THE IMPACT OF THE AMENDED DEEP OFFSHORE AND INLAND BASIN PRODUCTION SHARING CONTRACTS ACT ON THE ECONOMICS OF OIL PRODUCTION IN NIGERIA

***Amieibibama Joseph**
Department of Petroleum & Gas Engineering, University of Port Harcourt, Nigeria
*Amieibibama.joseph@uniport.edu.ng
&
Imanze Omonghegbe
Department of Petroleum Resources, Nigeria
Imanze99@yahoo.com

ABSTRACT

The Deep Offshore and Inland Basin Production Sharing Contract Act (DOIBPSCA) was amended and signed into law November 4, 2019; which marks the beginning of a new era for Nigeria Production Sharing Contracts (PSC). The framework was designed to offer incentives to investors willing to take highly risky and capital-intensive deep offshore petroleum exploration and exploitation projects, especially during low oil price regimes. The amendment was necessitated following some flaws in the original Act. One major flaw is the need for a revisit to conduct comprehensive review 15 years after granting a lease and when the price of oil is above $20. This work aim to ascertain how the amended Act have impacted on deep offshore investments in some fields (OMLs 118, 138, 125, and 133) in Niger Delta. The Discounted Cashflow Model (DCFM) technique was used to carry out pre and post amendment PSC amendment evaluations, while a Monte Carlo simulation, using Crystal Ball software was used for the Stochastic and Sensitivity Analyses. From this study, it was observed that the amended Act caused a significant contractor NPV devaluation. The Federal Government also incurred losses of up to $2.32billion from the leases under the original Act. The Amended Act would increase the Government revenue within a 30 USD per barrel oil price threshold and attractive the contractor take after the amendment. It was observed that of all the variables sensitized, oil price has the highest impact on the profitability of investments under this amended PSC Act, followed by production rate.

Keywords: NPV, Contractor take, Government take, discounted cash flow, Production Sharing Contracts (PSC).

INTRODUCTION

Monetizing the entire petroleum industry-related value chain is the goal of most oil producing countries. Efficient and effective exploration and exploitation of the resources need the technical know-how and expertise of a contractor e.g., International Oil Companies (IOCs); consequently, host governments rely on these IOCs, who later partake in the profit sharing of the resources (Iledare, 2010). With a progressive contractual agreement having fair profit-sharing formula, the IOCs and host governments can forge a mutual relationship. This agreement could be either a Joint Venture (JV) or a Production Sharing Contract, which entails legal-binding obligations of the IOC to produce the resources at their expense with the possibility to recoup their investments plus earn profits during and after production (Wigwe-Chizindu, 2019).

The role of the Petroleum Industry is critical for the generation of revenue for a host nation and general economic growth. However, the existing fiscal system greatly impacts the value of the accrued revenue. Fiscal regimes are agreements, laws, and government regulations the host government design to oversee and regulate the oil and gas exploration and exploitation activities of the contractor, making the IOCs legal entities and the host government, a political entity (Gudmestad et al., 2010; Echendu, 2018). Foreign investors extensively assess the fiscal regime of the host nation with their proposed exploration and production activities to determine whether their investment would be worth it (Nakhle, 2001). Investors and mineral owners get a clearer picture of the distribution of the value accrued by the resources with the aid of petroleum fiscal systems (Echendu 2019).

The Petroleum Industry of Nigeria had witnessed several changes over the years. Since the discovery of oil at Oloibiri, Bayelsa State, 1951; operations in the Nigerian oil industry are yet to attain 21st century standards due to various compromises (Adeogun, 2018). The industry's business, operational landscape, and environments remain dynamic locally and internationally. Some of the key Nigerian petroleum-related regulations, including the Petroleum Profits Tax Act, Nigerian National Petroleum Corporation Act, and Petroleum Act 1969, have become obsolete and cannot suit the current realities of the oil and gas industry. Following this, the Legislative arm of the Nigerian Government, the Senate, passed the amended Deep Offshore and Inland Basin Production Sharing Contract Act (DOIBPSCA) in October 15, 2019. This Amendment is intended to provide incentives to key players of offshore oil and gas activities and give clarity to gray areas in the original DOIBPSCA of 2004. Some of the areas this amendment addressed include (DOIBPSCA, 2019):

i. Volatility and high-risk level of offshore and associated terrains.
ii. Enlargement of reserves portfolios
iii. Bottlenecks that exist in joint operational contract funding
iv. Host government's control and charge over various concessions
v. The need for increased foreign investments into offshore and inland basin terrains

The rising need for host governments to maximize value for their oil and gas resources requires them to design a fiscal system that will favor them, as well as the contractors. The Nigeria government observed the inadequacies of the existing deep-water fiscal regime, which failed to maximize value from deep offshore and associated terrain-related oil and gas resources. Consequently, the government amended the existing framework to suit current realities. In this work, evaluations were made to investigate the impact of the amended fiscal regime (DOIBPSCA) on the economics of deep offshore oil production in Nigeria. This was achieved through the determination of the impact of the change in the royalty rate between the original and amended Act in deepwater PSCs; investigating the economic viability of the Act for investors; reviewing the robustness of the amended Act while capturing its performance amidst uncertainties, and addressing non-technical matters which result from the amendment.

Deep Offshore and Inland Basin Production Sharing Contracts (DOIBPSCA) 2019: A Summary of the Amendment

The amended act stipulates a 50% fixed rate for Production Profit Tax on all Production Sharing Contracts (DOIBPSCA, 2019). The Act also grants a 50% tax allowance to the Nigerian National Petroleum Corporation (NNPC) for all petroleum-related operations and stipulated a graduated royalty rate for offshore operations and a 10% royalty rate for Inland Basin operations. Four key changes this amendment made to the original Act for PSCs include:

i. The integration of production and price-based systems to replace the original Act which was production-based alone. Condensates and crude oil royalty rate was pegged at 10% for offshore operations and 7.5% for Inland Basin (DOIBPSCA, 2019). This rates are applicable at above $20 per barrel oil price.
ii. Review of the Act when the oil price exceeds $20 per barrel in favor of the host government. A comprehensive review after 15 years of enacting the Act and thereafter, a review after every 5-years.
iii. The NNPC can call for PSCs review every 8 years as stipulated in section 16(A).
iv. Defaulters and non-compliant contractors are liable for at least ₦500 million fine or at most, 5 years imprisonment after conviction by a competent court according to section 16(B).

Table 1 gives a summary of the oil price-based graduated royalty rate stipulated by the DOIBPSCA 2019. As can be seen in Table 1, the applicable royalty rates increases with increasing oil price. However, the royalty rate is capped at 10% when the oil price exceeds $150/bbl.

Table 1: Graduated Royalty Rates based on Oil Price (*KPMG, 2019)*

Oil Price (US$)	**Applicable Royalty Rate (%)**
0-20	0
20-60	2.5
60-100	4.0
100-150	8.0
Above 150	10.0

METHODOLOGY

To evaluate the impact of the amended Act on deep offshore and inland basin PSCs profitability, the Discounted Cash Flow Model (DCF) was adopted. This method evaluates various profitability indicators to show how different petroleum investments fared before and after the amendment of the Act. Data obtained from the Department of Petroleum Resources (DPR), the regulatory body of the oil and gas industry in Nigeria, was used for the analysis. The data comprised of various reserves for deep-water fields (OMLs 118, 138, 125, and 133) and their production history. The profitability indicators used for the analysis include: Net Present Value (NPV), Internal Rate of Return (IRR), and discounted government and contractor takes, respectively. Table 2 summarizes the concession contract data for the OML's considered.

Table 2: Concession Contract Data (Department of Petroleum Resources, 2017; Offshore Global Data, 2019)

Concession	Reserves (MMbbl.)	Operator	Area (km^2)	Water Depth (metre)	Date of Grant	
					Start	Expiration
OML 118	600	SNEPCO.	1167	4000	28/11/2005	27/11/2025
OML 138	500	Total E&P	656	850	17/05/2007	16/05/2027
OML 125	250	NAE	1219	800	02/01/2003	01/01/2023
OML 133	500	Esso E&P	1100	1200	08/02/2006	07/08/2026

The oil fields have a total estimated reserves of 1850 MMbbl. The depth of water range between 800 and 4000 meters, which is equivalent to between 2625 and 13123 ft; implying that they are deepwater oilfields. Table 3 is the annual production data from the different OMLs between 2010 and 2017 respectively.

Table 3: Annual Production Data for OML Deep Water Field (DPR, 2017)

Stream / Year	**OML 118 (MMbbls)**	**OML 138 (MMbbls)**	**OML 125 (MMbbls)**	**OML 133 (MMbbls)**
2002	-	-	0	-
2003	-	-	11.58	-
2004	-	-	13	-
2005	0	-	14.6	0
2006	10.2	-	14.6	32.22
2007	10.2	-	14.6	37.79
2008	18.9	-	14.6	44.33
2009	35.1	-	14.6	52.0
2010	65.1	0	11.5	61.3
2011	51.6	0	10.4	52.5
2012	64.3	28.9	8.3	46.4
2013	50.9	38.4	8.0	37.0
2014	58.3	44.5	8.3	36.0
2015	69.7	39.7	8.2	33.4
2016	75	37.3	7.0	45.8
2017	61.4	36.0	5.0	45.0

Table 3 gives the various annual production histories from inception of production of the OMLs considered. An exponential decline pattern was assumed for all the OMLs investigated. The cost outlay for the field development of the four deepwater concessions are shown in Table 4. As can be seen in Table 4, OML 118 had the highest field development cost of $3600 million, while OML 125 is the least with $1000 million.

Table 4: Concession Cost Outlay Summary **(**Offshore Global data, 2019, equatorexploration.com, 2019)

Concession	Field Development Cost (MM$)
OML 118	3600
OML 138	2700
OML 125	1000
OML 133	3000

Other relevant data used for the analyses include (Offshore Global Data, 2019):

i. For OML 118; peak production rate = 205.48Mbbl/d, peak production rate @ the start of decline phase = 168Mbbl/d.
ii. For OML 138; peak production rate = 122Mbbl/d, peak production rate @ the start of decline phase = 109Mbbl/d.
iii. For OML 125; peak production rate = 40Mbbl/d, peak production rate @ the start of decline phase = 30Mbbl/d.
iv. For OML 133; peak production rate = 190Mbbl/d

It was also assumed that the decline phase ensued for all fields considered in 2017, 2014, 2010, and 2017, for OMLs 118, 138, 125, and 133, respectively. The Net Present Value (NPV) is calculated using:

$$NPV = \sum_{t=1}^{k} \frac{NCF_t}{(1 + r)^t} \quad (1)$$

where NCF_t is the annual cash flows assuming end of year cash receipts, r is the discount rate which reflect the value of alternative use of funds, t is the time in years and k is the lifetime (in years) of the project. The Internal Rate of Return (IRR) is determined using:

$$NPV = \sum_{t=1}^{k} \frac{NCF_t}{(1 + IRR)^t} = 0 \quad (2)$$

where IRR is the internal rate of return. To account for uncertainty in the projected economic model, the stochastic analysis was carried out using Crystal Ball software and Table 5 summarizes the input data for the model.

Table 5: Input Distribution for Stochastic Modelling

Input variables		Distribution type	Min	Mean	Max
OML 118 OPEX (MM$)	Fixed	Triangular	3% CAPEX	5%	7% CAPEX
	Variable	Triangular	12% GR	15% GR	18% GR
OML 138 OPEX (MM$)	Fixed	Triangular	3% CAPEX	5%	7% CAPEX
	Variable	Triangular	12% GR	15% GR	18% GR
OML 125 OPEX (MM$)	Fixed	Triangular	3% CAPEX	5%	7% CAPEX
	Variable	Triangular	12% GR	15% GR	18% GR
OML 133 OPEX (MM$)	Fixed	Triangular	3% CAPEX	5%	7% CAPEX
	Variable		12% GR	15% GR	18% GR
Oil price ($/bbl.)		Triangular	30.00	55.00	65.00
Discount rate		Lognormal		15%	

A triangular probability distribution for the fixed and variable costs and oil price were assumed since the minimum, maximum, and most likely values of these variables are known while a log-normal probability distribution was assumed for the discount rate; since it is ideal for positively skewed variables. A sensitivity analysis was also carried out using Crystal Ball to evaluate the responsiveness of the project economics to changes to various input parameters. This is to give a clearer picture of the impacts of each parameter to enable investors pay particular interest for decision making processes. With an elasticity of ±20% from the mean, the evaluation was enhanced using spider diagram.

RESULTS

Deterministic Results

Scenario 1: Analyses in this scenario are carried out at a discount rate of 15%

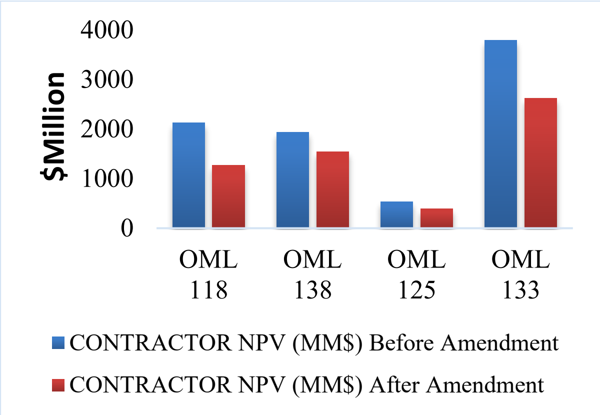

Figure 1: Comparison of Contractor's NPV for various Terms@15% discount rate

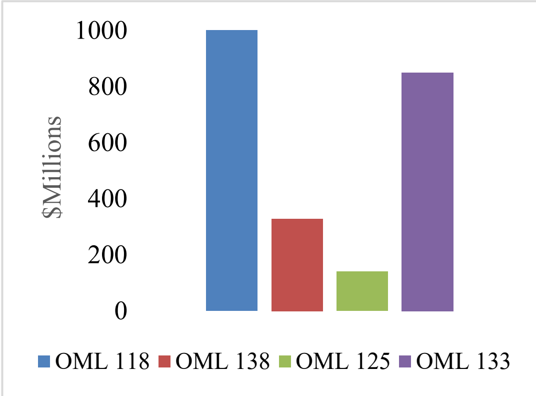

Figure 2: Government Losses from Previous PSC OMLs @ 15% discount rate

Table 6: Government Take@ 15% discount rate

	Before Amendment	After Amendment
OML	78%	87%
OML	73%	79%
OML	77%	83%
OML	69%	76%

Table 7: IRR Comparison for each OML

	Before Amendment	After Amendment
OML 118	18%	17%
OML 138	19%	18%
OML 125	20%	17%
OML 133	20%	19%

Scenario 2: The analysis in this section adopts a discount rate of 12.5%.

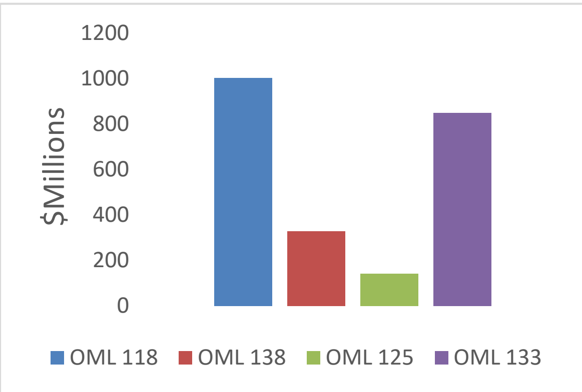

Figure 3: Government Losses from Previous PSC Terms @ 12.5% Discount Rate

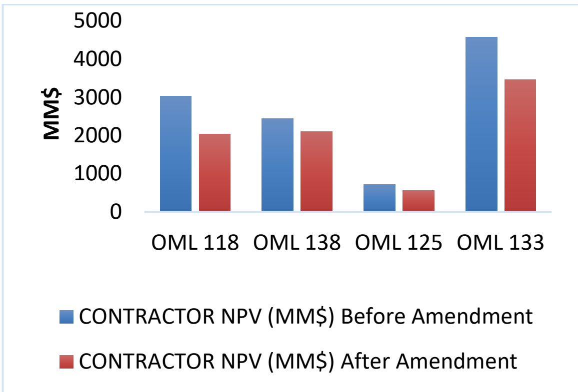

Figure 4: Comparison of Contractor's NPV for each OML @ 12.5% Discount Rate

Table 8: Government Take @ 12.5% Discount Rate

	Before Amendment	After Amendment
OML 118	75%	83%
OML 138	71%	77%
OML 125	74%	80%
OML 133	68%	75%

Scenario 3: The analysis in this section adopts a discount rate of 17%.

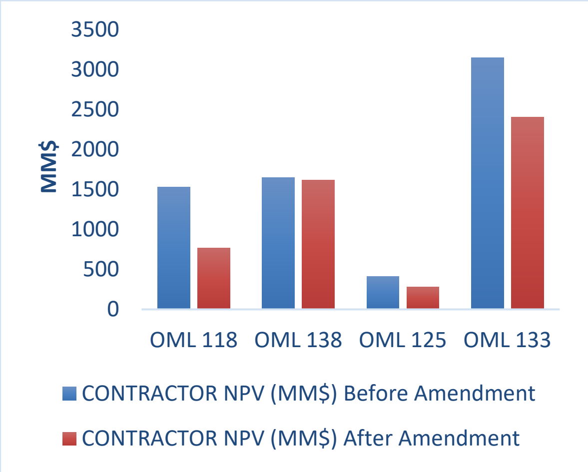

Figure 5: Comparison of Contractor's NPV Per OML @ 17% Discount Rate

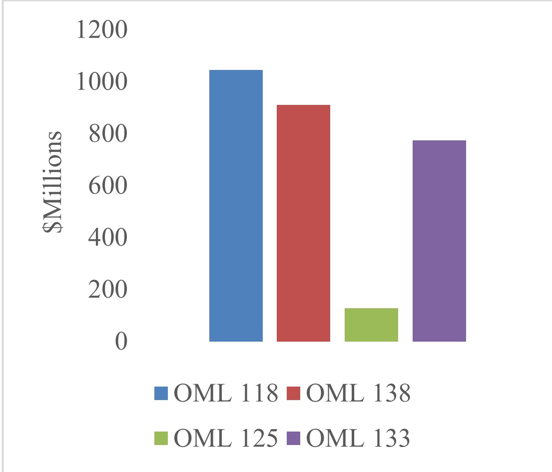

Figure 6: Government Losses from Previous PSC Terms @ 17% Discount Rate

Table 9: Government Take @ 17% Discount Rate

	Before Amendment	After Amendment
OML 118	81%	91%
OML 138	75%	79%
OML 125	80%	86%
OML 133	70%	78%

Stochastic Results

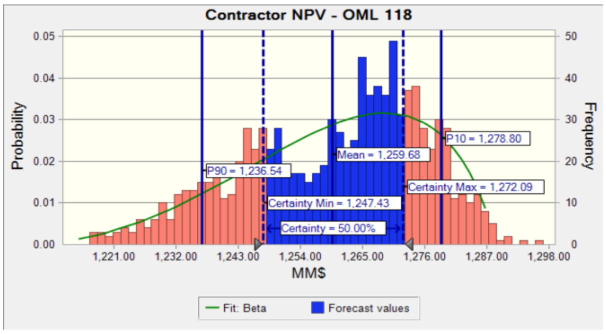

Figure 7: OML 118 Stochastic Contractor NPV After Amendment

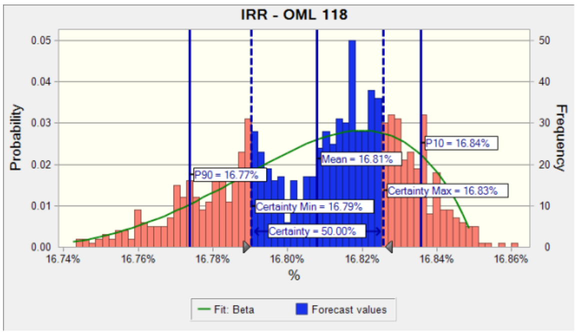

Figure 8: OML 118 Stochastic IRR After Amendment

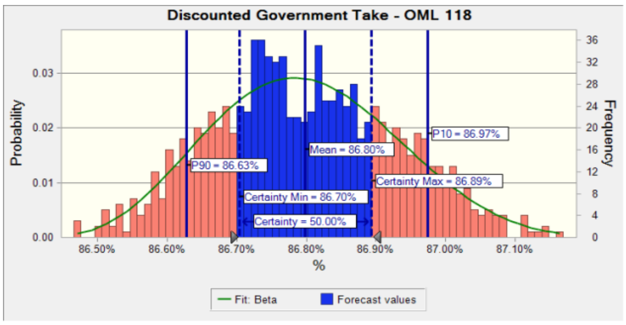

Figure 9: OML 118 Stochastic Govt. Take After Amendment

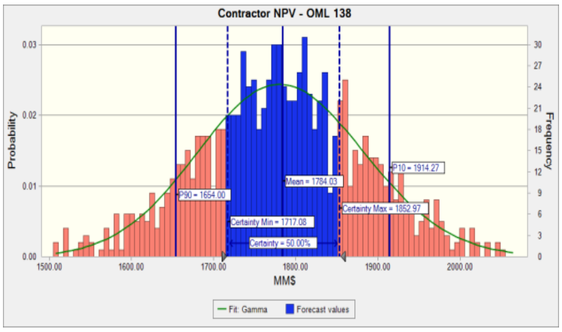

Figure 10: OML 138 Stochastic Contractor NPV after Amendment

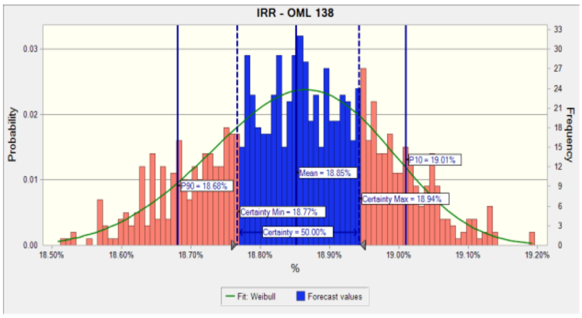

Figure 11: OML 138 Stochastic IRR After Amendment

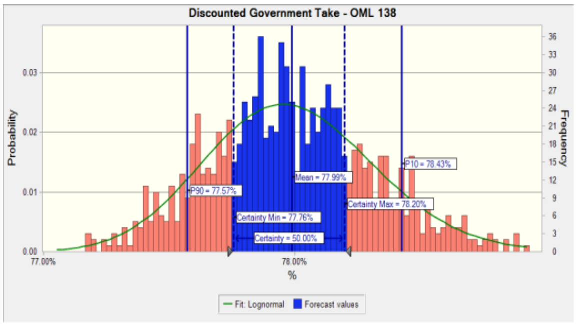

Figure 12: OML 138 Stochastic Govt. Take After Amendment

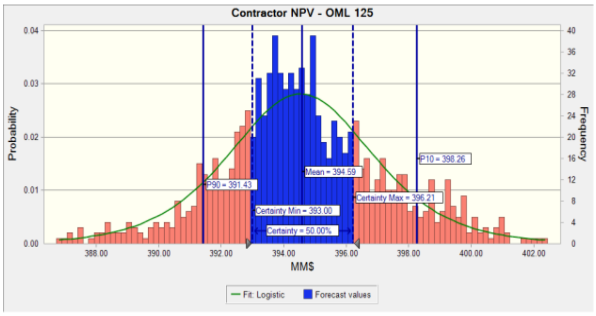

Figure 13: OML 125 Stochastic IRR After Amendment

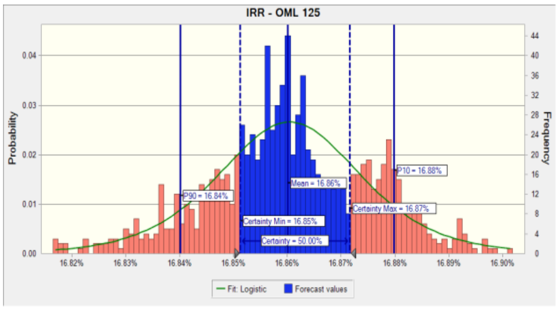

Figure 14: OML 125 Stochastic Contractor NPV after Amendment

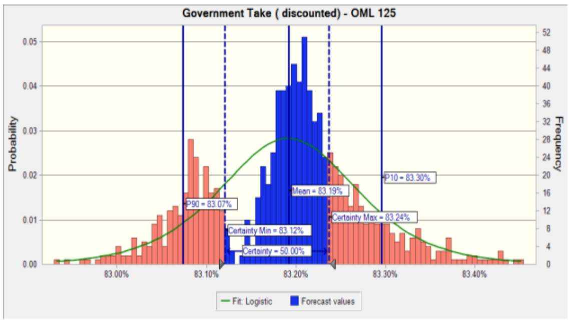

Figure 15: OML 125 Stochastic Govt. Take After Amendment

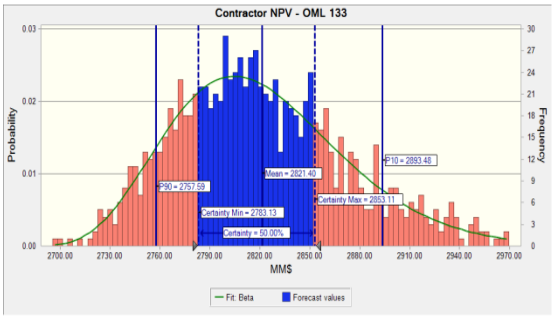

Figure 16: OML 133 Stochastic Contractor NPV after Amendment

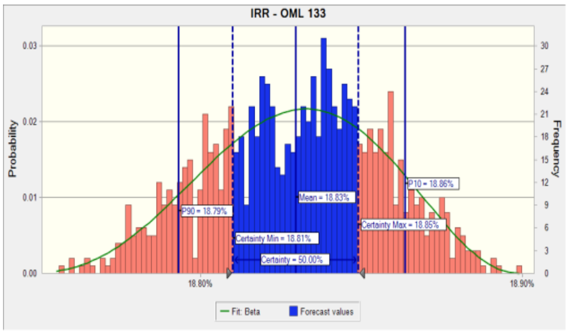

Figure 17: OML 133 Stochastic IRR after Amendment

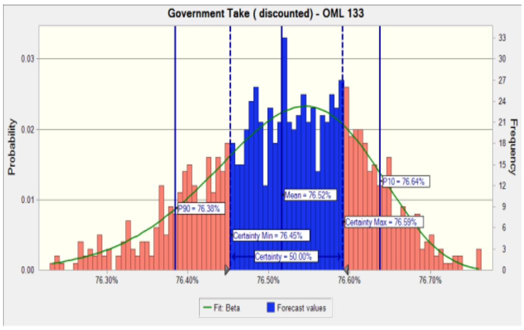

Figure 18: OML 133 Stochastic Govt. Take After Amendment

Sensitivity Analysis

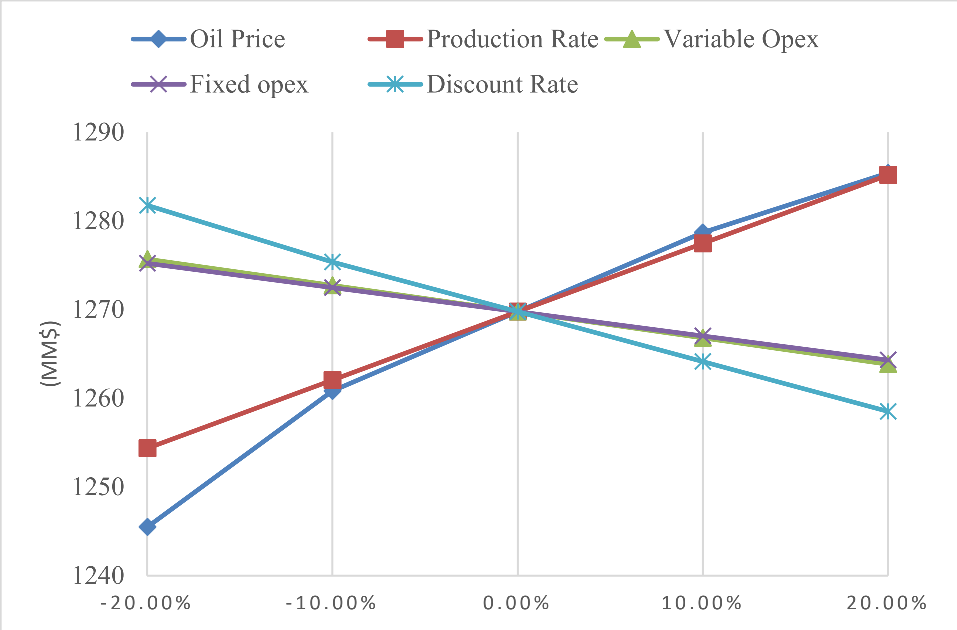

Figure 19: Sensitivity Analysis of Amended PSC on Deepwater Projects (NPV)

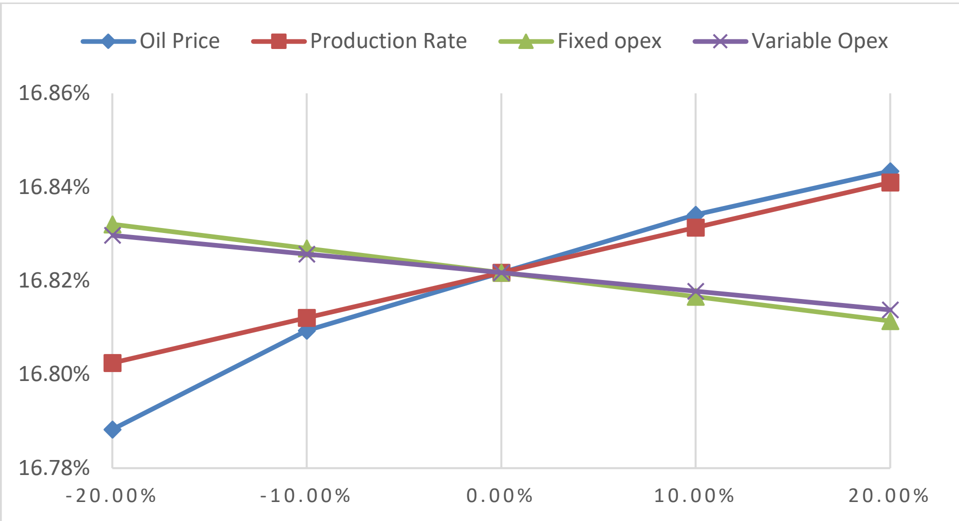

Figure 20: Sensitivity Analysis of Amended PSC on Deepwater Projects (IRR)

DISCUSSION

Figure 1 shows the contractor take before and after amendment for the different OMLs. As can be seen in Figure 1, the amended DOIBPSCA 2019 has a regressive effect on the contractor NPV for the four OMLs compared to the original Act; and shows a remarkable difference on the NPV of the contractor at a discount rate of 15%.

OML 118 experienced a $860 million devaluation when compared with the original Act. There was a devaluation from $1.97billion to $1.82 billion for OML 138, $538million to $395million for OML 125, and $3.72billion to $2.83billion for OML 133 respectively. This implies that the amendment will favor the contractors less. The amendment also led to a significant change in the government's take as shown in Table 6.

As observed in Table 6, the amendment will cause a corresponding increase in government take across the OMLs ranging from 76% - 87%. The delay in amending the fiscal terms by the Federal Government of Nigeria led to a significant loss as shown in Figure 2. It was also observed that a total loss of up to $2.32 billion comprising $1billion from OML 118, $329million from OML 138, $141million from OML 125, and $850million from OML 133 up to 2020 (Beginning of Year) when the deep offshore and inland basin production sharing contract were amended and enacted. This implies that the amendment is favorable to the host government. Table 7 gives a comparison of the IRR of the OML's before and after the amendment. Although, the amendment resulted in a drop in the IRR values for oil and gas investments, they are however, still above the discount rate used in the analysis. This implies that petroleum investments will remain economically viable under the amended Act. Similar regressive trends and losses was observed when the discount rate was varied to 12.5% and 17% as shown in Figures 3 to 6.

In the midst of uncertainties, the PSCs under the amended Act remain viable to the contractor as shown in Figure 7. With a P90 of $1.236 billion, there is a 90% chance that the contractor's NPV will keep adding value to its portfolio under the amended DOIBPSCA. Figure 8 shows the result of the stochastic analysis on the IRR for the amended Act.

From Figure 8, the PSC exhibits a P90 of 16.77%, 1.77% higher than the discount rate,under uncertainties. This implies that the venture under the amended Act is economically viable. The Federal Government retains a significant share of the proceeds from the resources exploration and exploitation of its resources, with a P90 value of 86.63%, as shown in Figure 9. For OML 138 as shown in Figure 10, at 50% certainty, the contractor will generate NPV in the range between $1.717 and 1.852 billion. Figure 10 also shows that at P90, there is 90% chance of the project generating NPV of about $1.664 billion and NPV of $1.914 billion at P10 respectively. These represent the maximum possible contractor NPV through 2027 when the lease will expire. These positive NPV values further emphasizes the positive impacts of the amended bill on Nigerian offshore oil and gas ventures.

The minimum possible IRR (18.68%) is viable as the value is greater than the discount rate (15%) and a Government Take of at least 77.57% is expected for OML 138 as shown in Figures 11 and 12. For OML 125, IRR is expected to range between 16.84% and 16.88% which is greater than 15%, thus indicating a viable venture as shown in Figure 13. There is a 50% chance that the contractor will have NPV in the range between $393 and $396 million and a 90% chance that the contractor will have an NPV of at least $391.43 million; while the Government Take is expected to be at least 83.07% under the prevailing economic uncertainties, as shown in Figures 14 and 15 respectively. The amended DOIBPSCA framework consistently gives a positive NPV in uncertainties, making it suitable for investors.

For OML 133, the contractor is sure of generating a positive NPV range between $2.78 billion and $2.85 billion, at 50% certainty as shown in Figure 16. The maximum attainable contractor NPV is $2.89billion with only a 10% chance of occurrence. However, there is a 90% chance that the contractor will generate an NPV of $2.76billion. Figure 17 shows that the minimum possible IRR (18.79%) is a viable as the value is greater than the discount rate (15%) and the Government Take of at least 76.38% is expected as shown in Figure 18.

Figure 19 shows the sensitivity of the amended PSC on deepwater projects using spider diagram. From Figure 19, the price of oil has the highest impact on the contractor NPV under the amended bill, followed by production rate, discount rate, and technical costs. Low oil prices can translate to low revenue and lesser profitability for the contractor and the Federal

Government alike. Consequently, both parties must consider this factor during the planning phase. Also, the discount rate, which has the highest negative impact, must be carefully selected to ensure optimized results. Figure 20 shows that oil price and production rates have the highest impacts on the PSCs' economic viability, further emphasizing the need to pay attention to these parameters.

CONCLUSIONS

The amendment of the DOIBPSCA in 2019 is more beneficial to the federal government than the contractor. However, the contractors will still retain a fair share of the proceeds even under uncertainties. The work observed an average government take increase from 74% to 81% before and after amendment. The work also observed that oil and gas ventures under the amended Act will remain viable to the contractors since the IRR values are greater than the 15% discount rate. Finally, the sensitivity analysis results showed that oil price, production rate, and discount rates have significant impacts on the overall profitability of PSCs under the amendment.

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