Flexible Gross Split Sharing

A new fiscal model for the upstream petroleum industry

May 15, 2017

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1. Introduction

Governments have the duty to maximize the benefits of the resources owned by the State for the benefit of the nation. In the case of oil and gas this is implemented through a variety of petroleum arrangements, such as concessions, licenses, leases, license contracts, production sharing contracts or risk service contracts.

These petroleum arrangements define the "fiscal systems". This means the payments to be made to the government or to the contractor or both. Governments attempt to maximize the revenues from oil and gas development. This is means achieving the highest possible revenues per barrel or Mcf, while balancing this objective with encouraging higher levels of production. Furthermore, policies such as maximization of employment and business opportunities, protecting the environment and minimizing negative social impacts are implemented to optimize the overall national result.

To maximize petroleum revenues, governments have, during the last forty years, increasingly adopted fiscal systems whereby governments receive a share of the profits or profit oil/gas. This requires control and verification of costs to ensure that the government receives its fair share. The profit shares or profit oil/gas shares are increasingly based on complex sliding scales based on the internal rate of return or R-factors or other economic indicators. Such formulas increase the dependence on effective cost control and verification.

As a result, cost control procedures have become increasingly complex. Procedures include prior approval of budgets and charts of accounts, approval of changes in budgets over certain percentages, approval of procurement policies, monthly or trimestral approval of costs, interim and final audits, etc. These detailed procedures tend to be costly for governments and may slow down the approval process for the work programs to be undertaken.

At the same time, the problem is that most government departments do not have qualified personnel to carry out such cost control and verification, due to hiring and salary limitations. Even if ample qualified personal would be available, governments often do not have up-to-date information on actual costs to guide audits.

As a result, the trend towards increased and more complex sharing of the resource rent between governments and companies based on a share of the profits in kind or cash has become increasingly problematical for governments.

As a result, an entirely new fiscal model is now emerging.

This is a model based on a flexible sharing of the gross revenues or gross production with less or no emphasis on profit sharing, except for the payment of corporate income tax and other generally applicable taxes.

The flexibility is created by linking the gross split to variables that are easier to verify for government, such as the oil or gas price, the level of production, well productivity, water depth, well depth, gravity of the oil, chemical content of the gas, etc.

Any of the petroleum arrangements can be modified to create a fiscal system based on flexible gross split sharing. A production sharing contract could be based simply on a split of the gross revenues without cost oil or gas. A royalty under a license contract could be modified into a flexible gross revenue split to be paid in cash or kind. Under a risk service contract the government could pay to the service contractor a share of the oil and gas based on a flexible gross split in cash or kind.

In other words, from a fiscal perspective, under a flexible gross split sharing, there is no longer a difference between a license contract, production sharing contract or risk service contract. They are all based on the same sharing mechanism.

The concept of production sharing contracts based on gross production sharing without cost recovery has already existed for a while. Trinidad and Tobago and Bolivia introduced such contracts in the 1970's. However, these were contracts with a simple production based sliding scale.

Mexico introduced in 2014 a new petroleum revenue law which provides in Article 13 for the possibility of production sharing contracts without cost recovery. As a result, I developed in 2014 a detailed fiscal system for Mexico based on a flexible gross revenue split. However, at the time it was decided to adopt a regular PSC with cost recovery. A copy of the 2014 Mexican proposal without cost limit is attached as Annex A.

Indonesia introduced in January 2017 a new PSC model based on a comprehensive flexible gross revenue split. During April, this year, I proposed a flexible gross revenue split for Iraq to solve the problems with their risk service contracts, called Technical Services Agreements. This is now being evaluated. Other countries are also looking at this concept for modification of concessions or license contracts.

In this report, flexible gross split sharing will be considered in more detail.

2. <u>Design of Flexible Gross Split Sharing</u>

2.1 <u>Style of Formula</u>

Despite the simplicity of the overall concept, already significant different style formulas are introduced or proposed.

Area. The formula would typically be based on the technical or economic data related to a contract or license area. However, for special projects, such as LNG projects, one might base the formula on a group of contract or license areas.

Within a contract or license area, the formula could be based on the results for individual fields, clusters or fields or for unconventional projects. The formula would then be the sum of the components for the contract or license area. This was the concept proposed in Mexico.

Where a contract area is separated in individual blocks or production areas, one might use such blocks as a basis.

However, also some components of the formula could be based on the total contract area, such as the total production from the contract area, while other components such as the gravity of the oil could be field by field within the contract area.

Oil and Gas. Formulas would be different for oil and for gas as in Indonesia and proposed for Mexico and Iraq. In this case "oil" could be crude oil and condensates, while "gas" could be raw gas or natural gas liquids and natural gas. However, also, (1) all liquids could be combined with natural gas being treated separately or (2) the total gas production could be based on the Btu equivalent of condensates, natural gas liquids and natural gas with crude oil being separate. Also for the production levels, the total oil and gas production on a barrel of oil equivalent could be used, as is the case in Indonesia.

Government or Contractor. The formula could specify the gross revenue share going to the contractor with the remainder going to the State, as is the case in Indonesia. Alternatively, the gross revenue share could specify the share going to the State, with the remainder going to the contractor as is proposed for Iraq and was proposed in 2014 in Mexico.

Math Style. All Flexible Gross Split Shares so far introduced or proposed have, what is called in Indonesia, a ***progressive split*** and a ***variable split.*** Indonesia has in addition a ***base split.***

The ***progressive split*** is based on a variable where by the share to government increases (or the contractor share decreases) with a higher value for the variable. For instance, the share to government increases with higher levels of production.

The progressive split could be based on two or more components, for instance in Indonesia it is based on two components: the level of cumulative production and the price level. In the proposal for Iraq it is based on three components: the daily production, price level and well productivity.

The ***variable split*** is an adjustment to the split based on a fixed value being added or subtracted to the results of the progressive split (plus the base split). For instance, in Indonesia the gravity of oil is incorporated based on a variable split. For heavy oil the contractor receives 1% more of the total production. However, the variable split could also be a multiplier. For instance, in Mexico a production method factor was proposed, whereby the share to government was reduced on a percentage basis for secondary, tertiary and unconventional production.

The variable split could be based on a few or many components. Iraq has only two components, while Indonesia has ten components.

Indonesia also has a ***base split*** percentage, which is the start percentage that applies prior to applying the progressive split and variable split. The base split is 57% for government (and 43% for the contractor) for oil. The split for gas is 52% for the government (and 48% for the contractor).

In Indonesia, the formula is as follows:

Contractor Share before Tax = Base Split +/- Variable Split +/- Progressive Split

For Iraq, the proposed formula is as follows:

Government Share = Progressive Split +/- Variable Split.

For Mexico, the formula proposed in 2014 was:

Government Share = Progressive Split * Variable Split

2.2 <u>Progressive Split Components</u>

Cumulative Production Level. Indonesia uses the cumulative production as a progressive split variable based on barrel equivalent of production. Below one million barrel equivalent 5% is added to the base split for the contractor. Over 150 million barrels equivalent 0% is added. There is a step wise sliding scale in between.

Daily Production Level. For Iraq, it is proposed to use the daily production level. The scale is separate for oil and for gas. In the case of Iraq, the formula is a continuous linear function based on four benchmark points. The gross split to government is higher with higher levels of production. The split is determined monthly.

The advantage of a daily production level split is that that towards the end of the life of the field, the production declines and thereby the gross split to government declines. This prolongs the economic life of the field.

Oil Price. Indonesia has a step function with respect to the oil price. Below $ 40 per barrel 7.5% is added to the base split for the contractor. Over $ 115 per barrel 7.5% is subtracted from the base split for the contractor. Between $ 70 and $ 85 per barrel the adjustment is 0%. Indonesia does not adjust the oil price for inflation.

In the case of Iraq, it is proposed that the share going to government is 12.5% at an oil price of $ 40 per barrel and 37% over $ 150 per barrel, in between there are linear functions based on four benchmark points. In the case of Iraq, it is proposed to adjust the oil price on an annual basis for inflation.

Gas Price. Indonesia does not have a progressive split for the gas price. Iraq has such a split.

Well Productivity. An important variable that determines the economics of oil and gas fields is the productivity per well. Therefore, a progressive scale based on well productivity is a useful concept to capture economic rent for governments. The proposal for Iraq has a scale that moves from 0% to 8% between 500 and 10,000 barrels of oil per day per well.

The well productivity is simply determined by taking the total production from the field or contract area and dividing it by the number of wells that are effectively used for production or injection.

2.3 Variable Split Components

Many factors influence the profitability of oil and gas fields. There is therefore a wide variety of possible variable split components. Since Indonesia has the largest number of variable components, the Indonesia list will be used as a basis for discussion and subsequently some other variable components will be discussed from other proposals.

Indonesian Variable Split Components

In the case of Indonesia, the share of the contractor is the basis for the formula and therefore additional percentages improve the gross revenue split of the contractor.

Status of Field. The contractor is offered an extra 5% for the implementation of the first development plan for the field. The number is reduced to 0% for subsequent or further development plans. During the final continuation of production 5% is subtracted.

The extra 5% for the first phase of field development will improve the profitability for the contractor and therefore encourage investment. The subtraction of 5% will create less attractive economics during the final phase of the field, which may result in accelerating abandonment.

Location of Field. For the onshore there is no change in the split. For shallow water of less than 20 meters deep, 8% is added to the split. This percentage is increased with greater water depth to a total of 16% for waters of more than 1000 meters. The location of the field was also a variable in the Mexico proposal with more beneficial terms for deeper water.

Depth of Reservoir. This is the vertical depth to the producing reservoirs. Indonesia adds 1% for reservoirs deeper than 2500 meter. This is not stimulating deep drilling very strongly.

The vertical reservoir depth is not necessarily a good indicator of the well depth. The drilling of deviated or horizontal wells is rather common. In other proposals, therefore, the average well depth is being used as will be discussed below.

Infrastructure. Indonesia adds 2% for operations in new frontier areas and for well-developed areas the number is 0%.

Reservoir Type. Indonesia distinguishes between conventional and non-conventional reservoirs, such as shale oil, shale gas and coalbed methane. For non-conventional reservoirs 16% is added to the contractor split.

This is a rather significant increase and should strongly encourage the development of non-conventional resources once oil and gas price conditions return to higher levels. In the 2014 Mexico proposal non-conventional oil and gas was also stimulated.

CO2 content of gas. The contractor receives support for high CO2 gas. Below 5% CO2 there is not support. Over 60% CO2 in the gas, the increase in the contractor share is 4%. In between there is a sliding scale. The Mexican proposal of 2014 also provided support for high CO2 gas.

H2S content of gas. The contractor also receives support for sour gas. Below 100 ppm of H2S for there is no support. Over 500 ppm there is an extra 1% for the contractor share. In between these values there is a sliding scale.

The support of sour gas is relatively modest compared to the significant extra costs required for sour gas production. The Mexico proposal of 2014 provided for stronger support.

Crude Oil Gravity. Below 25 degrees API, the contractor receives an additional 1%.

Again, this seems rather weak support for heavy crude oils. The Mexico 2014 proposal provided for much stronger support for heavy crude oil. The Iraq proposal also contains a gravity component.

Local Content. Indonesia provides support for local content. Below a local content of 30% the support is 0%. Over 70% it is an additional sharing percentage of 4% for the contractor. In between there is a sliding scale.

This is somewhat unusual. Usually local content provisions and fiscal provisions are not inter-mingled.

Stage of Production. Indonesia separates the stages of primary recovery with 0%, secondary recovery with an additional 3% and tertiary recovery with an additional 5%. Tertiary recovery includes a wide range of EOR techniques. The Mexican 2014 proposal also provided support for secondary and tertiary recovery.

Other Variable Split Formula Components

Well depth. Both in the 2014 proposal in Mexico and the proposal for Iraq, the well depth is included. The well depth is the average for the field or contract area based on producers and injectors that are being used actively for the operations. The Mexican proposal included strong support for deeper wells. In Iraq, it is a modest feature, since it is expected that in Iraqi fields drilling costs are relatively low and well productivities are high.

Time factor. To encourage investment, the Mexican 2014 proposal included a time factor. During the first five years of production for new fields, the percentage payable to government was multiplied by a time factor from 60% to 100% for five 12-month periods. The first 12 months the payment to government was only 60% of the calculated amount, etc.

Start Out Condition Factor. In the Mexico proposal of 2014 a “start out condition” factor was included ranging from 0% to 10%. The purpose of this factor was to distinguish between new contract areas that would still require exploration and areas that would be up for bids with already producing fields. For areas representing high exploratory risk the additional percentage to government was 0%. For existing fields the percentage was 10% to government. There were also intermediate values for other conditions, such as a discovered but not yet producing field.

3. Discussion of Flexible Gross Split Sharing

3.1 Problems of Flexible Gross Split Sharing

A Flexible Gross Split Sharing Formula based on technical and economic parameters has several problems.

Gross Splits are strongly cost regressive.

Appropriately structured Gross Split systems based on technical parameters adjust to cost variation due to these parameters. For instance, the percentage to government in deep water would be less than in shallow water, or highly productive wells would have a higher percentage to government than wells producing lower volumes.

However, such parameters based on Gross Splits do not respond to other reasons for differences in costs. For instance, the cost of an onshore well to the same depth could be very different depending on market conditions. During certain periods or in certain areas there could be scarcity of drilling rigs or drilling services. This means that the costs of wells could be different due to these market conditions. Such cost differences are not captured by the Gross Split parameters.

This means that these systems are strongly "cost regressive". Increases in costs due to market conditions reduce strongly the level of profitability. The market conditions are often beyond the control of the investors. This means that these systems are riskier to contractors.

Inducement of sub-optimal investments

Systems based on technical parameters, such as daily levels of field production could lead in some cases to inducement of development plans of a lower proposed production levels than would be optimal. They could also lead to delay of field expansion until percentages related to daily production have declined in the later stages of field development. This means sliding scales based on daily production should be designed to minimize this effect.

Systems based on well production levels could sometimes lead to an inducement to drill more wells than necessary. For instance, it is my view that the PSC terms applicable to the Libra field in Brazil, have such a problem under low well productivities and low oil prices. Again, sliding scales need to be designed to minimize this effect.

Technical parameters are not good indicators of profitability.

Systems based on technical parameters are not always good indicators of profitability. This is mainly due to the absence of response to market conditions as described above.

However, also the time value of money is not considered. In other words, two fields resulting in the same level of daily production may have different development scenarios depending on economic, social or environmental factors. Fields which reach faster certain levels of daily production are often more profitable. Yet, this may not be captured by the technical parameters.

Systems based on Flexible Gross Splits are difficult to design

Systems based on Flexible Gross Splits are often difficult to design if the objectives are:

- To maximize the extraction of extra-ordinary profits by government,
- To encourage the highest level of investment in a wide variety of resources, and
- To minimize sub-optimal investments.

To more variables are included in the design, the more the above objectives are likely to be achieved. However, the more variables are included, the more complex the formulas and sliding scales become.

3.2 Benefits of Flexible Gross Split Sharing

No Cost Control.

Of course, the main benefit of the use of Flexible Gross Split Sharing is that no cost control or auditing is required, other than for corporate income tax purposes. This greatly simplifies the contract implementation and administration.

Easy to Apply to Contracts which are producing.

Systems based on Flexible Gross Split Sharing are easy to apply to contract areas that are already producing. The parameters would apply on the field by field or project by project basis. Therefore, there is no problem with differences between existing production and production from new investments.

This means that they are very well suited for new exploitation contracts to be concluded at the end of an existing license contract, PSC or risk service contract.

They are superior systems to capture short term extra-ordinary profits.

From a government perspective, the problem with R-factors or IRR based formulas is that one might have to wait for many years until an R-factor or cumulative IRR system provides for the high values that relate to capturing windfall profits. Flexible Gross Split Sharing contracts are excellent systems to rapidly capture extra-ordinary profits as soon as conditions change, provided the systems are administered on a monthly or trimestral basis. For instance, higher payments to government are made as soon as high price levels occur.

They do encourage efficient operations and application of new technology.

The fact that the systems are cost regressive, means that they are excellent systems to encourage efficient operations. Assuming a 25% corporate income tax rate, the investor keeps $ 0.75 for every dollar saved.

This is a very strong incentive to focus on efficiency, bringing costs down and applying the best possible technology.

3.3 Maximum Range of the Gross Split

Table 1 provides for the maximum range of the flexible gross split share.

The minimum share is primarily a political decision.

For instance, the government may decide that as a minimum the government should obtain a 5% share under low oil prices. A low oil price may be defined as $ 40 per barrel (in 2017 $). Based on a 25% corporate tax rate, the cost level that would result in a particular IRR can be back-calculated.

On the assumption that the government determines that the minimum IRR for the contractor should be between 15 and 17% in real terms, the resulting maximum costs in terms of capital and operating expenditures is $ 24 per barrel. Higher cost fields would not be attractive.

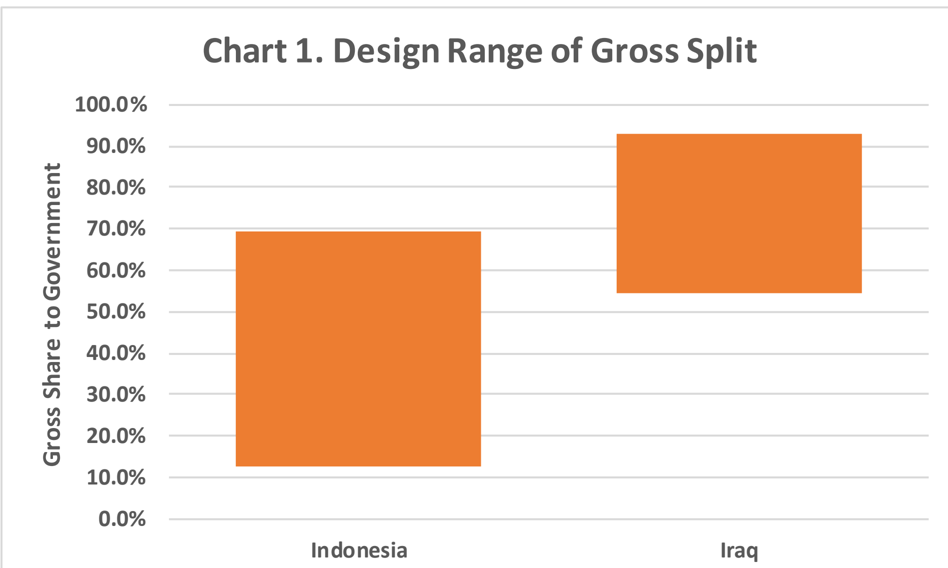
Table 1. Maximum Range of Flexible Gross Split Share

Oil Price	**($/bbl)**	**$40**	**$150**
Capex and Opex	**($/bbl)**	**$24**	**$6**
Tax Rate	**(%)**	**25%**	**25%**
Gross Split to Government		**5.0%**	**93.5%**

The maximum flexible gross split share for government would apply to Middle East style cost conditions under very high oil prices. Based on the same IRR range and an oil price of $ 150 per barrel and capital and operating expenditures of $ 6 per barrel, the maximum split would be 93.5% for government.

There are certain design limitations that covers such a wide range, to be discussed in the next chapter. Therefore, governments may wish to design for a narrower maximum range.

Chart 1 illustrates the design range for Indonesia and Iraq. The Indonesian share to government ranges from 12.5% to 69.5%. The Iraqi share to government ranges from 54.5% to 93%. These different ranges are due to the different economic conditions in Indonesia and Iraq.



4. Design Limitations

There are different ways in which a gross split fiscal system can be designed. My preference is to concentrate first on the progressive split formula components, in the following order: (1) production level, (2) price and (3) well productivity.

Subsequently, the variable split formula components can be determined.

4.1 Target Progressive Gross Splits for the Level of Production

With respect to the progressive split for the cumulative or daily production level it can be recommended to first define a maximum target split for a relatively large field. Where the scale is based on daily production, the maximum level would apply to the plateau level of production. As production declines, lower rates would apply.

The split for large fields would be based on conventional oil and gas and based on primary production in well-developed onshore areas. For oil one would use relatively light oil.

Large fields are typically lower costs on a per barrel basis. Therefore, such fields would pay a high split. Smaller fields would then pay less to government. In case large fields are produced under high costs conditions, such as EOR of heavy oil, the variable split formula components can correct for this.

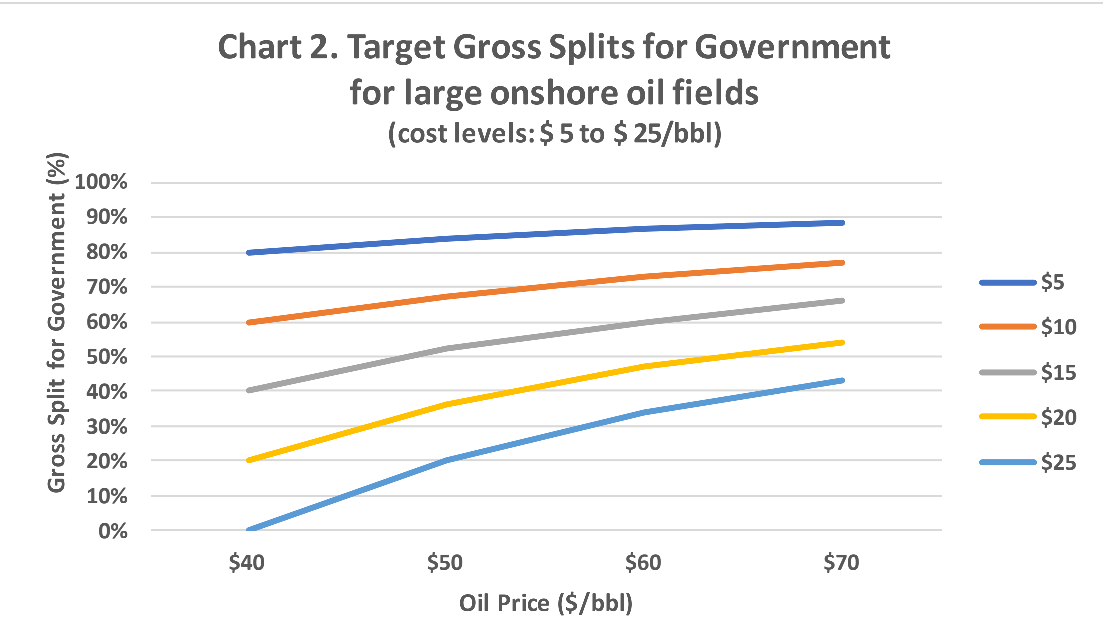
The maximum gross split for production would need to be determined for a particular price level. For oil, this could be the international oil price as is done in Indonesia. However, it is more accurate to use the actual value of the oil at the measurement point in the oil field. This would take transport and quality differentials into account.

For gas, the price level would be based on the local market conditions.

As can be easily understood, the maximum gross split for production levels depends very much on the assumptions of the typical applicable costs and the price level. Table 2 provides an overview of various price-cost combinations. This table is developed using a target profitability of between 15% and 17% IRR on an un-risked basis.

Table 2. Target Gross Splits for Government for large onshore oil fields				
	Price levels ($/bbl)			
Costs/bbl	$40	$50	$60	$70
$5	80.0%	84.0%	86.5%	88.5%
$10	60.0%	67.0%	73.0%	77.0%
$15	40.0%	52.0%	60.0%	66.0%
$20	20.0%	36.0%	47.0%	54.0%
$25	0.0%	20.0%	34.0%	43.0%

Chart 2 provides the same in a chart.



It seems from the Indonesian regulations that a target price between US $ 70 and $ 85 per barrel was used, since this is associated with the 0% price adjustments, while the large field would be more than 150 million barrels. Such a field would be subject to a gross split of 57% to government. Based on Chart 2 this would correspond approximately with a US $ 20 per barrel cost assumption. In Indonesia, the split becomes more favorable for the contractor for smaller fields and under lower prices.

Under the current price conditions, my recommendation is to use a lower target price for setting the production based progressive scale. For instance, for a $ 20 per barrel cost level, a maximum 36% gross split at $ 50 per barrel would be a good target. The daily production based scale can then range from 5% for low levels of production to 36% for high levels of production, for instance.

Of course, for conditions such as in Iraq, where cost levels range from $ 5 to $ 10 per barrel for large fields a much higher gross split can be used, although in this case higher split could be a combination of the production and price based results.

4.2 <u>The Progressive Split Component related to Price</u>

With respect to the progressive split related to price there are important design limitations.

An important principle is that the contractor should always have an incentive to seek the highest possible price. Therefore, the price formula should be such that gross split scale to government is not increasing so strongly with higher prices that the contractor would be worse off under a higher price. In other words, the cash/barrel would decline with higher prices. Under an acceptable system, the cash/barrel to the contractor should continue to increase under higher prices.

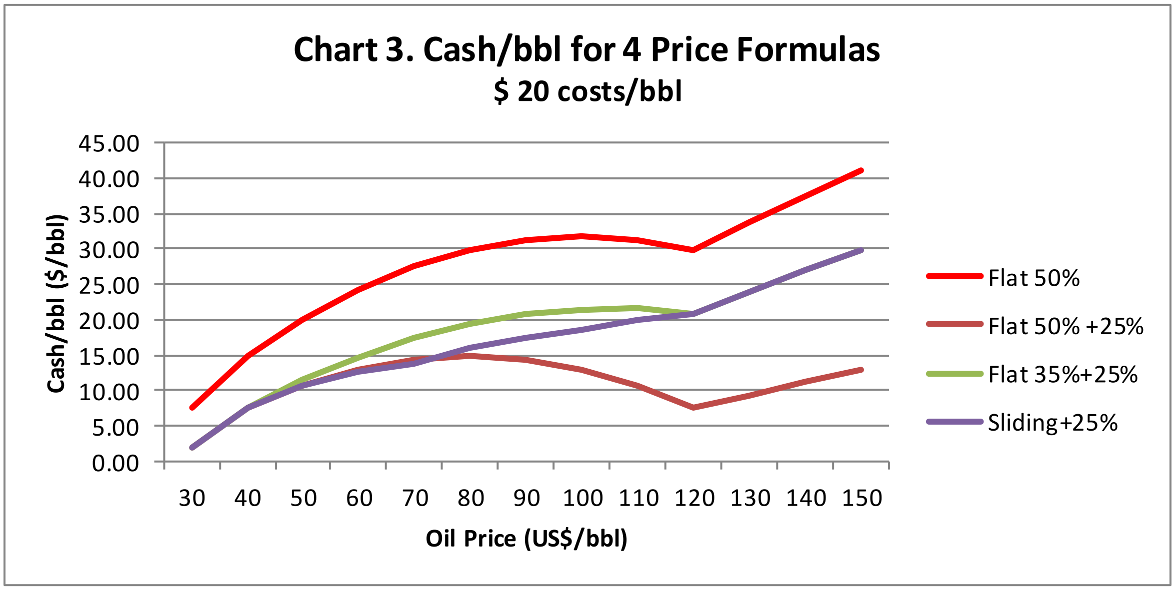
Chart 3 is the display of four alternative price formula options as follows:

(1) Between an oil price of $ 40 and $ 120 per barrel the gross split to government increases from 0% to 50% on a linear basis
(2) This is option (1) but in addition there is a 25% flat gross split share
(3) This is option (2) but now the 50% is reduced to 35%
(4) This is an option whereby there is a flat 25% share plus a price sensitive share with four price benchmarks with the following gross splits to government:
    a. At $ 40 per barrel the split is 0%
    b. At $ 70 per barrel the split is 20%
    c. At $ 100 per barrel the split is 30%
    d. At $ 120 per barrel the split is 35%

    Below $ 40 the split is 0% and over $ 120 the split is 35%. In between the benchmarks the split increases linearly.

The cash/barrel is calculated assuming a 25% corporate income tax rate.

Chart 3 illustrates how for Option 1 the cash/bbl declines between $ 100 and $ 120 per barrel. For Option 2 the cash/bbl declines between $ 80 and $ 120 per barrel. For Option 3 there is a slight dip in cash/bbl between $ 110 and $ 120 per barrel. For Option 4 the cash/bbl increases regularly over the entire price range. This means Option 4 is the only acceptable option.



The gross split to government cannot increase too fast with higher prices. Also, if the goal is to have strong price progressivity, it is important to gradually reduce the slope, so the slope becomes flatter under higher prices.

4.3 <u>The Progressive Split Component related to Well Productivity</u>

The productivity of oil and gas wells is a powerful indicator of profitability. An onshore well to 2 km deep producing 2 barrels per day is uneconomic. A well producing 20 barrels per day would be marginal, while at 200 barrels per day the well would be profitable. Higher well productivities of 2,000 barrels per day or 20,000 barrels per day indicate very profitable conditions.

Therefore, a progressive split formula component related to well productivity is a recommended addition to the formula.

The link to profitability could be further enhanced by counting wells that are producers as well as injectors. This will automatically adjust economics when comparing primary, secondary and tertiary production methods.

The well productivity is simply the total production per field or contract area divided by the number of “useful wells”.

Useful wells are wells that are actively contributing to the production operations. This means that wells in suspension, to be abandoned or with intermittent production would be excluded from the calculation.

A major problem with adding well productivity to the equation is that one wants to avoid that contractors start simply drilling injection wells to lower the gross split rate to government. This means that the progressive scale must be carefully designed.

This can be done by doing detailed analysis of the effect of an incremental injection well. A cash flow analysis is done with and without and additional injection well. If the formula results in a reduction of the gross split payments that is higher than the capital and operating costs of the well, than the formula gives perverse results. It is economic to drill unnecessary wells.

To create reliable results, the analysis should preferably be done based on a high oil price, such as $ 120 per barrel or similarly high gas price. This is recommended because the higher the price, the more the possibility for perverse results that need to be avoided.

Tables 3A, 3B and 3C provide for a typical analysis and search for the recommended sliding scale.

Table 3A illustrates the analysis of a field of 120 million barrels with 44 wells and the analysis of one more injector well being drilled and operated.

The well productivity Scale 1 starts at 20 barrels of oil per day per well with a starting percentage of 20%. The percentage is 0% below 20 barrels of oil per day per well. At 20,000 barrels of oil per day per well the percentage is 38% to government and over this level the percentage remains the same. In between there are benchmarks for 200 and 2,000 barrels of oil per day per well with gross split levels of 30% and 35% to government. In between the benchmarks there is a linear function determining the gross split for each productivity level.

Table 3A illustrates how the reduction in gross split payments is much larger than the costs of the well. The reduction in payments is experienced over the life of the field after the drilling of the well. The NPV@10% of the incremental investment is $ 1.9 million and the incremental IRR is 19.6% in real terms. This means that with this scale it would be beneficial to drill the injector just to lower the gross split.

This means the design of the royalty scale must be “flatter”. This can be achieved by increasing the volume steps.

Table 3A. Analysis of a progressive split for well productivity, Scale 1				
Proposed Scale bopd per well	Gross Split to Government			
20	20%			
200	30%			
2,000	35%			
20,000	38%			
Analysis (2017 $)		**Base +1**	**Base**	**Incremental**
Field Size	(million bbls)	120	120	0
Producers	(wells)	40	40	0
Injectors	(wells)	5	4	1
Oil Price	($/bbl)	120	120	0
Gross Revenues	(Million $)	14400.0	14400.0	0
Capex	(Million $)	548.3	540.0	8.3
Opex	(Million $)	1252.5	1251.5	1.0
SubTotal	(Million $)	12599.3	12608.5	-9.2
Royalties	(Million $)	4384.8	4405.4	-20.6
Corporate Income Tax	(Million $)	2054.7	2051.9	2.9
Total	(Million $)	6159.7	6151.2	8.5
NPV @ 10%	(Million $)	2591.7	2589.9	1.9
IRR	(%)			19.6%

Table 3B shows Scale 2 with an increase of the volume steps, ranging from 60 to 60,000 barrels of oil per day per well.

This now creates a negative incremental NPV@10% of -$1.2 million and the incremental IRR is only 6.8%. This would make the well rather marginal and it is unlikely that a contractor would drill the well just to lower the gross split.

However, the problem of possible perverse investments can be further reduced by making the scale "flatter" by also lowering the benchmarks.

Table 3B. Analysis of a progressive split for well productivity, Scale 2				
Proposed Scale bopd per well	Gross Split to Government			
60	20%			
600	30%			
6,000	35%			
60,000	38%			

Analysis (2017 $)		Base +1	Base	Incremental
Field Size	(million bbls)	120	120	0
Producers	(wells)	40	40	0
Injectors	(wells)	5	4	1
Oil Price	($/bbl)	120	120	0
Gross Revenues	(Million $)	14400.0	14400.0	0
Capex	(Million $)	548.3	540.0	8.3
Opex	(Million $)	1252.5	1251.5	1.0
SubTotal	(Million $)	12599.3	12608.5	-9.2
Royalties	(Million $)	3857.7	3873.3	-15.5
Corporate Income Tax	(Million $)	2186.5	2184.9	1.6
Total	(Million $)	6555.0	6550.3	4.7
NPV @ 10%	(Million $)	2724.4	2725.5	-1.2
IRR	(%)			6.8%

This is shown in Scale 3 in Table 3C. This scale results under these conditions in a negative incremental IRR. The investment in an extra injector just for the purpose of lowering the gross split would not be attractive.

Table 3C. Analysis of a progressive split for well productivity, Scale 3				
Proposed Scale bopd per well	Gross Split to Government			
60	20%			
600	25%			
6,000	27%			
60,000	28%			
Analysis				
(2017 $)		**Base +1**	**Base**	**Incremental**
Field Size	(million bbls)	120	120	0
Producers	(wells)	40	40	0
Injectors	(wells)	5	4	1
Oil Price	($/bbl)	120	120	0
Gross Revenues	(Million $)	14400.0	14400.0	0
Capex	(Million $)	548.3	540.0	8.3
Opex	(Million $)	1252.5	1251.5	1.0
SubTotal	(Million $)	12599.3	12608.5	-9.2
Royalties	(Million $)	3366.5	3373.9	-7.4
Corporate Income Tax	(Million $)	2309.3	2309.7	-0.4
Total	(Million $)	6923.4	6924.9	-1.4
NPV @ 10%	(Million $)	2931.2	2935.3	-4.1
IRR	(%)			neg

As can be seen from this analysis, the design of a proper progressive split component based on well productivity requires rather detailed analysis. It is not possible to avoid perverse investments under all conditions. However, it can be sufficiently suppressed to create a valuable additional component to the formula.

It should be noted that the economics of the well is not only determined by the well productivity, but also by the well depth. The deeper the well, the higher the well productivity must be to economic. Therefore, an interesting concept is to make the volume scale a function of the average well depth. This was done in the Mexican 2014 proposal.

In the Iraq fiscal proposal, the well depth was simply included as a variable split component.

5. Gross Split Implementation

As described in the previous chapter, there are significant design limitations on the progressive split formula components. Yet, actual conditions could require a system that would cover a wider range of circumstances than permitted by the limitations on the progressive splits.

There are the following solutions to this issue:

(1) Make extensive use of variable split components to create a single system for the entire country, as proposed in Indonesia, or
(2) Create specific geographical regions in the country with different cost structures, as proposed for Mexico in 2014, or
(3) Create multiple cost level contracts, or
(4) Adjust the contract during its implementation as is also proposed in Indonesia.

Extensive Use of Variable Split Components

Indonesia has created a single system for the entire country making extensive use of variable split components. For instance, for the location of the field, a base line 0% is allocated for onshore conditions. For shallow offshore water of less than 20 meter water depth 8% is added to the contractor share, for less than 50 meter water depth 10% is added, for less than 150 meter 12%, less than 1000 meter 14% and for more than 1000 meter 16%.

This certainly creates differentiation for the different water depth zones. However, these percentages are than subsequently combined with field sizes from less than 1 million barrels to more than 150 million barrels. For a field of 1 million barrels 5% is added to the contractor share, with a sliding scale downward to 0% for a 150 million field. A field of 1 million barrels is rational in an onshore environment, but is not economic in 1000 meter water depth and therefore is not a useful parameter for very deep water. Even 10, 20 or 50 million barrels may not be economic in ultra-deep water.

The difference between “well developed” and “new frontier” is only 2%. Yet, field sizes for much of the new frontier areas would have to be significantly larger than 1 million barrels to justify new pipelines or other infrastructure.

In other words, in some cases the Indonesian system result in calibration combinations that are not reflective of the various economic conditions.

Geographical Regions

An alternative that was proposed in 2014 in Mexico is to define the location of the field in different geographical regions and link the field size and well productivity to such regions.

This permits to have different progressive split formulas for each region. This will make it possible to calibrate better for the actual economics of each region. For instance, for ultra-deep water a sliding scale based on much larger field sizes and higher well productivities would be used.

It is therefore, that I would recommend this approach.

Multiple Cost Levels in the Same Contract

A different approach could also be used, which is to have different cost levels in the same contract. For instance, in some contract areas, both unconventional and conventional reserves may occur in the same area, in different formations. Different terms could apply to such different types of operations.

It is also possible to have low cost, moderate cost and high cost operations with different terms in the same contract area. This is a system that I recommended for the small fields service contracts with PDO in Oman and was adopted.

A flexible gross split sharing contract could be designed to apply to different cost levels in the same contract area. This also improves the possible accuracy of calibration.

Contract Adjustment

Article 7 of the Indonesian regulations (8 year 2017) implementing the gross split PSC, identifies the possibility for the Minister to increase the split if it exceeds a certain economic level or decrease the split if such level is not achieved.

It is unclear how this will be implemented. The concept of “economic level” presumably is linked to a level of profitability. However, this in turn would again require the extensive cost control and verification that the gross split is meant to avoid.

Apart from an “economic level”, it may be possible to adjust the gross split based on other variables that can be determined objectively and accurately, such as the steel price, certain labour cost levels, the level of general inflation, etc.

Such adjustments may reduce the impact of the strong cost regressive nature of the gross split sharing contract.

6. Conclusions

In principle, flexible gross split sharing is a viable new fiscal model. The model eliminates or reduces significantly administration related to cost control and has the potential to accelerate investments in the petroleum industry under low oil and gas price scenarios based on well-defined price progressive formulas. The model strongly encourages efficiency.

However, the model is more difficult to design and calibrate for a wide variety of conditions than models based on profits. Also, the model increases significantly the cost overrun risk to contractors.

<u>Annex A</u>

Annex A. Mexican 2014 proposal.

Note: Mexico decided for a PSC with cost recovery, so this proposal was not implemented.

In Mexico the extra share going to government (in addition to royalties and tax) was called “Contraprestación”.

<u>Total Contraprestación</u>

The Total Contraprestación for a Contract Area is the sum of the Contraprestación for all Fields, Field Clusters and Unconventional Projects in the Contract Area.

The Total Contraprestación for a Field, Field Cluster or Unconventional Project is determined by the following formula:

$$TC = (VP + VC) \times AMo\% + VG \times AMg\%.$$

In this formula:

TC is the Total Contraprestación
VP is the Contractual Value of Petroleum less the Royalties for Petroleum
VC is the Contractual Value of Condensates less the Royalties for Condensates
VG is the Contractual Value of Natural Gas less the Royalties for Natural Gas
AMo% is the Adjustment Mechanism Percentage for Petroleum and Condensates
AMg% is the Adjustment Mechanism Percentage for Gas.

The Adjustment Mechanism Percentage will be based on the following formula for Petroleum and Condensates:

$$AMo\% = T\%*Po\%*Pr\%*(Fpo\%+Fwo\%+S\%)$$

AMo% is the Adjustment Mechanism for Petroleum
T% is the Time Factor
Po% is the Oil Price Factor
Pr% is the Production Method Factor
Fpo% is the Petroleum Field Production Factor
Fwo% is the Petroleum Well Production Factor
S% is the Start Out Conditions Factor

The Adjustment Mechanism Percentage will be based on the following formula for Gas:

*AMg% = T%*Pg%*Pr%*(Fpg%+Fwg%+S%)*

AMo% is the Adjustment Mechanism for Gas
T% is the Time Factor
Po% is the Gas Price Factor
Pr% is the Production Method Factor
Fpg% is the Gas Field Production Factor
Fwg% is the Gas Well Production Factor
S% is the Start Out Conditions Factor

Production in measured in Barrels of Petroleum Equivalent, using a conversion factor of 6000 cubic feet per barrel.

The formula for AMo% is subject to a minimum percentage for Petroleum (including Condensates) of 1% and a maximum percentage of 87%. The formula for AMG% is subject to a minimum percentage of 1% and a maximum percentage of 70%.

As will be obvious, these very high percentages only apply under unusually profitable conditions such as if Middle East style oil fields would be discovered onshore under high oil and gas price conditions. Also if another Cantarell would be discovered, very high percentages would apply.

<u>Contraprestación Components</u>

<u>Time Factor</u>

In order to encourage the production of new Fields or new Unconventional Projects a Time Factor is introduced.

For Existing Fields the Time Factor is 100%.

For New Fields the Time Factor is:
60% for the first 12 month of production
70% for the following 12 months of production
80% for the following 12 months of production
90% for the following 12 months of production
100% thereafter.

<u>Oil Price Factor</u>

The purpose of the Oil Price Factor is to create price progressivity in addition to the royalty formula.

The Petroleum Base Price is $ 50 per barrel in constant 2015 $.
The Petroleum Price Limit is $ 150 per barrel in constant 2015 $.

If the Contractual Price for Petroleum ("OP") is equal to or less than \$ 50 per barrel the Oil Price Factor ("Po%") is:

Po% = (OP/ Petroleum Base Price) x 60%

Over the Petroleum Base Price and up to the Petroleum Price Limit the formula is:

Po% = 60% + (OP – Petroleum Base Price) x 0.8%

Over the Petroleum Price Limit the Po% is 140%.

Gas Price Factor

The purpose of the Gas Price Factor is to create price progressivity in addition to the royalty formula and to protect investments under the current low gas prices.

The Gas Base Price is \$ 4 per MMBtu in constant 2015 \$
The Gas Price Limit is \$ 20 per MMBtu in constant 2015 \$.

If the Contractual Price for Gas ("GP") is equal to or less than \$ 4 per MMBtu the Gas Price Factor ("Pg%") is

Pg% = (GP/ Petroleum Base Price) x 60%

Over the Gas Base Price and up to the Gas Price Limit the formula is:

Pg% = 60% + (GP – Petroleum Base Price) x 5%

Over the Gas Price Limit the Pg% is 140%.

Production Method Factor

The purpose of the Production Method Factor is to stimulate Secondary and Tertiary recovery and the development of Unconventional Resources. As indicated before it is remarkable how little activity is going on this this respect in the current 14 conversion contracts due to the lack of adequate fiscal terms.

The Production Method Factor is:

- 100% for Primary Recovery Methods
- 85% for Secondary Recovery Methods
- 70% for Tertiary Recovery Methods, and
- 60% for Unconventional Recovery Methods

If a Field is producing under various different production methods the Production Method Factor shall be determined based on the weighted average of the various types of production based on an independent petroleum engineering report.

Petroleum Field Production Factor

The purpose of the Petroleum Field Production Factor is to increase the Contraprestacion with higher levels of Field, Field Cluster or Unconventional Project production.

The Petroleum Field Production Factor is determined by the following formula:

$$Fpo\% = C\%*G\%$$

In which

C% is the Daily Hydrocarbon Production Factor
G% is the Gravity Factor

C% is based on the following scale:

Below Benchmark # 1 – 0%
At Benchmark # 1 - 5%
At Benchmark # 2 - 25%
At Benchmark # 3 - 35%
At Benchmark # 4 - 50%
Over Benchmark# 4 - 50%

In between Benchmarks linear interpolation is used.

The Benchmarks are determined as follows:

Daily Field production level benchmarks in barrels of petroleum equivalent					
Benchmark	Onshore	Offshore 0-200 m	Offshore 200–1000 m	Offshore 1000-2000 m	Offshore over 2000 m
#1	1000	2000	4000	7000	10000
#2	20000	40000	80000	100000	150000
#3	100000	150000	200000	300000	500000
#4	1000000	1250000	1500000	1750000	2000000

As can be seen from the table, the "slope" of the linear relationship from small fields to large fields becomes less. This is to avoid that presentation of development plans with lower than optimal production.

Gravity Factor

The Gravity Factor applies to Oil. It is included to stimulate the development of heavy oil. Many of the contract areas contain very heavy Oil. The production of this oil, and in particular Tertiary recovery project through steam drive of this Oil will be expensive. Therefore an incentive is provided to develop these resources with much higher recovery factors through the Gravity Factor

The Gravity Factor is determined on the API gravity of the Petroleum. Above 23 degrees API the Gravity Factor is 100%. Below 8 degrees API the Gravity Factor is 70%. Linear interpolation is used between 8 and 23 degrees API.

Gas Field Production Factor

The Gas Field Production Factor is determined by the following formula:

$$Fpg\% = 0.8*C\% - Q\%$$

In which

C% is the same Daily Hydrocarbon Production Factor as used for Petroleum.
Q% is the Quality Factor

Quality Factor

Some of the gas in Mexico contains large amounts of H_2S or large amounts of CO_2 or both. The removal of H_2S and CO_2 is costly. Therefore, an additional incentive would assist in bringing these resources about. Much of gas currently being flared contains volumes of H_2S and CO_2 and therefore the Quality Factor will assist in reducing flaring, by making recovery of this gas more economic.

It is suggested that Q% is:

- 5% if the H_2S content of the gas exceeds 5 ppm
- 5% if the CO_2 content of the gas exceeds 2%
- 8% if both the H_2S content exceeds 5ppm and the CO_2 content exceeds 2%.

Petroleum Well Production Factor

The purpose of the Petroleum Well Production Factor is to increase the Contraprestacion with higher levels of well production.

The Petroleum Well Production Factor is determined by the daily production of the Field, Field Cluster or Unconventional Project divided by the number of active Wells (producers, water injectors, gas injectors). The inclusion of water and gas injectors is to stimulate Secondary recovery.

Furthermore the Petroleum Well Production Factor includes a Depth Factor in order to encourage the drilling of deeper wells.

The Petroleum Well Production Factor is based on the following scale:

- Below Benchmark # 1 – 0%
- At Benchmark # 1 - 5%
- At Benchmark # 2 - 25%
- At Benchmark # 3 - 35%
- At Benchmark # 4 - 40%
- Over Benchmark # 4 - 40%

In between Benchmarks linear interpolation is used.

The Benchmarks are determined as follows ("D"is the Depth Factor and * is the multiplication symbol):

Daily well production benchmarks in Barrels of Petroleum Equivalent					
Benchmark	Onshore	Offshore 0-200 m	Offshore 200–1000 m	Offshore 1000-2000 m	Offshore over 2000 m
#1	20*D	40*D	200*D	500*D	1000*D
#2	200*D	400*D	800*D	2000*D	4000*D
#3	1000*D	2000*D	4000*D	6000*D	8000*D
#4	10000*D	12500*D	15000*D	20000*D	30000*D

As can be seen also for well productivity the slope of the linear equations becomes less with higher levels of well productivity. This is to avoid encouraging drilling unnecessary wells.

Depth Factor

In order to take account of Well Depth the values in the previous table are multiplied by the Depth Factor with depth measured along the well bore up to the lowest or furthest producing formation over 1000 m:

Well Depth in meters	Depth Factor
1000	1.00
1500	1.20
2000	1.50
2500	1.90
3000	2.40
3500	3.00
4000	3.70
4500	4.50
5000	5.40
5500	6.40
6000	7.50
6500	8.70
7000	10.00

The measurement of the well depth along the well bore will stimulate horizontal wells and the development of Unconventional resources.

Start Out Condition Factor

The Start Out Condition Factor ensures that a high Contraprestacián is obtained for Fields that are already producing at the Effective Date of the Contract. At the same time the Factor encourages the drilling of new exploration wells, in particular high risk wells.

The proposed Start Out Condition Factor of the Field or Unconventional Project as follows:

- 10% for Existing Fields
- 8% for Field derived from discoveries existing at the Effective Date
- 5% for Fields derived from exploration project with a probability fo commercial success of higher than 30%
- 3% for Unconventional Projects
- 3% for Fields derived from an exploration project with a probability of commercial success of 15 – 30%
- 0% for Fields derived from an exploration project with a probability of commercial success below 15%.