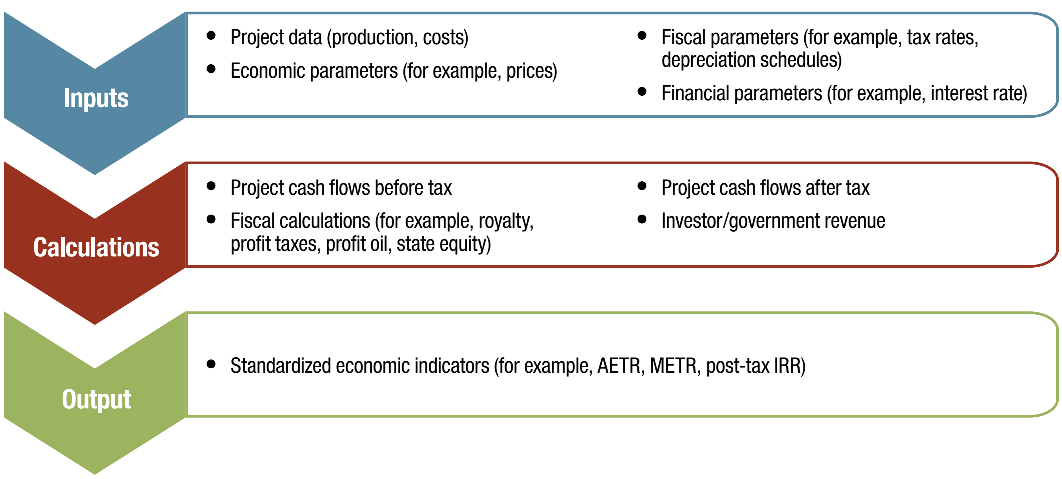
[8] Smith (2012) develops a model characterizing the company's optimal investment choice for exploration investment and primary and secondary recovery from a successful well, given the fiscal regime, as well as the time at which to abandon the field.

B. FARI: A Framework for Fiscal Modeling

Because of these characteristics, fiscal regimes must be evaluated over the entire lifecycle of resource projects, from exploration[9] to decommissioning of upstream facilities, in the case of a petroleum field; or to closure and rehabilitation in the case of a mine.[10] This project-level approach estimates the government's share of a resource project's total pre-tax net cash flows (in effect, the economic rent[11] when calculated in discounted terms at a rate equal to the minimum return to capital), as well as the effect of the interactions among the different parameters constituting the fiscal regime.

The FARI methodology discussed in this manual relies on a simple Excel-based DCF model. DCF is a valuation method traditionally used to calculate the net present value (NPV) of an investment. In this approach, the expected values of future cash flows are discounted back to a base year. As inputs, the model requires fiscal parameters, annual project costs and production volumes, economic assumptions (prices, inflation, interest and discount rates), as well as financing assumptions. The model calculations are performed on an annual basis (but could be adapted to shorter intervals if necessary), starting with the calculation of the project net cash flows before any fiscal impositions. Next, the model calculates each fiscal payment according to the fiscal regime parameters entered and the total government revenue from the project. The model then estimates several indicators that allow for the evaluation of the fiscal regime along relevant criteria (Figure 3).

Figure 3. Data flow in FARI modeling



[9] FARI evaluates fiscal regimes over the full life cycle of resource projects with successful discovery, starting from the exploration phase. However, the model can also be calibrated to evaluate the effect of unsuccessful exploration, if the user is interested in the effect of attaching probabilities to outcomes in expected monetary value (EMV) analysis.

[10] This is usually the case, unless the explicit intention is to model incremental cash flows from a specific point onward in a project's life.

[11] In this context, rent is defined as revenues in excess of all necessary costs of production including the minimum rate of return to capital.

III. FARI: Model Inputs

A. Resource Project Data

In FARI, project data is entered in a predefined template which contains placeholders for production volumes and different categories of costs.

Production Profile

The production profile refers to the annual quantities of output from the project measured at the valuation point – for example, barrels of crude oil from an oil field, or tons of copper concentrate from a mine.[12] Resource projects can produce multiple minerals, but from an economic perspective there is usually a clearly identifiable primary product.[13] For example, a mine that produces copper as its primary product may also produce silver and molybdenum as by-products. Similarly, a petroleum field can produce both crude oil and natural gas, but from a project feasibility perspective only one of the two hydrocarbons is the primary product.[14] The stylized models accompanying this manual make the assumption of a single commodity produced.

The stage of processing of a product obtained from a resource project is critical for any economic or fiscal analysis, and can have important implications for the calculation of royalties and other taxes (Box 2). In the case of mining, some projects may produce only ore which is then sold to a third party for smelting and further refining; while other projects may produce concentrate or more refined products, such as copper cathodes or iron ore pellets. Detailed information on the production process is thus important, in particular, identifying where the first delivery point is, how product prices are determined at that point, and what activities are subject to the EI fiscal regime.[15]

Cost Profile

The definition and classification of the fiscal treatment of the costs associated with each phase of a resource project – exploration, development, production, and decommissioning – is central to fiscal regime evaluation. Each phase entails a different set of cost categories that need to be properly treated from a fiscal point of view. For example, some costs may be depreciated over a certain number of years,

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[12] For fiscal regime evaluation it may not be necessary to differentiate between production and actual sales or exports. In practice, however, this distinction is important and should be reflected when the model is used for revenue forecasting.

[13] The primary product usually determines the commercial feasibility of the project, in the sense that the project economics and the investment decision are based on production and price assumptions for this product. In mining, the sale of secondary product generates "by-product credits" which are often treated as a reduction in costs. For example, the total cost per unit of production is calculated as total cash costs, as defined above, net of by-product revenues earned from all metals other than the primary metal produced, divided by the total volume of primary metal produced.

[14] In TA work, the FARI model has been adapted to handle multiple products.

[15] The valuation of prices carries particular importance when the transactions are between related parties, which raises transfer pricing considerations.

Box 2. Valuation Point(s) for Fiscal Purposes

Defining the valuation point is essential to determine the taxable base for the different fiscal instruments constituting the upstream fiscal regime. In practice, there may be as many valuation points as tax and non-tax instruments in the fiscal regime. For example, royalties may be levied on the value of production at the wellhead (or mine mouth), while CIT may be imposed on taxable income arising at the point of sale. In the case of fiscal instruments targeting resource rent, the valuation point is likely to be the physical point that separates upstream from midstream and downstream activities.

Once the valuation point is clearly defined, the corresponding price and any allowable deductions are also determined in reference to this point to calculate the tax base. For a simple ad-valorem royalty levied on the value of production at the wellhead or mine mouth, a "net-back pricing" approach is commonly used to determine the wellhead or mine mouth price (assuming sales take place later in the supply chain). The net-back price is calculated by starting with the value of the product at the point where it is first sold (at arm's length prices), and then subtracting the estimated costs of moving the product from the wellhead or mine mouth to the point of sale.

while others may be expensed as incurred. In addition, some fiscal mechanisms may allow the deduction of certain costs, sometimes with an allowance in addition to the original costs incurred (also referred to as *uplift*), while others may not.[16]

As for production, project costs are gathered and recorded on an annual basis in the model. These annual sets of cost categories constitute the *project's cost profile*. Accurate cost profiles are often more challenging to construct or obtain than production profiles. This is because cost estimates tend to change relatively more (both in magnitude and frequency) than production forecasts, as projects move from concept development to design and implementation.

FARI classifies project costs according to the phase of the project and their fiscal treatment (whether they are expensed or subject to a depreciation schedule). In the model, *capital expenditure is* classified as development costs (separated between tangibles and intangibles), and replacement capital.[17] *Tangible development expenditures*, such as investments in property, plant, and equipment, may be subject to specific depreciation schedules (for example, the straight line method, units of production or declining balance). On the other hand, *intangible development*

[16] For example, ad-valorem royalties often allow deductions from revenue for transportation, refining, and processing costs. CIT, on the other hand, typically allows deductions for capital expenditure (subject to a depreciation schedule), operating costs, decommissioning costs, and interest expense from debt financing.

[17] FARI treats these three expenditure categories as aggregates, each with a separate depreciation schedule. The user can introduce additional depreciation schedules when costs need to be disaggregated further within each category (for example, if the applicable fiscal regime requires different depreciation rules for different types of tangible development costs).

expenditures,[18] such as drilling or pre-stripping[19] costs, are often expensed as incurred or, in some cases, amortized by the units of production method. *Replacement capital costs*, which are also likely to be depreciated for tax purposes, reflect investments needed post-development to maintain the field or mine in operation, as machinery and equipment wear out and have to be replaced.

Similarly, FARI classifies *operating costs* into several categories:[20] costs directly related to the extraction process (that is, the process of extracting mineral ore or hydrocarbons from the ground); costs related to processing, refining and beneficiation activities, such as liquid separation, washing, crushing and grinding; transportation costs incurred before the physical point where royalties or CIT are imposed (usually at the mine gate or at the free on board (FOB) export point); and other operating costs, such as selling, general, and administrative expenses.[21] While all operating costs are commonly expensed as incurred, some fiscal regimes may limit how much of certain operating costs can be deducted in a year – hence the relevance of this cost breakdown in the model.

Since prices in FARI are commonly linked to international benchmarks, the model also allows for the deduction of *transportation, refining, and processing costs* incurred beyond the point where the fiscal instruments are levied. This separate category of costs is used not only to determine taxable income for CIT purposes (by netting back the international benchmark price to the point of CIT assessment) but also, in some cases, to calculate the royalty base.

Table 1 illustrates how production and cost data are entered in the model for two stylized mining and petroleum projects that will be used in the rest of this technical note. Data are entered for each production and cost category on an annual basis. If there is no production or cost in a particular year, the corresponding cell is left blank. The cells in yellow denote hard coded data entered into the model (user input). Further, in the examples showcased here, only costs related to successful exploration are included.

[18] Intangible assets are defined as identifiable non-monetary assets without physical substance.

[19] Pre-stripping costs refer to the process of removing waste materials (or overburden) to access the ore body at an open-pit mine.

[20] This distinction is more relevant in mining than in petroleum, as the former involves more segmented activities during production.

[21] Companies usually treat the cost of sales as operating cost, placing selling, general and administrative expenses in a separate cost category. In FARI, these are included under "other operating costs."

TABLE 1. PRODUCTION AND COST DATA IN RESOURCE PROJECTS

MINING PROJECT															
Total	**Raw Project Data**	**Year**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
1,900	Production gold	000 ounces	-	-	100	200	200	200	200	200	200	200	200	200	-
48	Transport post-fiscal point	$mm const	-	-	3	5	5	5	5	5	5	5	5	5	-
95	Refining and processing post-fiscal point	$mm const	-	-	5	10	10	10	10	10	10	10	10	10	-
10	Exploration costs	$mm const	10	-	-	-	-	-	-	-	-	-	-	-	-
50	Development costs - intangibles	$mm const	10	40	-	-	-	-	-	-	-	-	-	-	-
200	Development costs - tangibles	$mm const	50	150	-	-	-	-	-	-	-	-	-	-	-
50	Replacement capital costs	$mm const	-	-	10	10	10	10	10	-	-	-	-	-	-
380	Operating costs - mining	$mm const	-	-	20	40	40	40	40	40	40	40	40	40	-
380	Operating costs - milling	$mm const	-	-	20	40	40	40	40	40	40	40	40	40	-
114	Operating costs - other	$mm const	-	-	6	12	12	12	12	12	12	12	12	12	-
20	Decommissioning costs	$mm const	-	-	-	-	-	-	-	-	-	-	-	-	20
PETROLEUM PROJECT															
Total	**Raw Project Data**	**Year**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
	Oil production	Mbpd	-	-	10	25	75	60	48	38	31	25	20	-	-
121	Oil production	MMBbl	-	-	4	9	27	22	18	14	11	9	7	-	-
484	Transport post-fiscal point	$mm const	-	-	15	37	110	88	70	56	45	36	29	-	-
250	Exploration costs	$mm const	250	-	-	-	-	-	-	-	-	-	-	-	-
500	Development costs	$mm const	-	500	-	-	-	-	-	-	-	-	-	-	-
75	Replacement capital costs	$mm const	-	-	15	15	15	15	15	-	-	-	-	-	-
3,628	Operating costs	$mm const	-	-	110	274	821	657	526	420	336	269	215	-	-
200	Decommissioning costs	$mm const	-	-	-	-	-	-	-	-	-	-	-	200	-

Note: *$mm const* means millions of dollars at constant prices; *000 ounces* means thousand ounces; *Mbpd* means thousand barrels per day; *MMBbl* means million barrels. These conventions are used throughout the document.

B. Economic Assumptions

Prices

The input price in the model must reflect the type of product generated and sold by the project. In FARI, price assumptions for petroleum products and most major minerals are often linked to benchmark or "spot market" prices. These prices are transparent, publicly available through commodities or futures exchanges[22] and, in most cases, projections (going out up to five years) are relatively easy to obtain. In the stylized version of the model accompanying this manual the user can choose one constant price path in real terms, but other price options could be easily included.[23]

Inflation

While the project cost data and price assumptions are entered in the model in real terms, the fiscal calculations are done in nominal terms by applying an assumed inflation factor. This approach ensures that capital depreciation and other tax-related calculations better reflect tax calculations in practice. Model results are then converted back to real terms for consistency of presentation. Inflation rates may in reality vary across different cost categories but for simplicity, FARI only uses one inflation rate[24] which is applied uniformly to both price and costs.

Interest Rate

Another key input in the model is the real interest rate. This rate, usually set up with a margin over the long-term U.S. Treasury rate, is used with an adjustment for inflation to calculate various financing charges relevant to the fiscal calculations. For example, if a country requires companies to set up a decommissioning fund and such a fund is allowed to earn interest, the chosen interest rate is applied to calculate the interest gains made by the decommissioning fund. Another example is when the state participation is "carried" during certain periods of the project (commonly during exploration and/or development). If under this type of arrangement the state is required to repay with interest its portion of costs covered by the party developing the project (commonly referred to as the "contractor"), the chosen interest rate forms the basis for the interest charge associated with the carried interest. Finally, if the contractor finances part of its costs with debt, the chosen interest rate also forms the basis for the interest expense incurred as a result of this type of financing.

Discount Rates

The main model results are expressed in NPV terms to account for the time value of money, reflecting the time preferences (that is, a dollar today is worth more than a dollar tomorrow) and

[22] In the case of commodities traded over-the-counter (that is, without the regulations and supervision of a commodities exchange), trade journals or publications regularly publish reliable reference prices.

[23] For example, the version of the FARI model used in TA work can be run with prices from the World Economic Outlook (WEO), user-defined prices, and stochastically generated prices.

[24] Different categories of inflation, say by cost categories, may be added to the model. However, these would have to follow the same classification as the project costs (that is, exploration, development, operating, and decommissioning costs).

opportunity costs of the projects' stakeholders (that is, the cost of borrowing or investing in an alternative project). Given that the results are presented in real terms, the discount rates are also expressed in real terms in the model. In general, selecting the right discount rates is difficult, especially when the government and the contractor have different preferences, risks, and liquidity needs.

The model uses a discount rate to calculate the NPV of government revenues, the average effective tax rate (AETR), and the government share of total benefits.[25] Since these indicators are related to the government share of the project's pre-tax cash flows, this discount rate ideally approximates the government's real discount rate. Discount rates vary from country to country and, in general, these differences are likely to reflect differences in time preferences and opportunity costs (whether to spend now or in the future) among countries. For example, developing countries with urgent short-term needs are likely to have higher discount rates than advanced economies.

A second discount rate is used in the calculation of indicators quantifying the effect of the fiscal regime on the investor, such as the marginal effective tax rate (METR) and the project break-even price.[26] Similar to the discount rate for the AETR and the share of total benefits, the discount rate for the METR ideally approximates the discount rate of private mining or petroleum companies in the country of analysis. This discount rate must reflect geological, political, and economic risks associated with the development of the resource project and can be proxied by the investor's cost of capital (Box 3). There are many issues around the appropriate choice of discount rate and these are extensively covered in the literature.[27] FARI takes a pragmatic approach and allows the user to enter the discount rate considered appropriate for the specific case analyzed.

C. Financing Assumptions

Project financing assumptions are simplified in the model and only pertain to the debt financed portion of the capital raised by the investor.[28] The main objective in simulating debt financing costs is to determine the interest expense, if any, that would enter the calculation of CIT.

The model allows the option to select the percentage of pre-production development costs financed with debt. It is common for exploration costs to be fully financed with equity, while development costs financed with a combination of debt and equity. In selecting the portion of development costs financed with debt, any applicable thin capitalization rules must be taken into

[25] For a definition of AETR and share of total benefits, see Box 5 on government indicators.

[26] For a definition, see Box 4 on investment indicators.

[27] For example, why should a diversified company care about project-specific risk? Or a diversified shareholder about company risk? In addition, some have argued that if tax treatment is certain, the discount rate should be the risk free rate (Fane (1987), Bond and Devereux (1995)). However, is often hard to know what the risk free rate is.

[28] The only exception is when the state participation is carried. In this case, a portion of the state's costs is in fact financed by the private contractor.

account.[29] Additional debt parameters are also used in the model, such as the repayment period of the loan and the loan's interest rate.[30] Table 2 illustrates how the financial and economic assumptions are set up in the model. Again, all cells in yellow denote hard coded data entered into the model.

Box 3. Estimating the Investor's Cost of Capital

From an investor perspective, the cost of capital—that is, the rate of return required by the suppliers of capital—applied to a specific project depends on the characteristics of the project: the riskier the cash flows, the higher the cost of capital for the project. Leaving diversification issues aside, the most common approach to estimate the rate of return demanded by investors is to calculate the marginal cost of each source of capital and then take the weighted average of these costs. This approach is also known as the weighted average cost of capital (WACC). Once the WACC for the company[31] as a whole has been calculated, the rate could be adjusted upward or downward to reflect the risk of a particular project. The WACC for a company, before any project-related adjustment, is calculated as follows:

$$WACC = w_d r_d (1-t) + w_e r_e$$

where w_d and w_e are the proportion of debt and equity respectively; rd and re are the marginal cost of debt (pre-tax) and equity respectively; and t is the company tax rate. Since in most countries interest on debt financing is deductible from income taxes, the pre-tax cost of debt is adjusted to account for this tax shield.

The cost of debt (r_d) usually reflects the yield to maturity (or annual return) on the company's debt (for example, its long term bond rate). As for the cost of equity (r_e), there are various ways to calculate it. Common approaches include the capital asset pricing model (CAPM), in which an equity risk premium is added to the risk-free return; and multifactor and build-up models in which a set of risk premia is added to the risk free rate to account for other risk factors.

[31] In finance theory, the WACC is commonly estimated at the company level. In FARI, however, there's an implicit assumption that the company only develops a single project. Therefore, the company's and the project's WACC are effectively the same. For a thorough discussion on the cost of capital see Courtois, Lai and Peterson (2008).

[29] Many countries place limits on the tax deductible interest expense that a firm can recognize. For example, a 1:1.5 debt to equity ratio limit implies that a company can only deduct the interest expense resulting from corporate debt that is equal to 1.5 the amount of corporate equity. Other countries simply limit the amount of tax deductible interest expense to a percentage of earnings before interest, taxes, depreciation, and amortization. Similarly, production sharing contracts may exclude financing costs from recoverable costs or put a limit on how much can be recovered.

[30] These assumptions may be overly simplistic. Resource projects may have several types of debt, such as senior debt, mezzanine debt, and revolving loan facilities. Other elements, such as any grace period granted after the last drawdown from the loan facility or the treatment of interest expense during the development stage (whether it is paid or capitalized), can also be incorporated. However, this technical note is mainly concerned with the interest expense used in the calculation of taxable income, hence the simple assumptions made here.

TABLE 2. FINANCIAL AND ECONOMIC ASSUMPTIONS		
FINANCING ASSUMPTIONS	**UNITS**	**INPUT**
Percent of development costs borrowed	%	70%
Repayment period (beginning production)	years	5
Real interest rate	%	5.0%
ECONOMIC ASSUMPTIONS		
Discount rate government	%	10.0%
Discount rate contractor	%	12.5%
Inflation rate	%	2.0%
Gold smelter price	$/ounce	1,300
Transport post-fiscal point	$/ounce	25
Smelting and refining charge post-fiscal point	$/ounce	50

IV. FARI: Fiscal Calculations

A. Project Cash Flows before Fiscal Impositions

After all the necessary economic and financial parameters are known and the project price and cost data have been entered, the model calculates the project pre-tax net cash flows. These constitute the base on which the fiscal calculations will be made later on.

The annual pre-tax project net cash flows are first calculated in constant dollars, as:

$$\textit{Pre-tax } CF_t = (\textit{MarketPrice x Production})_t - \textit{Trans\&Proc}_t - \textit{Expl\&Capex}_t - \textit{Opex}_t - \textit{DecommCosts}_t$$

where the sales value of the mineral produced is given by the market price and volume of production (*MarketPrice x Production*); transportation and processing costs (*Trans&Proc*) represent costs incurred beyond the point where the title of the resource changes ownership (and where the CIT is levied); exploration costs (*Expl*) include the finding and appraisal costs specifically related to the project ; capital expenditure (*Capex*) includes development costs (both intangibles and tangibles) and capital replacement costs during production; operating costs (*Opex*) include costs directly related to the production process; decommissioning costs (*DecommCosts*) refer to the costs of cleaning up and restoring the mine site;[32] and the subscript *t* stands for the year. Table 3 below illustrates the pre-tax project net cash flows, using constant prices, for a hypothetical gold mine. All cells in Table 3 are in grey, denoting they contain formulas instead of hard data.

[32] FARI does not include working capital (current assets minus current liabilities) in its cash flow analysis. The appropriate level of working capital will vary from project to project, and from company to company. Moreover, working capital is a measure of the ability of a company (or project) to meet short-term claims and over the life of the project it will net out.

After applying the appropriate inflation index, the next block of data (Table 4) displays the pre-tax cash flows of the project in nominal terms. The values are obtained by multiplying the price and cost data in Table 3 by the assumed inflation rate of 2 percent (as entered in Table 2). This block of data is the foundation for the fiscal calculations in the model as it represents the base on which royalties, CIT, other profit or rent based taxes, and other levies are estimated.

Once the annual pre-tax net cash flows are determined, two important parameters can be calculated: the project NPV at given discount rates and the project internal rate of return (IRR) before tax. The project NPV is calculated using the formula:

$$\boldsymbol{NPV = CF_0} + \frac{CF_1}{(1+r)^1} + \frac{CF_2}{(1+r)^2} + \frac{CF_3}{(1+r)^3} \ldots + \frac{CF_n}{(1+r)^n}$$

where CF_n is the net cash flow[s] in year n, and r is the discount rate. The latter accounts for the opportunity cost of capital and the premium required to take into account project or country-specific risks. The IRR is the discount rate at which the NPV of the cash flows becomes zero.[33]

The hypothetical gold mining project, given the market price and cost assumptions described above, is a profitable one on a pre-tax basis with a real return of 41 percent and NPV of USD508 million (on flows discounted at 10 percent[34]). Similar to the mining project, the petroleum project example is also profitable on a pre-tax basis, with a real IRR of 36 percent and NPV of USD1,021 million (on flows discounted at 10 percent). Tables 5 and 6 show the constant and nominal cash flows for the petroleum project.

The pre-tax net cash flows form a basis on which to measure the relative effect of the fiscal regime on the project. In general, a project is considered viable, on a pre-tax basis, if its NPV is positive; or if the IRR is higher than the company's cost of capital or hurdle rate. However, since both the NPV and the IRR are likely to be lower when the fiscal regime is factored in, determining the viability of the project is done on a post-tax basis. In FARI, a project is considered viable when the post-tax NPV, using the assumed hurdle rate required by the investor, is not negative or the post-tax IRR is equal or higher than the investor's discount rate.

[33] Two standard issues can arise in corporate finance when evaluating projects. The first one is that NPV and IRR analysis for mutually exclusive projects may yield conflicting results (for example, if the IRR of project A is higher than that of project B but the NPV of project B is higher than that of project A, the project with the higher NPV should be chosen). Second, a project may generate multiple IRRs if its negative cash flows occur at different times during the project life.

[34] The discount rate of 10 percent is used for illustration purposes here, although it may not be unrealistic for the government discount rate in some developing countries. Foreign investors usually argue for discount rates higher than the government's.

TABLE 3. GOLD MINE: PRE-TAX PROJECT NET CASH FLOWS (CONSTANT PRICES)

Pre-tax cash flows are initially calculated in real terms, using constant prices and constant costs.

Total	Project Pre-Tax Cash Flows: Real	Year	1	2	3	4	5	6	7	8	9	10	11	12	13
1,900	Production gold	000 ounces	-	-	100	200	200	200	200	200	200	200	200	200	-
2,470	Gross revenue	$mm const	-	-	130	260	260	260	260	260	260	260	260	260	-
143	Transport and processing post-fiscal point	$mm const	-	-	8	15	15	15	15	15	15	15	15	15	-
2,328	Net revenue	$mm const	-	-	123	245	245	245	245	245	245	245	245	245	-
10	Exploration costs	$mm const	10	-	-	-	-	-	-	-	-	-	-	-	-
50	Development costs – intangibles	$mm const	10	40	-	-	-	-	-	-	-	-	-	-	-
200	Development costs – tangibles	$mm const	50	150	-	-	-	-	-	-	-	-	-	-	-
50	Replacement capital costs	$mm const	-	-	10	10	10	10	10	-	-	-	-	-	-
874	Operating costs	$mm const	-	-	46	92	92	92	92	92	92	92	92	92	-
20	Decommissioning costs	$mm const	-	-	-	-	-	-	-	-	-	-	-	-	20
1,204	Total costs	$mm const	70	190	56	102	102	102	102	92	92	92	92	92	20
1,124	Project pre-tax cash flows	$mm const	-70	-190	67	143	143	143	143	153	153	153	153	153	-20
40.7%	Internal rate of return (real)	%	-	-	-	-10	13	25	31	35	38	39	40	41	41
508	Project pre-tax cash flows NPV10	$mm const													

TABLE 4. GOLD MINE: PRE-TAX PROJECT NET CASH FLOWS (MARKET PRICES)

Inflation assumptions are applied to both costs and prices to arrive to pre-tax cash flows at market prices.

Total	Project Pre-Tax Cash Flows: Nominal	Year	1	2	3	4	5	6	7	8	9	10	11	12	13
2,827	Gross revenue	000 ounces	-	-	135	276	281	287	293	299	305	311	317	323	-
163	Transport and processing post-fiscal point	$mm nominal	-	-	8	16	16	17	17	17	18	18	18	19	-
2,664	Net revenue	$mm nominal	-	-	127	260	265	270	276	281	287	293	299	305	-
10	Exploration costs	$mm nominal	10	-	-	-	-	-	-	-	-	-	-	-	-
51	Development costs - intangibles	$mm nominal	10	41	-	-	-	-	-	-	-	-	-	-	-
203	Development costs - tangibles	$mm nominal	50	153	-	-	-	-	-	-	-	-	-	-	-
54	Replacement capital costs	$mm nominal	-	-	10	11	11	11	11	-	-	-	-	-	-
1,000	Operating costs	$mm nominal	-	-	48	98	100	102	104	106	108	110	112	114	-
25	Decommissioning costs	$mm nominal	-	-	-	-	-	-	-	-	-	-	-	-	25
1,344	Total costs	$mm nominal	70	194	58	108	110	113	115	106	108	110	112	114	25
1,320	Project pre-tax cash flows	$mm nominal	-70	-194	69	152	155	158	161	176	179	183	187	190	-25
43.5%	Internal rate of return (nominal)	%	-	-	-	-9	15	27	34	38	40	42	43	44	44
602	Project pre-tax cash flows NPV10	$mm nominal													

Note: $mm nominal means millions of dollars at market prices. This convention is used throughout the document.

TABLE 5. PETROLEUM FIELD: PRE-TAX PROJECT NET CASH FLOWS (CONSTANT PRICES)

Pre-tax cash flows are initially calculated in real terms, using constant prices and constant costs.

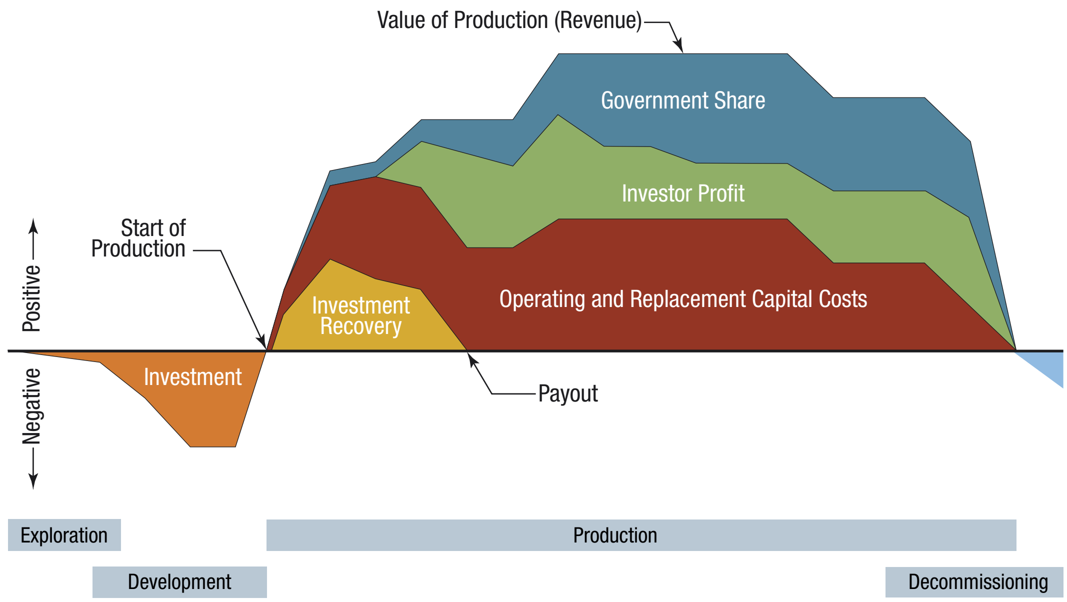
Total	Project Pre-Tax Cash Flow: Real	Year	1	2	3	4	5	6	7	8	9	10	11	12	13
121	Oil production	MMBbl	-	-	4	9	27	22	18	14	11	9	7	-	-
7,257	Gross revenue	$mm const	-	-	219	548	1,643	1,314	1,051	841	673	538	431	-	-
484	Transport costs post-fiscal point	$mm const	-	-	15	37	110	88	70	56	45	36	29	-	-
6,773	Net revenue	$mm const	-	-	204	511	1,533	1,226	981	785	628	502	402	-	-
250	Exploration costs (expensed)	$mm const	250	-	-	-	-	-	-	-	-	-	-	-	-
500	Development costs (depreciable)	$mm const	-	500	-	-	-	-	-	-	-	-	-	-	-
75	Replacement capital costs (depreciable)	$mm const	-	-	15	15	15	15	15	-	-	-	-	-	-
3,628	Operating costs	$mm const	-	-	110	274	821	657	526	420	336	269	215	-	-
200	Decommissioning costs	$mm const	-	-	-	-	-	-	-	-	-	-	-	200	-
4,653	Total costs	$mm const	250	500	125	289	836	672	541	420	336	269	215	200	-
2,120	Project pre-tax cash flows	$mm const	-250	-500	80	222	697	554	441	364	292	233	187	-200	-
35.5%	Internal rate of return (real)	%	--	--	--	--	10	24	30	33	35	35	36	35	-
1,021	Project pre-tax cash flows NPV10	$mm const													

TABLE 6. PETROLEUM FIELD: PRE-TAX PROJECT NET CASH FLOWS (MARKET PRICES)

Inflation assumptions are applied to both costs and prices to arrive to pre-tax cash flows at market prices.

Total	Project Pre-Tax Cash Flow: Nominal	Year	1	2	3	4	5	6	7	8	9	10	11	12	13
8,144	Gross revenue	$mm nominal	-	-	228	581	1,778	1,451	1,184	966	788	643	525	-	-
543	Transport costs post-fiscal point	$mm nominal	-	-	15	39	119	97	79	64	53	43	35	-	-
7,601	Net revenue	$mm nominal	-	-	213	542	1,659	1,354	1,105	902	736	600	490	-	-
250	Exploration costs (expensed)	$mm nominal	250	-	-	-	-	-	-	-	-	-	-	-	-
510	Development costs (depreciable)	$mm nominal	-	510	-	-	-	-	-	-	-	-	-	-	-
81	Replacement capital costs (depreciable)	$mm nominal	-	-	16	16	16	17	17	-	-	-	-	-	-
4,072	Operating costs	$mm nominal	-	-	114	291	889	725	592	483	394	322	262	-	-
249	Decommissioning costs	$mm nominal	-	-	-	-	-	-	-	-	-	-	-	249	-
5,162	Total costs	$mm nominal	250	510	130	306	905	742	609	483	394	322	262	249	-
2,439	Project pre-tax cash flows	$mm nominal	-250	-510	83	236	754	612	496	419	342	279	227	-249	-
38.2%	Internal rate of return (nominal)	%	--	--	--	--	12	26	33	36	37	38	39	38	
1,200	Project pre-tax cash flows NPV10	$mm nominal													

Figure 4. Illustrative Breakdown of Project Net Cash Flows



The following two sections explain how different fiscal regimes for mining and petroleum impact the economics of the resource projects. In particular, the terms of the fiscal regimes determine when and what share of a project's pre-tax net cash flows are allocated as revenue to the government. For example, part of the revenue generated by a project with the cash flow profile in Figure 4 will be allocated to the recovery of the original investment and to operating and replacement costs, the remaining net cash flows (the combined yellow and purple areas) being then divided between the investor and the government according to the terms of the fiscal regime. Two such fiscal regimes are discussed in the following sections: a tax/royalty system with application to mining; and a production sharing system with application to petroleum.

B. Typical Calculations for a Tax/Royalty Regime

Tax/royalty schemes are more often found in the mining sector, generally comprising taxes on production (commonly known as "royalties"); CIT; and in some cases, additional rent or profits taxes which in practice come in various forms (such as variable income tax, tax surcharge on cash flows, or windfall taxes, to list a few).[35] The government may also participate in the project either as a passive investor or by acquiring a carried interest.[36] Indirect taxes, such as import duties and value added tax (VAT) can be substantial in specific situations, but are neither discussed, nor modeled here.[37]

[35] A number of countries apply tax/royalty schemes to petroleum too, in combination with rent taxes: UK (Petroleum Revenue Tax), Norway (Supplemental Petroleum Tax), Australia (Petroleum Resource Rent Tax), Brazil (Special Participation), and Alaska (Production Tax called ACES).

[36] The different forms of state participation (free, carried or full equity) are addressed in this and next sections.

[37] Where minerals and petroleum are exported under the usual destination-based VAT, the output will qualify for zero-rating as an export. However, VAT can still impose a tax burden on exporters if the refund system is inadequate.

In the model, the fiscal parameters are entered in a section at the top of the page. The first column of the yellow area in Table 7 illustrates the minimum set of parameters that would be required to set up a fiscal regime in the base case. This regime is assumed to consist of 5 percent royalty on sales value (assessed at the mine gate), 30 percent CIT, and 10 percent state participation in the form of free equity. A 15 percent withholding tax on dividend payments abroad also applies. Two alternative regimes containing variants of additional profits tax are further evaluated, and their parameters are entered in columns 2 and 3. Specifically, the second regime assumes a 20 percent surcharge on cash flows (calculated after CIT), while the third regime assumes a 20 percent resource rent tax payable after a nominal rate of return of 10 percent is achieved (on cumulative results net of CIT payment).

Royalty

Royalties are levies on production, charged either as a fixed fee per unit of production ("specific" royalties) or as a percent of (a measure of) the value of production ("ad-valorem" royalties). The base on which royalties are applied can make a significant difference for government revenue.[38]

For the gold mining project discussed here, the royalty is assumed to apply ad-valorem on the value of the mineral at the mine gate, generically labeled in the model as "net revenue." This value is calculated as the "gross value" of the mineral produced (that is, the sales value at the export point abroad) with deductions for (i) refining and smelting charges, (ii) transportation from the mine to the FOB delivery point, and (iii) freight from FOB to the location where the international benchmark price is quoted. These deductions are consolidated under transportation and processing costs (*Tansp&Proc*) in the formula below. This adjusted price used in the calculation of royalty may be different from the actual sales price used in the calculation of revenue for CIT purposes.[39]

$$RoyaltyBase_t = NetRevenue_t = (MarketPrice \times Production)_t - Trans\&Proc_t$$

Corporate Income Tax

The CIT is calculated on taxable income, defined as net revenue less allowable deductions: exploration costs[40] (in this particular illustration, assumed capitalized and the deducted in full when production starts), intangible capital expenditure (assumed to be deducted in full), depreciation of capital expenditure, operating costs, and interest paid (up to the limit permitted by applicable thin capitalization rules, if any). Depending on the fiscal regime, the expensing or amortization of pre-production capital costs can start immediately or can be deferred until the beginning of production, hence the switch in the model (Table 7). Where contributions to a decommissioning

[38] See Otto and all (2006) for a discussion of various types of royalties and bases of imposition.

[39] Some countries simply prefer an international benchmark price without any deductions due to lack of capacity to monitor transportation and processing costs. In such situations, the royalty rates tend to be lower relative to regimes in which such costs are allowable deductions. In the model, the base for royalty would then become the "gross" or market value of the product: $RoyaltyBase_t = GrossRevenue_t = (MarketPrice \times Production)_t$

[40] Exploration costs, which may be capital in nature, are often deductible in the year incurred or at the commencement of production. The deduction varies from country to country, and could include immediate deduction or amortization over a specific period (for example, 5 or 10 years) or the life of the mine.

fund are made in cash, they are usually also treated as a deduction. The royalty is a deductible expense from the income tax base. In the regime modeled here, losses at the end of each year are carried forward indefinitely until fully recovered, although some jurisdictions may impose limits either on the period of time such losses can be claimed in future tax years or on the maximum loss offset allowable in each year (in order to preserve a minimum tax base).

$$CITbase_t = NetRevenue_t^{41} - Royalty_t - Opex_t - CapexDepr_t - Interest_t + LossCarryForward_{t-1}$$

TABLE 7. FISCAL REGIME PARAMETERS: MINING

Three mining fiscal packages are analyzed. Alternatives 2 and 3 build on the first regime by introducing a cash flow tax, and respectively a resource rent tax. The yellow background designates hard-coded inputs into the model.

Fiscal Regime Assumptions					
Regime name		Royalty + CIT	Royalty + CIT	Royalty + CIT + SCF	Royalty + CIT + RRT
Select regime number		**1**	**1**	**2**	**3**
Royalty rate	**%**	**5%**	**5.0%**	**5.0%**	**5.0%**
Royalty base (net/gross)	switch	net	net	net	net
Decommissioning provision (yes/no)	**swtich**	**yes**	**yes**	**yes**	**yes**
Commencement of decommissioning provision	% depletion	60%	60%	60%	60%
Corporate Income Tax rate	**%**	**30%**	**30.0%**	**30.0%**	**30.0%**
Exploration costs (expensing)	switch	deferred	deferred	deferred	deferred
Development costs - intangibles (expensing)	switch	deferred	deferred	deferred	deferred
Development costs - tangibles (depreciation)	switch	deferred	deferred	deferred	deferred
Development costs - tangibles and replacement capital depreciation	years	5	5	5	5
Surcharge on Cash Flows rate	**%**	**0%**		**20%**	
CIT deductible from the base (yes/no)	switch	-		yes	
Resource Rent Tax rate	**%**	**0%**			**20%**
RRT threshhold	%	0%			10%
CIT deductible from the base (yes/no)	switch	-			yes
Dividend Withholding Tax	**%**	**15.0%**	**15%**	**15%**	**15%**
State equity (free)	%	10.0%	10%	10%	10%

Additional Profits Taxes

Countries apply different fiscal mechanisms to capture project economic rents beyond what regular fiscal instruments, like royalty and income tax, are able to achieve. Two mechanisms illustrated here are

[41] While the price used for royalty and CIT purposes may differ depending on the fiscal regime (for example, the royalty may be based on a benchmark or regulated price rather than the actual price), the model generally assumes the same price for both.

the Surcharge on Cash Flows and the Resource Rent Tax.[42] The key difference between this category of taxes and the CIT is that capital expenditure is deducted in full (thus, not depreciated) and interest is not explicitly allowed as a deduction from the base.[43]

The *Surcharge on Cash Flows (SCF)* is a tax on project cash flows applicable once the cumulative project net cash flows become positive, usually after deduction for royalty. When the surcharge tax is levied "after tax", the net cash flows are further adjusted with a deduction for income tax paid in the year. Some regimes may also allow an uplift on the capital expenditure incurred during the development phase as further deduction from the net cash flows, to allow a minimum return on capital.

Modeling-wise, the SCF liability is the SCF tax rate multiplied by the positive balance at the end of each year, obtained by estimating net cash flows in the year and deducting any negative balance from the previous period (Table 8). When the end-year balance is positive and tax is paid in the year, the balance of accumulated cash flows is set to zero for the next year so that the same cash flows are not taxed twice (given that the cumulative negative cash flows up to that period have been offset in full). When the end-year balance is negative, the amount is carried in full to the next period.

$$SCFbase_t = Pre\text{-}taxNCF_t - Royalty_t(-CIT_t) + NegativeBalance_{t-1}$$

The *Resource Rent Tax (RRT)* is modeled in a very similar fashion as the SCF, with the only difference that the end-year negative balance is carried forward with an uplift, the equivalent of an interest rate. This is usually thought of as a minimum required return to investor or threshold above which economic rents are generated. When the accumulated negative cash flows are fully offset by revenues, the positive balance becomes taxable at the rate of the RRT.

$$RRTbase_t = Pre\text{-}taxNCF_t - Royalty_t(-CIT_t) + (Uplift\ x\ NegativeBalance_{t-1})$$

Like the SCF, the RRT can be applied before CIT (in which case the RRT is deductible in calculating the CIT) or after CIT (in which case CIT paid is treated as a cash outflow). The example shown in Table 8 assumes that both the SCF and the RRT are paid on after-tax proceeds. As expected, the RRT payments occur later in time relative to the SCF, which is consistent with the idea of allowing the investor to not only recover their costs (as in the case of SCF) but also earn a minimum return on after-tax cash flows (cumulatively, from the start of the project), before the RRT is payable.

[42] For a taxonomy of additional profit tax mechanisms see IMF (2012), and for a discussion of cash flow taxes see Boadway and Keen (2010). In respect to the tax literature, the Resource Rent Tax modeled in this manual replicates many features of the Brown Tax, with the investor receiving an annual uplift on accumulated losses until recovered. However, unlike the Brown Tax, the investor does not receive a refund for losses when the project proceeds are not sufficiently large to allow their full recovery, and from that point of view is not fully neutral. Further, the Surcharge on Cash Flows mechanism described here should be regarded as an "asymmetric" cash flow tax.

[43] In the case of the RRT, interest (and the cost of capital in general) is recognized through the minimum rate of return that needs to be achieved before the tax is charged. In the SCF, the cost of capital is usually recognized by providing an uplift to exploration and development expenditures.

TABLE 8. MODELING ROYALTY AND PROFIT/RENT TAXES

The royalty calculations are modeled first, followed by Corporate Income Tax. The Cash Flows Tax Surcharge and the Resource Rent Tax are also modeled for alternative regimes 2, and respectively 3.

Total	Fiscal Calculations	Year	1	2	3	4	5	6	7	8	9	10	11	12	13
Royalty															
2,827	Gross revenue	$mm nominal	-	-	135	276	281	287	293	299	305	311	317	323	-
2,664	Net revenue	$mm nominal	-	-	127	260	265	270	276	281	287	293	299	305	-
2,664	Royalty base: net revenue	$mm nominal	-	-	127	260	265	270	276	281	287	293	299	305	-
133	Royalty payable	$mm nominal	-	-	6	13	13	14	14	14	14	15	15	15	-
Corporate Income Tax															
2,664	Net revenue	$mm nominal	-	-	127	260	265	270	276	281	287	293	299	305	-
133	Royalty	$mm nominal	-	-	6	13	13	14	14	14	14	15	15	15	-
10	Exploration costs (expensed)	$mm nominal	-	-	10	-	-	-	-	-	-	-	-	-	-
51	Development costs - intangibles (expensed)	$mm nominal	-	-	51	-	-	-	-	-	-	-	-	-	-
257	Development costs - tangibles and replacement capex (depreciation)	$mm nominal	-	-	43	45	47	49	51	9	7	4	2	-	-
1,000	Operating costs	$mm nominal	-	-	48	98	100	102	104	106	108	110	112	114	-
25	Decommissioning provision	$mm nominal	-	-	-	-	-	-	-	-	6	6	6	7	-
40	Interest payment	$mm nominal	-	-	13	10	8	6	3	-	-	-	-	-	-
1,147	Taxable income before prior period losses	$mm nominal	-	-	-43	94	97	101	104	153	152	158	163	168	-
-43	Prior period losses carried forward	$mm nominal	-	-	-	-43	-	-	-	-	-	-	-	-	-
1,104	Taxable income after losses	$mm nominal	-	-	-43	51	97	101	104	153	152	158	163	168	-
344	CIT payable	$mm nominal	-	-	-	15	29	30	31	46	46	47	49	50	-
In Regime 2 Surcharge on Cash Flows															
1,147	Taxable income before losses for CIT purposes	$mm nominal	-	-	-43	94	97	101	104	153	152	158	163	168	-
40	(add back) interest deduction	$mm nominal	-	-	13	10	8	6	3	-	-	-	-	-	-
257	(add back) depreciation deduction	$mm nominal	-	-	43	45	47	49	51	9	7	4	2	-	-
-257	(deduct) depreciable capital in full	$mm nominal	-50	-153	-10	-11	-11	-11	-11	-	-	-	-	-	-
-344	(deduct) CIT paid	$mm nominal	-	-	-	-15	-29	-30	-31	-46	-46	-47	-49	-50	-
843	Adjusted taxable income before prior period losses	$mm nominal	-50	-153	2	123	112	114	116	116	113	115	116	118	-
-532	Prior period losses	$mm nominal	-	-50	-203	-201	-78	-	-	-	-	-	-	-	-
311	Adjusted taxable income after prior period losses	$mm nominal	-50	-203	-201	-78	35	114	116	116	113	115	116	118	-
169	Surcharge on Cash Flows payable	$mm nominal	-	-	-	-	7	23	23	23	23	23	23	24	-

TABLE 8. MODELING ROYALTY AND PROFIT/RENT TAXES (CONTINUED)															
Total	**Fiscal Calculations**	**Year**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
In Regime 3 Resource Rent Tax															
-747	RRT opening balance	$mm nominal	-	-70	-271	-235	-135	-36	-	-	-	-	-	-	-
-75	(add) uplift on negative balance	$mm nominal	-	-7	-27	-24	-14	-4	-	-	-	-	-	-	-
1,187	(add) project NCF after royalty, bonus and decommissioning	$mm nominal	-70	-194	63	139	142	144	147	162	159	162	165	168	-
-344	(deduct) CIT paid	$mm nominal	-	-	-	-15	-29	-30	-31	-46	-46	-47	-49	-50	-
21	RRT closing balance	$mm nominal	-70	-271	-235	-135	-36	74	116	116	113	115	116	118	-
154	Resource Rent Tax payable	$mm nominal	-	-	-	-	-	15	23	23	23	23	23	24	-
843	NCF after royalty and CIT if deductible	$mm nominal	-70	-194	63	123	112	114	116	116	113	115	116	118	-
34%	Cumulative IRR	%	0	0	0	-17	5	17	24	28	30	32	33	34	34

From a tax administration point of view, net cash flows can be calculated starting from the taxable income (before prior period losses and as reported on the tax return) with two basic adjustments. One needs to add back net financial cost and capital depreciation, and deduct capital expenditure in full to arrive to net cash flows after royalty.

$$Pre\text{-}taxNCF_t = CITbase(beforeLCF)_t + NetFinancialCost_t + CapexDepr_t - Capex_t$$

In Table 8, this approach is illustrated in the adjusted taxable income for the SCF.

Withholding Taxes

Since the calculations in the FARI model are undertaken from the perspective of a foreign investor, the model accounts for withholding tax on dividend distributions to non-residents, assumed to be a final tax.[44] The model takes a "residual dividend" approach in calculating the base for the dividend withholding tax (DWT), although the practice may differ significantly across companies and projects.[45] In this approach, the assumption is that all the initial positive free cash flows to equity are allocated to the payment of the return of capital (i.e. the refund of the original equity injection in the project), with any residual cash thereafter distributed in full as dividends to shareholders. In the model, this latter segment triggers a tax obligation, and happens when the cumulative free cash flows from the beginning of the project to the current year become positive.

[44] By ignoring withholding taxes on payments abroad, the fiscal regime essentially becomes a model of taxation at corporate level. In that sense, it would apply to domestic investors.

[45] In practice, the Income Statement reports the net profit (loss) which takes into account book depreciation and book tax. The company decides on a payout ratio relative to this net profit (loss), and the dividends are then paid from the cash available according to results reported on the Cash Flows Statement. Since the distribution policy is unknown ex-ante, a safe and conservative modeling assumption is that cash is first used to cover the return of capital, with any available cash thereafter paid out as dividend.

The withholding on dividend comes on top of all other taxes paid by the investor, thus further diminishing its net cash flows (Table 9). While withholding on income to shareholders is not a tax on the project itself, withholding on dividend distributions made to non-residents (assumed to be the investors in the resource project) is treated as a final tax from the perspective of the host government.

State Participation ("free" and "carried")

Two forms of state participation are often found in mining: "free" and "carried" equity. In the case of free equity (also known as "unpaid participation"), shares in the EI company are allocated to the state for nil consideration.[46] In other words, the government takes a share only in the profits of the project but does not contribute to the capital investment or operating costs. The free state participation is fiscally equivalent to a tax on dividend distributions (except with respect to entitlements if the company is wound up), and thus in the FARI framework it is modeled like an additional withholding tax on dividends.

In a carried interest, the investor usually meets all the costs attributable to the government during exploration, appraisal and even development, after which the state meets its prorated share of operating costs in a similar fashion as the investor. The private investor may or may not receive a compensation for the funds advanced on behalf of the state, and where repayment does occur, it may include a nominal interest. Carried equity is thus similar to a RRT, in the sense that the state cash contributions initially met by the investor are repaid from the government's share of net profits with interest; or similar to the cash flow tax mechanism discussed above, when the contributions on behalf of the state are repaid without interest. The stylized mining example considered here assumes only the case of free equity participation (Table 9).

The three tax/royalty regimes with the parameters described in Table 7 produce different outcomes for the government. The first regime generates USD666 million over the life of the project, the second regime USD795 million, and the third regime USD784 million (Table 10). The second and third regimes generate higher revenue on account of the additional profit taxes.

[46] In practice, the unpaid equity is often accompanied by tax concessions, or contribution of rights or infrastructure. Hence, it is not strictly "free."

TABLE 9. WITHHOLDING TAX AND STATE PARTICIPATION

Dividends paid to shareholders and distributed to the state on account of its participation in the project are both modeled as a percent of distributable cash, calculated as the net cash flows available after the recovery of the initial costs with exploration and development.

Total	Fiscal Calculations	Year	1	2	3	4	5	6	7	8	9	10	11	12	13
Illustration for Regime 1															
1,187	Project NCF after royalty, bonus and decommissioning	$mm nominal	-70	-194	63	139	142	144	147	162	159	162	165	168	-
40	Lender net cash flows	$mm nominal	-42	-136	43	43	43	43	43	-	-	-	-	-	-
344	Corporate Income Tax	$mm nominal	-	-	-	15	29	30	31	46	46	47	49	50	-
-	Surcharge on Cash Flows	$mm nominal	-	-	-	-	-	-	-	-	-	-	-	-	-
-	Resource Rent Tax	$mm nominal	-	-	-	-	-	-	-	-	-	-	-	-	-
803	Contractor cash flow before distributions	$mm nominal	-28	-58	19	80	69	71	73	116	113	115	116	118	-
3,949	Cumulative contractor cash flow before distributions	$mm nominal	-28	-86	-67	13	82	153	225	341	454	569	685	803	-
803	Distributable cash	$mm nominal	-	-	-	13	69	71	73	116	113	115	116	118	-
80	State participation	$mm nominal	-	-	-	1	7	7	7	12	11	11	12	12	-
723	Dividend payment	$mm nominal	-	-	-	12	62	64	65	104	102	103	105	106	-
108	Dividend Withholding Tax	$mm nominal	-	-	-	2	9	10	10	16	15	15	16	16	-
614	Contractor NCF after DWT and state participation	$mm nominal	-28	-58	19	77	53	54	55	89	87	88	89	90	-

TABLE 10. SUMMARY REVENUE RESULTS: MINING

DATA IN MILLION USD (MARKET PRICES)	Units	Royalty/CIT	Royalty/CIT + SCF	Royalty/CIT + RRT
Royalty	$mm nominal	133	133	133
Income Tax	$mm nominal	344	344	344
Additional profits tax (RRT or SCF)	$mm nominal	-	169	154
State participation	$mm nominal	80	63	65
Dividend withholding tax	$mm nominal	108	86	88
Total government revenue	$mm nominal	**666**	**795**	**784**

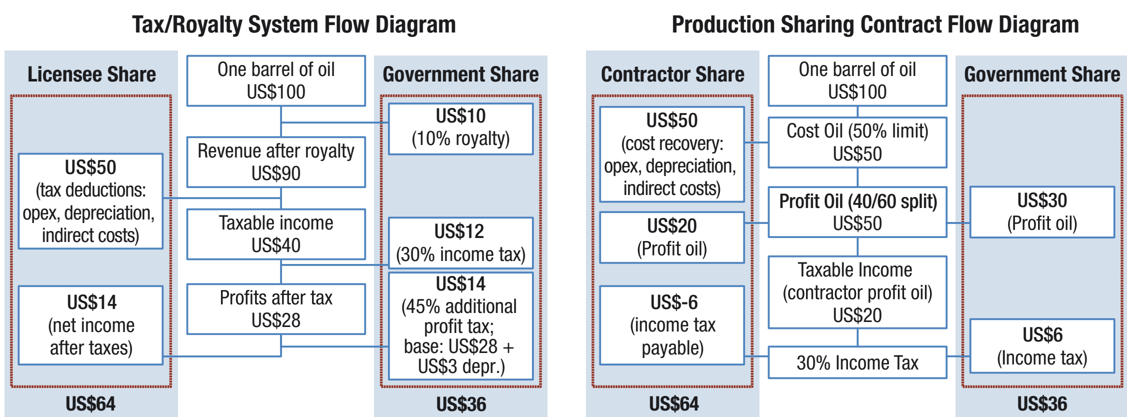
C. Typical Fiscal Calculations for Production Sharing Systems

Production sharing fiscal regimes diverge from tax/royalty systems in one key respect. Under a production sharing contract (PSC), the government retains the ownership of the resource in the ground but appoints the investor as "contractor" to develop the resource at its own risk. In return for meeting the exploration and development costs, the contractor receives a share of production, part to recover costs incurred in the project ("cost petroleum"), part as payment for its work ("profit petroleum"). Profit petroleum is what remains from production after the allocation of cost petroleum, and is divided between the government and the contractor according to different production or profitability indicators. In case of unsuccessful discovery, the contractor is not paid anything. On the other hand, in a tax/royalty system the investor or "licensee" is granted the ownership of the resource at the point of extraction in exchange for a payment to the government, usually in the form of a royalty. Tax/royalty and production sharing systems can be made fiscally equivalent, and it is rather legal or political considerations that lead some jurisdictions to prefer PSC schemes.[47]

To illustrate in a very simplified way the difference between the two systems, Figure 5 compares the flow of payments under a tax/royalty regime with the payments under a production sharing scheme. From one barrel of oil, for ease of illustration assumed to sell for USD100, under both systems the government receives the same revenue (USD36), but the mechanisms to arrive to that result differ considerably. In the tax royalty system, the government receives USD10 in royalty, USD12 in income tax, and USD14 in additional profits tax. In the PSC system, the government revenue consists of USD30 in profit oil and USD6 in income tax.

Figure 5. Flow of Payments: Tax/Royalty vs PSC

In the PSC diagram below, the base for CIT is equal to cost petroleum plus profit petroleum minus allowable tax deduction. Normal tax deductions in the tax/royalty regime are assumed to be equal to the cost recovery in the PSC.



Note: To calculate the base for the additional profit tax, non-cash charges are added back to taxable income and capital expenditures are deducted in full in the year incurred. In this example, "US$3 depr" refers to depreciation associated with capex incurred in previous years; for simplicity, the assumption made here is of zero capex in the current year.

[47] Hybrid regimes exist too in practice, but they are not addressed here.

The rest of this section explains steps in the modeling of two hypothetical, yet representative, PSC regimes. Under the first regime, the government share of profit petroleum is determined by the daily rate of oil production (DROP). Under the second regime, the profit petroleum is allocated according to a measure of investor payback or R-Factor ratio, an indicator explained in the following sections. A third regime consisting of royalty and income tax is also included for illustration purposes. This regime imposes a royalty of 15 percent and a higher income tax in place of production sharing. The details of these regimes and the corresponding parameters are summarized in Table 11. In all three cases, the government also exercises a direct participating interest of 10 percent in the project, which on the table is reflected by the state-owned company (SOC)'s participation in the joint venture.

TABLE 11. PETROLEUM FISCAL REGIME PARAMETERS
The yellow background designates hard-coded inputs into the model.

Fiscal Regime Assumptions					
Regime name		PSC (DROP)	PSC (DROP)	PSC (R-Factor)	Royalty/ Tax
Select regime number		**1**	**1**	**2**	**3**
Bonus					
Production bonus (start of production)	$mm	50	50	50	50
Royalty rate	%	0%	0%	0%	15%
Royalty base (net/gross)	switch	net	net	net	net
Decommissioning provision (yes/no)	switch	yes	yes	yes	yes
Commencement of decommissioning provision	% depletion	60%	60%	60%	60%
Cost Recovery					
Cost recovery ceiling	%	80%	80%	80%	100%
Development and replacement capital depreciation	years	5	5	5	
Investment uplift (yes/no)	switch	no	no	yes	no
Investment uplift	%	0%		15%	
Uplift limit	years	5	5	5	
Profit petroleum sharing	switch	DROP	DROP	R-Factor	Tax/Royalty
DROP tiers					
Profit petroleum tier 1	Mbpd	15	15		
Profit petroleum tier 2	Mbpd	30	30		
Profit petroleum tier 3	Mbpd	45	45		
Profit petroleum tier 4	Mbpd	60	60		

TABLE 11. PETROLEUM FISCAL REGIME PARAMETERS (CONTINUED)					
Fiscal Regime Assumptions					
Regime name		PSC (DROP)	PSC (DROP)	PSC (R-Factor)	Royalty/ Tax
Select regime number		**1**	**1**	**2**	**3**
R-Factor tier 1	R-Factor			1.00	
R-Factor tier 2	R-Factor			1.50	
R-Factor tier 3	R-Factor			2.00	
R-Factor tier 4	R-Factor			2.50	
Government share of profit petroleum					
Govt. share tier 1	%	40%	40%	40%	
Govt. share tier 2	%	50%	50%	50%	
Govt. share tier 3	%	60%	60%	60%	
Govt. share tier 4	%	65%	65%	65%	
Govt. share tier 5	%	75%	75%	75%	
Corporate Income Tax rate	%	20%	20%	20%	30%
Exploration costs (expensing)	switch	deferred	deferred	deferred	deferred
Development costs (depreciation)	switch	deferred	deferred	deferred	deferred
Development costs and replacement capital depreciation (years)	years	5	5	5	5
Dividend Withholding Tax	%	5%	5%	5%	5%
State owned company (SOC) participation in joint venture	%	10%	10%	10%	10%
Participation from development or production	switch	development	development	development	development

Bonus

The bonus is a lump sum payment made in relation to signature and/or production milestones. As a fiscal instrument, it is more often seen in petroleum rather than in mining. When licenses are awarded in auctions, competitive bidding for petroleum blocks can give rise to significant signature bonuses, often reflecting the relative prospectivity of a particular basin. In addition to signature bonuses, investors may also pay production bonuses upon achieving certain production thresholds (linked either to daily rates or to cumulative production). All three fiscal regimes in Table 11 assume that a bonus of USD50 million is payable at the start of production.

Cost petroleum

Once production starts and revenues are generated, a portion of the production (either in monetary value or in kind) after royalty,[48] if payable, is allocated to the contractor to recover costs incurred in respect to the petroleum operations. This is commonly referred to as "cost petroleum." Recoverable costs include operating costs; capital costs (either expensed or depreciated and amortized, according to the provisions in the PSC, and in some cases with an additional allowance as in the PSC/R-Factor regime in Table 11); investment credits, if any; contributions made to the decommissioning fund; and unrecovered costs from the previous period. Table 12 provides an illustration of the calculations as they apply to the PSC/DROP regime in Table 11. Some PSCs may also allow the recovery of interest expense, though this is not common practice and is usually subject to strict limitations.

TABLE 12. COST PETROLEUM CALCULATIONS

Total	Joint venture cost recovery	Year	1	2	3	4	5	6	7	8	9	10	11	12	13
7,601	Net revenue	$mm nominal	-	-	213	542	1,659	1,354	1,105	902	736	600	490	-	-
6,081	Cost recovery ceiling	$mm nominal	-	-	170	434	1,327	1,083	884	721	589	480	392	-	-
250	Exploration costs (expensed)	$mm nominal	250	-	-	-	-	-	-	-	-	-	-	-	-
591	Development costs depreciation	$mm nominal	-	-	105	108	112	115	118	13	10	7	3	-	-
Opening balance		$mm nominal	-	250	250	299	264	-	-	-	-	-	-	-	-
250	Exploration with uplift (if applicable)	$mm nominal	250	-	-	-	-	-	-	-	-	-	-	-	-
591	Depreciation of development and replacement capital costs with uplift (if applicable)	$mm nominal	-	-	105	108	112	115	118	13	10	7	3	-	-
4,072	Operating costs	$mm nominal	-	-	114	291	889	725	592	483	394	322	262	-	-
249	Decommissioning provision/costs	$mm nominal	-	-	-	-	-	-	68	56	47	40	37	-	-
6,225	Total recoverable costs	$mm nominal	250	250	469	698	1,264	840	778	552	451	368	303	-	-
5,162	Cost petroleum	$mm nominal	-	-	170	434	1,264	840	778	552	451	368	303	-	-
Closing balance		$mm nominal	250	250	299	264	-	-	-	-	-	-	-	-	-
5,162	Cost petroleum	$mm nominal	-	-	170	434	1,264	840	778	552	451	368	303	-	-
4,646	Cost petroleum to contractor	$mm nominal	-	-	153	390	1,138	756	701	497	406	332	273	-	-
516	Cost petroleum to state owned company (SOC)	$mm nominal	-	-	17	43	126	84	78	55	45	37	30	-	-
2,439	Profit petroleum	$mm nominal	-	-	43	108	395	514	326	349	285	232	187	-	-

The concept of recoverable costs is in a way equivalent to the deductions allowed in the calculation of CIT in the tax/royalty system, with an important distinction: many PSCs impose a ceiling ("cost petroleum limit") on the amount of revenue allowed to be used to recover costs. In tax/

[48] As in mining, some PSCs also charge royalty on production. The royalty can be levied on gross or net revenue, the latter allowing the netting back of transportation (pipeline tariff) and other specified costs from the final price. The royalty rate may vary with location (onshore, shallow offshore, deep offshore), type of hydrocarbon (crude oil, natural gas), and/or production rate.

royalty systems there is usually no limitation on the amount of revenue against which costs can be deducted. However, some costs may be subject to depreciation schedules which, similarly to the cost recovery limit in PSCs, may cause a time delay in recovering costs.

Profit petroleum

The part of production remaining after cost petroleum represents the production that will be divided between the contractor and the government, and is commonly referred to as "profit petroleum." When a limit is imposed on the amount of production available for cost recovery, a minimum amount of production will always be available for sharing. In this sense, the combination of a cost recovery limit (while it applies) and a minimum government share of profit petroleum operates like a de facto minimum royalty on production.[49]

Profit petroleum can be shared between the government and the contractor according to different mechanisms. This analysis illustrates two common production sharing mechanisms used to define a scale of sharing rates: DROP and R-Factor (the payback ratio).[50] Under the DROP scheme, the government's share of profit petroleum increases with the daily rate of production, often with several tiers. In the PSC/DROP regime 1 in Table 11, the government share of profit petroleum is given by the average of the profit petroleum tiers weighted by the corresponding production in each tier. For example, in a period in which the average daily production rate is 48 thousand barrels (Mbpd), as in year seven in Table 13, the government share is 40 percent on the first 15 Mbpd, 50 percent on the next 15Mbpd, 60 percent on the next 15Mbpd, and 65 percent on the remaining production of 3Mbpd. The weighted average of 51 percent[51] is the percentage share of profit petroleum to which the government is entitled given the average production rate of 48Mbpd in that period.

Under the R-Factor scheme, the government share of profit petroleum increases with a measure of investor payback from the project. The specific definition of this measure, also known as "R-Factor" or pay-back ratio, may vary between contracts; in the accompanying model, it is expressed as the ratio of cumulative contractor net revenues from the start of the project to total investment.[52]

$$\textit{R-Factor}_t = \frac{\sum_{i=1}^{t-1}(Revenues_i - Opex_i - ReplacementCapex_i - Royalty_i)}{\sum_{i=1}^{t-1}(Exploration_i + DevelopmentCapex_i)}$$

[49] In PSC, the combination of a cost recovery limit and a minimum government share of profit oil has the same effect as royalty, as there is always an portion of production accruing to the government from the start of production. For example, for USD100 in revenue, if there is a 50 percent cost recovery limit and 40 percent minimum government share of profit petroleum, the government has a claim on USD20 of the original revenue (USD100 x (1-50%) x 40% = USD20), which is equivalent to a 20 percent royalty.

[50] A similar mechanism, the rate of return (ROR), is more closely aligned with profitability indicators also used by investors for decision making. The ROR sets the government profit petroleum share relative to the cumulative return earned by the project from the start of exploration to the date of sharing. The difference between the ROR and the R-Factor is that the former takes into account the time value of money.

[51] The weighted average is calculated as follows: [(40%*15+50%*(30-15)+60%*(45-30)+65%*(48-45)]/48.

[52] In other formulations, the R-Factor may also be defined as the ratio of cumulative project revenue to cumulative total costs.

where *t* is the current year, revenues are the sum of cost and profit petroleum received by investor, and the denominator represents total investment during exploration and development. The R-Factor is calculated on cumulative cash flows up to the prior year (*t-1*) to avoid circularity in the model. An R-Factor of 1.0 indicates that all exploration, development, replacement capital and cumulative operating costs to the date of sharing have been recovered (on a cash basis, and ignoring the time value of money, in the sense that it simply compares cumulative sums of net revenues and costs, with no interest adjustment). In Table 14, the government share of profit oil is 40 percent before the R-Factor reaches the value of 1, then 50 percent when the R-Factor varies from 1 to 1.5, increasing to 60 percent when the R-Factor varies from 1.5 to 2 and to 65 percent when the R-Factor is between 2 and 2.5, to become 75 percent once the R-Factor passes the threshold of 2.5. These values and thresholds reflect the parameters of the second regime inputted in Table 11.

TABLE 13. PROFIT PETROLEUM SHARING: DROP

Profit petroleum is allocated between the government and the contractor according to the daily rates of production. The state-owned company (SOC)'s share of profit oil represents the state participation in the project as a joint venture partner.

	Total	Daily Rate of Profit Petroleum	Year	1	2	3	4	5	6	7	8	9	10	11	12	13
	2,439	Profit petroleum	$mm nominal	-	-	43	108	395	514	326	349	285	232	187	-	-
Govt. share	Mpbd	Daily rate of production	Mpbd	-	-	10	25	75	60	48	38	31	25	20	-	-
40%	15	Tranche 1	Mpbd	-	-	10	15	15	15	15	15	15	15	15	-	-
50%	30	Tranche 2	Mpbd	-	-	-	10	15	15	15	15	15	10	5	-	-
60%	45	Tranche 3	Mpbd	-	-	-	-	15	15	15	8	1	-	-	-	-
65%	60	Tranche 4	Mpbd	-	-	-	-	15	15	3	-	-	-	-	-	-
75%	> 60	Tranche 5	Mpbd	-	-	-	-	15	-	-	-	-	-	-	-	-
	-	Check		-	-	-	-	-	-	-	-	-	-	-	-	-
		Government share	%	-	-	40	44	58	54	51	48	45	44	42	-	-
		Government share: DROP	%	-	-	40	44	58	54	51	48	45	44	42	-	-
		Joint venture share	%	-	-	60	56	42	46	49	52	55	56	58	-	-
	1,215	Government profit petroleum	$mm nominal	-	-	17	48	229	276	166	169	129	102	79	-	-
	1,224	Joint venture profit petroleum	$mm nominal	-	-	26	61	166	238	160	181	156	130	108	-	-
	1,102	Profit petroleum to contractor	$mm nominal	-	-	23	55	149	214	144	163	140	117	97	-	-
	122	Profit petroleum to SOC	$mm nominal	-	-	3	6	17	24	16	18	16	13	11	-	-

State participation (paid up equity)

When the state takes equity in petroleum projects, this usually occurs in the form of either carried or full equity interest in an unincorporated joint venture.[53] It is less usual for the government to take

[53] Contrary to an incorporated joint enterprise where participants establish a company that holds the joint assets, pays expenses and (usually) manages the project, unincorporated joint ventures do not use a separate company and the participants operate more like a partnership.

free participation in petroleum projects. Carried equity participation has been discussed in the mining section above. Full equity (also known as "working interest") means that the government must meet in full its prorated share of costs of exploration, development and production from the first day of the project. In other words, the government has paid-up equity on commercial terms, and an opportunity to share both the upside and the downside risk. Table 15 illustrates the allocation of project cash flows between the state, represented by the state-owned company (SOC), and the contractor starting from the development stage of the project.

Table 16 shows the government revenue raised under the two PSC regimes and the comparative tax/royalty scheme. At the assumed price level and chosen parameters for the DROP and R-Factor mechanisms, the three regimes generate similar revenues yet with different instruments.

TABLE 14. PROFIT PETROLEUM SHARING: R-FACTOR

Profit petroleum is allocated between the government and the contractor according to the R-Factor. Total profit petroleum is smaller than in the previous example as capital costs are recovered with a 15 percent allowance over the original cost.

Total	Fiscal Calculations	Year	1	2	3	4	5	6	7	8	9	10	11	12	13
2,336	Profit petroleum	$mm nominal	-	-	43	108	332	473	326	349	285	232	187	-	-
5,265	Cost petroleum	$mm nominal	-	-	170	434	1,327	881	778	552	451	368	303	-	-
1,043	(add) Joint venture profit petroleum	$mm nominal	-	-	26	65	199	237	131	140	100	81	65	-	-
81	(deduct) Replacement capital	$mm nominal	-	-	16	16	16	17	17	-	-	-	-	-	-
4,072	(deduct) Operating costs	$mm nominal	-	-	114	291	889	725	592	483	394	322	262	-	-
249	(deduct) Decommissioning provision/costs	$mm nominal	-	-	-	-	-	-	68	56	47	40	37	-	-
	Cumulative net contractor revenue	$mm nominal	-	-	66	259	880	1,255	1,487	1,640	1,750	1,838	1,906	-	-
760	Investment (exploration and development)	$mm nominal	250	510	-	-	-	-	-	-	-	-	-	-	-
	Cumulative investment	$mm nominal	250	760	760	760	760	760	760	760	760	760	760	-	-
	R-Factor (previous period)		-	-	-	0.09	0.34	1.16	1.65	1.96	2.16	2.30	2.42	-	-
	Government share	%	40	40	40	40	40	50	60	60	65	65	65	-	-
	Government share: R-Factor	%	40	40	40	40	40	50	60	60	65	65	65	-	-
	Joint venture share	%	60	60	60	60	60	50	40	40	35	35	35	-	-
1,293	Government profit petroleum	$mm nominal	-	-	17	43	133	237	196	210	185	151	122	-	-
1,043	Joint venture profit petroleum	$mm nominal	-	-	26	65	199	237	131	140	100	81	65	-	-
939	Profit petroleum to contractor	$mm nominal	-	-	23	59	179	213	118	126	90	73	59	-	-
104	Profit petroleum to SOC	$mm nominal	-	-	3	7	20	24	13	14	10	8	7	-	-

TABLE 15. STATE PARTICIPATION: ALLOCATION OF PROJECT CASH FLOWS

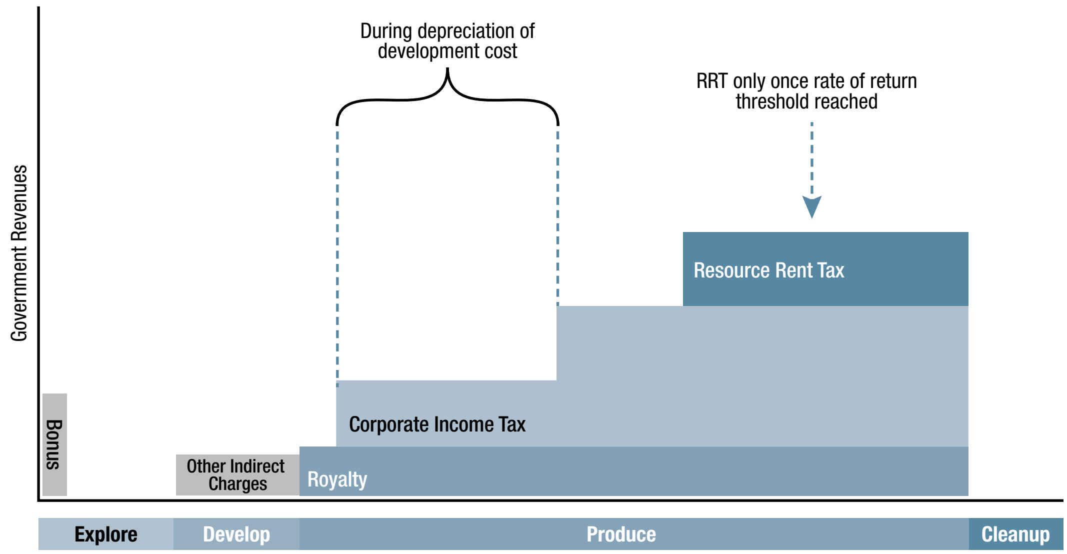
Total	Joint venture (JV) sharing of project cash flows	Year	1	2	3	4	5	6	7	8	9	10	11	12	13
	SOC (state-owned company)	%	0	10	10	10	10	10	10	10	10	10	10	-	-
	Contractor	%	100	90	90	90	90	90	90	90	90	90	90	-	-
Contractor share of JV															
6,841	Net revenue after royalty	$mm nominal	-	-	191	488	1,493	1,219	994	811	662	540	441	-	-
250	Exploration costs (expensed)	$mm nominal	250	-	-	-	-	-	-	-	-	-	-	-	-
459	Development costs (depreciable)	$mm nominal	-	459	-	-	-	-	-	-	-	-	-	-	-
73	Replacement capital costs (depreciable)	$mm nominal	-	-	14	14	15	15	15	-	-	-	-	-	-
3,665	Operating costs	$mm nominal	-	-	103	261	800	653	533	435	355	289	236	-	-
224	Decommissioning provision/costs	$mm nominal	-	-	-	-	-	-	62	51	42	36	33	-	-
45	Production bonus	$mm nominal	-	-	45	-	-	-	-	-	-	-	-	-	-
2,125	Net cash flow	$mm nominal	-250	-459	30	212	679	551	385	326	265	215	171	-	-
SOC share of JV															
760	Net revenue after royalty	$mm nominal	-	-	21	54	166	135	110	90	74	60	49	-	-
-	Exploration costs (expensed)	$mm nominal	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Development costs (depreciable)	$mm nominal	-	51	-	-	-	-	-	-	-	-	-	-	-
8	Replacement capital costs (depre-ciable)	$mm nominal	-	-	2	2	2	2	2	-	-	-	-	-	-
407	Operating costs	$mm nominal	-	-	11	29	89	73	59	48	39	32	26	-	-
25	Decommissioning provision/costs	$mm nominal	-	-	-	-	-	-	7	6	5	4	4	-	-
5	Production bonus	$mm nominal	-	-	5	-	-	-	-	-	-	-	-	-	-
264	Net cash flow	$mm nominal	-	-51	3	24	75	61	43	36	29	24	19	-	-

TABLE 16. SUMMARY REVENUE RESULTS: PETROLEUM

DATA IN MILLION USD (MARKET PRICES)	Units	PSC (DROP)	PSC (R-Factor)	Royalty/Tax
Production bonus	$mm nominal	50	50	50
Royalty	$mm nominal	-	-	1,140
Profit petroleum	$mm nominal	1,215	1,293	-
Corporate income tax	$mm nominal	201	187	322
Dividend withholding tax	$mm nominal	38	35	35
State participation	$mm nominal	142	135	150
Total government revenue	$mm nominal	**1,646**	**1,699**	**1,697**

Figure 6. Government revenue profile

Production and indirect taxes raise revenue early on, while profit-related instruments later in the project life.



D. Time Profile of Government Revenue

In addition to the net present value of total government revenue over the life of the project, it is also important to observe the annual revenue flows. Different types of instruments will ensure different timing of government revenues and the choice among these instruments will determine the sharing of risk between the government and investor. At one end of the spectrum, royalties ensure early and stable receipts to the government but they usually remain a relatively modest source of revenue particularly when the profitability of the project increases over time. At the other end of the spectrum, rent-related taxes are triggered later in the life of the project, but are more responsive to increases in profitability (Figure 6).

V. FARI: Results and Application

A. Fiscal Regime Design and Evaluation with FARI

In its TA work, FAD uses several metrics for fiscal regime evaluation.[54] From an investor's perspective, key indicators are the post-tax NPV of the project, the post-tax IRR, the payback period, and the break-even price (explained in Box 4).

These indicators refer to the investor as the capital provider, or the provider of total funds outlaid (equity, debt, and retained earnings spent on project investment), thus before taking into account financing decisions.[55] The model can also calculate the equivalent indicators for the equity investor alone.

[54] For a detailed description of criteria and tools, see Daniel, Goldsworthy, and all (2010). An updated discussion of EI fiscal regimes evaluation criteria is further covered in IMF (2012).

[55] These indicators are identical to the post-tax, pre-finance results in corporate finance. Debt is taken into account only in the calculation of CIT to show the effect of interest on the tax base.

Box 4. Investor Post-Tax Profitability Indicators[56]

Post-tax NPV

The post-tax NPV is the discounted present value of the total stream of net cash flows received by the investor over the life of the project. In this case, the investor's net cash flows are derived from gross revenues after deducting all project costs and all tax payments to the government:

$$\textit{Post-tax } NCF_t = \textit{Pre-tax } NCF_t - Royalty_t - Taxes_t$$

As in standard discounted cash flow (DCF) analysis, the post-tax investor NPV is then calculated as:

$$\textit{Post-tax } NPV = \sum_{t=0}^{n} \frac{\textit{Post-tax } NCF_t}{(1+r)^t}$$

where $\textit{Post-tax } NCF_t$ is the investor net cash flows in year t, r is the discount rate, and n is the last year of the project. Other things equal, an investor prefers projects with higher positive NPVs.

Post-tax IRR

A complementary measure to the NPV is the IRR, or the discount rate at which the NPV of the stream of cash flows is zero. The IRR in this case is the return on total funds (whatever the proportions of equity and debt), but the model also calculates the return to equity by further netting out the lender cash flow from the two equations above.

Payback Period

In EI projects, the payback period occurs when the cumulative cash inflows from production are sufficient to recover the cumulative cash outflows incurred with exploration, development, operating costs and taxes. The payback period can be calculated on undiscounted or discounted cash flows, and on leveraged and unleveraged funds. Other things equal, an investor prefers a short payback period.

From a government's perspective, key indicators are the AETR (a measure of "government take"), the METR, and the progressivity of the fiscal regime (explained in Box 5). These indicators are particularly useful in policy decision-making when comparing the existing regime in a country with alternative regimes.

As with any similar simulation analyses, FARI results in a single project case may differ from actual project results for three main reasons: (1) an implied assumption of full efficiency in revenue assessment and collection by the relevant authorities; (2) an implied assumption of a full project ring-fence, so that no revenue is lost by deduction of costs carried across from other projects; and (3) for corporate income tax, whether by assessment or withholding, an applied assumption of no losses through international tax planning. Each of these assumptions could be relaxed and the model adapted to different assumptions about the resulting effects.

[56] In TA work, the FARI model has also been used to perform expected monetary value (EMV) and stochastic probability analysis. A relevant discussion is available in Daniel, Goldsworthy, et. al (2010).

Box 5. Government Indicators[57]

Average Effective Tax Rate (AETR)

The AETR is the ratio of the NPV of government revenue (composed of royalty, income tax, resource rent tax, withholding taxes, and so on, as specified by the fiscal regime) to the NPV of the pre-tax net cash flows of a successful project, both calculated in discounted value. The AETR thus indicates how much revenue a fiscal regime raises and is one of the definitions of "government take."

$$AETR = \frac{NPV(Gov\ Revenue)}{NPV(Revenue - Exploration - Dev\&ReplacementCapex - Opex - Decomm)}$$

Marginal Effective Tax Rate (METR)

In FARI analysis, the METR is defined as the wedge that the tax system drives between the minimum after-tax return that the investor requires and the pre-tax project return needed to realize it. The METR reflects the burden placed by the fiscal regime on a project at the margin of viability (i.e. projects that lie at the far end of a sector's cost curve), thus indicating the extent to which the regime affects business investment decisions.

$$METR = \frac{Pre\text{-}tax\ IRR - Post\text{-}tax\ IRR}{Pre\text{-}tax\ IRR}$$

In the model, an important first step in the calculation of the METR is to determine the price at which the post-tax investor return equals the hurdle rate, or the breakeven price. The pre-tax return is then calculated assuming the project is executed with this price.

Breakeven Price

An indicator of the fiscal burden on a marginal project and complementary to the METR, the breakeven price is the minimum price required to yield a specified post-tax return to capital over the full-life of the project. The breakeven price is determined by the model through iterations and then compared with the initial user price assumption. A breakeven price above the user price implies that the project is economically unviable post-tax.

Progressivity

In FAD TA work, progressivity has been broadly defined as the ability of the fiscal regime to capture a larger share of profits in highly profitable projects, while reducing the tax burden in low profitability ones. The degree of progressivity in a fiscal regime can be analyzed by plotting the share of government revenue in project total benefits, or "quasi-rents," over a range of pre-tax rates of return.

Total benefits are defined as revenues less operating costs and replacement capital expenditure after start-up. They can be thought of as "quasi-rents" in that they represent the project proceeds available to meet the recovery of the original capital investment, the fiscal payments, and a required return to capital. This measure is also similar to the concept of Cash Flows from Operations reported by companies, but excluding taxes.

[57] The indicators listed here may be somewhat different from the rest of the taxation literature. For example, there is no single accepted definition of progressivity in the resource context, and the concepts of AETR and METR have been applied using varying definitions. See Daniel, Goldsworthy, and all (2010) and IMF (2012) for a detailed discussion, examples, and definitions.

Box 5. Government Indicators (Continued)

The range of project pre-tax rates of return is obtained by varying the assumed prices or unit costs in the model. Graphically, a regime is progressive when the government's share in project benefits rises as the intrinsic profitability of the project rises in response to either increasing prices or decreasing costs.

$$Gov.\ Share\ of\ Total\ Benefits = \frac{NPV(Gov\ Revenue)}{NPV(Revenue - ReplacementCapex - Opex - Decomm)}$$

B. Fiscal Regime Evaluation: An Illustrative Example

This section illustrates how to evaluate and compare fiscal regimes by the economic indicators discussed in Box 5. Taking the hypothetical petroleum project described above, including the exploration phase, this note analyzes the three fiscal regimes summarized in Table 11: a PSC with profit petroleum sharing based on DROP; a PSC with profit petroleum sharing based on an R-Factor scheme; and a simple concession system composed of royalty and CIT. All three regimes include state participation, fully paid from the start of development.

Before computing the different indicators, it is helpful to visualize the timing of total government revenue in relation to the project's pre-tax net cash flows (Figure 7). Generally, the government revenue profile follows that of the project, with several distinctions depending on the design of each regime. Under the PSC/DROP system, the government revenue follows closely the production profile, reaching its highest point at the peak of production. A similar behavior is observed in the royalty/CIT regime, which also relies on production taxes and generates higher revenues during the first years of production. Under the PSC/R-Factor scheme, revenues increase later in the project life relative to the other two regimes as the ratio of cumulative net revenue to cumulative investment (that is, the R-Factor) surpasses the profitability thresholds. The government cash outflows observed between the first and second year of the project under the three regimes is explained by the state's fully paid equity participation from the end of exploration onward, which requires the government to contribute to its share of costs during the development phase.

While this simple illustration is useful in observing the time profile of revenue, it does not explain how the three regimes compare in terms of overall government take. The AETR is a helpful indicator in assessing the revenue raising capacity of the fiscal regime. A project is attractive to the investor at any AETR less than 100 percent as long as the discount rate is equal to the minimum discount rate demanded by the investor. In other words, as long as taxes paid do not exceed the pre-tax rent on a project, investors will receive more than the required minimum return and will have an incentive to proceed. In this particular scenario, with a discount rate of 10 percent, the royalty/tax scheme generates the highest AETR, in large part due to the fact that government revenues are more front-loaded than in the other two regimes (Figure 8).[58]

[58] Of critical importance is that the AETR will generally vary with the assumed pre-tax profitability of the project, reflecting, for instance, assumptions about future commodity prices and input costs.

Figure 7. Petroleum Analysis: Time Profile of Government Revenue

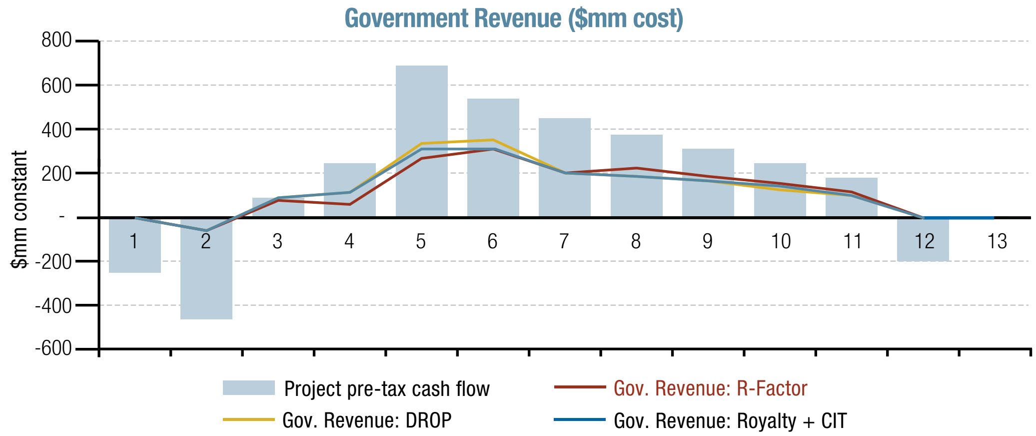
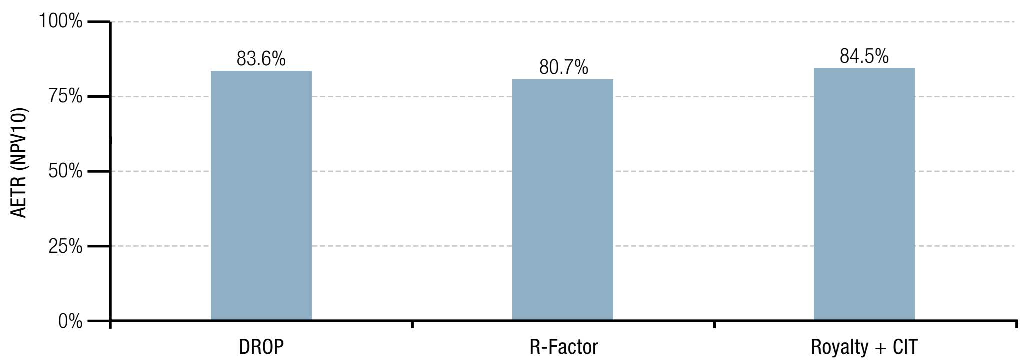
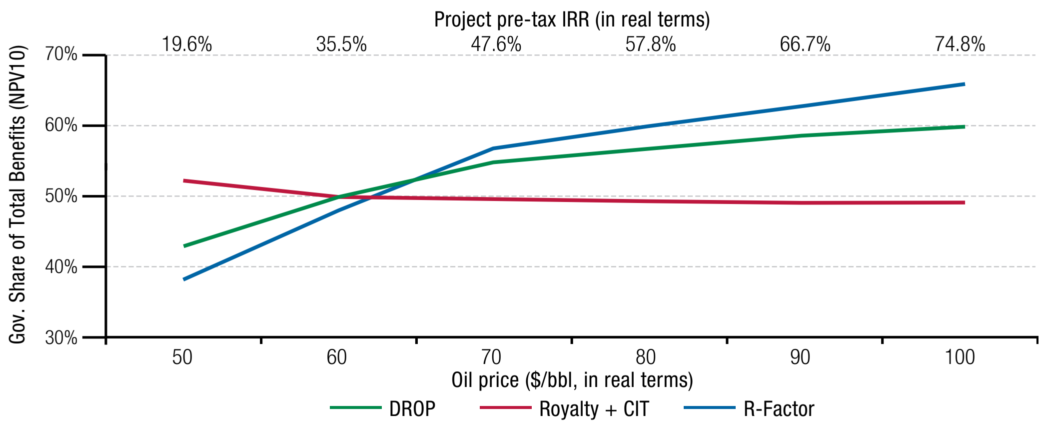


Figure 8. Petroleum Analysis: Government Take



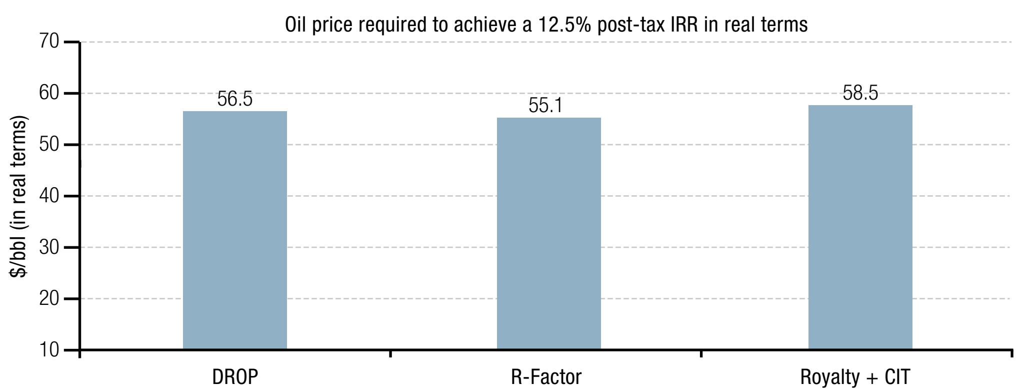
The AETR is only a snapshot, however, because it is calculated under one single price path and one set of costs assumptions. It does not explain how a fiscal regime fares in different circumstances – in particular, how progressive the fiscal package is. The progressivity of the three regimes is evaluated by estimating the government share of total benefits over a range of different prices and corresponding pre-tax IRRs. 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. According to this analysis, the PSC/R-Factor option is the most progressive of the three regimes evaluated (Figure 9): the government share of total benefits is relatively low when prices and project outcomes are low, but it increases faster than in the other two regimes as the project becomes more profitable. This property of the regime is explained by its reliance on a profit-based mechanism to determine the government share of profit petroleum. In contrast, the Royalty + CIT scheme in this illustration is regressive, in large part due to the relatively high royalty rate which places a heavy burden on low profitability projects.

Figure 9. Petroleum Analysis: Progressivity



An important consideration in designing fiscal regimes is their potential effect on marginal projects – that is, projects that just generate the minimum after-tax rate of return required by the investor. The relative burden that the three regimes would impose on a marginal project is evaluated using the breakeven price or the price required to meet the investor's minimum post-tax rate of return. For this analysis, it is assumed the investor would demand a minimum real rate of return of 12.5 percent. Consistent with the progressivity results, the R-Factor and the royalty/CIT options exhibit the lowest (USD55.1 per barrel) and highest (USD58.5 per barrel) breakeven price, respectively (Figure 10). These values are still below the project price of USD60 per barrel, indicating that the project is viable under all three fiscal regimes.

Figure 10. Petroleum Analysis: Breakeven Price



C. International Comparisons of Fiscal Regimes

The FARI model is an aid to fiscal regime design and evaluation, particularly through comparative analysis. Countries are often interested to compare their fiscal regimes internationally and across alternative scenarios on their AETR, METR, and progressivity. However, as any model, it represents a simplification of reality. FARI focuses on the evaluation of the fiscal regime assuming all other factors remain constant. In cross-country comparison, there are many conditions that affect the decision to invest, such as differences in the size and quality of the deposits across locations, the maturity of the EI sector, or the general business and operating environment. The fiscal regime is just another, though very important, factor that affects investment. The purpose of any comparative analysis in FARI is to isolate and examine the effects of the different fiscal regimes, as they are packaged in different countries, on the decision to invest, not to determine the actual government take or investor returns in those locations.[59] Results thus should be interpreted with care and taking into account all these caveats.

Moreover, each indicator reflects only certain, sometimes isolated, properties of the fiscal regime. Any thorough exercise requires that the evaluation be made across more than one criterion. For example, the government take calculated on a project of average profitability could indicate that the fiscal regime is robust enough to capture a reasonable share of the resource rent for the government, but that is an incomplete assessment without further analysis of the progressivity properties of the system. It might be that at the margin, the regime puts a heavy burden on investment, thus deterring the development of what could be a nascent sector; or that for very profitable projects the government take is drastically reduced. The AETR measure alone is not able to convey this wide range of perspectives.

D. Revenue Forecasting

While the primary use of the model is the design and evaluation of fiscal regimes, the FARI framework can be applied also to revenue forecasting. Where the fiscal terms, underlying historical data, and reliable projections are available, it is possible to interpret with some degree of accuracy the timing and amount of payments that the government should expect to receive from an EI project. This method identifies interactions between fiscal terms and kinks or jumps in revenue profile that would not be possible to predict with simple economic methods (such as extrapolation or vector auto-regression models). For example, the timing of the CIT is affected not only by production, price, and operating cost profiles, but also by the schedule of capital allowance, loss carry forward rules, and the size of the royalty payment. They are usually difficult to derive in more generic economic models.

The FARI modeling approach has particular value for countries where the resource sector is concentrated around a few large-scale projects. In that case, each project can be modeled on an individual sheet and the results aggregated in a live summary table. Relevant information can then be extracted and fed into the macro-fiscal model of the country, to include not only resource revenue projections but also data on exports, prices, portfolio and foreign direct investment, interest and debt amortization, and production volumes. Economists in the Africa Department at the IMF, for instance, have successfully used FARI for revenue forecasting in a number of countries.

[59] Modeling comparisons with examples separately relevant to each country rather than comparing only across the same field example is, in principle, possible.

E. Tax Administration

Both fiscal regime design and revenue forecasting take a forward-looking approach, for a hypothetical project and outcomes. Analysis can be done also on a backward-looking basis, using historic data and actual project outcomes. Where data on actual revenue collection is available by project and, ideally, by fiscal instrument, the FARI framework can be used in revenue administration for tax gap analysis. This is done by comparing the EI revenues effectively paid to or collected by the government with what the model predicts should have been paid.

The benefits of using FARI for tax administration are three-fold: first, discrepancies between the model predictions and actual tax collections may provide useful information on possible sources of revenue leakage, such as accounting manipulation and abusive tax planning; second, it allows the tax authority to set realistic tax collection targets and monitor performance more closely; and third, the exercise allows a better calibration of the FARI model itself improving its revenue forecasting power.

At present, FAD does not use FARI for tax gap analysis. However, as large EI projects continue to be developed in countries that actively receive technical assistance on natural resource taxation, it is expected that FARI can be used to monitor tax collections and compliance in their EI sectors.

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Annex

Annex. Sources of Project Information for FARI

The primary sources for production and cost data are host governments and/or the companies that develop and operate the EI projects in the country. Companies are commonly required to submit to the host governments work plans for exploration and development activities, as well as production plans. In most cases, a company is not permitted to advance from one phase of the project to the next until the government has approved the respective work plan. As a result, host governments usually have repositories of annual production and cost data for existing and potential projects.

In a number of countries, publicly traded companies are also required to file technical reports with the country's securities administration to disclose technical information about their mineral projects. These reports usually include a detailed economic analysis section with the following information:

- a clear statement of and justification for the key assumptions used in the economic analysis;
- cash flow forecasts on an annual basis using mineral reserves or mineral resources, and an annual production schedule for the life of the project;
- a discussion of net present value (NPV), internal rate of return (IRR), and payback period of capital with imputed or actual interest;
- a summary of the taxes, royalties, and other government levies or interests applicable to the mineral project or to production, and to revenue or income from the mineral project; and
- sensitivity or other analysis using variations in commodity price, grade, capital and operating costs, or other significant parameters, as appropriate, with a discussion of the impact on results.

For example, the Canadian Securities Administration requires that companies listed in the country's stock exchanges file a national instrument for the Standards of Disclosure for Mineral Projects within Canada, known as NI-43-101. This instrument is available to the general public at no cost, and contains scientific, technical and economic information on resource projects. Similarly, the Australian Stock Exchange in its listing rules requires mineral companies to file a JORC (Joint Ore Reserves Committee) code for reporting exploration results, mineral resources and ore reserves. Similar to the NI-43-101, the JORC code also includes technical and economic studies. A further example is given by the South African Code for Reporting of Exploration Results, Mineral Resources and Mineral Reserves (SAMREC) and the South African Code for the Reporting of Mineral Asset Valuation (SAMVAL).

In addition to these instruments and codes, companies also provide detailed information on resource projects to potential investors in the form of corporate presentations, annual reports, management discussion and analysis (MD&A), and rights issues prospectus. All these documents are usually available on the company website and updated regularly. Information from these sources can be extracted and organized to fit the FARI data template (Box 1).

Box 1. Reconciling FARI with Companies' Financial Statements

A key assumption in FARI is that the fiscal analysis is done on a project by project basis. One of the difficulties in practice is that publicly traded companies report their financial statements in a consolidated manner. Furthermore, most mining and petroleum companies usually have a relatively large portfolio of resource projects, and may be vertically integrated with projects along the entire value chain in the upstream, midstream and downstream activities. For these reasons, it is difficult to reconcile FARI results with the results reported in companies' financial statements.

However, the different components of a company's financial statements can be used to calculate free cash flows to the firm (FCFF), or cash flow available to all the firm's capital providers, which in turn could be compared against the investor net cash flows calculated in FARI. The examples below reconcile the post-tax cash flows from FARI (Table 1) and the FCFF derived from the financial statements of the company (Table 2).

TABLE 1. POST-TAX CASH FLOWS FROM FARI

	FARI Calculations	Comments	Sources of Information
	Gross Revenue	Value of mineral resources	Production profile and price assumptions
Less	Project Expenditures	Incurred capital and operating expenditures (expensed)	Cost profile
Equals	**Pre-Tax Cash Flows**		
Less	Royalty	Calculated in FARI according to countries' legislation	Fiscal regime terms and regulations
Less	Corporate Income Taxes	Calculated in FARI according to countries' legislation	Fiscal regime terms and regulations
Less	Additional Profit Taxes	Calculated in FARI according to countries' legislation	Fiscal regime terms and regulations
Equals	**Post-Tax Cash Flows**		

TABLE 2. FCFF FROM COMPANIES' FINANCIAL STATEMENT[60]

	Companies' Statements	Comments	Sources of Information
	Gross Revenue	Sales value of resources	Income statement
Less	Cost of sales and SG&A	Operating costs and SG&A	Income statement
Less	Depreciation charges	Book depreciation	Income statement
Less	Interest expense	Interest on debt	Income statement
Less	Tax payable	Royalties and taxes payable	Income statement
Equals	**Net income**		
Plus	Non-cash charges	Depreciation expense and other non-cash charges	Income statement and balance sheet
Plus	After-tax interest expense	Calculated as interest expenses times (1 – tax rate)	Income statement
Less	Capital expenditures	All capital costs, as incurred	Income statement and balance sheet
Less	Working capital investment	Calculated as current assets minus current liabilities	Balance sheet
Equals	**Free cash flow to the firm**	**Similar metric to post-tax cash flows from FARI**	

The FCFF is a key metric because it adjusts financial statement flows to better reflect the cash flows available to all investors in the firm. The FCFF is calculated by adding non-cash charges (such as depreciation) and after-tax interest expense to net income, and by subtracting capital expenditures and non-operating investment in working capital. In theory, FCFF from an upstream company that operates only one project should reconcile with the post-tax cash flows from FARI, as a total over the life of the project.

[60] In some countries the income statement is referred to as profit and loss statement (or P&L).

TNM/16/01

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ISBN: 978-1-51357-511-7