Nigeria's Back-in Rights to OPL 245:

An Economic Analysis

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1.0 INTRODUCTION

Our previous report, Government Revenues from OPL 245: Assessing the Impact of Different Fiscal Terms, analysed the fiscal terms of the 2011 Resolution Agreement (RA) and concluded that they were unfavourable to the Federal Government of Nigeria (FGN).[1] Specifically, the 2011 RA does not reserve any share of oil production, known as "profit oil", for the FGN or the Nigeria National Oil Corporation (NNPC). Rather it grants all profit oil to Eni and Shell.

Our original analysis did not consider the option, provided for in the 2011 RA, for the Government to acquire a stake in OPL 245 through what are known as "back-in" rights. Eni responded to criticism of the fiscal terms set out in the 2011 RA by highlighting that the analysis did not take into account the rights that the FGN has to "back in" to OPL 245.[2] Shell has also reiterated the importance of assessing the value of the back-in rights.[3]

There are indications that the Government has considered exercising its back-in rights. In September 2017 the Attorney-General of the Federation, Mr. Abubakar Malami, wrote to the President advising that the government should make use of their right to acquire a stake in OPL 245.[4]

This report provides an economic analysis of the FGN's back-in rights as set out in the 2011 RA. It begins with a review of sole risk contracts allocated to indigenous Nigerian companies in the 1990s, and the associated Back-in Regulations put in place in 2003. It then examines changes to the back-in rights between the draft RA and the specific terms that are set out in the signed RA. These terms are then analysed by adding a fifth fiscal regime scenario to the existing Resources for Development's economic model for OPL 245.[5] The report concludes with a comparison of the economic impact of the exercising of the back-in rights on both the FGN, and Eni and Shell.

1.1 Indigenous Companies and Back-in Rights

Beginning in the early 1990s, Nigeria sought to expand the role of indigenous (Nigerian) companies[6] in both the production of oil and in the provision of oilfield goods and services.

[1] See Don Hubert, Government Revenues from OPL 245: Assessing the Impact of Different Fiscal Terms, Resources for Development Consulting, 2018.

[2] "… a spokesperson told CNBC via email, and claimed Global Witness' analysis may have overlooked the Nigerian government's 50 percent back-in right on the oil block." Nigeria will lose $6 billion in 'corrupt' oil deal with Shell and Eni, report claims, CNBC, 27 November 2018.

[3] Letter from Shell to Global Witness, 25 March 2019.

[4] "Your Excellency, the beneficial approach I counsel in the circumstances is for the federal government to take advantage of the terms of the agreement under clauses five and 11 to acquire a stake in the OPL 245 converting it to a production sharing contract (PSC) between FGN/NNPC, Shell and Agip after negotiating with the ENI/Shell to absorb the cost of the FGN/NNPC entry under the said clauses five and 11 through the PSC mechanism." Malami tells Buhari no evidence Diezani, Adoke stole, Pulse, 19 February 2018.

[5] A revised version of the OPL 245 excel model, including the back-in analysis, is available at Government Revenues from OPL 245: Assessing the Impact of Different Fiscal Terms

[6] A '"Nigerian Company" means a company formed and registered in Nigeria in accordance with the provision of Companies and Allied Matters Act with not less than 51 % equity shares by Nigerians.' Clause 106, Nigerian Oil and Gas Industry Content Development Act, 2010.

Indigenous companies were given preferential treatment in the allocation of Oil Prospecting Licences (OPL) under the Indigenous Concession Programme.

Through this scheme, Nigerian-owned companies would be allocated an OPL on a "sole risk" basis. In sole risk contracts, the indigenous company is both the Contractor and the Concessionaire or Licence Holder (in this report the term Concessionaire is used to denote the entity with the right to issue oil rights contracts to private companies). The indigenous company would retain a 60% stake in the OPL and offer 40% to international oil companies in order to secure the necessary capital and technical expertise.

Under these terms of a sole risk contract, the government would not receive a share of profit oil. Government revenue would come only from royalties and taxes. However, for at least some sole risk OPLs (including 245 and 246 – see Section 2.1 and Text Box 2) the government reserved the right to acquire a participating interest (to back in) to any subsequent Oil Mining Lease (OML).[7]

On coming to power in 1999, the civilian government sought to protect its revenue interest in OPLs allocated on a sole risk basis. In some cases, the licences were simply cancelled. For example, 16 deep water licences were cancelled in July 1999,[8] while a further 31 licences, including some deep water blocks, were cancelled in June 2000.[9]

Text Box 1: What Are Back-in Rights?

Governments or government entities are normally the Concessionaire or Licence Holder and have the authority to enter into contracts with private companies. In addition, governments are sometimes equity partners in oil projects, alongside international oil companies. This means that they may also hold a share of the rights allocated to the Contractor.

In some cases, the government acts as a full equity partner, and shares all of the risks associated with exploration. More commonly, governments encourage companies to take the exploration risk and reserve the right to acquire a stake (to "back in") to a share of the Contractor rights following a commercial discovery. In some cases, governments are "carried" (they do not have to pay their share of costs) until the start of development. From the start of production, a government that has backed-in would be a full equity partner alongside the companies, with all the associated rights and responsibilities.

The meaning of back-in rights as they might apply to OPL 245 is different. Here back-in rights are being applied to a sole risk contract where both the Concessionaire and the Contractor rights are held by private companies. The back-in rights as set out in the 2011 RA do not allow the government to acquire a full 50% stake in the Licence. Nor do they allow the government to reacquire the complete Concessionaire / Licence Holder rights. The terms of the RA allow the government to secure the rights of Concessionaire for the share of the Block (up to 50%) that they choose to acquire.

[7] The NNPC has not been successful in asserting back-in rights to OPL 216 / OML 127 held on a sole risk basis by Famfa since 1993. Two separate efforts by the NNPC to assert back-in rights were rejected in court, though it appears that the decision was based more on how the government sought to apply the back-in rights than the rights themselves. See NNPC v. Famfa Oil Limited (2012).

[8] Moses Asamu, Nigeria's Deepwater Province Taking Off Now That New Government in Place, Oil and Gas Online, 1999.

[9] Nigeria revokes 31 exploration licenses, Oil and Gas Journal, 2000.

For the remaining sole risk contracts, the government sought to assert its right to acquire a stake in future OMLs through its back-in rights. Specifically, the government sought to clarify its back-in rights for deep-water blocks in the Deep Water Block Allocation to Companies (Back-in Rights) Regulations of 2003.[10]

The regulations granted the government the right to back-in and acquire five-sixths of an indigenous company's interest. Given the normal commercial structure of 60% indigenous company and 40% international oil companies, the FGN would have the right to take up a 50% participating interest.

The regulations indicate that for Blocks governed by a "production sharing arrangement," the fiscal terms shall not be less favourable than the latest version of the government's model production sharing contract (PSC).

2.0 BACK-IN RIGHTS IN THE 2011 RESOLUTION AGREEMENT

The inclusion of back-in rights was a controversial element in the RA negotiations. The RA allows the FGN to back in to OPL 245 based on the repayment of past costs (in cash and through cost recovery) and through the signing of a PSC governing the FGN's stake in the Block. These back-in rights would not make the FGN a full equity partner. Rather, they allow the FGN to regain its position as Concessionaire and to receive the associated share of profit oil for half of OPL 245.

2.1 Back-in Rights for OPL 245

OPL 245 was originally allocated to Malabu in 1998 on a sole risk basis. Under this arrangement, Malabu held both the Concessionaire rights and the Contractor rights, with the government reserving the right to a participating interest (back-in rights) for future OMLs. Specifically, the original allocation letter for OPLs 214 and 245 stated:

> "that the allocated blocks would be operated on "Sole Risk" basis but with the understanding that the Government reserves the right to a participating interest at any time in the life of any subsequent Oil Mining Lease when it so wishes."[11]

As would be expected, Malabu was entitled to bring in a foreign partner to provide technical and financial resources. The stake to be held by the foreign partner, however, was limited. A separate letter, issued on the same date, stated "Foreign participation in the blocks shall not exceed 40% (i.e. 60/40 indigenous to foreign)."[12] Prior to Malabu's rights to the block being revoked in 2001, the company was negotiating to allocate 40% of the rights to OPL 245 to Shell.

From 2003 through until 2006, the rights to OPL 245 were held by Shell under a PSC signed with the NNPC.[13] Under the PSC structure, the NNPC was the Concessionaire and Shell was

[10] Deep Water Block Allocations to Companies (Back-In-Rights) Regulations, 2003.

[11] Application for Discretionary Allocation of OPLs 214 and 245, Letter from Department of Petroleum Resources, 29 April 1998.

[12] OPLs 214 and 245, Letter from Department of Petroleum Resources, 29 April 1998.

[13] 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.

the Contractor. The 2003 PSC did not provide the government any rights to acquire an equity stake (a share of Contractor rights) in OPL 245 or in any subsequent OML.

When Malabu's rights were reinstated in 2006, the block was once again held on a sole risk basis. The 2 December 2006 letter detailing the out-of-court settlement provides Malabu with a "full and total reinstatement of all it's [sic] rights."[14] The nature of the rights was further confirmed in 2010 by the then Attorney General and President Goodluck Jonathan who agreed that Malabu holds the rights of "Concessionaire/Operator/Contractors of the Block."[15]

The rights granted to Eni and Shell in the 2011 RA suggest that OPL 245 continued to be held on a sole risk basis. The NNPC is not a party to the agreement, with Eni and Shell being both Concessionaire and Contractor. This characterization appears to be confirmed by the Department of Petroleum Resources (DPR), with OPL 245 being listed in their 2017 annual report as a "sole risk" contract.[16]

The allocation of Concessionaire and Contractor rights for the different phases of OPL 245 are set out in Figure 1.

Figure 1: OPL 245 Concessionaire and Contractor Rights

Sole Risk (1998)	PSC (2003)	Sole Risk (2006)	Sole Risk (RA) (2011)
Concessionaire: 100% Malabu	Concessionaire: 100% NNPC	Concessionaire: 100% Malabu	Concessionaire: 50% Eni 50% Shell
Contractor: 100% Malabu	Contractor: 100% Shell	Contractor: 100% Malabu	Contractor: 50% Eni 50% Shell

2.2 *The Draft Resolution Agreement and Response*

Draft versions of the Resolution Agreement appear to have excluded back-in rights for the government, terms strongly opposed by the NNPC and Department of Petroleum Resources. The then Director of the DPR, in a letter of 1 April 2011, claimed that the provisions of the "Resolution Agreement as proposed are highly prejudicial to the interests of the Government."[17] Among these reasons was the exclusion of the FGN's right to back-in to the Block, as provided for in legislation. Specifically, the DPR Director stated:

> (iv) Further more, the Resolution Agreement proposes to award OPL 245 to NAE and SNEPCO on a Sole Risk basis *with out* [sic] *the FGN nor any of its agencies having a right*

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

[15] Letter from Ibrahim Magu, Acting EFCC Chairman to Attorney General of the Federation "Re: OPL 245 Request for Update on Investigation", 1 September 2016, p7.

[16] Annual Report: Nigerian Oil and Gas Industry, Department of Petroleum Resources, 2017.

[17] See W. A. Obaje, Letter from the Department of Petroleum Resources to the Attorney General and Minister of Justice Regarding the OPL 245 Resolution Agreement, 1 April 2011, p. 5.

of "back-in" in an future OML derived from the Block (this is untenable because parties can not by their Agreement exclude the operation of a Legislation in force). [18]

2.3 Back-in Rights in the Signed Resolution Agreement

The section on back-in rights appears to be one of the most prominent changes between the draft and the final FGN RA. The final terms are set out in Clause 11:[19]

> If at any time FGN and/or its relevant agencies and institutions *decides by law* to participate or acquire any interest in the Oil Prospecting license or any OML for Block 245 issued pursuant to this FGN Resolution Agreement, the FGN undertakes to NAE and SNEPCO that:
>
> (i) the participation of the FGN and/or its relevant agencies and institutions shall be exercised by way of *acquiring not more than fifty (50%) percent interest* under the Oil Prospecting licence or relevant oil mining lease *subject to the payment by FGN to NAE and SNEPCO of the cost of the latter's' acquisition of Block 245* which shall be an amount equal to the proportionate share relative to the interest acquired by the FGN and/or its relevant agencies and institutions of the sums paid by NAE and SNEPCO under Clauses 2 and 3 of this FGN Resolution Agreement net of any taxes, levies or other duties whatsoever, *plus accrued interest* as agreed by the relevant parties; and
>
> (ii) the FGN and/or its relevant agencies and institutions shall enter into a production sharing contract with NAE and SNEPCO as Contractors for the exclusive conduct of petroleum Operations in respect of the FGN's acquired interest in the Block 245, "FGN PSC". The terms of the FGN PSC shall be no less favourable than the terms previously agreed between NNPC and SNUD in the agreement referenced in Preamble E [the 2003 PSC agreed between the NNPC and Shell]; and
>
> (iii) the FGN and/or its relevant agencies and institutions' *proportionate share relative to its acquired interest, of all costs incurred by NAE and SNEPCO* in Block 245 from the date of the grant of the Oil Prospecting Licence, pursuant to Clause 1.3, up to the date of the acquisition of interest by FGN and/or its relevant agencies and institutions pursuant to this Clause 11, *shall be recoverable by NAE and SNEPCO under the FGN PSC*.

2.4 Analysis of the Resolution Agreement Back-in Rights

Clause 11 of the Resolution Agreement indicates that the FGN can decide "by law" to acquire an "interest" in OPL 245 of up to 50%. If it does so, it must pay its proportionate share of the $1.3 billion paid by Shell and Eni, plus accrued interest at a rate to be agreed.

The second paragraph clarifies the nature of the interest that the FGN could acquire. A PSC would be signed between the FGN and the Contractors (Shell and Eni) covering only the FGN's acquired interest. This contract is referred to as the FGN PSC. The terms of that contract would

[18] Obaje Letter, p. 6. Emphasis added.

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

Text Box 2: Back-in Rights for OPL 246 / OML 130

1998: OPL 246, an oil block that bordered on OPL 245, was allocated on a sole risk basis on 22 February 1998 to an indigenous Nigerian company named South Atlantic Petroleum (SAPETRO).

1998: On 26 May 1998 SAPETRO received consent from the Minister of Petroleum to farm down to two international oil companies: Total Upstream Nigeria Ltd (Total) with a 24% stake and the operatorship; and Brasoil Oil Services Company Nigeria Ltd (Petrobras) with a 16% stake. SAPETRO retained the remaining 60%.

2000: Exploration drilling began in 1999 and the Akpo field was discovered in 2000.

2005: In advance of the development of the Akpo field, one half of OPL 246 was converted into Oil Mining Lease (OML) 130.

2005: The NNPC exercised its rights to back in to 50% of SAPETRO's share of OML 130.

2005: The NNPC, however, did not retain the full 50% stake. It signed a typical deep water PSC with SAPETRO dated 25 April 2005 giving the NNPC Concessionaire rights to 50% of the OML.

2005: The Concessionaire and Contractor rights to the other 50% of the OML continued to be held by private companies. They signed a PSA on 26 April 2005 that set out the rights and responsibilities of the joint venture partners.

2006: CNOOC Ltd acquired 90% of SAPETRO's Contractor stake in the portion of OML 130 covered by the PSC. The payment was $2,268 million and included $518 million in SAPETRO's carried back costs.

Table 1: Ownership Structure – OML 130

	PSA (50% of the Block)		PSC (50% of the Block)	
	Concessionaire	Contractor	Concessionaire	Contractor
NNPC			100%	
SAPETRO	20%	20%		10%
Total	48%	48%		
Petrobras	32%	32%		
CNOOC				90%
TOTAL	100%	100%	100%	100%

There is no physical separation of the block. Production and costs are shared equally between the PSA and PSC contracts. The PSA portion of the block retains the sole risk structure, and as a result, the NNPC receives no profit oil from 50% of the OML. The NNPC is the Concessionaire for the PSC portion of the OML and therefore receives profit oil from 50% of the OML. The relevant fiscal terms are set out in Table 2.

Table 2: Fiscal Terms – OML 130

	PSA (50%)	PSC (50%)
Royalty Oil	0%	0%
Cost Oil Limit	N/A	100%
Tax Oil	50%	50%
Profit Oil NNPC	N/A	30–65%*

* Sliding scale based on cumulative production.

be no less favourable than those of the original PSC signed in 2003 between the NNPC and Shell.

The structure of these back-in rights appears similar to the outcome of the NNPC's exercising of its back-in rights for the adjacent, and highly unusual, OPL 246 / OML 130. In that case, the indigenous Nigerian company (SAPETRO) held a 60% stake in the OPL. NNPC exercised its right to acquire 5/6 of the rights of SAPETRO. Following the NNPC's back-in, half the block was held on a sole risk basis (among private companies) and half the block was held under a typical PSC with the NNPC as the Concessionaire and SAPETRO as the Contractor (see Text Box 2).[20]

The third paragraph indicates that the FGN portion of past costs incurred by Shell and Eni following the allocation of the new OPL (the $1.3 billion costs associated with the RA) are to be cost recoverable within the FGN PSC. The result is that an additional $650 million would be added to the cost recovery pool and would be repaid to Eni and Shell through future cost oil.[21]

3.0 ASSUMPTIONS FOR BACK-IN ANALYSIS

Assumptions on back-in rights are drawn from the 2011 RA. Fiscal term assumptions are derived from the 2011 RA / 2012 PSA as well as the 2003 PSC signed between the NNPC and Shell. Production, cost and price assumptions are based on the original Resources for Development Consulting OPL 245 report.[22]

3.1 Back-in Rights Assumptions

This assessment of the economic costs and benefits to the FGN of taking up their back-in rights as set out in the RA is based on the following assumptions:

1. The FGN takes up 50% interest in OPL 245 as allowed by the RA.
2. The FGN pays Eni and Shell $870 million (50% of $1.3 billion plus interest at Libor +4%).[23]
3. 50% of OPL 245 is governed by a PSC between FGN and the Contractors (Eni and Shell).
4. The FGN has Concessionaire rights in the PSC while Shell and Eni are the Contractors.
5. The terms of the FGN PSC are those set out in the 2003 PSC between the NNPC and Shell.
6. Acquisition costs of $650 million (50% of $1.3 billion) are recoverable within the FGN PSC.
7. 50% of OPL 245 is governed on a sole risk basis (2012 PSA signed by Eni and Shell).
8. Production and costs are divided equally between the PSA and PSC contracts.

[20] For details on the structure of OPL 246 / OML 130, see Disclosable Transaction Relating To Acquisition Of Interests In Offshore Nigerian Oil Mining License, CNOOC, 2006.

[21] This is somewhat unusual as under the terms of the 2003 PSC, the Signature Bonus is identified as "non-recoverable" See Article 2.5 of the 2003 PSC.

[22] See Don Hubert, Government Revenues from OPL 245: Assessing the Impact of Different Fiscal Terms, Resources for Development Consulting, 2018.

[23] We assume "simple interest at the rate of 30-day LIBOR plus 4 per cent" based on the example of the award with interest for Shell and Esso in a dispute with the NNPC surrounding OML 133. See Court sets aside $2.5b judgment by Shell, Esso against NNPC, The Nation, 26 June 2017.

Based on the terms of the 2011 RA, we assume that the Block will be split (as is the case with OML 130) with 50% governed by the PSA between Shell and Eni and 50% governed by the FGN PSC (see Figure 2).

The PSA portion of the Block would continue to be governed by the terms set out in the 2011 RA and the associated 2012 PSA between Eni and Shell. There is no royalty due to water depth, there is no cost oil, government revenues would be limited to taxes, and all profit oil is split between Eni and Shell. We assume that the FGN PSC portion of the Block will be governed by the fiscal terms as set out in the 2003 PSC between the NNPC and Shell. This is a standard deep water PSC based on the model contract of 2000 and the Petroleum Profits Tax Act. There is no royalty assessed due to water depth. There is a cost oil allocation and no annual limit on cost recovery. The Petroleum Profits Tax is assessed, in deep water, at 50%. The government receives 30% of available profit oil based on the first 350 million barrels of production. The high-level fiscal terms governing the two halves of the Licence under the back-in scenario are set out in
Table 3.

Figure 2: OPL 245 Concessionaire and Contractor Rights with Back-in

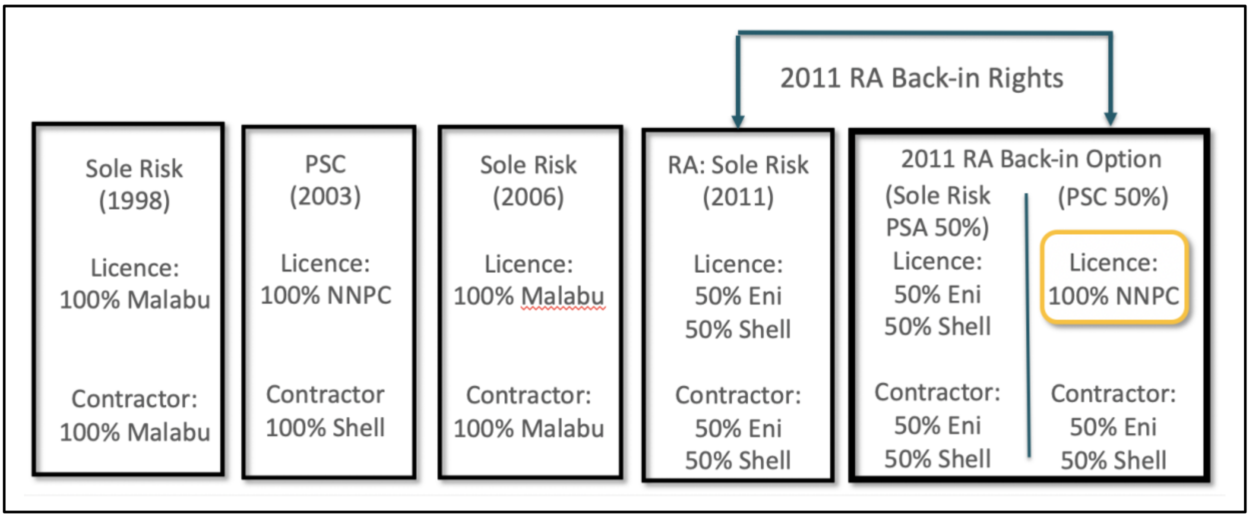

Table 3: Fiscal Term Summary for OPL 245 Back-in Scenario

	Eni Shell PSA (50%)	FGN PSC (50%)
FISCAL TERMS	2011 RA / 2012 PSA	2003 PSC
Royalty	0%	0%
Cost Recovery Limit	N/A	100%
Petroleum Profits Tax	50%	50%
Profit Oil to FGN	N/A	30%

3.2 Production and Cost Assumptions

Production, cost and price assumptions for this back-in analysis are the same as those used in Resources for Development Consulting's original study of OPL 245.[24]

[24] Government Revenues from OPL 245, Resources for Development Consulting, 2018.

Oil production assumptions are based on recoverable reserves of 560 million barrels. We assume Final Investment Decision 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.

Development costs are based on a 2010 Shell Proposal to Commence Negotiations[25] study that estimates the total project development expenses at $9.3 billion. These costs, when corrected for inflation to 2018, total $10.8 billion. Operating cost estimates are based on published information about Floating Production and Storage Offloading vessel (FPSO) leasing costs.[26] For the remaining operating costs, data was adapted from Ghana's Jubilee field, corrected for inflation.[27] 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.

The oil price used for the base case analysis is $70 per barrel (in 2018 money) based on World Bank forecasts of average crude oil price, adjusted for oil price differentials to Brent.[28] We also test the fiscal regimes against two higher oil prices: $85 and $100.

4.0 ECONOMIC RESULTS

Table 4 compares the 2018 Back-in scenario with the potential government revenues if OPL 245 was governed by the terms of the original 2003 PSC between the NNPC and Shell, and the terms contained in the 2011 RA / 2012 PSA.

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

	2003 PSC	2011 RA 2012 PSA	2018 Back-in	2018 Back-in No Repayment
Royalty	0	0	0	0
VAT and NDDC Levy[29]	1,086	1,086	1,086	1,086
Education Tax	596	596	596	596
Petroleum Profits Tax	8,072	8,072	8,072	8,072
FGN Profit Oil	4,592	0	1,932	1,932
RA Repayment	0	0	-870	0
Total Gov't Cash Flow	14,347	9,754	10,816	11,686
Government Take	60%	41%	45%	49%

[25] Shell Nigeria Ultra Deep Limited, Proposal to Commence Negotiations, 2010.
[26] Saipem Wins $5.42bn Contract for Zabazaba-Etan Devt Project in OPL 245, This Day, 20 November 2017.
[27] *A Step Change for Tullow and Ghana*, Tullow Oil, 1 October 2008, p. 75.
[28] 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.
[29] The Value Added Tax and the Niger Delta Development Commission Levy are both calculated from expenditures, rather than project revenues. They are included in the table in order to show overall government cash flow.

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As would be expected, the economic benefits to the government under the 2018 Back-In scenario fall between the 2003 PSC and the 2011 RA / 2012 PSA. In the "back-in" scenario, the government pays $870 million in order to reacquire Concessionaire rights that generate nearly $2 billion in government revenue over the lifecycle of the project. Overall government take rises from 41% to 45%. However, total government revenues are $3.53 billion less than they would have been under the 2003 PSC, and government take is a full 15% lower than the 2003 scenario. According to the International Monetary Fund, a mature oil producing country like Nigeria should expect a government take of 65% to 85%.[30]

In order to move beyond the current impasse, it is conceivable that the FGN could be offered back-in rights to OPL245 without the need for repayment of its share of the $1.3 billion. Obviously, this would increase government cash flow by $870 million. It would also increase the overall government take to 49%. Total government revenues, however, would still be $2.7 billion less than under the terms of the 2003 PSC.

Importantly, the government share of profit oil is substantially less than half of what it would have been if the 2003 terms governed the entire block. One-half of government profit oil under the 2003 terms would be $2,296 million. Profit oil from the 50% of the block governed by the FGN PSC would be $1,932: a difference of $364 million.

There are two reasons for this reduction in government profit oil. First, the government share of profit oil under the 2003 PSC increases from 30% to 35% when cumulative production exceeds 350 million barrels. While total recoverable reserves are estimated at 560 million barrels, with only half of that production (280 million barrels) governed by the PSC terms the threshold to the second level of the profit oil split is never reached. This results in a reduction of $169 million in government revenue. Second, Eni and Shell's remaining share of the upfront payment in the 2011 deal ($650 million) is cost recoverable within the FGN PSC. As this provision allocates additional cost oil to Eni and Shell, it results in a reduction in government revenue from profit oil of $195 million.

5.0 COMPANY RESPONSES

Shell and Eni were asked for their comments on the findings of this analysis, the assumptions used and the input data used in the model.

Shell noted that they believed that Resources for Development model included a wrongful factual assumption saying it did "not apply the capital allowance correctly in accordance with Second Schedule of the Petroleum Profits Tax Act." (PPT Act). Shell were invited to specify what they believed was incorrect or provide their interpretation of this point however they declined to provide further details.

Based on Shell's response, we have reviewed the capital allowance provisions In the Second Schedule of the PPT Act and have consulted with other experts. While we recognize that there may be other interpretations of these capital allowance provisions, we retain our original interpretation within our model and analysis as we believe it is in line with accounting practice and consistent with the PPT Act.

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

Shell did not comment further on the specific points put to them saying "In line with correct legal process, many of these issues will be considered by the court and we do not wish to interfere with those proceedings". They added that "We acted in good faith, in trying to unlock what had become a decade–long, intractable dispute, resulting from the FGN's allocation of the block to two parties - Shell and Malabu. The FGN of course had its own interest in resolving the disputes, which had hampered development of the block for many years, therefore preventing Nigeria from benefiting from any economic activity from OPL 245." Shell has also denied all allegations of criminality or wrongdoing in the deal.

Eni claimed in light of their ongoing trial Eni is "unable to disclose… information relevant for the pending proceedings, nor is it otherwise willing to publicly disclose data that are sensitive in nature." They noted that Eni appointed experts in court will "cover the significant benefits for Nigeria" from the deal and that it will be shown to be "transparent, lawful and beneficial for Nigeria".

6.0 CONCLUSIONS

Back-in rights normally allow the government to secure an equity stake, as a Contractor, alongside private oil companies. Back-in rights associated with sole risk contracts in Nigeria were designed to allow the NNPC to secure a 50% stake in a Licence where the indigenous Nigerian company holds 60% and the foreign partner holds 40%.

Licences allocated on a sole risk basis granted both Concessionaire and Contractor rights to the indigenous Nigerian company. These were the terms under which Malabu held OPL 245 from the initial allocation in 1998 and again following the reinstatement in 2006. Under the 2003 PSC with Shell, however, the NNPC held 100% of the Concessionaire rights while Shell held 100% of the Contractor rights.

The back-in rights as set out in the 2011 RA are not consistent with the provisions of the 2003 Back-in Regulations. First, they do not allow the government to acquire a 50% stake in the entire Licence. Rather, they allow the government to acquire a 50% of the Concessionaire rights, and therefore the associated share of profit oil. The provisions set out in the RA appear to be similar to those that govern the highly unusual OML 130 after NNPC backed-in to that Licence. Second, the back-in rights as set out in the 2011 RA are not based on the most recent model PSC employed in the 2005 and 2007 licencing rounds. Importantly, the 2005 model PSC terms included an 8% royalty in deep water. Rather, the RA references back to the more generous 2003 PSC signed between NNPC and Shell.

If the government were to exercise the back-in rights in the 2011 RA, the NNPC would hold 50% of the Concessionaire rights, while Eni and Shell would retain 50% of the Concessionaire rights as well as 100% of the Contractor rights. In order to exercise the back-in rights, the government would be required to pay for its share of the acquisition costs plus interest. Assuming that the government were to take up a 50% stake as provided for in the RA, we calculate that the government's share of the Signature Bonus and the 2011 payment, plus interest at Libor +4%, would be $870 million.

While the government would then hold 50% of the Concessionaire rights to OPL 245, this would generate substantially less than 50% of the government revenue from profit oil than would be generated under the 2003 NNPC Shell PSC. As only 50% of production is allocated through the FGN PSC, cumulative production never exceeds the first 350-million-barrel profit oil tranche. In addition, the 2011 RA allows the contractor to recover the remaining 50% of the Signature Bonus and 2011 RA payment. Combined, these provisions result in a reduction in revenue from government profit oil of $364 million.

Our original report on OPL 245 showed that, due to the loss of any government share of profit oil, future government revenues under the 2011 RA would be $4.5 billion less than under the terms of the 2003 PSC. If the government were to take up the back-in rights contained in the 2011 RA, future government revenues would still fall short of the revenues expected under the 2003 PSC by $3.53 billion. Even if the FGN were not required to repay its share of the 2011 payment, revenues would fall short of those generated by the 2003 PSC by $2.7 billion.

Although the NNPC and DPR protested against the 2011 RA, arguing that the government should retain Concessionaire rights to the Licence, these rights were granted to Eni and Shell. The back-in rights contained in the 2011 RA allow the government to reacquire only 50% of the Concessionaire rights, and at the cost of 50% of the $1.3 billion Resolution payment. Exercising these rights would provide them with substantially less than half of the future revenue from the Concessionaire rights that the NNPC already held under the 2003 PSC with Shell. The truncated back-in rights set out in the 2011 RA fall far short of the revenues that the government should receive from a deep water licence agreed in 2011.