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Contracts for Petroleum Development - Part 3

The flows of oil revenues are quite complex. This note presents the results of two hypothetical simulations -- one a progressive production sharing regime and the other regressive -- to illustrate qualitatively how they affect the amount and timing of government revenue and investors' profits.

Briefing Notes 7 and 8 [1,2] gave an overview of different types of contractual arrangements in the upstream petroleum sector and defined key payment streams under production sharing agreements (PSAs). This note, the last in a three-part series, provides quantitative examples of how varying fiscal parameters affect the size and timing of government revenue streams. To this end, the note takes two sets of fiscal parameters—one progressive and the other regressive—and follows revenue streams over the life of a contract.

Two Fiscal Systems

The simulations take a hypothetical field that, over 19 years, produces 100 million barrels of oil. The production profile (Figure 1), associated costs, and financial flow calculation methodologies are taken from [3]. The simulation considers both steady oil price levels and the historical annual price of Brent crude oil—an important marker crude whose price movement is taken as a barometer of the overall oil market—expressed in 2006 U.S. dollars[1] between 1988 and 2006 (Figure 2). The average price in Figure 2 is $30 a barrel. The first year of operation is the year in which the contract becomes effective. It is worth noting that the start of production in Figure 1 is much sooner than what occurs in practice; the exploration period was shortened for brevity in this note.

The two fiscal cases are summarized in Table 1. In both cases, for income tax purposes, straight-line depreciation of capital expenditures over five years is assumed and there is no limit on the recognition of expenses incurred for petroleum operations, which may be carried forward from one year to the next until they are fully recovered. For computing the government's share of profit oil in production sharing, a ceiling on cost recovery is imposed in one case. Smaller payments, such as surface rental and other fees, are omitted for simplicity.

The first case considered is regressive: royalty, tax, and production sharing rates do not increase with increasing net-of-cost income. There is a signature bonus of US$20 million, the royalty rate is fixed at 10 percent, and cost recovery for production sharing is restricted to 60 percent in any given accounting period. All these provisions are designed to ensure early revenue. The government receives 70 percent of profit oil. After these payments, the contractor pays an income tax of 30 percent on profits derived from the remaining income.

The second case does not have a signature bonus and has sliding scale royalty and production sharing schedules, the details of which are shown in Table 2. The royalty rate does not reach 10 percent, the rate set in case 1, until the extracted oil fetches at least US$25 a barrel. As the oil price increases, however, the royalty rate rises with it and reaches a maximum of 40 percent

[1] These prices are *real* prices—adjusted for inflation—rather than *nominal* prices. Although the nominal price of Dubai Fateh crude oil was US$39.50 a barrel in November 1979, markedly lower than the high of US$69.52 a barrel reached in July 2007, in real terms this crude hit the highest in history in November 1979—equivalent to US$90.32 a barrel in 2007 U.S. dollars. The prices in Figure 2 are adjusted for inflation so that past prices shown are higher than the nominal price at each time period (except the price in 2006).

Figure 1 Production profile

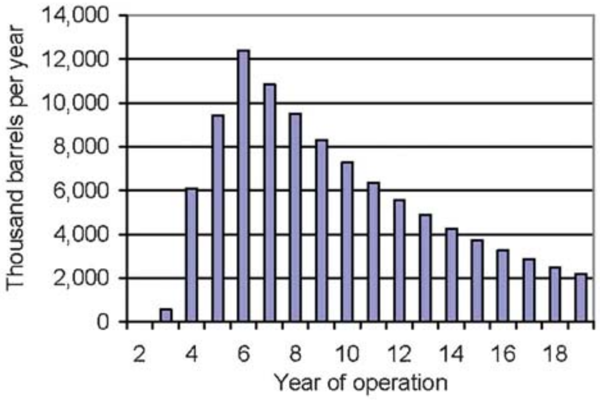


Figure 2 Price of oil in 2006 US$

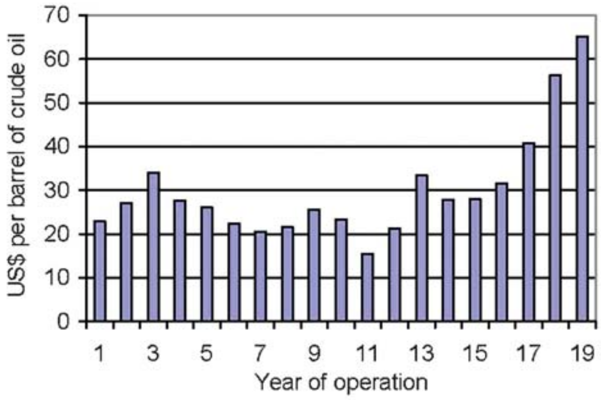


Table 1 Two Cases Considered

Case	1	2
Royalty	10%	Sliding scale as a function of oil price
Signature bonus	$20 million	None
Taxable income	Gross revenue minus (royalty + bonus + production share + eligible expenses)	Gross revenue minus (royalty + eligible expenses)
Income tax	30%	30%
Government's share of production	70%	Sliding scale as a function of IRR
Cost oil ceiling	60%	None

Table 2 Sliding Scale Royalty and Production Sharing in Case 2

Oil price, US$/bbl	<20	20-25	25-30	30-35	35-40	40-45	45-50	50-60	>60
Royalty, %	5	7.5	10	15	20	25	30	35	40
IRR threshold, %	<20	20	30	35	40	>50			
Government share of profit oil, %	0	40	70	75	80	90			

above US$60 a barrel, considerably above that in case 1. The government's share of profit oil increases as the contractor's internal rate of return (IRR) increases. As Briefing Note 8 described, this sliding scale production share makes this PSA a rate-of-return contract. The government share is zero if IRR is 20 percent (in practice, and especially in new PSAs, the government shares production from the outset), and is only 40 percent when IRR is between 20 and 30 percent. The government's share rises rapidly above this threshold, and is as high as 90 percent when IRR exceeds 50 percent. In case 2, an income tax of 30 percent is paid before profit oil is shared.

Impact of Different Price Levels

Constant oil price scenarios

Calculations were carried out assuming different constant oil price levels. In each scenario, a constant oil price was assumed during the entire life of the contract, and the same calculation was repeated at seven price levels, ranging from US$20 to $80 a barrel.

Figure 3 shows the percentage of net-of-cost income that flows to the government. Each price level represents a scenario run. Annual revenues were computed using discounted cash flow analysis to take the time value of money into account (see Briefing Note No. 7). The discount rate used in this note was 12.5 percent. The percent received by the government was computed by dividing the aggregate discounted government revenues by total discounted receipts from the sale of oil minus total discounted expenditures (that is, net income).

It is immediately clear from Figure 3 that the two fiscal systems are very different. In case 1, the percent received by the government declines with rising oil price, whereas the reverse is observed in case 2, clearly illustrating that case 1 is regressive, case 2 progressive.

Figure 3 Percent received by the government (discounted)

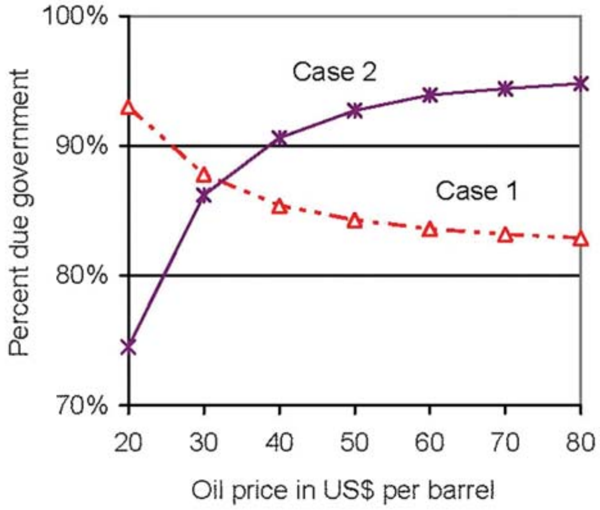
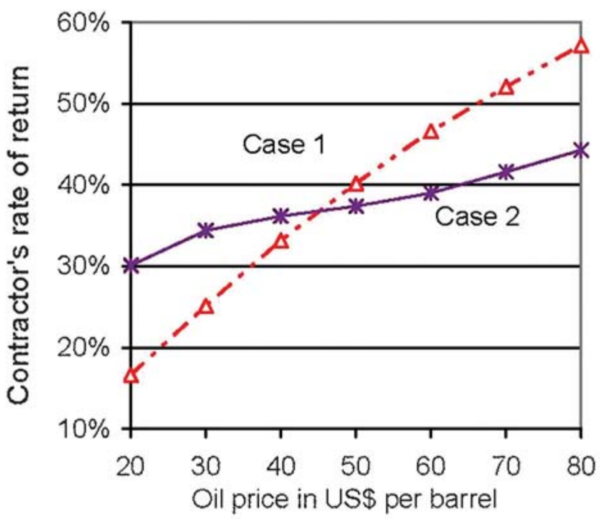


Figure 4 shows the contractor's rate of return, which is a measure of profitability. In case 1, the rate of return is markedly lower than that in case 2 at low oil prices, but the two curves cross near US$45 a barrel above which case 1 gives higher rates of return. That is, case 1 is unattractive to investors in a low oil-price environment but very attractive if oil prices soar.

What these two figures illustrate is that a progressive regime is more likely to assure a reasonable return to investors even when world oil prices are low (or alternatively in high-cost fields, such as marginal fields), but limits the amount of profits that the contractor can earn in "good times." Conversely for the government, a progressive regime may provide less revenue when times are tough—low oil prices, high production costs, or both—but provide more income if the project becomes profitable.

Figure 4 Contractor's internal rate of return



Impact on Revenue Flow

Figure 5 shows annual government revenues using the oil price history shown in Figure 2. This assumes that the price of oil extracted in this hypothetical field fetches the same price as Brent. There are marked differences between the two cases during the first five years. In the first year, the government receives a signature bonus of US$20 million in case 1 but nothing in case 2. The government receives no revenue in year 2, and in practice years of little revenue will last longer than a year. As production starts, government revenue rises more rapidly in case 1, but falls below that in case 2 beginning in year 7. Government revenues in case 1 are more front-loaded.

Table 3 compares the overall government revenue over the life of this oil field at different (constant) oil price levels, calculated using discounted cash flow analysis. In case 2, despite being back-loaded, the aggregate revenue is lower than in case 1 below US$40 a barrel, but is 14 percent higher at US$80 a barrel, a highly profitable scenario, The ratio of government revenues is higher for a doubling and quadrupling of oil prices in case 2.

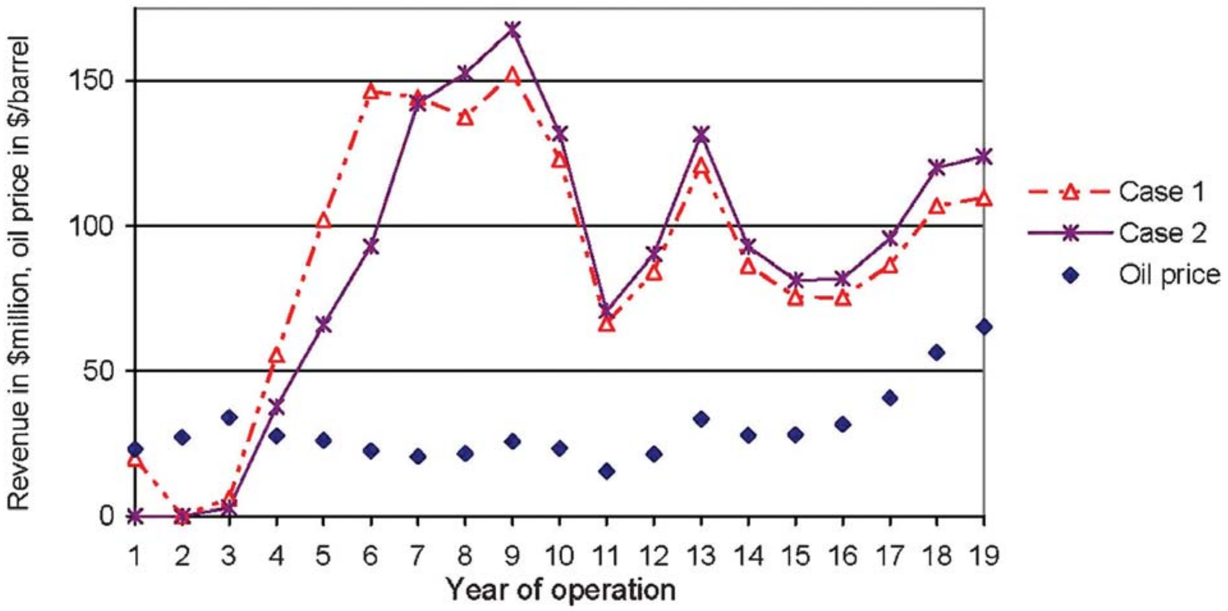
Table 3 Impact of varying oil prices on government revenues, US$ million [revenues are adjusted (discounted) to 2006]

Case	1	2
US$20 a barrel	420	336
US$30 a barrel	733	719
US $40 a barrel	1,041	1,103
US $60 a barrel	1,659	1,864
US $80 a barrel	2,280	2,608
Revenue ratio for $60/$30	2.3	2.6
Revenue ratio for $80/$20	5.4	7.8

Observations

The two cases discussed in this note illustrate the type of trade-offs that governments have to consider in setting fiscal parameters. So-called regressive parameters are more likely to ensure early revenue as well as minimal revenues in adverse circumstances, but also to discourage investments, especially in marginal fields. Pro-

Figure 5 Annual Government Revenue for the Real Brent Oil Price Scenario



gressive regimes may encourage investments in adverse situations and also increase government revenues in favorable circumstances, but could delay the arrival of government revenues and reduce them if oil prices fall, production costs increase, or both.

Table 3 also illustrates that, as one would expect, the impact of oil price variation on government revenue volatility is amplified if fiscal parameters are linked to profitability indices. But it is difficult to try to control revenue volatility by means of fiscal parameters. A recommended approach is to design the fiscal system to maximize government revenue in the long run, and to use other instruments¾such as oil funds or risk management strategies including hedging¾to deal with revenue volatility.

In all cases, the government's (and the government's perception of investors') assessment of future oil price movements, production cost escalation, and the field's prospectivity (its attractiveness as an exploration target) will influence how to set fiscal parameters for long-term government revenue maximization.

This three-part series has had to simplify complex issues for the sake of readability and brevity. The long-term nature, large upfront investments, and significant uncertainties surrounding petroleum projects present a considerable challenge to the formulation of the fiscal framework and contractual terms in any country. It is important to note that, because each project is situation-specific, fiscal systems cannot merely be transplanted from one country, area, or project to another; what works well in Algeria may not work well in Cambodia. In this regard, it is important to retain flexibility in fiscal systems¾capable of adapting to changes in market conditions, government policy, and geological and country risks.

References

[1] World Bank. 2007. "Contracts for Petroleum Development – Part 1." Petroleum Sector Briefing Note No. 7, October.

[2] World Bank. 2007. "Contracts for Petroleum Development – Part 2." Petroleum Sector Briefing Note No. 7, November.

[3] Daniel Johnston. 2003. *International Exploration Economics, Risk, and Contract Analysis*. Tulsa, Oklahoma: PennWell Corporation.

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