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Government Share and Economic Analysis: Case Study of Campos Basin, Brazil

Décio H. Barbosa, ANP, and José Gutman, ANP

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Abstract

The purpose of this paper is to evaluate the economic potential of oil fields located in deep-water Campos basin, under different cost structure and price scenarios, via-à-vis the government revenue share resulting from the current fiscal terms introduced by the new Petroleum Law. The outcomes show that the Brazilian fiscal regime is competitive in a world basis and the analysed oil fields are economically attractive under the scenarios most likely to happen.

Introduction

The Brazilian Constitution establishes that the nation's deposits of oil, natural gas and other hydrocarbon fluids are a property of the State. The State holds also the monopoly over the exploration and production of such mineral resources, but it may grant to public and private companies the rights to develop and produce them. This is bound by a concession agreement, executed after an auction, and subject to the payment of a set of petroleum levies. According to the Law n^{o} 9,478, of 1997, known as the Petroleum Law, the *Agência Nacional do Petróleo* - ANP is the sole responsible for granting the concessions, collecting the petroleum levies, distributing the proceeds, as well as conducting the regulation thereof.

Besides the petroleum levies, oil and gas companies operating in Brazil must also pay other non-specific taxes levied on companies in general, irrespective of the nature of their business.

This paper shall present the main changes in the Brazilian fiscal terms for oil and gas companies introduced by the new Petroleum Law. It highlights, among others, some key issues as the set up of new petroleum levies, the twofold increase of royalties and the new version of the temporary admission regime applied to equipment importation for E&P activities.

In addition, this paper also aims to evaluate, under two different cost structure and three price scenarios, the government revenue share as well as the economic potential of oil fields located in deep-water Campos basin — the Brazilian biggest sedimentary basin holding an 8 (eight) billion barrels of proved reserves.

The authors developed an economic model, later shown in this paper, comprising the hypothesis assumed in the examples herein and a full description of the Brazilian fiscal system. Sensitivity analysis of the economic potential and government share have been carried out to deep-water oil fields. The field sizes modeled were 250, 500, 750 and 1,000 million barrels of oil, and the analysis was carried out at three different oil prices ($15/bbl, $20/bbl and $25/bbl) and two cost structures (**Table 1**).

At a later time, it is performed a government share comparison between the Brazilian case (deep-water Campos basin oil fields), whose outcome was generated using the ANP's economic model, and some selected peer countries, whose outcome came from the international literature.

Brazilian Fiscal System

The main components of the Brazilian fiscal regime are (1) the petroleum levies, (2) the direct taxes, and (3) the indirect taxes.

1 – Petroleum Levies

Articles 45 to 51 of the Petroleum Law outline the petroleum levies, also called the government take under the Petroleum Law. These are signature bonus, royalties, special participation fee and acreage rental fee. They represent the remuneration paid by the concessionaire to government for the right over the hydrocarbons, in accordance with the E&P concession agreement. Only royalties existed prior to 1997. The Petroleum Law introduced the other three forms of government take.

1.1 - Royalties

The Petroleum Law increased the previous royalty rate from a fixed 5% to a basic 10% value and introduced the Ministry of Science and Technology as a new beneficiary of the proceeds. As an immediate consequence of such an increase in the royalty rate, the collected amount doubled. On the other hand, according to this Law, the new beneficiary should use the royalties' proceeds to foster the development of new oil and gas products and processes.

Another important change introduced by the new Petroleum Law has to do with royalty assessment, since a new production valuation criterion has been envisaged. Fiscal Decree n^o 2,705, released on August 3, 1998, known as the *Government Take Decree*, established fiscal arrangements in the petroleum sector. Among its provisions the Decree states that royalty on oil shall be paid on its market value. This is defined as the greater of the sales price or the Minimum Value. Consequently, Portaria[1] ANP n^o 206, of 2000 (former n^o 155, of 1998), set forth the assessment methodology for the Minimum Value applicable to each oil field. **Fig. 1** shows the relationship between the domestic and international oil prices for royalties' purposes before and after the issuance of the *Government Take Decree*. Prior to the release of the Decree, domestic oil prices used for royalties had pratically no relationship with international oil prices, what was causing a substantial distortion in the internal valuation of the proceeds.

References 1 and **2** contain more detail on the changes in royalties since the enactment of the Petroleum Law, concerning the collection and distribution issues, the amounts involved, pricing methodology, forecasting, etc.

1.2 - Signature Bonus

The Petroleum Law introduced the signature bonuses for the first time in the Brazilian legal framework. A signature bonus is paid as a lump sum by the winning company of the concession auction, on the signing of the concession contract. The ANP sets a minimum value of the bonus in the invitation to bid for a particular block, however the amount paid forms part of the bid.

Note that, in August 1998, by the time of the monopoly flexibilization, when the ANP recognized Petrobras' rights over 397 concession areas, a bonus was not charged for the areas granted to Petrobras since they were not the object of an auction.

Thus, the signature bonuses were paid by the first time in September 1999, upon the signing of the Licensing Round 1 agreements, and amounted to R$ 321.7 millions (≈US$ 169.6 millions), corresponding to 12 exploratory blocks, with the majority falling in the range of US$4 – 18 million.

21 out of 23 offered blocks were granted to 16 different companies in License Round 2 (June 2000). At this time the signature bonuses amounted to R$ 468.3 millions (≈US$ 254.7 millions).

1.3 - Special Participation Fee (SPF)

The Petroleum Law set up the Special Participation Fee (SPF), which is an additional income tax paid on the profits of the field and applicable only for giant oil and gas fields. In the mid-1970's, both the US (*Windfall Profits Tax*) and the UK (*Petroleum Revenue Tax - PRT*) set up similar levies on profits, which were later abolished. Nowadays, besides Brazil, other countries, as Australia (*Petroleum Resource Rent Tax* – PRRT) and Norway (*Special Petroleum Tax*) for example, also adopt this kind of additional income tax. Other examples can be found in **Ref. 3**.

While royalty is levied on gross revenues, the SPF is levied on profits before the corporate income tax. The assessment methodology for the SPF is outlined in Portarias ANP n^o 10 and n^o 102, both issued in 1999. Allowable deductions include operating costs, depreciation, royalty payments, exploration and appraisal expenditures, any losses brought forward from previous periods, a provision for abandonment expenditure, leasing costs and any signature bonus paid on the block. Costs from outside the licence area cannot be offset against the special participation profits of the field but dry hole costs and seismic costs from within the original licence can be offset.

The Special Participation Fee is chargeable on a sliding scale, which varies according to the location of the field — onshore, shallow water (≤400m) or deep water (>400m) —, its level of production and for the first four years of the field life. The relevant rates applicable to offshore deep-water are given in **Table 2**.

The SPF is a progressive levy since the rates gradually increase as production (and consequently profitability) grows. On the other hand royalties are regressive because they are levied on gross revenues, regardless whether the field is making a profit or not.

As the SPF is levied on profits for giant fields, it captures part of the petroleum economic rent generated in high oil price scenarios. Government is supposed to use the proceeds of such economic resources in order to obtain a sustainable growth, either by applying them in developing arrangements to lure domestic and international investments or by making provisions to meet harsh times whether they are to happen.

Each country treats the issue in a particular way, depending on its energetic and industrial orientation, but some overall points related to oil and gas industries should reflect a better infrastructure, the wealth of public information on the hydrocarbon resources and the institutional security.

According to items II and III of article 8 of the Petroleum Law, the ANP is responsible to promote studies aiming at the delimitation of blocks, for the purpose of concession of the activities of exploration, development and production. It's also the ANP responsibility to regulate the execution of geological and geophysical surveys, applied to oil exploration, and aiming at the collection of technical data for the commercialization, under a nonexclusive basis (spec survey).

As a consequence of the above, 40% (forty percent) of the SPF's proceeds are conveyed to the Ministry of Mines and Energy, for the payment of geological and geophysical studies and services applied to oil and natural gas exploration, promoted by the ANP. 10% (ten percent) of the SPF's proceeds are conveyed to the Ministry of Environment, destined to the development of studies and projects related to the protection of the environment and to the recovery of

[1] Portaria (Portuguese name) is an Administrative Ruling issued by the ANP's board.

environmental damage caused by the petroleum industry activities.

The ANP/SPG[2] team estimates that, among the current concession agreements whose production profiles are known (approximately 350), just 13 fields shall pay the SPF, 12 of them located in Campos basin and 1 in Santos basin (**Ref.2**).

Table 3 splits the Brazilian offshore fields into shallow water (≤ 400m) and deep water (>400m) and depicts, for a given field size, the estimated point in time at which a SPF levy is paid and the number of years it shall continue being paid[3].

Table 4 illustrates, for the cases listed in Table 3 when the SPF payments are due, the rates (%) applicable to gross revenue that produces an outcome equivalent to the SPF levy. This is an attempt to find out, for the field sizes under analysis, an equivalent royalty rate that would have the same SPF economic impact. This chart illustrates the SPF's progressiveness as a result of the link of special participation to production rates. It was assumed a typical 10% fixed royalty.

1.4 - Rental Fees

The Petroleum Law introduced in the Brazilian legal framework a third component, the annual rental fees. They may vary depending on geological characteristics, the location of the sedimentary basin and other relevant factors. The proceeds derived from the rentals, as well as from the bonuses, are destined to support the ANP's expenses needed for the execution of its activities.

Table 5 sets out the range of rental payments, in R$/km^2, that may be specified during various contractual stages.

2 – Direct Taxes

For the purpose of this paper, the direct taxes comprise not only the income taxes but also the social contributions (PIS and COFINS) levied on oil and natural gas turnover.

2.1- Income Taxes (IT)

The taxes levied on income comprise both the Corporate Income Tax (IRPJ) and the Social Contribution on Net Profit Tax (CSLL), currently calculated at a combined rate of 34%. This is comprised of a basic 15% corporate income tax plus a surtax of 10% plus a Social Contribution Tax of 9%. The government intends to reset the combined tax to 33% (its pre-May 1999 level) on January, 2003, by reducing the Social Contribution on Net Profit Tax to 8%.

Corporate income tax (CIT) is chargeable on the total up and downstream profit of a company. No ring fencing applies. The normal deductions apply in calculating profits, including operating costs, depreciation, royalty, signature bonuses, rentals, any losses brought forward from previous periods and financing costs. In addition, the Special Participation Fee is taken as a deduction when calculating corporate income tax. The abandonment allowance is not qualified as an income tax deduction.

The legal entities can be taxed on both actual or presumed profit regimes alternatively. They shall compute their income on a quarterly basis with quarters ending on March 31, June 30, September 30 and December 31 of every calendar year.

The legal entity, taxed on the actual profit regime[4], can also opt on making tax payment and assessment on a monthly estimate basis, by applying, on the monthly gross revenue, the same percentile (8% for the oil industry) of presumed income. At the year-end a full tax computation and reconciliation is done.

Non-equity joint ventures under the Brazilian legal framework are called “consortia”. Consortium is not taxed as an entity; it is treated like a partnership. Consequently each consortium member retains its separate legal identity for everything, including tax purposes, being taxed on a pro rata share of its respective incomes and expenses.

There is no consolidation of corporate groups for Brazilian income tax purposes.

Tax law does not permit loss carry-backwards and provide less than full loss offset for tax-loss firms. Although losses may be carried forward with no time limitation, there is a cap for offsetting them against taxable income. Carry-forwarded losses (net operating losses) cannot be offset, in any period, by more than 30% of the period's taxable income. Such losses are carried forward without interest or any form of indexation to compensate for inflation.

The gains or losses in exchange transactions can be taxed or deducted in a cash or accrual regime, at the discretion of the tax payer. Again, there is no cost indexation in order to compensate for inflation.

Table 6 compares the current legislation's treatment given to both CIT and SPF, with regard to the E&P costs, which are eligible for deduction.

2.2- Social Contributions Levied On Gross Revenue

There are two social contribution taxes levied on gross revenues in the same way as royalty is charged, which are due when production is sold to the domestic market. The Contribution for the Worker's Social Integration Programme (PIS) is levied at the rate of 0.65%, and the Contribution for the Social Security Funding (COFINS) is charged at 3%.

Since February 1999, the chargeable base for both of these social contributions is the operating revenue, which includes, besides the turnover, the financial gains (interest and exchange gains).

3 – Indirect Taxes

In this paper the term "indirect taxes" refers to taxes and social contributions that are levied by federal, state and municipal authorities on investment (equipment, facilities, etc.) and

[2] Superintendence of Government Take Control (SPG) of the National Petroleum Agency (Agência Nacional do Petróleo - ANP)

[3] Assumptions: US$18.00/bbl Brent Dated, CAPEX and OPEX costs from literature.

[4] Companies with an annual turnover of R$ 240 million (US$ 120 million) or above shall be taxed on an actual profit basis.

services used by the oil and gas companies in E&P projects. Note that the turnover/revenue based social contributions PIS and COFINS are considered both direct or indirect taxes, depending on whether they are levied on oil and gas revenues (direct taxes) or on investment or service used by the industry (indirect taxes). These taxes may have a heavy economic impact on both CAPEX (Capital Expenditure) and OPEX (Operating Expenditure) costs.

In practical terms, the concept of indirect taxation in Brazil is not quite simple, and the applicable taxes depend on the circumstances (tangible or intangible) and origins (domestic or imported) of the goods and services. Anyway, the following taxes are to be considered to compute an indirect taxation average level: Municipal Service Tax (ISS), State Value Added Tax (ICMS), Withholding Tax (*in lieu of corporate income tax* - IRRF), Import Duty (I.I.), Federal Tax on Manufactured Products (IPI), Provisional Contribution on Financial Transactions (CPMF), and the Social Contributions PIS and COFINS.

In the development phase of an oil and gas venture, expenditures are substancially high. To mitigate the tax burden in this initial period, there is a world trend to postpone the taxation to the production phase, hence reducing the regressiveness of the fiscal system (**Ref. 3**).

In this particular, a key form of indirect taxation with which the industry has taken issue has been import duties. Brazilian law requires that import duties must be paid on all equipment used for exploration and production (including for example drilling rigs, floating production platforms and equipment, which would normally have been exported from Brazil following use).

To cope with that the Government passed Law nº 9,826 (August 23 1999), followed by the Presidential Decree nº 3,161 (September 2 1999), which introduced the Special Temporary Admission Regime (REPETRO), a temporary exemption specifically for the upstream sector of the oil industry. This special customs regime allows for certain specific oil industry equipment to be temporarily admitted into Brazil and remain for the duration of a specific concession contract (which could be for the lifetime of the field) without the payment of import duties.

Qualifying items include geophysical survey equipment, drilling rigs and associated equipment, fixed and floating production or storage facilities, risers and remote operated vehicles (ROVs).

The suspension of indirect taxation (I.I., IPI and ICMS) is valid for goods and equipment imported prior to January 1, 2006. This regime also made Brazilian-made equipment exempt from certain indirect taxes (PIS, COFINS, IPI and ICMS). It is thought likely that there may be a further extension to the regime's timeframe. In order to qualify for the special regime, the private company must lodge a financial guarantee equivalent to the suspended taxes with the government.

According to ANP/SPG team studies, the average impact of indirect taxes on CAPEX costs, not considering the exemptions provided by the special regime REPETRO, corresponds to 38%. In other words, indirect taxation would increase CAPEX costs by 38%. On the other hand, considering the application of the REPETRO regime, such impact goes down to only 6%[5]. Therefore, the REPETRO regime cuts CAPEX costs by 23%, reducing substancially the burdensome indirect taxation and the production costs.

Again, according to ANP/SPG team studies, the impact of indirect taxes on OPEX costs is about 20% on average. As the REPETRO regime applies only to tangible goods, it has little effect on OPEX costs, where intangibles (services) prevail.

Hopes are that the indirect taxation structure will be simplified as part of a wider fiscal reform package currently before the Brazilian Congress.

Treatment given to the State Value Added Tax (ICMS) in the model under discussion is worth mentioning. A second key form of indirect taxation with which the industry has taken issue is the level of state value added taxes paid on goods and services. If a company starts a standalone project, in the pre-production phase, during which there is no revenue, it accumulates a reasonable amount of ICMS credits to be offset at the time production starts and is sold. For upstream companies with no Brazilian downstream presence, this is a particular issue, since their way of recovering this tax is when crude is sold to refineries.

On the other hand, whether a company has revenues from other ongoing projects, this is no longer an issue, since it can immediatelly recover these tax credits by offsetting them against tax debits generated by sales.

In other words, consolidation in a country basis is allowed for ICMS taxes. For this reason, the economic model doesn't consider the levyance of the ICMS tax.

Table 7 shows the direct and indirect taxes levied on an E&P Project.

Methodology and Assumptions

As mentioned in the introduction, the main goal of this analysis is to evaluate the economic potential (concessionary's profitability) resulting from the exploration, discovery and development of a range of the deep-water field sizes and cost structures that might be expected in the Campos basin. For the purpose of this study the term "*deep-water*" refers to offshore production beyond the 400 metres bathymetric curve.

Much of the focus of fiscal system analysis in the upstream sector of the petroleum industry is on the division of profits such as government or state "take". Government take is the percentage share of the economic profits obtained by the government through bonuses, royalties, taxes, etc.

The timing of the taxation over the life of the development has a significant impact on investor's profitability. To take the time value of money into account, economic indicators are utilized such as the internal rate of

[5] REPETRO doesn't apply to intangibles, which causes a 6% increase in costs. The economic model considered CAPEX comprising 70% of tangibles (tax free) and 30% of intangibles (chargeable).

return (IRR) and the discounted net present value (NPV), which provide a better measure of the profitability of an opportunity.

The simulations of the Brazilian cases used an independent economic model designed by the ANP/SPG team, encompassing the fiscal system described so far (petroleum levies, direct and indirect taxes).

Four different deep-water field sizes at two cost structures were modeled under three oil price scenarios. Only oil fields were considered in the analysis. Production profiles, development and operating costs and crude prices utilized in this study reflect expected Brazilian conditions. **Table 1** depicts the production costs used in this study.

For all cases reported, the exploration and appraisal (E&A) investments were not considered, since, with a few exceptions, these are usually not material[6] in the take context. The CAPEX costs were distributed along the first 8 years of the project's cash flow (5,3%; 10,7%; 18,7%; 20,0%; 16,0%; 13,3%; 10,7% e 5,3%), comprising 30% of intangibles (services) and 70% of tangibles (facilities, equipment, etc.).

It was assumed a nonescalated 2% year inflation for the US dollar (**Ref. 4**).

In a subsequent approach, eight countries, which, in a certain extent, compete with Brazil for E&P investments, were selected for comparison. They are Angola (deep-water/frontier terms), Congo (deep-water/frontier terms), Egypt (deep-water/frontier terms), Equatorial Guinea, Nigeria (deep-water/frontier terms), Norway, the United Kingdom and the United States (Outer Continental Shelf, deep-water/frontier terms)[7]. The economic data for these countries were obtained from the international literature (**Ref. 4**).

Case Study: Campos Basin, Brazil

The input values for the fiscal system using the ANP/SPG independent economic model are outlined in the next paragraphs.

Petroleum levies: US$ 15 millions signature bonus[8], 10% royalty rate applied to full production volume, US$ 1,850/km^2 rental fee[9] and SPF according to Portarias ANP n^o 10/99 and ANP n^o 102/99 for deep-water offshore.

Direct taxes: 34% (combined) CIT and 3.65% Social Contributions (PIS + COFINS). It has been assumed that the produced oil would be sold in Brazil.

Indirect taxes multipliers: (1 + 6%) for CAPEX and (1 + 20%) for OPEX.

A 25 ^{o}API gravity oil has been used, reflecting the average oil gravity expected for deep-water Brazil projects (approximately Brent Dated minus 15%).

The results for Brazil are presented in **Table 8** and in **Figures 2**, **3** and **4**. They consider three price scenarios (US$15/bbl, US$20/bbl and US$25/bbl) and two cost structures (low and high development costs (Table 1)).

Fig. 2 displays the internal rate of return (IRR) as a function of three variables: field size, cost structure and oil price. It shows that: (i) the IRR increases significantly with the increase of both oil price (≈1% per US$/bbl) and field size (≈1% per 100 MMbbl); (ii) the IRR goes up by approximately 5% as we move from a high cost to a low cost structure; and (iii) except for the high cost/low oil price case, all other cases have the IRR above 10%.

Fig. 3 displays the undiscounted government take (GT@0%) for different field sizes, cost structures and oil price scenarios. It shows that: (i) the range of undiscounted government take is 52%-61% for all cases, but one (the high cost / low oil price case); (ii) the undiscounted government take is moderately sensitive to oil price for large fields and highly sensitive for small ones; and (iii) interestingly to notice is the possibility of the existence of regressive (high cost/low oil price), neutral (low cost/low oil price) and progressive (the remainders) regimes, as a result of the combination of cost structure, price scenario and fiscal terms.

Fig. 4 is similar to Fig. 3 except for the fact that the government take is discounted at 12.5% (GT@12.5%). It illustrates that: (i) except for the low cost/high oil price case (which is neutral), the "take" regressiveness springs up as the cash flows are discounted; (ii) because royalty is linked directly to production levels, the levies are larger early in the development when production is highest and become lower as the resource depletes (the impact of these levies early in the project is demonstrated by the increased percentage of government take when calculated on a discounted basis); and (iii) under a low price environment, small and moderate size fields have a discounted government take above 100%. It just means that the project's rate of return is less than the discount factor being applied.

Comparison with Other Countries

Figures 5 and **6** display total government take levels for a 750 million-barrel offshore field with a low development cost. The comparison is made at US$ 18 per barrel.

Fig. 5 shows that the combination of direct taxes (combined corporate tax plus PIS and COFINS on sales of oil and gas), indirect taxes on investment, royalty, rentals and special participation is about 58% undiscounted for Brazil, about average with the countries in the comparison.

Fig. 6 shows all government take levels when cash flows are discounted at 12.5% nominal discount rate. The government take in Brazil increases from 58% undiscounted to about 79% discounted. The structure of the Brazil's taxes results in a larger increase in discounted government take than other countries shown in the comparison, positioning Brazil slightly above Egypt and Congo and below Norway. Royalty and Special Participation rates based on production level tend to "front-end" load taxes.

Figures 7 and **8** display government take levels for a smaller 250 million-barrel offshore field with a low

[6] Usually CAPEX costs outweight E&A costs by 40-50 times.
[7] For countries with several fiscal terms, the deep-water/frontier terms have been used in these comparisons.
[8] Average bonus offered for deep-water Campos blocks in the two Licence Rounds over the last 2 years.
[9] Assumed 400-km^2 average oil field acreage for Campos basin.

development cost. The comparison is also made at US$ 18 per barrel.

The total level of direct and indirect taxes, royalty, rentals and special participation is about 56% on an undiscounted basis, as shown in the **Fig. 7**, slightly above the average 50% level corresponding to Nigeria, Equatorial Guinea, the United States and Egypt.

Fig. 8 shows the impact of the structure of the various fiscal systems by viewing government take with discounted cash flows. Three fiscal regimes presents government take above 100%. The government take in Brazil increases from 56% undiscounted to about 90% discounted at 12.5%, pratically levelling with the US regime.

Conclusions

Significant potential for new hydrocarbon discovery exists in Brazil, most of it in deep-water offshore, where E&P efforts are costly and technically challenging.

International investments are necessary to achieve a desired activity level in deep water underexplored or nonexplored basins.

In this particular, the study highlights some important aspects of the Brazilian tax system and its potential impact on international energy investment and the development of petroleum resources in Brazil.

The new Petroleum Law set up a new framework: the State acting as a regulator, granting concession areas in exchange for the payment of levies by the concessionaires.

A set of three new petroleum levies were introduced (signature bonus, special participation and rental fees), and royalty was raised from 5% (fixed rate) to 10% (default rate).

Important changes in oil pricing methodology where also introduced with the reference oil price used for royalties and SPF calculations being indexed to international “arm’s lenght” prices.

Significant changes also occurred with the introduction of new beneficiaries of the petroleum levies: the Ministry of Science and Technology, the Ministry of Mines and Energy and the Ministry of Environment.

Brazilian customs authorities have recognized that the imposition of indirect taxes on investment in high cost development areas would not result in the desired level of exploration. The introduction of the REPETRO regime was a key factor to mitigate that, since it had the desired effect of reducing both the discounted and undiscounted government take as well as improving the return (IRR). CAPEX costs were significantly reduced (around 23% as shown in the example) under such a regime.

The economic study of Campos basin showed that, under the current Brazilian fiscal system, the fields are economically attractive for the scenarios most likely to happen.

The relationship between government take and exploration attractiveness is very complex, influenced by the size and quality of discoveries, crude quality and price, and the structure of the government take. In spite of that, this analysis demonstrates that the current level of government take is generally competitive and appropriate for international deep-water exploration and development.

Nomenclature

Bbl = barrel of oil
MM bbl = millions of barrel of oil
MM boe = millions of barrel of oil-equivalent
R$/km^2 = Real (Brazilian currency) per square kilometer
US$/bbl = United States' dollars per barrel

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Table 1 – Costs used in the analysis (US$/bbl)

	250 MMbbl	500 MMbbl	750 MMbbl	1000 MMbbl
OPEX	3,5	3.2	2.5	2.2
Low CAPEX	3.0	2.6	2.5	2.0
High CAPEX	4.5	4.3	3.8	3.5

Table 2 – Offshore deep-water Special Participation rates

000 b/d	Year 1	Year 2	Year 3	Year 4 +
< 31.0	-	-	-	-
< 51.7	-	-	-	10
< 62.0	-	-	10	10
< 72.4	-	-	10	20
< 82.7	-	10	10	20
< 93.1	-	10	20	20
< 103.4	10	10	20	30
< 113.7	10	20	20	30
< 124.1	10	20	30	30
< 134.4	20	20	30	35
< 144.8	20	30	30	35
< 155.1	20	30	35	35
< 165.4	30	30	35	40
< 175.8	30	35	35	40
< 186.1	30	35	40	40
< 196.5	35	35	40	40
< 217.1	35	40	40	40
> 217.1	40	40	40	40

Table 3 – Years the SPF is due (estimates)

Field Size (MM boe)	Offshore £ 400m	Offshore > 400m
50	No SPF applies	No SPF applies
100	No SPF applies	No SPF applies
250	Year 5, 6 or 7 to 15[10]	Year 5, 6 or 7 to 13
500	Year 5, 6 or 7 to 16	Year 5, 6 or 7 to 16
1000	Not applicable [11]	Year 4, 5 or 6 to 18
2000	Not applicable	Year 4, 5 or 6 to 22

Source: Ref. 2

Table 4 – SPF rates equivalent to a 10% royalty

Field Size (MM boe)	Offshore £ 400m	Offshore > 400m
250	1% to 2%	0,5% to 1%
500	4,5% to 6,5%	3,5% to 5%
1000	Not applicable	9% to 12%
2000	Not applicable	14% to 16%

Source: Ref. 2

Table 5 – Acreage rental rates

Contract Period	Rental (R$/km^2)
Exploration	10 – 500
Extension of Exploration (if any)	20 – 1,000
Development	20 – 1,000
Production	100 – 5,000

Table 6 – Fiscal treatment for eligible deductions: CIT versus SPF

	CIT	SPF
Ring Fence	Country	Field
Interest Deduction?	Yes	No (Except for *leasing*)
SPF Deduction?	Yes	No
Loss Offsetting	Yes, 30% limit	Yes, no limit
E&A costs	Amortized over field life	Expensed
CapEx costs	Depreciated, IN-SRF nº 162/98	
Domestic Goods	Normal depreciation	Normal and accelerated depreciation
Exchange Variation (positive/negative)	Add or deduct from revenue	No
Overhead costs	Expensed	No
OpEx costs	Expensed	

Source: Ref. 1

Table 7 – Taxes levied on E&P project

Taxes	(1)	(2)	(3)	(4)	(5)
I.I.	Ō	Ō	Ō		
IPI	Ō	Ō	Ō		
ICMS	Ō	Ō	Ō		
ISS		Ō	Ō		
CPMF		Ō	Ō		
IOF			Ō		Ō
PIS			Ō		
COFINS			Ō		
IRPJ				Ō	Ō
CSLL				Ō	

Source: Ref. 1

Notes: (1) Import, (2) Pre-production, (3) Transactions, (4) Profit, and (5) Profit Remittance

[10] The first year the SPF is due could be the 5th, 6th or 7th, depending on the project's CAPEX cost. The higher the CAPEX cost, the longer it will take for the project to break even. Once CAPEX declines, lead time from start up to break-even tends to be smaller.

[11] Giant oil field distribution expected in deep-water.

Table 8 – Campos basin outcomes

Brent Price US$/bbl	Field Size MMbbl	IRR (%a.a.)		Government Take(%) Undiscounted		Government Take(%) Discounted@12.5%	
		Low CAPEX	High CAPEX	Low CAPEX	High CAPEX	Low CAPEX	High CAPEX
25.00	**250**	21.8	14.8	51.8	53.4	66.3	85.3
	500	23.9	15.2	54.2	55.7	66.6	84.6
	750	24.6	17.3	56.5	56.9	67.8	79.0
	1000	28.8	18.4	57.6	58.4	66.5	77.6
20.00	**250**	16.3	10.2	54.5	57.3	79.9	>100
	500	18.6	10.9	56.2	58.6	75.4	>100
	750	19.7	13.2	57.4	58.7	74.5	95.5
	1000	23.6	14.3	58.5	59.8	70.8	89.9
15.00	**250**	9.5	4.3	60.9	70.9	>100	>100
	500	12.1	5.7	60.5	65.6	>100	>100
	750	13.8	8.3	60.1	62.5	92.6	>100
	1000	17.3	9.5	60.5	62.6	81.0	>100

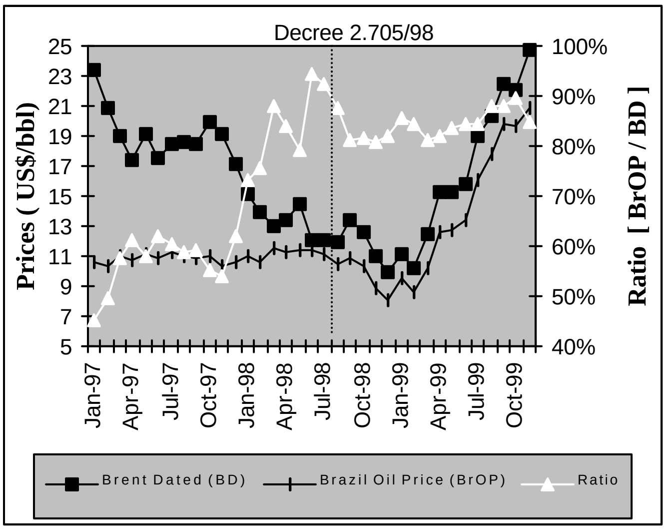

Fig. 1: Data series of Brent Dated vs. average Brazilian Oil Price. Source: Ref. 2

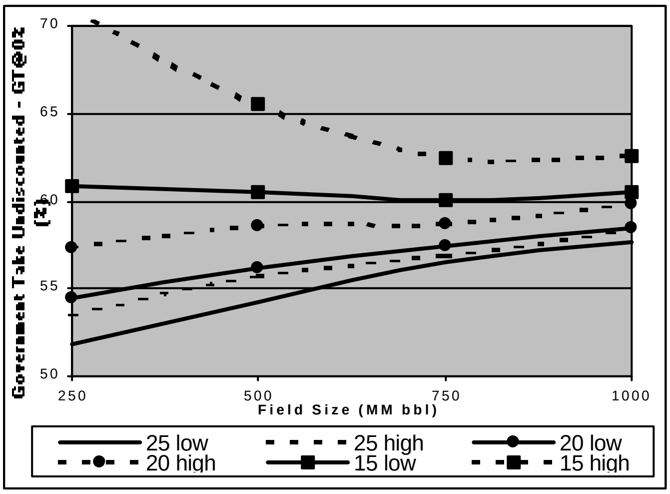

Fig. 3: Sensitivity analysis: GT@0% vs. Field Size

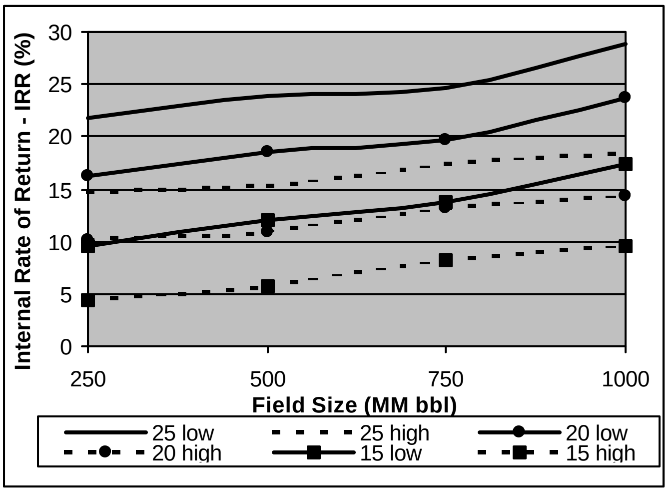

Fig. 2: Sensitivity analysis: IRR vs. Field Size

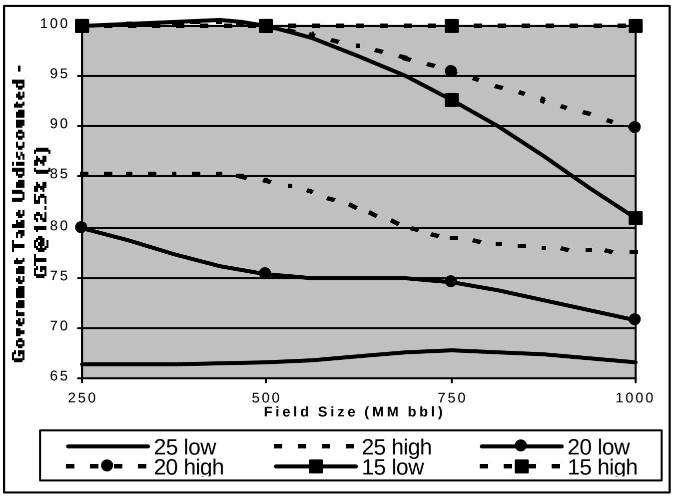

Fig. 4: Sensitivity analysis: GT@12.5% vs. Field Size

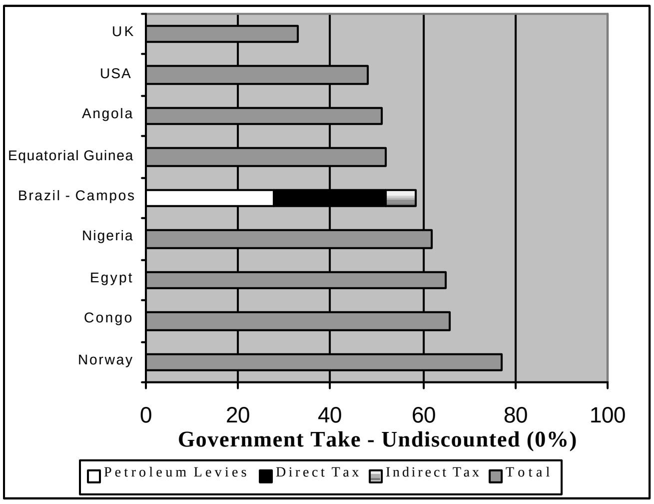

Fig. 5: 750 MMbbl, Low Capex, US$ 18.00/bbl

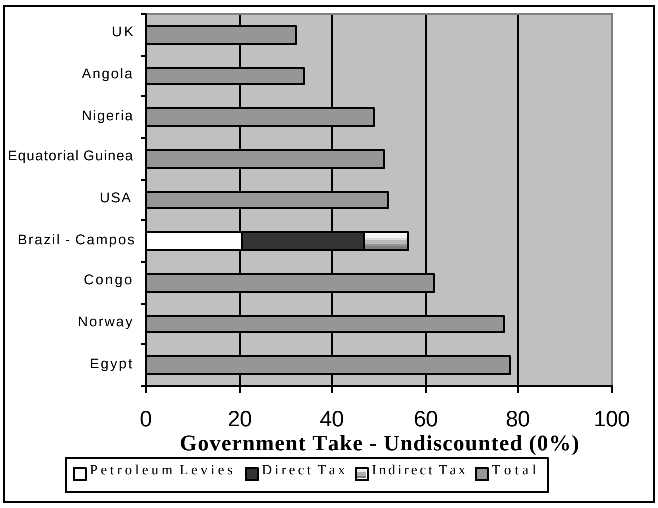

Fig. 7: 250 MMbbl, Low Capex, US$ 18.00/bbl

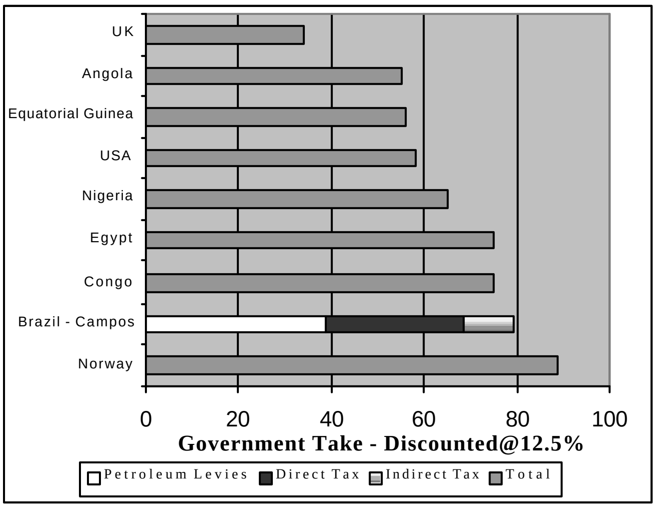

Fig. 6: 750 MMbbl, Low Capex, US$ 18.00/bbl

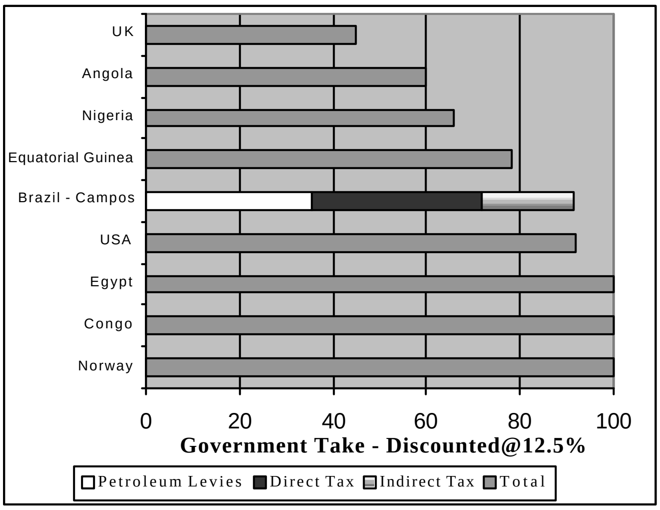

Fig. 8: 250 MMbbl, Low Capex, US$ 18.00/bbl