# The Impact of New Nigerian Petroleum Industry Bill (PIB) 2021 on Government and Contractor Take

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## Abstract

In this research paper, the impact of the new Nigerian Petroleum Industry Bill (PIB) 2021 on both the government and the contractor take is investigated in detail. For the purpose of this study, three different simulated reservoir sizes are assumed for onshore, shallow water, and deep water terrains using QUE$TOR software. These base cases are 40 MM bbl, 100 MM bbl, and 1000 MM bbl oil in place. A detailed cash flow model of the new bill is developed to evaluate the terrain-based performance using selected profitability indicators such as internal rate of return (IRR), Profitability Index (PI ), discounted and undiscounted take of both the contractor and the government. To evaluate the impact of the selected variables on the selected indicator, Crystal Ball is used to perform the Monte Carlo simulation approach. Based on stochastic analysis, our results show that both IRR and PI are higher for onshore concessions in comparison with both shallow and deep water concessions. On the other hand, the contractor's take for deep water concessions is significantly higher than the onshore and shallow water fields. The key feature of the proposed PIB 2021 is that it provides the government with increasing take with increasing the reservoir size. This progressive feature may encourage the contractors to develop the small and marginal fields which have low profitability under the current fiscal systems. Finally, the contractor take is reported to be the lowest for shallow water concessions. This lower

take may discourage the investors from investing in shallow water concessions unless proper incentives are provided.

**Keywords:** Nigerian Petroleum Industry Bill; Government Take; Contractor Take; Hydrocarbon Tax; Cost Price Ratio.

## 1. Introduction

Upstream Petroleum Agreement includes all the legal, contractual, and fiscal aspects which determine the financial framework between the host governments and the foreign oil and gas companies or the contractors. The cornerstone of such systems is how the wealth is shared between the contracting parties and how the costs are recovered [1, 2]. Oil has been considered to be the dominant source of Nigerian government revenue, contributing about 90 - 95% of total exports and approximately 80% of total government [3].

Three different strategies are available for the host government to explore for and develop its hydrocarbon resources. The first strategy is a standalone strategy in which the host government runs its petroleum sector alone and no private companies are available. In such a case, there's no need for the fiscal system. In the second strategy, there's no direct involvement of the host government only private companies. The third strategy involves direct cooperation between the host government and foreign oil and gas companies [2]. There are two types of fiscal regimes, there are concessionary and contractual fiscal regimes. Each government developed its fiscal tools to capture higher economic rent at certain predetermined conditions [4].

In its basic form, the concessionary system has three components, which are royalties, deductions, and tax. Royalty is usually a percentage of the gross revenue from the sale of hydrocarbons, royalty can either be paid in cash or in kind. To determine the taxable income, deductions such as operating costs for the whole project, depreciation of capitalized assets, depletion, and amortization, all drilling costs are deducted from the net revenue [1, 5, 6].

Under contractual systems, the government retains ownership of minerals. The oil companies have a role of "contractors" who develop and extract in return for compensation according to the contractual arrangements with the host government[1, 7]. Contractual arrangements are further classified into production sharing contracts (PSC) or sometimes production sharing agreements (PSAs) and service contracts or service agreements (SA).

A PSC allocates a portion of the produced oil called cost oil to the contractor to recover all costs (operating and capital cost) also known as OPEX and CAPEX that are paid during the different phases of the project. This is done after royalties have been paid to the government of gross production. The rest called the Profit Oil is then shared between the Host Government and the IOC according to terms stated in the contractual agreement [1, 5].

Under service contracts, foreign companies act as contractors who receive a fee for services rendered [8]. These agreements are further divided into pure and risk service contracts. In pure service contracts, the contracts are paid for the services provided regardless of if there's discovery or not. However, in risk service contracts, the contractor is only compensated in case of commercial discovery. The fee usually allows the recovery of all or part of costs and a profit component [7].

The Royalty and Tax (R/T) fiscal regime of Nigeria has different versions. They are R/T (1993) and R/T (2000). Under the typical royalty tax system, Nigerian National Petroleum Corporation (NNPC) holds about 55-60% interest in joint venture agreements (JV) with international oil companies. For onshore discoveries, the royalty is a fixed percentage of 20 % of gross revenue while it is modeled as a sliding scale decreasing with an increase in water depth. The tax burden on the contractor is 67.5% for the first five years and 85% subsequently. Niger Delta development tax, as well as the education tax, are included in the RT (2000) version. Cost deduction is limited to only about 80% of the net revenue after royalty for R/T (2000)[4].

The Nigerian production sharing contract (PSC) has many versions. They are PSC (1993), PSC (2000), and PSC (2005). PSC (1993), PSC (2000), and PSC (2005) have similar provisions except for modification on the tax rate with inclusion of Education tax and Niger delta development levy, net revenue after royalty deduction is for cost recovery and is limited to about 80% for PSC (2005) and 100% of net revenue after royalty for PSC (1993) and PSC (2000). Royalty for an onshore field is 20% of gross revenue while royalty rates reduce with depth for shallow and deep water. Profit oil is shared between contractor and host government on a sliding scale basis i.e the lower the production, the higher the profit oil share for the contractor, and lower for the host government[4].

For the fiscal system to be efficient, it should provide a stable business environment, provide a balance between risk and reward, minimize sovereign risk, a stable business environment, provide the potential for a fair return to both the host government and investors, incorporate flexibility for changing economic conditions, minimize complexity and administrative burdens and finally promote competition and market efficiency [9-13].To provide an efficient and progressive fiscal regime, The Nigerian petroleum industry over the years has experienced several changes. One major reform of interest in this research is the introduction of the Petroleum Industry Bill (PIB) 2021.

The Petroleum Industry Bill (PIB) 2021 seeks to provide legal, governance, regulatory and fiscal framework for the Nigerian Petroleum Industry and the development of Host Communities. It contains Five Chapters, 319 Sections and, 8 Schedules dealing with Rights of Preemption; Incorporated Joint Ventures; Domestic Base Price and Pricing Framework; Pricing Formula for Gas Price for the Gas Based Industries; Capital Allowances; Production Allowances and Cost Price Ratio Limit; Petroleum Fees, Rents and Royalty; and Creation of the Ministry of Petroleum Incorporated.

## 2. Overview of Petroleum Industry Bill (PIB) 2021

Chapter four of the approved PIB 2021 introduces the fiscal framework of the petroleum industry, which has the following objectives:

- To establish a progressive fiscal framework that encourages investment in the Nigerian petroleum industry, balancing rewards with risk and enhancing revenues to the Federal Government.
- To provide a forward-looking fiscal framework that is based on core principles of clarity, dynamism, and fiscal rules of general application.
- To establish a fiscal framework that expands the revenue base of the FG, while ensuring a fair return for investors.
- To simplify the administration of petroleum tax; and
- To promote equity and transparency in the petroleum industry fiscal regime.

The first appendix of PIB 2021 determines the various laws that have implications for the oil and gas industry. The fiscal and tax amendments in the PIB will apply upon:

a. Conversion of existing Oil Prospecting Licenses (OPLs) and Oil Mining Leases (OMLs) to Petroleum Prospecting Licenses (PPLs) and Petroleum Mining Licenses (PMLs)
b. Termination or expiration of unconverted licenses, and
c. Renewal of OMLs

Consequently, holders of OPLs and OMLs that do not convert to PMLs will continue to be taxed under the current petroleum profit tax (PPT) Act pending the expiration of their licenses.

## 2.1 Royalty

Royalty is the first cash expense made to the government by the contractor when the production of oil or gas begins as a fraction of the gross revenue. Royalty may be paid in kind or in cash. According to the seventh schedule of PIB 2021, two different types of royalty are proposed: production-based royalty and price-based royalty.

### 2.1.1 Production Based Royalty

For onshore, shallow water, and deep offshore fields, production-based royalties are summarized in **table1**, **table 2,** and **table3**. For natural gas and natural gas liquids, royalty will be on the chargeable volume in the relevant area at the rate of 5% of the chargeable value. However, the royalty rate for gas produced and utilized in-country shall be 2.5%.

| From KBOPD | To KBBL/D | Royalty Percentage % |
|---|---|---|
| 0 | 5 | 5.00% |

| | | |
|---|---|---|
| >5 | 10 | 7.50% |
| >10 | | 15 % |

**Table 1- Production-based royalty for onshore fields.**

| From KBOPD | To KBBL/D | Royalty Percentage % |
|---|---|---|
| 0 | 5 | 5.00% |
| >5 | 10 | 7.50% |
| >10 | | 12.50% |

**Table 2- Production-based royalty for shallow water fields.**

| From KBOPD | To KBBL/D | Royalty Percentage % |
|---|---|---|
| 0 | 50 | 5.00% |
| >50 | | 7.50% |

**Table 3- Production-based royalty for deep offshore fields.**

### 2.1.2 Price Based Royalty

For fields in onshore, shallow water, and deep offshore areas, the royalty rates will apply as follows:

- Below US$50 per barrel – 0%
- At US$100 per barrel – 5%
- Above US$150 per barrel – 10%
- Prices between ranges will be determined by "linear interpolation"

Price royalty does not apply to gas or production from Frontier acreages.

### 2.2 Government levies or Crypto Taxes:

- Sustainable Community Development (SCD) Levy is 1% of the Gross Revenue
- The Niger Delta Development Commission (NDDC) is 3% of the OPEX and CAPEX including abandonment contributions
- Value Added Tax (VAT) is 5% of OPEX and CAPEX excluding abandonment contributions
- Petroleum Host Community Development (PHCD) is 3% of the OPEX of the preceding year.
- Education Tax is 2% based on the accessible profit

### 2.3 Tax

It provides for the current Petroleum Profits Tax (PPT) to be split into hydrocarbon tax (HT) and companies' income tax (CIT).

The HT, together with CIT, will apply to companies engaged in upstream petroleum operations.

### 2.4 Hydrocarbon Tax (HT):

The HT is a new tax that applies to crude oil, condensates, and natural gas liquids produced from associated gas operations. It is charged and assessed on profits from crude oil on such operations in each accounting period at the following rates for new acreages and converted acreages respectively:

• Converted/renewed Onshore and Shallow Offshore - 30%

• Onshore and Shallow Onshore (including marginal fields) and PPLs - 15%

The hydrocarbon tax (HT) will not apply to deep offshore projects to encourage exploratory activities in that area. Costs that cannot be directly attributable to production will not be allowable for deduction under HT. Section 263 and 264 of the PIB 2021 determine the allowed and non-allowed deductions for the hydrocarbon tax calculations.

### 2.5 Company Income Tax (CIT):

Companies engaged in upstream petroleum operations will also be taxed under CIT using a similar estimate mechanism to that provided for HT. However, will not be deductible for CT purposes. CIT will be applied as an entity-based tax, thereby allowing for consolidation of results across terrains. This means that there are no field-by-field restrictions. The company income tax is 30%. For both the hydrocarbon tax and company income tax, the ring-fence will not be applied.

### 2.6 Capital Allowance

According to the fifth schedule, the capital allowances rates are summarized in **table 4**.

| Qualifying Capital Expenditure | 1st Year | 2nd Year | 3rd Year | $4^{th}$Year | $5^{th}$Year |
|---|---|---|---|---|---|
| Qualifying Plant Expenditure | 20% | 20% | 20% | 20% | 19% |
| Qualifying Pipeline Expenditure | 20% | 20% | 20% | 20% | 19% |
| Qualifying Building Expenditure | 20% | 20% | 20% | 20% | 19% |
| Qualifying Drilling Expenditure | 20% | 20% | 20% | 20% | 19% |

**Table 4- Capital allowance rates according to PIB 2021.**

Expenditure incurred on exploration and the first two (2) appraisal wells in the same field is to be treated as 100% deductible costs in the year incurred. Expenditure incurred on exploration and the first two (2) appraisal wells in the same field is to be treated as 100% deductible costs in the year incurred. However, additional exploration and appraisal expenditures in the same field relating to the pre-production period are to be amortized and deducted upon commencement of the company's accounting period at an annual allowance of 20% for the first four (4) years and 19% in the fifth year with a 1% retention value

### 2.7 Cost Price Ratio:

According to the six schedules, all deductible costs under the HT will be subject to a cost price ratio limit of 65% of gross revenues, subject to the relevant exclusions, determined at the measurement points. The allowed costs under the cost price ratio do not include royalties, rentals, and any government levies and crypto taxes.

Any excess costs not deducted due to the restriction may be deducted in subsequent years of assessment provided that:

a. The total costs to be deducted shall not exceed the actual costs incurred, and
b. The total costs to be allowed as deduction in those subsequent years shall be such an amount that, if added to the sum of the total deductible costs, shall not exceed the specified cost price ratio limit of 65%; and
c. Any unrecovered costs (i.e., costs that exceed the cost price ratio limit) upon the termination of petroleum operations will not be deductible for HT purposes.

### 2.8 Production Allowance:

According to the sixth Schedule, the PIB 2021 replaces the Investment Tax Allowance (ITA) and Investment Tax Credit (ITC) with a Production allowance per crude oil production as follows:

- For onshore areas, the production allowance is the lower of 8 $ /bbl and 20% of the fiscal price up to accumulative maximum production of 50 MMbbl and the lower of 4$/bbl or 20% of the fiscal oil price thereafter.
- For shallow water areas, the production allowance is the lower of 8 $ /bbl and 20% of the fiscal price up to accumulative maximum production of 100 MM bbl and the lower of 4$/bbl or 20% of the fiscal oil price.
- For deep offshore areas, the production allowance is the lower of 8 $ /bbl and 20% of the fiscal price up to accumulative maximum production of 500 MM bbl and the lower of 4$/bbl or 20% of the fiscal oil price.

### 2.9 Bonuses, Fees, and Rentals

Bonuses, Rents, and Fees in the PIFB are negotiated between the government and Contractor. All of which depends on the kind of license (Petroleum License or Petroleum Exploration License)

## 3. Cash Flow Model for PIB 2021

Several methods are employed in the assessment of petroleum fiscal systems, cash flow models are commonly used to evaluate the profitability of a capital investment project. The cash flow is usually preferred for economic analysis because it employs discounted cash flow concepts that take into consideration the timing of cash flows and the economic opportunity cost on capital [2, 4, 5, 14, 15].

The detailed deterministic cash flow model of PIB 2021 can be coded in an excel sheet using the following workflow:

| 1. **Royalty Calculations** |
|---|

| | | |
|---|---|---|
| Annual Revenue | = | Average Daily Production (KBOPD)*No.Days Per Year*Average Oil Price ($/BBL) |
| Production Based Royalty | = | Annual Blended Royalty Percentage * Annual Revenue |
| Price Based Royalty | = | Price Based Royalty Percentage * Annual Revenue |
| Annual Royalty Payments | = | Production Based Royalty+ Price Based Royalty |
| Annual Revenue Net Royalty | = | Annual Revenue - Annual Royalty Payments |
| Blended royalty percentage is calculated as a sliding scale royalty | | |

| **2. Government Levies and Crypto Taxes** | | |
|---|---|---|
| Sustainable Community Development (SCD) Levy | = | 1% * Annual Revenue |
| The Niger Delta Development Commission (NDDC) | = | 3% of the OPEX and CAPEX Including Abandonment Contributions |
| Value Added Tax (VAT) | = | 5% of OPEX and CAPEX Excluding Abandonment Contributions |
| Petroleum Host Community Development (PHCD) | = | 3% of the OPEX of the Preceding Year. |
| Total Government Levies and Crypto Taxes | = | (SCD) +(NDDC)+ (VAT)+ (PHCD) |

| **3. <u>Education Tax</u>** |
|---|

| | | |
|---|---|---|
| *Accessible Profit Claimed Deductions* | = | *Expensed Exploration and Appraisal Costs*<br>*Intangible CAPEX*<br>*OPEX*<br>*Abandonment Contributions*<br>*Loss Carry Forward* |
| *Chargeable Accessible Profit* | = | *Revenue Net Royalty - Accessible Profit Claimed Deductions* |
| *Education Tax* | = | *2% * Accessible Profit (if Positive)* |

| **4. Hydrocarbon Tax** | | |
|---|---|---|
| Total Claimable Technical Costs for Hydrocarbon Tax | = | Expensed Exploration and Appraisal Costs<br>Intangible CAPEX<br>Depreciated Tangible CAPEX<br>OPEX<br>Abandonment Contributions<br>Loss Carry Forward |
| Available Revenue Limit | = | Cost / Price Ratio (65%) * Annual Revenue |
| Allowed Technical Costs | = | Minimum of (Total Claimable Technical Costs or Available Revenue Limit) |
| Total Claimable Hydrocarbon Tax Deductions | = | Royalty<br>Total Government Levies and Crypto Taxes<br>Allowed Technical Costs<br>Production Allowance<br>Loss Carry Forward |
| Chargeable Profit for Hydrocarbon Tax | = | Annual Revenue - Total Claimable Hydrocarbon Tax Deductions |
| Annual Hydrocarbon Tax Payments | = | Hydrocarbon Tax Percentage * Chargeable Profit for Hydrocarbon Tax (if Positive) |

| **5. Company Income Tax** |
|---|

| | | |
|---|---|---|
| Total Claimed Company Income Tax Deductions | = | Annual Royalty<br>+ Expensed Drilling and Appraisal Wells<br>+ Intangible CAPEX<br>+ Depreciated CAPEX<br>+ OPEX<br>+ Abandonment Contributions<br>+ Total Government Levies and Crypto Taxes<br>+ Annual Education Tax Payments<br>+ Loss Carry Forward |
| Chargeable Profit for Company Income Tax | = | Annual Revenue - Total Claimed Company Income Tax Deductions |
| Annual Company Income Tax Payments | = | Company Income Tax Percentage * Chargeable Profit for Company Income Tax (If Positive) |

| 6. **Contractor NCF** | | |
|---|---|---|
| Contractor NCF ($NCF_{con}$) | = | Annual Revenue - (<br>Annual Royalty Payments<br>+CAPEX<br>+OPEX<br>+Total Government Levies and Crypto Taxes<br>+Education Tax<br>+Annual Hydrocarbon Tax Payments<br>+Annual Company Income Tax Payments) |

| 7. **Government NCF** | | |
|---|---|---|
| Government NCF ($NCF_{gov}$) | = | Annual Royalty Payments<br>+Total Government Levies and Crypto Taxes<br>+Education Tax<br>+Annual Hydrocarbon Tax Payments<br>+Annual Company Income Tax Payments) |

Common profitability measures adopted include net present value (NPV), internal rate of return (IRR), and profitability index (PI). NPV is calculated by discounting all the cash inflow and the cash outflow[7, 15-19] and is given by Eq.1

$$NPV = \sum_i^n \frac{(NCF)_i}{(1+id)^i} \quad \text{......Eq.1}$$

Internal rate of return (IRR) is the discount rate at which NPV is equal to zero. If the project IRR is higher than the cost of capital or the company-specific criteria, the project will be economically viable. To calculate IRR we equate Eq.1 with zero as shown by Eq.2.

$\sum_{i}^{n} \frac{(NCF)_i}{(1+IRR)^i} = 0$ ………………………………………………………………….Eq.2

The profitability index (PI) is used as an indicator of the investment efficiency in terms of how many dollars was gainare ed per dollar invested in the project. The profitability index (PI) is given by Eq.3.

Profitability index (PI) = $1 + \frac{NPV_{con}}{present\ value\ of\ investment\ costs}$…………………………Eq.3

After computing the respective net cash flow for the contractor and the government, their respective undiscounted takes can be computed by Eq. 4 and Eq.5, respectively :

$Undiscounted\ Contractor\ Take\ (NCF\ \%) = \frac{NCF_{con}}{NCF_{con}+NCF_{gov}}$ ……………………………..Eq.4

$Undiscounted\ Government\ Take(NCF\ \%) = \frac{NCF_{gov}}{NCF_{con}+NCF_{gov}}$ ………………………Eq.5

Considering the time value of money, the discounted contractor and government take can be computed by Eq. 6 and Eq. 7, respectively:

$Discounted\ Contractor\ Take(NPV\ \%) = \frac{NPV_{con}}{NPV_{con}+NPV_{gov}}$ ………………………………..Eq.6

$Discounted\ Government\ Take(NPV\%) = \frac{NPV_{gov}}{NPV_{con}+NPV_{gov}}$ ………………………………Eq.7

## 4. PIB 2021 Analysis Methodology

To provide reliable and accurate analysis of PIB 2021, the following procedure is adopted through this pap

1. For each terrain - onshore, shallow water, and deep water – three hypothetical base cases with different reservoir sizes are developed using QUE$TOR software developed by HIS Markit Energy. These three base cases are:
   - Small reservoir with 40 MM bbl oil  in place.
   - Medium reservoir with 100 MMbbl  oil in place.
   - Large reservoir with 1000 MMbbl oil in place

Those base cases are summarized in Appendix A in **tables A-1 through table A-9**.

2. To account for the uncertainties inherent in the economic data assumptions, stochastic analysis using Crystal Ball software is performed. The independent variables and their assumed probability distributions are defined in **Table 5**. Monte Carlo Simulation with 10,000 trials is then run with the percentile computed as probability equal or above a value.
3. The impact of the selected stochastic variables on contractor internal rate of return (IRR), profitability index (PI), undiscounted and discounted contractor, and government take is reported. The reported values are the base case, mean, P90, P50, P10, and 50% confidence interval of the value. The discounted take and the contractor profitability index are calculated assuming a 10% discount rate.

| | Independent Variable | Distribution | Inputs | Inputs Values |
|---|---|---|---|---|
| 1 | Oil Price | Beta PERT | Minimum | 40 |
| | | | Likeliest | 60 |
| | | | Maximum | 120 |
| 2 | Q-new/Q-Base Case | Beta PERT | Minimum | 50% |
| | | | Likeliest | 100% |
| | | | Maximum | 150% |
| 3 | CAPEX-new/CAPEX-Base Case | Beta PERT | Minimum | 50% |
| | | | Likeliest | 100% |
| | | | Maximum | 150% |
| 4 | OPEX-new/OPEX-Base Case | Beta PERT | Minimum | 50% |
| | | | Likeliest | 100% |
| | | | Maximum | 150% |

**Table 5- The probability distributions of the independent variables.**

## 5. Results and Discussion

A sample of Monte Carlo simulation results for undiscounted and discounted take for both the host government and the contractor for onshore, shallow water, and deep-water concessions for

40 MM bbl reservoir are shown in **Appendix B on Fig.B-1 through B-12**. The Stochastic results are summarized **in Tables 6,7 and 8** for 40 MM bbl, 100 MM bbl, and 1000 MM bbl reservoirs, respectively. The stochastic results show the IRR for all the simulated cases under the base case, Mean, P90, P50, and P10 are higher than the discount rate of 10 %, indicating that the projects are economically viable, and the contractor can recover the cost of capital. For the same reservoir size, the internal rate of return IRR for the deep-water concessions is lower than the onshore and shallow water. For 40 MM bbl reservoir size, the reported P 50 values of IRR are 50%,45%, and 39% for onshore, shallow water, and deep-water concessions respectively. The same results are obtained also for the profitability index, where the profitability index for deep water concessions is lower than both the shallow water and the onshore reservoirs. The main reason for the low values of IRR and PI for deep water is the high extraction costs of such concessions in comparison with the shallow water or onshore reservoirs.

As it is obvious from **the previously mentioned tables that** for the same terrain, both the undiscounted and discounted government take increases with increasing the reservoir size. For example, under the base case scenario, the discounted host government take for onshore fields are 62%, 69%, and 71 % for 40, 100, and 1000 MMBBL reservoirs respectively. The increase of the government take with the reservoir size or the increase of the contractor take with the decrease in the reservoir size strongly prove that the proposed PIB 2021 provides both the contractor and the government with win-win situations. This progressive behavior of the contractor take with the reservoir size will encourage the contractors to develop small or marginal fields which were not on its priority list. For deepwater concessions, the reported contractor take is higher than its take for onshore or shallow water fields. For example, with 50 % confidence, the discounted contractor take is confined between 54% and 56% for 40 MM bbl reservoirs. The main reason for the higher contractor takes for deepwater concessions is because there's no hydrocarbon tax which accounts for 30% of the tax income for both the shallow water and onshore fields. For shallow water concessions, the contractor take is reported to be the lowest in comparison with both the deep water and onshore concessions. Two factors are responsible for the low contractor take for shallow water fields. The first one is because there are no tax incentives like the deep offshore fields which have no hydrocarbon tax. the second factor is because of the higher extraction costs in comparison with onshore fields.

| **40 MMBBL** | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Profitability Indicators | Terrain | Base Case Value | Mean | P 90 | P 50 | P10 | 50% Confidence | |
| | | | | | | | From | To |
| IRR | Onshore | 48% | 51% | 37% | 50% | 65% | 43% | 58% |
| | Shallow Water | 43% | 42% | 41% | 45% | 57% | 44% | 54% |
| | Deep Water | 37% | 39% | 30% | 39% | 48% | 34% | 44% |
| PI | Onshore | 3.2 | 3.6 | 2.2 | 3.3 | 5.6 | 3.1 | 4.7 |
| | Shallow Water | 3.0 | 3.1 | 2.1 | 3.2 | 5.4 | 2.85 | 4.5 |
| | Deep Water | 1.9 | 3.6 | 1.8 | 3.4 | 5.2 | 2.3 | 4.2 |
| Undiscounted Contractor Take | Onshore | 38% | 38% | 36% | 38% | 40% | 37% | 39% |
| | Shallow Water | 35% | 34% | 32% | 34% | 37% | 33% | 35% |
| | Deep Water | 58% | 58% | 56% | 58% | 59% | 57% | 59% |
| Undiscounted Government Take | Onshore | 62% | 62% | 60% | 62% | 64% | 61% | 63% |
| | Shallow Water | 65% | 66% | 63% | 66% | 68% | 65% | 67% |
| | Deep Water | 58% | 58% | 56% | 58% | 59% | 41% | 43% |
| Discounted Contractor Take | Onshore | 38% | 37% | 36% | 37% | 39% | 36% | 38% |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Shallow Water | 35% | 34% | 31% | 34% | 36% | 32% | 35% |
| | Deep Water | 56% | 55% | 53% | 55% | 57% | 54% | 56% |
| Discounted Government Take | Onshore | 62% | 63% | 61% | 63% | 64% | 62% | 64% |
| | Shallow Water | 65% | 66% | 64% | 66% | 69% | 65% | 68% |
| | Deep Water | 44% | 45% | 43% | 45% | 47% | 44% | 46% |

**Table 6- Monte Carlo simulation results for 40 MM bbl reservoir.**

| 100 MMBBL | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Profitability Indicators | Terrain | Base Case Value | Mean | P 90 | P 50 | P10 | 50% Confidence | |
| | | | | | | | From | To |
| IRR | Onshore | 36% | 37% | 26% | 37% | 49% | 35% | 44% |
| | Shallow Water | 28% | 27% | 19% | 27% | 34% | 26% | 32% |
| | Deep Water | 21% | 23% | 16% | 23% | 31% | 20% | 28% |
| PI | Onshore | 1.99 | 2.22 | 1.05 | 2.06 | 3.61 | 2% | 3% |
| | Shallow Water | 1.49 | 1.47 | 0.66 | 1.37 | 2.4 | 1.4% | 2% |
| | Deep Water | 1.02 | 1.33 | 0.49 | 1.22 | 2.32 | 1% | 2% |
| Undiscounted Contractor Take | Onshore | 33% | 33% | 30% | 33% | 35% | 31% | 34% |
| | Shallow Water | 31% | 32% | 29% | 32% | 34% | 30% | 33% |
| | Deep Water | 55% | 55% | 53% | 55% | 57% | 54% | 56% |
| Undiscounted Government Take | Onshore | 67% | 67% | 65% | 67% | 70% | 66% | 69% |
| | Shallow Water | 69% | 68% | 66% | 68% | 71% | 67% | 70% |
| | Deep Water | 45% | 45% | 43% | 45% | 47% | 44% | 46% |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Discounted Contractor Take | Onshore | 31% | 30% | 29% | 30% | 32% | 29% | 31% |
| | Shallow Water | 28% | 27% | 25% | 28% | 30% | 27% | 29% |
| | Deep Water | 47% | 46% | 38% | 48% | 52% | 44% | 51% |
| Discounted Government Take | Onshore | 69% | 70% | 68% | 70% | 71% | 69% | 71% |
| | Shallow Water | 72% | 73% | 70% | 72% | 75% | 71% | 73% |
| | Deep Water | 53% | 54% | 48% | 52% | 62% | 49% | 56% |

**Table 7- Monte Carlo simulation results for 100 MM bbl reservoir.**

| 1000 MMBBL | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Profitability Indicators | Terrain | Base Case Value | Mean | P 90 | P 50 | P10 | 50% Confidence | |
| | | | | | | | From | To |
| IRR | Onshore | 46% | 47% | 38% | 47% | 57% | 42% | 52% |
| | Shallow Water | 36% | 38% | 28% | 37% | 48% | 33% | 46% |
| | Deep Water | 27% | 29% | 21% | 29% | 38% | 27% | 36% |
| PI | Onshore | 4.8 | 5.47 | 3.24 | 5.16 | 8.12 | 4.04 | 6.55 |
| | Shallow Water | 2.23 | 2.55 | 1.35 | 2.39 | 3.94 | 2.1 | 2.9 |
| | Deep Water | 1.33 | 1.67 | 0.78 | 1.56 | 2.71 | 1.2 | 2.4 |
| Undiscounted Contractor Take | Onshore | 30% | 29% | 27% | 29% | 31% | 28% | 30% |
| | Shallow Water | 31% | 30% | 28% | 30% | 32% | 29% | 31% |
| | Deep Water | 52% | 53% | 51% | 53% | 56% | 54% | 56% |
| Undiscounted Government Take | Onshore | 70% | 71% | 69% | 71% | 73% | 70% | 72% |
| | Shallow Water | 69% | 70% | 68% | 70% | 72% | 69% | 71% |
| | Deep Water | 48% | 47% | 44% | 47% | 49% | 44% | 46% |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Discounted Contractor Take | Onshore | 29% | 28% | 26% | 28% | 31% | 27% | 29% |
| | Shallow Water | 26% | 26% | 24% | 29% | 30% | 28% | 30% |
| | Deep Water | 45% | 45% | 39% | 44% | 50% | 43% | 49% |
| Discounted Government Take | Onshore | 71% | 72% | 69% | 72% | 74% | 71% | 73% |
| | Shallow Water | 74% | 74% | 70% | 71% | 76% | 70% | 72% |
| | Deep Water | 55% | 55% | 50% | 56% | 61% | 54% | 57% |

**Table 8- Monte Carlo simulation results for 1000 MM bbl reservoir.**

## Conclusion and policy implications

In this study, the impact of the new Nigerian industry bill (PIB) 2021 on both the government and the contractor take statistics is presented. Three different reservoir sizes for each terrain-onshore, shallow water, and deep water - are developed using QU$STOR software. Depending on the stochastic results under different values of commodity prices, production rate, CAPEX, and OPEX the following points are concluded:

1. For the same reservoir size, the contractor internal rate of return (IRR) and profitability index (PI) for the onshore concessions are higher in comparison with shallow and deep water concessions because of low extraction costs.
2. For the same terrain, the discounted and undiscounted government take increases with increasing the reservoir size.
3. The increase of the contractor take with the decrease of the reservoir size may encourage the contractor to develop the marginal and small fields.

4. The proposed PIB 2021 is highly lenient to the investor for deep water concessions because there's no hydrocarbon tax. This behavior will encourage the investors to explore and develop technically and economically challenging deep-water concessions as both the contractor and the host government run in win-win situation.
5. Policy makers should provide more incentives to investors for shallow water concessions as the proposed PIB channels to much cash to the government in comparison with deep water and onshore fields.

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# Appendix A

| Year | Production Rate KBOPD | Facility Costs MM$ | Development Drilling Costs MM$ | OPEX MM$ | Exploration Costs MM$ | Appraisal Costs MM$ | Aband. Costs MM$ |
|---|---|---|---|---|---|---|---|
| 1 | | | | | 4.783 | | |
| 2 | | | | | | 4.783 | |
| 3 | | 18.03 | | | | | |
| 4 | | 22.64 | 20.06 | | | | |
| 5 | 2.493151 | 42.3 | 2.45 | 9.73 | | | |
| 6 | 7.506849 | | | 19.76 | | | |
| 7 | 10 | | | 20.04 | | | |
| 8 | 10 | | | 20.43 | | | |
| 9 | 10 | | | 20.92 | | | |
| 10 | 10 | | | 20.53 | | | |
| 11 | 10 | | | 20.13 | | | |
| 12 | 9.589041 | | | 20.56 | | | |
| 13 | 8.410959 | | | 20.63 | | | |
| 14 | 7.013699 | | | 21.22 | | | |
| 15 | 5.863014 | | | 20.86 | | | |
| 16 | 4.90411 | | | 20.01 | | | |
| 17 | 4.082192 | | | 20.2 | | | |
| 18 | 3.424658 | | | 19.85 | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 19 | 2.849315 | | | 19.63 | | | |
| 20 | 2.383562 | | | 19.89 | | | |
| 21 | 1.09589 | | | 10.09 | | | |
| 22 | | | | | | | 8.35 |
| 23 | | | | | | | 16.7 |

**Table A- 1: Onshore field with 40 MMBBL oil in place**

| Year | Production Rate KBOPD | Facility Costs MM$ | Development Drilling Costs MM$ | OPEX MM$ | Exploration Costs MM$ | Appraisal Costs MM$ | Aband. Costs MM$ |
|---|---|---|---|---|---|---|---|
| 1 | | | | | 4.783 | | |
| 2 | | | | | 4.783 | 4.783 | |
| 3 | | | | | 4.783 | 4.783 | |
| 4 | | 69.29 | | | | | |
| 5 | | 109.75 | 22.83 | | | | |
| 6 | 5.013699 | 70.72 | 39.17 | 14.07 | | | |
| 7 | 15.0137 | | 2.64 | 28.89 | | | |
| 8 | 20 | | | 29.65 | | | |
| 9 | 20 | | | 30.64 | | | |
| 10 | 20 | | | 31.79 | | | |
| 11 | 20 | | | 30.81 | | | |
| 12 | 20 | | | 29.92 | | | |
| 13 | 20 | | | 31.17 | | | |
| 14 | 20 | | | 31.74 | | | |
| 15 | 20 | | | 33.19 | | | |
| 16 | 20 | | | 32.35 | | | |
| 17 | 18.63014 | | | 30.48 | | | |
| 18 | 15.0137 | | | 30.89 | | | |
| 19 | 11.12329 | | | 29.71 | | | |
| 20 | 8.219178 | | | 29.1 | | | |
| 21 | 6.082192 | | | 29.57 | | | |
| 22 | 4.493151 | | | 29.65 | | | |
| 23 | 3.342466 | | | 28.53 | | | |
| 24 | 2.465753 | | | 27.58 | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 25 | 1.835616 | | | 31.19 | | | |
| 26 | 1.342466 | | | 32.24 | | | |
| 27 | 0.986301 | | | 28.78 | | | |
| 28 | 0.410959 | | | 13.97 | | | |
| 29 | | | | | | | 23.99 |
| 30 | | | | | | | 47.98 |

**Table A- 2: Onshore field with 100 MMBBL oil in place**

| Year | Production Rate KBOPD | Facility Costs MM$ | Development Drilling Costs MM$ | OPEX MM$ | Exploration Costs MM$ | Appraisal Costs MM$ | Aband. Costs MM$ |
|---|---|---|---|---|---|---|---|
| 1 | | | | | 4.783 | | |
| 2 | | | | | 4.783 | 4.783 | |
| 3 | | | | | 4.783 | 4.783 | |
| 4 | | | | | | 4.783 | |
| 5 | | 129.87 | | | | | |
| 6 | | 273.39 | | | | | |
| 7 | | 182.78 | 100.88 | | | | |
| 8 | 18.73973 | 122.76 | 119.25 | 24.27 | | | |
| 9 | 56.24658 | | 119.25 | 51.12 | | | |
| 10 | 93.75342 | | 70.84 | 56.27 | | | |
| 11 | 131.2603 | | | 64.94 | | | |
| 12 | 150 | | | 71.33 | | | |
| 13 | 150 | | | 71.33 | | | |
| 14 | 150 | | | 71.72 | | | |
| 15 | 150 | | | 72.34 | | | |
| 16 | 150 | | | 72.34 | | | |
| 17 | 150 | | | 77.82 | | | |
| 18 | 150 | | | 77.12 | | | |
| 19 | 150 | | | 71.02 | | | |
| 20 | 146.2192 | | | 70.63 | | | |
| 21 | 135.3425 | | | 70.22 | | | |
| 22 | 121.8904 | | | 69.76 | | | |
| 23 | 109.7808 | | | 68.5 | | | |
| 24 | 98.87671 | | | 67.07 | | | |
| 25 | 89.0411 | | | 65.36 | | | |
| 26 | 80.19178 | | | 63.83 | | | |
| 27 | 72.24658 | | | 68.5 | | | |
| 28 | 65.06849 | | | 68.47 | | | |
| 29 | 58.60274 | | | 62.93 | | | |
| 30 | 52.76712 | | | 62.33 | | | |
| 31 | 47.53425 | | | 61.78 | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 32 | 42.79452 | | | 60.91 | | | |
| 33 | 38.54795 | | | 59.86 | | | |
| 34 | 34.71233 | | | 59.15 | | | |
| 35 | 31.26027 | | | 59.5 | | | |
| 36 | 14.82192 | | | 30.02 | | | |
| 37 | | | | | | | 72.8 |
| 38 | | | | | | | 145.6 |

**Table A- 3: Onshore field with 1000 MMBBL oil in place**

| Year | Production Rate KBOPD | Development Drilling Costs MM$ | OPEX MM$ | Exploration Costs MM$ | Appraisal Costs MM$ | Aband. Costs MM$ |
|---|---|---|---|---|---|---|
| 1 | | | | 20 | | |
| 2 | | | | | 20 | |
| 3 | | 20 | | | | |
| 4 | 0.410959 | 20 | 3.13 | | | |
| 5 | 5.205479 | | 37.72 | | | |
| 6 | 9.589041 | | 39.88 | | | |
| 7 | 9.589041 | | 40.1 | | | |
| 8 | 9.589041 | | 42.47 | | | |
| 9 | 9.589041 | | 42.17 | | | |
| 10 | 9.589041 | | 49.27 | | | |
| 11 | 9.534247 | | 40.06 | | | |
| 12 | 8.739726 | | 42.07 | | | |
| 13 | 7.424658 | | 40.15 | | | |
| 14 | 6.30137 | | 39.43 | | | |
| 15 | 5.342466 | | 47.57 | | | |
| 16 | 4.547945 | | 40.17 | | | |
| 17 | 3.863014 | | 38.51 | | | |
| 18 | 3.287671 | | 37.02 | | | |
| 19 | 2.794521 | | 37.83 | | | |
| 20 | 2.356164 | | 45.98 | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 21 | 1.863014 | | 33.41 | | | |
| 22 | | | | | | 5.01 |
| 23 | | | | | | 60.15 |
| 24 | | | | | | 25.06 |

**Table A- 4: Shallow water field with 40 MMBBL oil in place**

| Year | Production Rate KBOPD | Facility Costs MM$ | Development Drilling Costs MM$ | OPEX MM$ | Exploration Costs MM$ | Appraisal Costs MM$ | Aband. Costs MM$ |
|---|---|---|---|---|---|---|---|
| 1 | | | | | 20 | | |
| 2 | | | | | 20 | 20 | |
| 3 | | | | | 20 | 20 | |
| 4 | | 77.15 | 7.26 | | | | |
| 5 | | 165.73 | 26.57 | | | | |
| 6 | 0.821918 | 175.42 | 42.72 | 4.34 | | | |
| 7 | 10.82192 | | 22.57 | 52.23 | | | |
| 8 | 20 | | | 53.18 | | | |
| 9 | 20 | | | 53.63 | | | |
| 10 | 20 | | | 58.48 | | | |
| 11 | 20 | | | 58.25 | | | |
| 12 | 20 | | | 65.76 | | | |
| 13 | 20 | | | 53.92 | | | |
| 14 | 20 | | | 61.72 | | | |
| 15 | 19.89041 | | | 57.96 | | | |
| 16 | 18.35616 | | | 54.51 | | | |
| 17 | 15.83562 | | | 66.13 | | | |
| 18 | 13.64384 | | | 58.36 | | | |
| 19 | 11.75342 | | | 56.76 | | | |
| 20 | 10.10959 | | | 53.04 | | | |
| 21 | 8.712329 | | | 55.09 | | | |
| 22 | 7.506849 | | | 74.09 | | | |
| 23 | 6.465753 | | | 57.72 | | | |
| 24 | 5.589041 | | | 52.94 | | | |
| 25 | 4.465753 | | | 48.52 | | | |
| 26 | | | | | | | 6.96 |
| 27 | | | | | | | 83.54 |
| 28 | | | | | | | 34.81 |

**Table A- 5: Shallow water field with 100 MMBBL oil in place**

| Year | Production Rate KBOPD | Facility Costs MM$ | Development Drilling Costs MM$ | OPEX MM$ | Exploration Costs MM$ | Appraisal Costs MM$ | Aband. Costs MM$ |
|---|---|---|---|---|---|---|---|
| 1 | | | | | 20 | | |
| 2 | | | | | 20 | 20 | |
| 3 | | | | | 20 | 20 | |
| 4 | | | | | | 20 | |
| 5 | | 233.55 | 32.5 | | | | |
| 6 | | 666.99 | 149.45 | | | | |
| 7 | 6.246575 | 861.95 | 229.26 | 9.41 | | | |
| 8 | 81.26027 | | 221.36 | 113.68 | | | |
| 9 | 150 | | | 122.46 | | | |
| 10 | 150 | | | 125.83 | | | |
| 11 | 150 | | | 163.17 | | | |
| 12 | 150 | | | 165.94 | | | |
| 13 | 150 | | | 163.13 | | | |
| 14 | 150 | | | 126.98 | | | |
| 15 | 150 | | | 176.63 | | | |
| 16 | 150 | | | 171.39 | | | |
| 17 | 150 | | | 128.85 | | | |
| 18 | 149.3699 | | | 166.49 | | | |
| 19 | 141.2329 | | | 162.78 | | | |
| 20 | 127.2055 | | | 159.18 | | | |
| 21 | 114.5753 | | | 122.12 | | | |
| 22 | 103.1781 | | | 132.6 | | | |
| 23 | 92.93151 | | | 216.37 | | | |
| 24 | 83.69863 | | | 170.06 | | | |
| 25 | 75.36986 | | | 121.24 | | | |
| 26 | 67.89041 | | | 127.23 | | | |
| 27 | 61.15068 | | | 195.26 | | | |
| 28 | 55.06849 | | | 198.67 | | | |
| 29 | 49.58904 | | | 120.83 | | | |
| 30 | 44.65753 | | | 125.26 | | | |
| 31 | 40.21918 | | | 175.08 | | | |
| 32 | 36.24658 | | | 175.68 | | | |
| 33 | 32.63014 | | | 161.22 | | | |
| 34 | 27.17808 | | | 110.46 | | | |
| 35 | | | | | | | 42.89 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 36 | | | | | | | 514.71 |
| 37 | | | | | | | 214.46 |

**Table A- 6: Shallow water field with 1000 MMBBL oil in place**

| Year | Production Rate KBOPD | Development Drilling Costs MM$ | OPEX MM$ | Exploration Costs MM$ | Appraisal Costs MM$ | Aband. Costs MM$ |
|---|---|---|---|---|---|---|
| 1 | | | | 27 | | |
| 2 | | | | | 27 | |
| 3 | | 4.17 | | | | |
| 4 | | 10.91 | | | | |
| 5 | 0.410959 | 82.12 | 0.79 | | | |
| 6 | 5.424658 | | 9.5 | | | |
| 7 | 10 | | 9.5 | | | |
| 8 | 10 | | 11.79 | | | |
| 9 | 10 | | 34.64 | | | |
| 10 | 10 | | 9.5 | | | |
| 11 | 10 | | 9.5 | | | |
| 12 | 9.917808 | | 13.17 | | | |
| 13 | 9.013699 | | 49.99 | | | |
| 14 | 7.534247 | | 9.5 | | | |
| 15 | 6.30137 | | 9.5 | | | |
| 16 | 5.260274 | | 11.79 | | | |
| 17 | 4.383562 | | 34.64 | | | |
| 18 | 3.671233 | | 9.5 | | | |
| 19 | 3.068493 | | 9.5 | | | |
| 20 | 2.575342 | | 9.5 | | | |
| 21 | 2 | | 8.71 | | | |
| 22 | | | | | | 5.17 |
| 23 | | | | | | 62.09 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 24 | | | | | | 25.87 |

**Table A- 7: Deep water field with 40 MMBBL oil in place**

| Year | Production Rate KBOPD | Facility Costs MM$ | Development Drilling Costs MM$ | OPEX MM$ | Exploration Costs MM$ | Appraisal Costs MM$ | Aband. Costs MM$ |
|---|---|---|---|---|---|---|---|
| 1 | | | | | 27 | | |
| 2 | | | | | 27 | 27 | |
| 3 | | | | | 27 | 27 | |
| 5 | | 4.51 | 6.73 | | | | |
| 6 | | 291.55 | 19.14 | | | | |
| 7 | | 747.45 | 109.6 | | | | |
| 8 | 9.178082 | 23.92 | 79.74 | 70.93 | | | |
| 9 | 19.17808 | | | 77.78 | | | |
| 10 | 20 | | | 77.82 | | | |
| 11 | 20 | | | 131.84 | | | |
| 12 | 20 | | | 82.73 | | | |
| 13 | 20 | | | 85.86 | | | |
| 14 | 20 | | | 78.55 | | | |
| 15 | 20 | | | 155.58 | | | |
| 16 | 20 | | | 84.89 | | | |
| 17 | 18.71233 | | | 77.8 | | | |
| 18 | 16.21918 | | | 85.79 | | | |
| 19 | 13.9726 | | | 132.47 | | | |
| 20 | 12.05479 | | | 82.6 | | | |
| 21 | 10.38356 | | | 77.67 | | | |
| 22 | 8.931507 | | | 77.64 | | | |
| 23 | 7.69863 | | | 163.42 | | | |
| 24 | 6.630137 | | | 85.4 | | | |
| 25 | 5.726027 | | | 77.59 | | | |
| 26 | 4.931507 | | | 77.58 | | | |
| 27 | 0.410959 | | | 6.46 | | | |
| 28 | | | | | | | 126.61 |
| 29 | | | | | | | 80.57 |

**Table A- 8: Deep water field with 100 MMBBL oil in place**

| Year | Production Rate KBOPD | Facility Costs MM$ | Development Drilling Costs MM$ | OPEX MM$ | Exploration Costs MM$ | Appraisal Costs MM$ | Aband. Costs MM$ |
|---|---|---|---|---|---|---|---|
| 1 | 0 | 0 | 0 | 0 | 27 | 0 | 0 |
| 2 | 0 | 0 | 0 | 0 | 27 | 27 | 0 |
| 3 | 0 | 0 | 0 | 0 | 27 | 27 | 0 |
| 4 | 0 | 0 | 0 | 0 | 0 | 27 | 0 |
| 5 | 0 | 0 | 47.66 | 0 | 0 | 0 | 0 |
| 6 | 0 | 935.5 | 139.46 | 0 | 0 | 0 | 0 |
| 7 | 0 | 2414.34 | 715.86 | 0 | 0 | 0 | 0 |
| 8 | 56.24658 | 294.66 | 854.29 | 136.23 | 0 | 0 | 0 |
| 9 | 131.2603 | 0 | 0 | 184.31 | 0 | 0 | 0 |
| 10 | 150 | 0 | 0 | 185.2 | 0 | 0 | 0 |
| 11 | 150 | 0 | 0 | 542.48 | 0 | 0 | 0 |
| 12 | 150 | 0 | 0 | 304.29 | 0 | 0 | 0 |
| 13 | 150 | 0 | 0 | 202.09 | 0 | 0 | 0 |
| 14 | 150 | 0 | 0 | 190.83 | 0 | 0 | 0 |
| 15 | 150 | 0 | 0 | 640.82 | 0 | 0 | 0 |
| 16 | 150 | 0 | 0 | 337.08 | 0 | 0 | 0 |
| 17 | 150 | 0 | 0 | 185.2 | 0 | 0 | 0 |
| 18 | 150 | 0 | 0 | 202.09 | 0 | 0 | 0 |
| 19 | 144.3014 | 0 | 0 | 548.02 | 0 | 0 | 0 |
| 20 | 131.8082 | 0 | 0 | 304 | 0 | 0 | 0 |
| 21 | 118.7123 | 0 | 0 | 184.69 | 0 | 0 | 0 |
| 22 | 106.9041 | 0 | 0 | 184.5 | 0 | 0 | 0 |
| 23 | 96.30137 | 0 | 0 | 656.84 | 0 | 0 | 0 |
| 24 | 86.71233 | 0 | 0 | 341.67 | 0 | 0 | 0 |
| 25 | 78.10959 | 0 | 0 | 184.03 | 0 | 0 | 0 |
| 26 | 70.35616 | 0 | 0 | 183.9 | 0 | 0 | 0 |
| 27 | 63.36986 | 0 | 0 | 541.07 | 0 | 0 | 0 |
| 28 | 57.06849 | 0 | 0 | 319.67 | 0 | 0 | 0 |
| 29 | 51.39726 | 0 | 0 | 189.22 | 0 | 0 | 0 |
| 30 | 46.27397 | 0 | 0 | 183.52 | 0 | 0 | 0 |
| 31 | 41.69863 | 0 | 0 | 639.05 | 0 | 0 | 0 |
| 32 | 37.53425 | 0 | 0 | 335.24 | 0 | 0 | 0 |
| 33 | 33.80822 | 0 | 0 | 200.2 | 0 | 0 | 0 |
| 34 | 30.46575 | 0 | 0 | 188.88 | 0 | 0 | 0 |
| 35 | 7.39726 | 0 | 0 | 45.81 | 0 | 0 | 0 |
| 36 | 0 | 0 | 0 | 0 | 0 | 0 | 653.7 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 37 | 0 | 0 | 0 | 0 | 0 | 0 | 653.7 |
| | | | | | | | |

**Table A- 9: Deep water field with 1000 MMBBL oil in place**

# Apendix B

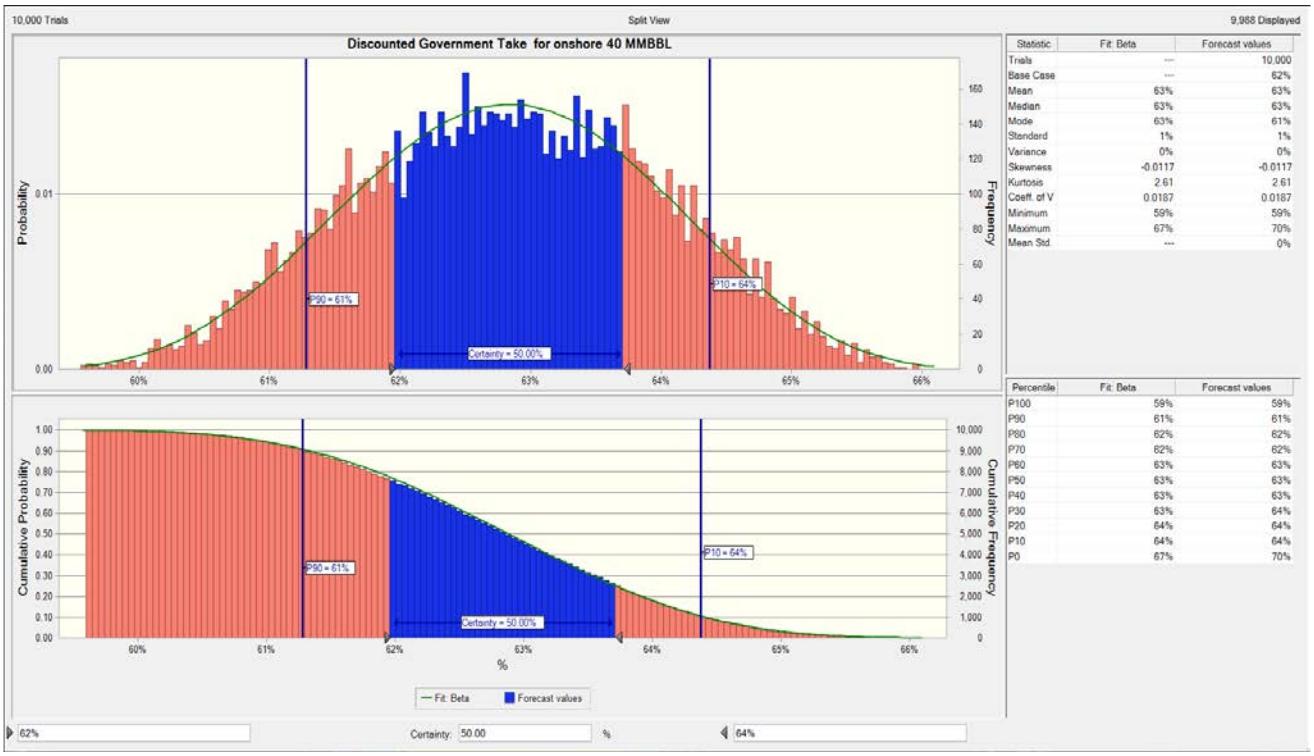


**Table B- 1: Discounted government take for 40 MM bbl onshore field.**

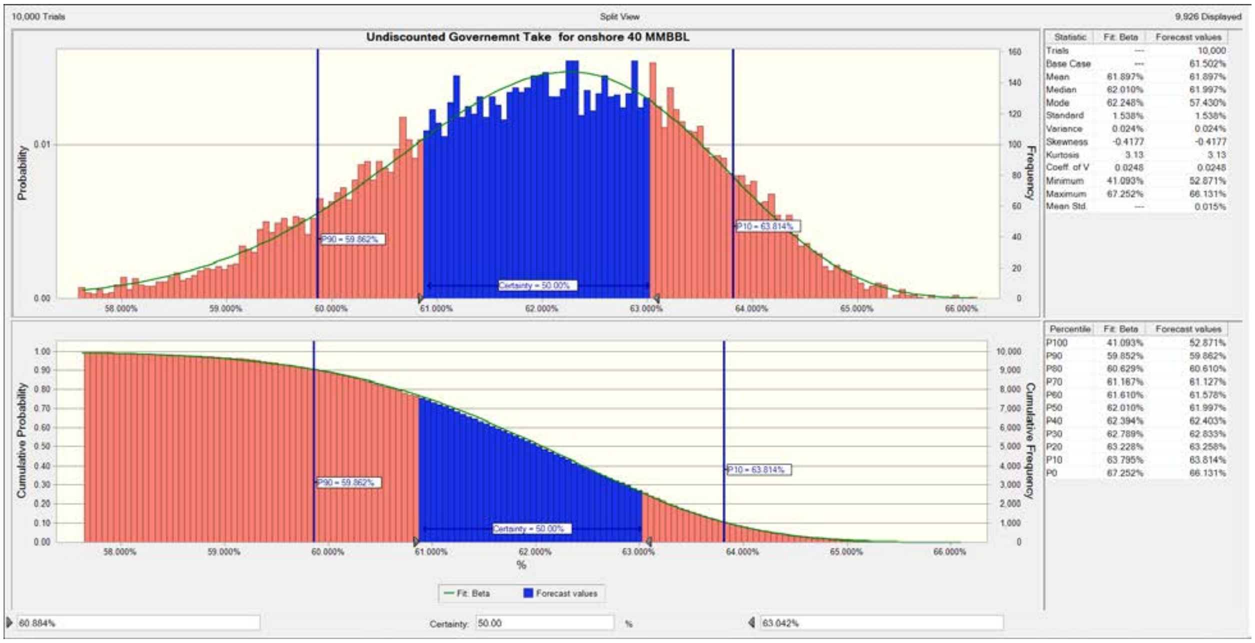


**Table B- 2: Undiscounted government take for 40 MM bbl onshore field.**

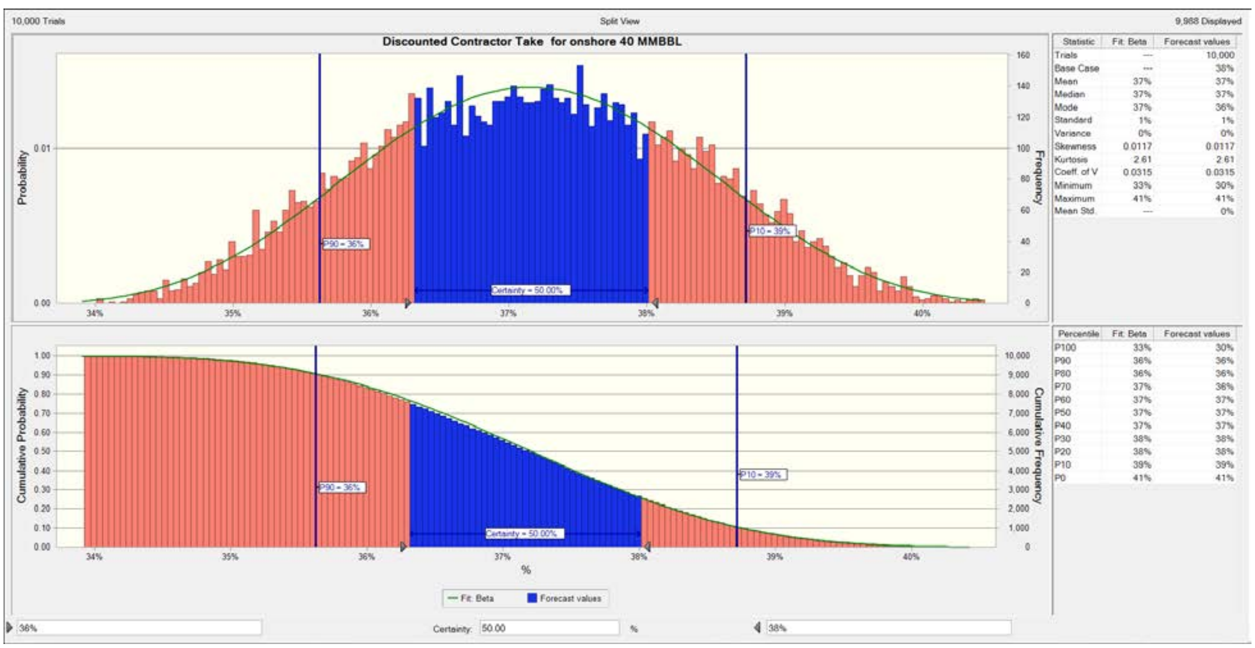


**Table B- 3: Discounted contractor take for 40 MM bbl onshore field.**

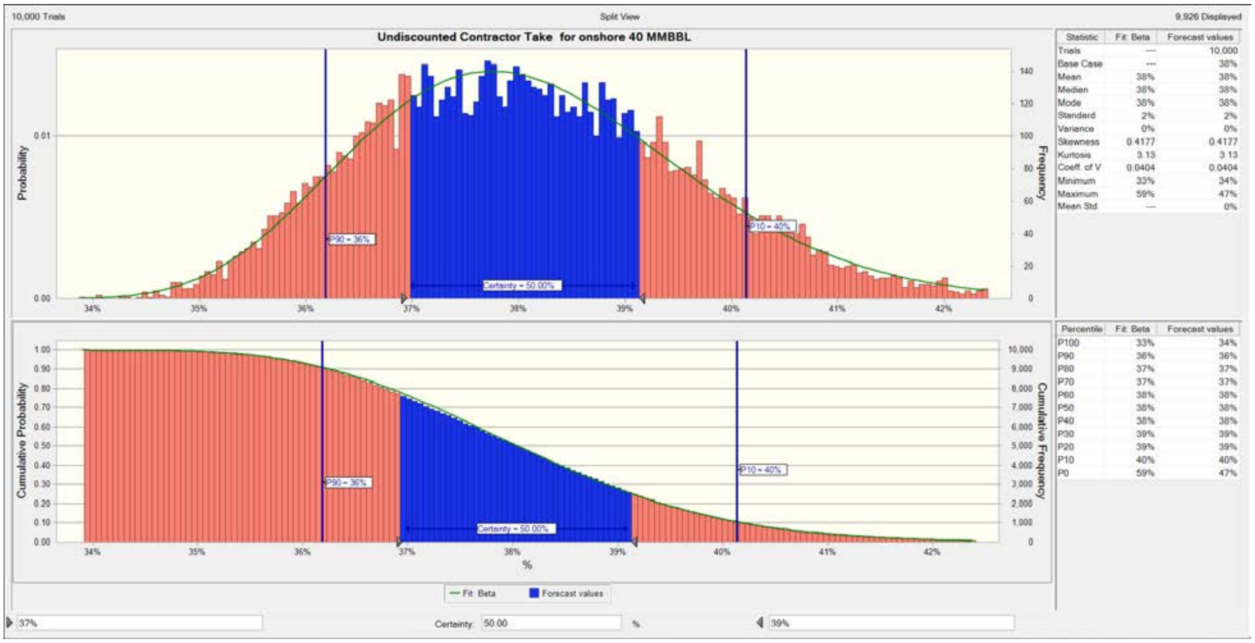


**Table B- 4: Undiscounted contractor take for 40 MM bbl onshore field.**

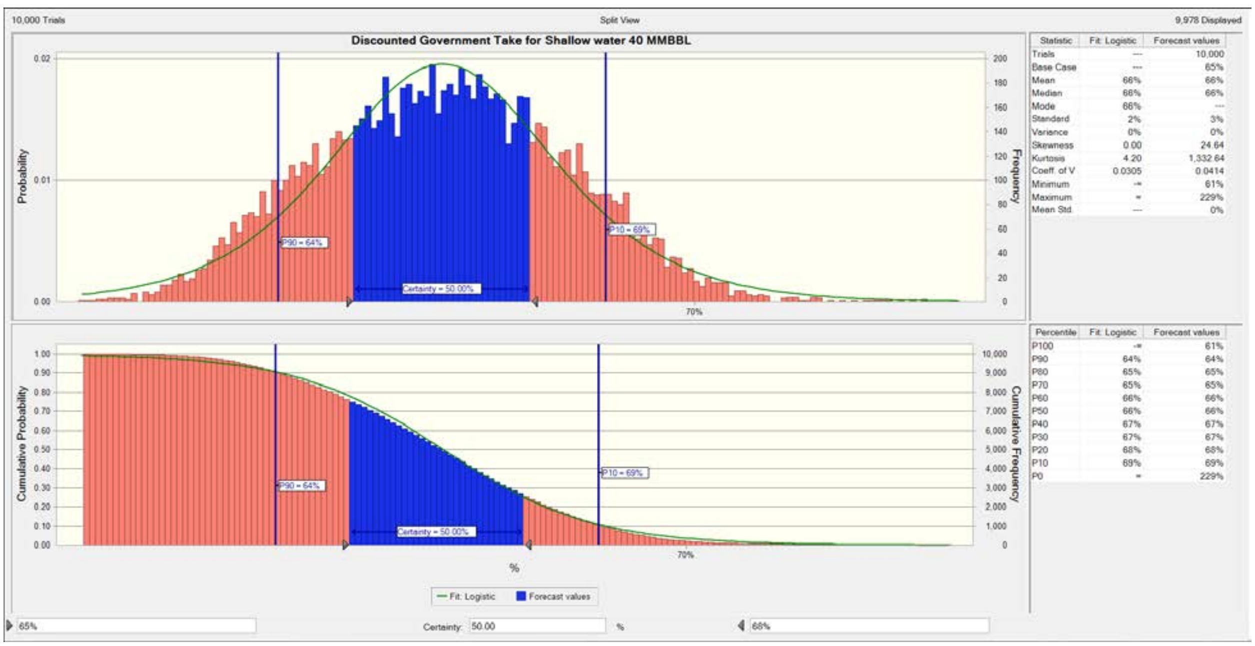


**Table B- 5: Discounted government take for 40 MM bbl shallow water field.**

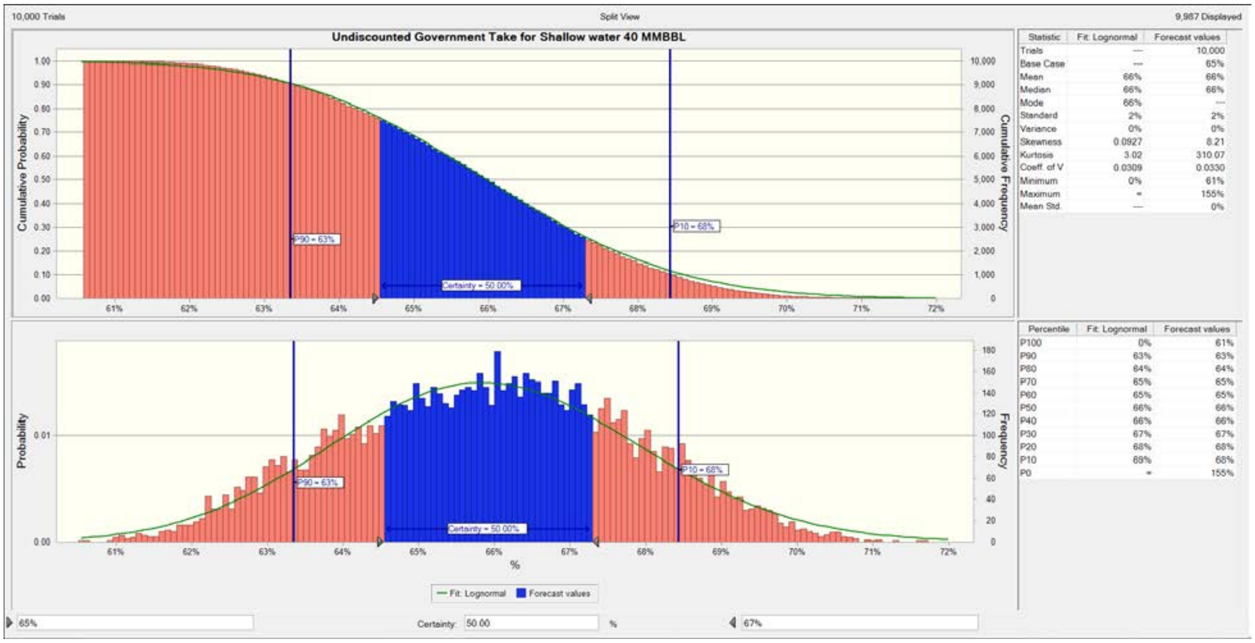


**Table B- 6: Undiscounted government take for 40 MM bbl shallow water field.**

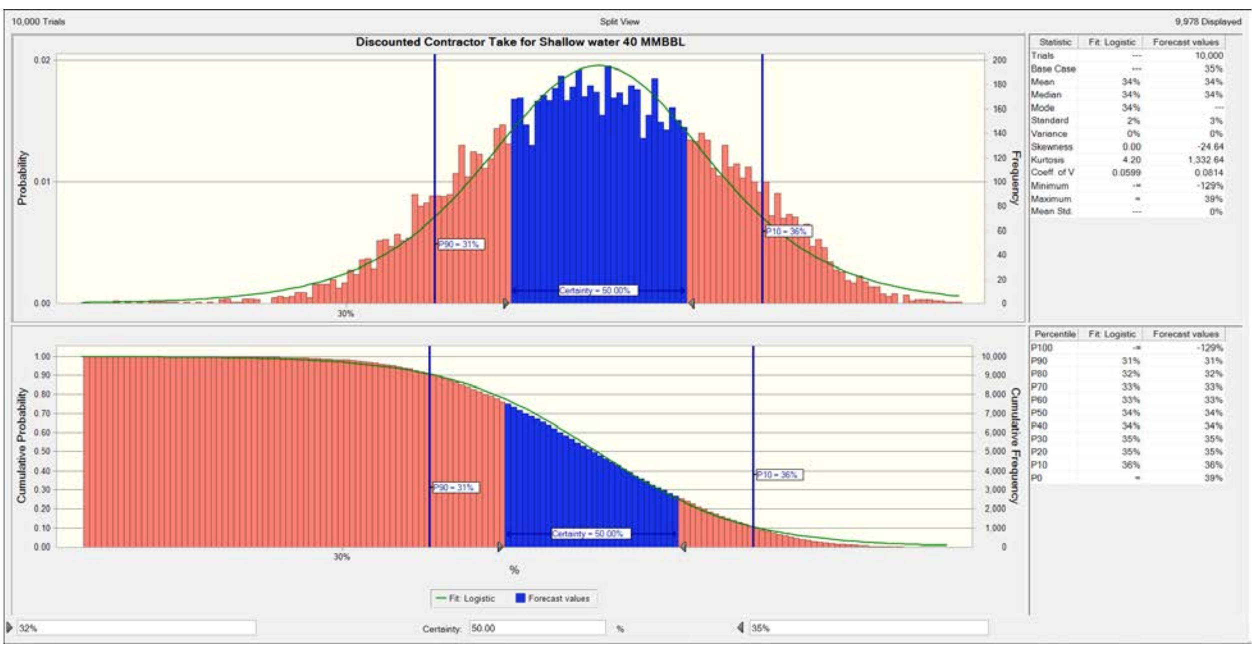


**Table B- 7: Discounted contractor take for 40 MM bbl shallow water field.**

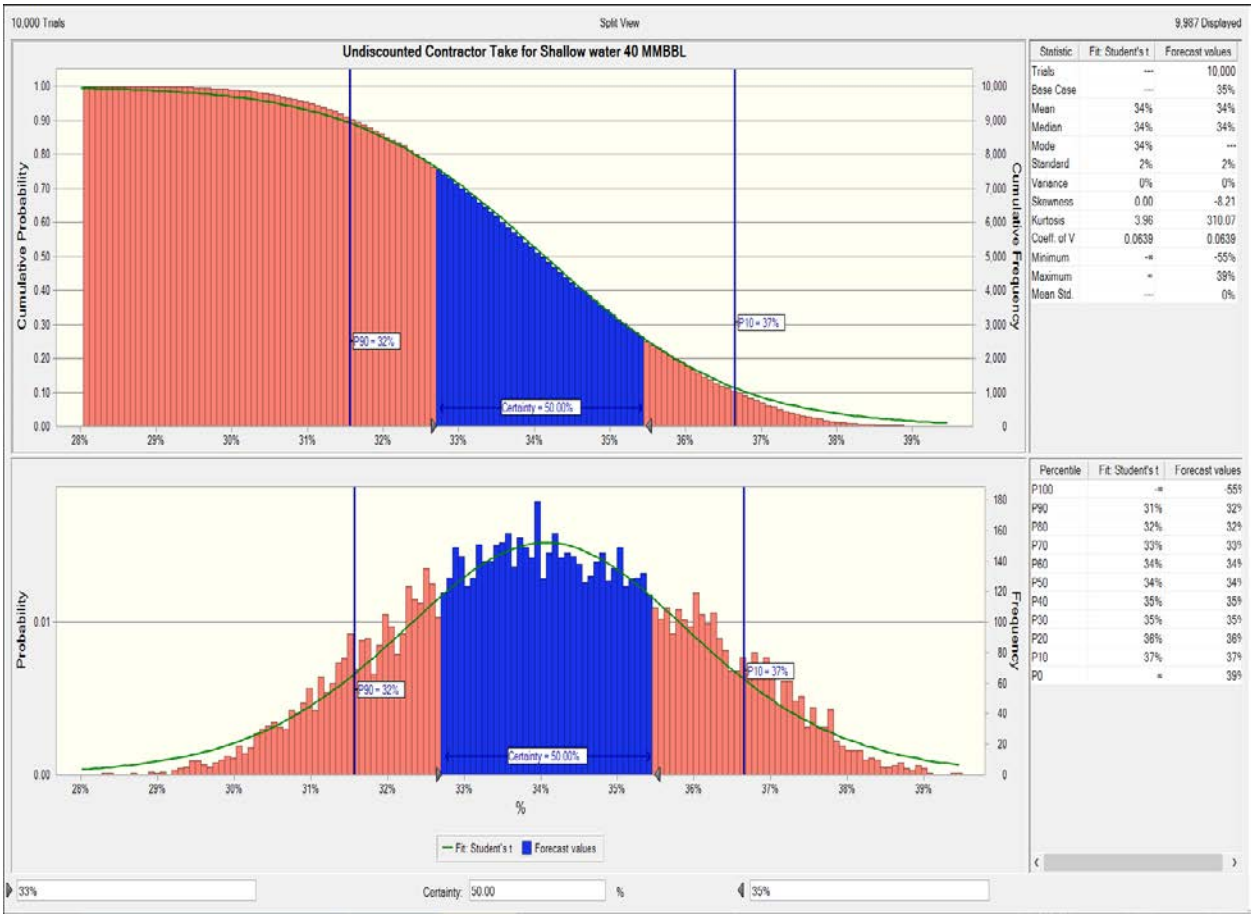


**Table B- 8: Undiscounted contractor take for 40 MM bbl shallow water field.**

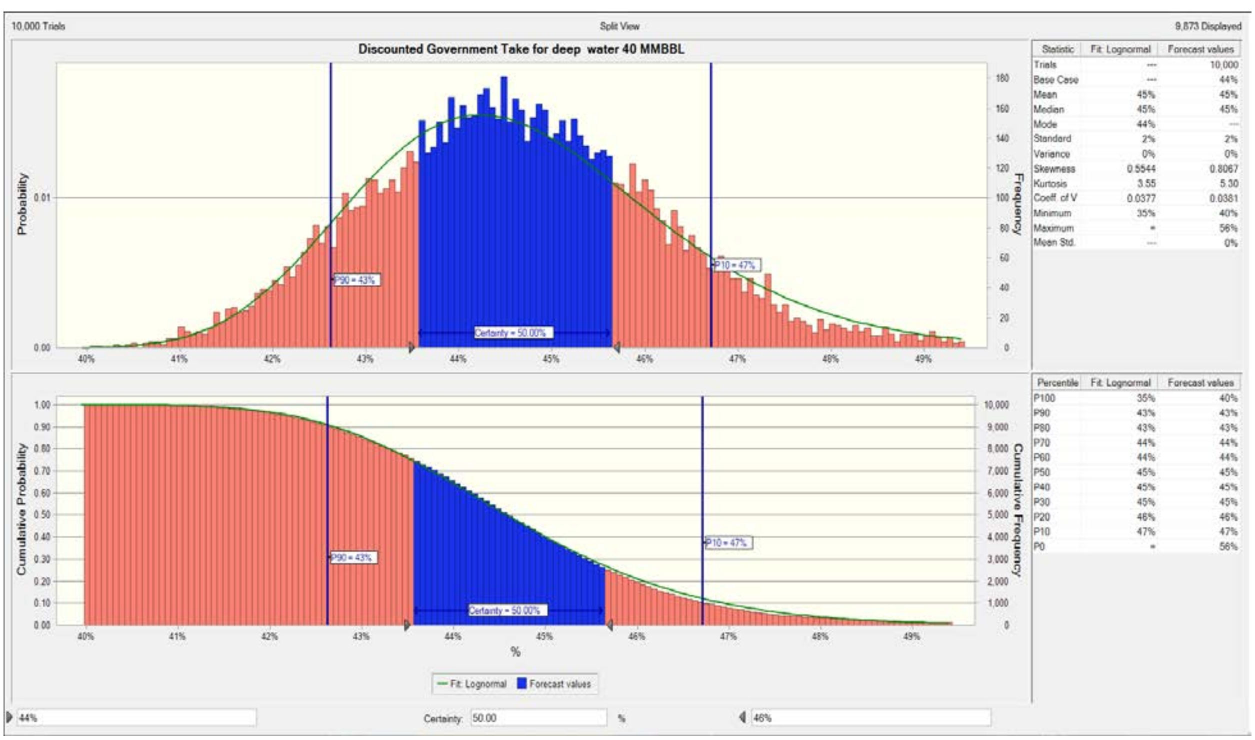

**Table B- 9: Discounted government take for 40 MM bbl deep water field.**

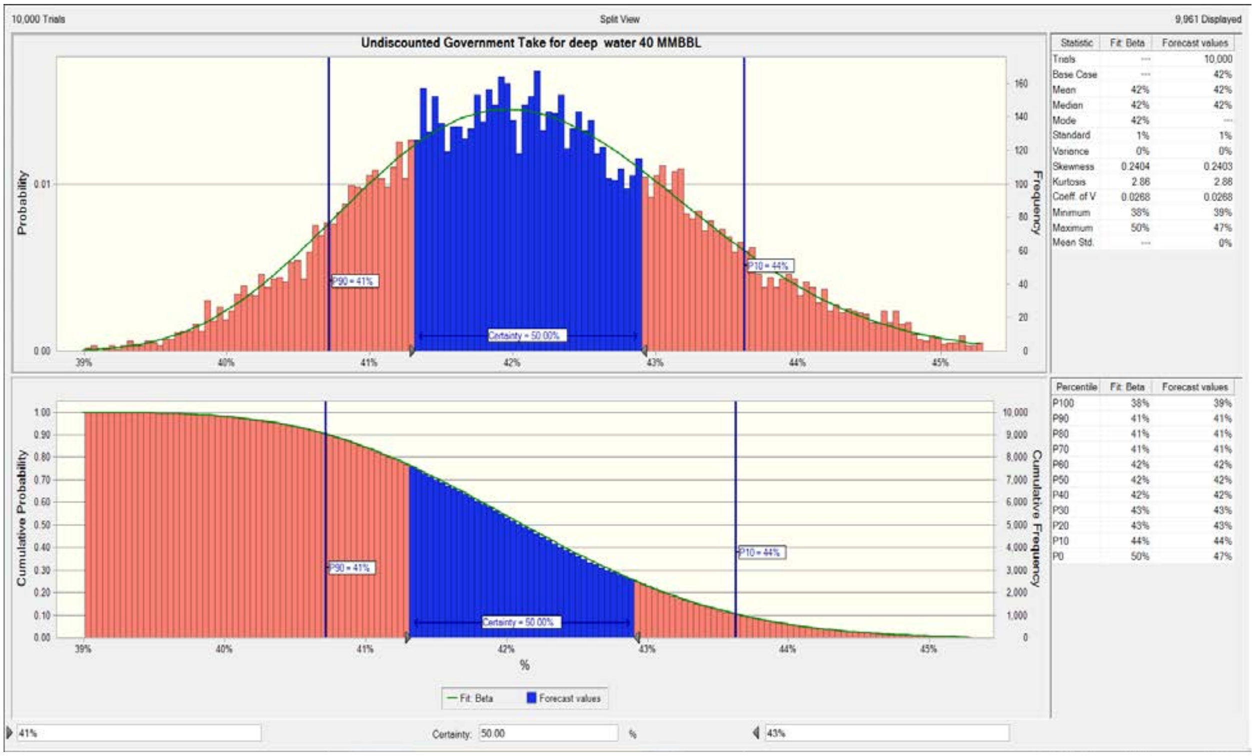


**Table B- 10: Undiscounted government take for 40 MM bbl deep water field.**

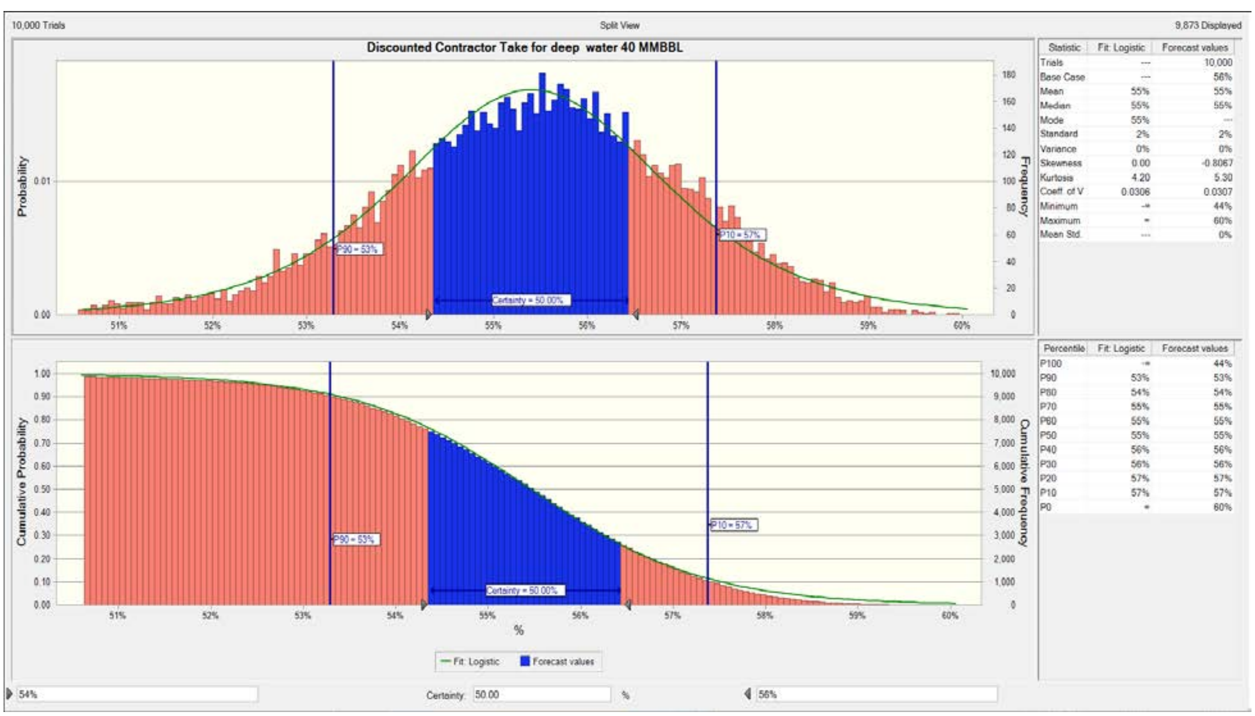


**Table B- 11: Discounted contractor take for 40 MM bbl deep water field.**

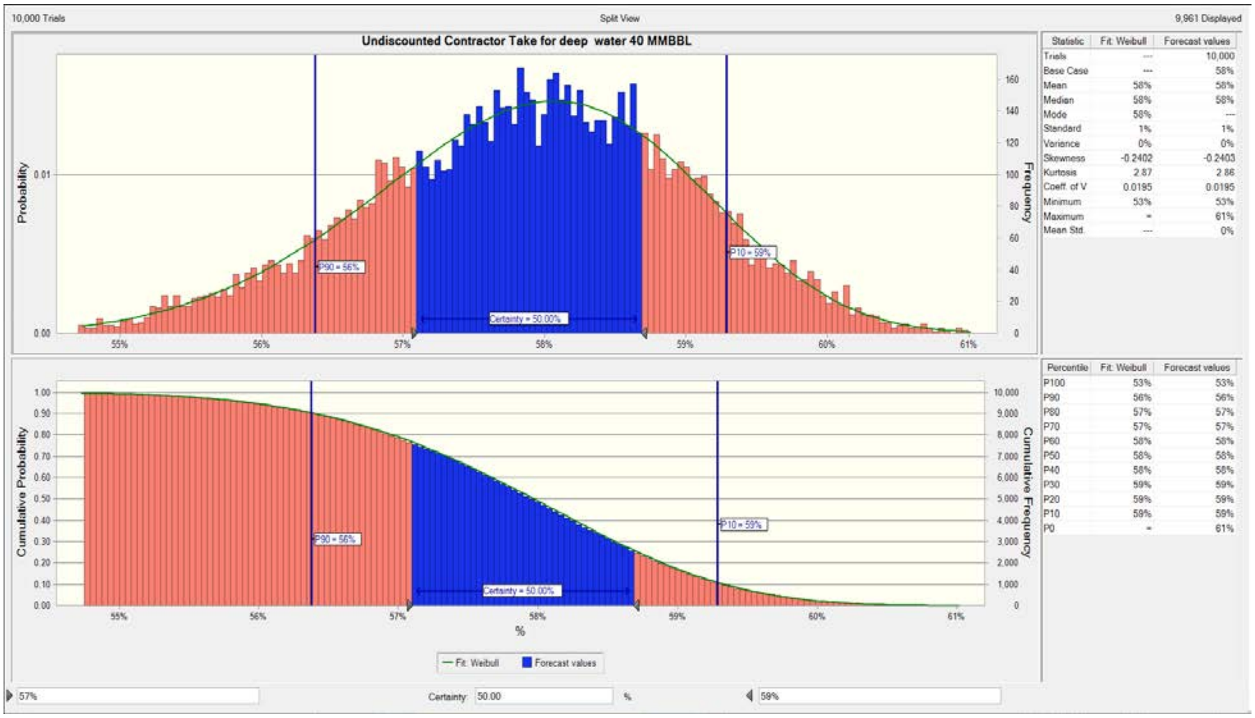


**Table B- 12: Undiscounted contractor take for 40 MM bbl deep water field.**