UPSTREAM REFORM

Round Zero, which deals with Pemex legacy assets, already underway

The opening of the Mexican upstream to private investment will be a multi-stage, complex process. The first stage – known as Round Zero -- began in March and should be completed by September 17th. It deals with the selection and allocation of assets that will be transferred to Pemex under the new legislation. Pemex has already presented its formal request of oil and gas licenses.[1] The list of fields and exploration areas was not made public, but can be inferred from the guidelines contained in the constitutional amendment[2] and from descriptive statistics that it published. The amendment establishes that Pemex may keep all fields that were producing on December 20, 2013, after presenting new development plans, and exploration acreage where Pemex has made commercial discoveries or made significant investments.

In the second case, on the basis of its work plans and evidence of its financial capacity, Pemex may carry out activities for 3 years, with a possible two-year extension. If successful, Pemex can then proceed to their development if it can demonstrate that it has the necessary technical, financial, and execution capabilities to explore and produce these hydrocarbons in an efficient and competitive manner. The government has not yet proposed explicit criteria that will be applied, but has formally detailed an extensive request for information.

The Pemex proposal leaves ample space for private investment in shale oil and gas in Northern Mexico, in tight sand and low energy reservoirs in the Chicontepec area in the State of Veracruz, and in deep-water areas in the Gulf of Mexico. Specific assets in other regions are not excluded, but their availability is not been made public. Mexico's Department of Energy[3] has offered to authorize uncontested assets as soon as possible and address what would probably be marginal cases toward the end of the process. As the deadline approaches, a certain amount of tension is bound to arise between Pemex and the government during the discussion of undecided assets. One outstanding and critical issue is the definition of the size of the blocks that will be formed for purposes of asset bidding and the allocation of contractual areas.

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[1] Asignaciones.
[2] Transitional Article 6.
[3] Secretaría de Energía (Sener).

Once the Pemex licenses are ratified in Round Zero, a second two-phased process begins. In one phase, Pemex legacy licenses will transition to new contractual and fiscal arrangements. In the other phase, contractual areas will be allocated to private parties through a well-defined public bidding mechanism. Pemex may also participate. It is not yet clear which phase will come first. It is assumed that the Pemex transition would come first, since new Pemex contracts could then form part of alliances and associations with third parties. However, the difficulties involved in this transition and the formation of these alliances might take more time than the establishment of a totally new joint operating agreements in assets that will be openly available. Valuing Pemex's initial asset contribution and segregating this value from what is contributed by its partners will not be easy tasks. There are many other issues that may arise, including the role that the Pemex trade union will play in these the partnership.

Four types of contracts to be available through a two-stage bidding process

The constitutional amendment explicitly prohibits concessions. Four types of contractual arrangement were initially proposed: service contracts, profit and production sharing agreements, and license contracts. Service contracts may include various forms of incentives and are paid in cash. Profit and production sharing agreements are very similar. Their main difference is that in profit sharing, title to production never passes to the contractor. The government sells the oil and gas produced and the proceeds go to a fund[4] that pays the contractor for the costs incurred and its share in the profits. Otherwise, these appear to be standard contracts used by the international oil industry, which allow for the booking of reserves. So-called license contracts are similar in structure to concessions, but will probably follow the Peruvian model[5] that simply alludes to contractors and not to concessionaires in its contractual clauses. Although the proposed hydrocarbon law refers to these contractual models and describes some of their basic terms and conditions, the Department of Energy and the Treasury[6] have not yet drafted standard contract forms and are probably waiting for the relevant secondary laws to be passed. Nor has the government offered guidelines with respect to the type of contract that will be applied to specific resources and geographical areas.

[4] Fondo Mexicano del Petróleo para la Estabilidad y el Desarrollo.
[5] Petroperú, contratos de licencia.
[6] Secretaría de Hacienda y Crédito Público (SHCP).

All of these contracts, with the exception of those relating to trans-border reservoirs, will be subject to a two-stage public bidding process. In the first stage, bidders will be selected on the basis of their qualifications, financial strength, work program, and minimum investment commitment. In the second stage, only one variable will be considered: the government's share in net income. However, in one variant of license contracts – the one that will probably be used for shale exploration and development -- the share in terms of gross income is considered. A high premium is placed on contractual simplicity. Bidding will be on a contract that leaves little space, if any, for negotiation. This is essential given the public mistrust that prevails with respect to the opening of the energy sector and the deeply embedded corruption in its activities. The government wants to minimize discretion in the decision making process in order to ensure full transparency in assigning contracts. It is aware that this might erode some of the benefits of a well-negotiated outcome. However, it is even more sensitive to potential scandals in these matters that could derail the reform effort. Responsibilities are well defined: the Department of Energy will design contracts, the Treasury will set their economic and fiscal terms, and the regulator (CNH) will run the bidding process. The same provisions and basic processes will be applied to associations related to Pemex contracts.

Acquiring joint venture partners through bidding is an awkward procedure, but centralizing this process in the government is the best way for Mexico to guarantee transparency in high value Pemex transactions.

Other complex issues are related to the specific form that these alliances and associations will take. As the government has strongly expressed that reforming the energy sector precludes the privatization of existing assets, it might opt for some form of farm-out agreement in which the foreign partners would acquire an interest in a Pemex exploration or production contract and would carry its capital expenditure and operating costs. The international company would also be the operator. The other form of alliance could be a standard joint-operating agreement. In this case, the new partner(s) could acquire an interest in an existing contract in exchange for an agreed consideration, and this could easily be construed as a partial sale of an asset.

The government may use the new Pemex contracts in two different ways, at two different times. Initially, it might want to modulate the speed of the transition from existing licenses to new contracts. This is important, as this migration will imply a lower government take. In this phase it might also want to concentrate on bidding out exploration acreage that is not under Pemex control. Later, the government could opt to open up Pemex legacy assets to the managerial discipline that partnerships would impose. This would allow additional time for the institutional developments that are needed for the success of these alliances and associations.

The government take on legacy assets will remain the same. It is only when Pemex migrates from existing licenses to contracts that the government take will be reduced. This is a powerful incentive for Pemex to make this transition to contracts as rapidly as possible. However, the actual migration will be moderated by government cash flow requirements, and it is the Department of Energy and the Treasury that hold the key of the process. The contracts to be used by Pemex and by new players set low signature bonuses and area rental fees, and very low royalty rates, with the government basically receiving revenues later in the life of the project based on the net income of ring-fenced contractual areas. This contrasts with short and mid-term government cash requirements. Bonuses only apply to license contracts and not to production sharing contracts. The amount of bonuses will be set by the Treasury, not by the contractor, on a case-by-case basis, before bidding begins. The Treasury has already signaled that they will represent a small fraction of expected project revenues. It is the government that sets them because it wants to evaluate bids on one single variable.

More intriguing is the level of royalties. A progressive scale is applied for oil, such that when prices are under $60 a barrel, they will be set at 5 percent. A formula of ([0.125 * oil price] -2.5) kicks in when prices are above $60 a barrel, such that at $100 a barrel, the royalty rate would be 10 percent.

For non-associated gas, the royalty is zero at $5 per million British thermal unit. When prices are between $5 and $5.50 per mmBtu, the following formula applies: [(price of natural gas–5) * 60.5] / (price of natural gas).

Above $5.50, this formula will be used: (price of natural gas) /100, providing a royalty rate of 7 percent for gas prices at $7 per mmBtu. Royalties for associated natural gas were simply set at: (price of natural gas/100).

The argument given by the Treasury for these low rates is that investment decisions based on taxes from gross revenues can distort investor decisions while taxes based on net profits do not. It is difficult to estimate the cost of potential distortions. Meanwhile, the Treasury is giving up assured revenues as production begins from royalties that can be easily estimated and monitored. However, there is a big difference relative to the oil royalty rates in other countries. For example, in Texas it is 25 percent, and offshore in the U.S. Gulf coast it is 18.75 percent. Although Norway and the U.K. have abolished royalties in their concessions, they did so when oil production in the North Sea was declining. Norway, in particular, does not require up front revenues given the size of its sovereign wealth funds.

The government faces difficult dilemmas in the choice, sequence, and timing of the assets to which it hopes to attract private investment. It has to find the right mix of frontier exploration assets, unconventional service intensive resources, marginal mature fields, and rich low cost shallow water developments. How government proceeds will give insight its priorities. High cost, high-risk projects with long lead times will not offer the government the oil income it needs in the medium-term. The economic rent that it captures can be significant but may be lower and further removed than in other projects. In shallow waters, private parties can both compete and cooperate with Pemex in lower risk projects. These ventures could also offer a more relevant best practice demonstration effect close to the Pemex legacy fields. The amount of economic rent might be greater, as well as the share captured by the government. A rolling five-year bidding calendar will prove to be a useful instrument that will more precisely reveal government priorities.