Government Revenues from OPL 245

Assessing the Impact of Different Fiscal Terms

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November 2018

RESOURCES for DEVELOPMENT CONSULTING

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EXECUTIVE SUMMARY

Block 245 is widely reported to be one of Nigeria's most potentially lucrative remaining oil concessions. According to Eni, the volume of recoverable reserves is estimated at 560 million barrels. Promising exploration prospects and substantial volumes of natural gas mean that the Block 245 is likely to be even more valuable than characterized in this report.

Three different sets of fiscal terms have governed Block 245 since 2003: a 2003 Production Sharing Contract (PSC) signed by Shell and subsequently rescinded; the terms of the 2005 Model PSC that applied to the original Nigerian contractor Malabu after its license was reinstated in 2006, and the terms contained in the 2011 Resolution Agreement (RA) and the associated 2012 Production Sharing Agreement (PSA) applicable since Eni and Shell jointly acquired the block.

The fiscal terms used in this analysis are drawn from the original documents, including the 2003 PSC signed between the Nigerian National Petroleum Corporation (NNPC) and Shell, Nigeria's 2005 Model PSC, and the 2011 Resolution Agreements, along with the associated Production Sharing Agreement (PSA) signed between Shell and Eni.

The 2003 and 2005 PSC terms are broadly similar, with only two significant differences: the 2005 contract includes a royalty for deepwater blocks and uses a measure of profitability (based on an R-factor) to allocate Profit Oil between the company and the government.

In contrast, the fiscal terms that emerged from the Resolution Agreement of 2011 are not consistent with the essence of a normal production sharing system. The RA called for a "production sharing agreement" (PSA) to be signed between Shell and Eni. The PSA was signed in 2012. No PSC was agreed on between the contractor and the government. As a result, two central features of a Nigerian PSC — Cost Oil to compensate the contractor and a share of Profit Oil allocated to the government — have been removed from the Block 245 fiscal regime.

The rights to Block 245 have been the subject of substantial controversy and legal action. To date, however, there has been no public domain assessment of the impact of these different sets of fiscal terms on potential revenue for the Government of Nigeria.

Discounted cash flow modelling is an industry-standard methodology used for valuation by oil companies and for revenue forecasting by governments. The results set out in this report are based on a discounted cash flow model for Block 245 prepared by Resources for Development Consulting.

The field data contained in this analysis comes predominantly from the companies themselves: Shell and Eni. The basic field data comes from a 2006 Valuation document prepared by Shell in support of arbitration proceedings. This data has been updated based on information from subsequent Shell reports and information published by Eni in 2011 as well as public domain sources from analogous blocks in neighbouring countries.

The different fiscal regimes generate very different revenue prospects for the Government of Nigeria. Under our base case assumptions, and assuming a future oil price of $70 per barrel, the 2003 PSC terms would generate $14.3 billion in government revenue over the lifespan of the project; while the 2005 terms would generate $15.6 billion. In contrast, the 2011 RA terms would generate $9.8 billion. The potential reduction of between $4.5 billion and $5.9 billion when compared to the 2003 or 2005 terms is due to the removal in the 2011 RA and the 2012 PSA of the central feature of the production sharing system: a share of Profit Oil for the government.

The differences in benefits grow under higher oil price scenarios. At $100 per barrel, the 2003 PSC terms would generate an additional $7.7 billion in government revenue, while the 2005 PSC terms would generate an additional $10.6 billion.

For nearly two decades, Nigeria has debated putting in place a new framework to govern the petroleum sector. This has been motivated in part by a sense that Nigeria was not generating a fair share of revenue from deepwater blocks covered by PSCs. Although the fiscal terms associated with the Petroleum Industry Fiscal Bill (PIFB) are not yet finalized, it is clear that they could generate more revenue for the government than the PSC terms originally signed by Shell in 2003.

Of the fiscal terms that could plausibly apply to Block 245 — three sets that have governed the Block at different times in the past, and one set that is currently being finalized — it is the terms of the 2011 Resolution Agreement and the 2012 PSA that are the least favourable to the Government of Nigeria.

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ACRONYMS AND DEFINITIONS

Agip	A subsidiary of Italian oil company Eni
bbl	Barrel of oil (unit of volume)
Block 245	Offshore oil concession
bpd	Barrels of oil per day
Eni	Italian oil and gas company
FGN	Federal Government of Nigeria
FID	Final Investment Decision
FPSO	Floating Production Storage and Offloading vessel
IMF	International Monetary Fund
IOC	International Oil Company
IRR	Internal Rate of Return
ITA	Investment Tax Allowance
kbpd	Thousands of barrels of oil per day
mmbbls	Millions of barrels of oil
NAE	Nigerian Agip Exploration Ltd. Subsidiary of Eni
NNPC	Nigerian National Petroleum Corporation
NPV	Net Present Value
OPL 245	Oil Prospecting Licence 245
PIFB	Petroleum Industry Fiscal Bill
PPT	Petroleum Profits Tax
PSA	Production Sharing Agreement
PSC	Production Sharing Contract
RA	Resolution Agreement
SNEPCo	Shell Nigeria Exploration and Production Company. Subsidiary of Shell.
SNUD	Shell Nigeria Ultra Deep Ltd. Subsidiary of Shell.

1.0 INTRODUCTION

Block 245 is widely reported to be one of Nigeria's richest remaining oil concessions.[1] The Block, currently held in equal shares by subsidiaries of Eni and Shell,[2] covers nearly 2,000 square kilometres. It is located on the southern edge of the Niger Delta in water depths of more than 1,200 meters.

Two main discoveries in 2005 (Etan) and 2006 (Zabazaba) resulted in an initial estimate of 875 million barrels of recoverable oil.[3] Current estimates of recoverable reserves, based on the contractor's preferred development plan, are 560 million barrels. The head of Eni's subsidiary in Nigeria has stated that the Zabazaba and Etan project will generate $8bn for the Federal Government of Nigeria (FGN).[4]

The Block was initially allocated to a Nigerian company, Malabu Oil and Gas, in 1998. Malabu brought Shell in as a partner in 2001. Later that year Malabu's rights were revoked and, following a bidding process, the Block was allocated to Shell. Malabu protested and the Block was returned to the Nigerian company in 2006. Malabu did not proceed with further exploration and Shell initiated arbitration proceedings. In 2011 three agreements were struck, resulting in the allocation of Block 245 to Agip (a subsidiary of the Italian oil company Eni) and SNEPCo (a subsidiary of Shell).

Over the intervening years, three different sets of fiscal terms have governed the Block. In 2003, Shell signed a production sharing contract (PSC) with the Nigerian National Petroleum Corporation (NNPC). The Resolution Agreement of 2006 restoring Malabu's rights made clear that the terms of the Government's Model PSC of 2005 would apply.

The 2011 Resolution Agreement, and the associated 2012 production sharing agreement (PSA) agreed between Eni and Shell, provide for a very different type of fiscal regime. The core elements of the production sharing system, including compensating the contractor for their costs (Cost Oil) and the sharing of after-cost production with government (Profit Oil), have been removed.

Over the past decade, Nigeria has questioned whether the deepwater PSCs were securing a reasonable share of government revenue. The Petroleum Industry Fiscal Bill (PIFB), currently being debated in the National Assembly, could provide an alternative set of fiscal terms should the Block be rebid.

Block 245 has been the subject of significant controversy, including extensive legal action both inside and outside Nigeria. To date, however, there does not appear to have been a public assessment of the economic benefits that could be expected to accrue to the FGN under these different sets of fiscal terms.

This study has been commissioned by Global Witness, HEDA Resource Centre, Re:Common, and The Corner House. It seeks to assess the value of Block 245 to the Government of Nigeria, and to the

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[1] Block 245 is a demarcated area offshore of Nigeria in the Gulf of Guinea. An Oil Prospecting Licence (OPL) is granted by the Ministry of Petroleum Resources and grants a company the right to explore for petroleum. An OPL can be converted into an Oil Mining Lease (OML) following confirmation of potential for commercial production. In this report, Block is used to designate the oil concession, while OPL is used only to refer to a specific Licence.

[2] The Eni subsidiary currently holding OPL 245 is Nigerian Agip Exploration Limited (NAE). The Shell subsidiary currently holding OPL 245 is Shell Nigeria Exploration and Production Company (SNEPCo).

[3] Shell Nigeria Ultra Deep Limited. *OPL245 Block December 2006 Valuation Study*, 2009.

[4] "NCDMB, NAOC Agree on Speedy Development of Zabazaba Deep Water Project," Press Release, Nigerian Content Development and Monitoring Board, 19 December 2016.

contractor, under four different sets of fiscal terms: the 2003 PSC terms, the 2005 Model PSC terms, the 2011 Resolution Agreement along with the 2012 PSA, and the 2018 PIFB terms.

The industry-standard methodology for assessing the potential value of an oil block is known as discounted cash flow modelling.[5] The methodology combines available project information on oil reserves and project costs, along with the relevant fiscal terms, within an Excel spreadsheet. Year-by-year revenue forecasts for both the government and the contractor can then be generated based on differing oil price scenarios.

Resources for Development Consulting has developed a discounted cash flow model for the combined development of Zabazaba (host) and Etan (satellite) oil fields in Block 245.[6] Initial estimates of recoverable oil reserves, plausible oil production profiles, and capital costs and operating cost estimates were drawn from a valuation document prepared by Shell in 2006 in advance of initiating arbitration proceedings against the Federal Republic of Nigeria.[7] These estimates have been updated based on additional information from Shell[8] and Eni[9] and data from analogous deepwater blocks in neighbouring countries. Details are provided in Section 4 and in Annex I.

As with any economic analysis based on public domain information, there are important limitations. Although additional exploration wells were drilled in 2013, the companies have released very little project-specific data in the past five years. Most significantly, there is considerable uncertainty about the volume of oil contained in Block 245. Shell and Eni both dispute the findings of this report. Their responses are quoted in Section 6.5 below.

Numerous media reports have suggested that, according to unnamed industry experts, the Block could contain up to 9 billion barrels of oil.[10] This speculation does not appear to be grounded in industry-standard reserve estimation techniques. We assume recoverable reserves of 560 million barrels based on data disclosed by Eni. There is also considerable, though unspecified, volumes of natural gas. Due to a lack of data and the uncertainty around what gas terms may apply, these have been excluded from our analysis. Given additional exploration prospects and the anticipated contribution of natural gas sales, the actual economic benefits for both the government and the contractor are likely to be higher than those suggested in this report.

Fiscal terms have been drawn from original documents, including:

- The relevant legislation and the original PSC, agreed between the NNPC and Shell on 22 December 2003.
- The relevant legislation, the Model PSC applicable in the 2005 and 2007 Licensing Rounds, and final fiscal terms for analogous deepwater blocks.[11]

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[5] Ken Kasriel and David Wood, *Upstream Petroleum Fiscal and Valuation Modelling in Excel: A Worked Examples Approach* (West Sussex, UK: Wiley, 2013).

[6] Available at http://www.res4dev.com/opl245 .

[7] Shell Nigeria Ultra Deep Limited, *OPL245 Block December 2006 Valuation Study*, 2009.

[8] Shell Nigeria Ultra Deep Limited, *Proposal to Commence Negotiations*, 2010.

[9] *2011 Exploration and Production Update Report*, Eni, 6 October 2011.

[10] See, for example, Xan Rice, "Nigeria Oil Deal Puts Focus on Energy Sector," *Financial Times*, 20 May 2012.

[11] Fiscal terms for blocks 321 and 323 are provided in "Exploring West African Waters," Corporate Presentation, Equator Exploration Limited, June 2006.

- The relevant legislation, the Resolution Agreement regarding OPL 245 that was signed in April 2011 and the associated Production Sharing Agreement signed between Agip and Shell on 21 February 2012.
- The Petroleum Industry Fiscal Bill (2018 (SB. 472))

Full details are provided in Section 3 and in Annex I.

This report begins with an overview of the most significant events affecting the allocation of rights to Block 245. This is followed by an overview of the fiscal terms that have been associated with the Block during the different periods of ownership. Section 4 sets out the modelling inputs and assumptions including production profiles and cost estimates, as well as the rationale for the different oil price forecasts employed. The next section contains the economic analysis comparing the revenues for the government, and profitability for the contractor, under the fiscal terms associated with the 2003 PSC, the 2005 Model PSC, and the 2011 Resolution Agreement. Section 6 analyses the potential impact for the government and the contractor of applying the Petroleum Industry Fiscal Bill (PIFB) to Block 245. The final section sets out the overall conclusions of the analysis.

2.0 TIMELINE FOR OPL 245

The most important events related to Block 245 for the purposes of this analysis are set out below.

1. In 1998 the Block was allocated to a Nigerian company named Malabu Oil and Gas Limited. In March 2001, Shell Nigeria Ultra Deep Limited (SNUD) agreed to farm into the Block, acquire a 40% stake.

2. In July 2001, the allocation of Block 245 to Malabu was revoked. Two oil companies — ExxonMobil and Shell's subsidiary SNUD — subsequently bid for the rights to the Block.

3. In 2002 the Block was allocated to SNUD. In 2003, a production sharing contract (PSC) was signed between the Nigerian National Petroleum Corporation (NNPC) and SNUD.[12] Malabu initiated legal action seeking reinstatement of its rights to the Block.

4. In 2006 a resolution to Malabu's litigation was reached, with the rights to the oil Block being returned to the Nigerian company. The letter confirming the return of the oil Block to Malabu indicated, "The fiscal terms of the 2005 PSC shall apply to this restoration."[13]

5. SNUD contested the reinstatement of the Block to Malabu and in 2007 brought proceedings against the FGN at the International Centre for Settlement of Investment Disputes, seeking full restitution of its rights as set out in the 2003 PSC.

6. In 2011 a series of three Resolution Agreements were prepared as part of the reallocation of the rights to Block 245 to Shell and Eni.[14] The Agreements were executed in April 2011.

7. In the Resolution Agreement between FGN and Malabu, in consideration for payment of $1,092,040,000 Malabu grants consent for the reallocation of Block 245.

8. The Resolution Agreement (29 April 2011) between FGN, SNUD, SNEPCo, and NAE (the Resolution Agreement or RA) sets the terms that govern the continued exploration and future production in the Block. It contains, among others, the following provisions:

   - The FGN reallocates the Block to Nigerian Agip Exploration Limited (NAE, a subsidiary of Eni) and Shell Nigeria Exploration and Production Company (SNEPCo) (Clause 1.2).

   - NAE, on behalf of NAE and SNEPCo, shall pay $1,092,040,000 to the FGN to settle existing claims over Block 245 (Clause 1.3).

   - With the issuance of a new OPL, the 2003 PSC signed with SNUD is terminated (Clause 1.4).

   - NAE and SNEPCo agree to execute a Production Sharing Agreement (PSA) to set out the rights and obligations between themselves for the operation of the Block (Clause 4).

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[12] Production Sharing Contract by and between the Nigerian National Petroleum Corporation and Shell Nigeria Ultra Deep Limited covering Block 245 Offshore Nigeria, 22 December 2003.

[13] The fiscal terms associated with the 2005 PSC included an 8% royalty and a profit split based on an R-factor (See Section 3.3). Letter from Edmund Daukoru, then-Minister of State for Petroleum, to Malabu Oil and Gas Limited, 2 December 2006.

[14] "Block 245 Resolution Agreement between FGN, SNUD, NAE, Shell Nigeria Exploration and Production Company (SNEPCo) and Nigerian Agip Exploration Limited (NAE)," 29 April 2011.

- The PSA between Eni and Shell shall be treated as a Production Sharing Contract (PSC) as defined in Section 17 of the Deep Offshore and Inland Basins Production Sharing Contract Act, Cap D3, LFN 2004 (Clause 5).
- The agreement includes a "stabilization" clause requiring that NAE and SNEPCo be protected from any future changes to the fiscal terms covering OPL 245 and any subsequent Oil Mining Lease (OML) (Clause 6).

9. On 11 May 2011, identical letters were sent to the Managing Directors of Shell and Eni in Nigeria regarding the OPL 245 Resolution Agreement/Letter of Award.[15] The letters confirm that the conduct of petroleum operations shall be governed by a PSA between Shell and Eni, and that the fiscal terms as provided by the Deep Offshore and Inland Basin Production Sharing Contracts Act, Cap 3, LFN 2004, shall be applicable to the PSA between Shell and Eni.
10. A PSA was signed between Eni and Shell for OPL 245 on 12 February 2012.[16] The agreement clarifies that there shall be no Cost Oil allocation and that Profit Oil will not be shared with the NNPC or the FGN and will be allocated to Eni and Shell in proportion to their Participating Interest.

[15] Letter from Diezani Alison-Madueke, then-Minister of Petroleum Resources, to SNEPCo regarding OPL 245 Resolution Agreement/Letter of Award, 11 May 2011; and Letter from Diezani Alison-Madueke, then-Minister of Petroleum Resources, to Eni regarding OPL245 Resolution Agreement/Letter of Award, 11 May 2011.

[16] Production Sharing Agreement between Nigerian Agip Exploration Limited and Shell Nigeria Exploration and Production Company Limited, 12 February 2012.

3.0 FISCAL TERMS FOR OPL 245

Widespread use of the Production Sharing Contract (PSC) in Nigeria began in the early 1990s. Prior to this period, many oil projects were joint ventures between the Nigerian National Petroleum Corporation (NNPC) and private oil companies. As an equity partner, the NNPC generated revenues alongside the private companies but was also required to pay its share of costs. As the NNPC was frequently unable to meet its upstream payment obligations (known as cash calls), the FGN decided to adopt the production sharing system for blocks in order to encourage exploration in deepwater offshore.[17]

Under the PSC arrangement, the NNPC is the holder of the concession while the international oil company (IOC) is the contractor. Under these contracts, the government generates revenue through three main fiscal instruments: the payment of a royalty (dependent on water depth), taxes, including an Education Tax and a Petroleum Profits Tax (PPT), and a share of after-Cost Oil production, referred to as Profit Oil, allocated to the NNPC.

Three different variations of the PSC have been used in the intervening years. A Model PSC was prepared in 1993 and was the basis for an initial eight contracts with international oil companies (IOCs). A revised Model PSC was developed in 2000 and was the basis for a further eight contracts with IOCs. The Model PSC was revised again for the 2005 licensing round and was also used for the 2007 licensing round.[18]

The fiscal terms that originally governed Block 245 were set out in a PSC agreed between NNPC and Shell in 2003. That contract was based on the Model PSC of 2000. Relevant legislation included the Petroleum Act, Cap 350, LFN 1990, and the Petroleum Profits Tax Act, Cap 354, LFN 1990.

Although no new contract was signed, when the Block was returned to Malabu in 2006 the agreement was clear that the terms of the 2005 PSC would apply.[19] Relevant legislation would have included the updated Deep Offshore and Inland Basin Production Sharing Contracts Act, Cap AP D3, LFN 2004, and the updated Petroleum Profits Tax Act, Cap P13, LFN 2004.

The fiscal terms that currently govern the Block were set out in the 2011 Resolution Agreement and in a 2012 Production Sharing Agreement signed between Eni and Shell. The RA states that a Production Sharing Agreement will be signed between Eni and Shell and that this agreement will be treated as a PSC as defined in the Deep Offshore Production Sharing Contracts Act of 2004.

3.1 Nigeria PSC Fiscal Instruments

The Nigerian petroleum fiscal system employs a series of common fiscal instruments, including royalties, cost and Profit Oil, and a tax on petroleum profits. The terms for royalties, Education Tax, and Petroleum Profits Tax are set by an applicable Law of the Federation of Nigeria, while the terms for cost recovery and profit sharing are set in contracts for individual blocks executed between the contractor and the NNPC.

[17] "Taxation and State Participation in Nigeria's Oil and Gas Sector," Energy Sector Management Assistance Programme (ESMAP) Technical paper; no. ESM 057, World Bank, 2004, p. 43.

[18] Model Production Sharing Contract by and between the Nigerian National Petroleum Corporation and ________ Covering OPL ____ Offshore Nigeria, 2005.

[19] Letter from Edmund Daukoru, then-Minister of State for Petroleum, to Malabu Oil and Gas Limited, 2 December 2006.

The sequence in which these fiscal instruments are applied, however, is unusual when compared to other countries that apply a production sharing regime, with the Petroleum Profits Tax (PPT) being assessed before the allocation of Profit Oil. Each of the main fiscal instruments is described below in the order in which they are applied. Value Added Tax (VAT) of 5% on domestic capital and operating costs, and the Niger Delta Development Commission (NDDC) Levy of 3% of overall expenditures are included as costs of production (See Annex I).

Royalties

For most fiscal regimes, the payment of a royalty is the first step in the calculation of government revenue. As a result, it is often known as a payment "off the top." Royalties are commonly calculated as a percentage of the value of production and are paid in full from the start of production.

Under the terms of the Deep Offshore and Inland Basin Production Sharing Contracts Act, royalty payments for deepwater Blocks are determined by water depth. Originally, the royalty rate was set at 0% for water depths over 1,000 meters. The 2005 Model PSC retained a variable royalty rate based on water depth and set the rate at 8% for water depths of more than 800 meters.

Cost Oil

The second step in fiscal calculations is the recovery of costs by the contractor. Production sharing systems allow the contractor to recover its costs through an allocation of production termed "Cost Oil." Cost recovery includes exploration, operating, abandonment, and intangible development costs, which are added to recoverable costs immediately, plus the tangible development costs which are added through a five-year straight-line depreciation.

In the first years of production, accumulated exploration and development costs normally exceed the value of total production. Many production sharing systems place a limit on the proportion of overall production that can be devoted to Cost Oil. This is done in order to ensure that at least some Profit Oil is available to be split between the contractor and the government at early stages in the project when total investor costs to be recovered often exceed total project revenues.

The original 2003 PSC did not impose a limit on the amount of production that could be allocated to Cost Oil. Under these terms, 100% of production could be allocated to costs. The 2005 Model PSC imposed a cost recovery limit with no more than 80% of production eligible for cost recovery. Under the terms of the PSA signed between Shell and Eni, there is no allocation of Cost Oil.

Taxes

Two different taxes are integral to fiscal regime calculations for Nigerian PSCs. First, there is an Education Tax, assessed at a rate of 2% of Assessable Profits. The Education Tax base is gross revenue less royalties, operating costs, intangible development costs, financing interests, and exploration costs. Then Education Tax is deducted to arrive at Assessable Profits.

The second tax is the Petroleum Profits Tax (PPT). For blocks governed by a PSC, the PPT is assessed at 50% of Chargeable Profits. The PPT tax base is Assessable Profits less a capital allowance. The Capital Allowance is the sum of tangible development cost depreciation, abandonment costs, and the Investment Tax Allowance (ITA = 50% of tangible costs).[20]

Profit Oil

[20] The maximum Capital Allowance permitted is 85% of Assessable Profits less 1.7x the ITA.

The final step in the fiscal calculations is the allocation of the remaining oil production, known as "Profit Oil", between the contractor and the government.

The division of remaining production is normally based on some kind of sliding scale. Traditionally, the percentage of Profit Oil flowing to the government increases with the volume of production (either daily production or cumulative production). An alternative is to base the Profit Oil split on some measure of profitability. One option is the use of a measure of cumulative project revenue to cumulative project costs: a ratio known as an "R-factor."[21]

Under the 2003 PSC, Profit Oil would have been allocated based on a sliding scale that provided a greater share to the government as cumulative oil production increased. In the Model PSC of 2005, the basis for the allocation of Profit Oil was changed to an R-factor, which in theory gives a greater link to profitability. The fiscal terms associated with the 2011 RA and the 2012 PSA do not include Profit Oil for NNPC or the FGN.

A summary of the high-level fiscal terms is provided in Table 1. Details for each of the three fiscal regimes are provided below.

Table 1: Summary of Fiscal Terms for Block 245

	2003 PSC	2005 Model PSC	2011 RA/2012 PSA
Royalty	0%	8%	0%
Cost Recovery Limit	100%	80%	N/A
Education Tax	2%	2%	2%
Petroleum Profits Tax	50%	50%	50%
Profit Oil	30–65% (cumulative production)	30–75% R-factor	N/A

3.2 2003 Production Sharing Contract

The fiscal terms that first applied to Block 245 were set out in a PSC signed between the Nigerian National Petroleum Corporation (NNPC) and Shell Nigeria Ultra Deep Limited (SNUD) in 2003,[22] as well as in relevant legislation, including the Petroleum Act, Cap 350, LFN 1990, and the Petroleum Profits Tax Act, Cap 354, LFN 1990.

According to the Petroleum Act, royalties for Block 245 were 0% given that the water depth was greater than 1000 meters (Article 61). According to the PSC, the cost recovery limit was set at 100%. The Profit Oil split varies according to cumulative production tranches, where the government's share increases as cumulative production does. The tranches are shown in Table 2.

[21] An R-factor of 1 is reached when the contractor 's revenues equal the contractor's costs on a cash basis (ignoring the time value of money).

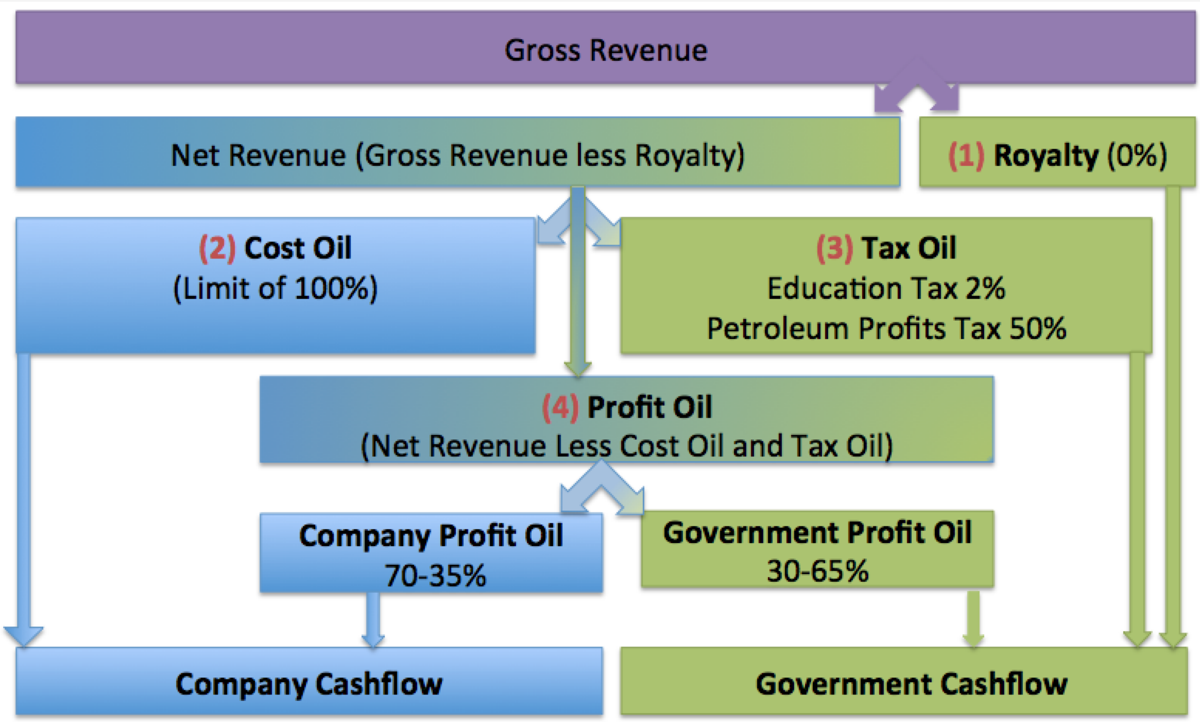
[22] Production Sharing Contract by and between the Nigerian National Petroleum Corporation and Shell Nigeria Ultra Deep Limited covering Block 245 Offshore Nigeria, 22 December 2003.

Table 2: Profit Oil Tranches—2003 PSC (mmbbls)

Cumulative Production	Government	Contractor
0–350	30%	70%
351–750	35%	65%
751–1000	47.50%	52.5%
1001–1500	55%	45%
1501–2000	65%	35%
Higher than 2000	Negotiable	Negotiable

The structure of the 2003 PSC is set out in Figure 1 below.

Figure 1: 2003 PSC Fiscal Structure



3.3 2005 Model Production Sharing Contract

Under the terms of the Model PSC of 2005,[23] the royalty rate for water depths greater than 1,000 meters was set at 8%. The cost recovery calculations were the same as those in the 2003 PSC, but a biddable cost recovery limit was included. The Model PSC indicated that no more than 80% of production in any one year could be allocated to costs.[24] Costs exceeding this limit would be carried forward to the next year. The Profit Oil split was based on an R-factor, which is the ratio of cumulative

[23] Model Production Sharing Contract by and between the Nigerian National Petroleum Corporation and _________ Covering OPL _____ Offshore Nigeria, 2005.

[24] Article 9.1(d).

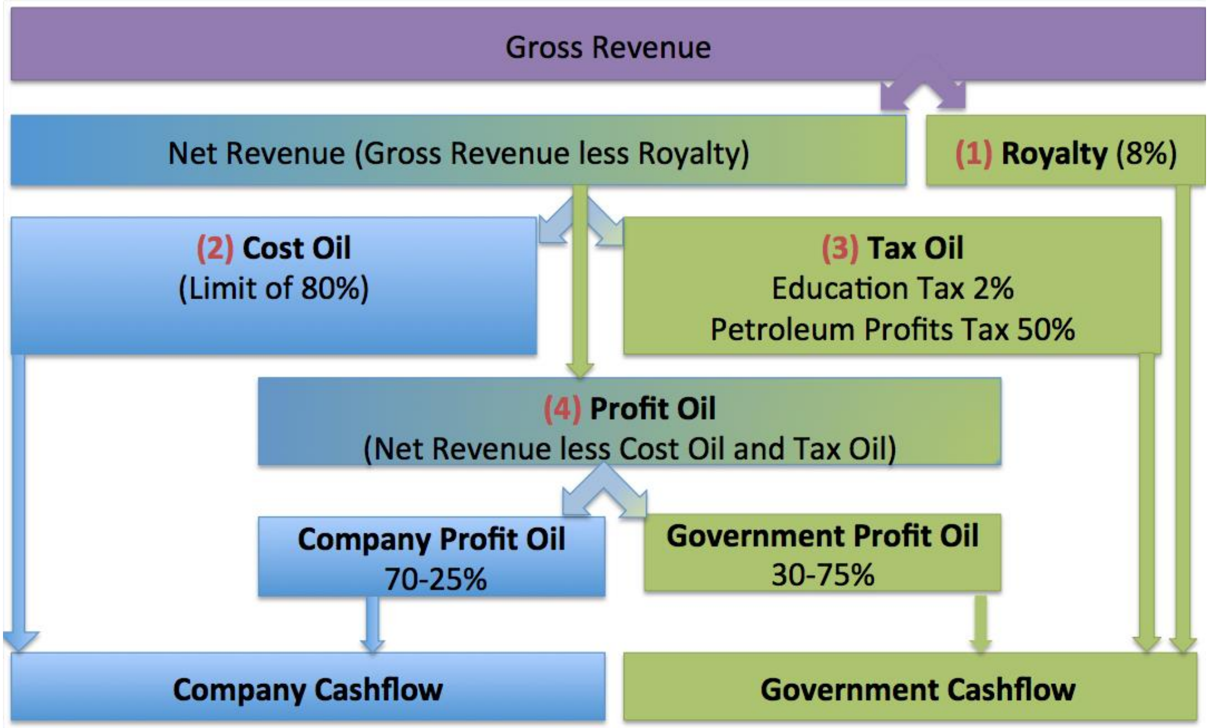
project revenues paid to the contractor over cumulative costs paid by the contractor. The tranches are shown in Table 3.

Table 3: Profit Oil Tranches—2005 PSC

R-factor	Government	Contractor
Lower than 1.2	30%	70%
Between 1.2–2.5	25%+((2.5-R)/(2.5-1.2))*(70%-25%)	1-(25%+((2.5-R)/(2.5-1.2))*(70%-25%))
Higher than 2.5	75%	25%

The structure of the 2005 PSC is set out in Figure 2 below.

Figure 2: 2005 Model PSC Fiscal Structure



3.4 2011 Resolution Agreement and 2012 Production Sharing Agreement

The fiscal terms that emerged from the Resolution Agreement of 2011 and the associated PSA signed between Eni and Shell in 2012 are not consistent with the essence of a normal production sharing system.

The PSA signed in accordance with the Resolution Agreement is not an agreement between the NNPC and the contractor, as was the case with the 2003 PSC and would have been the case if Malabu had signed a contract based on the 2005 Model PSC. The PSA is an agreement between the two international oil companies Eni and Shell. In other contexts, this agreement could be called a Joint Venture Agreement or a Joint Operating Agreement.

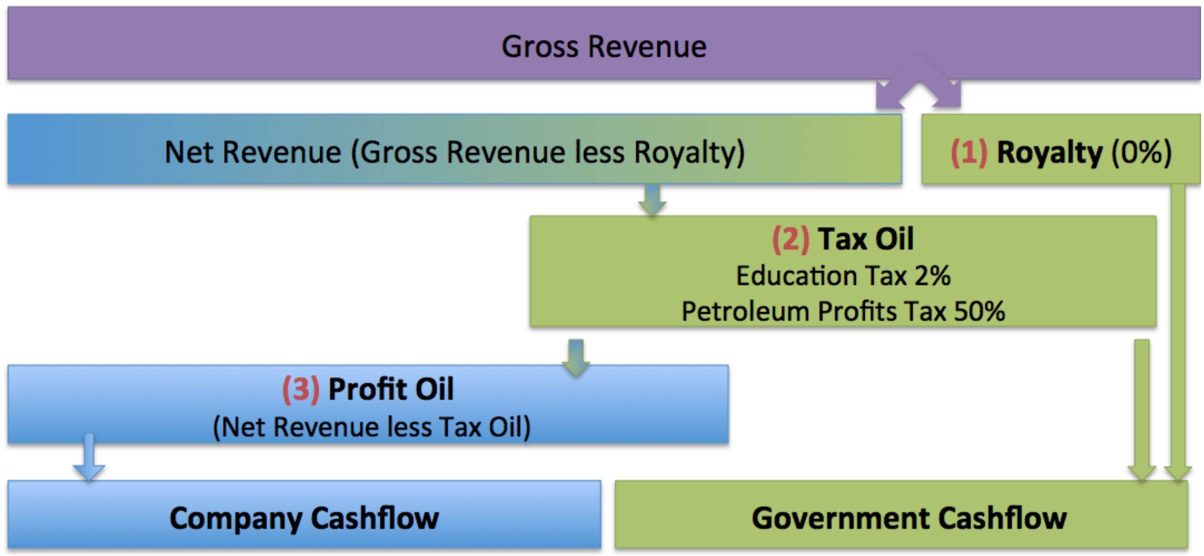
According to the PSA, two central features of a standard Nigerian PSC — Cost Oil to compensate the contractor for costs and a share of Profit Oil allocated to the government — no longer apply to the current OPL 245.

Although signed in 2011, the Resolution Agreement does not build on the Model PSC of 2005 but rather indicates that the fiscal terms that govern OPL 245 would be those set out in the Deep Offshore and Inland Basin Production Sharing Contracts Act, Cap D3, LFN 2004. As a result, for water depths greater than 1000 meters, the royalty rate is 0%.

The main sources of government revenue, therefore, would be the Education Tax and the Petroleum Profits Tax.

The fiscal structure that emerges from the 2011 RA and the 2012 PSA is set out in Figure 3 below.

Figure 3: 2011 RA / 2012 PSA Fiscal Structure



4.0 Modelling Inputs and Assumptions

As with any economic analysis based on public domain information, there are important limitations. The sections below set out modelling and input assumptions for oil production and project costs as well as oil price scenarios.[25]

4.1 Oil Production Estimates

Oil production assumptions are based on recoverable reserves of 560 million barrels. We assume Final Investment Decision[26] in 2018 with production beginning in 2021. Production peaks at 150,000 barrels per day, tapering off until the end of the project lifecycle in year 13.

In 2006, Shell estimated recoverable reserves for Zabazaba and Etan at 875 million barrels.[27] Based on their preferred approach to development, however, their valuation included only 459 million barrels. Recoverable reserves for Block 245 are now widely reported as 560 million barrels.[28] The breakdown of total reserves between the Zabazaba and Etan fields was pro-rated using Shell 2006 study reserves distribution.

Block 245 can also be expected to produce substantial, though unspecified, volumes of natural gas. According to the Shell Valuation of 2006, "associated gas will be exported through a 130km long pipeline" in order to avoid the penalty payments for gas flaring that Nigeria has levied since the Petroleum Profits Taxation Act of 2004. For the Zabazaba field, Shell data suggests that gas would account for 21% of production on a barrel of oil equivalent basis. No data was provided for Etan. However, Shell attributed no revenue or value to natural gas, in part because commercial terms were not included in the 2003 PSC. Given the lack of available data, this report does not include an assessment of the potential revenues that might be generated from gas.

Oil production profiles were estimated separately for Zabazaba and Etan, drawing on the profiles in the 2006 Shell study. First oil is assumed to be in 2021. The 2006 study assumed peak production of 110,000 barrels per day (bpd) based on the capacity of the expected floating production storage and offloading vessel (FPSO). Bidding documents for the FPSO now indicate a vessel with a capacity of 150,000 barrels per day.[29] The plateau and field life were extended to allow for the reserves increase from 2006 to 2018. The decline rates were assumed to be the same as the 2006 profiles, with small variations to match the ultimate recovery. The tail ends of the production profiles were checked against an economic cut off so that the field's annual income will not be lower than the operating cost in the last years of field life (using an oil base price of $70/bbl).

[25] The first step in our analysis was to seek to replicate the results of the Shell 2006 Valuation (NPV10 at $45/bbl = $1,590 million). Our base case analysis, using data from the 2006 valuation and fiscal terms from the 2003 PSC, generated an NPV of $1,537 million, a difference of only 3.4%.

[26] Final Investment Decision or FID is the decision by the operator (and joint venture partners) to proceed with the full development of a project (also known as project sanction).

[27] Shell Nigeria Ultra Deep Limited. *OPL245 Block December 2006 Valuation Study*, 2009, p. 9.

[28] Zabazaba and Etan Integrated Development Project, Offshore Technology, 2017.

[29] See Tender No: CIZ/SPR/ABJ/L006604/2016.

4.2 Project Cost Estimates

Exploration costs were drawn from the Shell 2006 valuation study and updated for recent exploration activities. Shell's study states a $208 million investment up to 2006, and identifies $113 million of pre-development costs spent up to that date. During 2013, three additional exploration wells were drilled (Zabazaba-3 and -4, and Etan-3). The costs of these wells was estimated by pro-rating the 2006 well costs based on rig rate data from 2006 and 2013. We therefore assume total exploration costs of $581 million.[30]

Developments costs were based on a 2010 Shell Proposal to Commence Negotiations[31] study that estimates the total project development expenses at $9.3 billion. These costs, when corrected for inflation to 2018, total $10.8 billion.[32] As the companies have provided no information on the phasing of development costs, we have drawn on data from the Jubilee field in Ghana.[33] We chose Jubilee as a representative analog due to the similar recoverable reserves, fluid properties, distance to shore, water depth, and envisioned production facilities.

Operating cost estimates are based on published information about FPSO leasing costs.[34] For the remaining operating costs, data was adapted from Ghana's Jubilee field (e.g. well workovers and maintenance, field logistics, pipeline inspections etc).[35] These costs were then corrected for inflation. The resulting operating cost of $14.94 per barrel was then multiplied by recoverable reserves in order to find the project's total operating costs. This was converted to a constant annual operating cost, as fixed operating costs normally represent the bulk of total operating costs.

Abandonment costs were drawn from the 2006 Shell valuation study, updated and corrected for inflation.

All cost estimates are inflated at 2% from 2018.

4.3 Oil Price Scenarios

Plausible estimates of future oil prices are required for estimating future government revenue. It is widely accepted that even the best oil price forecasts are little better than educated guesses. According to former BP CEO Lord John Browne, the future oil price is "inherently unpredictable."

The objective in fiscal regime analysis is not to try to predict future prices, but rather to test the different sets of fiscal terms under a range of potential prices. Forecast prices are for Brent crude, the world's most widely used benchmark price. As there is no data in the public domain on the quality of crude expected from Block 245, no discount or premium has been added. Oil price is inflated at 2% from 2018.

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[30] Average well costs from 2006 were pro-rated up to equivalent well costs in 2013 based on indicated deepwater rigs rates of $110,000/day in 2006 and $185,000/day in 2013.

[31] Shell Nigeria Ultra Deep Limited, *Proposal to Commence Negotiations*, 2010.

[32] In this case, and others, costs have been adjusted from their original base year to the 2018 base year used in our model, based on actual historic Consumer Price Index (CPI) data available from the US Bureau of Labour Statistics.

[33] *A Step Change for Tullow and Ghana*, Tullow Oil, 1 October 2008, p. 74.

[34] Saipem Wins $5.42bn Contract for Zabazaba-Etan Devt Project in OPL 245, This Day, 20 November 2017

[35] *A Step Change for Tullow and Ghana*, Tullow Oil, 1 October 2008, p. 75.

The oil price used for the base case analysis is $70 per barrel (in 2018 money). This is somewhat lower than the current price for Brent crude and is based on World Bank forecasts of average crude oil price, adjusted for oil price differentials to Brent.[36] We also test the fiscal regimes against two higher oil prices: $85 and $100.

5.0 Economic Analysis of Three Fiscal Regimes

This section assesses the impact of applying the three different sets of fiscal terms — the 2003 PSC, the 2005 Model PSC, and the combined terms contained in the 2011 RA and 2012 PSA — to Block 245. The comparison is based both on the implications for government revenue and on the attractiveness for the contractor.

For the government, we focus on two key metrics: the total revenue flowing to the government and the so-called government take. The overall government revenue is simply the sum of the relevant revenue streams (royalties, Education Tax, Petroleum Profits Tax, and Profit Oil) year-by-year over the life of the project. The government take is the share of divisible (after-cost) revenue allocated to the government, as compared to the company, over the lifecycle of the project. According to the International Monetary Fund (IMF), a mature petroleum-producing country could expect to secure a government take of 65-85%.[37]

For the company, we focus on three key metrics measured from the time of the Final Investment Decision (FID): Net Present Value (NPV), Internal Rate of Return (IRR), and Payback period (Payback). NPV is the value in today's money of future cash flows, discounted to take into account the cost of capital (discount rate). For the base case analysis, we assume a discount rate of 10%. A positive NPV is normally an indication that a company will consider moving forward with the investment. The IRR is the discount rate that would generate an NPV of zero. It provides an indication of the company's return on their investment and their assessment of risk. Oil companies normally expect an IRR of greater than 10-12%. Payback is the number of years from the start of production after which the company has recovered its initial investment. While the Payback period will depend on the project, from the company perspective shorter is always better.

As mentioned above, it is likely that the company economics are more favourable than characterized here. First, natural gas costs are included in the analysis while revenues are not. Second, based on early drilling and oil production in surrounding blocks, it is likely that recoverable reserves will increase as more drilling is undertaken.

5.1 Base Case Scenario

Table 4 shows the results when the base case project is run against the original 2003 PSC, the 2005 Model PSC, and the 2011 RA combined with the 2012 PSA.

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[36] World Bank Commodities Price Forecast, 24 April 2018. Indicates an average crude price of $64.7/bbl (long term price in 2021) in constant 2018 money. Extracting Brent from the average, using Dubai and West Texas Intermediate differentials, results in a Brent forecast oil price of around $70/bbl.

[37] *Fiscal Regimes for Extractive Industries: Design and Implementation*, International Monetary Fund, 15 August 2012, p. 29.

Table 4: Base Case Analysis ($70/bbl) —Government Revenues and Government Take (USD millions)

	2003 PSC	2005 PSC	2011 RA/2012 PSA
Royalty	0	3,746	0
Education Tax	596	522	596
PPT	8,072	6,236	8,072
Profit Oil	4,592	4,024	0
Total Gov't Cash Flow	**14,347**	**15,615**	**9,754**
Government Take	60%	65%	41%

The difference in government revenues from the three regimes is striking. The 2003 PSC terms would generate $14.3 billion in government revenue, while the 2005 terms would generate $15.6 billion. In contrast, the 2011 RA terms would generate $9.8 billion.

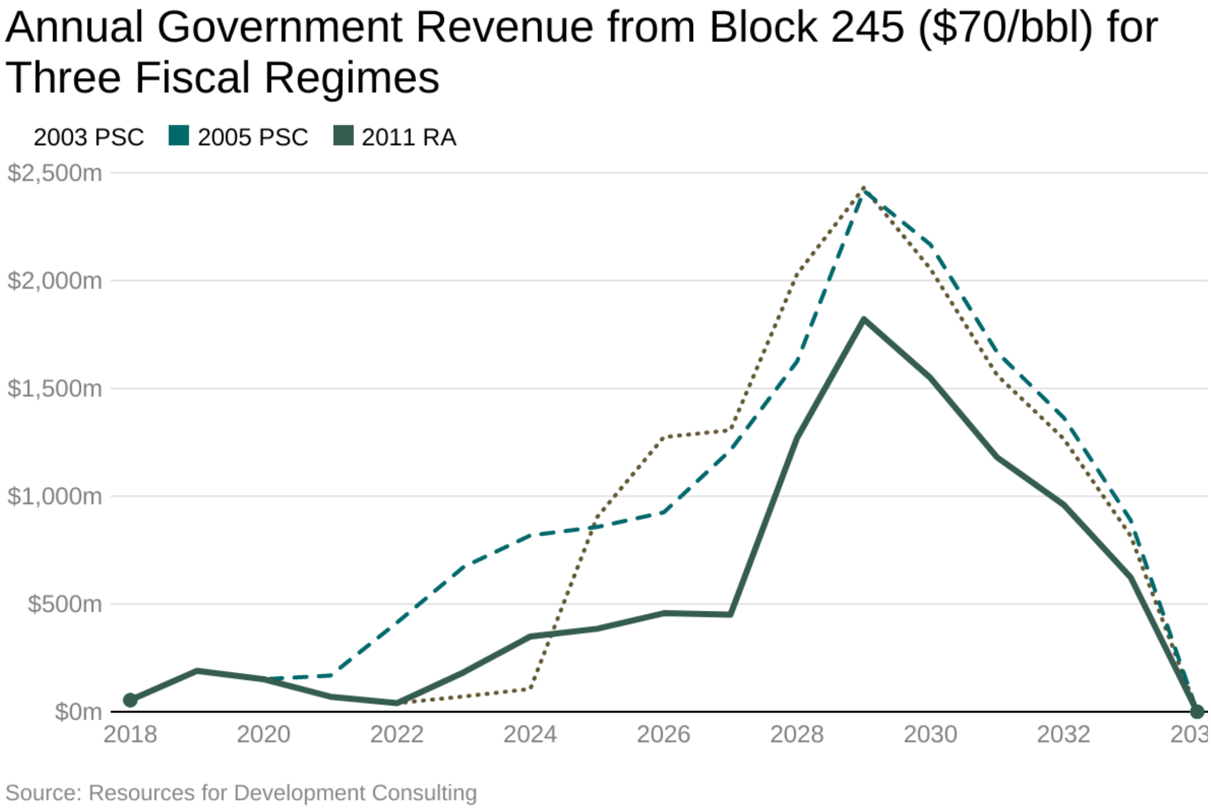
While the government take for the 2003 and 2005 PSCs is on the low side of what might be expected for an established petroleum producer like Nigeria (60% and 65% respectively), they are both far better than the 41% generated by the 2011 RA/2012 PSA.

The potential reduction of between $4.5 billion and $5.9 billion when compared to the 2003 or 2005 terms is due to the removal in the 2011 RA and the 2012 PSA of a share of Profit Oil for the government.

Annual Revenue Analysis

Figure 4 shows the total revenue that would flow to the government year-by-year for each of the three fiscal regimes.

Figure 4: Annual Government Revenue from Block 245 ($70/bbl) for Three Fiscal Regimes



The 2003 PSC generates no government revenue in the early years as there is no royalty and all production is allocated to cost recovery (Cost Oil). Government revenue from increased Profit Oil begins in 2026. PPT generates the second revenue spike in 2029.

The 2005 Model PSC generates significant government revenues from the start of production. This is due to the 8% royalty and the 80% cost recovery limit that guarantees a minimum share of government Profit Oil every year.[38] Profit Oil becomes significant in 2028 and PPT peaks in 2031.

The 2011 RA/2012 PSA terms generate less revenue at all phases of the project lifecycle. As with the 2003 PSC, there is no government revenue in the early years as there is no royalty and no government Profit Oil. Government revenue becomes significant only in 2028 and 2029 when PPT payments become significant.

Contractor Economics

[38] The effective royalty rate (ERR) is the minimum share of production that the government would secure in any year. For the Model 2005 PSC the ERR is 13.5%. This is comprised of 8% royalty combined with Profit Oil amounting to 5.52% of total production (100% of production less 8% royalty; less a 73.6% allocation to Cost Oil based on the 80% limit; leaves 18.4% of production for Profit Oil). The minimum government share of Profit Oil is 30% or 5.52%.

Strong revenues for the government are one basis for assessing a fiscal regime. The terms, however, must also be sufficiently good for the contractor in order to make it an attractive investment. Table 5 below shows the contractor economics for the three fiscal regimes.[39]

Table 5: Contractor Economics for Block 245 ($70/bbl) for Three Fiscal Regimes (USD Millions)

	2003 PSC	2005 PSC	2011 RA/2012 PSA
Total Cash Flow	9,588	8,320	14,180
Net Present Value	1,143	385	2,690
Internal Rate of Return	12.6%	10.9%	15.3%
Payback Years	7	8	7

All three fiscal scenarios generate a positive NPV. The contractor would be expected to move ahead with the investment in all three cases, particularly given the possibility of significant additional reserves as more extensive drilling is undertaken. As would be expected, the 2005 Model PSC represents the toughest set of terms and the 2011 RA/2012 PSA the most generous. The IRR for all three cases exceeds the contractor's minimum expectations.

[39] Total Cash Flow is calculated over full field life. Economics are calculated from Final Investment Decision onwards.

5.2 High Oil Price

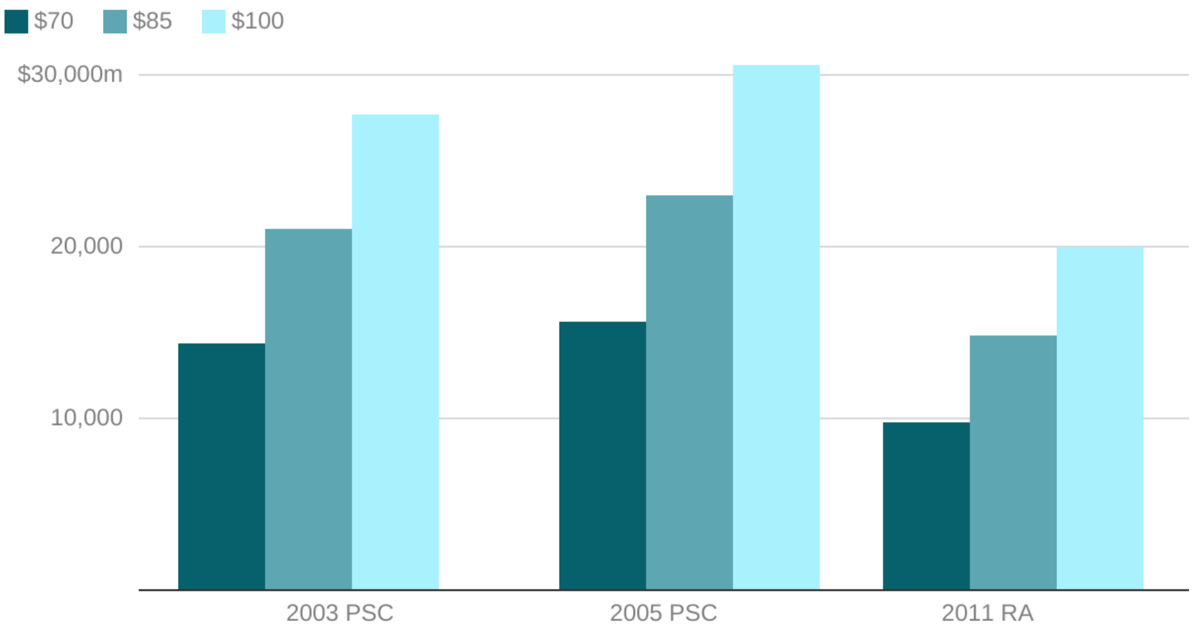
As oil price is inherently unpredictable, it is important to assess potential government revenues against a range of prices. As described above, we have chosen to generate model results at three different oil prices: $70, $85 and $100 per barrel. The specific results showing total lifecycle government revenues and government take are show in Table 6.

Table 6: Government Revenue and Take from Three Fiscal Regimes at Differing Oil Prices (USD Millions)

	2003 PSC		2005 PSC		2011 RA/2012 PSA	
$70	14,347	60%	15,615	65%	9,754	41%
$85	21,024	62%	22,991	68%	14,870	44%
$100	27,714	63%	30,588	70%	19,986	45%

The results for government revenue are show in a different format in Figure 5.

Figure 5: Government Revenue from Three Fiscal Regimes at Differing Oil Prices



Source: Resources for Development Consulting

As the data above shows, the *difference* in economic benefits accruing to the company and to the government grows significantly as the oil price rises.

Table 7 shows the additional revenues that would accrue to the government over the lifecycle of the project if the 2003 PSC terms or the 2005 PSC terms were applied in place of the 2011 RA/2012 PSA. At $85 per barrel, the 2003 PSC terms would generate an additional $6.1 billion in government revenue, while the 2005 PSC terms would generate an additional $8.1 billion. At $100 per barrel, the differences are $7.7 billion and $10.6 billion respectively.

Table 7: Additional Government Revenue at Differing Oil Prices (USD Millions)		
	2003 PSC	**2005 PSC**
$70	+4,592	+5,860
$85	+6,154	+8,121
$100	+7,728	+10,602

Contractor Economics at Higher Prices

Table 8 below shows the contractor economics assuming an oil price of $85 per barrel.

Table 8: Contractor Economics for Block 245 ($85/bbl) (USD Millions)			
	2003 PSC	**2005 PSC**	**2011 RA/2012 PSA**
Total Cash Flow	12,945	10,978	19,099
Net Present Value	2,718	1,801	4,919
Internal Rate of Return	16.0%	14.0%	19.3%
Payback Years	7	7	6

As would be expected, the contractor economics are highly sensitive to oil price. All scenarios show strong NPVs and IRRs. The 2011 RA/2012 PSA terms are particularly attractive, with an NPV of nearly $5 billion and an IRR of almost 20%.

5.3 Increased Oil Volume

The 2009 Shell valuation indicated technically recoverable oil reserves of 875 million barrels.[40] The production volume contained in the valuation was based not on total reserves, but on the specific development concept that had been selected. In this increased oil volume analysis, we assume that the full 875 million barrels are produced. We have adjusted project costs accordingly.[41] As in the base case scenario, we include the costs associated with gas development but not the revenues that would follow.

Table 9 shows the individual government revenue streams projected from 875 million barrels of production at the base case price assumption of $70 per barrel.

[40] Shell Nigeria Ultra Deep Limited. *OPL245 Block December 2006 Valuation Study*, 2009, p. 9.

[41] For the 875 mmbbls sensitivity, the same capital expenditure as the 560 mmbbls Base Case was used, as the majority of the increased reserves are assumed to result from larger reservoir volume accessed with the planned wells and better than expected reservoir performance. Additional years of the annual operating costs were added to represent extended field life and FPSO lease period in this case.

Table 9: 875 Million Barrel Case ($70/bbl) — Government Revenues and Government Take (USD millions)

	2003 PSC	2005 PSC	2011 RA/2012 PSA
Royalty	0	6,210	0
Education Tax	1,065	943	1,065
PPT	20,289	17,245	20,289
Profit Oil	9,782	9,082	0
Total Gov't Cash Flow	**32,542**	**34,887**	**22,760**
Government Take	66%	71%	46%

Government revenues are highly sensitive to oil price. Table 11 shows the additional government revenue that would be generated, at different oil prices, with production of 875 million barrels.

Table 10: Additional Government Revenue at Differing Oil Prices (USD Millions)

	2003 PSC	2005 PSC
$70	+9,783	+12,126
$85	+12,642	+16,600
$100	+15,517	+21,491

Higher oil production also makes the project much more attractive for the contractor.

Table 11: Contractor Economics for 875 Million Barrels ($70/bbl) (USD Millions)

	2003 PSC	2005 PSC	2011 RA/2012 PSA
Total Cash Flow	16,509	14,165	26,291
Net Present Value	2,637	1,664	5,177
Internal Rate of Return	14.8%	13.1%	17.8%
Payback Years	7	8	7

The NPVs are strongly positive, with the 2011 RA case being more than $5 billion. Rates of return are also well above industry expectations.

6.0 THE 2018 PETROLEUM INDUSTRY FISCAL BILL

For nearly two decades the FGN has been debating changes to deepwater PSC terms in order to increase government revenues. Since the widespread introduction of PSCs in the early 1990s, the terms have been tightened through new model PSCs and revisions to core legislation. As the terms of the 2011 RA were being negotiated, the FGN was proposing significant changes to Nigeria's petroleum fiscal regime under the banner of the Petroleum Industry Bill (PIB).

The process of revising Nigerian fiscal terms is ongoing, with a Petroleum Industry Fiscal Bill currently being debated in the National Assembly. This Section seeks to assess the value of Block 245 to the contractor and the government if it was governed by the terms contained in the 2018 PIFB and an associated PSC.

6.1 Government Revenues from Deepwater PSCs

Since the late 1990s, Nigeria has considered revisions to deepwater PSCs in order to secure a greater share of revenue for the government. Changes have been made to both contracts and national legislation. Each step in the evolution of Nigeria's model PSC, from 1993 to 2000 to 2005, represented an effort to secure a greater share for the government. Most significant was the inclusion of a royalty, even for deepwater blocks, in the 2005 Model PSC.

A similar pattern can be seen in revisions to national legislation, including the Deep Offshore PSC Act of 1999 (and its update in 2004) and the Petroleum Profits Tax Act of 1990 (also updated in 2004). For example, the Deep Offshore PSC Act of 1999 replaced the existing Investment Tax Credit with a less generous Investment Tax Allowance for PSCs signed after 1998.

Potentially more significant, however, was an early amendment to the Deep Offshore PSC Decree of 1999 that created a legal basis for the government to renegotiate the royalty and tax terms that were associated with the PSCs. The original Deep Offshore PSC Decree of 1999 sought to bring clarity to the legal framework governing Nigerian PSCs. That Decree, which came into effect in March of 1999, contained details on the applicable royalty rates (based on water depth) and the applicable tax rate for the PPT. Clause 17 provided that "the provisions of this Decree shall be liable to review after a period of 10 years from the date of the commencement and every five years thereafter."

A first amendment to the Deep Offshore PSC Decree came only two months later. In May of 1999, the review provisions were changed allowing for the provisions of the Decree to be reviewed "if the price of crude oil at any time exceeds $20 per barrel." The rationale for the change was also included in the Decree: "the share of the Government of the Federation in the additional revenue shall be adjusted under the Production Sharing Contracts to such extent that the Production Sharing Contracts shall be economically beneficial to the Government of the Federation." The right to review was effective when the Decree Amendment came into effect: oil prices exceeded $20 per barrel already in January of 1999 and were nearly $40 per barrel by the end of the year.

The FGN issued a notice of intention to review the terms of the Decree, but there has been no actual renegotiation. In part, this is due to stabilization clauses and the risk of lengthy arbitration battles. Nigerian PSCs contain clauses on "Change to Legislation." The contracts contain what is known as an economic equilibrium clause where, if there are changes to legislation or regulations "which materially affects the commercial benefits accorded to the Contractor," the government commits to additional changes to "restore the commercial benefits which existed under the Contract as of the Effective Date."[42]

6.2 The Petroleum Industry Bill

Rather than renegotiation of existing PSCs, efforts to secure a better deal with oil companies focused on the preparation of new petroleum legislation under the banner of an omnibus Petroleum Industry Bill (PIB).

The origins of the PIB lie in the Report of the Oil and Gas Reform Implementation Committee (OGIC) set up by the Federal Government in 2000.[43] One of four main objectives of the PIB, as set out by the Minister of Petroleum Resources in a major speech in 2009, was "to collect more revenues from large profitable fields in the deep offshore waters."[44]

Key features of the PIB as submitted to the National Assembly in 2008 included twin royalties based both on oil price and production volumes, the introduction of a Nigeria Hydrocarbons Tax at 25% for deep water (replacing the PPT), the inclusion of corporate income tax at 30% as a separate revenue stream, and the removal of a series of investment incentives.[45] A revised version of the Bill was prepared by the federal Inter-Agency Team (IAT) and submitted to the National Assembly in 2010. The terms in this draft were less onerous for companies while also being more profit sensitive. A final "Senate" version of the PIB was introduced in 2011 (SB 236).

The PIB was never passed into law. In 2015 the government decided to split the omnibus PIB into four separate bills, including a Petroleum Industry Fiscal Bill (PIFB).

In 2016 the Government published a consultation draft for a new National Petroleum Policy.[46] The Policy was focused on the reform of the petroleum fiscal regime. The first of the four main objectives was to "increase the government take in deep water, consistent with Section 16 of the Deep Offshore Act, comparable to international levels."[47] The fiscal terms proposed were broadly consistent with the PIB terms as set out in the Senate version of 2011.[48] The final National Petroleum Policy, published in 2017, is oriented more towards higher-level principles and does not contain any details on proposed fiscal terms.[49]

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[42] See 2003 PSC, Clause 26.

[43] Keynote Address By The Honourable Minister Of Petroleum Resources On The Proposed Petroleum Industry Bill (PIB), 16 July 2009, p. 2.

[44] Keynote Address By The Honourable Minister Of Petroleum Resources On The Proposed Petroleum Industry Bill (PIB), 16 July 2009, p. 7.

[45] See The Petroleum Industry Draft Bill, HB 159, 2009; and An overview of the Petroleum Industry Bill, NNCP, 2009, p. 15.

[46] Consultation Draft, National Petroleum Policy: Nigerian Government Policy and Actions, Ministry of Petroleum Resources, 2016.

[47] Section 16 of the Deep Offshore Act is the provision for reviewing royalty and tax rates associated with PSC discussed above.

[48] Consultation Draft, National Petroleum Policy: Nigerian Government Policy and Actions, Ministry of Petroleum Resources, 2016, p. 90.

[49] National Petroleum Policy: Nigerian Government Policy and Actions, Ministry of Petroleum Resources, 2017.

The PIFB is currently under review by the National Assembly.[50] While the status of the Bill is currently unclear, it is the most recent set of proposals for a new fiscal regime that could be applied to Block 245. The PIFB includes clear provisions for a sliding scale royalty based on production volume and a Petroleum Income Tax (replacing the PPT).

While the PIFB will continue to be associated with a PSC, there is no new Model PSC in the public domain. PSC terms, including the cost recovery limit, the method of allocation of Profit Oil, and the Profit Oil tranches, are drawn from the Government Memorandum on the PIB prepared by an Inter Agency Team of the Government of Nigeria.[51]

6.3 PIFB 2018 Fiscal Regime Terms and PSC Assumptions

The first step in the fiscal calculations would be a sliding scale royalty based on the volume of production ranging from 5% to 10% (See Table 12).[52]

Table 12: Sliding Scale Royalty—2018 PIFB

Production Volume	Royalty Rate
0-50 kbpd	5%
50-100 kbpd	7.50%
+100 kbpd	10%

The second step in the fiscal calculations would be the allocation of Cost Oil. The 2016 Draft National Petroleum Policy indicates that there will be a cost recovery limit.[53] We assume that the limit will be 80% based on the Government Memorandum on the Petroleum Industry Bill.[54]

The third step in the fiscal calculations would be the allocation of Tax Oil. The Education Tax would continue to be assessed at 2% of Assessable Profits.[55] A new Petroleum Income Tax (PIT) would be assessed at 40% of Chargeable Profits. The tax base is Assessable Profits less a Capital Allowance and a Production Allowance.[56]

The final step in the fiscal calculation would be the allocation of Profit Oil. The Government Memorandum on the Petroleum Industry Bill indicates that proposed terms for PSCs are Profit Oil splits based on cumulative production. The details are set out in Table 13.

Table 13: Profit Oil Tranches—2018 PIFB / PSC (mmbbls)

Cumulative Production	Government	Contractor
0–750	20%	80%
7,51–1,000	30%	70%

[50] The Petroleum Industry Fiscal Bill 2018 (SB. 472)

[51] "Final Explanatory Memorandum of the Government Memorandum on the PIB (2009)," Inter Agency Team on the Petroleum Industry Bill, September 2010.

[52] The Petroleum Industry Fiscal Bill 2018 (SB. 472), p. 76.

[53] See Consultation Draft, National Petroleum Policy: Nigerian Government Policy and Actions, Ministry of Petroleum Resources, 2016, p. 90.

[54] Government Memorandum on the Petroleum Industry Bill, p. 61.

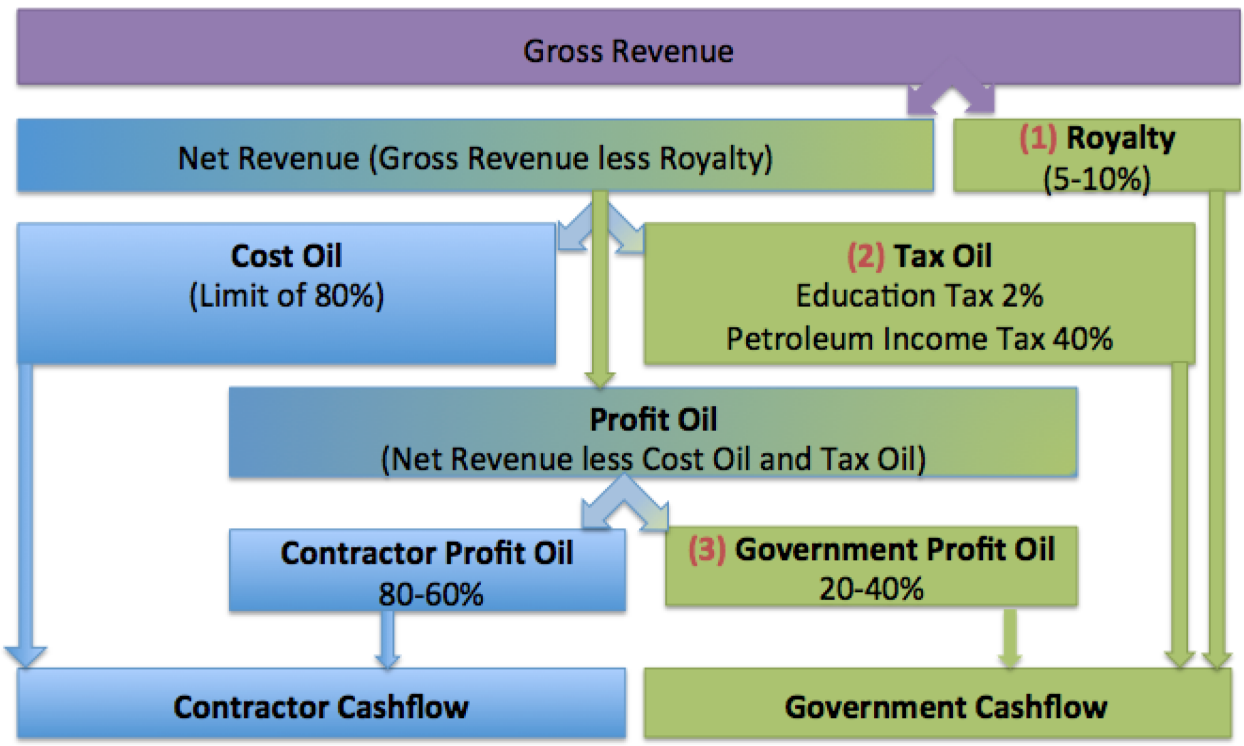
[55] Education Tax Act CAP E4 LFN 2004.

[56] The Petroleum Industry Fiscal Bill 2018 (SB. 472)

1,001–2,000	40%	60%
Higher than 2000	Negotiable	Negotiable

The structure of the 2018 PIFB and the associated PSC terms is set out in Figure 6.

Figure 6: 2018 PIFB / Associated PSC Fiscal Structure



6.4 Results for the Four Fiscal Regimes

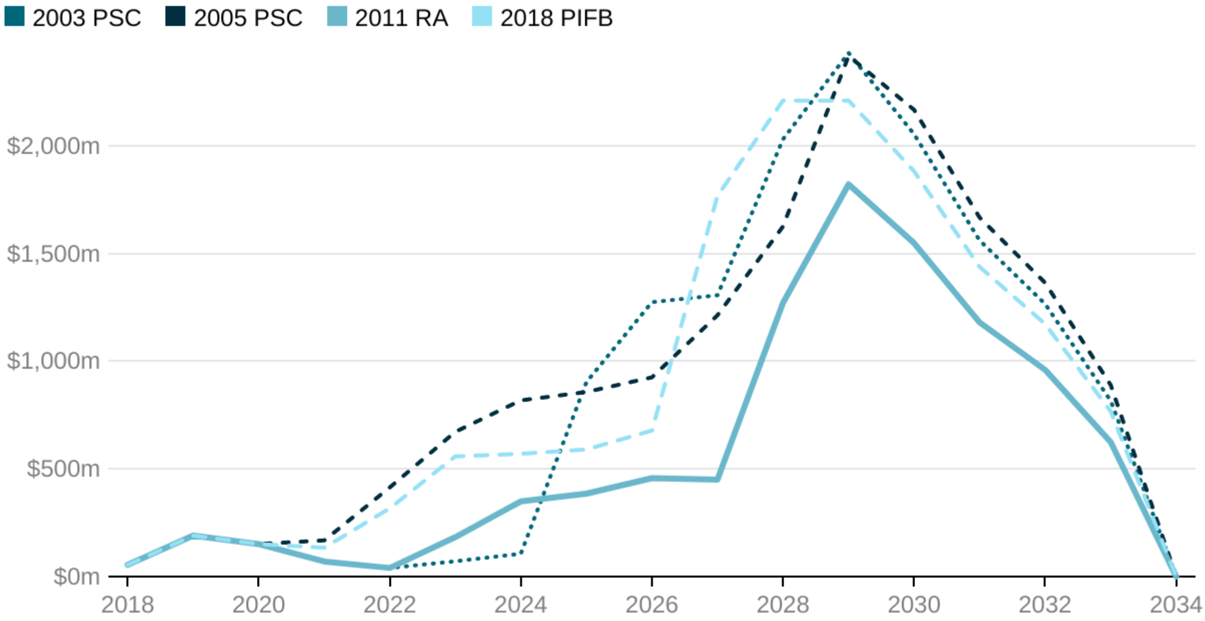
Table 14 shows the results when the base case project is run against the original 2003 PSC, the 2005 Model PSC, the 2011 Resolution Agreement, and the 2018 PIFB terms. The results suggest that the impact of the revised fiscal terms falls somewhere between the 2003 and 2005 PSC fiscal terms.

Table 14: Base Case Analysis ($70/bbl) — Government Revenues and Government Take (USD millions)

	2003 PSC	2005 PSC	2011 RA 2012 PSA	2018 PIFB
Royalty	0	3,746	0	3,306
Education Tax	596	522	596	568
PPT	8,072	6,236	8,072	7,449
Profit Oil	4,592	4,024	0	2,305
Total Gov't Cash Flow	14,347	15,615	9,754	14,714
Government Take	60%	65%	41%	61%

Figure 7 shows the total revenue that would flow to the government year-by-year for all four sets of fiscal terms.

Figure 7: Annual Government Revenue from Block 245 ($70/bbl) for Four Fiscal Regimes



Source: Resources for Development Consulting

Table 15 shows the additional revenue that would flow to the Government if the 2003, 2005 or 2018 terms were to replace those contained in the 2011 RA and the 2012 PSA. Once again, the 2018 terms generate revenues in between those of the 2003 PSC and 2005 PSC.

Table 15: Additional Government Revenue at Differing Oil Prices (USD Millions)

	2003 PSC	2005 PSC	2018 PIFB
$70	+4,592	+5,860	+4,960
$85	+6,154	+8,121	+6,981
$100	+7,728	+10,602	+9,852

Table 16 below shows the contractor economics for the four fiscal regimes. The 2018 PIFB terms generate a positive NPV ($751 million) and a sufficiently strong IRR (11.7%). Under these revised terms, the project would continue to be a good investment for the contractor.

Table 16: Contractor Economics for Block 245 ($70/bbl) for Four Fiscal Regimes (USD Millions)

	2003 PSC	2005 PSC	2011 RA 2012 PSA	2018 PIFB
Total Cash Flow	9,588	8,320	14,180	9,220
Net Present Value	1,143	385	2,690	751
Internal Rate of Return	12.6%	10.9%	15.3%	11.7%
Payback Years	7	8	7	8

6.5 Responses from Shell and Eni

Shell and Eni were asked for their comments on the findings of this analysis and offered the opportunity to update or correct the input data used in the model as set out in Annex I.

Shell did not comment on the specific points put to them saying only that "The statements in your letter are based on faulty methodologies which do not meet adequate qualitative standard. They fail to take into account elements that are typically used by the industry (e.g., geology), make wrongful factual assumptions (such as by using obsolete of irrelevant data), misconstrue the terms of the 2011 settlement and even reference legislation which has not been passed."

Eni claimed in light of their ongoing trial it would be "inappropriate for us to comment on such circumstances outside the court." They did not comment on the specific points put them other to say "the technical and contractual assumptions adopted as the basis for the analysis appear to be partial and inaccurate, if not misleading."

7.0 CONCLUSIONS

The fiscal terms that currently govern Block 245 are not consistent with the essence of a normal production sharing system.

The 2011 RA called for a “production sharing agreement” to be signed between Shell and Eni. This agreement, signed in 2012, establishes the terms that govern the relationship between the two joint venture partners, Shell and Eni. In other contexts this document would be called a Joint Operating Agreement.

Importantly, the 2011 RA did not call for a PSC to be signed between the international oil companies and the NNPC, as would normally be the case. As a result, two central features of a Nigerian PSC — Cost Oil to compensate the contractor and a share of Profit Oil allocated to the government — have been removed from the current Block 245 fiscal regime.

Two other sets of fiscal terms have governed the Block 245 since 2003: a 2003 Production Sharing Contract (PSC) signed by Shell and subsequently rescinded; and the terms of the 2005 Model PSC that applied to the original Nigerian contractor Malabu after its license was reinstated in 2006. The 2003 and 2005 PSC terms are broadly similar, with only two significant differences: the 2005 contract includes a royalty for deepwater blocks and uses a measure of profitability (based on an R-factor) to allocate Profit Oil between the company and the government.

If the Block were to be re-allocated in the future, fiscal terms from the PIFB could be expected to apply. While these terms are not yet finalized, it appears that they would result in a sliding-scale royalty and a new Petroleum Income Tax.

The value of the Block for the contractor and the Government can be compared under these different sets of fiscal terms using an industry-standard methodology known as discounted cash flow analysis. The results in this report are based on an economic model for Block 245 based largely on data from Shell and Eni.[57] Shell and Eni both dispute the findings of this report, as set out in Section 6.5.

The different fiscal regimes generate very different revenue prospects for the Government of Nigeria. Under our base case assumptions, and assuming a future oil price of $70 per barrel, the 2003 PSC terms would generate $14.3 billion in government revenue over the lifespan of the project; while the 2005 terms would generate $15.6 billion. In contrast, the 2011 RA terms would generate $9.8 billion. The potential reduction of between $4.5 billion and $5.9 billion when compared to the 2003 or 2005 terms is due to the removal in the 2011 RA and the 2012 PSA of the central feature of the production sharing system: a share of Profit Oil for the government.

The differences in benefits grow under higher oil price scenarios. At $100 per barrel, the 2003 PSC terms would generate an additional $7.7 billion in government revenue, while the 2005 PSC terms would generate an additional $10.6 billion.

Of the four sets of fiscal terms could plausibly apply to Block 245 – three sets that have governed Block 245 at different times in the past and one set that is currently being finalized – those that currently govern the Block are the least favourable to the Government of Nigeria.

[57] Available at http://www.res4dev.com/opl245.

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ANNEX I: MODELLING INPUTS AND ASSUMPTIONS

OIL FIELD INPUTS AND ASSUMPTIONS				
Component	**2006—Data**	**Source/Description**	**2018—Revised**	**Source/Description**
Production				
Reserves (MMbbls)	459	As reported in 2006 Shell Valuation Study.	560	Zabazaba and Etan Integrated Development Project, Offshore Technology, 2017.
Project Lifespan	15 Years	As reported in 2006 Shell Valuation Study.	13 Years	Years of production from 150,000 bpd profile from Ismael Guerrero "Operating Models in the FPSO Business", October 2014.
Plateau Production	110,000 bpd	Production profile was replicated from Shell 2006 Valuation Study (decline rate of ~40%), production limited by 120,000 bpd FPSO.	150,000 bpd	See Tender No: CIZ/SPR/ABJ/L006604/2016.
Costs				
Exploration Expenditures (MM$us)	207	As reported in 2006 Shell Valuation Study.	581	From 2006 Shell valuation study, including pre-FID development studies, plus the cost of 3 exploration wells drilled in 2013.

OIL FIELD INPUTS AND ASSUMPTIONS				
Component	**2006—Data**	**Source/Description**	**2018—Revised**	**Source/Description**
Development Costs (MM$us)	5,511	As reported in 2006 Shell Valuation Study (in 2006 money).	10,830	From Shell Proposal to Commence Negotiations 17/3/2010 corrected for inflation since calculations are based on 2018 money.
Development Costs Phasing	Year -2: 13% Year -1: 45% Year 0: 35% Year 1: 7%	From Tullow Oil Report "A step change for Tullow and Ghana"; assuming Ghana's Jubilee field as a representative analog.	Year -2: 13% Year -1: 45% Year 0: 35% Year 1: 7%	From Tullow Oil Report "A step change for Tullow and Ghana"; assuming Ghana's Jubilee field as a representative analog. Etan development drilling spend was delayed four years from initial start of Zabazaba production.
Operation Costs (MM$us)	1,304	As reported in 2006 Shell Valuation Study.	8,368	Includes $5.42 Billion Saipem FPSO contract from "Saipem Wins $5.42bn Contract for Zabazaba-Etan Devt Project in OPL 245"; This Day; 20th November 2017, and Deepwater Field Operating Costs from "A Step Change for Tullow and Ghana", Tullow Capital Markets Day, Ghana, 1 October 2008, with the latter corrected for inflation since calculations are based on 2018 money.
Abandonment Costs (MM$us)	567	As reported in 2006 Shell Valuation Study.	709	Based on 2006 Shell Valuation Study; corrected for inflation since calculations assume 2018 money.
Value Added Tax (VAT)	5%	VAT at 5% is payable on all domestic operating and capital costs.	5%	VAT at 5% is payable on all domestic operating and capital costs.

OIL FIELD INPUTS AND ASSUMPTIONS				
Component	**2006—Data**	**Source/Description**	**2018—Revised**	**Source/Description**
NDDC Levy		Not included in the 2006 Shell Valuation Study.	3%	Niger-Delta Development Commission Act (2000) Section 14(2)(b) stipulates a 3% charge on the total budget of any oil producing company operating onshore and offshore in the Niger-Delta area.
Inflation Rate	3.5%	As reported in 2006 Shell Valuation Study.	2%	US Bureau of Labor Statistics

Oil Price	Assumption	Description / Source
Brent Crude	$70 Base Case: Sensitivities at $85 and $100	World Bank Commodities Price Forecast (April 24th 2018) indicates a Crude (average) price of $64.7/bbl (long term price in 2021) in constant 2018 $. World Bank (WB) crude price forecasts are based “average price of Brent, Dubai and West Texas Intermediate, equally weighed.” The current differentials of these crudes (based on their prices quoted in October 24th 2018) indicated an adjustment of +$6.01/bbl between WB crude average price and Brent. We therefore use $70 /bbl Brent as our base case price.
Discount to Brent	$0/bbl	No public domain information on discount or premium to Brent for crude from OPL 245. Nigerian crudes normally sell at either a small discount or small premium to Brent.
Inflation Rate	2%	The same inflation rate was applied to oil price as was applied to costs from the cost base year.

FISCAL TERMS				
Component	**Assumption**	**Description / Source**		
2003 Production Sharing Contract and 1990 Petroleum Act				
Royalty	0%	Royalty based on water depth. According to the 1990 Petroleum Act, for water depth of more than 1,000 meters the rate is 0%.		
Cost Recovery Limit	100%	The 2003 PSC does not contain a limit on the proportion of annual production that can be allocated to cost recovery.		
Capital Depreciation	5 years	Five (5) year straight line.		
Education Tax	2%	The Education Tax is assessed at a rate of 2% of Assessable Profits. The tax base is gross revenue less royalties, operating costs, intangible development costs, financing interests, and exploration costs.		
Petroleum Profits Tax	50%	The Petroleum Profits Tax (PPT) is assessed at 50% of Chargeable Profits. The tax base is Assessable Profits less a capital allowance. The capital allowance is the sum of tangible development cost depreciation, abandonment costs, and the Investment Tax Allowance (ITA = 50% of tangible costs).		
Profit Oil	30–70%	**Cumulative Production**	**Government**	**Contractor**
		0–350 mmbls	30%	70.00%
		351–750 mmbls	35%	65.00%
		751–1000 mmbls	47.50%	52.50%

<table>
<tr><th colspan="5">FISCAL TERMS</th></tr>
<tr><th>Component</th><th>Assumption</th><th colspan="3">Description / Source</th></tr>
<tr><td rowspan="4">Profit Oil</td><td rowspan="4">30–70%</td><th>Cumulative Production</th><th>Government</th><th>Contractor</th></tr>
<tr><td>1001–1500 mmbls</td><td>55%</td><td>45.00%</td></tr>
<tr><td>1501–2000 mmbls</td><td>65%</td><td>35.00%</td></tr>
<tr><td>Higher than 2000 mmbls</td><td>Negotiable</td><td>Negotiable</td></tr>
<tr><td colspan="5">2005 Model Production Sharing Contract and 2004 Deep Offshore Production Sharing Contracts Act</td></tr>
<tr><td>Royalty</td><td>8%</td><td colspan="3">Royalty based on water depth. According to the 2005 Model PSC the royalty rate for water depths of greater than 800 meters is 8%.</td></tr>
<tr><td>Cost Recovery Limit</td><td>80%</td><td colspan="3">In the Model PSC, the cost recovery limit was open to bids, with the minimum limit being 80%.</td></tr>
<tr><td>Capital Depreciation</td><td>5 years</td><td colspan="3">Five (5) year straight line.</td></tr>
<tr><td>Education Tax</td><td>2%</td><td colspan="3">The Education Tax is assessed at a rate of 2% of Assessable Profits. The tax base is gross revenue less royalties, operating costs, intangible development costs, financing interests, and exploration costs.</td></tr>
<tr><td>Petroleum Profits Tax</td><td>50%</td><td colspan="3">The Petroleum Profits Tax (PPT) is assessed at 50% of Chargeable Profits. The tax base is Assessable Profits less a capital allowance. The capital allowance is the sum of tangible development cost depreciation, abandonment costs, and the Investment Tax Allowance (ITA = 50% of tangible costs).</td></tr>
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<tr><th colspan="5">FISCAL TERMS</th></tr>
<tr><th>Component</th><th>Assumption</th><th colspan="3">Description / Source</th></tr>
<tr><td rowspan="4">Profit Oil</td><td rowspan="4">30–70%</td><th>R-factor</th><th>Government</th><th>Contractor</th></tr>
<tr><td>Lower than 1.2</td><td>30%</td><td>70.00%</td></tr>
<tr><td>Between 1.2–2.5</td><td colspan="2">25%+((2.5-R)/(2.5-1.2))*(70%-25%)</td></tr>
<tr><td>Higher than 2.5</td><td>75.00%</td><td>25.00%</td></tr>
<tr><td colspan="5">2011 Resolution Agreement and 2012 Production Sharing Agreement</td></tr>
<tr><td>Royalty</td><td>0%</td><td colspan="3">Royalty based on water depth. According to the 2004 Deep Offshore Production Sharing Contracts Act, for water depth of more than 1,000 meters the rate is 0%.</td></tr>
<tr><td>Cost Recovery Limit</td><td>N/A</td><td colspan="3">According to the 2012 PSA, there is no Cost Oil allocation.</td></tr>
<tr><td>Capital Depreciation</td><td>5 years</td><td colspan="3">Five (5) year straight line.</td></tr>
<tr><td>Education Tax</td><td>2%</td><td colspan="3">The Education Tax is assessed at a rate of 2% of Assessable Profits. The tax base is gross revenue less royalties, operating costs, intangible development costs, financing interests, and exploration costs.</td></tr>
<tr><td>Petroleum Profits Tax</td><td>50%</td><td colspan="3">The Petroleum Profits Tax (PPT) is assessed at 50% of Chargeable Profits. The tax base is Assessable Profits less a Capital Allowance. The Capital Allowance is the sum of tangible development cost depreciation, abandonment costs, and the Investment Tax Allowance (ITA = 50% of tangible costs).</td></tr>
<tr><td>Profit Oil</td><td>N/A</td><td colspan="3">According to the 2012 PSA, Profit Oil is allocated to Eni and Shell according to their equity stakes. There is no Profit Oil allocation to the NNPC or the FGN.</td></tr>
</table>

<table>
<tr><th colspan="4">FISCAL TERMS</th></tr>
<tr><th>Component</th><th>Assumption</th><th colspan="2">Description / Source</th></tr>
<tr><td colspan="4">2018 Petroleum Industry Fiscal Bill and Production Sharing Contract Terms</td></tr>
<tr><td rowspan="4">Royalty</td><td rowspan="4">5–10% production-based</td><td colspan="2">According to the 2018 PIFB, the royalty rate is based on a sliding scale depending on the volume of production. (The Petroleum Industry Fiscal Bill 2018 (SB. 472)</td></tr>
<tr><td>0–50 kbpd</td><td>5%</td></tr>
<tr><td>50–100 kbpd</td><td>7.50%</td></tr>
<tr><td>+100 kbpd</td><td>10%</td></tr>
<tr><td>Cost Recovery Limit</td><td>80%</td><td colspan="2">Government Memorandum on the Petroleum Industry Bill, p. 61.</td></tr>
<tr><td>Capital Depreciation</td><td>5 years</td><td colspan="2">Five (5) year straight line.</td></tr>
<tr><td>Education Tax</td><td>2%</td><td colspan="2">The Education Tax is assessed at a rate of 2% of Assessable Profits. The tax base is gross revenue less royalties, operating costs, intangible development costs, financing interests, and exploration costs (Calculated as 2/102 x Assessable Profits).</td></tr>
<tr><td>Petroleum Income Tax</td><td></td><td colspan="2">The Petroleum Income Tax (PIT) is assessed at 40% of Chargeable Profits (40% is the rate for Deepwater). The tax base is Assessable Profits less a Capital Allowance and a Production Allowance. The Capital Allowance is the sum of intangible well costs, tangible development cost (depreciated). The Production Allowance is the lower of $3/bbl or 30% of Official Selling Price, multiplied by a Cost Efficiency Factor. There is also an Additional Production Allowance calculated based on Reserves Replacement Ratio. The Petroleum Industry Fiscal Bill 2018 (SB. 472)</td></tr>
<tr><td>Profit Oil</td><td>20-40%</td><td colspan="2">Government Memorandum on the Petroleum Industry Bill, p. 61.</td></tr>
</table>

FISCAL TERMS				
Component	**Assumption**	**Description / Source**		
		Cumulative Production	**Government**	**Contractor**
		0–750	20%	80%
		7,51–1,000	30%	70%
		1,001–2,000	40%	60%
		Higher than 2001	Negotiable	Negotiable