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Assessing the Impact of Deep Offshore and Inland Basin Production Sharing Contract Ammendments on the Economics of Deep Offshore E&P Assets in Nigeria

Oghenerume Ogolo, Petroleum and Gas Engineering Department, Nile University of Nigeria; Omowumi O. Iledare, Institute for Oil and Gas Studies, University of Cape Coast; Petrus Nzerem and Ikechukwu S. Okafor, Petroleum and Gas Engineering Department, Nile University of Nigeria; Emeka Iloegbunam, Innovationeering Limited; Isaac P. Ekeoma, University of Port Harcourt

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Abstract

Nigeria recently amended the Deep Offshore and Inland Basins Act. The Act seeks to generate aditional annual revenue of over $1 billion for the government. The 2019 Law seems attractive to the government in the short run in terms of early rent extraction; on one hand, the seeminglly attractiveness of the fiscal terms in the Ammended Act, which is to expand output from investment in Nigeria deep offshore in the country is conjectural. The purpose of this paper is to evaluate the impact of the amendments to the PSC Act on value creation and addition to stake holders using systems and economic metrics that include investment earning power and discounted government take. A designed petroleum economic modeling framework applied to the fiscal terms in the new Act show a significant decrease in value addition to contractor portfolio of assets by about 25% but increases government discounted take statistics from 63.70% to 72.64% in comparison to the fiscal and contract terms in PSC 1993. The IRR and FLI obtained using the terms in the new Act were 23.66% and 0.043, respectively.

Introduction

Globally, petroleum fiscal system is a key factor influencing the flow of E&P investments into oil and gas producing nation (Echendu et al., 2015). Iledare, 2004 defines the petroleum fiscal system as the contractual, tax, legislative and fiscal element that underlies E&P operations in oil and gas producing province. The petroleum fiscal system helps to determine how companies will recover their cost of investment and how profit will be shared between companies and the host government (Echendu et al., 2015; Oyekunle, 2011). The production sharing contract (PSC) arrangement under the contractual type of petroleum fiscal system usually stipulates a cost recovery limit and a profit-sharing mechanism for companies and the government, based on total profit oil (Johnston, 2003; Mian, 2002; Nyoor, et al., 2019). It is imperative that fiscal systems need to be designed in such a way that they are attractive to companies and contains fiscal elements that will enable government to get more revenues from investment in the oil and gas sector, without compromising adequate reward that are proportionate to the risk incured.

Nigeria uses the PSC arrangement for investment in the inland basin and deep offshore region of the country. In 1993, due to the low oil price, a PSC arrangement was introduced in Nigeria to attract deep offshore investments. The royalty rate was reduced with increasing water depth and companies pay zero royalties on production from water depth beyond 1000 m. This was done as a form of incentives to encourage companies to invest in the country despite the low price of oil. It was stipulated that the act will be reviewed after 15 years and changes can also be made if the oil price rises above $20 per barrel in real terms. However, the act was not reviewed as stipulated until 2018.

In 2018, the President of the Federal Republic of Nigeria proposed the Deep offshore and Inland Basin Production Sharing Contract Amendment (DOIBPSCA) to the National Assembly for consideration and passage. The DOIBPSCA seeks to generate an annual revenue of over $1 billion for the government. The bill was passed by the National Assembly in October, 2019 and the President on November 5th, 2019 assented to the DOIBPSCA (KPMG, 2019; PWC, 2019). The amendment presents arrangements for price-reflective royalties, 8-year occasional audit of the Production Sharing Contracts ("PSCs") and penalties for any violations of the provisions of the Act.

It is good for policies to be made to increase government's revenue from the oil and gas sector but as such, the government must be mindful of the impact of such policies so as not to deter investors from investing in the offshore region of the country. This research work accessed the impact of the DOIBPSCA on the economics of deep offshore E&P assets in Nigeria. It considered the impact of the amendments on value creation and addition to stake holders using economics and systems metrics, such as investment earning power and discounted government take.

Methodology

Discounted cash flow (DCF) method was used to evaluate the impact of the DOIBPSCA and 1993 PSC aranangement on E&P investment in the deeoffshore region of Nigeria. This was achieved using spreadsheet modeling technique. DCF method enables the incorporation of the time value of money in the modeling process to account for inflation which might occur in the future. The fiscal arrangement in Table 1 and economic assumptions in Table 2 were used as the basic input variables for the petroleum economic modelling. A generalized cash flow model is shown in equation one.

$$NCFt = GRt - ROYt - CAPEXt - OPEXt - BONUSt - \frac{PO}{Gt} - TAXt - OTHERt \quad \text{Equation 1}$$

Where

NCF_t = After-tax net cash flow in year t

GR_t = Gross revenues in year t

ROY_t = Total royalties paid in year t

$CAPEX_t$ = Total capital expenditures in year t

$OPEX_t$ = Total operating expenditures in year t

$BONUS_t$ = Bonus paid in year t

PO/G_t = Government profit oil in year t

TAX_t= Total taxes paid in year t

$OTHER_t$ = Other costs paid in year t.

Table 1—1993 PSC and DOIBPSA Fiscal Arrangement

	1993		DOIBPSCA	
	Water Depth	**Royalty Rate**	**Water Depth**	**Royalty Rate**
Royalty Rate	(Metres)	(%)	(m)	(%)
	<=100	18	<200	8
	10-200	16.667	>200	10
	201-500	12	**Oil Price**	**Royalty Rate**
	501-800	8	($)	(%)
	801-1000	4	0-20	0
	>1000	0	>20-60	2.5
			61-100	4
			>100-150	8
			Above 150	10
Profit Oil	**Cummulative Oil Production**		**Contractor's Profit Oil Share**	
	(MMBOE)		(%)	
	<350		80	
	350-750		65	
	751-1000		55	
	1001-1500		50	
	>1500		40	
Cost Recovery Option	100%			
Education Tax	2% levy on accessible profit.			
Petroleum Profit Tax	50%			
Bonus	Production bonuses and signature bonuses are negotiable			
NDDC	2% of total budget			
Depreciation	Straight line depreciation technique for 5 years			

Table 2—Economic Assumptions

Input Data		
Year Begin	2017	Year
Signature Bonus	100	$MM
Exploration Activities	300	$MM/year
Exploration Years	2	Years
Development Well	2019	Year
Field Development	3	Years
Water Depth	1100	m
1st year	1500	$MM
2nd year	2400	$MM
STOIP	1905	MMBBL
Production Begins in	3	Years

Input Data		
Initial Production	10	MBOPD
Instantaneous Production year	2019	Year
Peak Production	120	MBOPD
Peak Production Begins	2023	Year
Peak Period	3	Years
Effective Decline Rate	12.50%	%
Field Life	20	Years
Number of Days	365	days/year
Fixed Operating Cost	5%	of CAPEX
MOD Oil Price	65	$/bbl
Discount Rate	10	%’

The exponential method of the decline curve analysis was employed to forecast the production from the field using the production parameters as shown in Table 2. The field was assumed to be located in a water depth of 1100 m in the deepoffshore region of the Niger Delta. The field life was 20 years.After forecasting the production of oil from the field, the next stage was to determine the technical cost for exploration and field development activities. The exploration of the field will take 2 years while the development of the field will take 3 years. But production of the field will begin at the end of the third year to enable the generation of revenues early.The technical cost was depreciated using straight line depreciation technique putting into consideration the cost recovery option specified in the PSC arrangement. PSC arrangement are designed to allow companies recoup either a certain percentage or total of their technical cost incurred during the life of an E&P asset through the introduction of a cost recovery option. The specified cost are recovered before the calculation of profit oil.Using the fiscal terms enshrined in both the DOIBPSCA and 1993 PSC arrangement, profitability indicators such as government take, contrator's take, internal rate of return, net present value and front-end loading index were determined. Profitability indicators are measures used by firms to evaluate the economic viability of any project. These indicators were used to determine the economic viability of E&P projects using the DOIBPSCA and 1993 PSC arrangements. The profitability indicators were calculated using the generalized NCF model shown in equation 1 (Echendu et al., 2015). The following equations were used for the calculation of each of the profitability indicaors considered.

- Net Present Value (NPV)

$$NPV = \sum_{i=1}^{n} \frac{NCF_t}{\left(1+i_d\right)^t}. \qquad \text{Equation 2}$$

Where NCFt = New cash flow in year t
i_d= Discount rate
t= Time

- Internal Rate of Return (IRR)

$$\sum_{t=1}^{n} \frac{NCF_t}{(1+IRR)^t} = 0 \qquad \text{Equation 3}$$

- Unit Technical Cost (UTC)

$$UTC = \frac{(CAPEX + OPEX)}{Reserve} \qquad \text{Equation 4}$$

- Contractor and Government Take

$$Government\ Take\,(GT) = \frac{Government\ NPV}{(Government\ NPV + Contractor\ NPV)} \quad \text{Equation 5}$$

$$Contractor\ Take\,(CT) = \frac{Contractor\ NPV}{(Government\ NPV + Contractor\ NPV)} \quad \text{Equation 6}$$

- Front-end Loading Index (FLI)

$$FLI = \frac{Discounted\ Government\ Take}{Undiscounted\ Government\ Take} - 1 \quad \text{Equation 7}$$

Empirical Results and Analysis

Field Production Data

Figure 1 shows the oil production rate of the field. The initial oil production rate was 10 Mbbl/day and the peak production rate was 120 MMbbl/day which began in year 2023 and plateau for 3 years. The annual and cumulative production of the field is shown in Figure 2. The peak annual production was 1,825,000 MMbbl of oil. While the cumulative oil production for the entire life of the field was 457.3 MMbbl. This means that about 24% of the original oil initially in place was recovered during the productive life of the field.

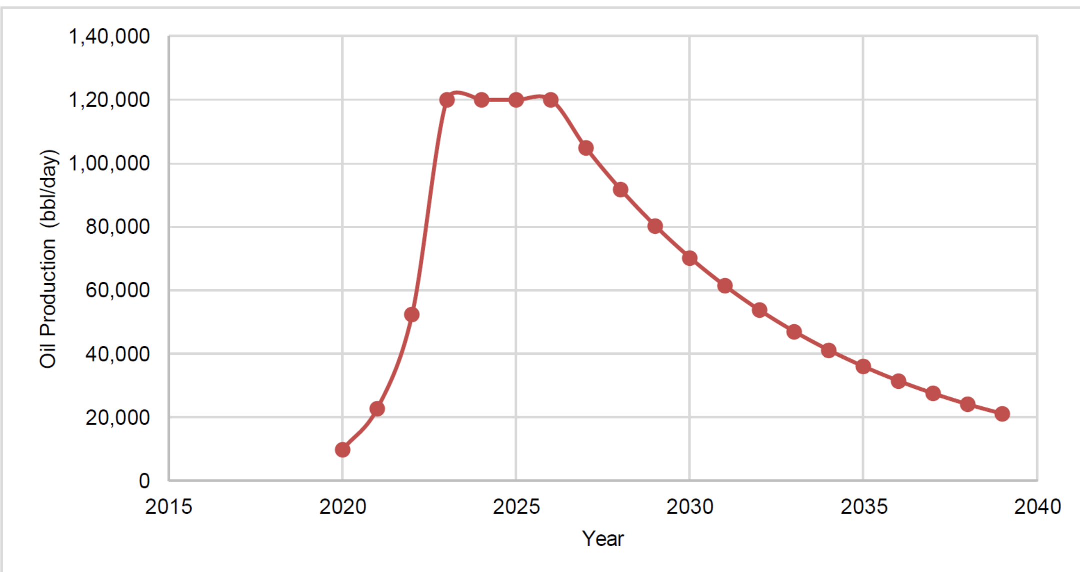
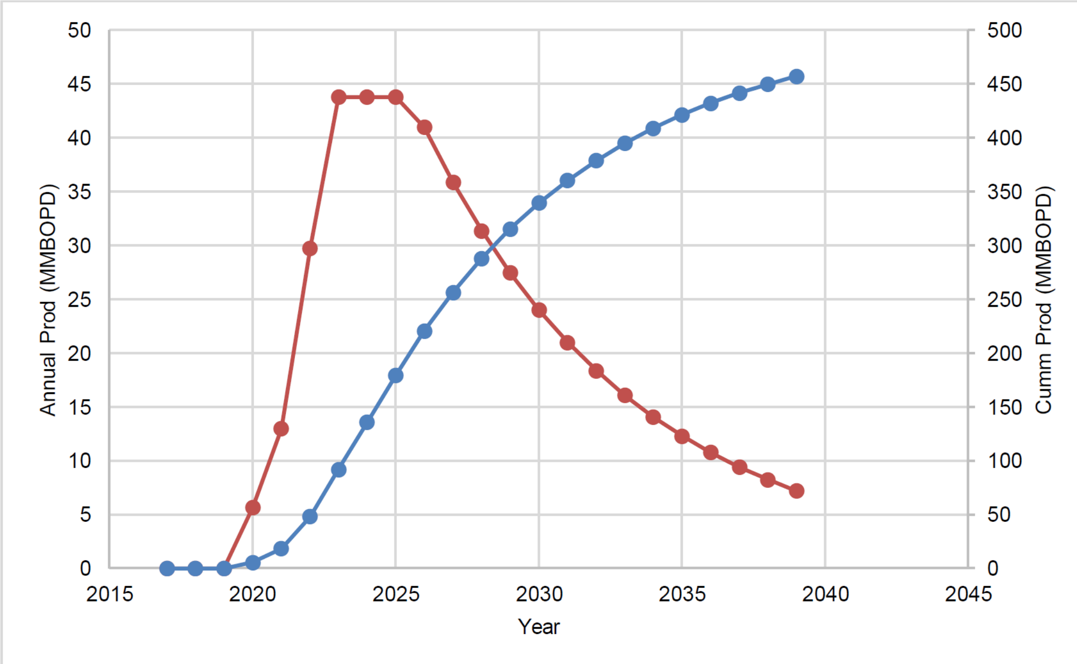


Figure 1—Field oil production rate



Field 2—Field annual and cumulative oil production

Profitability Indicators

Table 3 show the profitability indicators determined from the two economic models comparing the impact of the DOIBPSCA and the 1993 PSC arrangement. The NPV of the contractor's take (CT) in the 1993 PSC and the DOIBPSCA were $2687.93 MM and $2025.56 MM, respectively. This shows about 25% reduction in the CT amounting to the sum of $662.37 MM as a result of the ammendment. Though the government motive of introducing the bill so as to increase her revenue was achieved as the NPV of the government take (HG) was increased from $4716.24 MM to $5378.61 MM, indicating an increment of $662.37MM which is about 14% of the NPV of the HG in the 1993 PSC. The discounted take statistics of the host government under the 1993 PSC and DOIBPSCA were 63.70% and 72.64% while that of the CT were 36.30% and 27.36%.

Table 3—Profitality indicators determined from the economic models

Metric Systems Measures	1993 PSC		2019 DOIBA	
	HG	CT	HG	CT
Net Present Value ($MM)	4716.24	2687.93	5378.61	2025.56
Internal Rate of Return (IRR)		31.15%		23.66%
Undisc Take statistics	61.92%	38.08%	69.67%	30.33%
Disc Take Statistics	63.70%	36.30%	72.64%	27.36%
UNIT CAPEX, $/bbl		10.76		10.76
UNIT OPEX, $/bbl		9.84		9.84
UNIT Technical Cost, $/bbl		20.60		20.60
FLI		0.029		0.043

The increment in the HG NPV and reduction in CT NPV as observed was as a result of the price reflective royalty introduced in the DOIBPSCA and the fact that companies drilling in the offshore region above 1000 m depth pay a royalty of 10% as opposed to the 1993 PSC arrangement where companies do not pay any royalties to the government. Similarly, the same observation was made in the IRR and the FLI. The IRR of the CT in the 1993 PSC and DOIBPSCA were 31.15% and 23.66%. This value is low and it shows the rate at which companies will recoup their initial investment capital when they invest under the DOIBPSCA. The FLI of the CT in the 1993 PSC and DOIBPSCA were 0.029 and 0.043. This shows that the FLI in the DOIBPSCA is front end loaded compared to the FLI in the 1993 PSC arrangement. This is as a result of the increment in the government's revenue through the addition of a dynamic royalty instrument that do not just account only for the depth changes but also reflects changes in the price of crude oil.

Conclusion

The impact of the amendments seems to achieve government's objective of increasing her revenue generation from the oil and gas sector as the HG take increased from $4716.24MM to $5378.61MM. But on the perspective of the contractors, the bills seem to reduce future investment in the deep offshore region of the country as the CT take reduced by about 25% amounting to the sum of $662.37MM. The NPV of the CT under the 1993 PSC arrangement was $2687.93 MM and under the DOIBPSCA, the NPV of the CT was $2025.56 MM. The discounted take statistics of the HG under the 1993 PSC and DOIBPSCA were 63.70% and 72.64% while that of the CT were 38.08% and 30.33%. The DOIBPSCA is front end loaded considering the FLI of 0.043 that was obtained using the DOIBPSCA compared with the FLI obtained using the 1993 PSC which was 0.029. DOIBPSCA will increase government revenue as a result of the amendments but might hinder investors from undertaking new E&P projects in the deep offshore region.

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