Report on
Proposed Mexico Model Contract and Bid Conditions for First Shallow Water Bid Round

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EXECUTIVE SUMMARY

On December 11, 2014, the Comisión Nacional de Hidrocarburos (CNH) released the Bid Conditions for the First Shallow Water Bid Round for Mexico. The Bid Conditions included the proposed model form of Production Sharing Contract (Model PSC) that would be awarded to successful bidders for shallow water blocks. CNH requested comments on the Bid Conditions and the Model PSC. This Report is written by us as independent international petroleum experts in response to CNH's request for public commentary. It was not commissioned by any party, and was not reviewed by any party prior to its release.

Background

The changes in the Mexican Constitution and enactment of secondary legislation have created a good framework for attracting foreign investment in Mexico's petroleum industry. It holds the promise that Mexico can increase oil and gas production, grow government revenues from oil and gas, attract new investors and investments, develop business opportunities and employment and provide opportunities for PEMEX to grow into an internationally competitive company. The challenge for the Government is to realize this potential by completing Mexico's petroleum regime through the design of a petroleum contract that will achieve those objectives and conducting bid rounds that will attract investors to Mexico.

Protecting the state's interests is a key part of creating a durable petroleum regime. It is clear that this has been the focus of the constitutional amendments, the Hydrocarbon Law, the Hydrocarbon Revenue Law and the work of CNH and others in the Mexican government who have prepared the Model PSC and the Bid Procedure. The comments in this report are therefore restricted to pointing out where international experience and practice would suggest that there may be other ways to achieve these objectives, or where the fiscal terms of the Model PSC may not be competitive with jurisdictions that compete with Mexico for private oil and gas

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investment. It is clearly the government's prerogative to identify the state interest and determine the best way to protect it; as non-Mexican advisors, we trust that our comments will be taken in the positive and constructive manner in which they are intended.

Shallow Water Circumstances

The shallow water area in Mexico is very mature. PEMEX has already discovered and developed the most attractive shallow water oil and gas fields, including the giant Cantarell field. The potential of discovering large and low cost oil and gas fields in Mexico's shallow water regions is low. While significant exploration potential remains, it is likely that most discoveries will be smaller fields with relatively high costs. Also, natural gas prices in Mexico are lower than in most areas of the world. Therefore, in order to attract significant foreign investment, the terms and conditions have to be fully competitive with terms in similar international conditions. Also, the design of the Model PSC will need to recognize that the activities are to take place in a mature basin with existing facilities.

Analysis of Bid Conditions and Model PSC

Our main conclusion is that the terms of the Model PSC are tough compared to other petroleum contracts for similar opportunities because it features:

- fiscal terms for shallow water conditions that are not competitive
- small contract areas,
- tough minimum work commitments,
- short time frames for implementation of exploration and development activities,
- a large number of non-recoverable cost items,
- a lack of an economic structure for investment in commercialization facilities
- a large number of discretionary decision requirements on the part of CNH,
- extensive administration and reporting requirements, and
- early termination and penalty provisions for breach of non-fundamental contract provisions.

We are concerned that the application of such terms to Mexico's mature shallow water conditions may significantly reduce the interest in the bidding round, in particular under the current declining oil prices.

Administrative Constraints

Setting up the required petroleum administration in Mexico will be a challenging task because Mexico intends to award a large number of blocks in the coming year. One would have expected that in this environment the Government would have opted for a contract that would be easy to administer. Instead the Model PSC is involves a large number of administrative decisions and extensive reporting. This is compounded by a fiscal design that encourages contractors to 'gold plate' their costs, so cost will be very difficult to control and audit. This creates significant potential that petroleum operations in Mexico will not be conducted in a manner that is efficient for the Mexican state. It also adds administrative challenges for investors.

Other Deficiences and Opportunities for Improvements

We identified a number of deficiencies in the Bid Conditions and Model PSC that create the following opportunities for improvements:

- The definition of Commercialization Installations should include gas processing
- Activities to be carried under the Model PSC and activities permitted under the Bid Conditions should be corresponding
- Scope needs to be created for economic development of midstream operations to be carried out by the Contractor in order to sell its oil or gas
- Budget approval procedures should be eliminated
- The overhead allowance under the Accounting Procedure should be increased to reflect a figure closer to industry standards
- The Accounting Procedure should allow Contractors to provide services to each other
- The fiscal terms are need to be made more competitive in view of the fact the proposed adjustment mechanism removes all "upside"
- The fiscal terms should take exploratory risk into account in order to make exploration economic,
- The proposed IRR system should be adjusted to eliminate the severe "gold plating" effect
- Volume progressivity should be introduced in the fiscal terms
- The transition provisions should be revised because returning the contract area to CNH after 25 to 35 years is not the most sensible approach under the new Mexican legislation
- Extension of the Contract term should be simpler
- The exploration periods should be increased to reflect international standards
- The Minimum Work Program obligations should be clarified
- The requirement of two wells as the minimum work obligation during the first three years for small contract areas should be modified
- Voluntary extra wells should be credited to the next exploration phase,
- A Significant Gas Discovery concept should be added to make gas exploration attractive
- The time for presenting a Development Plan should be increased
- The discretion for rejecting a Development Plan should be circumscribed
- The relinquishment provisions for the very small contract areas should be made less aggressive
- The bid variable of participation for the State should be adjusted to prevent counter-productive overbidding
- The Measurement Point should not be restricted to the Contract Area
- The provisions for determining Contract Prices and net back calculations should be adjusted to recognize the circumstances existing in Mexico

- There should be a back stop provision if decision making by CNH starts to slow down petroleum operations

To the extent that the Model PSC and Bid Conditions may be models for other activities in Mexico, we identify the opportunities for improvements to these situations, and for the migration of PEMEX operations to a PSC structure.

Recommendations

Significant amendments to the Model PSC are suggested in order for Mexico to fully benefit from the Constitutional and legislative changes that have been adopted in Mexico. This report contains thirty-eight recommendations to achieve this goal.

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1. INTRODUCTION

1.1 Purpose of the Report

This report contains a commentary on the Mexico Model Contract for shallow water (Model PSC) and Bid Procedure as announced December 11, 2014 by CNH. During the announcement, not only interested parties, but also the public was requested to make comments on the documents provided.

This report is written by us as independent international experts in order to provide such comments. This report was not requested by any party. Nor was this report reviewed with any party prior to its release.

The process of changing the Mexican Constitution and creating the respective legislation and regulations has created an attractive framework for attracting foreign investment. This will permit Mexico to increase oil and gas production, increase government revenues from oil and gas, increase investments, business opportunities and employment and provide new opportunities for PEMEX to grow in an internationally competitive company.

The comments in this report are provided from the view of ensuring a further successful implementation of the policies of the Government of Mexico.

We believe that in order to achieve this goal, it is necessary to significantly amend the Model PSC and Bid Conditions in order to make the contract more attractive for investors, make it easier to administer and deal with a number of deficiencies.

Under the Constitutional changes:

- SENER is in charge of the selection and drafting of the exploration and production contract,
- SHCP is in charge of determining the fiscal terms, and
- CNH is the regulator implementing the provisions and concluding and administering the contracts.

This report is therefore meant to provide suggestions and recommendations for input in the decision making processes of SENER, SHCP and CNH.

Protecting the state's interests is a key part of creating a durable petroleum regime. It is clear that this has been the focus of the constitutional amendments, the Hydrocarbon Law, the Hydrocarbon Revenue Law and the work of CNH and others in the Mexican government who have prepared the Model PSC and the Bid Procedure. The comments in this report are therefore restricted to pointing out where international experience and practice would suggest that there may be other ways to achieve these objectives, or where the fiscal terms of the Model PSC may not be competitive with jurisdictions that compete with Mexico for private oil and gas investment. It is clearly the government's prerogative to identify the state interest and determine the best way to protect it; as non-Mexican advisors, we trust that our comments will be taken in the positive and constructive manner in which they are intended.

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1.2 Approach to designing a petroleum regime

The authors of this Report have considerable international experience advising states around the world in the design of their petroleum regimes. This Report is written for the purpose of evaluating the Model PSC and the Bid Conditions to assist the government of Mexico with respect to its emerging new petroleum regime. In order to permit a better understanding of our recommendations, it is useful to describe our approach to the design of petroleum regimes.

1.2.1 Defining a "Petroleum Regime"

A petroleum regime is the set of rules adopted by a state to govern the exploration for and development of its petroleum resources. This set of rules can be found in the state's constitution, petroleum law, petroleum regulations and the petroleum contracts granted by the state to oil & gas companies. States with well-developed petroleum regimes tend to have all of these in place. Mexico is in the midst of creating its new petroleum regime following the amendment of the Constitution and the enactment of the secondary laws (in particular, the Hydrocarbon Law and Hydrocarbon Revenue Law ("LISH") and the related petroleum regulations. Mexico's new petroleum regime will be complete once the forms of petroleum contract are defined. The publication of the Model PSC and the Bid Conditions for shallow water is a key step in this process.

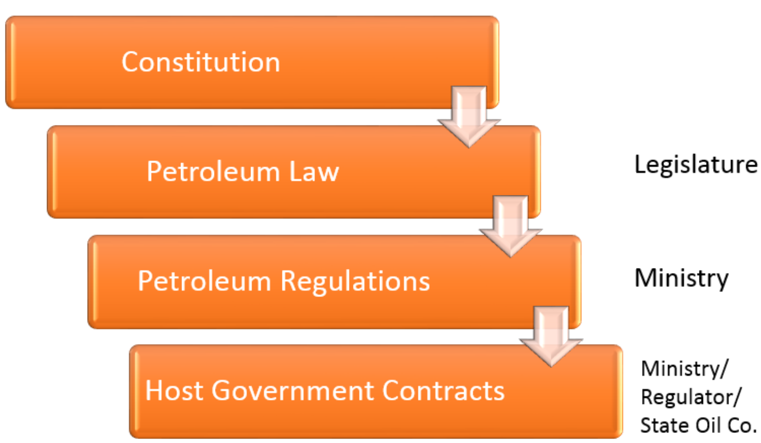


Figure 1- Components of a Petroleum Regime

Under a petroleum regime, the host government typically will delegate responsibility for administration of hydrocarbon exploration and development to a competent authority. In most jurisdictions this will be delegated to a government ministry, department or agency; in other cases, it will be delegated to a national oil company who will have both an administrative as well as commercial role. Pemex has had that function in Mexico until the enactment of the Hydrocarbon Law; now CNH will be taking on the role of the competent authority, and Pemex's role will be as a commercial oil & gas company owned by the state, and who will compete with other oil & gas companies for the award of petroleum contracts.

1.2.2 Balancing Host Government and Investor Objectives

A successful petroleum regime is one which achieves the optimal development of the state's hydrocarbon resources. In order to achieve this goal, the petroleum regime must strike the right balance between the interests of the state and the interests of investors, if private investment is permitted in the state. What makes this particularly difficult is that exploration and development of hydrocarbons from a contract area will continue for a period of 25 years or more, during which petroleum prices and costs are bound to change, and attitudes of the state and investors will also change.

It is the *responsibility of the state* to design its petroleum regime to suit its needs and, if private investment is to be welcomed, the needs of investors. States create their constitution, laws, regulations and contracts, not investors. Therefore, it is useful to examine the usual needs of the state and investors in the design of a petroleum regime. First the investor issues will be described, and then the issues for the state will be reviewed.

Investor Interests. Oil and gas companies decide whether to invest in a state based on their assessment of three questions:

- Is the geology attractive?
- Do the fiscal terms make exploration and production profitable?
- Is the petroleum regime attractive?

As a proven petroleum state, Mexico clearly passes the first test. The last two tests are determined by how the state designs its fiscal terms (royalty, taxes and other payments to the state) and the details of the petroleum law, regulations and contract. These are within the state's control: the state defines the fiscal terms and other features of the petroleum regime.

For investors, the upstream fiscal terms need to be designed in a way that permits it to earn an adequate return on risks and costs that it assumes in exploring for oil and gas. The principal factors that investors consider in evaluating the fiscal terms are the relative competitiveness of the fiscal terms to those in competing jurisdictions with similar petroleum opportunities, and whether the fiscal terms create attractive development opportunities across a range of petroleum prices and costs.

For investors who find the geology and fiscal terms adequately attractive to justify investment, they will focus on three key attributes of the petroleum regime: the *right to monetize*, *stability* and *enforceability*.

- *The Right to Monetize*. The 'right to monetize' refers to the need for an investor who has made a discovery of oil to be able to take those further steps necessary to convert that discovery into money. There are many steps along the path from discovery to money. Following discovery, the hydrocarbon resources need to be evaluated, declared commercial, developed, produced, gathered, processed, transported, often exported, and marketed. The petroleum regime needs to be designed in a way that investors can see that the regulatory terms and structures are in place to allow the monetization of the resource, and that any government approvals required along that path can be obtained with an adequate degree of certainty.

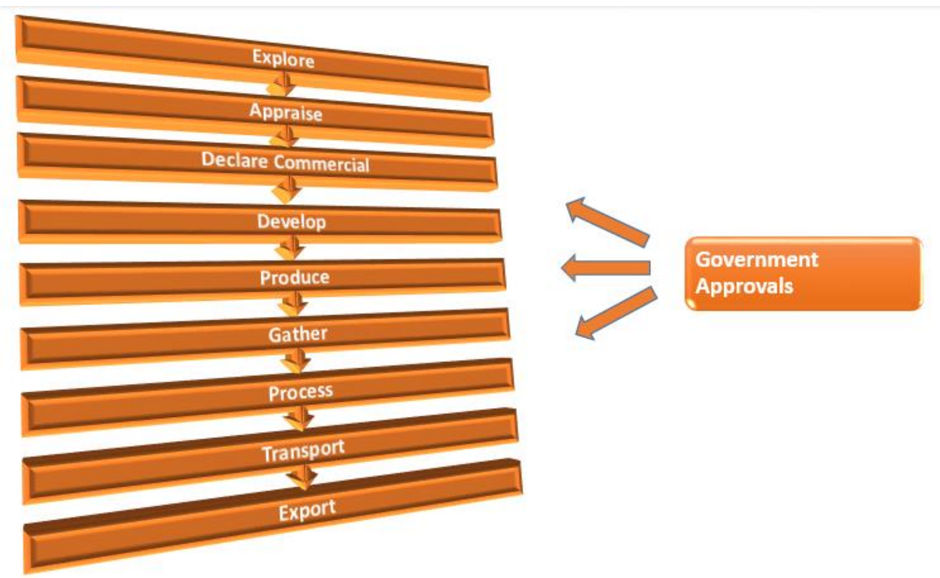


Figure 2- The Path to Monetize a Hydrocarbon Discovery

Private investment in hydrocarbon exploration and development has not occurred in Mexico for decades, so the path to monetization will be a new one for investors other than Pemex. A number of the comments on the Model PSC relate to eliminating gaps and clarifying procedures to ensure that the right to monetize exists in Mexico.

- *Stability*. An investor commits to explore for oil and gas and if exploration is successful, to extract hydrocarbons for a long term, often over twenty years. The decision to invest was made based on a pre-investment assessment of the suitability of the fiscal terms and the petroleum regime; consequently, the investor does not want to see changes to those terms after it has made its investment. In other words, oil and gas companies are seeking *stability* in the places where they invest. Many states provide stability assurances, whether through bilateral or multilateral treaties, investment legislation or contractual provisions. However, a number of other states do not provide such assurances.

We note that the Model PSC does not include a contractual stability guarantee; whether Mexico has bilateral or multilateral treaties with other states, and the status of Mexican investment legislation is beyond the scope of this review.

- *Enforceability*. Sometimes disputes arise between states and investors. The global experience has been that when such disputes involve foreign investors, and the dispute resolution mechanism involves local courts of the host state, there is a 'home field advantage' that often results in foreign investors being unable to enforce their rights against the state. Consequently, it is frequent international practice in extractive industries that state-investor disputes will be resolved by international arbitration.

  We note that the Model PSC contemplates that administrative termination matters under clause 23.1 will be handled by Mexican courts. This is a requirement of the Hydrocarbon Law, so there is no scope for the Model PSC to alter this. The Model PSC provides that all other types of disputes will be resolved by arbitration, and in this respect it is consistent with the international practice preferred by foreign investors and adopted in many states.

With the enactment of the Hydrocarbon Law and the commencement of bid rounds, Mexico will be seeking to attract international oil companies to invest in Mexico's petroleum industry. A number of the comments in this report are suggestions to the government about how to create a petroleum regime that is ***competitive*** with the opportunities that oil companies have in other jurisdictions, and ***consistent*** with international standards and practices.

***State Interests*.** A good petroleum regime will address a number of issues that matter to the state. The key interests of the state are:

- fair share of hydrocarbon revenue
- prompt exploration and development
- reasonable controls over petroleum activity
- environmental protection
- local supply of goods and services
- local employment
- training for local personnel

In this report, the focus is placed on the first three features: fair share of hydrocarbon revenue, prompt exploration and development and control over hydrocarbon activity. The Hydrocarbon

Law and other Mexican legislation addresses the other factors, and these seem to be reflected in the Model PSC.

- *Fair Share of Hydrocarbon Revenue*. Chapter 3 of this report deals with this issue in more detail, but the relevant principles are that the state should receive an appropriate share of the revenues resulting from oil and gas production. One measure of the state share is described as the 'government take' or government share of the divisible income from petroleum activities. The global experience is that this share varies from as low as 19% to a high of 99%, depending on the country and the type of opportunity. A fair share for any government is a level that is competitive, taking into account the character and attractiveness of its petroleum resources. Since the attractiveness of the resources if very different around the world, the government take is very different. Also different conditions within a jurisdiction justifies different levels of government take for such different resources, for example for conventional and unconventional resources, or for oil and for gas. Apart from the level of government take, also the structure of the government take is important. In general we recommend that the government take is structured in such a way that the government take is higher for larger fields or more productive unconventional projects and under higher prices. The government take could also be higher for economic projects compared to marginal projects in terms of costs. If the state wants to fully develop its resources it is important that the fiscal system stimulates reasonably the maximum recovery of the oil and gas from the reservoirs. What is furthermore important is that the design of the fiscal system encourages efficiency in operations and avoids "gold plating". Although price progressivity is recommended, the increase in government take should not be so strong as to reduce the interest in obtaining fair market prices for the petroleum. The structure of the government take is furthermore impacted by government policies. An important issue is also the timing of the government take. For emerging economies with a relatively strong economy we typically recommend that governments avoid taking too large a share of the government take early in the cash flow and concentrate more on taking a larger share after payout of the investment. For nations that are eager to increase production it is also important that the government take is structured in such a manner that it makes a wide variety of petroleum resources economic and that the system encourages exploration.

- *Prompt Exploration and Development*. A state that has awarded petroleum rights does not want the investor to 'sit' on the contract area; exploration and development should occur promptly. This is typically addressed in the minimum work obligation and relinquishment provisions of the petroleum contract. It is also important to engage in a systematic development of the fields with a view of applying secondary and tertiary recovery methods, where this is economic.

- *Reasonable Controls over Petroleum Activity*. The activities of an oil and gas company should be subject to the review and control of the state, particularly where those activities have the potential to impact the environment and local communities. Also, the state has a legitimate interest in preserving the state's resources to ensure that they are developed prudently and not wasted.

2. CONTRACT OPTIONS AND PETROLEUM OPERATIONS

2.1 Contract Options

The main options for an exploration and production contract with CNH are:

(1) License Contracts
(2) Production Sharing Contract, without cost limit pursuant to Article 13 of the LISH.
(3) Production Sharing Contract, with cost limit.

From a legal perspective there is a considerable difference between a License Contract and a Concession. A License Contract is a contract signed by two parties who undertake mutual commitments. A Concession is a unilateral grant by Government with usually no other obligation on the part of Government than to follow the laws.

Nevertheless, the differences between License Contracts and Concessions are not completely understood at this time in the Mexican society. Concessions are forbidden by the Constitution. Due to possible confusion about License Contract versus Concessions, which could cause legal interference in the Contracts, the decision of the Government of Mexico to introduce a Production Sharing Contract ("PSC") is a decision that we support.

<u>PSC with or without cost recovery</u>

The Ley de Ingresos Sobre Hidrocarburos ("LISH") permits two types of PSCs:

(1) A PSC with cost recovery and cost limit, and
(2) A PSC without cost recovery, under Article 13 of the LISH.

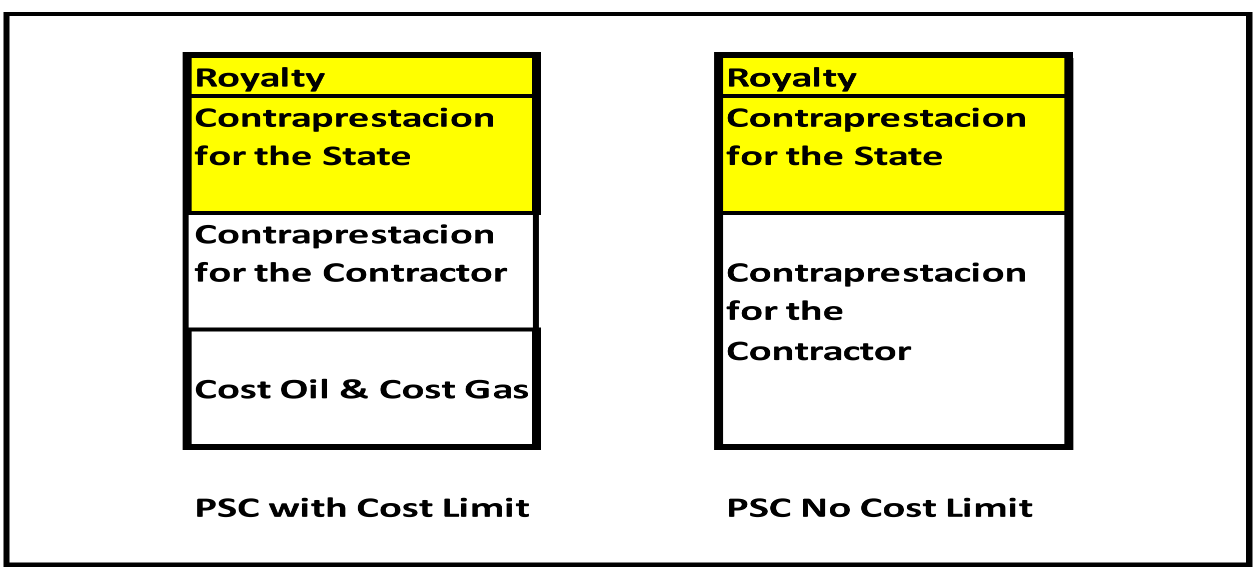


Figure 3- PSCs with and without Cost Recovery

In principle there is no mathematical difference between a PSC with or without cost recovery. The same amount of Contraprestacion for the State and the same amount of cash for the Contractor could result from both contracts.

However, the two options react quite differently economically.

The Government opted for a PSC with cost recovery and a cost limit. Nevertheless are significant advantages to a PSC without cost control. The main difference is that a PSC with cost recovery requires control, verification and auditing of costs.

The proposed PSC contemplates the following administrative steps:

- CNH will approve the annual budgets and any modifications to such budgets,
- Cost oil/gas calculations for cost recovery must be approved each month, and.
- At least one audit per year would be required.

International experience is that cost recovery approval often results in conflict situations with the regulator or NOC. It is not unusual that only 80% of the costs are approved for recovery.

However, more concerning is that the PSC with cost recovery requires a very extensive and well prepared administration with multi-disciplinary teams. In order to approve the budget for a well for example, technical knowledge is required about the drilling and geological characteristics of the well. Wells to the same depth could have very different costs for a variety of technical reasons. Approval of budgets, monthly payments of cost oil and cost gas and auditing of petroleum costs is therefore not just a matter of accounting, it is also a matter of having the technical knowledge of whether certain costs are reasonable. This requires multi-disciplinary teams to do such cost control if the cost control is to be effective and protecting the interests of Mexico.

Setting up such teams is a major task. It might take several years before such organizations are properly operational. Having contracts without cost control first would have permitted the Government to phase in the new administration.

<u>Recommendation # 1:</u> It is for this reason that we continue to recommend a PSC without cost recovery. We are also ready to recommend competitive fiscal terms for such a contract. Such terms would be easy to administer and would capture extra-ordinary profits.

It should be noted that even with a PSC without cost recovery, very significant administrative issues need to be dealt with by the administration. As will be discussed later in this report, there will remain considerable problems with measurement of production, measurement point location, determination of contract prices, etc. It is very desirable that the petroleum administration would deal with these issues first on the basis of a PSC without cost recovery before adopting a more complex PSC with cost recovery.

However, if the Government decides to maintain a PSC with cost recovery, the main focus should be to create a contract that is as easy as possible to administer.

A very important concern is that the terms and conditions that are included in the Model PSC are difficult to administer.

The unique nature of the Mexican PSC.

What is important to realize is that the Mexican PSC has to be rather different from typical international PSCs.

It is the first time in the world that a PSC would be introduced for a highly mature petroleum industry based on a complex existing infrastructure of pipelines and processing units that need rebuilding and expansion in many cases.

Also the Hydrocarbon Law provides for relinquishment of deep formations at the end of the exploration phase. This is essential if Mexico wants to fully develop the deeper formations. However, such provisions do not exist in any PSC in the world at this time.

The reality is therefore that the Mexican PSC will have to be different from traditional PSCs.

2.2 Petroleum Operations and requirement for a profitable midstream framework

Contradictory provisions on petroleum operations

The Bid Process and Model PSC are unclear as to the type of petroleum operations that can be carried out by the Contractor and how such operations are being dealt with.

Article 22.1(b) of the Bid Procedure indicates that only companies that are **exclusively** involved in exploration and extraction of hydrocarbons can enter into a PSC contract. This wording is copied from Article 31(II) of the LISH.

However, Clause 15.5 of the Model PSC contemplates that the Contractors may necessarily have to build **Commercialization Installations** downstream of the Measurement Point in order to sell the crude oil, condensates and natural gas.

The definition of Commercialization Installations includes transportation, compression and storage, but does not include gas processing. So, it is not clear whether the Contractor can engage in gas processing operations. Yet, in many cases, it is not possible to sell **raw** natural gas. Gas can usually only be sold once it is processed in a gas processing plant and has the specifications that permit pipeline transportation to final consumers. This means that unless the Contractor has the right to build gas processing plants it may not be possible to produce and sell gas. Since much of the gas may be associated gas, this in turn could limit the ability of the Contractor to produce oil.

<u>Recommendation # 2:</u> In order to resolve this matter, it is recommended to amplify the definition of Commercialization Installations to include gas processing. At the same time the definition could be further amplified by also permitting a range of other midstream operations, such as upgrading of heavy oils.

Assuming the definition of Commercial Installations is amplified, the Contractor would be permitted to engage in a wide range of midstream activities. Such Commercialization Installations may be more expensive than the upstream operations. So it seems that the companies may have to engage in extensive midstream operations despite being prevented from doing this under Article 31(II) of the LISH.

The contradictions between the Model PSC and the LISH create a material risk for investors.

<u>Recommendation # 3:</u> It can therefore be recommended to provide in 22.1(b) of the Bid Procedure an explanation that the construction and operations of Commercial Installations *(as amended pursuant to the above suggestions)*, for the purpose of being able to sell the production, shall be deemed to be functions of company that engages exclusively in exploration and production.

However, assuming that the companies constituting the Contractor are allowed to engage in the construction and operation of Commercialization Installations, the Model PSC does not provide a link to the regulatory framework.

Transportation of oil and gas outside the contract area is regulated under Article 48 of the Hydrocarbon Law by the CRE, while gas processing is regulated by SENER. Permits are required for the construction and operation of such facilities.

Yet there is no guarantee under the Model PSC that the Contractor will be issued the necessary permits where it complies with the provisions of the Hydrocarbon Law. This again constitutes a risk. For example, the most economic options for the Contractor may be to construct a pipeline to the shore from its shallow water block in order to separate, treat and process the hydrocarbons produced in the contract area onshore (similar to the setup as is currently being used for the Arenque block).

<u>Recommendation # 4:</u> It can therefore be recommended that the Model PSC provides for the Contractor to receive the necessary permits for midstream operations, where the Contractor complies with the various regulatory provisions.

<u>Recovery of midstream costs</u>

Article 15.5 of the Model PSC clarifies that the costs for Commercial Installations are not cost recoverable. This is logical since these costs are downstream of the measurement point and such costs are typically not recoverable.

Nevertheless, the Model PSC does not explain how the Contractor would make economic investments the midstream investments. This is a very serious omission in the Model PSC.

From some of the wording in the Model PSC it seems that the Government contemplates that the Contractor would only be able to get its capital and operations costs back and that no profit on these investments is contemplated.

For example, Article 15.5 states that the Contractor could charge the "Comercializador" **reasonable costs** for such installations and has to design the installations to accommodate the production of the Comercializador.

Section 1.10 of Annex 3 also mentions that the Contract Prices will be adjusted for the **necessary costs** between the Measurement Point and the sales point. Also it confirms that the price at the Measurement Point should always reflect market conditions. Paragraphs (a) and (b) of this Section 1.10 seem to exclude a profit margin for midstream operations.

There is no reference in the Model PSC or Annex 3 that the Contractor would be allowed a profit margin on the midstream installations.

This would greatly complicate the construction of the required midstream installations. It would also make it impossible to involve an independent midstream company or PEMEX in the construction and operations of such facilities.

The international practice is that the midstream operations of the construction and operation of pipelines, gas processing plants and other midstream facilities should be profitable operations by themselves. In fact, upgrading of the antiquated midstream infrastructure in Mexico should be a top priority in order to facilitate a rapid expansion of production.

Recommendation # 5: It can therefore be recommended that Bid Procedure and the Model PSC are amended:

(1) to refer in Article 15.5 of the Model PSC and Section 1.10 to the "tariff" for the midstream operations of transportation, storage, treatment and processing, rather than to the costs. A toll or tariff is understood to include a reasonable profit margin for the operations. The 'Comercializador" would therefore pay the "tariff" to the Contractor for the use of the midstream facilities. Also such tariff would be deducted from the sales price in order to arrive at the market value at the measurement point. Section 1.10 should include processing in additional to treatment in order to take into account gas processing operations, and

(2)To establish a procedure in the Model PSC how such tariffs would be determined.

3. FISCAL TERMS

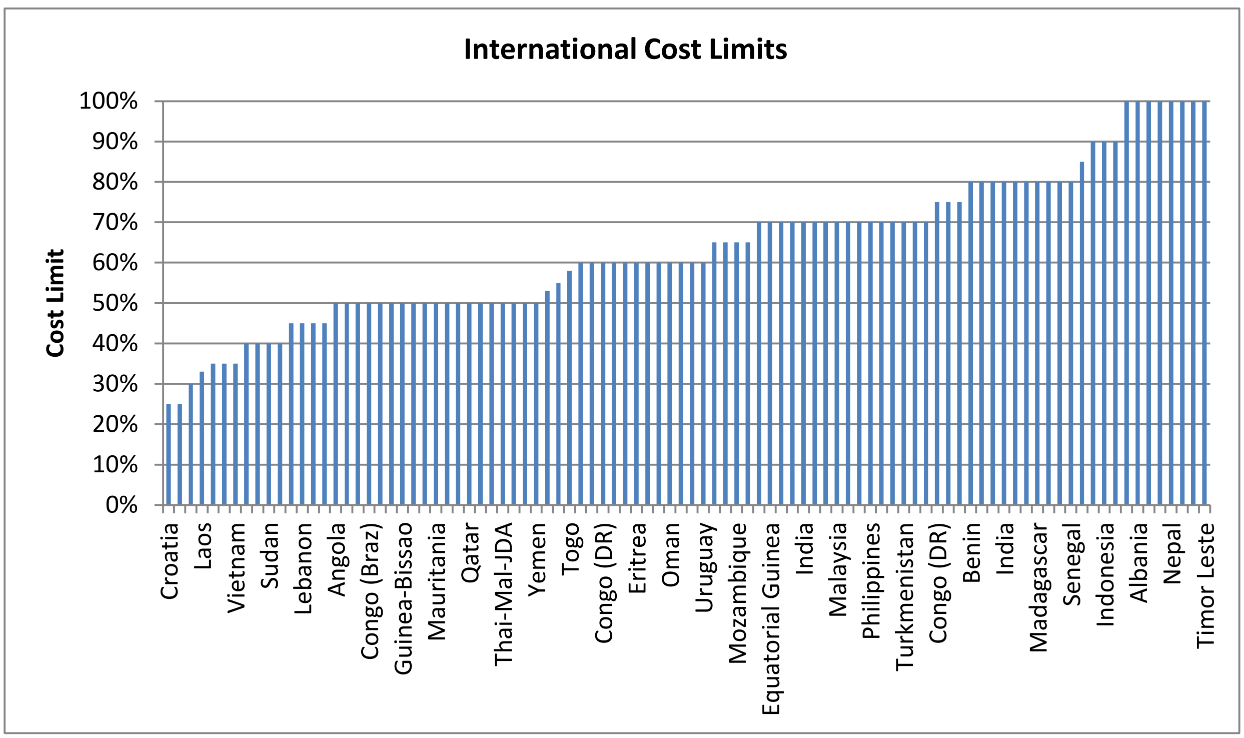
3.1 The rentals, royalties and corporate income tax.

The rental (Cuota Contractual), royalty and corporate income tax provisions of the LISH provide a viable starting point for fiscal terms for all of the resources of Mexico.

3.2 The Contraprestacion to the Contractor for Cost Recovery.

3.2.1 Cost Recovery Framework

The following chart illustrates the cost limits of all PSCs countries in the Van Meurs Petrocash data base. It can be seen how a 60% cost limit reasonably matches the international average at this point in time. This is therefore an acceptable competitive level.



It seems that there is no depreciation of capital costs required for the recovery of the costs under the Model PSC. This means for cost recovery purposes all costs are expensed. This is also a widely used international practice.

The basic cost recovery framework is therefore sound and in accordance with international practices.

3.2.2 Budget Process and the Accounting Procedure

In general the Accounting Procedure is consistent with international standards. However, a number of suggestions can be made.

Clause 11 in the Model PSC is a rather standard clause in PSCs. It is common that the annual budget is approved as part of the annual work program and budget approval procedure under a PSC.

Nevertheless, this Clause under the Model PSC does not serve an effective purpose in the context of the Mexican administrative setup. In typical PSCs the parties approving the budget are part of the Management Committee and are the same parties that will approve the recoverable costs. In Mexico the approval process is carried out by different entities. CNH approves the work program and budget and SHCP is in part responsible for approving the recoverable costs.

Clause 11.7 states that the budget approval procedure by CNH is solely for the purpose of authorizing the Contractor to incur the relevant expenditures. However, SHCP will decide whether these costs are recoverable or not, regardless of whether the costs have been approved by CNH.

Therefore CNH does not play any role in the cost recovery approval process.

Given this situation, Clause 11 is an excessive and unnecessary bureaucratic requirement.

CNH will have a challenging task to set up its new organization to administer petroleum contracts. Adding tasks to the CNH administration that do not serve a useful purpose is therefore counter-productive.

Furthermore, section 2.3(c) of the Accounting Procedure denies the recovery of costs in excess of 5% of the approved budgets or 10% for each item in the budget. This would require the Contractor to go back repetitively to CNH to get approvals for amendments in the budget. This is a further unnecessary step.

Recommendation # 6: It can therefore be recommended to delete Clause 11 from the Model PSC and section 2.3(c) from the Accounting Procedure.

Section 2.3 (cc) limits the overhead to 0.25% of the budget. This is by any international standard an excessively restrictive clause and will prohibit the Contractor to recover costs that a fair and necessary for the operations in Mexico.

Contractors will have overhead costs well in excess of these levels, in particular in the early contact years. It is rather common in PSCs that overhead costs incurred within the host country are fully recoverable. Overhead restrictions therefore typically only apply to overhead charges by the parent company. However, even these parent company overhead costs are typically based on a sliding scale based on the size of the operations. This procedure encourages companies to bring headquarter activities to Mexico. This is precisely what the Mexican objective should be, because these are the high quality jobs.

<u>Recommendation # 7:</u> It can therefore be recommended to make section 2.3(cc) of the Accounting Procedure applicable only to overhead costs of the parent company and establish a reasonable sliding scale based on the recovered costs.

An important omission in the Accounting Procedure is that the procedure does not deal with the provision of services by the Contractor to other Contractors. Due to the integrated and mature nature of the Mexican petroleum industry, it is very common that certain shallow water Contractors will separate and treat their production on platforms of another contractor. It is also likely that several Contractors may join in a single pipeline or processing plant. This is in particular the case if small and marginal fields would be discovered. In other words certain Contractors may deliver extraction and midstream services to other Contractors. Under typical PSCs the income of such services is typically credited against the cost recovery.

<u>Recommendation # 8:</u> It is recommended that the Accounting Procedure deals with services among Contractors and that income is credited against cost recovery.

3.3 Adjustment Mechanism Options – the IRR sliding scale.

The LISH requires that a petroleum contract contains an adjustment mechanism in order to effectively capture the extra-ordinary profits. This is consistent with prudent international practice and is essential if Mexico is to fully benefit from its resource development.

The very significant possible variations in technical conditions in the 14 blocks require a sensitive Adjustment Factor.

Basically three mechanisms are available for the Adjustment Factor:

(a) An IRR based system,
(b) An R-factor, or
(c) A progressive system based on technical parameters, or
(d) A combination of these factors.

Annex 3 of the proposed Model PSC relies solely on an IRR system for the Adjustment Mechanism.

3.3.1 <u>The IRR Concept</u>

<u>The IRR concept</u>

The concept of developing a fiscal system based solely on the rate of return is completely contrary to current international experience, since such contracts invariable result in massive gold plating.

"Gold plating" means that an incremental investment would result in a lowering of the Contraprestacion with an amount that is higher than the amount of the incremental investment. For example, an incremental investment of $100 million in a set of further development wells would result in a reduction of $200 million in Contraprestacion. This would make the investment in the wells profitable regardless of the merits of this investment. In other words, it is an invitation to squander money.

The effects of gold plating are more severe if the benchmark rates are higher than the hurdle rate and the profit differential is very large. Unfortunately, this is precisely what is proposed in the Model PSC. The benchmark rates of 15% and 30% are clearly over industry hurdle rates. The reduction of the profit share by 80% as proposed for the difference between SC1 and SC2, is extreme by international standards.

The proposed terms would therefore result in more severe gold plating than in most countries with such problems.

The gold plating will result in most producers proposing over-sized development plans (for example proposing 100 wells where the field can be developed with 50 wells) in order to bring the rate of return down. This in turn will place difficult burdens on CNH to adjust over-sized development plans.

The system will also lead contractors to propose excessive costs and will make proper cost control extremely difficult or impossible.

Contract based IRR system not effective.

Contrary to international practice for similar IRR systems, the IRR system in the Model PSC is proposed for the total of the Contract operations, not for the individual fields or projects in the Contract. This means that the IRR will be a blended IRR for all projects and field in the Contract Area. Given the mature nature of the Mexican petroleum industry, it is possible that various different operations may be carried out in the same contract area. For example, development of shallow gas may take place at the same time as the development of a deep oil field. In fact, work programs will require Contractors to fully develop the Contract Areas. This means that marginal shallow gas fields with a low IRR could be combined with a highly profitable deep oil field with a high IRR, thereby preventing Mexico to gain a fair share of the windfall profits on the deep oil field. Also, completely unjustifiably, two similar deep oil fields in adjacent contract areas would result in very different Contraprestaciones, depending on which other activities such deep fields would be combined with.

The solution would be to do the IRR separately for each project or field in the Contract Area. However, the cost control problems of such a scheme would be impossible, since it would be very easy for Contractors to cross-assign costs among projects and fields.

IRR not a viable profitability index

However, more importantly, the IRR would not be a viable profitability index to determine whether windfall profits are taking place under Mexican mature conditions. For example, a deep reservoir of one Contractor may tie in to the production facilities of a shallow reservoir Contractor. The deep Contractor would pay treatment fees to the shallow contractor for the use of the facilities. This means that the deep contractor has barely a negative cash flow and would instantly have to pay the SC2 values, making the development of such deep reservoirs uneconomic based on NPV per barrel criteria. Similar problems would occur in all cases where treatment or processing is done in other Contract areas or by PEMEX.

If the IRR system would be applied to other contract areas, a unique problem would be that several contracts may have already producing fields, such as the existing risk service contracts that are to be converted, which means these contracts would pay instantly the SC2 values. This in turn would make the conversion uneconomic.

Un-risked Production Based IRR not viable

The proposed rate of return is only the **un-risked** rate of return for the exploration and extraction operations. The proposed rate of return therefore does not take into account the dry hole risk.

For many smaller fields the risked rate of return would be well below the un-risked rate of return and therefore the proposed rate of return is not a reasonable reflection of overall profitability. As a result this system would make exploration for smaller fields uneconomic. The problem is that these are the most likely type of fields remaining in the onshore and shallow water.

A further very serious problem is that the proposed rate of return does not take into consideration the considerable downstream commitments that many operators will have to undertake in order to store, transport, treat and process their oil and gas production as discussed earlier. In some cases the midstream investment requirements may be more than the upstream requirements. Therefore the un-risked upstream IRR is not at all a reasonable reflection of the profitability of the operations of the Contractor.

In other words an IRR calculated pursuant to clause 7.1 as 20% may actually be only 8% on a fully risked and blended basis.

3.3.2 Lack of Volume Progressivity

Lack of Volume Progressivity

A very serious shortcoming of the Annex is a complete lack of volume progressivity. The Cantarell experience should be sufficient to demonstrate that most of the resource wealth in a nation is present in a few large fields. If un-expectedly a billion barrel discovery is made in any of the new contract areas, the lack of volume progressivity will mean that most of the extra-ordinary profits that should be captured by Mexico will fall in the hands of the Contractor based on the provisions of the current Annex of the Model PSC. The vast majority of the PSCs in the world have sliding scales based on daily production which increase the share to government of the Contraprestacion in case of very large discoveries. The absence of such provisions could be extremely detrimental to Mexico.

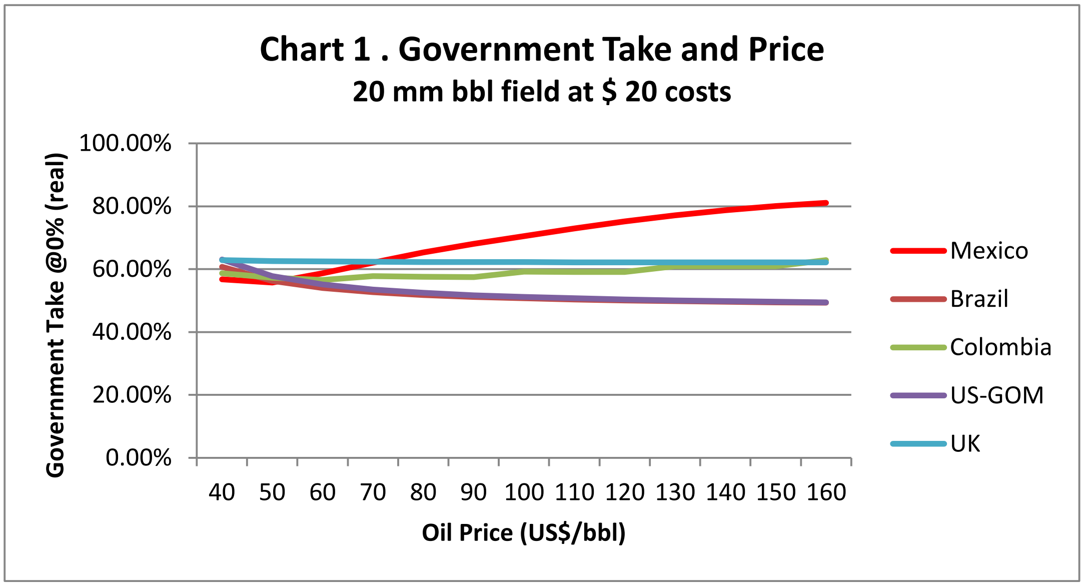
3.3.3 Economic Analysis of the Proposed IRR System

An analysis was done on the fiscal terms contained in the Annex 3 of the Model PSC, assuming an initial Government Contraprestacion of 20% of the Profits. This means the Contractor would have a profit share of 80% below 15% IRR before tax and 16% above 30% IRR. The analysis was done for standard shallow water fields costing $20/bbl capital and operating costs. Field sizes in the range of 20 to 1000 million barrels were evaluated.

The proposed terms were compared with shallow water terms for Brazil, Colombia, the US Gulf of Mexico and the UK. These are jurisdictions whose petroleum regimes will be competing for private investment capital that Mexico will want to attract.

Government Take Analysis. The undiscounted government take ("GT0") in real terms was evaluated for changes in price, volume and costs. The results are provided in Charts 1 through 3.

With respect to price, the Mexican GT0 becomes higher than the competing countries over $80 per barrel. The difference continues to grow for higher prices. At $140/bbl the government take reaches 80%, well above the competing jurisdictions.



The Mexican GT0 at a price of $80/bbl and $20/bbl costs creates conditions for small fields that are unattractive. As can be seen in Chart 2, for a 20 million barrel field, the GT0 would be highest in Mexico. The proposed Model PSC does not increase the government take as production volumes increase, as most other PSCs do. The Mexican government take does not change with higher volumes of production. Therefore, GT0 is comparable with other systems for large fields.

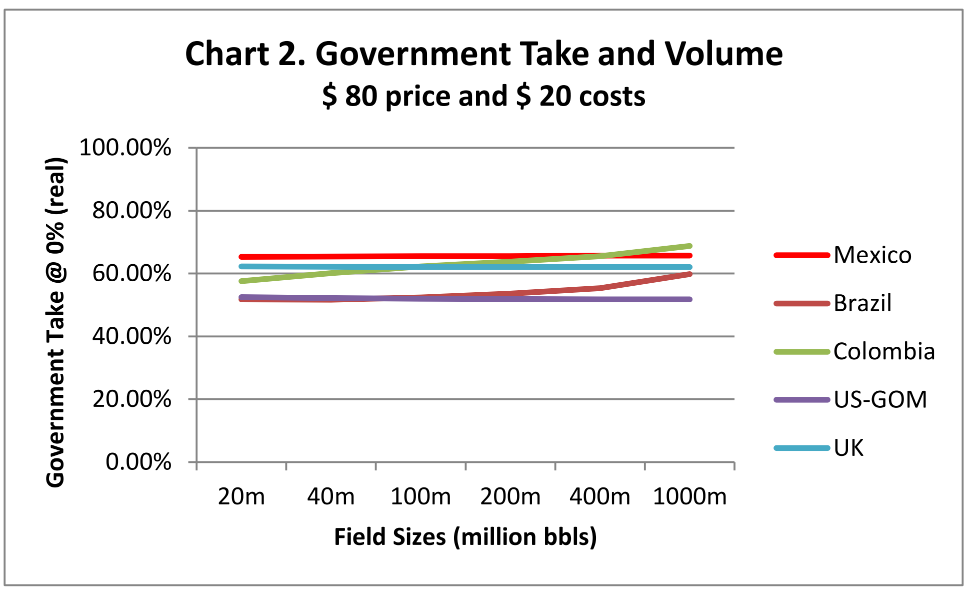
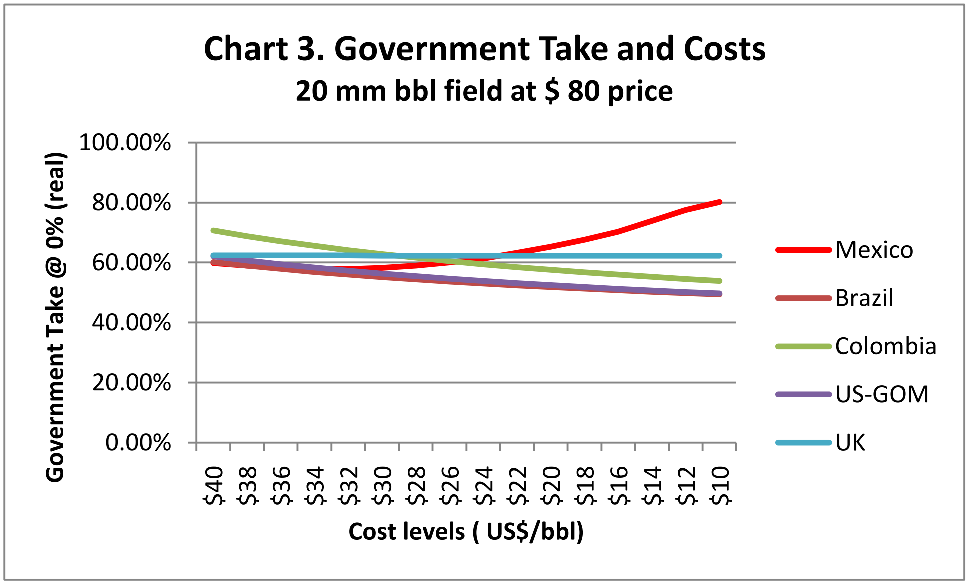


Chart 3 illustrates how the government take becomes considerable in excess of competing systems at $20/bbl costs or less assuming a price of $80/bbl and reaches a high of 80% at cost levels of $10/bbl.



Un-risked Profitability Analysis. Charts 4,5 and 6 show the un-risked profitability analysis. As can be expected, the IRR is relatively favorable up to a price of about $70 per barrel but becomes less attractive over $90/bbl.

A ratio that is often used by to measure the profitability is the Discounted Profit to Investment Ratio at 10% discount rate ("DPIR@10%"). This ratio is unattractive compared to the other systems over a price of $70 per barrel. The same behavior is for the Net Present Value discounted at 10% per barrel equivalent ("NPV@10% per boe").

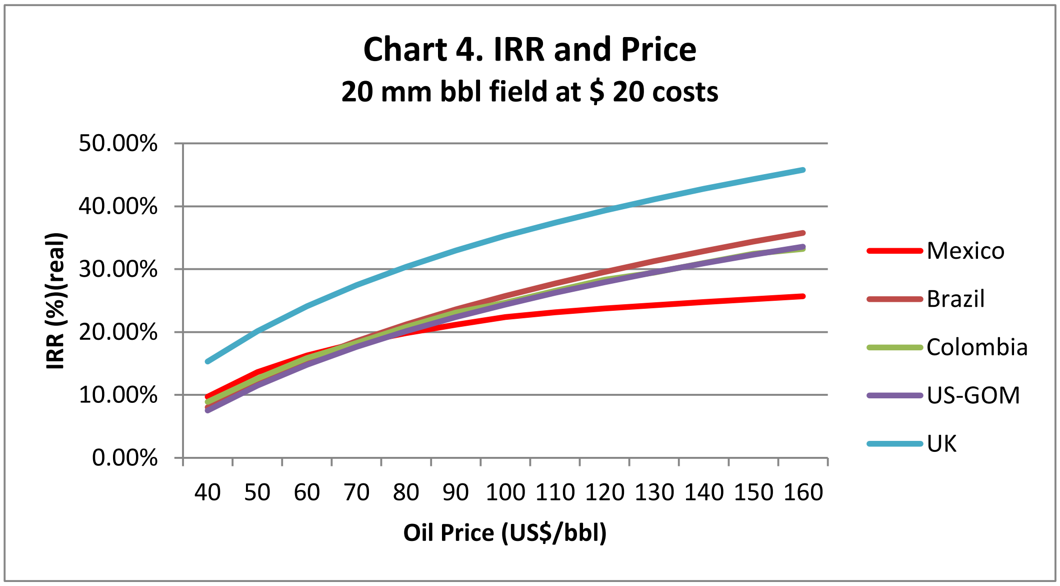


Chart 4. IRR and Price
20 mm bbl field at $ 20 costs
IRR (%)(real)
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
40 50 60 70 80 90 100 110 120 130 140 150 160
Oil Price (US$/bbl)
Mexico
Brazil
Colombia
US-GOM
UK

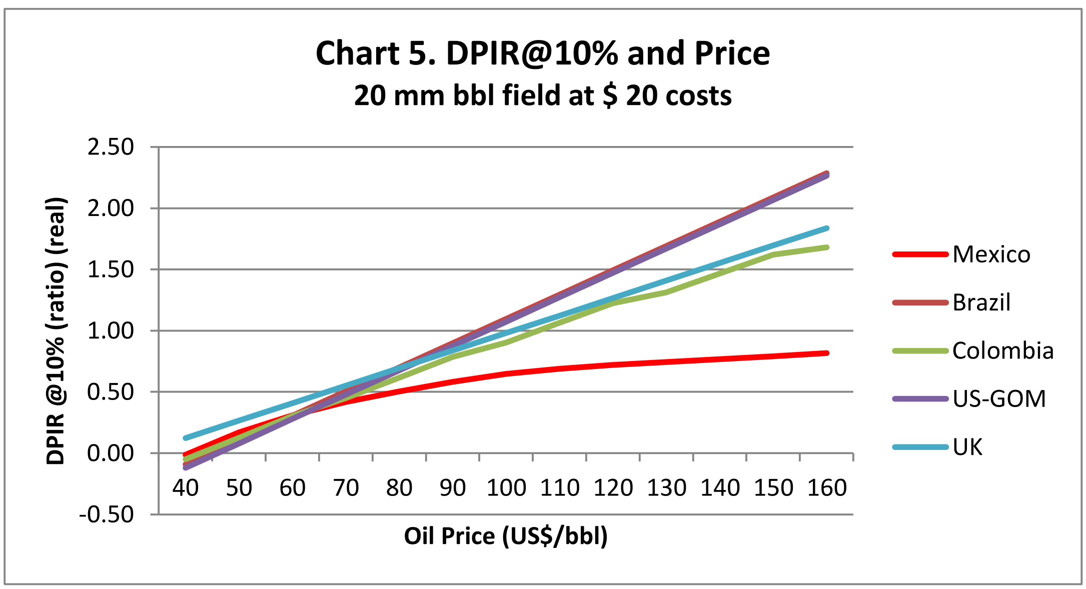
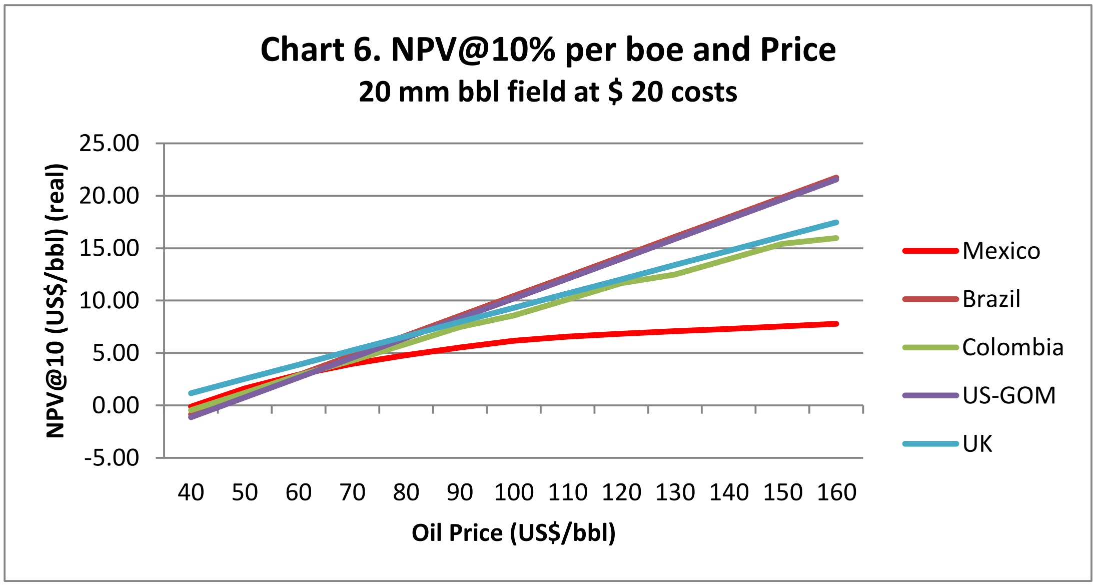


Chart 5. DPIR@10% and Price
20 mm bbl field at $ 20 costs
DPIR @10% (ratio) (real)
2.50
2.00
1.50
1.00
0.50
0.00
-0.50
40 50 60 70 80 90 100 110 120 130 140 150 160
Oil Price (US$/bbl)
Mexico
Brazil
Colombia
US-GOM
UK



Risked Profitability Analysis.

The Expected Monetary Value @ 10% ("EMV@10%) is calculated for an exploration project assuming a probability of a dry hole of 80% and a probability of discovering a 20 million barrel field of 20%. The EMV@10% is the weighted average of the dry hole cash flow and the discovery cash flow.

It can be seen in Chart 7 how the IRR based concept, which results in progressively lower Contraprestacion levels under higher prices, has the disastrous result of making exploration for small fields of 20 million barrels uneconomic for any price level up to $160 per barrel.

Yet, it is precisely the exploration for smaller fields in the mature shallow waters of Mexico that would be the main objective of Round 1.

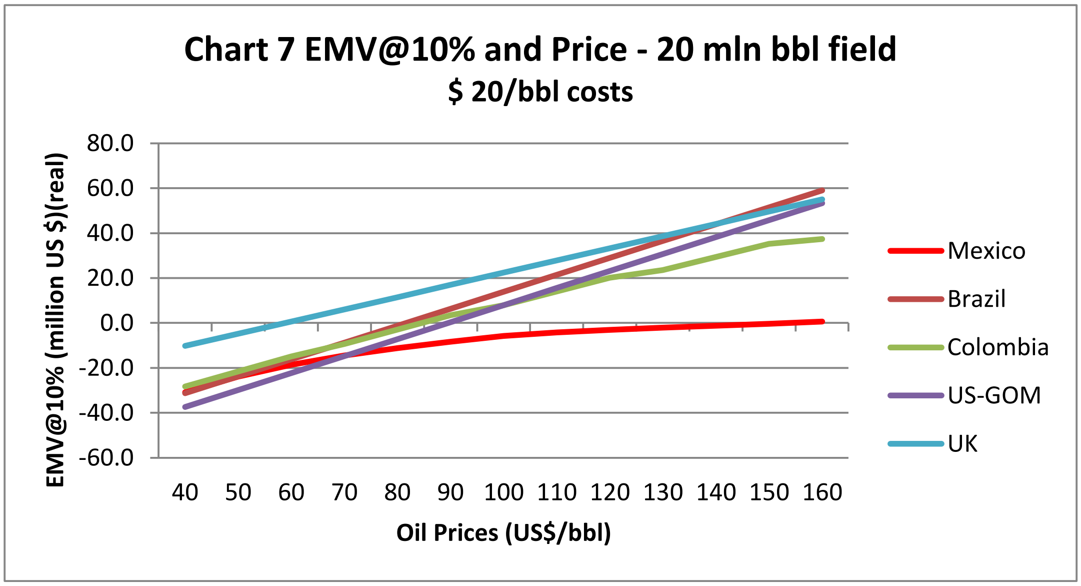
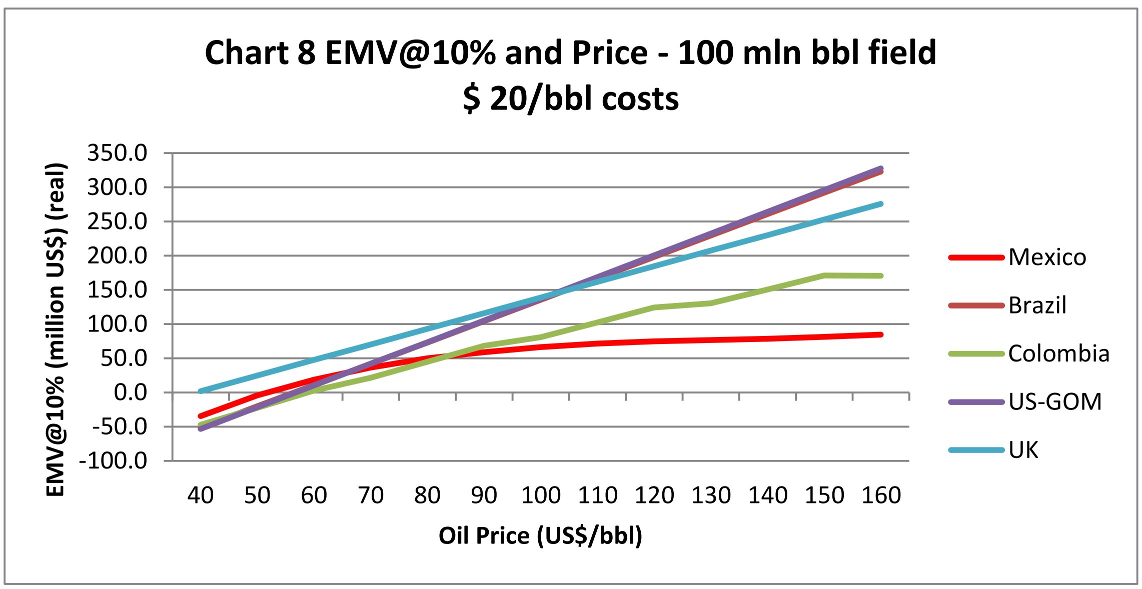
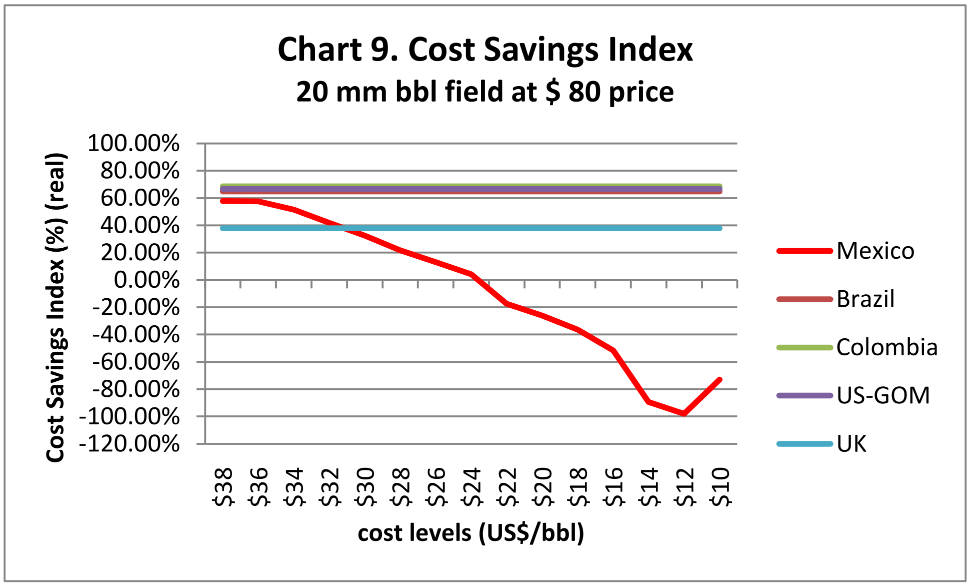


Chart 8 illustrates how even for large fields of 100 million barrels, exploration would be less attractive than competing jurisdictions for price levels of $90 per barrel or higher.



3.3.4 Gold Plating Analysis of the Proposed IRR System

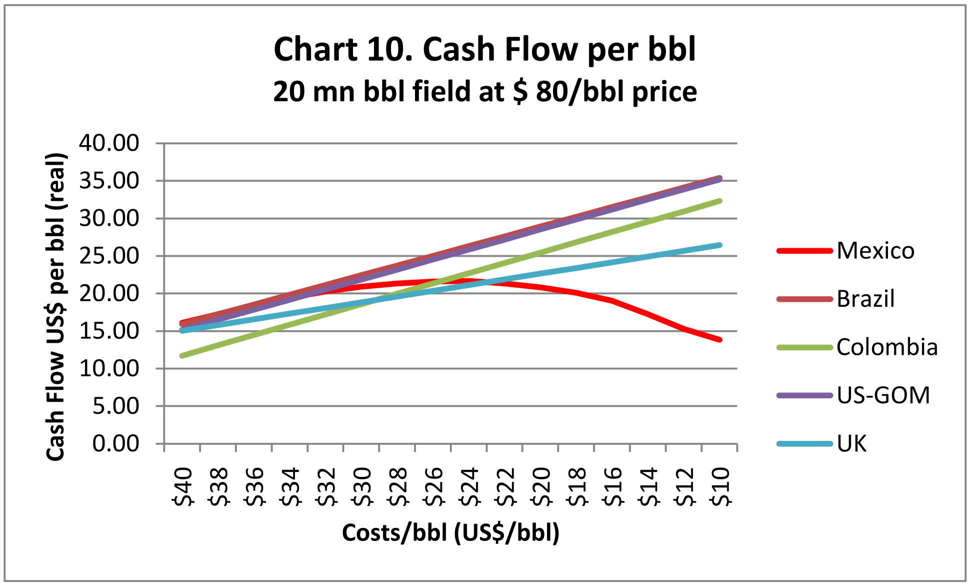
Cost Savings Index analysis. Chart 9 provides the cost savings index. The cost savings index measures how much an investor retains when saving a dollar of cost. In other words, if the cost savings index is 60%, the investor retains $0.60 when it reduces cost by a dollar. If the cost savings index is below 20% the system becomes very difficult to administer from a cost control concept, since the contractor has little incentive to minimize costs. A negative cost savings index indicates gold plating, which means that the investor has no incentive to save and in fact has an incentive to increase costs. The chart shows how at a cost level of $28/bbl (at a price of $80/bbl) or less the system becomes difficult to administer. At a cost level of $24/bbl or less, the system results in severe gold plating.



Cash Flow per barrel Analysis. Chart 9 resulted in a situation where the cost savings index becomes negative below a costs of $24 per barrel. The importance of this matter is further illustrated in Chart 10. Chart 10 shows the Undiscounted Cash Flow per barrel. Under normal systems the Cash Flow per barrel increases if the company is more efficient. This can be seen for the fiscal systems of Brazil, Colombia, the US Gulf of Mexico and the UK. This is actually the normal fiscal system in most countries in the world.

The Mexican system shows the bizarre result that the cash flow to the company becomes less when costs are lower than $24 per barrel. This means that the company is actually “punished” for being efficient and for achieving low costs. In the entire range of $30 to $24 per barrel costs the cash flow per barrel to the company remains more or less the same, so there is no incentive to be efficient from a cost point of view.

The reason for this result is that the Contraprestacion percentage to the Contractor diminishes very quickly under more profitable conditions.



3.3.5 Conclusion and recommendation on competitiveness of the fiscal terms

Conclusion. The proposed system:

- **Is attractive for investors relative to other fiscal systems under low prices (less than $60/bbl) and under high costs (more than $32/bbl),**
- **Is too tough for small fields (such as a 20 million barrel field in shallow water),**
- **Is not competitive over a price of $70/bbl (assuming $20/bbl costs) or for costs under $20/bbl (assuming a price of $80/bbl),**
- **Is uneconomic for exploring small fields at any price level, and**
- **Results in severe gold plating at costs of less than $24/bbl.**

Because of the very unfavorable terms under so-called "upside" conditions, and the unattractive exploration economics, the terms proposed in the Model PSC are not competitive for the shallow water opportunities offered in the first bid round.

The severe gold plating creates very difficult to impossible administrative cost control conditions for the Government. This in turn results in administrative risk for the Contractor. It also results in Mexico likely receiving a lesser return for their oil and gas resources than would be the case for a system with the same government take but without gold plating.

<u>Recommendation #9:</u> The Government of Mexico should make significant and material revisions to the fiscal provisions in the Model PSC. The best option would be to adopt a PSC without cost recovery, with an Adjustment Mechanism that uses technical factors to capture extra-ordinary profits. However, if the Government favors a cost recovery system,

the next best option is to create a fiscal system that combines modest IRR or R-factor based features with significant volume based and other technical factors in the Adjustment Mechanism. The resulting system should not feature gold plating under any economic condition and should be competitive with other countries.

We are prepared to suggest suitable terms for such a system.

4. CONTRACT TERM

4.1 Total Contract Term

Clause 3 of the Model PSC provides for a contract term of 25 years and two renewals of 5 years each. This means that the Model PSC terminates after 35 years.

An initial term of 25 years is reasonable and renewal periods of 5 years are also reasonable.

These terms are consistent with the fact that PSCs typically do not have indefinite renewals and areas are returned to the national oil company at the end of the contract.

However, in the case of Mexico, CNH or the FMP are not set up as petroleum producing companies and therefore it does not make sense to return the area to be returned to the State. Also, it is difficult to see how it is in the interest of Mexico to be faced with returned areas that are close to abandonment.

Clause 18.7 provides for the fact that after the end of the contract, CNH will simply appoint a third party to continue operations. There is no requirement for a transparent bid process for the re-contracting of the contract area that is returned. It would be prudent to do so because large and profitable oil or gas fields may have a life that extends well beyond the 35 years and therefore a considerable amount of profitable production may remain.

The concept of a final termination date of the contract and transfer of the contract to a third party does not make sense. There is no evidence that there a third party will provide a better management of the contract area than the original contractor.

<u>Recommendation # 10:</u> It can therefore be recommended that the PSC should have continuous renewals of 5 years each until the end of commercial production.

4.2 Renewal process

Clause 3.3 links the renewals to the presentation of an “Advanced Recovery” program. Advanced Recovery is defined as secondary or tertiary recovery programs. It should be noted that secondary recovery and pressure maintenance programs certainly do not qualify as “advanced recovery”.

It is the obligation of any Contractor to execute work programs in a manner that complies with best industry practice, as is also required in Clause 10.4 of the Contract. This includes the obligation to apply the practices that result in the highest possible recovery of the oil and gas provided such work programs are economic under the prevailing terms.

Therefore it does not make any sense to wait for 25 years before "advanced recovery" practices need to be applied. CNH should insist in the approval of work programs on a yearly basis on best industry practice including the best possible recovery of oil and gas. Therefore, it cannot be recommended to have special approval provisions for an advanced recovery program as part of a renewal process. Activities should simply continue normally.

The approval of a renewal is entirely discretionary by Government. Government could set unilaterally technical and economic conditions with respect to such renewal. This is certainly not international practice.

In such cases companies typically take a defensive attitude and slow down investments during the last five years of the contract in order to avoid losing the benefits of their investments. Also this places them in a better bargaining position for the renewal. None of this is in the interest of Mexico.

A better approach would be to allow automatic renewal for so long as oil and gas production is continuing, but subject to the application of the fiscal system then in effect at the time of renewal, and subject to reduction of the contract area to the remaining productive portion of the contract area.

Recommendation # 11: Therefore, it can be recommended to renew the contract under prevailing fiscal conditions and adjust contractual terms up or down on this basis.

4.3 Exploration Periods

Clause 4 of the Model PSC provides for a total exploration period of 5 contract years consisting of an initial period of 3 years and two renewals of one year each. The total exploration period is short by international standards. Typically the total exploration periods for shallow water PSCs range from 5 to 10 years.

It is unclear why such a short exploration period has been chosen. It should be noted that in most other countries in the world, companies have been exploring for many years and are intimately familiar with the geological conditions. In the case of Mexico, companies will have to become familiar the geology. Also there is no particular benefit to Mexico requiring companies to depart a contract area so quickly. Mexico has more than enough acreage for many bidding rounds. An exploration period which would reflect a world average would be more appropriate.

The appraisal period of one year plus one year for a renewal is also short. A more common period is a single period of two years.

<u>Recommendation # 12:</u> It can be recommended to have a total exploration period of 7 years, consisting of an initial period of 3 years and two renewals of 2 years each. The appraisal period should be a single period of 2 years.

5. WORK COMMITMENTS AND RELINQUISHMENTS

5.1 Contract Areas

The 14 contract areas offered in the Shallow Water first bid round range in size from 116 square km to 501 square km.

It should be noted that these are very small contract areas compared to typical areas for PSCs around the world.

Typical average PSC contract areas range from 500 square km to 2500 square km. However, much larger PSC contract areas also exist.

It seems that the small contract areas are selected based on targets already identified as a result of previous exploration by PEMEX. So it is likely that the areas contain at least technically viable exploration targets. However, it should be noted that subsequent geophysical surveys may alter the picture. The small areas will most likely not make it possible to search for alternative targets in this case.

It is unlikely that these small areas contain a large number of targets. Therefore, in case of a discovery there will not be much opportunity to follow up with further discoveries in these areas.

The small size of the areas is therefore unattractive compared to most PSCs.

5.2 Work Program

5.2.1 Unclear Minimum Work Program definition.

The definition of the Minimum Work Program is unclear and does not seem to be in accordance with best international practice.

The Minimum Work Programs are listed in Section V of the Bid Conditions. This section contains a table that lists the number of wells that needs to be drilled in the contract area and the amount of the expenditures that is estimated to be required for these wells. For example for contract area # 1, the minimum number of wells is 2 wells. The estimated expenditure is $112,585,000.

It is not clear how these two obligations relate to each other.

For example, if the Contractor has carried out a substantive geophysical program and has drilled two very deep wells, which reasonably evaluate all prospective formations, but fails to spend $112,585,000 on the total exploration program, has the Contractor failed to comply with the Minimum Work Commitments? Would CNH terminate the Contract in this case pursuant to Clause 23.1(b)?

This seems a very counterproductive approach to Minimum Work Programs.

One of the challenges that Mexico will face is the fact that the first bidding round is being launched when oil prices are in decline. One of the benefits of a decline of the oil price is that drilling rig rates and costs of other petroleum services may decline.

It is therefore possible that the exploration program can be carried out for much lower costs than estimated in Section V of the Bid Conditions. It would be very beneficial for Mexico if the exploration program would be carried out for lower costs, since this will create more fiscal revenues. It seems that the Minimum Work Programs would penalize a Contractor which carries out the program for lower costs, or is required to pay a penalty at a high cost estimate for failing to perform its minimum work obligation.

This certainly is not international best practice. The purpose is generally to carry out an effective and complete exploration program for the lowest possible costs.

In order to give priority to the work, it is necessary to define the depth of the wells to be committed. For example, as an example, Section V for contract area # 1 could list that one well needs to be drilled to a minimum depth of 4000 meter and a second well to 5000 meter.

Also Section V of the Bid Conditions and Clause 4.5 in the Model PSC should then clarify that the Minimum Work Program has been fulfilled if the Contractor has complied with drilling the wells to the minimum specified depth.

<u>Recommendation # 13:</u> It can be recommended:

(1) to define the minimum depth for each well listed in Section V of the Bid Conditions, and

(2) to clarify in Section V of the Bid Conditions and Clause 4.5 of the Model PSC that the Contractor has fulfilled the Minimum Work Program once the Contractor has drilled the wells to the specified depth.

Another issue to consider is the definition of the penalty in case of non-fulfillment of the Minimum Work Program.

The penalty method provided for in Clause 4.5 of the Model PSC is unnecessarily complex.

It requires an in-depth and aggressive audit of the exploration expenditures of the Contractor in order to determine the amount incurred in drilling. This is often conflictive and can lead to disputes.

The Contract administration can be simplified by simply requiring a penalty of an amount for every meter not drilled, for example $10,000. The drilled well depth cannot be disputed since logs are available to determine this matter to the meter accurate. The simple penalty will also better ensure that the Minimum Work Program will be carried out to the best of the Contractor's abilities.

This approach will also ensure that the Contractor will carry out the Minimum Work Program for the lowest possible costs.

<u>Recommendation # 14:</u> It can be recommended to establish a simple penalty of $10,000 for every meter not drilled under the Minimum Work Program and delete the cost estimation columns in Section V of the Bid Conditions and adjust the penalty procedures in Clause 4.5.

5.2.2 Size of the Minimum Work Program.

Under the current low oil prices, the Minimum Work Program in terms of drilling 2 wells during the Initial Exploration Period for most of the contract areas may be too tough.

It is understood that PEMEX may have identified drilling targets. However, the small contract areas and the fact that this is a mature exploration area will make drilling relatively unattractive, even if recommendations regarding improved fiscal terms would be implemented.

<u>Recommendation #15:</u> It can therefore be recommended to require only a single exploration well for each of the Contract Areas.

The possible drilling of more wells during the Initial Exploration Period can be left to the bid process.

5.2.3 Work Programs during the Renewals

It is an almost universal international practice that if voluntary wells are being drilled in addition to the Minimum Work Program during any exploration period, that such wells can be carried forward to fulfill work programs during the next exploration period.

Early exploration is in the interest of Mexico. Therefore, not permitting the carry forward of such early exploration work does not make sense.

<u>Recommendation # 16:</u> It can be recommended that Clause 4 of the Model PSC be amended to include the right to carry forward the work of voluntary additional wells.

Clause 4.3 and 4.4 contain the provision that the renewals can only be granted if the Contractor commits to the drilling of an exploration well with the same characteristics as the wells committed during the Initial Exploration Period.

The requirement to drill a similar well is a very unclear provision. Nor does this provision make sense.

For example, one could assume that during the Initial Exploration Period an exploration well of 5000 meter was drilled in accordance with the Minimum Work Program. Assume that this well established a discovery at 3050 meters in a particular formation. Assume also that the exploration well reasonable proved that the formations below the discovery formation are not prospective. In these conditions it would be very counterproductive if the Contractor has to commit to another 5000 meter exploration well for the renewal period.

<u>Recommendation # 17:</u> Therefore, it is recommended to require for each renewal period the drilling of a well to a specified depth or to the deepest formation for which production was established in prior wells, whichever is the shallower depth.

5.3 Significant Gas Discovery provisions

The Model PSC does not have a Significant Gas Discovery procedure.

Mexico can needs more gas for its growing economy. Yet, due to the low gas prices at this point in time, the development of gas discoveries will be a challenging proposition. Often whether or not gas discoveries are commercial or not, can only be determined after commitment to pipeline and gas processing infrastructure are made. Also often several gas discoveries need to be combined to create a commercial project. It is for this reason that it is common to permit the Contractor to make a "Significant Gas Discovery". A significant gas discovery is a discovery that may be commercial subject to infrastructure and other discoveries.

After declaring a significant gas discovery the Contractor is typically permitted a certain time frame, say up to a maximum of 10 years, to evaluate whether such a discovery can be developed for the domestic markets or as part of an LNG or other project. This is an important aspect of monetizing gas resources under conditions of very low gas prices. Prior to the end of the 10 year period the Contractor has to declare a Commercial Discovery or relinquish the area.

<u>Recommendation # 18:</u> It can be recommended to include in the Model PSC the possibility for a Significant Gas Discovery and include a 10 year period for the evaluation of possibilities for the commercial development of such discovery.

5.4 Timelines for reports and declarations

The times lines contained for the evaluation and development process are very short.

The following timelines apply:

- Clause 4.7: 15 days after a discovery for submitting a report on a discovery
- Clause 5.4: 60 days after the Appraisal period for submitting an Appraisal Report
- Clause 6.1: 60 days after the Appraisal period for making a Declaration of a Commercial Discovery
- Clause 6.2: 90 days after the Declaration of a Commercial Discovery for presenting a Development Plan.

Although there are some similarly short time lines in some other PSCs, it is not in the interest of Mexico to have such a rushed approach to the development of the oil and gas fields.

In particular a Development Plan should be carefully prepared. It is not possible to present a Development Plan for offshore installations and the possible related Commercialization Installations without doing some initial engineering studies. These studies have to be done properly in order to ensure safe operations, an adequate protection of the environment and the optimization of the facilities. Often certain facilities may require cooperation with other Contractors or with PEMEX for downstream infrastructure or even treatment and processing of the oil, gas, water and sediments produced in the Contract Area on platforms in other Contract Areas. Such discussions take time. It is in the interest of Mexico that Contractors carry out these operations meticulously and professionally. Therefore, a time frame of one year after the Declaration of a Commercial Discovery is a reasonable period.

<u>Recommendation # 19:</u> Therefore, the following time lines can be recommended:

- **Clause 4.7: 30 days after a discovery for submitting a report on a discovery**
- **Clause 5.4: 90 days after the Appraisal period or Significant Gas Discovery Period for submitting an Appraisal Report**
- **Clause 6.1: 90 days after the Appraisal period or Significant Gas Discovery Period for making a Declaration of a Commercial Discovery**
- **Clause 6.2: 365 days after the Declaration of a Commercial Discovery for presenting a Development Plan.**

5.5 Development Plan approvals and Development Plan Amendments

Clause 6.2 includes the provision the Development Plan can be rejected based on Applicable Norms.

<u>Recommendation # 20:</u> In order to provide more certainty to a Contractor that the Contractor can benefit from the production of a Commercial Discovery, it can recommended to include in this Clause the specific conditions under which a development plan can be rejected.

It is also important that it is understood among the parties that an oil or gas field may develop in various phases. The reference to “final maximum recovery factor” in Clause 6.2 may be interpreted to mean that the Development Plan has to include all phases. This would be an error.

For example, initially only primary recovery methods may be used, after some years secondary recovery methods may be introduced and finally tertiary recovery methods may be applied. It is not necessary, and in fact impossible, that the Development Plan includes the details of all these phases, since each phase depends on the information and experience obtained during the prior phase. Also entirely new technologies may be developed that could be beneficially applied to the oil or gas field.

<u>Recommendation # 21:</u> It can therefore be recommended to include a new Clause 6.5 that permits Contractor to update its development plan from time to time in order to provide for an orderly development of the oil and gas fields.

5.6 Relinquishments of the Contract Area

Clause 7.1 of the Model PSC includes relinquishment clauses which are rather standard for international PSCs. However, internationally, these clauses apply to much larger contract areas.

Given the very small size of the Contract Areas, the obligation to relinquish as much as 50% of the area could seriously impede further exploration. Clause 7.4 may result in a retention of some more acreage but this clause is discretionary and therefore does not guarantee that there will be reasonable acreage available for exploration.

A more secure mechanism for the Contractor would be desirable.

At the same time the relinquishment of very small pieces is not very relevant for Mexico, because such small areas may not result in viable new contract areas.

<u>Recommendation # 22:</u> Therefore, it can recommended to amend Clause 7.1 in order to establish that when the resulting area to be relinquished is less than 100 square km that relinquishment is not required.

5.7 Relinquishment of Deep Formations

The Hydrocarbon Law includes the innovative concept of relinquishing deeper formations. This is a modern concept that is now increasingly necessary to promote the development of unconventional resources and deeper formations.

Clause 7 of the Model PSC does not include a relinquishment provision of deep formations.

The concept of deep formation relinquishment and possible subsequent bidding rounds for these areas, requires that the concepts of Field Areas or Appraisal Areas are no longer exclusive. Field Areas of shallower formations can overlap Field Areas of deeper formations. The same applies for Appraisal Areas. New Contract Areas may be created below existing Field Areas or Appraisal Area.

Deep rights relinquishment is not applied currently in PSCs and would therefore require new types of administration provisions. Mexico will have a very significant challenge to establish the proper petroleum administration for the PSCs. So it seems logical not to introduce right away the concept of deep rights relinquishment and delay this extra complication for later implementation.

The Contractor should be provided the reasonable opportunity to fully develop the Field in the Development Area. As indicated above the field development may involve several phases.

<u>Recommendation # 23:</u> For these reasons, it can be suggested to include a Clause 7.5 in the Model PSC requiring deep rights relinquishment upon the termination of the initial term of 25 years.

This is an encouragement to fully develop any deeper formations in the Development Area prior to the end of the first 25 years.

6. BID VARIABLES

6.1 Adjustment of the Bid Variable Formula

Subchapter 5.2.1 of this Report recommends that the Minimum Work Program would be simply defined in terms of wells and the corresponding well depth in meters. For example, the minimum requirement could be the drilling of a well of 5,000 meters in the Initial Exploration Period. A penalty of $10,000 per meter not drilled would apply.

The Minimum Work Program bid could therefore be easily defined in the additional meters that the bidder intends to drill. For example, if the bidder is willing to commit to a depth of 5,500 for the first well and is willing to drill a second well of a depth of 3,800 meters, the total depth to be drilled would be 9,300 meters. This would be 86% more than the Minimum Work Program requirement. This would become the "Drilling Increment".

<u>Recommendation # 24:</u> It is therefore recommended that the work related bid variable would simply be the "Drilling Increment". In Article 16.2 of the Bid Conditions the "Investment Increment" would simply be replaced with the "Drilling Increment". The rest of the formula could stay the same. The "Investment Factor" would simply become the "Drilling Factor" and the weighting formula could stay the same.

The formula for the weighted average of the Economic Proposal would now become:

V = 0.9 * Participation + 0.1 * Drilling Factor

6.2 Over-bidding

The formula for the weighted average of the Economic Proposal has the disadvantage that the Participation percentage does not require an "out of pocket" commitment.

This may have two negative results:

(a) In order to win the bid, companies may over-bid, which in turn often results in problems later, and
(b) By bidding a high profit share for Government, the company limits the type of exploration and development projects that are economic in a block. This slows down the development of new production.

Over-bidding is usually aimed at getting the block in the hope that geological conditions or economic conditions (oil price), or both, would later on justify the high bid. Over-bidding results from the fact that the lack of a large upfront commitment permits companies to make such speculative bids. The problem is that if the speculative conditions do not materialize, it often leads to paralysis and/or renegotiation of terms. Companies tend to do whatever possible to "hang on" to the block, without having to engage in uneconomic activities. A famous case was the North Star Unit case in Alaska, which resulted in a court case which in turn made this case known in great detail.

Other cases were the Libyan bid EPSA IV bids in 1995 which were done on a production share bid. Companies made bids as low as 12.4% of production. This means companies were required to contribute 100% of the exploration costs and 50% of the development costs in order to earn only a share of 12.4% of the production on which a PSC sliding scale applied. Daniel Johnston in April 18, 2005 article describes how this was a case of overbidding. This results in only the largest most economic structures in a block being economic and delays and renegotiations for the smaller less economic fields.

Another interesting case of over-bidding was the Chevron bid for Block 52 adjacent to the Camisea gas field in 1995 in Peru. Chevron ended up giving the block back in 1999 directly as a result of having overbid the royalty sliding scale.

Such situations are not in the interest of Mexico.

6.3 Suggested Bonus link

A simple way to avoid over-bidding is to make a link with a required signature bonus.

For example, Article 16.2 of the Bid Conditions could be expanded by stating that for every 1% Participation increase, the bidder is required to offer a signature bonus of $10 million. Therefore, if the bidder would offer a 5.32% increase in the Government Share of the Contraprestacion, the bidder would have to offer a $53,200,000 signature bonus. This would constrain over-bidding.

Importantly, the signature bonus will be regarded as a sunk costs when considering the various investments. Therefore, such bonus will not have the effect of slowing down the developments or making certain fields or exploration projects uneconomic.

<u>Recommendation # 25:</u> It can be recommended to establish a link in Article 16.2 of the Bid Conditions through the requirement to pay a $10 million signature bonus for every 1% offered for increased participation by the Government, proportionately adjusted to the amount of the Participation bid.

7. VALUATION

7.1 Measurement Points

The LISH requires the determination of the Contractual Value of Hydrocarbons at the Measurement Points. At the Measurement Points the volumes of Petroleum, Condensates and Gas extracted are being determined.

The Ley de Hidrocarburos defines “Extraction” as purely an upstream activity. Gas processing and long distance pipeline transport outside field areas are not part of “Extraction”.

Therefore, the Measurement Point in the LISH is a point after the primary separation of Petroleum, Condensates, Raw Gas and water and prior to gas processing a pipeline transportation.

Article 3 (XVII) of the LISH does not require the Measurement Point to be in the Contract Area.

On the contrary, the definition of the “Measurement Point” in the Model PSC requires the measurement point to be in the Contract Area. As indicated earlier in this Report, it will not be possible or it will not be economic to locate the Measurement Point in the Contract Area.

For example, currently in Aranque, a crude oil, water, gas mixture is send by pipeline to the shore. The separation, treatment and processing and measurement takes place onshore, outside the Contract Area. This is the most economic setup. In a number of the 14 shallow water blocks it also may be the most economic concept in the same manner as in Arenque.

In some cases oil, gas and water may not be separated in the contract area and such processes may take place on other PEMEX owned platforms or onshore facilities or facilities of other contractors.

<u>Recommendation # 26:</u> Therefore, it can be recommended to delete the words “dentro del Area Contractual” from the definition of Measurement Point in the Model PSC.

However, the simple adjustment of the Measurement Point definition does not solve a larger problem.

The issue is that with respect to adjacent shallow water contract areas, such as contract areas #1, #2, # 3 and # 4, it is highly likely that the most economic options for producing oil and gas are options where the Contractors work together to create the most economic overall system.

If discoveries are made in all four contract areas, it would not make sense to have separate production facilities, treatment facilities and gas processing facilities for each Contract Area. The most economic option is to combine these activities. This creates a range of problems.

For example, Contract Area # 4 may mainly have oil production with little associated gas. The oil-water production is only a few thousand barrels per day. Therefore, it would make economic sense to transfer this production with an oil-water pipeline to Contract Area # 3 for separation and treatment. Contractor # 4 would pay separation and treatment fees to Contractor # 3, which in turn would credit these amounts against cost recovery. Contract Area # 3 would produce oil as well as large volumes of non-associated raw gas and condensates. The Measurement Point of Contract Area # 4 would therefore be in Contract Area # 3 and in this contract, the oil and condensate production of the two contract areas is comingled at the Measurement Point. In order to determine the production pertaining to each of the contract areas Gross Production Delivery Points have to be established prior to the Measurement Point where the Gross Production of each Contract Area is being measured. However, also Contract Areas # 2 and # 1 are in production. Contract Areas # 3, # 2 and # 1 have a joint crude oil pipeline to shore as well as a joint raw gas line which is owned by the Contractor of Contract Area # 2. The crude oil pipeline ties in to the PEMEX oil line for transport to the refineries. The Contractor of Area # 2 would also have a gas processing plant onshore for processing the gas. Contractor # 2 would provide gas pipeline transport services and gas processing services to Contractors #3 and # 1. Contractor # 2 would also provide crude pipeline transport services to Contractors # 4, # 3 and # 1. Contractor # 2 would at the exit of the gas processing plant, measure at Market Delivery Points the processed natural gas, LPGs, NGLs and plant condensates and allocate these volumes back to Contractors # 1, # 2 and # 3. Contractor # 2 would at the exit of the crude oil pipeline and connection to the PEMEX pipeline measure at the Market Delivery Point the crude oil and blended condensates that are transferred to PEMEX and allocate the production to Contractors # 1, # 2, # 3 and # 4. Contractor # 2 would charge pipeline and processing tariffs to the respective Contractors. The "Comercializador" would take all the respective shares at all Measurement Points and would pay all Contractors the respective pipeline transport tariffs and gas processing tariffs. In order to properly determine the Contract Prices for each Contract, the values at the Market Delivery Points have to be determined and netted back.

As can be easily understood, the Model PSC is written far too simplistically to handle these more complex situations.

<u>Recommendation # 27:</u> It can therefore be recommended to develop an Annex to the Model PSC that describes in detail the various adjustments that have to be made in order to properly determine the Contract Prices at the Measurement Points or deemed Measurement Points pursuant to the LISH.

We are prepared to suggest the terms of such an Annex.

The Annex would be based on three types of measurement points:

- Measurement Points

These are the typical measurement points where Oil, Condensates and Raw Gas are being measured as per the definition of the LISH.

- Gross Production Delivery Points

These are measurement points where a mixture of oil, gas, water, suspended solids, etc. are being delivered from the Contract area for further treatment to a Processor (another Contractor, PEMEX or an independent party) based on an agreement between the Contractor and Processor as to measurement practices and treatment fees.

- Market Delivery Points

These are the points where crude oil, condensates, natural gas, LPGs and NGLs are being measured for final transfer to the market in marketable conditions as a result of the Commercialization Installations and Operations.

7.2 Contract Price

7.2.1 Contract Price determination

As will be obvious from the discussions under Subchapter 2.2 and 7.1 of this Report, the provisions of paragraphs 1.4 through 1.10 of Annex 3 to the Model Contract are too simplistic and would not result in the construction of the Commercialization Installations that area necessary to increase oil and gas production in Mexico.

The proposed crude price formulas are implicitly based on gravity differentials that may not hold up during the year under significant international oil price movements. Also the relationship between condensate prices and crude prices may change considerably during the year under such circumstances. The crude price formulas may not reflect the prices to be received from PEMEX for deliveries to local refineries.

The proposed gas price system does not seem to capture the value of liquids in raw gas. The raw gas price at the measurement point is typically the netback from the product outputs at the gas processing plant, being pipeline gas, LPG, NGLs and sometimes plant condensates, netted back to the measurement point as illustrated in Subchapter 7.1 of this Report. There are no provisions in the Annex 3 for pricing LPGs and NGLs.

If the development of shale gas in Mexico would be successful it is likely that within a few years Mexico would have excess gas supplies. Annex 3 does not seem to deal with situations where gas would be directly used for producing petrochemical products or where gas would be exported as LNG.

Also it is unclear how the provisions would deal with gas from the same field being sold under different style gas contracts with different prices, such as for firm supplies and interruptible supplies.

The netback procedures provided in paragraph 1.10 would reasonable work for crude oil in international PSCs, but are very difficult to implement in the mature integrated petroleum industry in Mexico. In many cases there would not be adequate information on storage, treatment, gas processing and transport costs per barrel or Mcf. The Annex does not contain provisions how tariffs would be determined in this case as discussed in Subchapter 2.2.

Particular problems occur where such operations take place in outdated and antiquated facilities of PEMEX that may need upgrading before they can be used. For example, how would the tariff be determined for a PEMEX field connector pipeline that would have been upgraded, repaired and expanded by a Contractor?

Therefore, the market conditions at the measurement points cannot be determined under such conditions without major further procedures which are not contained in the Annex 3.

Recommendation # 28: A complete rewrite of Sections 1.4 through 1.10 is recommended to create an environment in which the construction and operation of Commercialization Installations can be undertaken in the profitable manner and where netback provisions are determined in a fair and commercial manner.

We are prepared to assist in suggesting suitable provisions.

7.2.2. Contract Price and Sales Price matching

It is unclear what Section 1.3 of the Annex 3 is trying to achieve. It is difficult to see, for example, how the sales values of the "Comercializador" can be matched with the Contract Price of the Contractor. There will always be discrepancies. Such discrepancies cannot be attributed back to the Contract Price, because this in turn would result in the need to adjust volumes to be delivered to the "Comercializador", which would set off a complex set of ongoing adjustments. It is unclear from Section 1.3 whether it is intended to match the Contract Prices with Sales Prices or to maintain discrepancies.

Recommendation # 29: It is recommended to clarify that there is no intention of matching Sales Prices of the "Comercializador" with Contract Prices.

8. CNH ADMINISTRATION AND MANAGEMENT COMMITTEE

8.1 CNH approval procedures

It is likely that CNH will initially face problems to administer the petroleum contracts. We suggest a system which is similar to that utilized by ANP in Brazil and ANH in Colombia.

<u>Recommendation # 30:</u> Therefore it is recommended that a special CNH approval process will be introduced in the Model PSC as follows:

1. **Contractor seeks approval in writing with all material attached as required.**
2. **Contractor cannot proceed with activities, while waiting for approval, unless otherwise contemplated in the Contract.**
3. **Within 60 days CNH can:**
    1. **Approve**
    2. **Ask for more information**
    3. **Reject the request**
4. **If CNH does not respond in 60 days the request is considered approved.**
5. **If CNH requires more information, such information shall be provided within 30 days and the above procedure will be repeated.**

This will assist in initially debottlenecking the operations of CNH.

8.2 Management Committee

A very good provision of the Model PSC is that there are no provisions for a Management Committee. This would have resulted in a wide range of separate administrative problems.

The concept of having CNH solely handle the actual contract administration, except for responsibilities of other entities is a good concept.

9. ADMINISTRATIVE COMPLEXITY

A key aspect of a petroleum regime is the regulatory and administrative structure utilized by the state to award petroleum contracts and regulate the performance of oil companies who hold such contracts. The constitutional amendments and Hydrocarbon Law adopt the modern structure used in many other parts of the world:

- Petroleum policy issues are addressed by SENER
- contract awards and regulation of performance occurs by CNH, an independent quasi-judicial authority, and
- the state role in commercial hydrocarbon activities are fulfilled by Pemex.

The constitution and the Hydrocarbon Law provide that a number of other governmental authorities will also be involved in hydrocarbon regulation: the Secretary of Energy, the Secretary of Finance, the National Agency for Industrial Safety and Environmental Protection of the Hydrocarbon Sector (the "Agency") and the Mexican Oil Stabilization and Development Fund (the "Fund").

9.1 Quantity of Administrative Decisions

Attached as **Annex A** is a table which lists all the decisions which are to be taken pursuant to the Model PSC (excluding its annexes). The table lists:

- the relevant authority
- the decision which it is required to take
- the frequency of the decision
- whether there are defined criteria in the Model PSC which govern that decision, and
- whether the Hydrocarbon Law or the Model PSC impose a time frame in which the decision must be taken

As noted earlier, it is positive that there is no Management Committee established by the Model PSC. However, as shown in Annex A, in place of a Management Committee, the Model PSC has created a **thirty** types of decisions that will be taken by a number of different state authorities. This is certainly more than is common in other jurisdictions. This promises to be administratively burdensome for both the government and oil and gas companies.

Attached as Annex B is a table listing all of the reports that are required to be delivered to a governmental authority according to the Model PSC (excluding its annexes), and information and data access rights which the contractor must give to the government. This table shows that there are twenty-four types of reports and access rights. While it is international practice that oil companies provide regular reporting of relevant petroleum operations, rarely is such an extensive reporting requirement seen other jurisdictions. These two tables are instructive to help understand how significant an administrative and regulatory burden is being created by the Model PSC.

9.2 Necessity of Administrative Functions

The many approvals or administrative functions required by the Model PSC includes a number which are not typically seen in international practice. In the interest of reducing the regulatory burden and being consistent with international practice, it is recommended that at least some of these approval requirements or administrative functions be:

- eliminated
- circumscribed with criteria that guides the decision (if the Model PSC does not already include this)

The following are some examples of functions which should be considered for removal or clarification.

Article 3.3(a) and (b): as discussed earlier in this report, the necessity of requiring an adequate new program of advanced recovery as a condition of five year extensions of the term is inconsistent with requiring a contractor to use good oilfield practice to conduct advanced recovery whenever it is appropriate. Also, there is no standard for assessing whether a proposed program is adequate. This type of naked discretion in relation to a decision that has a major impact of a contractor's interest may be challenging for CNH. In other jurisdictions, extension criteria are simpler: if production is continuing, then the term will continue, subject to the adoption of the then-current fiscal terms applicable in the state, and subject to reduction of the contract area to cover only the remaining production area.

Article 13.4: The need for CNH consent to sell or dispose or rent materials is an unnecessary provision when these materials are owned by the contractor as called for in the Model PSC. The fiscal treatment of any sale or disposition is adequately addressed in the Accounting Procedure (as a credit to recoverable costs); this is an adequate provision to address this issue.

Article 24: CNH has broad discretion over the approval of any assignment or change of control. Approving assignments or changes of control of a contractor is a valid discretionary decision point for a petroleum regulator. Transparency of such decisions can be improved if the Model PSC or other CNH regulations creates a set of empirical criteria for approving such decisions, and 'safe harbors' such as provisions that would allow assignment to:

- any company who qualified to bid for a similar petroleum contract in a prior bid round, or
- any company who currently holds a similar petroleum contract that is in good standing.

<u>Recommendation # 31:</u> The list of government decision requirements shown in Annex A be reviewed with a view to removing decisions where a discretionary decision is not necessary for proper petroleum administration, or to add objective decision criteria to govern the use of discretion.

<u>Recommendation # 32:</u> The list of reporting and access requirements shown in Annex B be reviewed with a view to determining whether each one is required.

10. JOINT VENTURE PROVISIONS

Oil and gas companies frequently form consortia to jointly bid for petroleum contracts, or assign fractional interests in petroleum contracts to create consortia following an award. They do so for a variety of reasons, such as:

- Share the costs and risks of exploration
- Participate with a technically or financially qualified oil company
- Monetize the investment they have made by way of a farmout or sale

Most petroleum regimes allow these kind of joint venture relationships, applying only a requirement that joint venturers be jointly and severally liable, and obliging the state to deal only with the designated operator on behalf of the consortium. Assignments of interests and changes in control often require the approval of the state to ensure that the assignee is technically and financially qualified.

The Bid Procedure and Model PSC adopt these concepts, and this is suitable and appropriate for Mexico.

However, the Bid Procedure go further than usual international practice in imposing the following restrictions on making a bid:

- any joint venture comprised of two companies having more than 1.6 MMBBLs of daily production
- no member of the joint venture may have a participating interest larger than the operator

Although it is not entirely clear in the Model PSC[3], it can be expected that these same consortium restrictions of the Bid Procedure may also apply to CNH approvals of any assignment of an interest in a petroleum contract.

These restrictions on joint ventures should be reconsidered. Many international joint ventures involve two or more companies each of whom have more than 1.6 MMBBLs of daily production. We understand that Mexico desires a competitive bid round, and may be concerned that competition may be restricted if large companies form bidding consortia. We believe that the opening of Mexico will be attractive to many companies and concerns about concentration are not warranted. For example, in Libya's EPSA IV bid round in 2005, more than one hundred companies sought to qualify for the 15 offered blocks, and more than 66 were approved by NOC during the qualification process. A similar outcome is likely in Mexico given the anticipation that exists for these opportunities. We also believe that the size restriction on consortia members may potentially reduce the number of bids because some large companies may wish to associate themselves only with other large companies, and may decline to bid altogether if they cannot do so.

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[3] See Clause 24.1

Requiring that no participant have an interest greater than the operator could restrict the operator's freedom to farm out its interest, which would be unattractive to potential operators. International practice is to require that the operator must have at least a minimum percentage interest in the project (a thirty percent threshold is common), but not necessarily be the largest participant.

Pemex is a possible bidder in the First Round. It obviously exceeds this production threshold. It would seem unusual for the state to impose a restriction on its own state oil company that would prohibit it from entering into a joint venture with any company that has more than 1.6 MMBBLs of daily production. Indeed, many states are concerned when its state oil company enters into a joint venture with a small company, not a larger one. Pemex is also a highly suitable operator for First Round awards; if it finds a suitably financially qualified joint venturer, a requirement that Pemex have the largest participating interest seems unwarranted restriction on the size of Pemex's investment.

Recommendation # 33: The prohibition of a joint venture of two companies having more than 1.6 MMBBLs per day of oil production be removed from the Bid Procedure.

Recommendation # 34: The requirement of the Bid Procedure that no joint venture participant have a larger participating interest than the operator be replaced with a provision that requires the operator to have a participating interest of at least 30%.

The Model PSC has been made available in both 'individual' and 'consortium' formats, with appropriate changes for each situation. We note that the early termination provisions of both forms read in the same way. This means that the bankruptcy or insolvency by one member of a consortium, or the commission of a corrupt action by one member of a consortium, would result in the termination of the petroleum contract for all parties. In our view, solvent joint venture participants, or those innocent of a corrupt act, should not suffer the consequences of their defaulting joint venturers.

Recommendation # 35: The early termination provisions in the consortium form of the Model PSC should clarify that breach of a final judgement, insolvency, bankruptcy or a corrupt act of a member of the consortium does not result in the termination of the petroleum contract for other solvent or innocent members of the consortium.

11. EARLY TERMINATION PROVISIONS

The Model PSC contains two types of early termination provisions.

Clause 23.1 deals with administrative rescission, defining a series of serious breaches which entitle CNH on behalf of the government to terminate the petroleum contract, after the contractor is given 30 days to respond and rectify its default. This clause implements in the Model PSC the required provisions for administrative rescission contemplated by Article 20 of the Hydrocarbon Law. Disputes in respect of administrative rescission are to be dealt with in Mexican courts.

Clause 23.2 expands the list of causes which entitle CNH to terminate the petroleum contract beyond the list established in Article 20 of the Hydrocarbon Law. Some of the listed grounds are reasonable and suitable (for example, insolvency or bankruptcy of the contractor, or breaching the anti-corruption clause). However, a number of the grounds for termination are much less serious grounds. For example, termination of the contract will occur where:

- failing to present the exploration plan or first work program within 45 days of its due date[4]
- any delay of 180 days in implementing any work program or development plan[5]
- providing incomplete or false information[6]
- any assignment or change of control occurs without CNH approval[7]

Moreover, unlike Clause 23.1, the termination provisions of Clause 23.2 do not provide for any notice to the contractor or any opportunity to remedy the default where a remedy would be appropriate solution (except for breaches of clause 23.2(J)).

Early termination is the state's 'nuclear weapon' for enforcing compliance with a petroleum contract. It is an appropriate power for CNH to have in its toolbox, but it should only be used for significant, material breaches following notice and a reasonable opportunity to remedy, and not for missed deadlines or incorrect reporting. Improvements to Clause 23.2 will give comfort to investors that their petroleum contract has reasonable assurance of stability.

[4] See clause 23.2(A)

[5] See clause 23.2(B)

[6] See clause 23.2(D). This provision expands on the administrative rescission right in clause 23.1(F), which reflects Article 20 V of the Hydrocarbon Law; but rescission arises there only in circumstances where the false or incomplete reports are provided on *more than one occasion*, with *wilful misconduct or without cause*. Clause 23.2(D) does not include these protective provisions, and it seem appropriate to do so

[7] See clause 23.2(H). A more suitable remedy would be to provide that any such assignment is invalid and has no legal effect

<u>Recommendation # 36:</u> Early termination provisions of the Model PSC should be altered to allow early termination only for fundamental or repeated breach, and provide for adequate notice of default and an opportunity to dispute or remedy.

12. ANTI-CORRUPTION

The Model PSC contains a strong anti-corruption provision that prohibits a contractor from making payments to public officials or political parties in relation to petroleum matters, where such payments are designed to obtain or retain business. This language matches anti-corruption legislation that is enacted by all OECD countries and who will likely be the home jurisdictions of most oil companies who will be bidders for the Mexican petroleum contracts.

Mexico also has strong anti-corruption legislation applicable within Mexico applying to both investors and public officials.

The procedures contemplated by the Hydrocarbon Law and the Bid Procedure also reflect modern requirements for transparent public bidding in the award of petroleum contracts. Moreover, the Hydrocarbon Law requires extensive reporting procedures to ensure that there is transparency of Mexico's petroleum industry.

These rigorous anti-corruption and transparency provisions could be further enhanced by reducing the number of situations in which government discretion is utilized in the administration of the petroleum contracts. As discussed in Section 9 above, the Model PSC involves a large number of decisions to be taken by Mexican public organs. Some of these do not involve a defined set of criteria for taking those decisions.

There can be no possibility for an illegal payment where there is no scope for a government official to make a decision that affects petroleum operations, or where the scope to take any such decision is circumscribed by objective criteria. Reducing the number of decision points and the number of interactions between contractors and government officials will further help to make petroleum administration corruption-proof. Where discretionary decisions are required as part of petroleum administration (as is the case in every jurisdiction), it will help if those decisions are taken in the context of objective criteria which are defined in the Model PSC or regulations. The recommendations made in Section 9 can help attain these objectives. Two examples of how this can be done are:

- CNH's role in taking a decision on whether to extend the term of a petroleum contract based on its assessment of whether an enhanced recovery program is considered by CNH to be adequate should be removed, because this involves a wholly discretionary decision by CNH.[8]
- Approving assignments or changes of control of a contractor is a valid discretionary decision point for a petroleum regulator. Transparency of such decisions can be improved if the Model PSC or other CNH regulations creates a set of empirical criteria for approving such decisions, and 'safe harbors' such as suggested in Section 9 of this report.

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[8] See Clauses 3.3(a) and (b). Section 9 contains a suggestion for an alternative approach to term extensions.

The other recommendations of this report referred to above, which are made in the interest of good petroleum administration, will also help to enhance the rigorous anti-corruption provisions of the Model PSC and Bid Procedure.

13. APPLICABILITY OF TERMS TO OTHER AREAS AND PEMEX

13.1 Applicability of terms to other areas

It would be very beneficial if Mexico would develop a Model PSC that is very similar for all the areas in Mexico.

As presented by CNH the Model PSC would be difficult to apply to many other areas and conditions in Mexico. This is because:

- The fiscal terms are not applicable to contracts with producing fields, such as many of the blocks intended for bids as well as for the PSCs that will replace the CIEP/COPF contracts as a result of migration. For any contract with existing production and a positive cash flow, the IRR based system could not be applied, since there is no IRR or alternatively the IRR would be considered infinite and the contractor would pay directly the maximum rate to government.

- The measurement point problems would be worse in the onshore areas than in offshore areas in view of the highly integrated nature of the onshore operations.

- The simple work program provisions could not be applied to the CIEP/COPF conversion contracts, since these contracts will require complex work commitments that would require the execution of a large number of developments in parallel, such as exploration, appraisal, field and project development and implementation of secondary and tertiary recovery.

- The fiscal terms, work program and relinquishment terms would be completely unacceptable and inapplicable to unconventional resources.

Assuming that the recommendations in this report for amendments to the Bid Conditions and Model PSC would be adopted, it would be much easier to apply the PSC to all of Mexico, since the fiscal terms can be designed in such a manner that terms could be applicable to all of Mexico. Also measurement point issues and Contract Price issues would be largely resolved.

However, a Mexico wide contract would need some further amendments to the ones proposed in this Report with respect to two areas:

(1) More complex and involved work commitments could be designed on a Work Unit system rather than "meters to be drilled" system. It would be easy to adjust the Minimum Work Program provisions further to such a system.
(2) The PSC could include a set of special provisions for work programs and relinquishments for unconventional resources, including overlapping Appraisal and Development Areas for conventional and unconventional resources in order to ensure that both activities can be carried out under the same contract.

<u>Recommendation #37:</u> It can be recommended to make a draft of a Mexico-wide contract, since this would greatly simplify the administration of all contract areas.

We are willing to suggest suitable provisions for consideration by Government.

14. THE FUTURE OF PEMEX

14.1 Economics of the Assignments

The fiscal terms included in the LISH in Title III for the Asignaciones (Assignments) create an unusually tough fiscal system for PEMEX as is illustrated in Charts 11 through 14. In fact, international oil companies would not want to work in Mexico under these terms.

Chart 11 illustrates that for costs in excess of $30 per barrel (at a price of $80 per barrel) the government take is more than 100% for a 20 million barrel fields. For every cost level the government take is well above competitive levels.

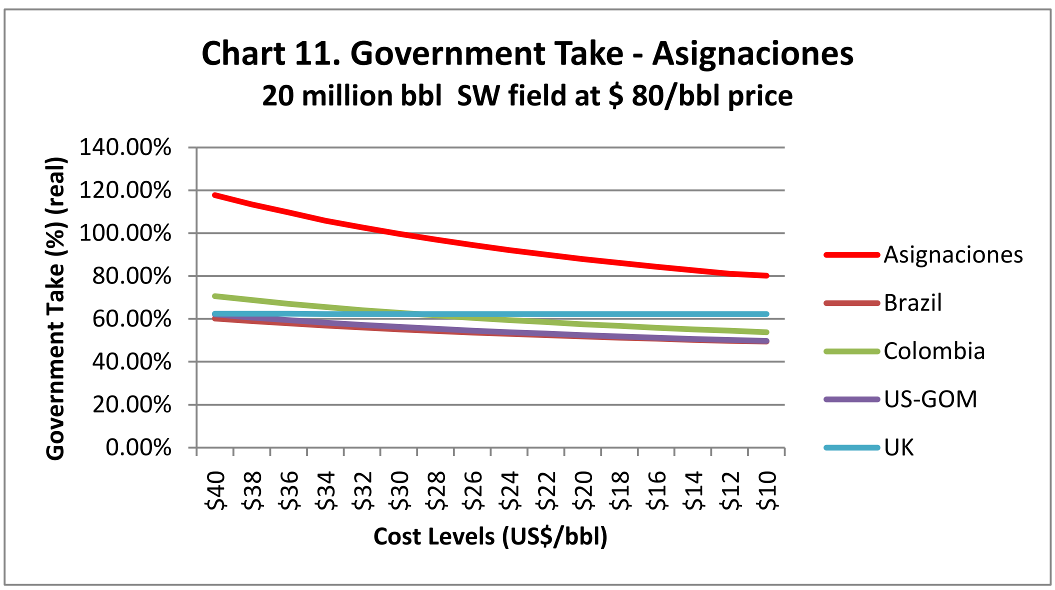


Chart 12 shows how for cost levels over $30 per barrel the cash flow is negative. Over the entire cost range the cash flow to PEMEX is $15 - $20 per barrel less than would be received by international companies around the world.

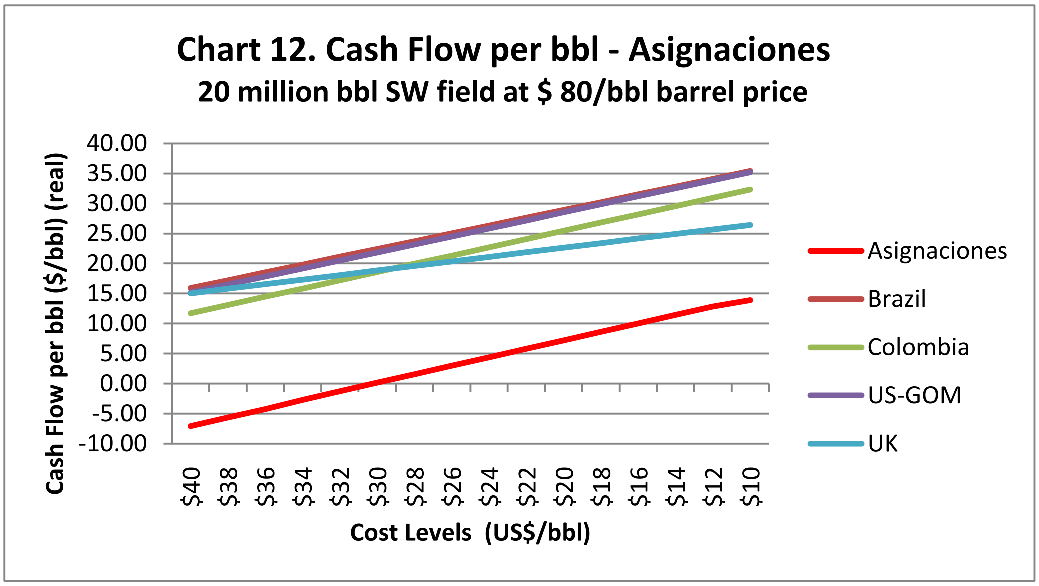


Chart 13 indicates how an IRR of 10% on an un-risked project would only be achieved over cost levels of $18 or less. The IRR would be 10 to 13 percentage points less than achieved by international oil companies in competing countries.

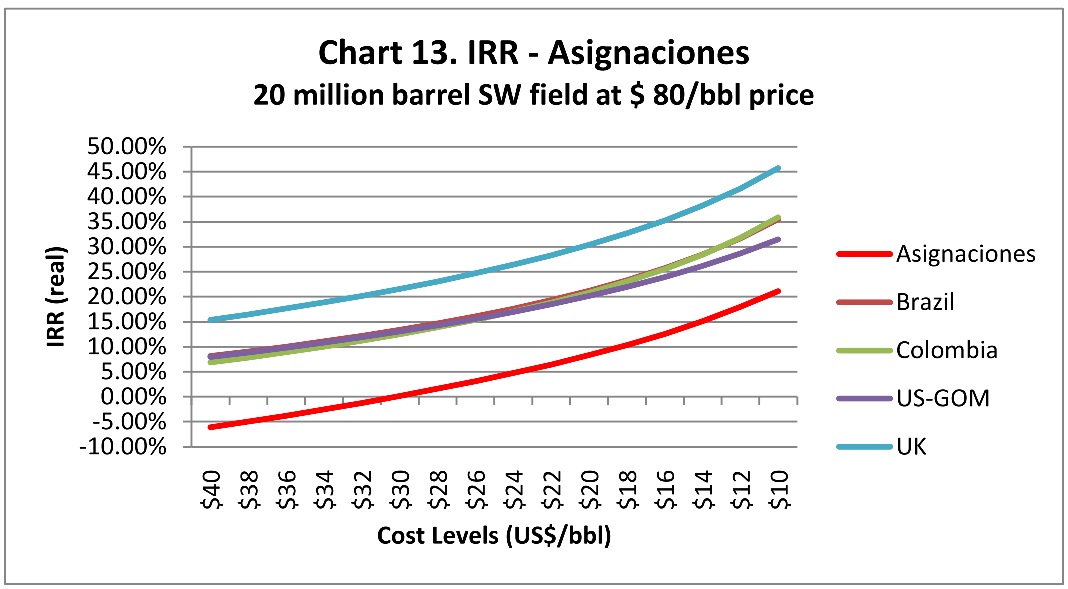
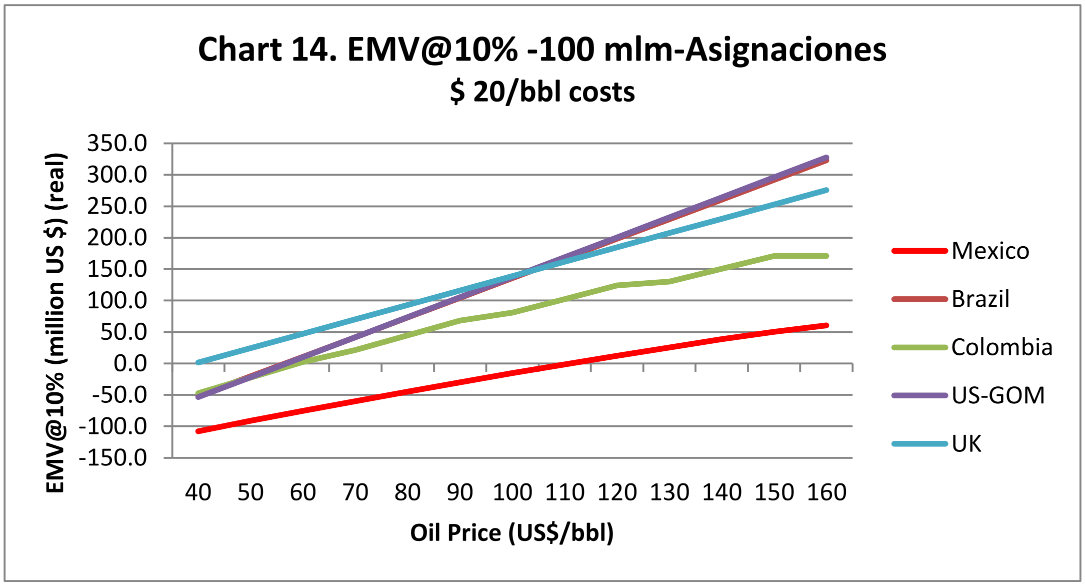


Chart 14 shows that even for a 100 million barrel target, exploration is not economic unless the oil price is $120 per barrel or more. In other words, essentially all exploration in the PEMEX Assignments is uneconomic.



It is clear that the terms in Title III of the LISH are designed to ensure that Mexico receives the same income from petroleum resources as before. In other words the terms are designed to maintain budget stability. This is, of course, a very important objective for Mexico.

However, from now on PEMEX is supposed to work as any other oil company in its investment decisions. The terms for existing and new investments are the same. This means that it is simply not economic for PEMEX to invest in exploration and in most development projects under the Assignment terms.

Therefore, the concept is that for new investments PEMEX could migrate to new Exploration and Extraction Contracts, as is provided in the Hydrocarbon Law.

14.2 Migration to CEEs

There are various ways in which PEMEX could migrate to new Exploration and Extraction Contracts ("CEEs") or achieve new terms:

- Through the conversion of the CIEP/COPF contracts
- Based on the Farm Out contracts
- Based on the regular migration provisions, or
- By participating directly with other companies in bidding round.

14.2.1 CIEP/COPF conversion

It is likely that production can be increased significantly over the coming decade in the CIEP/COPF contract areas to be converted, based on competitive international contractual and fiscal terms, as a result of the following programs:

- Improved drilling technology and drilling of horizontal wells,
- Secondary recovery of existing reservoirs in some of the fields,
- Tertiary recovery, in particular steam injection, in the heavy oil fields,
- Development of unconventional resources present in several of the blocks, and
- Exploration of deeper geological prospects in formations that have so far not been drilled by the Contractors.

The realization of this objective requires fiscal terms and work program commitments that fit the wide range of geological and technical conditions of the contract areas and permit the rebuilding and expansion of the largely inadequate infrastructure.

However, based on the Round 1 terms discussed in this report there is no basis for viable contracts, in particular if the IRR formula would be applied using the maximum rates.

This means that there would be no economic framework to participate for PEMEX in such contracts unless the contractual and fiscal terms are more attractive than the ones presented by CNH for Round 1.

14.2.2 Farm Out Contracts

The Farm Out contracts represent areas that are typically challenging and would permit PEMEX to engage in different types of developments.

The idea would be that PEMEX would conclude farm outs on these blocks. The Round 1 terms as proposed would not be a viable basis for the economic development of these blocks.

Therefore, there would be no “space” for PEMEX to retain an interesting working interest on a carried basis.

Again there would be no economic basis for PEMEX to conduct farmouts unless terms and conditions are truly competitive with international terms.

14.2.3 Other Conversions

As concluded in Subchapter 3.3.5 of this Report, the proposed Round 1 fiscal terms are not competitive from an international perspective. Also many of the other contractual terms are very tough. Therefore, the Round 1 terms would not be a viable framework to migrate to, since it would still leave PEMEX with less attractive terms than international oil companies in other countries.

As indicated in Subchapter 3, the Round 1 terms are competitive under high cost conditions.

However, it is not a viable migration process for PEMEX to only convert marginal projects.

14.2.4 Direct Participation

As will be clear from Chart 12, PEMEX does not have access to the cash flow that other international companies have. Accordingly, it will need to be selective in its participation in open bidding rounds.

14.2.5 Conclusion

A viable economic future for the upstream activities of PEMEX is dependent on establishing a migration process on much better terms than Round 1 terms as proposed by CNH.

Recommendation 38: It can be recommended to develop a clear transition plan for PEMEX providing for the migration of PEMEX to contractual and fiscal terms that are competitive and would permit participation by PEMEX on a carried interest basis.

ANNEX A

Government Decisions pursuant to the Model PSC

Section	Relevant Authority	Decision Required to be Taken	Frequency of the Decision	Are there defined criteria in the Model PSC?	Does the Hydrocarbon Law or the Model PSC Impose a Time Frame?
1.1	CNH and the Agency	Program of Risk Management	As required.	No	
3.3(a)	CNH	CNH has discretion to allow for a 5 year extension with the aim of implementing a new program of advanced recovery in the area of development.	Once - during last 5 years of the Contract	No	
3.3(b)	CNH	CNH has discretion to allow for a second 5 year extension provided the IOC undertakes to make additional investments related to the new Advanced Recovery program referred to in Clause 3.3 (a).	Once - during the first extension	No	
4.1	CNH	The IOC shall submit the exploration plan to CNH for approval.	Once - within forty-five (45) days following the Effective Date	No – cross references the terms of the applicable legislation	Legislation provides that no response within the time period is considered deemed approval (Art 36/37/44)
4.3	CNH	The IOC may apply for the first 1 year extension of the exploration period.	Once - at least sixty (60) days prior to the completion of the initial period of exploration.	Yes – if the IOC: (i) has fully complied with the minimum program of work during the initial period of exploration; and (ii) undertakes to drill an additional well, with the same characteristics than those provided for in the Minimum Work Program, in the contract area during the First Additional Period of exploration.	
4.4	CNH	The IOC may apply for the second 1 year extension of the exploration period.	Once - at least sixty (60) days prior to the completion of the First Additional Period of exploration.	Yes – if the IOC: (i) has the additional well drilled required in accordance with Clause 4.3 for the First Additional Period of exploration; and (ii) undertakes to drill an additional well, with the same characteristics than those provided for in the	

Section	Relevant Authority	Decision Required to be Taken	Frequency of the Decision	Are there defined criteria in the Model PSC?	Does the Hydrocarbon Law or the Model PSC Impose a Time Frame?
				Minimum Work Program, in the contract area during the First Additional Period of exploration.	
5.1-5.2	CNH	Work Program and Budget for the evaluation activities of the discovery in question	Once – for each discovery.	Yes - CNH may not deny approval to the proposed program of work without justifiable cause.	
6.1	CNH	Identification of the Development Area	Once – for each discovery.	No	
6.2	CNH	Development Plan Note: CNH may participate as an observer in the internal and external meetings for generation of the Development Plan	Within ninety (90) days following the declaration of a commercial discovery	No – cross references the terms of the applicable legislation	Legislation provides that no response within the time period is considered deemed approval (Art 36/37/44)
6.3	CNH	CNH can require amendments to the Development Plan based on 9 broad grounds.	CNH discretion	No	
6.4	CNH and the Agency	Amendments to the Development Plan.	IOC discretion	No – cross references the terms of the applicable legislation	Legislation provides that no response within the time period is considered deemed approval (Art 36/37/44)
7.4	CNH	IOC may apply for a reduction of the required relinquishments by providing a new work program and commitment of additional investment.	IOC discretion	No – CNH Sole discretion	
10.1	CNH	Work Program for each of the oil activities.	Annual	No – A detailed list of the individual activities is required.	
10.2	CNH	First Work Program (exploration period).	Within forty-five (45) days following the Effective Date and annually thereafter (prior to September 30th).	Yes – See Sec. 10.4 if they comply with: (i) the Minimum Work Program, the Plan of exploration and the Development Plan, as appropriate, (ii) the provisions of the accounting procedures, and other terms and conditions of this Agreement, (iii) the Industry Best Practices, (iv) the system of administration, and (v) the applicable legislation. However, the IOC shall modify any program of work that would have been contested or that	Legislation provides that no response within the time period is considered deemed approval (Art 36/37/44)

Section	Relevant Authority	Decision Required to be Taken	Frequency of the Decision	Are there defined criteria in the Model PSC?	Does the Hydrocarbon Law or the Model PSC Impose a Time Frame?
				would have received comments on the part of the CNH.	
10.3	CNH	First Work Program (development period).	Simultaneously with the Development Plan and annually thereafter (prior to September 30th).	Yes – See Sec. 10.4 if they comply with: (i) the Minimum Work Program, the Plan of exploration and the Development Plan, as appropriate, (ii) the provisions of the accounting procedures, and other terms and conditions of this Agreement, (iii) the Industry Best Practices, (iv) the system of administration, and (v) the applicable legislation. However, the IOC shall modify any program of work that would have been contested or that would have received comments on the part of the CNH.	
10.6	CNH	Amendments to approved Work Programs	IOC discretion	Yes - if IOC shows that changes are in conformity with the terms and conditions of this Agreement (including the minimum program of work, the exploration plan, and in his case, the Development Plan), the Best Practices of the industry, the system of administration and the applicable legislation.	
10.7	Applicable agency in accordance with the applicable legislation	Drilling permits and authorizations	As required under applicable legislation.	No	
11.2	CNH	First exploration budget.	Within forty-five (45) days following the Effective Date and annually thereafter (prior to September 30th).	Yes - in accordance with the accounting procedures.	
11.3	CNH	First development budget.	Simultaneously with the Development Plan and annually thereafter (prior to September 30th).	Yes - in accordance with the accounting procedures.	
11.5	CNH	Budget amendments.	IOC discretion	No	
12.2	CNH	Propose procedures for the delivery and receipt of hydrocarbons.	Within one hundred eighty (180) days of the start of regular commercial	Yes - The procedures must comply with the provisions of this Contract, the Chapter 11 of the most recent version of the	

Section	Relevant Authority	Decision Required to be Taken	Frequency of the Decision	Are there defined criteria in the Model PSC?	Does the Hydrocarbon Law or the Model PSC Impose a Time Frame?
			production.	Manual of Standards for measuring oil (Manual of Petroleum Measurement Standards of the American Petroleum Institute (American Petroleum Institute), the Best Practices of the industry and the applicable legislation.	
12.3	CNH	Measurement systems and third party calibration	As required	Yes - verify compliance with the applicable legislation and with the Best Practices in the industry.	
13.4	CNH	IOC cannot sell, rent, lease, encumber, warranty, or any other form dispose of materials, without the prior consent of the CNH	As required	No	
14.1(c)	Applicable agency in accordance with the applicable legislation	IOC to obtain all permissions from any applicable Government authority Government.	As required	No	
18.4	CNH	Calculation of deposits into the Abandonment fund.	Annual?	No	
18.7	CNH	Transition Plan for termination	No later than one year prior to the natural conclusion of this Contract	Yes - approval shall not be unreasonably withheld.	
20.3	Agency	Insurance policies and Insurer must meet Agency requirements.	As required	Yes - approval shall not be unreasonably withheld unreasonably.	
20.4	Agency	Modification of Insurance Policies	IOC discretion	No	
24	CNH	Assignments	IOC discretion	No	Legislation provides that no response within the time period is considered deemed approval (Art 15)

ANNEX B

Mexico Shallow Water Model PSC

Access and Notice Requirements

Section	Brief Description	Frequency
2.2	**Discovery of mineral resources**, other than hydrocarbons, in the Contractual Area.	within fifteen (15) days of the discovery
4.6	**Testing of any exploratory well** shall be reported along with projected program for the realization of the proof of testing.	at least ten (10) days prior to the commencement of the proof of testing
4.7	**Preliminary Notification of Discovery** - IOC will notify CNH of any discovery.	within five (5) working days to confirm any discovery
4.7	**Detailed Notification of Discovery** - IOC will submit to CNH: (i) all the technical information available related to the discovery, including the details of the quality, flow, and geological formations; (ii) a report analyzing the information and establishing the details about a possible program of testing of wells, and (iii) their preliminary criteria on the advisability of carrying out an assessment of that discovery, in accordance with the applicable legislation.	within the fifteen (15) days following notification of the discovery
5.4	**Evaluation Report** - IOC shall deliver to CNH a report of all evaluation activities carried out during the evaluation period that contains at least the information referred to in Annex 7.	Not later than sixty (60) days from the completion of the evaluation period
6.1	**Commercial Discovery** – IOC must inform CNH if it considers that the Discovery is a commercial discovery and submit a plan of development for the commercial discovery, in accordance with the provisions of clause 6.2.	Not later than sixty (60) days after the termination of any evaluation period
8.1	**Production Profile** – IOC shall include in their programs of work a production forecast for each well and reservoir.	At the start of the Regular commercial production

Section	Brief Description	Frequency
9	**Unitisation** – IOC must notify the Secretary of Energy and CNH in the event that any discovery is part of a structure, training, or reservoir that extends beyond the limit of the area under contract,	within the period laid down in the applicable legislation
10.5	**Indicative Work Programs** - IOC shall deliver to CNH an Indicative Work Programs for the following two (2) years, establishing the Petroleum Activities that IOC plans to carry out during these years.	along with the work programs referred to in this clause 10
10.8(a)	**Reports of drilling and geophysical** - IOC shall deliver to CNH all geological and geophysical information related to the contract area, as required under any applicable legislation.	during the drilling of any wells
10.8(b)	**Reports of drilling and geophysical** - IOC shall deliver to CNH a final report upon the completion, containing at least the information required by the applicable legislation.	upon the completion
10.9	**Progress Reports** - IOC shall provide CNH a detailed report of progress that shows the progress of petroleum activities during the previous quarter	within ten (10) working days following the end of each quarter
11.4	**Indicative budgets -** IOC shall prepare and submit to CNH, along with the budget referred to in clause 11.1 , an indicative budgets for each of the following two (2) years, establishing the costs that IOC expects incurred during those years.	along with the budget referred to in clause 11.1
11.9	**Obligation to maintain records** – IOC shall maintain in its offices in Mexico all the books of accounts, support documents and other records related to petroleum activities in accordance with the accounting procedures. All of these records shall be available to be inspected, reviewed and audited by any person designated by the Ministry of Finance or by any other competent governmental authority.	continuous
12.1	**Volume and Quality** - CNH may request the measurement of the volume and quality of hydrocarbons produced to wellhead in batteries of separation or along the systems of collection and storage, in which case, IOC shall supply and install the additional equipment required to carry out such measurements. All the information concerning the	continuous and as required under any applicable legislation

Section	Brief Description	Frequency
	measurement of Hydrocarbons Net in situ of the present contract shall be reported to CNH as provided in the applicable legislation.	
12.4	**Records** - IOC shall keep complete and accurate records of all the measurements of hydrocarbons, and shall put at the disposal of CNH faithful copies of the same.	continuous and as required under any applicable legislation
12.6	**Replacement of the Measurement System** – IOC shall notify CNH so its representatives may be present when any measuring system, elements, or software associated with the same is replaced.	replace any measuring system, elements, or software associated with the same
12.7	**Access to the systems of measurement** – IOC shall allow access to the facilities, equipment, systems, software and documentation of IOC relating to the measurement to the officials of CNH duly accredited or her designee.	continuous
14.1	**Additional Obligations of IOC** - (H) IOC shall provide CNH all the information about the existence of mineral, water and other types that are identified as a result of petroleum activities; (L) IOC shall facilitate representatives of the Agency, CNH, of the Secretariat of Finance and of any other authority, in performing inspections of petroleum activities and all the facilities, offices, records and books, as well as all the information related to the activities of the Petroleum and to provide for those representatives, at no cost, the facilities necessary for the exercise of its rights under this Contract, including (for Field operations) transport, accommodation, food and other services, in equal conditions to those provided by IOC to your staff; (M) IOC shall comply with the requests for information from the relevant authorities, including CNH, the Agency, the Secretary of Energy, the Secretariat of Finance and the Fund; (Q) IOC shall report to the Agency and CNH, with the	continuous

Section	Brief Description	Frequency
	appropriate detail, any emergency situations and the steps taken in this respect; (R) IOC shall immediately notify CNH of any judicial or administrative proceedings in which IOC is involved, in relation to this Agreement or with petroleum activities.	
14.3	**Environmental Liability and Industrial Safety** – (F) IOC shall notify CNH and the Agency of any pre-existing environmental liabilities.	Before the second anniversary of the Effective Date
15.5	**Marketing Facilities** - In the event that IOC builds marketing facilities, IOC shall give the marketer, at a reasonable cost, equal access to the facilities of Marketing for the portion of the production of hydrocarbons for the consideration of the State, on the understanding that the cost of marketing facilities shall not be considered a cost-recoverable. The design of marketing facilities must take into account the total volume of hydrocarbons Net, unless otherwise agreed between the Parties.	continuous
18.7	**Transition Plan for termination** -IOC shall submit to CNH for approval a plan for transfer of operations in the area of development that ensures the orderly and safe transmission of petroleum activities and all the materials (the "Transition Plan").	No later than one year prior to the natural conclusion of this Contract
19.3	**National Content** - (C) The IOC shall deliver to the Secretariat of Economy in the frequency established by the Secretariat, a report that includes information on the national content in form and in accordance with the procedure laid down in the provisions that may be issued such a unit to carry out the corresponding verification.	in the frequency established by the Secretariat
24.3	**Request of CNH**. The IOC shall provide CNH all information (including the relative to the assignee or to the person that will monitor IOC) that CNH requires in accordance with the applicable legislation, in respect of any application for approval of proposed divestiture in accordance with Clause 24.1 or a change of control of IOC in accordance with Clause 24.2 .	