A Monkey's View of Privatisation, Liberalisation and Upstream Taxation

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Faced with a choice between owning different oil companies, which one of these should one go for: Royal Dutch/Shell or PEMEX (the Mexican national oil company)? Many might think that the ridiculous comparison such a question implies means that only a monkey would take it seriously. After all, what possible point can there be in weighing the merits of a formidable oil multinational against those of a national oil company widely perceived as being in distress, thanks to levels of overmanning, corruption and administrative ponderousness that have been the stuff of legend ever since J. Paul Getty disparagingly commented that PEMEX was the only oil company he knew of that somehow contrived to lose money? Certainly, from an investor's point of view, the question posed is meaningless, in that it can only have one solution. And yet, in terms of cold hard cash there is one actor for whom the answer to this question is far from straightforward: the Mexican government (and, by extension, the 100 million people that it represents).

In what follows, we will present a numerical example to illustrate why this should be so. The ultimate objective of this counterintuitive exercise, however, is to highlight the priorities that governmental policy-makers in places like Mexico ought to have in mind when they feel compelled to take the plunge and establish the conditions under which they are prepared to allow the participation of private (and, more specifically, foreign) capital in their hitherto out-of-bounds upstream sectors.

First of all, though, we have to explain why we chose these two companies in particular. Few would argue that they are not representative of their respective peer groups: the international oil majors, on the one hand, and the national oil companies (NOCs) of large oil-exporting countries, on the other. However, the main reason behind their selection is more pedestrian; namely, the level of detail of the statistical information they publish dealing with the taxation of their upstream activities. In PEMEX's case, the company's status as issuer and/or guarantor of certain securities that fall within the regulatory authority of the Securities Exchange Commission means that it is among the few NOCs that publish financial and operational statistics that conform to US standards of disclosure. Shell's selection is warranted by the fact that it reports its royalty expenditures separately from other costs of production, whereas not a single one of its peers bothers to make this key distinction. Thus, Shell is the only multinational oil company for whom it is possible to know the sum total of its payments (royalties plus other upstream taxes) to natural resource owners. This is extremely important for the purposes of this exercise, whose point is to highlight the remuneration that the governments of countries like Mexico are able to obtain, *in their capacity as owners of an exhaustible natural resource*, when they allow capitalist enterprises (whether private like Shell or public like PEMEX) to exploit their hydrocarbon reserves. In addition, Shell does not include payments to US royalty owners in its royalty expense figures; instead, it treats the royalty share of its US output as hydrocarbons produced on behalf of other parties and purchased for resale. From an analytical point of view, this again is useful because ownership of subsoil resources in the USA is vested in the owner of the surface rather than in the Nation, the Crown, the State or other similar collective entity. Thus, royalty owners in the USA more often than not are private parties (although, in Shell's case, the vast majority of its US royalty obligations derive from its Gulf of Mexico offshore operations in areas under Federal jurisdiction). Including payments to private royalty owners in calculations meant to reflect the patrimonial contribution obtained by host governments would have distorted results, which is why we have only considered Shell's non-US operations.

Let us now turn to the numbers. In 2000, a banner year for the international oil industry, Shell's worldwide output of hydrocarbons excluding the USA amounted to 3.041 million barrels a day of crude oil equivalent (mb/d of coe), while PEMEX's was 3.854 mb/d of coe. The sale of this production generated \$21.014 billion in upstream revenues for Shell and \$33.22 billion for PEMEX, equivalent to \$20.98 and \$23.73, respectively, in per barrel terms. Of these revenues, Shell paid \$9.154 billion in direct upstream contributions to its various host governments (41.41 per cent of its gross revenues) while PEMEX paid the Mexican government \$23.712 billion (71 per cent of its gross revenues). On a per unit basis, these figures are equivalent to \$8.25/bcoe and \$16.94/bcoe, respectively. The comparison between the upstream contributions paid by both companies puts PEMEX's worth to the Mexican government in stark relief, even if one does not consider the additional, hidden, social security tax that the Mexican government effectively levies on PEMEX by forcing it to keep on its payroll tens of thousands of people surplus to its requirements.

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Of course, the taxation that PEMEX has to bear is unsustainable in the long run (because it can only be met by increasing the company's indebtedness), but a fiscal burden that PEMEX would find sustainable would still be way in excess of those which private oil companies have to contend with anywhere in the world. After all, had the rate of upstream taxation on the Mexican oil industry in 2000 been comparable to the average upstream tax rate (inclusive of royalties) paid by Shell in its global operations outside the USA, gross upstream revenues would have had to be $21 billion higher than they actually were for the government's fiscal income to remain at the level actually observed for that year. This would have entailed increasing Mexico's total hydrocarbon output by an enormous 63 per cent (equivalent to 2.45 mb/d of coe *so long as prices did not move in response to this change in output*. Had prices actually *fallen* (by around 35 per cent, say, to $15/b), the required increase in output would actually have been a daunting 100 per cent. Of course, the government's fiscal income could have been maintained regardless of lower tax through cost savings that would increase taxable income. However, the cost savings necessary to maintain the income that the government achieved in 2000 would have been the stuff of fantasy: no less than $9.24 billion *for that year alone* (40 per cent more than the money that PEMEX earmarked for investment in exploration and production activities, and equivalent to 40 per cent of the *total* costs that PEMEX incurred during that year). While it is indisputable that enormous sums of money are dissipated by inefficiencies in the operations of NOCs like PEMEX, these appear considerably smaller than those which the governments of large oil-exporting countries would stand to lose if they were to bring their upstream taxation in line with the flexible and investor-friendly fiscal regimes that prevail in countries where the likes of Shell operate. In any case, these governments should bear in mind that there is a fundamental asymmetry in this apparent trade-off between efficiency and taxation.

The amount of slack in the operations of many of these NOCs is such that noticeable improvements can be achieved with modest efforts. In other words, in terms of efficiency, the only way to go appears to be up. PEMEX's past fifteen years provide a reasonable example of this, and the advances made (modest as they might appear) are not all that easy to reverse: while the company's payroll may not be contracting at the moment, it will certainly not expand again to beyond the 150,000 mark, and even if the perverse influence of the oil workers' union has not been curbed, the days when it could expect the assignation of all of the company's major contracts are definitely in the past. Moreover, with a bit of political will on the part of the government, very significant cost reductions could be achieved in relatively short order, thanks to the fact that fixed costs represent a very high percentage of the company's total costs. For instance, in its E&P operations,

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PEMEX reports its unit production costs as $3.48/bcoe and variable production costs as only $0.90 (or 26 per cent of the total); the remainder is eaten up by fixed costs: administrative overheads (27 per cent), maintenance (31 per cent), salaries (14 per cent), employee benefit plans (16 per cent) and other fixed operational costs (12 per cent).

In terms of tax, the situation is exactly the reverse: the fiscal burden that these governments impose on their NOCs, as a rule, is very heavy and it is inconceivable that any private oil company would ever accept paying taxes at rates even remotely comparable to the one PEMEX has had to live with during the last quarter of a century, say. In other words, at comparable levels of output, the only way that tax revenues can go with the opening of the oil industry in a country like Mexico is down. Supporters of an *Apertura*-type policy do not dispute this, but argue that a much higher output coupled with cost savings introduced by companies subject to capital market discipline would leave the Mexican government financially better off than if it continued to entrust hydrocarbon extraction activities solely to PEMEX. And they support this contention by means of dazzling scenarios which show output, tax revenues and even industry profits increasing steeply, the latter as a result of the introduction of investment-neutral fiscal regimes intended to maximise production volumes.

The problem with these scenarios, though, is that they gloss over the fact that fiscal revenues associated to output maximisation have tended not to materialise, partly because large production increases by major oil exporters have normally translated into much lower international oil prices (recall 1998), and partly because 'progressive' (i.e. non-royalty) net income levies lend themselves to tax optimisation practices. Venezuela provides a sobering lesson in this regard. In the light of what has happened during and after the 1998 price crisis, the estimated fiscal revenue figures for the post-*Apertura* Venezuela could be seen as a brilliant joke, were it not for the fact that their mirage quality accelerated even further the financial and institutional ruin of a once prosperous nation. And the flexible nature of the country's oil taxation regime, whose most important element was the phasing out of the severance tax on oil exports (the so-called Fiscal Export Value), has been an unmitigated fiscal disaster. During 2000, oil export revenues for PdVSA were a record $US27.3 billion, out of which the government received $11.23 billion in direct upstream contributions (41 per cent of the total). The previous peak in Venezuelan oil export revenues occurred during 1981, but in that year the $19.1 billion of export sales generated $13.9 billion in royalties and income taxes for the government (73 per cent of gross export revenues).

In light of these experiences, then, what would a monkey say to policymakers in countries where the conditions for petroleum production are extraordinarily favourable regarding any potential trade-off between the tangible – and vital – oil fiscal income that they currently obtain against projected revenue increases associated with flexible fiscal regimes and output maximisation policies? His advice might run something like this: 'Listen mate, it's a jungle out there, so do as we monkeys do: make sure you never let go of a vine until you have the next one firmly in hand.'

Electricity Prices in the Single European Energy Market

John Bower

Introduction

Before 1986, energy in the European Union (EU)[1] was generally regarded as too important a strategic resource to be subject to competition and choice. Energy policy, legislation, and regulation were therefore left to individual member states to implement as they saw fit. However, creating an open cross-border market for energy stretching across the EU and on into neighbouring countries, became a goal for the European Commission (EC) from 1987 once the *Single European Act* had come into force. This legislation established the general principle of the 'single market' rather than separate national markets for goods and services in the EU. As a result, the EC set itself the objective of creating a single European energy market by 1 January 1993 but it was only some five years after this deadline had passed that it really began to take shape when the *Electricity Directive* (ED) passed into law in February 1997, along with the closely related *Gas Directive* (GD) in August 1998.[2]

The ED established common rules for the generation, transmission, distribution, and supply, sectors of the EU electricity industry and established the following principles:

i. Unbundling of accounts to prevent subsidisation and distortion of competition in vertically integrated firms;

ii. Competition in construction and operation of new plant either via an authorisation procedure, allowing markets to determine investment criteria, or via a tendering procedure, allowing central planners to determine when and where to build capacity;

iii. Open access to transmission and distribution, (T&D) networks guaranteed by the mandatory appointment of an Independent System Operator (ISO), and transparent and non-discriminatory carriage charges, with only reciprocity and system reliability allowing countries to bar access; and

iv. Consumers having the right to choose their supplier with approximately 26.5 per cent of total supply to be fully open to competition by February 1999, 28 per cent by February 2000, and 33 per cent by February 2003.

The GD also established similar principles for natural gas though the targets for supply competition were somewhat lower with a minimum of 20 per cent of total consumption to be eligible to choose supplier by August 2000, 28 per cent by August 2003, and 33 per cent by February 2008. In practice, the rate of increase in supply competition has been far greater than the minimum benchmarks suggest. By the end of 2001 approximately 70 per cent of electricity, and 75 per cent of gas, consumption in the EU was eligible though the percentage varied widely between countries.

These two directives therefore supported the creation of a single European energy market in two crucial ways. First; by guaranteeing open access to interconnected T&D networks they promoted the integration of national energy markets by allowing suppliers in any EU country to compete, as if they were all in one market, through cross-border trade. Secondly; by mandating that all gas used in generation should be immediately eligible for supply competition the ED and GD became explicitly linked, as increasing competition in the supply of gas for generation, especially to new entrant firms operating combined-cycle gas turbine (CCGT) plant, would naturally lead to increasing competition in the electricity market.

Given that electricity generation consumes approximately 45 per cent of total, and 70 per cent of non-oil, primary energy used in the EU, creating an economically efficient single European electricity market is a crucial step in creating an economically efficient single European energy market. When completed, energy producers will have no choice but to compete with each other, both within countries and across borders, in order to retain market share in supplying primary energy input for electricity generation, as well as electrical output.

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Economic theory suggests that an economically efficient single European electricity market should be characterised by an industry structure containing many generating and supply firms competing aggressively to sell electricity regardless of the size of the consumer, or the production, and consumption location. Wholesale markets, where generators and supply firms trade bulk electricity, should be *perfectly competitive* with prices equal to the short-run marginal cost (MC) of production of the last unit of generation capacity required to meet any given level of total EU demand. Likewise, retail markets, where consumers and supply firms contract with each other, should also be