Design of Fiscal System for Exploration of Shale Gas: How is it Different From Conventional Oil and Gas?

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Due to the success of shale gas developments observed in the US and lack of domestic legislation specifically for unconventional gas projects in the countries, an arising question is whether replicating the fiscal terms conceptually designed for conventional oil and gas exploration would be appropriate for the exploitation of unconventional gas deposits.

To address this question this article compares shale gas projects with conventional gas projects, aiming to assess if they have similar enough structures to be suitably covered by the same fiscal regime or if the legislation needs to address issues that are either different or behave in a particular way in unconventional gas projects.

The analysis indicated that gas projects – both from conventional or unconventional sources – have a set of singularities that make their economic appraisal remarkably different from oil projects. Put simply, gas projects have different business structures that leads to less margin of rent to be captured and a particular flow of revenues that should be taken into consideration when designing a fiscal system oriented to promote investments. It showed that investments in unconventional gas projects, besides having the particularities shared with conventional gas ventures, has its own singularities that are relevant enough to demand different kind of incentives and as a consequence a different treatment from fiscal policy makers.

The Shale Gas 'Revolution'

The shale 'boom' (Maugeri, 2012) or 'revolution' (Stevens, 2010), as recurrently referred, created an environment of unstable and divided projections about the future of the energy industry, especially regarding the real future of shale gas developments and its potential impacts on crude oil relevance in the world's energy matrix.

For commercial and technological reasons, from the late 1990s and continuously through the 2000s, the United States watched an exceptional growth in shale gas development within the country (Deloitte, 2011). From 2000 to 2010, the domestic gas production rose from 1% to over 20% (Stevens, 2012). This revolution was fundamentally related to two facts: i) the search for an alternative method of exploration able to diminish the increasing dependence on imports of natural gas from Canada; and ii) made viable by technological developments on horizontal drilling and fracturing techniques (Deloitte, 2011). The U.S. Energy Information

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Administrator's projects the production to progress from 7.8 trillion cubic feet in 2011 to 16.7 trillion cubic feet in 2040 (U.S. Energy Information Administration, 2013).

The projections of a wealthy future for shale gas in the United States made other nations with potential shale reserves devote its attention to the development of its own domestic resources. Since it a heterogeneous movement, something that is coming from outside, Governments are concerned in providing the adequate legal/fiscal environment to make those projects successful within its boundaries. That being so, a recurrent topic is whether the reproduction of the legal and fiscal regime conceptually conceived for the exploration of conventional oil and gas reservoirs would be appropriate for the development of unconventional gas deposits.

From the Government standing point, the overall legal regime needs to provide a system that is able to simultaneously i) give incentives for private investors to undertake the venture and ii) capture the greatest amount of rent available. The challenging task is how to provide those incentives, capture rent and at the same time address regulatory concerns related to the numerous uncertainties – commercial, technical, environmental, social – that so far surround the exploration of unconventional gas sources. For investors, on the other hand, the legal and fiscal standards need to show themselves clear and stable enough to accurately assess the financial feasibility of a project. It must be able to provide the correct incentives to guarantee to the investor a return that will adequately reward the risk borne. Additionally, it needs to assure that it won't be unilaterally changed compromising the economic viability of the project.

Those problems are, in a first moment, a policy concern that will involve a political decision on i) the kind of incentives that it wants to provide; and ii) how those incentives can be given considering the instruments available or potentially suitable in a given legal system. Hence, for the legal approach of the problem what should be asked is not only what kind of incentives are required, but also how the law addresses those incentives in accordance with what is prescribed in the system when considered as a whole.

Why is gas different from oil

Although not infrequently treated as the same, gas is different from oil and those deviations are remarkably relevant to be aware of when assessing whether a fiscal regime devised for oil projects (for conventional oil and gas projects, indeed) could appropriately be replicated for shale gas exploitation.

An important distinctive factor between oil projects and gas projects –not necessarily for unconventional gas projects – is the high transportation costs associated with gas: 'gas delivered to the final consumer has much higher costs per unit of energy' (Stevens, 2010) and 'much less flexibility in terms of transport and trade' (Stevens, 2010), since it can only be transported by pipeline or in the form of LNG. Pipelines are a conceptually simple form to transport gas, 'it is essentially a long tube buried in the ground or sea bed' (McLellan, 1992), but capital intensive infrastructure limited to a point-to-point transport, normally requiring long-term contracts to lock-in a minimum of revenue stream for at least ten years to payback the capital invested (McLellan, 1992). Similarly, 'LNG sellers must have access to regasification plants and LNG buyers must have access to liquefaction plants' (Stevens, 2010), what increases costs.

As a consequence of constraints in potential means of transportation, gas markets present another contrast with oil markets, being 'essentially a regional market rather than a truly global market' (Stevens, 2010), meaning that there is no relatively uniform price for gas trading as observed for oil. So far, the absence of a gas cartel to 'fulfil the same role as OPEC, i.e. restrain supply to ensure significantly higher prices than would exist in a competitive market' (Stevens, 2010) also contribute to different ranges between gas prices and oil prices.

Normally, to justify the production and delivery to the market, gas projects need to occur in large-scale operation, what is translated into high fixed costs that require full capacity operation to spread those fixed costs over a larger basis. 'Less than full capacity operation means that high fixed costs are spread over a smaller throughput and profits decline exponentially' (Stevens, 2010). As a consequence, to increase bankability of gas projects, it is traded through long term contracts, since the 'high initial cost also need to lock in future revenue streams' (Stevens, 2010).

Also, gas presents smaller heat content when compared to oil. This factor combined to the fact that gas presents less flexibility to be transported substantially increase the cost per unit of energy when delivered to the final consumer (Stevens, 2010).

General perspective on economics of unconventional gas projects: Definition of shale gas: why is it unconventional?

The natural gas obtained from the hydraulic fracturing of shale, sedimentary rock formations – source and reservoir (U.S. Energy Information Administration, 2013) - is classified as an unconventional resource. According to the EIA, the concept of unconventional oil and natural gas production is obtained by contrast with what do 'not meet the criteria for conventional production' (U.S. Energy Information Administration, 2013). As a consequence from the low permeability of formations where shale deposits are trapped, its exploration differs them from those deposits drilled from 'a geologic formation in which the reservoir and fluid characteristics permit oil and natural gas to readily flow to the wellbore' (U.S. Energy Information Administration, 2013. Put simply, as shale gas is 'found in a reservoir of low or zero permeability' (Royal Society and Royal Academy of Engineering, 2012), it 'cannot be produced, transported, and refined by conventional methods' (Maugeri, 2012). Advances in the use of hydraulic fracturing and increases in oil prices made it cost-effective to develop shale gas deposits, enabling the shale gas 'revolution' in the U.S.(Maugeri, 2012).

Technical background for unconventional gas

The geological and technical framework for exploration of shale gas is of key importance to assess the economics of the project; they are determinant to evaluate the costs production – both fixed and variable costs - and to forecast potential revenues, directly related to 'the actual costs, prices and production profiles' (Meurs; Rodgers; Kepes, 2011). The assessment of these parameters allows ranking of projects and are indispensable to orient the investment decision.

As mentioned, the development of unconventional sources will demand the use of particular technology and methods of enhanced recovery for extraction of natural gas in commercial quantities, namely horizontal drilling and hydraulic fracturing. Since the deposits are spread in a larger area than observed for conventional gas sources, the extensive use of horizontal drilling is required to maximize the surface contact with the unconventional deposits. (Stevens, 2010) Those mechanisms assess the gas often 'trapped within thick, horizontal rock strata, in relatively low intensity accumulations' (BG Group). Those formations also present a 'smaller recoverable content per unit of land', normally spread in 'larger geographic areas' (IEA, 2012) , being its ultimate recovery 'much lower (8-30%) than for a conventional well (60-80%)' (Stevens, 2010).

These variables – the average ultimate recovery combined with the decline rate in the early years - are key when calculating the 'extent of the requirement for unconventional gas wells for a projected level of production' (IEA, 2012) and 'can vary significantly between shale gas, tight gas and coalbed methane wells' (IEA, 2012). Furthermore, the conjunction of these factors impose the necessity of permanent drilling to keep production into commercial levels and as a consequence unconventional projects have a sustained capital intensity.

Depth is another parameter contributing to the fact that 'there are widely divergent costs estimates for shale gas, a problem compounded by the geological differences between the plays and between wells within the same play' (Stevens, 2011). Sensible variances in the depth of the reserves can drive considerable fluctuations in the economics of the project, since 'drilling costs are largely a function of depth' (Considine, 2010). It also means that the economic assessment of one project cannot be extrapolated for another play, because they can will most likely present divergent costs levels and projections based on this yardstick will be misleading. Depths of shale plays can 'vary from near surface to several thousand meters underground, while their thickness varies from just a few meters to several hundred' (IEA, 2012) and 'the deeper the well the higher is the cost' (Considine, 2010).

Another variable noteworthy mentioning is the degree of maturation of shale deposits, classified as wet gas or dry gas reserves, which can also vary between the shale formations.[2] This feature can impact the economics of the project while 'wet gas is currently considered to be more valuable in the marketplace as the natural gas liquids have inherent value as a commodity' (MCOR). As a matter of fact, 'most dry gas plays in the United States are probably uneconomic at the current low natural

[2] This classification is related to the amount of natural gas liquids (NGLs) present in the gas, being more valuable the deposits with higher content of NGLs, as its prices are correlated will oil prices rather than with gas prices (IEA, 2012).

gas prices, plays with significant liquid content can be produced for the value of the liquids only' (IEA, 2012).

In addition, 'release the shale or tight gas requires hydraulic fracturing using chemicals and sand to maintain the increased porosity one the rock structure has been fragmented' (Stevens, 2010). Without the use of mechanisms to enhance the flow rate of hydrocarbons, the operation is not economically feasible (IEA, 2012).

The use of those techniques is still associated with enhanced environmental risks that can be a barrier to the development of shale and tight gas in the future (Stevens, 2010). Although it uses a technology that is not new, and that have similarities with those used in the upstream industry (IEA, 2012), its large-scale use and other particularities of shale gas enhances the perception of risks of environmental impact and adverse social impacts regarding its use (IEA, 2012).

Another point to be made about shale gas developments that enhances the uncertainties entailed to its development is the absence – or lack of precision – of the so called learn by doing. Seeing that geological conditions can deeply vary between shale plays, it is more difficult to do an accurate assessment of the expected outcomes of the project. At the exploration stage, 'the longer learning curve for unconventional plays makes it much more difficult to develop comprehensive plans at this stage' (IEA, 2012).

Also, outside the United States, 'services will not be easily available and need to be mobilized and demobilized' (Meurs, 2013), initially reflecting substantially increased drilling costs (can go as high as 400% of what observed in North America) (Meurs, 2013). The development of local production can offset this issue in the medium term, bringing costs down.

Fiscal System For Shale Gas Developments

Governments when tailoring a fiscal policy for extraction of shale gas should consider that conventional oil and gas ventures present significant particularities. Though, it is not equivalent to say that there is any essential difference in general theoretical perspective on tax design. In the long term, the objectives are basically the same as those mentioned in the previous sections. Fiscal policy designers should be aware of the dynamics of the segment subject to taxation to effectively function as a revenue-raising instrument and to rule the behavior of taxpayers. Hence, the scope of this study was to compare the dynamics presented by conventional oil and gas projects and shale gas extraction. The survey showed that the dissimilarities are not only associated with the condition of being a conventional or unconventional source. *Ex ante*, those projects should be set apart on the basis that 'gas is different from oil' (Stevens, 2010).

Hence, considering in a first moment the several differences encountered between oil and gas projects, irrespective of its source, if conventional or unconventional, one conclusion outlined in this survey is key: gas projects have less rent available to be taxed. This reality is already translated in the fiscal system of some jurisdictions that apply an extenuated royalty rate for gas projects. With a world average Government Take for oil at around 72% or so the world average Take for gas is likely around 10 points less (at 62%).

To assess the economic rent generated by shale gas projects, when modeling a system to it, policy makers should also pay attention to a fundamental parameter for targeting the margin of rent available to be taxed: the *cost/price* ratio. It can show relevant variance when compared to average ratios for conventional oil and gas projects around the world.

Another point to be observed when comparing oil with gas is the indispensable relation of gas developments with downstream facilities. To increase bankability of gas projects, it is mostly traded under long-term contracts that will provide a predictable and certain revenue stream for repayment of the required infrastructure. This factor also contributes to the pointed fact that, ordinarily, there is less rent available to be captured by taxation on gas projects when compared to oil ventures.
In addition to the disparities related to gas being considerably different from oil, unconventional resources, such as shale gas, have intrinsic particularities that distinguish them from conventional sources. Those differences are related to geological singularities observed for those formations that demand a particular gearing for extraction that model its recovery rates and consequential cashflows in a different way from conventional oil and gas projects.

Those are significant parameters for governments to be conscious about when designing a fiscal system wishing to encourage investments in the segment. Having a clear panorama of those figures, it can spot more easily in which stage of the project should the burden of taxation be concentrated and the kind of incentives that would suit for the structure in the horizon. So accordingly, 'governments would need to seek a trade-off between regressive features (royalties, cost recovery limit, exploration tax) and progressive features (RoR, R-Factor based taxes, or production sharing) (Tordo, 2007). A particularly challenging task when devising a fiscal regime for development of shale gas deposits is how to address the enormous variances that can be find between shale plays, or even between shale wells performance: 'each shale formation has different geological characteristic that affect the way gas can be produced, the technologies needed and the economics of production (IEA, 2012). Considering that geological conditions can widely vary between unconventional gas plays (significant differences can be found even comparing wells within the same play), fiscal instruments imposed over a tax basis assessed project-by-project 'is consistent with the rationale of imposing the tax in accordance with the value of specific deposits, thereby capturing the resource rent' (Land, 1995). The system should be flexible enough to contemplate those singularities and self adjust its terms to communicate the envisaged signals.

In the short term, since there is still a strong uncertainty about crucial variables to the developments of those projects, and Governments willing to encourage investments may need to provide more favourable fiscal terms, while projects should need profits to be large enough to accommodate these failures (Jhonston, 1994) and investors will seek for a greater risk premium. That is because, to avoid risks related to lack of relevant information to the projects development, ‘investor’s main response to risk is to add a premium to the discount rate that they apply in evaluation of investment’ (Garnaut; Ross, 1983) The rate of return on the capital investment for such kind of project is ‘normally taken to be 10% for a project categorised as risk-free and rising with incremental risk’ (IEA, 2012).

Also, bearing in mind the constant push for technological improvements on declining rates and expected upwards on the shale production curve and in total cumulative production, the fiscal system should be sensitive to fluctuations in production levels while it may vary during the life of the project. This statement needs qualification since progressive instruments (such as sliding scale mechanisms) targeted to production levels can only ease the distorting effect of regressive features levied on a flat rate. In terms of capital costs, its significance is very dependent on production levels (IEA, 2012), since it can be spread over a larger number of units. Despite that, it will still have an overall regressive result if it does not reflect the costs of development and production of the extracting shale gas, which are significantly different from conventional oil and gas developments, in volume and timing of incurrence.

Additionally, since shale gas deposits are spread over a much larger area than what is observed for conventional reservoirs, the imposition of land fees should be imposed in lower rates for shale gas, since for the same level of production – appraised as an indicator of profitability – a greater area is demanded for non-conventional and can allocate a distortive burden of land fees impacting the economics of the project. Contrasting to conventional oil and gas, shale gas extraction requires greater large-scale operation and, as a consequence, ‘whereas onshore conventional fields might require less than one well per ten square kilometer, unconventional fields might need more than one well square kilometer’ (IEA, 2012).

To offset (or at least make it more discrete) regressivity issues, fiscal policy designers can adopt the use of taxation instruments linked to the profitability of the project (Rate or return or R-factor), since it will be targeting the financial reality of the project, irrespective of the activity generating the results (either conventional oil, conventional, associated or non-associated gas, unconventional gas). Progressive terms ‘can apply to any individual project and will generate a high government take only from the most profitable projects’ (Kellas, 2010). Nevertheless, a back-end loaded system normally means later revenues for the Government and a participation in the risk of the project developing as unprofitable.

Another factor to be considered for the purpose of putting in place an appropriate fiscal system when it comes to gas developments is the essential linkage between downstream facilities and gas projects, costly infrastructure that need to have its cost included in the cashflows. To make investments in gas more attractive, it is not uncommon for countries to offer better fiscal terms to gas projects when comparing to fiscal terms for oil exploration. These incentive can include uplifts for capital investments depreciation, accelerated depreciation schedules for costs incurred in transportation infrastructure, allowance for recovery of pipeline costs on the cost recovery pool and similar incentives (Kellas, 2010).

If the bonanza from shale prove itself as good as it is prospected to be, it is expected that there will be claims for tightening the terms of the already licensed areas, due to the obsolescing bargain, that shifts the position of power from the investor to the Government once the investment has been made and there is lack of alternative for the company than carrying on with the venture. Straightforwardly, ‘the incentives for governments increase to exercise coercive taxation, and this has a particularly negative effect on the owners of immobile assets’ (ICMM, 2009). This is a short term perspective attitude from the government side, though, because ‘by altering fiscal terms *ex post*, countries that have offered attractive fiscal regimes because of higher perceived political risks are further increasing those risks’ (ICMM, 2009). Having in mind that an unexpected change in the fiscal regime can have a distortive effect on the numbers of the project, investors should seek for a certain level of stability on the fiscal terms offered when assessing the feasibility of the venture.

This issue can also be counterbalanced (not eliminated, though, due to a possible increase in tax rates) if the tax allocation is sensitive to the profitability of the project. Furthermore, technological improvements and more availability of services can diminish production costs and hence adjust the impact of this increase in taxes on the rate of return of the project. The State can encourage investments in research and development of new technology that will cut down the drilling costs of shale gas projects by allowing those values to be expensed with an uplift provision.

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