Risk analysis of tax consolidation application in frontier areas on government income

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Abstract

A country needs stronger incentives to increase exploration investment in high-risk isolated frontier and deepwater areas. Tax consolidation is one of the possible incentives to raise exploration investment level in those frontier areas. Tax consolidation means that expenditures of non-producing contract(s) can be deducted from the income of producing contracts of the same contractor(s) for determination of taxable income. From the government point of view, the application of tax consolidation represents its current investment for future income. In this study, risk analysis of the application of tax consolidation in frontier areas was taken with Monte Carlo simulation to identify its impact on the Government of Indonesia (GOI) income and on the profitability of contractor as well as quantifying the risk involves respectively. The result showed, that from contractor's financial aspect, tax consolidation was more attractive incentive compared to increase in production sharing split. On the other hand, it was less attractive to the GOI, not only because it reduced GOI's NPV, but it also posed high risk to the GOI.

Keywords: *Tax consolidation, risk analysis, Monte Carlo simulation, production sharing contract*

Introduction

Given declining tendencies on Indonesia's geological potential especially in western part of Indonesia, there is increased necessity to enhance exploration activity level in other areas if it wants to maintain status as net exporter of petroleum resources. The remaining basins are found largely in eastern part of Indonesia, deep water and frontier areas, which are both riskier and costlier. Moreover, risk capital is in short supply and more difficult to attract, with other countries competing for the same investors. Therefore Indonesia needs stronger incentives to boost exploration investment in high-risk isolated frontier and deepwater areas.

Successful development of any potential petroleum prospects in frontier and deepwater will require an acceptable mix of favourable reservoir performance, attractive commercial contract terms, sound regulations, and production technologies that can meet the challenge. Reservoir performance and commercial incentives are two important drivers in searching oil and gas resources, while technological advancements are critical for developing them economically (Bergman, 1999).

The commercial risk can be reduced by the government, for example by making freely available exploration data and/or by financing exploration activities (Baunsgaard, 2001:6). Financing a portion of exploration activities can be done through tax consolidation. Tax consolidation means that expenditures of non-producing contract(s) can be deducted from the income of producing contracts of the same contractor(s) for determination of taxable income. Tax consolidation implies some sharing of exploration risk between the contractor and the government.

From the government point of view, the application of tax consolidation represents its current investment for future income. Specifically, it represents the reinvestment of a certain portion of government's current oil and gas revenues today to raise the level of exploration activity in achieving future profit. Hence tax consolidation is one of the possible incentives to be offered to raise exploration level in those frontier areas.

At the moment, tax consolidation is not allowed to be applied in petroleum contracts in Indonesia. As stated in the Oil and Gas Law Number 22/2001, the Indonesian PSC ring-fences the contract, which means that all costs associated with a given block or contract must be recovered from revenues generated within that block or contract (Yuwono, 1998). In reality, a form of tax consolidation is already applied to producing contracts in Indonesia. Although the number of non producing active and terminated contracts in Indonesia is almost five times more than the number of producing contracts, the total exploration expenditures of producing contracts are higher than those of non-producing active and terminated contracts. Exploration activities in producing contracts are higher due to several reasons such as cheaper exploration cost per well, lower risk, and ability to deduct exploration expenditures from revenues before tax is counted (tax-consolidation).

Conversely, it is different in non-producing contracts. The risk and the cost of exploration in new areas are higher than the ones in a producing contract. In addition, Indonesia requires each contract to be administered by a separate new company. This restricts consolidation and effectively erects a ring fence around each contract area. This condition gives additional burden to exploration activity in non-producing contracts, and it is shown in the actual total exploration expenditures, which are much lower than the ones in producing contracts. Incentives are needed to increase exploration activity level in new areas outside the producing areas.

Some countries had been successful in applying tax consolidation. United Kingdom, after applying tax consolidation in 1983 as part of its tax reform, realized a rapid recovery from severe drilling slump in 1978-1981 and enjoyed increased discoveries, which added an average of one billion barrels per year oil reserves through 1992 (IPA, 1995:4). In addition to UK, around thirty other countries had applied tax consolidation in their petroleum ventures, including, Norway, France, Germany, Denmark, Netherlands, Nigeria, Congo, Ghana, Australia, Brunei, China, India, Papua New Guinea, Thailand, Philippine, Turkey, Argentina, Canada, USA, Mexico, Peru and others (IPA, 1995:4).

These give compelling reasons to investigate the possibility of applying tax consolidation to Indonesian PSC terms. Risk analysis for the impacts of applying tax consolidation on the Government of Indonesia (GOI) income and on the profitability of contractor needs to be taken.

Literature review

Risk, Uncertainty and Risk Analysis

Uncertainty and risk refer to the outcomes and their implications of some future event, but they have very different technical meanings. Risk is the chance of injury, damage, or loss; the degree of probability of loss; or the amount of possible loss. Risk will be reserved to describe the potential gains or losses associated with particular outcomes. While uncertainty is the quality or state of being uncertain, lack of certainty, doubt. Uncertainty will describe and refer to the range of possible outcome (Murtha, 1995).

Due to its link to probability; risk can be accommodated through the purchase of insurance or hedging. For example, we do not know if we will be in an automobile accident next year, however, since the probability of being in an accident is known, to protect against that unfortunate outcome we can buy insurance. On the other hand uncertainty is the lack of knowledge concerning the probability distribution of future events. Insurance is unavailable to protect against negative outcomes. Therefore, it is vital that the analyst must incorporate uncertainty into their analysis and that the decision maker incorporates uncertainty into the decision process. A lack of knowledge does not put off making assumptions concerning potential outcomes that should be taken into consideration. Even so, uncertainty is an element of almost all decision process.

Generally any change, good or bad, includes some risk. Once the risks have been identified, a model can help to quantify the risks. Quantifying risk means putting a value or price on risk, to help someone decide whether a risk is worth taking. Risk analysis is any form of analysis that studies and efforts to quantify risks associated with an investment. The general objective of risk analysis is describing the range of possible outcome and their consequences. Risk analysis is a future-oriented activity, which is trying to forecast or guess events yet to come. One of the main reasons for this activity is to compare alternative investments (Murtha, 1997:37).

The risk analysis consists of estimating something with range of values rather than with a single value. For example, it is better reported that the NPV of a petroleum project is a normal distribution with a mean of 34 million and a standard deviation of 1.7 million USD than reported in single point estimation such as of 34 million USD.

Usually random variables are used to describe future events whose outcomes are uncertain. Random variable is any variable that has a probability distribution frequency (PDF) or a cumulative distribution frequency (CDF) that defines it. PDF and CDF of A are graphs that tell about how the values of A are distributed.

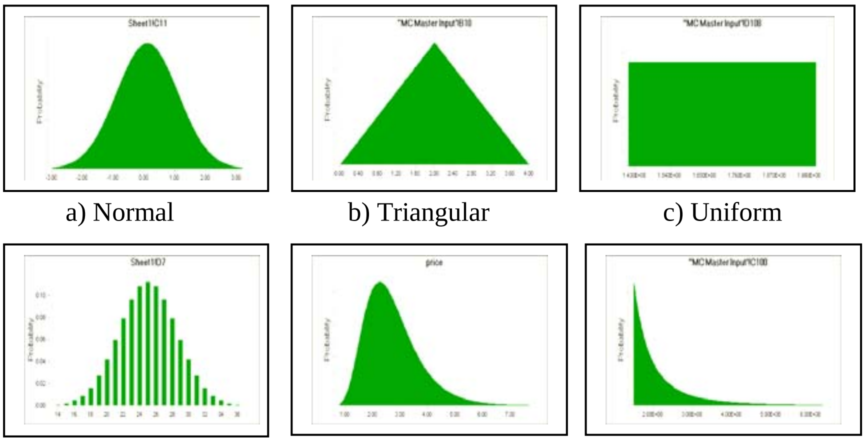
Some types of PDF are widely applicable in the petroleum industry (see Figure 1), such as (Murtha, 1995 and Crystal Ball, 2005):

a) *The Normal Distribution PDF*. The Normal Distribution describes many natural phenomena such as IQ’s, people heights, inflation rate, or error in measurements. It is a continuous probability distribution. The parameters are mean and standard deviation. There are three conditions underlying normal distribution: first some value of the unknown variable is the most likely (the mean of the distribution); second the unknown variable is equally likely to have value above or below of the mean (symmetrical about the mean); and third the unknown variable is more likely to be close to the mean than far away.

b) *The Triangular Distribution PDF*. In some sense, the triangular distribution is merely a simple description of variable, which is more likely to attain values near its mode than near the extremes. It is a continuous probability distribution. The parameters are the minimum, the most likely and the maximum. There are three conditions underlying the triangular distribution, the minimum and the maximum number of items must be fixed and the most likely number of items falls between the minimum and maximum values, forming a triangular shape of distribution.

c) *The Uniform Distribution* is completely specified by giving its minimum and maximum value~~s~~. There is no mode for the uniform distribution~~s~~ and the median equals the mean. In the uniform distribution, any values between the maximum and the minimum are equally likely to occur. It is a continuous probability distribution. There are three conditions underlying uniform distribution, the minimum value is fixed, the maximum value is fixed and all values between minimum and maximum are equally likely to occur.

d) *The Binomial Distribution* PDF is an example of a discrete distribution. A random variable X that is binomially distributed counts the number of successes in n independent trials where p is the probability of success on each trial. When p = ½ the binomial distribution is symmetric.



a) Normal b) Triangular c) Uniform

d) Binomial e) Log Normal f) Pareto

Figure 1: Some type of Probability Distribution Frequency

e) *The Lognormal Distribution* PDF. It describes variables, which are highly skewed to the right, which means that large values of X have much smaller probability than values of X in the opposite direction. It is a continuous probability distribution. The parameters are mean and standard deviation. There are three conditions underlying lognormal distribution, the unknown variable can increase without bound, but is confined to a finite value at the lower limit; the unknown variable exhibits a positively skewed distribution; and the natural logarithm of the unknown variable will yield a normal curve.

f) *Pareto Distribution* is widely used for the investigation of distribution that associated with such empirical phenomena such as city population size, the occurrence of natural resources, the size of companies, personal income, stock price fluctuations, and error clustering in communication circuit. It is a continuous probability distribution. The parameters are location and shape.

Risk analysis using Monte Carlo simulation

One method to carry out risk analysis is by using Monte Carlo simulation. Monte Carlo is a technique to calculate the uncertainty in a forecast of future event. The method was named Monte Carlo for its similarity with roulette game, a simple random number generator. It is effective in assessing risk and modelling uncertainty. Monte Carlo simulation allows us to replace uncertain quantities in spreadsheet models with reasonable estimates ranges and then see more accurately how that uncertainty affects the outcome of the model. It provides information concerning the best and the worst-case range of outcomes or probability of reaching specific targets.

This simulation involves approximation of the distribution of possible outcome of certain combinations of random variables, of which each has its own probability distribution function, through statistical sampling. This method is often used when the model is complex, non-linear, or involves more than just a couple uncertain parameters. A simulation can typically involve over 10,000 evaluations of the model, a task that in the past was only practical using super computers.

At each trial, the method will sample the distribution of each variable randomly and then calculate the outcome. As the number of trials increases, the distribution of experiment results will approximate the probability distribution function of the outcome. This distribution of the outcome will cater to questions such as the likelihood a certain project will generate NPV more than 100 million USD, a certain reservoir has 90% chance to have oil in place bigger than 100 million STB and others. These kinds of answers will help in assessing the risk of certain outcome.

Figure 2 shows an example of an application of Monte Carlo simulation to estimate a simple equation of $F = X*Y$. At each trial, the distribution function of the input parameters X and Y are sampled, the realizations of X and Y of the trial are then multiplied to calculate F. The trial process is then repeated multiple times, if the number of trials is sufficient enough then histogram of the trial results is the approximation of the distribution function of F.

The strength of Monte Carlo simulation are its universal applicability, the result contains maximum information about possible outcomes and the methods itself leads to sensitivity analysis. The advantages of the simulation include ability to sample the full range of each uncertain input parameter and to use it in generating the probabilistic model outcome. The second advantage is easy to implement, any input-output model can be utilised in the Monte Carlo process without making any modifications to the original model. The third advantage is that the Monte Carlo approach is conceptually simple and easy to explain.

Monte Carlo simulation starts with development of a model, i.e., one or more equations, together with assumptions and logic relating the parameter in the equation. After the model was developed, the second step is determining the influencing factors/variables, which may cause the largest affects against the outcome. Then to analyse and identify the inter relationship between each factors. This procedure is done by either using expert opinion or historical data information.

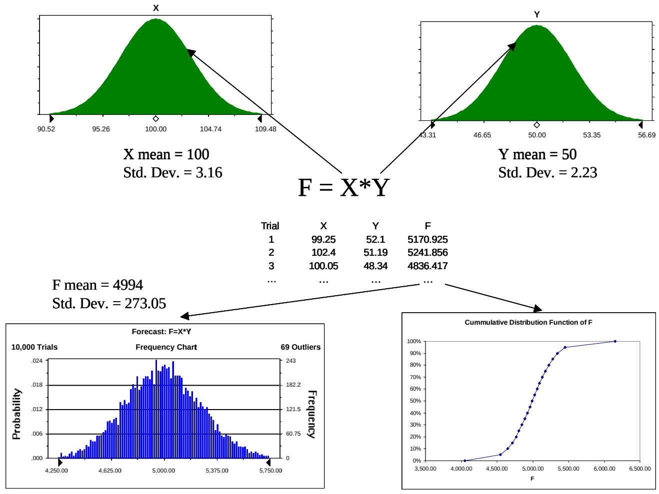


Figure 2: Schematic Example of Monte Carlo Simulation

The third step is to determine the input value~~s~~ for each variable above to be applied in the model. The input value~~s~~ for each variable~~s~~ above is in distribution form. Therefore, determining the most suitable distribution for each variable based on historical information or expert opinion has to be done. Lognormal distributions are often used for many of the volumetric model input, while triangular distributions are also fairly common and are easy to adapt because they can be symmetric or skewed either left or right. In the case there are sufficient historical data, they can be used to determine the suitable distribution. Expert opinion is only used to determine the distribution in the case there are not enough information available. Finally the fourth step is to run the model using Monte Carlo software to shape the probability distribution of the outcomes. Sensitivity analysis then will be drawn as the final step (Murtha, 1997:2-3).

A petroleum E&P venture is characterised as high risk and uncertainty venture. There are many uncertainties related to it, such as uncertainty on the existence of petroleum resources, uncertainties on the type and volume of hydrocarbons accumulation in case of discovery, price variation, lift costs variation due to different complexities of each accumulation, as well as other uncertainties. Therefore investment decision-making in this venture faces complex situation. As example due to its uncertainties, it is difficult to choose the accurate assumptions to forecast the profiles of input variables of the model such as production, cost, price and others in doing the cash flow analysis.

As mentioned earlier, under Monte Carlo simulation each input variable has its own probability distribution and the probability distribution of the outcome will cater to questions such as the probability a certain project has 80% chance will generate NPV more than 100 million USD and other. Moreover this method is often used when the model is complex, non-linear, or involves more than just a couple uncertain parameters. It also has many advantages and strength as already mentioned earlier. These facts imply that this method is appropriate to be used in making risk analysis in petroleum E&P venture.

Rate of return on investment

Jones, (1993:7-12), Seba (1998:155-189), and Newendrop (2000:16-46) recommended three parameters to determine the profitability of certain petroleum E&P project proposal, namely Net Present Value (NPV), Internal Rate of Return (IRR) and Payback Period (POT).

Net Present Value (NPV), which is derived by discounting a project's cash receipts using the required discount rate, summing them over the lifetime of the proposal and deducting the investment outlay. Each company has its discount rate. In the mineral investment, expenditures would be credited through the whole life of the project, so the NPV of the project is as follows:

$$NPV = \sum_{t=1}^{n} \frac{R_t}{(1 + k)^t} - \sum_{t=1}^{n} \frac{C_t}{(1 + k)^t}$$

where: C_t : initial cash outlay on the project
R_t : net cash flow at time t
n : project life
k : discount rate

If the present value of net in cash flow in the future is higher than the present value of investment (NPV > 0), the project is financially feasible because it is profitable. If the present value of net in cash flow on the future is lower than the present value of investment (NPV< 0) the project is financially not feasible because it is not profitable.

Internal Rate of Return (IRR), is defined as the rate of discount, which equates the present value of the stream of net receipts with the initial outlay (NPV = 0):

$$\sum_{t=1}^{n} \frac{R_t}{(1 + r)^t} = \sum_{t=1}^{n} \frac{C_t}{(1 + r)^t}$$

where: C_t : initial cash outlay on the project
R_t : net cash flow at time t
n : project life
r : the internal rate of return

In general the IRR will be compared to the relevant levels of company's minimum required of rate of return. Each company has its minimum required rate of return. If the IRR is higher than the company's minimum required rate of return, the investment is profitable and financially feasible. If it is lower, the investment is not profitable and financially is not feasible.

In the treatment of uncertainty and risks in petroleum E&P venture, most investors are risk averse; he/she will choose the less risky project than the more risky project with the same net present value. The risk premium depends on the riskiness of the project. Higher risks must be balanced with higher rate. This risk premium represents the company's required compensation for taking the risk. The size of the risk premium is affected by actions of the government, and will be lower if commercial and political risk can be reduced. The commercial risk can be reduced by the government, for example by making exploration data freely available or by financing exploration activities. While strengthening the macroeconomic and fiscal stability are required to reduce the political risks (Baunsgaard, 2001:6). Jones (1993:11) recommended the minimum required rate of return of the investment on petroleum E&P project as follows:

High risk : 30% - 40%
Medium risk: 20% - 30%
Low risk : 15% – 25%

The POT is the time needed for all investment outflows to be compensated by back inflows, the formula as follows:

$$\Sigma \text{ Cash inflow } - \Sigma \text{ Cash outflow } = 0$$

Uncertainty increases over time. A way to reduce this uncertainty is by giving the company high profit in the early of production activity (Siebert, 1984:30) that shortens pay out time (POT) of its investment. Shorter POT is better, because the cash-outflow can be paid out in shorter time, and in turn can be invested in other projects.

Methodology

The Monte Carlo simulations were drawn to identify the impact of tax consolidation application in frontier areas to GOI income and contractor’s profitability as well as to quantify the risks involve and compared it with the impact of increasing the contractor’s production sharing split. The tax consolidation application was set up strictly to improve the exploration activities in frontier area only.

Two simulations were drawn, as follows:
a) Single commercial contract analysis,
b) Aggregate combined contracts analysis.

Single commercial contract analysis

To compare how tax consolidation application in frontier area affected the GOI’s income and contractor’s profitability in case of a commercial discovery on a PSC contract, single commercial contract analysis was considered. Six possible scenarios combining tax consolidation and increasing contractor’s production sharing split were investigated:
(a) 65/35 production sharing split without tax consolidation (fifth incentives package figures) as the base case,
(b) 65/35 production sharing split with tax consolidation,
(c) 60/40 production sharing split without tax consolidation,
(d) 60/40 production sharing split with tax consolidation,
(e) 55/45 production sharing split without tax consolidation,
(f) 55/45 production sharing split with tax consolidation.

The financial model of the PSC contracts followed the Indonesian PSC Diagram Flow and Financial Model as shown in Figure 3 and Figure 4. Other than the contractor production sharing split and the tax consolidation above, the assumptions of the other PSC variables were set up the same as the highest figures of the fifth incentives package variables summarised in Table 1. They were as follows: the signature bonus was 26.6 million USD; the FTP of 10%; the investment credit of 102.14%; the depreciation of five years double declining balance; the DMO price of 25% of export price; the DMO holiday price of five years and the tax rate of 44%.

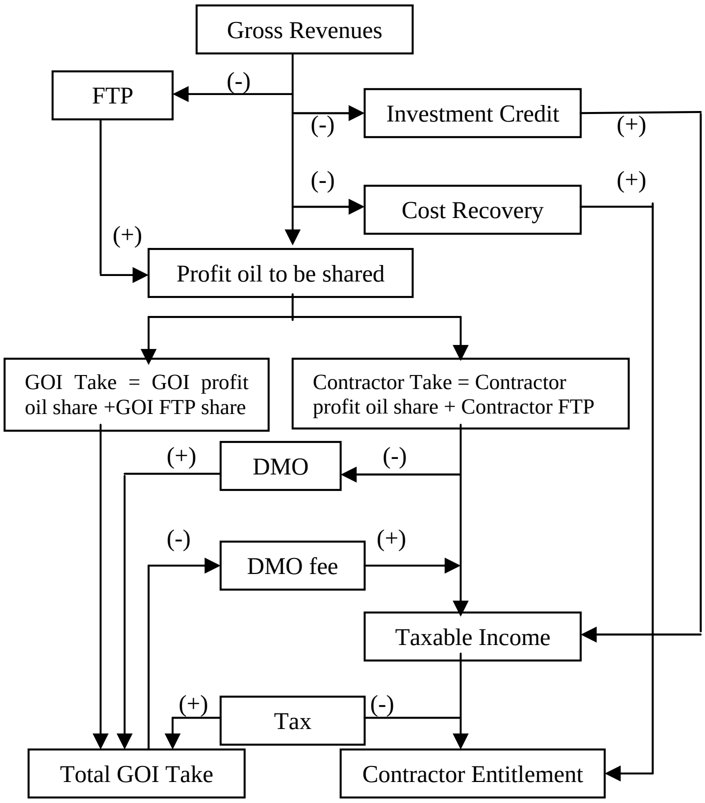


Figure 3: The diagram flow of Indonesian production sharing contract (Partowidagdo, 1993; Barmi, 1996; and Yuwono, 1998)

Gross revenues	=	Total oil revenues (Production x Price)
Net Revenues	=	Gross Revenues - FTP
Cost Recovery	=	Operating cost
"Cost petroleum"	+	Intangible capital costs
	+	Investment Credits
	+	Un-recovered costs carried forward
Equity to be split	=	Net Revenues – Cost recovery
Cont. equity share	=	Equity to be share x CPSF
Cont. FTP share	=	FTP x CPSF
Contractor Share	=	Contractor equity share
	+	Contractor FTP share
	-	DMO
	+	DMO fee
	-	Taxes
Net Contractor cash flow	=	Contractor Share – Total expenditures
GOI Share	=	GOI equity share
	+	GOI share from FTP
	+	DMO
	-	DMO fee
	+	Taxes

Figure 4: The financial model of the Indonesian production sharing contract

The first assumption was the tax consolidation was applicable strictly to cover exploration cost in frontier areas only. Duration of each activity was set up at one life cycle of PSC contract, 30 years. The exploration phase of each contract was assumed to be performed in the first 3 years, followed by development phase, if there was commercial discovery, which covers year 4 to year 8.

The input variables were the total additional contract in frontier area/year, the exploration cost, the tax rate, discovery outcome, the commerciality of discovery, the reserve discovery size, the development costs (capital and non capital costs), the production costs, the production type, the production profile and the oil prices. How the probability distributions of these input variables were established is described below.

The probability distribution of exploration expenditures for each area was assumed to be uniform distribution with minimum and maximum values of 140.9 million USD and 200 million USD respectively. The minimum value was set up at the minimum exploration commitment as stated in the IP5 terms (140.9 million USD), while the maximum value was set up at roughly three times the historical maximum exploration expenditures cash out in 2003 (BP Migas, 2004). All values were at 2004 value.

The tax rate was assumed similar to the IP5 terms of 44%. In the scenarios with tax consolidation, the tax consolidation cost to government was assumed as tax rate times the total exploration cost. In contrast there was no cost in the scenario without tax consolidation, the GOI income was the total GOI take in the entire scenarios. Therefore in the scenarios with tax consolidation, the tax consolidation cost to GOI was 44% of the total exploration expenditures while the remaining 56% of total exploration expenditures was the cost for contractors. The exploration expenditures were distributed evenly from the first to third years of the contract. It was assumed in single commercial contract analysis that the minimum commercial reserve size was 150 millions barrels of oil (Conoco Phillip, 2004).

The development cost per barrel, if there was commercial discovery, was assumed to have uniform probability distribution with minimum and maximum values of 6 and 9 USD per barrel respectively. The minimum value was set up at the 2004's average of development cost of 24 US petroleum companies that operated in eastern hemisphere (not including Middle East area), while the maximum value was set up at the 2004's average of development cost of world operation of 24 US petroleum companies (EIA, 2006:34). Half of the development cost was assumed to be capital expenditures. In the case of commercial discovery, the development cost was distributed evenly from year 4 to year 8 and escalated by 3% per year. This value was an average of the annual changes of US Consumer Price Index during 1990 to 2003.

The production costs were divided into two types, fixed production cost and variable production cost. Fixed production cost represented the expenses that were independent of production rate, while variable production cost represented the expenses that were dependent on the production rate of the field. The fixed production cost was assumed to have uniform distribution with minimum and maximum values of USD 20 and 30 millions respectively, while the variable cost was assumed to have uniform distribution with minimum and maximum values of 1 and 1.5 USD/barrels respectively. The production cost was also escalated by factor of 3% per year. While the probability distribution values of the production costs, both fixed and variable were based on educated guess, these values gave mean total production cost of around 4.31 USD/barrel. For comparison purpose, the 2006 EIA data showed that the average lifting cost worldwide was 4.25 USD/barrel, while for eastern hemisphere (not including Middle East area), the cost was 4.26 USD/barrel (EIA, 2006:34).

The type of hydrocarbon produced in each discovery was assumed to be oil. The production started in year six, where the oil yearly production was linearly increased from 50% of the plateau production to 100% plateau production in year 9. The yearly plateau production was set at 11% of the reserve. The plateau production was maintained for 2 years, afterward the production declined by 17.4% exponentially each year. Figure 5 shows the production profile in term of percentage of the total reserve.

Oil price probability was assumed to have triangular probability distribution with most likely value of 21 USD per barrel. The minimum and maximum prices were set at 9 and 76 USD per barrel respectively. This distribution was based on the approximation of actual yearly historical US crude oil price distribution since 1974 (after the historical OPEC embargo) adjusted to 2004 USD value. The oil price was escalated by 3% per year.

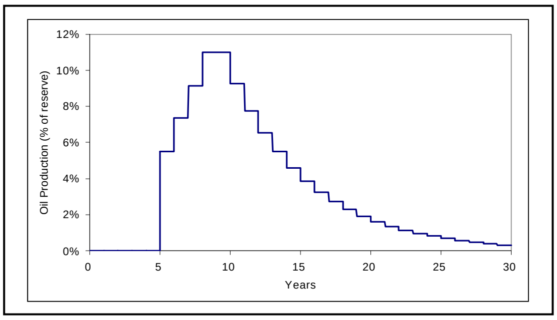


Figure 5: Yearly oil production profile for commercial contracts

To properly characterize the possible outcomes, the Monte Carlo simulations were drawn 10,000 times using Crystal Ball software academic professional edition version 7.2 from Decisioneering Inc.

The output variables from the contractor's view were the size and the probability distribution of contractor's NPV@25%, as well as the IRR. While from the GOI's view, the output variables were the size and the probability distribution of GOI's NPV@25%, IRR as well as the reserve addition. It was assumed that the tax reduction in tax consolidation scenarios was the GOI cash outflow or investment, so that the GOI's IRR could be calculated.

To simplify the comparison between tax consolidation application and production split increased, three scenarios were analysed in more detail as follows:

a) The 65/35 production split case without tax consolidation, which was referred as the base case,

b) The 65/35 split case with tax consolidation, which was referred as the tax consolidation case, and

c) The case with 55/45 production split case without tax consolidation, which was referred as the production split increase case.

In effect, the comparison was between the most conservative tax consolidation scenario and the most progressive production split scenario.

Another comparison was also made as well in term of the ratio of contractor's Cash Flow and contractor's share of exploration cost:

$$(NCF\ /\ EC)Ratio = \frac{NetCashFlow_{contractor}}{Exploration\,Cost_{contractor}}$$

The ratio of contractor's Net Cash Flow to its Exploration cost was used to calculate the approximate probability distribution of the number of contracts signed each year in aggregate combined contracts analysis below.

Aggregate combined contracts analysis

To analyse whether the increase in exploration activity associated with tax consolidation were beneficial to the GOI, another Monte Carlo simulation was evaluated. This time, the analysis was not based on single commercial contract; rather, the analysis was performed on the combined contracts basis; all total contracts in Indonesian frontier area are consolidated into one. The simulation was done for two scenarios; tax consolidation with 65/35 contractor production sharing split, and production sharing split 55/45 without tax consolidation, i.e. the tax consolidation scenario and increasing production split scenario.

The assumptions used in addition to the ones explained in the previous section were as below.

The analysis were limited to only the additional areas signed during the first 10 years since tax consolidation or increase in production split (55/45) started to be effective. While the number of contracts signed each year under tax consolidation scenario was assumed to have triangular probability distribution with,

a) Tax consolidation case (production sharing split 65/35 with tax consolidation): most likely value of 3, minimum and maximum values of 0 and 6 respectively.
b) Progressive improved production split case (production sharing split 55/45 without tax consolidation): most likely, minimum and maximum values were set up at ratio of NCF/CE of production split 55/45 case to NCF/CE of tax consolidation case times its each value in tax consolidation case.

The success probability of commercial discovery of each contract was assumed to be normally distributed, with mean 12.5% and P5 of 14.51; this value was set up at historical average ratio of producing PSC contract to total PSC contract signed during 1966 – 2003 in Indonesia. Assuming that the minimum commercial reserve discovery in frontier area was 150 million barrels (ConocoPhillips, 2004); the probability reserves size was assumed to have Pareto distribution with location 150 million barrels and P5 of 450 million barrels.

The total exploration cost described previously was applied only to contracts in which hydrocarbon reserves were discovered (whether commercial or non-commercial). If there were no discovery made, the exploration cost would only be 2/3 of the total exploration cost of contract with discovery, distributed in the first two years of the contract. The above assumption was made in consideration that if there were discovery after the drilling of the first few wells there would be more exploration activity to delineate and determine the reserve size and its commerciality. While if there were no discovery after the first few wells, then exploration activity was stopped.

The outcomes considered in this Monte Carlo simulation were the aggregate GOI and contractor's NPV@25% and IRR as well as the reserve addition. It means that the cash flows of all possible contracts were combined into single cash flow to determine the aggregate NPV@25% and IRR. Similar to the single contract simulation, it was assumed that the tax reduction was the GOI cash outflow/investment, so that the GOI's IRR could be calculated.

Results and findings

Single commercial contract analysis results

To properly characterize the possible outcomes of the six scenarios, the simulations/trials were repeated 10,000 times. The results of the six scenarios are showed in Figure 6 to Figure 8. The histograms of the base case (65/35 production sharing split with tax consolidation) are presented in Figure 9. The histograms for other scenarios had similar shapes but with different values of parameters as described in Figure 6, Figure 7, and Figure 8.

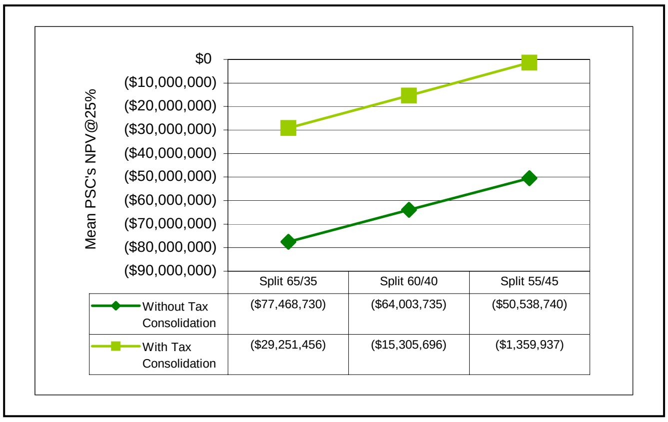


Figure 6: Mean NPV@25% of contractor

Figure 6 shows that all six scenarios gave negative mean and median of contractor's NPV@25%, suggesting that they were not sufficient to pass the commercial performance. Figure 7 shows that the mean and median of contractor's IRR of 65/35 production split with tax consolidation scenario were around 23% compared to 22% in 55/45 production split without tax consolidation scenario. In comparison, the base case, 65/35 case without tax consolidation, the mean and median of contractor's IRR were around 21%. This result shows that, from the financial aspect of the contractor, the application of tax consolidation was better than the improvement in production split term from 65/35 to 55/45. However, both incentives still could not raise the contractor's IRR to above the minimum required rate of return of high risk investment suggested by Jones's (over 30%).

Also, as shown in Figure 8, the application of tax consolidation reduced the values of mean NPV@25% for the GOI to 299 million USD, 313 million, and 327 million from 348 million USD, 361 million and 375 million USD for production sharing split of 55/45, 60/40 and 65/35 respectively. The values of mean GOI's IRR for the cases with tax consolidation were 74.31%, 75.03% and 75.75% for production sharing split of 55/45, 60/40 and 65/35 respectively as were seen in Table 2. While in without tax consolidation cases, the IRR was undefined since there was no monetary cost for the GOI.

Compared to the base case, the application of tax consolidation increased contractor's mean NPV@25% by 48 million USD. On the other hand, the improvement of production sharing split of 55/45 without tax consolidation increased contractor's mean NPV25@% by 27 millions USD.

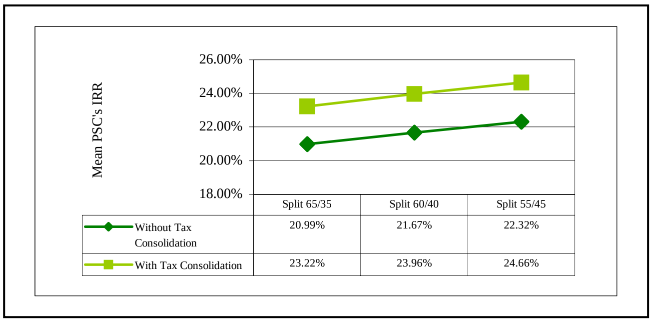


Figure 7: Mean IRR of contractor

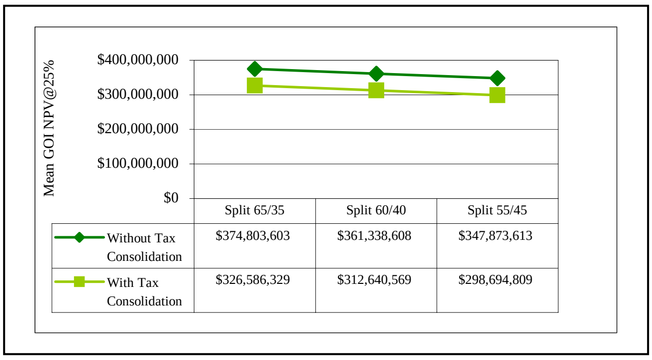


Figure 8: Mean NPV@25% of GOI

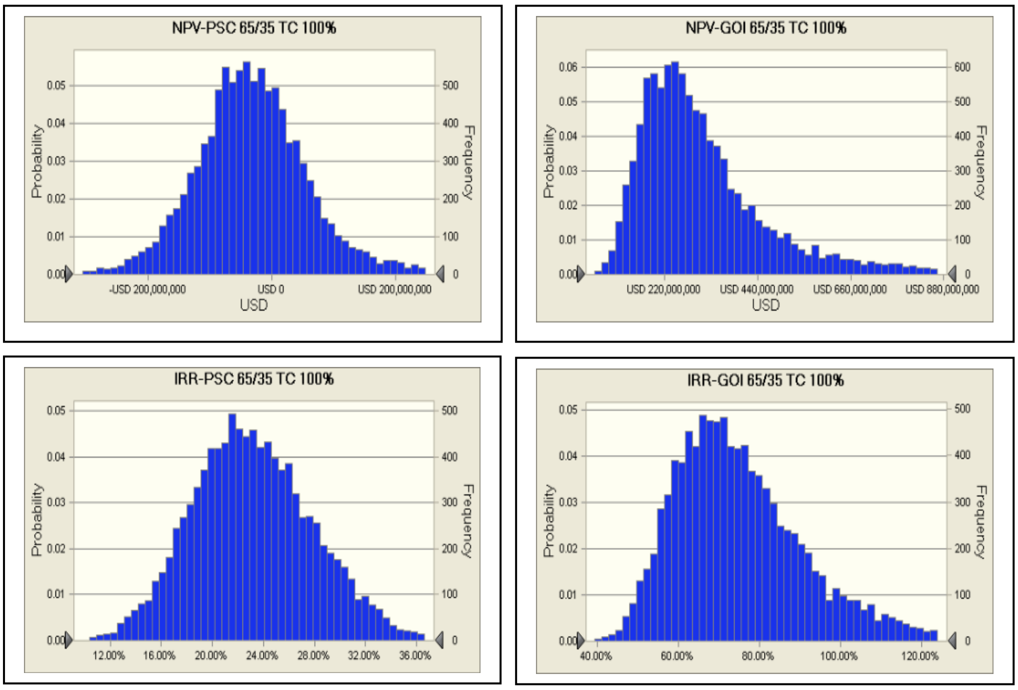


Figure 9: Histograms of 65/35 production sharing split with tax consolidation

From the GOI point of view, the application of tax consolidation reduced its mean GOI-NPV@25% by 13% from 375 million USD to 327 million USD in the base case, while the increase in production sharing split reduced it to 347 USD million, a reduction of around 7%. The mean of GOI-IRR in production sharing split 65/35 with tax consolidation case is 75.75%, a good and healthy value. However, this also meant some financial risk to the government, considering the fact that in the production split scenario, the GOI-IRR was undefined; there was no financial risk to the GOI.

Figure 10 and Table 3 show probability distribution of the ratio of (Net Cash Flow/Exploration Cost) of the base case, 65/35 production sharing split with tax consolidation, and 55/45 production sharing split without tax consolidation to the base case (Net Cash Flow/Exploration Cost) from the Monte Carlo simulation. Naturally, the ratio for the base case was 1, while the ratio values of 65/35 production sharing split with tax consolidation, and 55/45 production sharing split without tax consolidation were 1.63 and 1.17 respectively. This suggests that the application of tax consolidation will potentially give contractor 1.63 times more net cash flow for each dollar spent in exploration, on the other hand improvement in production sharing split to 55/45 will increase it by only 1.2 times. Direct comparison between the two cases also shows that tax consolidation case will potentially gave almost 1.4 times as much as the case with production sharing split increase for each dollar spent in exploration. This value would be used to approximate the number of contracts signed in the aggregate contract analysis mentioned in the next section.

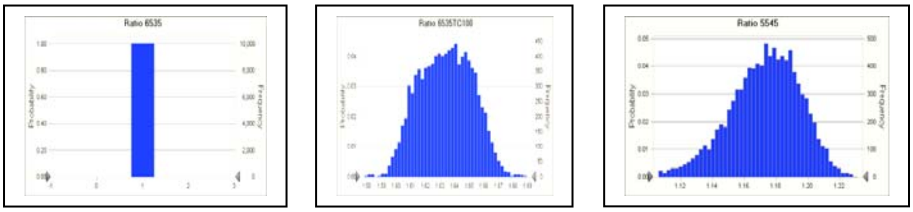


Figure 10: Histograms of ratio contractor's net cash flow to its exploration cost for tax consolidation scenarios

With the assumptions as described above, on the basis of single commercial contract, the results suggest that from the point of view of contractor, tax consolidation application was more attractive incentive than progressive improvement in production sharing split from 65/35 to 55/45. Hence, it was more likely to increase the level of exploration investment. However, it came with more penalties, and more importantly, the tax consolidation application came with more risk to the GOI than the increasing production sharing split scenario.

Aggregate combined contracts analysis results

The analysis in the previous section shows that tax consolidation can potentially be more attractive incentive to the contractor than progressive improvement in production sharing split to increase the level of E&P investment in Indonesia. However, it came at a price to the government, as it posed risk and reduced the NPV and cash flow share of GOI in a single contract basis. To assess whether the increase in exploration investment (thus more contracts signed) would eventually generate more aggregate NPV for the government, analysis on the aggregate level was performed by Monte Carlo simulation.

As mentioned earlier, the aggregate combined contract analysis was limited to only the additional areas signed during the first 10 years since tax consolidation (production sharing split 65/35 with tax consolidation) application or increase in production sharing split to 55/45 starts to be effective. While the number of contracts signed each year under tax consolidation scenario was assumed to have triangular probability distribution with:

a) Tax consolidation case (production sharing split 65/35 with tax consolidation): most likely value of 3 and minimum and maximum values of 0 and 6 respectively.

b) Progressive improved production split case (production sharing split 55/45 without tax consolidation): most likely value of 2 and minimum and maximum values of 0 and 4 respectively.

The most likely value of 3 and 2 in cases a) and b) respectively were obtained based on the ratio of (Net Cash Flow/Exploration Cost) of the respective cases. As mentioned in the previous section, the ratio between the two cases from the single contract analysis was found to be around 1.4. This ratio was then used to approximate the ratio of likelihood of the number of contracts between the 2 cases (3 and 2, or ratio of 1.5).

The simulation results after 10,000 trials are presented in Table 4and Table 5. The results show that, under the assumption of the number of additional contracts mentioned above, tax consolidation application can potentially add more than 700 million STB of reserve, almost doubling the potential reserve addition from production split increase scenario (425 millions STB). However, the mean GOI IRR was only around 22%, less than the minimum required rate of return high-risk investment as suggested by Jones (30%). Consequently the mean and median of GOI NPV@25% were negative (minus 35 millions USD and minus 108 millions USD respectively. In contrast, in the production split improvement case, the mean and the median GOI NPV@25% were USD 252 and USD 185 millions respectively.

Figures 11 to 13 show the histograms and the cumulative distributions of the GOI's NPV@25% and IRR. They show that in tax consolidation case, the probability of the GOI's NPV@25% lower than zero or equivalently the probability of the IRR to be lower than 25% was around 60%. This suggests that application of tax consolidation, under assumptions specified in this study, was a high-risk decision for the GOI

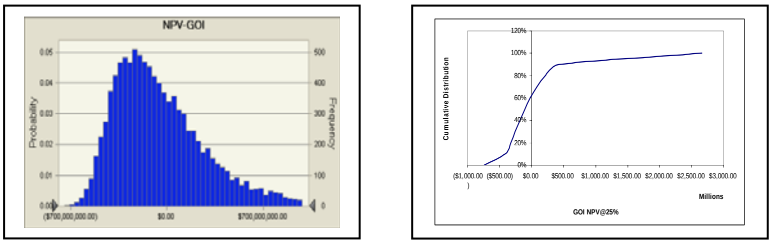


Figure 11: Histogram and cumulative distribution of GOI's NPV@25% of tax consolidation scenario

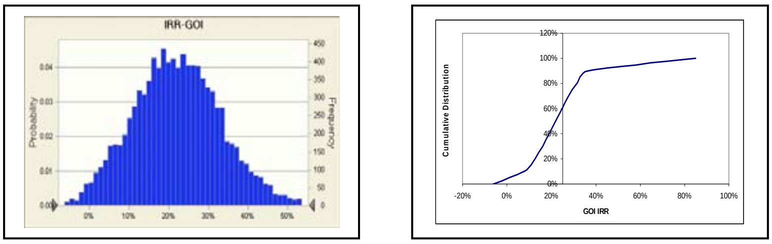


Figure 12: Histogram and cumulative distribution of GOI's IRR of tax consolidation scenario

From contractor's views, the mean aggregate of NPV@25% in both tax consolidation and production split improvement scenarios were negative, while the mean aggregate IRR were 10.3% and 7.9% respectively. These suggest that the tax consolidation application could increase the contractor's IRR. However, the contractor's IRR as an aggregate was relatively low, even with tax consolidation applied, indicating that the investment was not very attractive. It can be concluded that under the assumptions used in this study, the application of tax consolidation poses high risk to the government. Hence the application of tax consolidation was not likely to be beneficial.

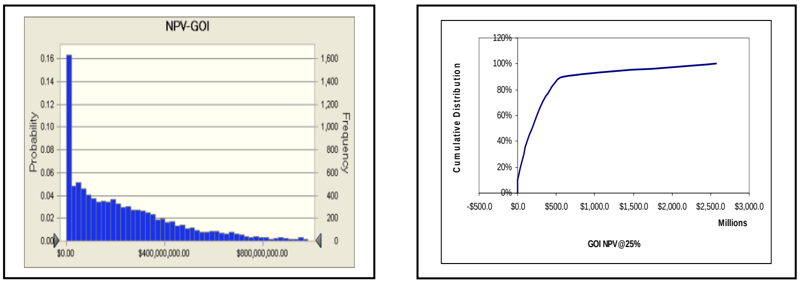


Figure 13: Histogram and cumulative distribution of GOI's NPV@25% of production sharing split improvement case scenario

Under the assumptions described in the study, following conclusions are reached:

1) From contractor's financial aspect, tax consolidation was more attractive incentive compared to increase in production sharing split. It did not only give higher NPV@25% but also reduced the exploration risk.
2) Tax consolidation was less attractive to the GOI, not only it reduced GOI's NPV@25% but it also posed financial risk to the GOI.
3) The application of tax consolidation at the aggregate level posed high risk to the GOI; hence, unless, the potential additional reserves and potential effects to local economy development outweighed the risk, the application of tax consolidation is not likely to be beneficial.

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Table 1: Assumptions in Tax-consolidation simulation (BP MIGAS, 2004 and Petrominer, 2004)

<table>
<tr><td colspan="4">MODEL
The Indonesian PSC financial model</td></tr>
<tr><td colspan="4">PSC CONTRACT TYPE
The Fifth Incentives Package (the highest figures)</td></tr>
<tr><td>1</td><td colspan="2">Signature bonus</td><td>26.6 million USD</td></tr>
<tr><td>2</td><td colspan="2">Minimum Exploration commitment</td><td>140.9 million USD during the first three operation years</td></tr>
<tr><td>3</td><td colspan="2">FTP</td><td>10% all for GOI</td></tr>
<tr><td>4</td><td colspan="2">Depreciation</td><td>5 years DDBL</td></tr>
<tr><td>5</td><td colspan="2">Investment Credit</td><td>102.14%</td></tr>
<tr><td>6</td><td colspan="2">Contractor production sharing split</td><td>35%</td></tr>
<tr><td>7</td><td colspan="2">- DMO quantity</td><td>25% of contractor production share</td></tr>
<tr><td>8</td><td colspan="2">- DMO holiday price</td><td>5 years</td></tr>
<tr><td>9</td><td colspan="2">- DMO Price</td><td>25% of export price</td></tr>
<tr><td>10</td><td colspan="2">Tax rate</td><td>44%</td></tr>
<tr><td colspan="4">SCENARIO AND ASSUMPTION</td></tr>
<tr><td>No</td><td>Item</td><td>Assumption</td><td>Remark</td></tr>
<tr><td>11</td><td>Tax consolidation application</td><td colspan="2">Strictly to cover exploration cost in frontier areas only</td></tr>
<tr><td>12</td><td>Analysis was limited to</td><td>The additional contracts signed in the first 10 years after tax consolidation was issued.</td><td>Historical showed that each PSC generation effectively used around 10 years after that changed to other generation.</td></tr>
<tr><td>13</td><td>Duration of contract</td><td>30 years</td><td>Duration PSC contract life cycle.</td></tr>
<tr><td>14</td><td>Period of analysis</td><td>2004 –2033 period</td><td></td></tr>
<tr><td>15</td><td>Discount rate and discount date</td><td>25%
1/1/2004</td><td>The minimum required rate of return of high risk petroleum E&P investment (Jones, 1993).</td></tr>
<tr><td colspan="4">INPUT VARIABLES ASSUMPTIONS</td></tr>
<tr><td>16</td><td>Exploration cost/area</td><td>Uniform probability distribution with minimum and maximum value of 140.9 and maximum of 200 million USD. All values were at 2004 value.</td><td>The minimum value was set up at the minimum exploration commitment as stated in the IP5 terms (140.9 million USD for the first three contract), while the maximum value was set up at roughly three times the historical maximum exploration expenditures cash out in 2003 (BP Migas, 2004).</td></tr>
<tr><td>17</td><td>Development expenditures/barrel</td><td>Uniform probability distribution between 6 to 9 USD/barrel, in which 50% was capital expenditures.</td><td>The minimum value was set up at the 2004's average of development cost of 24 US petroleum companies that operated in other eastern hemisphere (except Middle East), while the maximum value was set up at the 2004's average of development cost of world operation of 24 US petroleum companies (EIA, 2006:34). If there was commercial discovery that covers year 4 to year 8.</td></tr>
<tr><td>18</td><td>Escalation of cost rate</td><td>3% / year</td><td>Average of the changes of US Consumer Price Index during 1990 – 2003 period</td></tr>
<tr><td>19</td><td>Fixed production cost</td><td>Uniform probability distribution with minimum and maximum values of 20 and 30 million USD.</td><td>Educated guess. The combination of fixed and variable operating cost give mean of total operating cost of 4.31 USD/barrel in line with 2004 EIA data (EIA, 2006: 34).</td></tr>
</table>

20	Variable production cost	Uniform probability distribution between 1.0 to 1.5 USD/barrel.	See above
21	Year production start	Year 6	
22	Hydrocarbon produced	Oil	
23	Production profile trend	Constant plateau rate for first three years of production then decline exponentially.	Plateau rate set to 11% of reserve. Initial decline rate 17.4 %/year
24	Oil price	Triangular distribution with minimum, mode and maximum values of 9, 21 and 76 USD /barrel, in 2004 value.	Approximation of historical US crude oil price during 1974 – 2003 period, adjusted to 2004 value.
25	Oil Price escalation	3%/year	Average changes of historical US crude oil price during 1974 – 2003 period .
OUTPUT VARIABLES			
26	**GOI view:** GOI's NPV@25%, IRR and reserves addition value and probability distribution		
27	**Contractor view:** Contractor's NPV@25% and IRR value and probability distribution		

Table 2: Summary of GOI-IRR for tax consolidation scenarios

Statistics	IRR-GOI – with Tax Consolidation		
	Split 55/45	Split 60/40	Split 65/35
Mean	74.31%	75.03%	75.75%
Median	71.40%	72.12%	72.85%
Mode	---	---	---
Standard Deviation	16.85%	17.00%	17.20%
Variance	2.84%	2.89%	2.96%
Minimum	39.71%	39.55%	39.38%
Maximum	175.64%	180.73%	176.42%
Range Width	135.93%	141.18%	137.04%

Table 3: The ratio contractor's NPV@25% to its exploration cost

Statistics	Split 65/35	Split 65/35 with Taxconso	Split 5545
Trials	10,000	10,000	10,000
Mean	1.00	1.63	1.17
Median	1.00	1.63	1.17
Mode	1.00	---	---
Standard Deviation	0.00	0.02	0.02
Variance	0.00	0.00	0.00
Minimum	1.00	1.54	1.04
Maximum	1.00	1.75	1.23
Range Width	0.00	0.21	0.19

Table 4: Aggregate Monte Carlo simulation summary for tax consolidation scenario

Statistics	Reserve	NPV-GOI	IRR-GOI	NPV-PSC	IRR-PSC
Mean	716,338,520	(34,824,952)	22.23%	(613,898,134)	10.33%
Median	665,356,438	(108,612,062)	21.89%	(609,571,664)	10.70%
Mode	0	0			
Standard Deviation	430,322,113	363,026,952	11.16%	170,609,668	5.49%
Variance	2.E+17	1.E+17	1.25%	3.E+16	0.30%
Minimum	0	(743,367,579)	-6.25%	(1,693,400,920)	-9.90%
Maximum	2,756,223,012	2,661,762,388	84.93%	390,092,512	31.14%
Range Width	2,756,223,012	3,405,129,966	91.18%	2,083,493,431	41.04%

Table 5: Aggregate Monte Carlo simulation summary for production sharing split increase scenario

Statistics	Reserve	NPV-GOI	NPV-PSC	IRR-PSC
Mean	426,604,047	252,004,050	(644,331,019)	7.92%
Median	372,586,054	184,733,801	(644,746,388)	8.07%
Mode	0	0		
Standard Deviation	332,825,229	260,633,272	169,762,552	5.84%
Variance	1.11.E+17	6.78.E+16	2.88.E+16	0.34%
Minimum	0	0	(1,487,165,140)	-12.40%
Maximum	2,381,082,061	2,573,900,429	289,158,210	29.47%
Range Width	2,381,082,061	2,573,900,429	1,776,323,349	41.88%