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An Evaluation of a Royalty Relief Model for Mature Fields

Abstract

This paper presents a an evaluation of a deterministic model for royalty relief using a combination of different types of decline curves, operational costs, and prices of several oil types. The paper also provides an analysis of its impact in the cash flow of the project and in tax collection. The model allows obtaining a balance between profitability and fiscal demands of projects under a royalty and tax (R&T) fiscal framework. In the proposed model, the simulation of financial variables for mature fields with reserves within a range of 500 thousand to 2 million barrels, indicates competitive results considering the amount of investments and the inherent risks of the project.

Keywords: Mature petroleum fields, royalty relief model, oil production strategy

Introduction

Petroleum production involves the transformation of a non-renewable asset into reproducible capital. The initial decision to invest is greatly influenced by the existing tax regime. The taxation imposed upon oil and gas E&P projects frequently affects the production strategy, reducing recoverable reserves, and thus generating a direct impact on the productive activity, affecting firm's profitability and government rent. The excessive tax burden can lead to premature abandonment of fields, generating inadequate production strategies and forcing producers to direct investments to countries or regions that are more attractive. On the other hand, a non-neutral tax regime can provoke unnecessary reduction in government revenues, with little or no increase in overall production. Governments attempt to capture as much as economic rent as possible through various fiscal regimes. This appropriation, because it is defined as a pure "surplus", will not negatively affect economic standards of neutrality and efficiency.

The great challenge in oil and gas fiscal regimes is to find equilibrium in the way revenue and profit are shared between the regulatory regime and the oil company. Unfortunately, there is no standard procedure to evaluate thoroughly the actual performance of the different fiscal regimes. This paper will address impacts of royalty relief in royalty and tax systems (R&T) on the profitability of mature fields.

Fields can be characterized as mature when they have attained more than half of its productive profile curve and showing increasing operational costs. In most of the cases during their productive lives, mature fields need incentives to remain attractive for the petroleum industry.

A recent trend of changes in tax systems has created opportunities for new investments in mature fields in diverse geographical areas. This has been particularly true in Latin America, where important political and economic changes have introduced a new era of business in the petroleum sector. For example, the new regulatory framework in Brazil, that ended the monopoly of the Brazilian State company - Petrobras - in 1997, created new market opportunities for small and mature fields. The Brazilian tax regime, which is based upon the R&T system, allows the Brazilian National Petroleum Agency (ANP) to give discounts of up to 50% on the regular royalty tax (10%), according to the characteristics of the fields in the concession.

In Brazil and generally in all R&T systems, royalty is the only tax that effectively may have an ad-hoc management, that is, a flexible rate under criteria of ANP. The discount given by ANP can be viewed as an instrument to stimulate

E&P activities and to increase the economics of the fields. This is especially important in the case of mature and marginal fields that may require investments in enhanced oil recovery (EOR). In addition, when production declines, full royalty rate can cause producers to abandon fields prematurely. Results presented here show that royalty relief may extend project life by two or three years.

Royalties are attractive to regulators because they are certain and reasonably predictable, ensure a stable flow of revenues over the life of a producing field, and are easy to estimate and monitor. At the same time, royalties are criticized for being regressive and failing standards of economic efficiency.

The model described in this paper provides a balance between profitability and government earnings. The two main objectives of the model are:

(i) Attract companies to invest in mature fields with a clear incentive policy, but without reducing tax collection unnecessarily;

(ii) Extend the productive life of fields and, by that, generate revenues that otherwise would not take place.

The simulations presented here are based on the Brazilian taxation regime. However, the model can be extended to different fiscal systems of oil and gas fields in which royalty represents an important part of taxation.

Methodology: Cash Flow Components and Estimation of Government Take

A traditional discounted cash flow (DCF) method is used to measure the profitability of the project, and the classical indicator NPV (Net Present Value) measures the return obtained by the firm. The ratio NPV/bbl of the field is also used to estimate the relationship between volume and value. In each year, the company net cash flow is estimated using the following relationship (Eq. 1):

$$NCF = (R - Roy - PIS - OC - IW - D) * (1 - T) + D - Inv \quad (1)$$

where,

NCF is the Net Cash Flow; **R** is the gross Revenue, given by $k \cdot p \cdot q$ (where **p** is the price of the Brent Dated oil and **q** is the number of barrels produced in the considered year. The conversion factor **k** depends only on the characteristics of oil produced); **Roy** is the total amount paid in Royalties; **PIS** is a social tax, directly related to gross revenue; **OC** is the Operational Cost in the considered year; **IW** is the investment accounted as costs¹; **D** is the total depreciation; **T** is the corporate tax rate; **Inv** is the sum of all investments, except **IW**, and is considered linearly depreciable in 10 years.

Estimation of Government Take (GT)

Two questions are raised in the discussion about E&P taxation: **What can be considered a fair government-take? How can it be properly measured?** After the creation of OPEC, a typical **GT** would vary from 60 to 70%. A survey made by Petroconsultans, in 1995, including 110 countries, showed that in more than 90% of these countries, **GT** ranged from 55 to 75%. Other similar study conducted by Van Meurs (1998) shows similar levels of taxation. Once the DCF analysis and its indicators (NPV and IRR) are being used to evaluate project performance, the same concept is naturally extended when it comes to evaluating government's cash flow. Therefore, the term **GT** refers to discounted government take. In this paper, **GT** is considered the proportion of net revenue that is collected by government (federal, state, and local). Taxes considered in the model are the ones currently being charged in Brazil.

Barbosa and Gutman (2001) estimated that, for projects in Campos Basin (Brazil) indirect taxes² are 20% of operational costs and 6% of capital expenditures. Similar values are shown by UNICAMP (2001). In this study, these

¹Some investments, like expenditures in drilling and completion, may be accounted as yearly costs, in some fiscal regimes.

²There are several indirect taxes and levies under the Brazilian fiscal regime such as the ISS (municipal), ICMS (state sales tax), CPMF (federal tax, charged over financial transactions), II (Import/Export Tax) and IOF (charged over loans and leasing operations).

values are used for the cash flow simulations

The yearly total tax collection (**TC**) is the sum of all taxes, participations and levies collected by government, and the project Net Revenue (**NR**) in each year is given by the sum of the Net Cash Flow (**NCF**) of the company and the government tax collection (**TC**). **NR**, thus, represents the yearly economic rent of the project. Once having net cash flow and tax collection for each year of the project, these series can be converted to their present value, at a given discount rate, obtaining **NPV** and **TCPV**, respectively. Thus, the government take of the whole project is given by the following expression (Eq. 2):

$$GT = \frac{TCPV}{NPV + TCPV} \quad (2)$$

TC series were discounted at the same rate as **NCF** series, although different rates could also be used.

The Royalty Relief Model

Eq.3 presents the royalty relief, assuming a 10% default rate over total production:

$$Roy = RoyM - RR \quad (3)$$

where: **RoyM** is the maximum royalty and **RR** is the royalty relief, ranging from zero to 5% of gross revenue **R**. First, **GP** is calculated using the maximum royalty rate. The value estimated for Gross Product Before Royalty Relief (**GPBRR**) is:

$$GPBRR = (R - RoyM - PIS - OC - IW - D) \quad (4)$$

In the model, the royalty relief (**RR**) is a linear function of **GPBRR**, limited to zero and **RoyM/2**, since royalty rate cannot go below half of its original value. Figure 1 illustrates the model: when **GPBRR** is low (up to a lower limit **L₁**), full relief is given, and as **GPBRR** increases up to a higher limit **L₂**, **RR** decreases linearly. If **GPBRR** is higher than **L₂**, **RR** is zero.

$$RR = \begin{cases} 0.05 \cdot R & \text{if } GPBRR < L_1 \\ \frac{RoyM(L_2 - GPBRR)}{2(L_2 - L_1)} & \text{if } L_1 < GPBRR < L_2 \\ 0 & \text{if } GPBRR > L_2 \end{cases} \quad (5)$$

It is necessary to estimate the values **L₁** and **L₂**, defined as fractions of gross revenue **R** in each year. The model defines **L₁=c₁R** and **L₂=c₂R**, **c₁** and **c₂** are fixed, so **L₁** and **L₂** are different for each year in the project. Obviously, **1>c₂>c₁>0**. To ensure that **RR** decreases at a lower rate than **GPBRR** increases when **L₁<GPBRR<L₂**, it is necessary that **c₂ - c₁>0.05**. Hence, **RR** is not fixed during the whole project. Then, the company Net Cash Flow in a given year **t** (**t>0**), will be:

$$NCF_t = GP_t \cdot (1 - T) + D_t - Inv_t \quad (6)$$

and,

$$GP_t = (R_t - RoyM_t + RR_{t-1} - PIS_t - OC_t - IW_t - D_t) \quad (7)$$

For year **t=0**, **GP** is the same as in Eq. (7), with the exception of **RR_{t-1}** that is suppressed from the equation. For the purpose of obtaining the royalty rate (**rr**) in year **t**, the following equation is used:

$$rr_t = \frac{RoyM_t - RR_t}{R_t} \quad (8)$$

$$SimSc = \sum_{i=1}^4 P_i(NPV_i > 0) + \sum_{i=1}^4 P_i(0.55 < GT_i < 0.75) \quad (9)$$

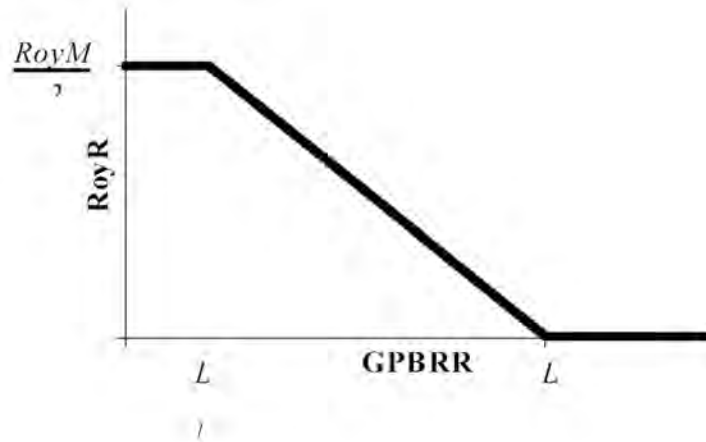


Figure 1 - The Royalty relief Model.

Estimation of parameters c_1 and c_2

There are two main concerns when determining c_1 and c_2 . First, to allow adequate NPV output values for the project, and second, to reach reasonable government take values. For that purpose, four different typical fields with recoverable volumes of 200, 500, 1000, and 2000 Mbbl were evaluated.

Both government take and NPV depend on uncertain variables, such as *oil price, variable operational costs, fixed operating expenses, investments, and production schedules*. According to the goals established, c_1 and c_2 values were adjusted using an optimization process in order to reach a higher score with a new combination (c_1, c_2). Monte Carlo simulation was employed with 1000 iterations. Eq. (9) presents the scores obtained from stochastic simulation: where,

$P_i(NPV_i > 0)$ is the simulated probability of obtaining a positive NPV value for field i (the hypothetical fields were numbered from 1 to 4), and $P_i(0.55 < GT_i < 0.75)$ is the simulated probability of obtaining a Government Take value within the range 55% - 75%, which is considered a *fair* range.

The only constraint adopted was that *TCPV* could not be reduced by more than 2%, when compared to the "no relief" scheme. Royalty reduction is compensated in two forms:

- (i) - Project life is extended and taxes are collected during this extra period of production;
- (ii) - As Gross Profit (*GP*) increases when royalties are reduced, there is an increase in the collection of Corporate Tax.

Results and sensitivity analysis

Table 1 presents probability distributions attributed to the input variables in the simulations, according to historical data and estimations. Capital expenditure occurred in the two initial years. Discount rate is 15%, which is a reference value for E&P investments in Brazil. Production would stop when expenses exceeds revenue. A US\$0,50/bbl abandonment cost is added to the operational cost (*OC*) in the last year of operation, but this is not considered for the decision of abandoning the field. Production schedule for each field are shown in Table 2. Three different curves were considered, however: *high*, *low* and *no* investments in EOR. Production curves are different for each case.

Table 1 - Probability distributions for input variables

<i>Variable</i>	<i>Unit</i>	<i>Min</i>	<i>Avg.</i>	<i>Max</i>	<i>Std. Dev.</i>
Oil Price	US\$/ bbl	-	20	-	4
Production*	% variation	80	100	120	-
Fixed expenses	% of CAPEX	2	5	8	-
Variable Operating Cost	US\$/bbl	1.50	2.50	3.50	-
Investment (low EOR)	US\$/bbl of recoverable volume	0.00	0.50	1.00	-
Investment (depreciable)	US\$/bbl of recoverable volume	1.50	2.00	2.50	-
Conversion Factor (k)	-	0.75	0.9	1.05	-

Table 2: Comparisons between financial indicators with Royalty Relief and "No relief" scheme

Field Volume	Δ Tax Collection	Δ Cumul. Prod.	Δ NPV (MU\$)	Project Outlast*
200Mbbbl	-2.0%	3.3%	48.2	3 years
500Mbbbl	-1.0%	2.8%	128.1	2 years
1MMbbbl	-0.8%	3.0%	208.0	1 year
2MMbbbl	-0.8%	2.5%	344.7	1 year

The optimum values found for parameters c_1 and c_2 are **0.21** and **0.56** respectively. Both **NPV** and government take distributions are assuming as lognormal. Table 2 shows the addition in total cumulative production, variations of NPV and tax collection, and project outlast of the fields submitted to the model when compared to the full royalty scheme.

Figure 2 shows the effect of price on government take. As prices increase, **GT** values diminish because indirect taxes are fixed and do not depend on price variations, then NPV grows at a higher rate than **TC**. As prices decrease, **GT** increases at a high rate because NPV declines faster than **TC**. If prices go down to a situation in which NPV is negative (US\$13,50 and under), **GT** may assume values above 100%, even with full royalty relief. The model tends to give **full relief** when **GT** is high and to **reject the relief** when **GT** is low. The other three fields show similar results. Profitability estimations using NPV/barrel ratios indicate the same behavior, which is higher for larger fields: US\$1.50/bbl, US\$1.35, US\$1.17 and US\$0.64/bbl for the 2,000, 1,000, 500, and 200 Mbbbl fields, respectively.

Figure 3 shows break-even price with and without royalty relief (and its adjusted linear functions) for field size (recoverable volume). The 200 and 500Mbbbl field become economic at reasonable prices (around US\$15) when the model is applied. Subjected to full royalty rate, these fields are economic at prices (higher than US\$25) that would probably lead companies to a decision of not investing. Three distinct areas in the graph show that:

- **Region (1):** the upper region area above the line of "without relief", that shows combinations of recoverable volume and price under which fields are economic with full royalty rate;

- **Region (2):** shows the combinations of price and recoverable volume for which the royalty relief program is effective. In others words, under these combinations of price and recoverable volume, projects are uneconomic (have negative NPV values) when submitted to full royalty rate. When the royalty relief model is applied, however, these projects have positive NPV.

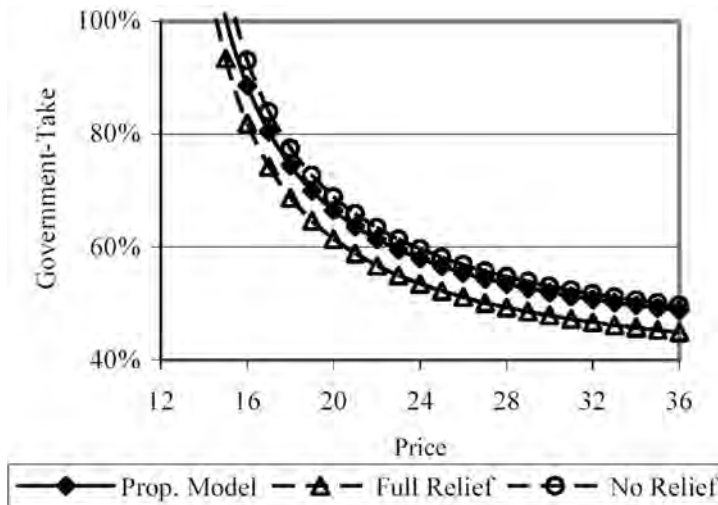


Figure 2 - Government Take values under different price scenarios (1000Mbbbl field).

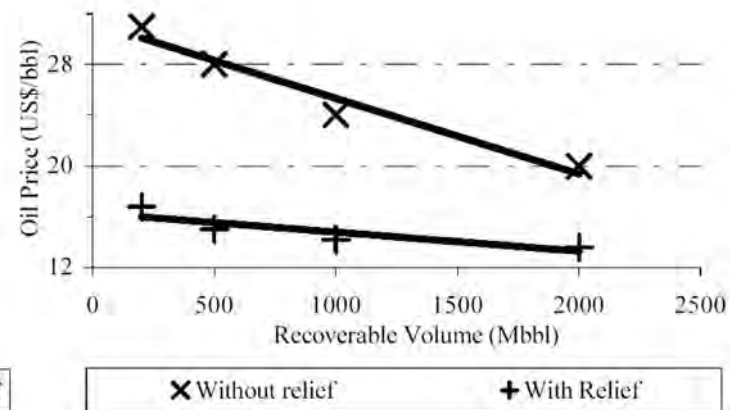


Figure 3 - Break-Even Price and Recoverable Volume (with and without royalty relief)

- **Region (3):** the lower region shows the combinations of price and recoverable volume under which projects are uneconomic even with royalty relief.

Conclusion

Royalty relief can be seen as a tool to enhance production and attract investments by reducing risks and increasing returns of E&P projects. NPV and IRR volatilities, generated by prices and other variables are reduced, once impacts of unpredictable events (for example, price fluctuation) are balanced by a variation in the royalty rate. For mature fields, that are frequently marginally economic, the royalty relief can play a very important role in determining investment decisions.

The comparison of results of the model with a "no relief" scheme shows that, when the full royalty scheme is applied, fields with reserves smaller than 1000 thousand of bbls (which is the case of many mature fields) have little possibility of having a good risk-return relation. In such scenarios, projects are very susceptible to price volatility and other variables. Meanwhile, a full relief model takes from the government the possibility of capturing part of the economic rent when prices are exceptionally high. For fields with small reserves (ie. 200Mbbbl), even a full relief model shows little efficiency. With the current tax structure prevailing on these fields, they seem to be inherently uneconomic and little attractive to investments. To make these fields attractive, other kinds of incentives must be implemented. A combination of royalty relief mechanisms and economic incentives for investments in enhanced oil recovery - EOR (for instance, an uplift in their depreciable value) could prove effective.

The model shows that fields with reserves superior to 500 thousand of bbl are competitive under the base case price and cost scenario. Being able to pay less in royalties when fields reach a considerable advanced stage of maturity and/or when profits are low would attract investors. Immediate loss in tax collection will be compensated by an increase in overall production due to longer life of operation of these fields, if investors foresee a comprehensive taxation policy.

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