Nigeria Oil and Gas Guide

Volume 1

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INTRODUCTION

Power industry experts have repeatedly emphasized the importance of gas as a veritable source of fuel for the Nigerian power sector. This is supported by the fact that 70% of Nigeria's power generation stations are thermal. It is therefore the case that any investor in power generation who desires to run a profitable business should develop a keen interest in the gas sector.

Nigeria has an abundance of gas (rich in liquid and low in sulphur) in gas reservoirs or produced along with oil as associated gas in the nation's Niger Delta region which makes Nigeria a country with the 9th largest gas reserve globally. Nigeria's gas reserves are also reported to exceed the countries' oil reserves thereby providing the country with an alternative source of fuel and national income.

Inspite of these statistics, a lingering challenge in Nigeria's path to power supply is the availability of gas for power generation. This section of the Guide analyses the gas to power challenge in view of the urgent need to find pragmatic solutions to the gas supply constraints.

GAS REQUIREMENTS IN THE NIGERIAN POWER SECTOR

Nigeria has an estimated 187 trillion cubic feet of proven natural gas reserves and 600 trillion cubic feet of unproven reserves. These reserves have remained grossly untapped and this has negatively impacted the power sector reforms undertaken by the Federal Government of Nigeria (FGN) and the plan of achieving the 40,000 Mw 2020 target.

Currently, the largest single consumer of natural gas in Nigeria is the power sector. Five (5) of the recently privatized Power Holding Company of Nigeria ("PHCN") power generation plants namely Ughellii, Geregu, Afam, Sapele and Egbin power plants are thermal generation plants and account for about 70% of the gas consumed domestically. The combined daily gas requirement of these plants at peak is estimated at 1500 million cubic feet per day ("mmcfpd"). This figure is set to increase when the 10 National Integrated Power Projects ("NIPP") gas power plants (which are currently being sold off to private investors and at several stages of completion) become operational.

Majority of the privatized PHCN thermal plants were and are still suffering from gas supply constraints and thus are unable to generate power at their optimal capacities.

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The recent postponement of the official commencement of the Transition Electricity Market ("TEM") by the Nigerian Electricity Regulatory Commission ("NERC") until the satisfaction of all expected conditions in the Nigeria Electricity Supply Industry ("NESI") has been attributed to the gas challenge in the power sector. TEM is a period where the electricity market would be governed by contracts between market participants across the value chain. Upon commencement of TEM:

- The Power Purchase Agreement ("PPA"), the Vesting Contract ("VC") and the Gas Supply Agreement ("GSA") will become effective and operational;
- The market rules will also become fully effective;
- The Nigerian Bulk Electricity Trading Company ("NBET") will step in as a counterparty to the Gencos and the Discos with respect to relevant industry contracts (that is the PPA and the VC);
- The Gencos will be assured of adequate gas supply since gas suppliers will be guaranteed of receiving due payments for gas supplied;
- The Nigerian Gas Company ("NGC") will be liable to pay liquidated damages for failure to fulfil its obligations to deliver gas to Gencos in accordance with the terms of the GSA signed between the NGC and some of the hermal Gencos (like Sapele and Geregu Gencos) in 2013.

Thus, the postponement invariably acknowledged that the issue of gas supply is a major constraint to growth of the power supply.

GAS TO POWER CHALLENGE

The power sector is estimated to require up to 3.5 billion cubic feet per day (bcfd) of gas, over the next three years and could require more than 5 bcfd when power plants under the NIPP scheme are privatized.

The inability to access gas for power generation has been attributed to infrastructure and pricing challenges as opposed to the absence of demand or supply. These issues are considered below:

Transportation Infrastructure

In Nigeria, the primary method of transporting natural gas from the point of production to domestic users is by pipeline. Thus, pipelines are a crucial infrastructure for the commercialization of gas reserves.

The NGC, a subsidiary of the Nigerian National Petroleum Company (NNPC), owns and operates the main pipeline transmission systems in Nigeria and acts as the major gas merchant. Other gas transportation pipelines, gas-processing facilities and other associated infrastructure are currently owned by individual upstream gas producers and are dedicated to their respective operations.

NGC's pipeline infrastructure comprises of two unintegrated pipeline networks: the Alakiri-Obigbo–Ikot Abasi Pipeline, otherwise known as the Eastern Network and the Escravos–Lagos Pipeline System (ELPS), also known as the Western Network. It is important to note that majority

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of the thermal generations plants are able to obtain gas from these pipelines by entering into agreements with the NGC to have their own pipelines keyed into NGC's pipeline network which are grossly inadequate to meet the needs of the domestic markets. The question that then comes to mind is "who is responsible for developing gas transportation infrastructure?" The answer to this question will either allocate responsibility to gas asset holders or the Federal Government of Nigeria ("FGN"). A number of plausible reasons why priority is not placed on investments in gas infrastructure by asset holders come to mind. Gas pipelines generally costs at least 4 times as much as oil pipelines and takes a longer time to complete; it is a lot cheaper for the IOC's to simply flare associated gas and concentrate efforts on oil production. Also, gas infrastructure investments may leave an investor exposed to politically inspired violence. The existing NGC pipelines have been a subject of recurrent vandalism.

GAS SUPPLY INFRASTRUCTURE FOR NDPHC POWER PLANTS		
S/N	NDPHC POWER PLANT	GAS INFRASTRUCTURE
1.	Benin Power Plant	18"x 1.2km Pipeline from ELP to the Ihovbor Pressure Reduction & Metering Station. 18"x 610m pipeline from Ihovbor PRMS to Benin Power Plant. 16"x 14km pipeline from Nigerian Petroleum Development Company, (NPDC), Oredo to the ELP.
2.	Calabar Power Plant	24 x 53 Km pipeline from Oron to the Calabar power plant.
3.	Egbema Power Plant	18"x 4km pipeline from SPDC/NPDC Egbema-East to Egbema Power Plant. 18"x 8km pipeline from SPDC/NPDC Egbema-West to Egbema Power Plant.
4.	Gbarain Power Plant	18"x 1.5km pipeline from SPDC Gas plant to Gbarain Power Plant.
5.	Geregu Power Plant	18"x1.5km pipeline from NGC Geregu to Geregu Power Plant.
6.	Ogorode Power Plant	16"x 810m pipeline from NGC Sapele to Sapele Power Plant
7.	Olorunsogo Power Plant	-
8.	Omoku Power Plant	18" x 1.5km Pipeline from NAOC Facility to the Omoku Power Station.
9.	Omotosho Power Plant	12"x 810m from NGC Omotosho to the Omotosho Power Plant

The question that then comes to mind is "who is responsible for developing gas transportation infrastructure?"

On the other hand, given its sovereignty and the exponential economic benefits that will be experienced by the power sector and the Nigerian economy as a whole, it appears that FGN is best placed to provide at a minimum, the backbone infrastructure. Attempts currently being made by FGN in this regard include the ongoing construction of the Calabar-Umuahia-Ajaokuta pipeline as well as the construction of the Aba-Enugu-Gboko pipeline. Work is also being done to increase the capacity of the ELPS from 1 bcf per day to 2.2 bcf per day (**Source:** Ventures Magazine 25th May 2012). Furthermore, a 24km gas transmission pipeline system from Owaza to NDPHC power plant at Alaoji, Abia State was recently concluded to aid gas supply to the NDPHC power projects across the country.

Vandalism Challenge

A major source of concern regarding the FGN's investment in gas pipelines is the issue of vandalism. The NNPC has labeled the incessant vandalism of gas pipelines as a national security challenge which calls for a major social re-orientation of the inhabitants of the people who live in areas where the gas pipelines are located. In other to address the menace of pipeline vandalism, the NNPC has installed modern technology to supervise major gas pipelines and indicate early breaches of the pipelines (**Source**: Dr. David Ige Group Executive Director Gas to Power NNPC, speaking at Detail Business Series).

Pricing Challenge

The current markets for Nigeria's gas includes the domestic and export markets. On the exports side, Nigeria appears to be doing relatively well with the country ranked as the 5th largest Liquidified Natural Gas ("LNG") exporter in the world in 2013. The profitability of export gas creates a preferential pull for the International Oil Companies (IOCs) and provides high returns to the FGN through tax receipts and dividends from their equity stake in gas production.

However, beyond the economic benefits derived from exports, the FGN recognizes that disproportionate focus on export LNG results in shortage of gas for domestic utilization and directly jeopardizes Nigeria's power sector development goals. From a profitability standpoint, an incentive for gas infrastructure development is a market driven gas price that guarantees return on investments. The NNPC recently acknowledged that domestic gas prices would increase by 2016 (**Source:** Business Day Newspaper, March 27 2014). The NNPC has put in place a strategy wherein the price of gas in the domestic market would be strategically increased to attain parity with the export price **(Source:** Dr. David Ige, Group Executive Director Gas to Power NNPC, speaking at Detail Business Series). This would be achieved by benchmarking the current price of gas with the export price and encourage more "willing buyer willing seller" transactions wherein private gas transactions would drive up the current prices to meet the export price.

Priority of International Oil Companies ("IOC") and Acreage of Gas:

Due to the stability of international oil prices and the current pricing structure of domestic gas, IOCs prioritize investments in the exploration of oil reserves over exploration of gas reserves.

It seems that the current situation of flaring associated gas will continue until such a

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time as major gas companies like Gazprom and British Gas enter into the Nigerian Market. A possible solution in this regard the passage of the Petroleum Industry Bill ("PIB") which would provide a clear line of sight on the gas policies of the FGN. This will assist new entrants into the gas sector as well as the current IOCs to make informed investment decisions and business plans for gas projects.

ATTEMPTS AT ADDRESSING THE GAS CHALLENGE IN THE POWER SECTOR

The Gas Master Plan:

The Gas Master Plan unveiled by the Federal Government in 2008 seeks to address the lingering issues in the gas sector and by extension, the gas issues in the Nigerian power sector. The Gas Master Plan recognizes the infrastructure gap and provides a fairly comprehensive solution to the problem.

The PIB's National Gas Transportation Network Code (The "Network Code"):

To ensure development of the domestic gas market, the PIB has incorporated provisions relating to a Network Code. The FGN reasoned that successful transportation of gas for power generation and other domestic use requires a set of rules geared towards setting a standard threshold as to the quantity and quality of gas that can be fed into gas pipelines.

The Network Code is to be implemented by the Downstream Petroleum Regulatory Agency ("DPRA") upon passage of the PIB.

"The Gas Master Plan unveiled by the Federal Government in 2008 ... recognizes the infrastructure gap and provides a fairly comprehensive solution to the problem."

FGN Intervention:

At a recent inter-ministerial press briefing involving the Minister of Petroleum Resources, the Minister of Power, the Governor of the Central Bank of Nigeria (CBN), the Group Managing Director of NNPC and Chairman of the NERC, the FGN revealed its plan to offset approximately N25 billion outstanding legacy gas related debts owed to gas suppliers by the defunct PHCN Gencos. It is expected that this will boost stakeholders' confidence in the gas sector, regarding their willingness to supply gas to power plants going forward.

Funding:

In terms of funding, the FGN is reported to have allocated US$ 450 Million out of the US$ 1 Billion Eurobond recently raised in July 2013 for gas infrastructure. The sum of US$ 8 Billion has also been earmarked by the government for full execution of the Gas Master Plan.

FGN has also indicated that the sum of US$550 Million had been released to the Sovereign Wealth Fund (SWF) managed by the Nigeria Sovereign Investment Authority (NSIA) for investment in the power sector. US$200 Million of this amount would be deployed into the Infrastructural Fund of the NSIA to finance gas to power investments with the private sector, while the balance of US$350 Million will go into a liquidity facility which NBET will manage on behalf of the Federal Government to boost investors' confidence in the power sector reform.

World Bank Incentives:

The World Bank has also set aside needed funds to guarantee the development of Nigeria's gas infrastructure and more specifically to support the power industry. In April 2013, the World Bank provided its first Partial Risk Guarantee ("PRG") for USD$145 Million to support Nigeria's gas sector and bring more electricity to Nigerian consumers. The PRG agreements in support of a Gas Supply and Aggregation Agreement ("GSAA") were signed between the World Bank and the now defunct PHCN, Egbin Power Plc, Chevron Nigeria Limited and Deutsche Bank. Under the GSAA, Chevron Nigeria Limited contrcated to supply gas to Egbin power plant, for a term of 10 years.

Private Sector Efforts/Investment Opportunities:

Accugas Nigeria Limited, Seplat and Oando Gas and Power are local companies actively involved in supplying gas to thermal plants located in the Niger Delta area of the country. Opportunities abound for more private gas companies to invest in the sector. Debt financing will be essential for raising the funding required in this regard. Financiers have stated a willingness to fund gas transactions where the project structure adequately addresses the following:

- A credit worthy offtaker of the gas must be identified;
- The price of gas must guarantee adequate returns on investment;
- Availability of the requisite infrastructure to transport the gas to the buyers.

Another opportunity for private sector involvement can be identified in the current clamor for the privatization of the NGC. A concession of the NGC to a private sector entity will invariably result in greater efficiency in the gas transportation and sales and thereby enable the government focus more on the regulatory aspect of the sector.

"Accugas, Seplat and Oando are local companies actively involved in supplying gas to thermal plants located in the Niger Delta area of the country"

GAS TO POWER FISCAL INCENTIVES

FGN has put in place policies to encourage the use of gas for power. One of such policies can be found in the form of an incentive created under the Companies Income Tax Act ("CITA") 2004. Section 39 of CITA provides tax incentives for companies engaged in gas utilization (defined to include its use in power plants). The incentives include a three-year tax holiday (with possible renewal for additional two years); accelerated capital allowances after the tax-free period; tax free dividend during the tax-free period; and tax deductibility of interest payable on any loan obtained for a gas project with the prior approval of the Minister of Finance.

In addition, there is also another incentive under the Industrial Development (Income Tax Relief) Act ("IDA") 2004. The IDA was enacted to promote and incentivize industries/products considered extremely pivotal to the development of the country and classified them as pioneer industries/products. The following incentives are available to companies that fall under a

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Ihovbor Power Plant (http://www.nipptransactions.com/wp-content/uploads/2013/02/Ihovbor-simple-cycle-451-MW-4-x-112.5-GE-frame-9E-CTs.jpg)

pioneer industry or that manufacture pioneer products:

- a tax holiday period of three years commencing on the production day with a possible extension for a maximum of two years;

- the capital expenditure on qualifying assets incurred during the tax relief period is treated as having been incurred on the first day following the tax relief period.

The Minister for Commerce and Industry (now Trade and Investment) on behalf of the President, issued the Industrial Development (Additional List of Pioneer Industries) Notice No. S. I. 11 of 2008 which included Utility Services industry as a pioneer industry and specifies that "Independent power generation utilizing gas, coal and renewable energy sources" is a pioneer product.

Other incentives include:

- 15% investment capital allowance which shall not reduce the value of the asset;

- All fiscal incentives under the gas utilization down-stream operations in 1997 are to be extended to industrial projects that use gas in power plants, gas to liquid plants, fertilizer plants and gas distribution/transmission plants;

- Gas is transferred at 0% ppt and 0% royalty;

- Interest on loans for gas projects is to be tax deductible provided that prior approval was obtained from the Federal Ministry of Finance before taking the loan;

- All dividends distributed during the tax holiday shall not be taxed.

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GAS AND POWER REFORMS: FUTURE OUTLOOK

The recent power sector reforms by the Nigerian government could potentially catalyze Nigeria into an industrial powerhouse.

Presently, it seems that the government and a few of the Independent Power Producers (IPP's) and the NIPPs are starting to align gas supply risks in their power projects and NERC is starting to show its flexibility to amend the electricity tariffs to accommodate commercial gas prices. New gas pipelines are being constructed to convey gas to power plants. Also, gas supply and transportation agreements are being made bankable and enforceable.

In the short term, the Nigerian government plans to increase the price of gas for power plants. The government hopes this would drive infrastructure investment in the sector and increase domestic supply by making the sector more attractive to investment. The planned increase is commendable.

From a profitability standpoint, an incentive for investment in gas supply is a market driven price that guarantees return on investments. An upward adjustment of the minimum price of gas is therefore inevitable and the invariable result will be an increase in electricity tariffs since the Multi-Year Tariff Order (MYTO) is reviewed bi-annually against certain indices – which include gas prices.

In addition, the Gas Infrastructure Blue Print should be implemented as a matter of urgency to emplace the proposed gas pipeline network which will connect off-takers in the eastern, western and northern parts of Nigeria to gas producers. The private sector can be involved in the construction, operation and maintenance of gas pipelines through bankable PPP's with the right mix of FGN guarantees, credit enhancement schemes and other incentives. An example of FGN support will be investment of Nigeria Sovereign Investment Authority's gas to power funds in private sector led gas infrastructure development initiatives.

CONCLUSION

Nigeria's gas to power challenge is not insurmountable. If Nigeria's power plants will live up to the current demand for power, access to natural gas must be guaranteed. Availability of gas is invariably linked to increased prices and higher operating costs for the thermal plants which will result in higher electricity tariffs.

From an investor's perspective, the current gas infrastructure deficit presents a viable investment opportunity for companies who decide to engage in the development of gas transportation pipelines, gas processing facilities and other associated infrastructure.

Source: http://rtecrtp.files.wordpress.com/2011/06/natural_gas_pipelines.jpg

THE NIGERIAN GAS MASTER PLAN

In 2008, the Gas Master Plan was developed as part of a holistic strategy to boost power generation through gas sector development. The Gas Master Plan aims at ensuring domestic gas affordability, availability and long- term supply security in a manner that delicately balances the need for revenue generation from gas exports and ensures the delivery of a fair rate of return on investments to both the user and supplier of gas.

The Gas Master Plan is a considered guide aimed at achieving the successful commercial exploitation and management of Nigeria's gas sector and comprises of: (a) the National Domestic Gas Supply and Pricing Regulations (the **"DSO Regulations"**) (b)) the National Domestic Gas Supply and Pricing Policy (the **"Gas Pricing Policy"**) (c) the Nigerian Gas Infrastructure Blueprint (the **"Blue Print"**). Each aspect of the Gas Master Plan is discussed under relevant headings below.

Domestic Supply Obligations:

The objective of the DSO Regulations is to ensure availability of gas for domestic utilization. The DSO Regulations impose an obligation on every person licensed to produce petroleum ("asset holders") to dedicate a specific volume of gas towards domestic gas demand requirement and to deliver gas to a purchaser in accordance with specified nomination procedure. Clause 5 of the DSO Regulations also:

- Empowers the Minister of Petroleum Resources to stipulate the requisite amount of gas to be set aside periodically by asset holders.
- Mandates oil and gas producers to comply with their obligations or face penalty or restricted export of its
- Establishes a Department of Gas within the Ministry of Petroleum Resources that will oversee the execution of the DSO Regulation in conjunction with the Department of Petroleum Resources (DPR).

It should be noted that the DSO was created to cater majorly for the PHCN successor companies and the NIPPs. Thus the DSO is an interim measure to ensure the availability of gas in the power sector. The "willing buyer, willing seller" structure will drive the gas sector ultimately giving the buyers the discretion as to who they can purchase gas from. (**Source:** Dr. David Ige, Group Executive Director Gas to Power NNPC, speaking at Detail Business Series)

The Gas Pricing Policy:

The Gas Pricing Policy is an attempt to create a favourable pricing regime for indigenous purchasers of natural gas. The Policy categorizes domestic demand into three broad groups. These groupings are:

- **The Strategic Domestic Sector**: this refers to a limited set of sectors that have a significant direct multiplier effect on the economy, namely, the power sector (residential commercial users). This sector is under a regulated pricing regime which will be determined on cost-of- supply basis;
- **Strategic Industrial Sector**: this refers to industries that utilize gas as feedstock in the production of value-added products that are primarily destined for export such as methanol, Gas to Liquids ("GTLs") and fertilizer. This sector partakes in a pseudo regulated pricing regime on product net-back prices; and
- **Commercial Sector**: this refers to sectors that use gas as fuel and includes manufacturers of cement or steel and heavy industrial users of power. Entities in this category are considered potential major revenue earners in view of their capacity to bear high gas prices.

It is important to note that the Gas Pricing Policy does not fix prices for the sale of gas; it merely sets out the indices for ascertaining the floor price for dry gas supplied to different sections in the domestic market. However, by virtue of section 2 (5) of the DSO Regulations the Department of Gas within the Ministry of Petroleum (DPR) is empowered to establish the floor price or aggregate price as a basis for gas supply to the domestic sector. The 3 approaches for determining the floor price include:

- **The Regulated Pricing Regime (Cost of Supply basis)**. This applies to the strategic domestic sector. The floor price for this category is determined by establishing the lowest cost of supply that allows a 15% rate of return to the supplier.
- **The Pseudo- Regulated Pricing Regime (Product Netback basis)**. This applies strictly to strategic industrial sectors. In this group, the floor price is not based on the cost of supply of gas but on the netback of the product price i.e. long run price of the finished product. The intent is to ensure that feed gas price is affordable to ensure competitiveness of manufactured products in the international markets.
- **The Market led Regime (alternative Fuels basis).** This floor price determination approach applies to all other sectors that use gas as fuel or wholesale buyers buying gas for subsequent resale. For this category, the price of gas is indexed to the price of alternative fuel such as LPFO. The indexation will be established during negotiation.

Gas Infrastructure Blueprint:

The Gas Infrastructure Blueprint ("the Blueprint") is a robust gas infrastructure layout which seeks to ensure connectivity between the major gas reserve sources and the demand centers through Central Processing Gas Facilities and a pipeline network. At these central processing gas facilities, processes for the extraction of gas will also be available and the recovered products will be supplied to the domestic market through available infrastructure.

The Central Gas Gathering and processing facilities as designed in the Blueprint is proposed to be located at (i)

Source: http://sweetcrudereports.com/wp-content/uploads/2014/04/Oandos-128-Km-gas-pipeline.jpg

Warri/Forcados area; (ii) the Akwa Ibom/Calabar area and (iii) the Obiafu area.

It is also important to note that 3 franchise areas will be delineated around these central processing facilities, thus only licensed investors within a franchise area will be allowed to develop and operate the facility, thereby preventing proliferation of gas facilities with attendant cost impacts.

The Blueprint further provides for the development of 3 major domestic gas transmission systems that will transmit gas to demand areas across the country:

A. The Western Transmission System:

This network comprises of the existing Escravos Lagos Pipeline System ("ELPS") which would connect from Lagos and runs through the western states (from Sagamu in Ogun State) to terminate at Jebba (Kwara State). The key market for this network will be the domestic market, feed industrial and residence demands and also the West Africa Gas Pipeline. Expected gas throughput is 3,250MMscf/d.

B. The South-North Gas Transmission System:

This will take dry gas from Akwa Ibom/Calabar Central Gas Gathering and processing facility to Ajaokuta, Abuja, Kano and Katsina. The line will also serve the Eastern states of Anambra, Abia, Ebonyi, Enugu and Imo. This pipeline is also expected to convey gas for the proposed Trans-Sahara gas project. Expected throughput at peak is 3800MMscf/d.

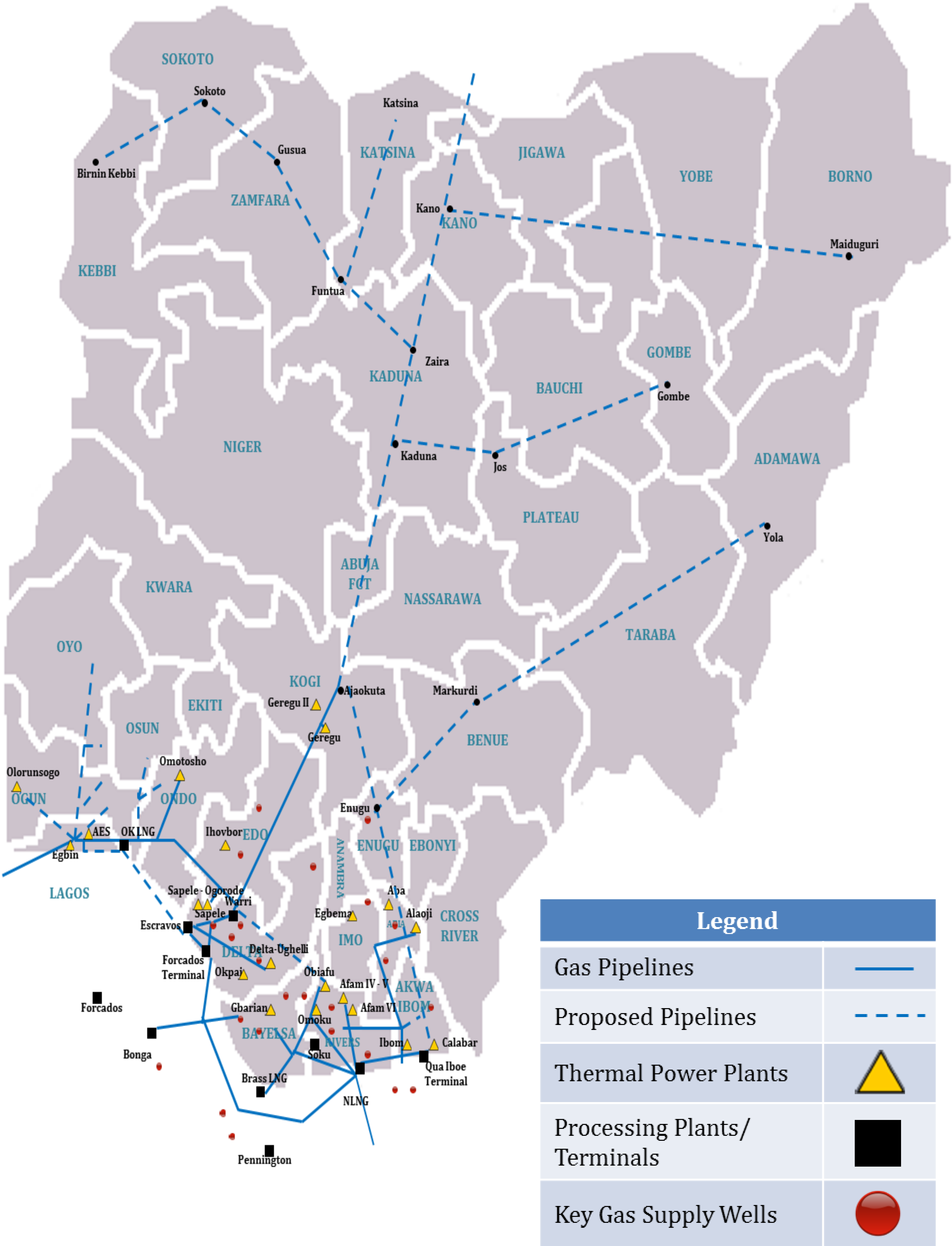
The proposed construction of the South- North Gas Transmission System will be undertaken using a public private partnership structure. This avails private sector entities an opportunity to participate in the transaction. (**Source:** Dr. David Ige, Group Executive Director Gas to Power NNPC, speaking at Detail Business Series).

C. The Interconnector System:

This network is expected to link the Eastern gas fields with the other transmission systems.

It is anticipated that this transmission infrastructure will enable the industrialization of the Eastern and Northern parts of Nigeria and enable connectivity between the East, West and North which currently does not exist.

EXISTING PIPELINE NETWORK



2. UPSTREAM ASSETS DIVESTMENTS IN NIGERIA

BACKGROUND

Industry experts estimated that by the end of 2013, International Oil Companies (**IOCs**) operating in Nigeria would have sold at least 300,000 barrels per day (bpd) worth of equity in onshore and shallow-water producing assets in the Niger delta region. There have been speculations regarding the reasons for the divestments and the strategy of the IOCs in this regard. This section of the Guide seeks to assess the key issues relating to the ongoing divestments .

DIVESTMENT HISTORY

The divestments started in 2006, when an oil and gas services contractor - Willbros Group discontinued its operations in Nigeria and sold its assets for $155.3million to Ascot Offshore Nigeria Limited. This was done notwithstanding Nigeria accounting for about 25% of the company's global revenue in 2004.

SPDC, the current largest oil producer in Nigeria also launched its divestment programme in 2010 with the joint divestment of 45% participating interests in OML 26 by Shell, Total E&P Nigeria Ltd, and Nigeria Agip Oil Company (together **SPDC JV**) to First Hydrocarbon Nigeria Limited (FHNL). SPDC has received estimated cash proceeds of over $2 billion from the divestment of its interests in eight OMLs operated in the Niger Delta to indigenous Nigerian companies. These assets include OMLs 30, 34, 40, 26, 42, 4, 38 and 41. In October 2013, the SPDC JV put up 45% interests in each of OMLs 18, 24, 25 and 29 for sale; these OMLs have a combined production capacity of 70,000 bpd.

Other divestees include Conoco Phillips which sold its 17% stake in the Brass LNG project, as well as its upstream assets to Toronto-listed Oando Energy Resources. Chevron is also currently in the midst of a divestment programme involving 5 shallow water blocks namely OMLs 52, 53, 55, 83 and 85.

KEY ISSUES RELATING TO THE DIVESTMENTS

Some of the key issues relating to IOC divestments are discussed below:

Minister's Consent

Valid transfers or assignment of interests in oil mining leases in Nigeria require the Minister of Petroleum Resources' consent by virtue of paragraph 14, First Schedule of the Petroleum Act. However, the Minister may refuse to grant consent unless the proposed assignee:

- is of good reputation;
- has sufficient technical knowledge, experience and financial resources;
- is in all respects acceptable to the Federal Government.

Ministerial consent requirement has caused delays in some of the divestment transactions as witnessed in OMLs 60 – 63 & 131, where it took about 12 months to obtain consent. The implication of this delay can be far reaching in view of the fact that ministerial consent is often a key transaction milestone, particularly from the perspective of lenders.

Prior to the decision in *Moni Pulo Limited v. Brass Exploration Limited and 7 Others*, a method employed to circumvent the need for ministerial consent was the transfer of shares in the company which holds the rights or interests in an oil mining lease or licence. However, following the Federal High Court's decision in Moni Pulo's case, it is now clear that ministerial consent is a mandatory requirement and its absence renders an assignment transaction inchoate.

NNPC's pre-emptive right

The Joint Operative Agreements (JOA) between NNPC and its joint venture partners contain pre-emption clauses. This presupposes that for a valid divestment, NNPC must be afforded the "opportunity" to exercise its right of pre-emption and must waive this right.

One of the major issues that needs to be addressed prior to a buyer's commitment to the divestment process is the manner in which NNPC will be engaged to secure its requisite approval.

Transfer of Operatorship to NNPC

In cases where the divesting party is the Operator of the asset, the JOA gives the non -operators the right to decide on an Operator for the relevant asset going forward. This contractual provision can be interpreted to mean that an assignment of interests by all joint venture partners excluding NNPC effectively transfers the decision of operatorship to NNPC.

The usual assumption by bidders is that NNPC will waive its right to assume operatorship. However, as witnessed on the divestment of OMLs 30, 34, 40 and 42, NNPC has in some instances decided to exercise its right to operate the blocks through its upstream arm, the Nigeria Petroleum Development Company (NPDC). This posed a great challenge because foreign financiers were wary of financing such acquisitions due to perceived operator risks. This issue stalled the completion of these transactions considerably.

Financial Structure

Raising acquisition financing is a front burner issue in the divestment process. Available options in this regard include debt or equity financing and the preferred option is largely dependent on issues such as availability of security and transaction timelines.

From a debt standpoint, availability of security is critical. Typically, the preferred bidder is a special purpose vehicle (SPV) with no historicals or assets that can be used as security. Lenders will typically seek parent company guarantees and personal guarantees from the sponsors of these SPVs. However, a viable structure for raising non-recourse debt finance is Reserve Based Lending which collaterizes the facility by the value of the assets which are to be acquired by the borrower.

Acquisition financing can also be raised from equity contributions or shareholder loans. Usually, such shareholder loans will be subordinated to the rights of the lenders under the Facility Agreement and intercreditor arrangements may be required in this regard.

Divestment Litigations in Nigeria

Given the lengthy time frame for concluding litigation cases in Nigeria and the overall effect which this will have on the divestment timelines, potential litigation is a major source of concern

A typical example of a delayed transaction arising from litigation is Chevron's divestment of OMLs 52, 53 and 55 in 2013. Brittania-U instituted a legal action challenging

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Seplat's emergence as the preferred bidder on grounds that Brittania-U was the highest bidder, offering $1.015 billion, while Seplat and its partners came second with an offer of about $900 million . The Federal High Court recently granted an interim injunction restraining Chevron Corporation of the United States and its Nigerian subsidiary, Chevron Nigeria Limited or their agents from negotiating the sale of the OMLs to Seplat or any other bidder, apart from Brittania-U Limited.

The delay in achieving completion of this transaction continues; Seplat has filed an appeal to challenge the ex-parte order of the Federal High Court and the Court of Appeal has reserved its ruling on the appeal challenging the ex-parte order.

CONCLUSION

The current wave of divestments by the International Oil Companies portend great benefits for Nigeria as it represents the single largest opportunity for indigenous companies to ascend to the league of major upstream players .

DIVESTED ASSETS *

Divesting Company	Asset	Production (bopd)	Equity	Status	Acquirer/Preferred Bidder
Chevron	OML 52	n/a	40%	Ongoing	Ongoing
Chevron	OML 53	3,500	40%	Ongoing	Ongoing
Chevron	OML 55	3310	40%	Ongoing	Ongoing
Chevron	OML 83	n/a	40%	Ongoing	Ongoing
Chevron	OML 85	n/a	45%	Ongoing	
SPDC, NAOC and Total	OML 4	n/a	45%	Completed	Seplat Petroleum
SPDC	OML 13	n/a	30%	Ongoing	Ongoing
SPDC	OML 16	n/a	30%	Ongoing	Ongoing
SPDC, NAOC and Total	OML 18	21,000	45%	Ongoing	Ongoing
SPDC, NAOC and Total	OML 24	25,000	45%	Ongoing	Ongoing
SPDC, NAOC and Total	OML 25	33,000	45%	Ongoing	Ongoing
SPDC, NAOC and Total	OML 26	6,010	30%	Ongoing	First Hydrocarbon
SPDC, NAOC and Total	OML 29	62,000	45%	Ongoing	Ongoing
SPDC, NAOC and Total	OML 30	15,600	45%	Completed	Heritage Oil
SPDC, NAOC and Total	OML 34	15,000	45%	Completed	ND Western
SPDC, NAOC and Total	OML 38	50,000	45%	Completed	Seplat Petroleum
SPDC, NAOC and Total	OML 40	2,500	45%		Elcrest Nigeria Limited
SPDC	OML 41	n/a	n/a	Completed	Seplat Petroleum
SPDC, NAOC and Total	OML 42	12,000	45%	Completed	Neconde Consortium
SPDC	OML 71	n/a	30%	Ongoing	Ongoing
SPDC	OML 72	n/a	30%	Ongoing	Ongoing
Philips Oil	OML 60	43,000	20%		Oando Energy Resources
Philips Oil	OML 61		20%		
Philips Oil	OML 62		20%		
Philips Oil	OML 63		20%		
Conoco E&P	OML 131		95%		
Philips Deepwater	OPL 214		20%		
Total	OML 138	100,000	20%		Sinopec

***SOURCE: Ecobank Research - IOC divestments in Nigeria: Opportunities, Challenges and Outlook –August 2013**

2. UPSTREAM ASSETS DIVESTMENTS IN NIGERIA

TYPICAL DIVESTMENT PROCESS CHART

PROCUREMENT PHASE

a. Seller invites prequalified bidders to submit bids for acquisition of participating interests in specified asset(s)

b. Bidders evaluate and conduct legal, financial, environmental and technical due diligence on asset(s)

c. Bidders raise equity/or debt financing for the bid deposit representing a percentage of the Consideration

d. Submission of bids and payment of bid deposit by the Bidders

e. Evaluation of bids by the Seller

COMMERCIAL NEGOTIATION PHASE

a. Notification of preferred bidder (Buyer)

b. Commercial issues such as offtake arrangements, transition operations, provision of technical services, straddled field arrangements etc. are negotiated by the Seller and the Buyer

c. Buyer raises equity and/or debt financing for the balance of the Consideration

d. Sale & Purchase Agreement is executed

e. Parties commence fulfilment of all Conditions Precedent to completion of the transaction

NOTIFICATIONS OF OTHER JV PARTIES

a. Waiver of pre-emption rights by NNPC and other JV partners

b. Apply for and obtain NNPC and other JV partners' consent to the divestment

REGULATORY/GOVERNMENTAL APPROVAL

a. Submit application to the Ministry of Petroleum Resources through the Department of Petroleum Resources (DPR) for consent to assign Seller's participating interests

b. DPR conducts Due Diligence on the Buyer to determine reputation, technical knowledge, experience and financial resources

c. DPR makes recommendation to the Minister

d. Minister consents to transfer of participating interest

TRANSACTION CLOSE

The Consideration is transferred to the Seller and title is transferred to the Buyer

3. MARGINAL FIELDS LICENSING ROUND – KEY ISSUES

INTRODUCTION

The Nigerian marginal fields regime was established by the Federal Government of Nigeria (FGN) in its bid to encourage indigenous participation in the Nigerian oil and gas industry. The first licensing round, conducted by FGN in 2003/2004 led to the successful award of 24 marginal fields to 31 indigenous companies. Recent figures suggest that marginal fields contribute around 2% of Nigeria's total oil and gas output. (**Source:** Mr. George Osahon, Director, Petroleum Resources, said speaking at the Society for Petroleum Engineers, SPE, 2013 Nigerian Annual International Conference and Exhibition, NAICE, in Lagos).

The 2003/2004 operators and farmees encountered various financial and technical challenges in bringing the marginal fields to first oil. The recent announcement of the 2013/2014 Licencing Round has brought these challenges to the fore and has once again made marginal fields a topical issue.

What is a Marginal Field?

A marginal field is any oil field in which available ***reserves*** do not make it commercially viable for the holders of Oil Mining Leases ("OML"), typically the International Oil Companies ("IOCS") to develop. Such fields are located within existing OMLs operated by IOCs and are left dormant for a considerable amount of time.

Due to the economics involved in petroleum exploration, marginal fields are unattractive to IOCs but can be viable investments for Indigenous Petroleum Exploration Companies ("INDICOs") who have significantly smaller operating budgets.

"One of the major issues faced by the 2003/2004 awardees was attaining a sufficient level of financial capability prior to farming into the fields since they had only obtained bridge financing for asset acquisition."

Statutory Basis for Award of Marginal Fields

The Petroleum Act ("the Act") forms the basis for the farm out of Marginal Fields. Under the Act either the President or a leaseholder with the approval of the President may farm out a Marginal Field from an OML.

Marginal Fields are defined by the Act as "such field(s) as the President may, from time to time, identify as a marginal field". In addition, the Guidelines expand the definition of a marginal field to include "any field that has (oil and gas) reserves booked and reported annually to DPR and have remained unproduced for a period greater than 10 years".

Such fields may be characterized by high viscosity crude oil, high gas and low oil reserves, or may be previously producing fields that have been abandoned for over 3 years by the leaseholder for economic or operational reasons.

Challenges faced by Previous Awardees

One of the major issues faced by the 2003/2004 awardees was attaining a sufficient level of financial capability prior to farming into the fields since they had only obtained bridge financing for asset acquisition.

Also, many operators have suffered setbacks due to a lack of technical expertise. Compounding this issue is the lack, in some cases, of the necessary associated infrastructure to develop the fields, thereby leading to increased costs and delays in production.

It now appears that the initial valuations of reserves may have been overly optimistic. Many of the fields suffer from low reserve level, making such fields commercially unviable for development. As such, operators face an uphill battle in their attempt to recoup their acquisition and development investments .

2013/2014 LICENSING ROUND

In November 2013, the Minister of Petroleum Resources announced FGN's intention to commence the 2013 Marginal Fields Licensing Round ("Licensing Round"). Following this announcement, the Department of Petroleum Resources ("DPR") released the Guidelines for Farm out and Operation of Marginal Fields ("the Guidelines"), as well as Pre-qualification, Technical and Commercial Field-Specific Bid Submission Requirements ("the Requirements").

In spite of the timelines provided in the Guidelines, the Licensing Round is yet to commence. One major cause of delay is the selection of the fields to form part of the bid; DPR is still liaising with the various leaseholders regarding potential marginal fields.

"...current operators have suffered setbacks due to a lack of technical expertise. Compounding this issue is the lack, in some cases, of the necessary associated infrastructure to develop the fields, thereby leading to increased costs and delays in production."

PRACTICAL CONSIDERATIONS

A number of issues must be considered by prospective bidders looking to acquire marginal fields. These issues are elaborated below:

- ***Valuation Challenges*:** The valuation of the reserves in a marginal field will undoubtedly be an issue of paramount importance as the available reserves may form the basis for ascertaining the bid price. Since there are no indications that bidders will be given an opportunity for physical inspection of the marginal fields, steps must be undertaken to conduct independent investigations to ensure appraisals are well informed and commercial bids are well priced based on the attendant risks.

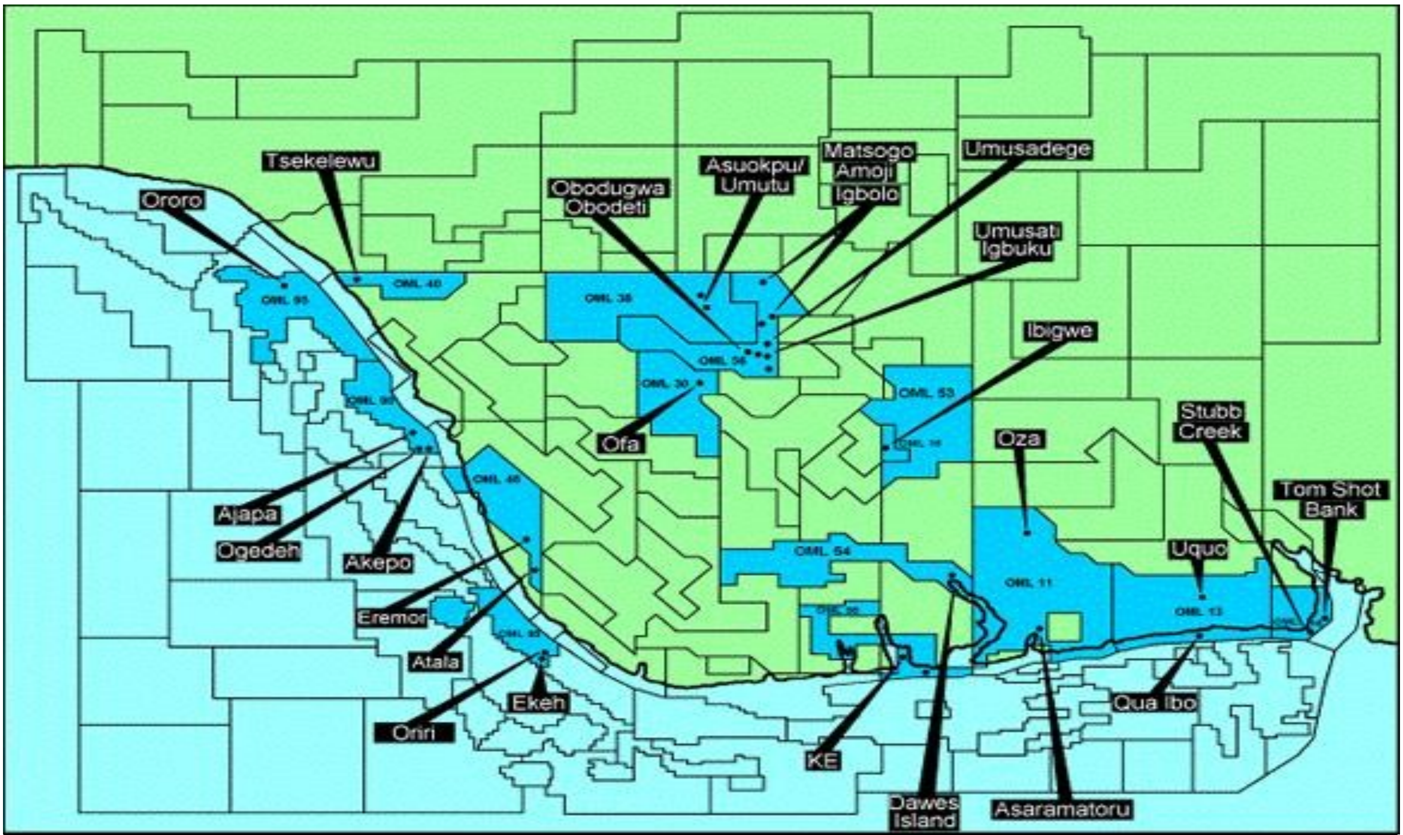
- ***Technology***: Marginal fields sometimes require unconventional technical expertise for development. Bidders must ensure that their technical bids cover the utilization of enhanced oil-recovery schemes like gas injec-

3. MARGINAL FIELDS LICENSING ROUND – KEY ISSUES

tion and Plasma-Pulse (similar to gas injection), horizontal drilling and fracking (injecting fluid into the ground to create cracks that provide access to more oil and gas reservoirs) to extract the maximum potential from the fields. The adoption of unconventional methodologies effectively leads to potential downtime in procuring requisite technical expertise. To mitigate this risk, bidders should leverage on alliances with foreign partners that can provide the relevant expertise.

- ***Joint Operating Agreement***: Bidders must also be prepared to negotiate a Joint Operating Agreement if the fields are awarded to more than one company. Previous bid rounds set precedent for random pairing of bidders to share an asset. Such circumstances pose a risk as parties have to conduct joint operations with companies with which they have no previous working relationship and no aligned interests.

- ***Shared Facilities***: An offshoot of marginal field operations is that the awardee will, for economic reasons, most likely utilize existing facilities of the oil mining lease holder at a fee (ullage fee). Though the process of determining ullage fees is a commercial issue, the DPR is empowered under the Guidelines to adjudicate in situations where leaseholders and awardees disagree on applicable ullage fees.



Niger Delta Marginal Fields (http://sweetcrudereports.com/wp-content/uploads/2013/12/Marginal-fields.jpg)

FINANCIAL CONSIDERATIONS

The ability of prospective bidders to secure adequate funding for the acquisition of marginal fields and its development to the point of production is pertinent. The Guidelines and Requirements clearly state that bids shall be evaluated with a view to accessing parties' ability to promptly and efficiently develop the field. Thus, interested companies must ensure that funding issues are properly addressed not only as a pre-requisite for submitting a viable commercial and technical bid, but to ensure that it can develop the field expeditiously after the award. Some financial issues to be considered by prospective bidders include:

- ***Acquisition Costs**:* As stated in the Guidelines, a key component in the award process for marginal fields is the payment of a signature bonus of US$300,000 within 120 days of the award of the field. Failure to pay this bonus can lead to the revocation of the award by FGN. Interested companies must secure this sum in addition to other acquisition and development costs to mitigate the risk of revocation.

- ***Cost of Development**:* It has been said that a marginal field in the Niger Delta Basin can cost about $US40 to $US70million to develop in the initial years to first oil and as much as $US6 per barrel may be expended to extract petroleum. Reliable projections on development costs and an understanding of the intricacies of marginal field operations may be a success factor for bids as such matters will be assessed during evaluation.

- ***Leverage on Foreign Partnerships***: The traditional modes of funding Marginal Field acquisition and development is via bank financing and partnership with foreign financial partners. Inviting foreign financial partners has become inevitable as Nigerian lenders are unwilling or unable to provide finances because most indigenous companies generally lack currently producing assets, which can be used as security for finance.

- ***Commodity Trading Houses**:* Bidders

3. MARGINAL FIELDS LICENSING ROUND – KEY ISSUES

can partner with Commodity Trading Houses to secure development funding. These institutions may provide finance in exchange for the chance to offtake crude oil from the field as was done by Glencore in 2013 via an Exclusivity Off-take Agreement with Sirius Petroleum for the Ororo Marginal field in OML 95 (farmed out by Chevron).

- ***Reserve Based Lending:*** Some lenders may be willing to provide financing under a reserve base lending structure, which involves a non-recourse loan based on the expected present value of future production from the fields in question. Taken into account will be factors such as the level of available reserves, expected oil price, a discount rate, assumptions for operational expenditure, capital expenditure, tax and any price hedging employed. Such funding is potentially attractive to specific lenders, who may eventually want to syndicate or securitize the debt.

OUTLINE OF AWARD PROCEDURE BASED ON THE GUIDELINES AND REQUIREMENTS

Submission of Applications

The prescribed application forms have not been made available to the public despite the DPR's notification that the Licensing Round will proceed as scheduled. Also, provisional timelines set by the DPR for application submissions have lapsed. Interested companies have to wait till definitive deadlines are issued

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Prequalification

Only Nigerian registered companies having at least 51% of the beneficiary interest being held by Nigerians are eligible for prequalification. Furthermore, the company's objects must be limited to exploration and production. Interested companies must have a minimum of 4 promoters, with no promoter owning more than a quarter of the company's equity and at least one shareholder must have experience in the oil and gas sector.

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Bid Submission

Pre-qualified bidders will be able to access the Online and Physical Data Rooms, after which they will declare their interest in select fields, with no more than three (3) fields of interest per company. Upon review of relevant data, pre-qualified companies shall submit field-specific technical and commercial bids in prescribed form.

←

Bid Evaluation

Bids will be evaluated by a Selection Committee comprising of DPR, leaseholder representatives and financial consultants. Recommendations on potential awardees will be made to the Minister of Petroleum and the President and successful applicants will be notified by DPR.

↓

Negotiation

Upon award of a Marginal Field, successful applicants will be obliged to begin negotiations with leaseholders on the terms and conditions of the Farm - Out Agreement, such negotiations should be concluded within 90 days of the award.

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Renewal

After consent is granted to the Farm – Out Agreement, the Farmee will have 24 months to show verifiable evidence of efforts made to progress the work on the fields according to approved plan. If not, the Minister of Petroleum shall, on the recommendation of the DPR, withdraw the award of the field and void the Farm-Out agreement.

4. RESERVE BASED LENDING AS A FINANCING OPTION FOR LOCAL OIL AND GAS COMPANIES

INTRODUCTION

Continuing divestments of oil and gas assets by the International Oil Companies ("IOCs") in favour of bigger and more secure offshore blocks as well as the marginal field licensing rounds have led to the emergence of a growing number of indigenous operators as key players in the oil and gas industry.

An important consideration for potential and current investors is the funding options that are available for acquisition and development of the acquired assets. This section of the Guide evaluates reserve based lending as a viable option in this regard.

RESERVE BASED LENDING

Background

Also known as borrowing base financing, Reserve Based Lending (RBL) originates from the US lending market. RBL has become a popular choice for oil and gas companies that do not have the track record to qualify for more traditional types of financing.

RBL is a generic term used to describe a loan arrangement unique to the oil and gas sector whereby a facility is collateralized by the value of the borrower's hydrocarbon assets. It is a hybrid of corporate, project and asset-based financing which involves lending on a non-recourse basis against a portfolio of upstream development or producing (usually proven) hydrocarbon assets (i.e. the borrowing base) where the amount of the available facility is determined based on the underlying value of such assets.

In 2010, Nigerian banks (Stanbic IBTC Bank and First City Monument Bank) provided a 5-year senior secured acquisition and reserve based lending facility of up to $230 million to First Hydrocarbon Nigeria Limited for the acquisition and development of OML 26 under the Shell divestment. Spurred by the success of this pioneer RBL transaction, Nigerian lenders now consider RBL as a viable financing option for the Nigerian oil and gas market.

Borrowing Bases

Typically, specialist reservoir engineers are engaged by the technical bank (acting on behalf of all the lenders) to produce detailed forecasts based on the estimated value of the available reserves, expected oil prices and a number of other economic and financial factors. Using these forecasts, the technical bank will calculate the borrowing base i.e. the expected net present value (NPV) of the future production from the fields in question.

"RBL is a generic term used to describe a loan arrangement unique to the oil and gas sector whereby a facility is collateralized by the value of the borrower's hydrocarbon assets."

The borrowing base amount will typically be somewhere around 50% to 70% of evaluated assets. This percentage valuation is used to provide the bank with some cover in the event that prices fall or estimated reserves fall short. This cushion also helps the lenders to recover any additional costs that might be incurred in connection with enforcement proceedings. RBL transactions are tightly structured to ensure that the borrowing base always exceeds the finance; lenders require regular updates regarding the borrowing base. To this end, semi-annual reserve reports are provided by the reservoir engineers to account for the fluctuation in value of the asset portfolio.

Revolving Facilities

Once the borrowing base amount is agreed on, the technical bank and the other lenders decide the aggregate commitment which will be made available to the borrower in form of revolving loans. The amount available for drawdown by the borrower is usually the lesser of the borrowing base amount and the lenders' aggregate commitment.

Typically, to ensure diversification and lessen the reliance on the performance of any one field or reservoir, assets can be brought into and taken out of the borrowing base ring fence, subject to pre-agreed conditions. As reserves reduce over time, the available revolving facility will amortize in accordance with the projected production of the relevant asset(s). The level of committed facility made available to the borrower will be in line with any adjustment to the borrowing base.

RBLs are traditionally forward looking based on projections and not back ward looking based on accounts. Therefore, the facility agreement typically emphasizes cover ratios such as project life ratio, loan life ratio and debt service cover ratio as opposed to financial covenants. These ratios drive debt capacity and repayment under the facility agreement.

SECURITY REGIME UNDER NIGERIAN LAW

Like any other financing transaction, security is a fundamental issue in RBL. A key legal consideration for any RBL lender is the security regime in the jurisdiction where the borrowing base assets are located. Security options available to RBL lenders and the challenges associated with these options under Nigerian law are considered below.

Assignment of Participating Interests in an Oil Mining Lease

The federal government of Nigeria owns and controls all petroleum resources within Nigeria. A typical title held by industry participants is an Oil Mining Lease (OML), which is limited to participating interests in the petroleum resources discovered in the geographical area covered by such lease. Prior consent is required from the Minister of Petroleum Resources for the assignment or transfer of an OML or any associated right, power or interest therein.

A key legal consideration for any RBL lender is the security regime in the jurisdiction where the borrowing base assets are located.

In practice, this provision is interpreted as requiring ministerial consent for the assignment of legal title to an oil mining lease by way of security for an RBL transaction. Requisite consent shall not be granted unless the Minister is satisfied that the proposed assignee:

4. RESERVE BASED LENDING AS A FINANCING OPTION FOR LOCAL OIL AND GAS COMPANIES

- Is of good reputation or is a member of a group of companies with good reputation;
- Has access to sufficient technical knowledge and experience and sufficient financial resources to enable it to effectually carry out a programme (for operations) satisfactory to the Minister; and
- Is acceptable to the Federal Government of Nigeria in all respects.

The assignment option is considered unattractive by most lenders because the consent procedure is tedious and laden with bureaucracy. As recently decided in the unreported case of *Moni Pulo Limited v. Brass Exploration Limited & 7 Others*, failure to obtain ministerial consent under any guise is fatal and renders an assignment of interest in an OML inchoate.

Due to the challenges associated with obtaining ministerial consent, RBL lenders may consider the assignment of security option an unattractive proposition and instead look to other forms of security.

"As recently decided in the unreported case of Moni Pulo Limited v. Brass Exploration Limited & 7 Others, failure to obtain ministerial consent under any guise is fatal and renders an assignment of interest in an OML inchoate."

Share Charge and All Asset Debenture

Given the reluctance of lenders to take an assignment over the borrower's participating interests, an equitable charge over the entirety of the shares in the borrower is an ideal security structure for RBL transactions in Nigeria. Such charge is usually a first ranking charge over all the shares held by the borrower's shareholders and any subsequently issued shares and is usually in addition to an all asset debenture, creating a fixed and floating charge over the entire present and future assets of the borrower.

The share charge must be registered with the Corporate Affairs Commission (CAC) within 90 days after its creation for it to be a valid security which affords public notice.

Domiciliation of Revenues

Given the aforementioned problems around securing assignments of oil and gas assets, it is crucial that lenders exert sufficient control over cash flows arising from the borrowing base. To achieve this, receivables and payments under offtake agreements are usually domiciled with the lenders in "collection accounts" as part of the security package. Under the account domiciliation structure, the borrower instructs relevant offtakers to domicile payments accruing under key contracts with specified account banks until the facility is either fully repaid or notice to the contrary is given. Fortunately, this does not require ministerial consent.

A challenge to the effectiveness of domiciliation of revenue streams as an effective security option for RBL transactions is found in the provisions of Section 52(f) of the Nigerian Oil and Gas Industry Content Development Act. This section requires all operators in the oil and gas industry to maintain a bank account in Nigeria into which they are to retain a minimum of 10% of their total revenue accruing from Nigerian operations. This requirement affects the domiciliation of funds with foreign lenders and may pose a substantial challenge to the utilization of revenue streams as security.

Assignment of Key Contracts

Structuring a bankable RBL is usually dependent on the credit worthiness of the offtakers for the crude oil or gas produced from the borrower's assets. The rights and benefits of the borrower under key contracts such as crude handling agreement, gas sale agreements or other offtake agreements as well as insurance contracts are typically assigned to lenders. In all cases, lenders will seek to perfect their security by giving notice of such assignment to the borrower's counterparties under those contracts.

"The rights and benefits of the borrower under key contracts such as crude handling agreement, gas sale agreements or other offtake agreements as well as insurance contracts are typically assigned to lenders."

OTHER STRUCTURING CONSIDERATIONS

The nature of RBL means that lenders should be able to adequately limit their exposure through the operation of the borrowing base. To ensure greater security, lenders may deploy additional innovative methods to limit their exposure. Issues for consideration under various practical circumstances are discussed below:

- ***Borrowing base assets held by multiple entities***: in such cases the lenders may, for example, require each asset-owning entity to cross-guarantee the debts of each other entity. A cross guarantee ensures that the entities are jointly liable to the lender but severally liable as between themselves.
- ***Hedging arrangements***: hedging is not a critical requirement for RBLs in view of the conservative approach adopted by lenders in determining the borrowing base amount. However, parties may agree to a hedging arrangement as part of treasury management with the benefit of such hedging arrangement assigned to lenders as part of the security package.
- ***Existing security interests***: where the borrowing base is subject to existing security interests (e.g. shareholder loans), it is necessary for the RBL lenders to decide whether to refinance such indebtedness or for the RBL lenders to join in the existing security package. In case of the later, the RBL lenders may insist on appropriate inter-creditor documentation giving them priority in the event of enforcement of security.
- ***Representations and Warranties***: Lenders may seek protections in the RBL finance documents through covenants that the relevant assets will be developed and operated in accordance with the applicable law and that cer-

4. RESERVE BASED LENDING AS A FINANCING OPTION FOR LOCAL OIL AND GAS COMPANIES

tain financial ratios will be maintained. However, the scope of such warranties should be limited where the borrower is not the operator or has minority stake in the asset.

- ***Sovereign Risk considerations***: given the Nigerian situation, the risk of expropriation of assets, change of law, host community unrest etc. may be considered significant by lenders. Usually this is addressed by offshore accounts, credible international crude oil or gas offtakers and the understanding that hydrocarbons are internationally traded and priced products with prices which are generally not directly linked to the performance of the country. However, lenders may require political risk insurance to address these concerns.

CONCLUSION

The opportunities presented to local upstream players and contractors by IOCs' divestments and the marginal field licensing round has resulted in the need for diverse sources of funding as well as innovative financing structures. RBL remains an attractive option in this regard.

Although, the traditional banking concept which emphasizes vanilla lending currently holds sway, more Nigerian banks are willing to further embrace the RBL concept for their lending decisions where the transaction dynamics are right.

"... the risk of expropriation of assets, change of law, host community unrest etc. .. may be considered significant by lenders and can be addressed by offshore accounts, credible international crude oil or gas offtakers and the understanding that hydrocarbons are internationally traded and priced products ..."

Source: http://sweetcrudereports.com/wp-content/uploads/2012/10/Oil-rig-1.jpg

5. LEGAL AND REGULATORY FRAMEWORK FOR THE OIL AND GAS INDUSTRY IN NIGERIA

KEY LEGISLATIONS AND REGULATIONS GUIDING THE NIGERIAN OIL AND GAS SECTOR

- Constitution of the Federal Republic of Nigeria 1999
- Nigerian National Petroleum Corporation Act 1977
- Petroleum Act 1969
- Petroleum Drilling and Production Regulations 1969
- Oil Pipelines Act 1956
- Oil and Gas Pipelines Regulations 1995
- Nigeria Liquefied Natural Gas (Fiscal Incentives, Guarantees & Assurances) Act 1990
- Mineral Oils Safety Regulations 1963
- Associated Gas Reinjection Act 1979 & Associated Gas Reinjection Regulation 1985
- National Energy Policy 2003
- Companies Income Tax Act 2007
- Nigerian Gas Master Plan 2008
- National Domestic Gas Supply and Pricing Regulations 2008
- National Domestic Gas Supply and Pricing Policy 2008
- National Oil and Gas Policy 2004
- National Environmental Standards and Regulations Enforcement Agency ACT 2007
- Nigerian Oil & Gas Industry Content Development Act 2010
- Oil Terminal Dues Act 1969
- Petroleum Profits Tax Act 1959
- Territorial Waters Act 1967

REGULATORY FRAMEWORK

NIGERIAN NATIONAL PETROLEUM CORPORATION (NNPC)

The NNPC is the state oil corporation which was established on April 1, 1977. In addition to its exploration activities, the Corporation was given powers and operational interests in refining, petrochemicals and products transportation as well as marketing. In 1988, the NNPC was commercialized into 12 strategic business units, covering the entire spectrum of oil industry operations: exploration and production, gas development, refining, distribution, petrochemicals, engineering, and commercial investments. Currently, the subsidiary companies include:

- ***Nigerian Petroleum Development Company (NPDC)***: NPDC is charged with the responsibility of carrying out petroleum exploration and production activities. NPDC's activities cover the spectrum of the upstream oil and gas business.

- ***Nigerian Gas Company (NGC)***: NGC was initially established to efficiently gather, treat, transmit and market Nigeria's natural gas and its by-products to major industrial and utility gas distribution companies in Nigeria and neighboring countries. NGC also focuses on transmission, distribution and marketing of natural gas.

- ***Pipelines and Products Marketing Company (PPMC)***: PPMC is directly responsible for sourcing and distribution of petroleum products to all parts of Nigeria at a uniform price.

- ***Integrated Data Services Limited (IDSL)***: IDSL is responsible for the provision of geophysical, geological, reservoir engineering and data storage and management services in the global oil and gas industry.

- ***National Engineering and Technical Company Limited (NETCO)***: NETCO is charged with the responsibility of acquiring engineering technology through direct involvement in all aspects of engineering in the oil and gas and non-oil sectors of the economy.

- ***Hydrocarbon Services Nigeria Limited (HYSON)***: HYSON is involved in marketing and distribution of petroleum products activities in Nigeria. HYSON is in business to market Nigeria's excess petroleum products in the West and Central African sub regions and elsewhere, as well as to import various petroleum products in order to augment shortfalls from domestic refineries production.

- ***Warri Refinery and Petrochemical Co. Limited (WRPC)***: WRPC was established to efficiently and profitably process crude oil into petroleum products, manufacture and market petrochemical products through effective resource utilization, while exploiting new business opportunities.

- ***Kaduna Refinery and Petrochemical Co. Limited (KRPC)***: KRPC is charged with the responsibility of refining crude oil into high value petroleum and petrochemical products.

- ***Port Harcourt Refining Co. Limited (PHRC)***: PHRC is in business to optimally process hydrocarbon into petroleum products for the benefit of all stakeholders.

- ***NNPC Retail***: This subsidiary is charged with the responsibility of establishing and profitably operating model retail outlets with efficient service delivery of petroleum and allied products to customers in an environmentally friendly manner.

- ***Duke Oil***: This subsidiary is engaged in direct oil trading activities in the spot market to achieve operating capability, downstream integration and additional profit from oil operations.

DEPARTMENT OF PETROLEUM RESOURCES (DPR)

DPR has the statutory responsibility of ensuring compliance with petroleum laws, regulations and guidelines in the oil and gas Industry. The discharge of these responsibilities involves monitoring of operations at drilling sites, producing wells, production platforms and flowstations, crude oil export terminals, refineries, storage depots, pump stations, retail outlets, any other locations where petroleum is either stored or sold, and all pipelines carrying crude oil, natural gas and petroleum products, while carrying out the following functions, among others:

- supervising all petroleum Industry operations being carried out under licences and leases;
- monitoring petroleum industry operations to ensure they are in line with national goals and aspirations including those relating to gas flaring and domestic gas supply obligations;
- ensuring that health safety and environment regulations conform with national and international best oil field practice;
- maintaining records on petroleum industry operations, particularly on matters relating to petroleum reserves, production/exports, licenses and leases;
- advising Government and relevant

5. LEGAL AND REGULATORY FRAMEWORK FOR THE OIL AND GAS INDUSTRY IN NIGERIA

Government agencies on technical matters and public policies that may have impact on the administration and petroleum activities;

- processing industry applications for leases, licences and permits;
- ensure timely and accurate payments of rents, royalties and other revenues due to government;
- maintain and administer the National Data Repository (NDR).

NATIONAL PETROLEUM INVESTMENT MANAGEMENT SERVICES (NAPIMS)

National Petroleum Investment Management Services (NAPIMS) is the Corporate Services Unit (CSU) and the Exploration and Production (E&P) Directorate of the NNPC. NAPIMS is charged with the responsibility of managing FGN's investment in the upstream sector of the oil and gas industry. Its objective is to enhance the margin accruing to FGN through effective supervision of the Joint Venture Companies (JVCs), Production Sharing Companies (PSCs) and Service Companies (SCs).

NIGERIAN CONTENT DEVELOPMENT AND MONITORING BOARD (NCDMB)

The Nigerian Content Development and Monitoring Board was established by the President, following the signing into law of the Nigerian Oil & Gas Industry Content Development Act 2010 on 22nd April, 2010. Before the Act became effective, matters pertaining to Nigerian Content were managed by the then Nigerian Content Division of NNPC. That Division has ceased to exist and its duties have been subsumed into the responsibilities of NCDMB. The Board has full responsibility for all matters pertaining to Nigerian content in both the upstream and downstream sectors of the oil & gas industry.

Some of NCDMB's responsibilities include:

- Increasing indigenous participation in the oil and gas industry;
- Building local capacity and competencies;
- Creating linkages between the oil and gas sector and other sectors of the national economy;
- Boosting industry contributions to the growth of Nigeria's national gross domestic product;
- Training and employment of Nigerians in the oil and gas sector;
- Establishment of critical facilities such as pipe mills, docking & marine facilities, pipe coating facilities in Nigeria;
- Promoting indigenous ownership of marine vessels, offshore drilling rigs, etc;
- Promoting services which support industry activities such as banking, insurance, legal, etc.

http://www.naijainvest.com/wp-content/uploads/2013/07/shell-oil-field.jpg

THE GAS AGGREGATION COMPANY OF NIGERIA (GACN)

The Gas Aggregation Company of Nigeria (GACN) was incorporated in 2010. It was created to manage domestic gas supply obligations volumes and to act as first point of contact for gas buyers to access gas for domestic market use. It is important to note that GACN is not a regulator, its objectives include:

- Domestic gas demand management;
- Administration of gas network;
- Conduct of due diligence assessment on eligible gas buyers;
- Allocation of available gas from the domestic supply obligations to credible buyers;
- Facilitation of the expeditious execution of Gas Sale and Aggregation Agreements and Gas Transportation Agreements between the buyers, sellers and transporters of gas;
- Enable the creation of a potential gas trading hub for Nigeria and the West Africa region - 'Nigeria's Henry Hub';
- Facilitate the future commercial trading of both physical and paper instruments process for wholesale gas supply from gas producers to eligible gas purchasers within Nigeria.

THE NATIONAL ENVIRONMENTAL STANDARDS AND REGULATIONS ENFORCEMENT AGENCY (NESREA)

The National Environmental Standards and Regulations Enforcement Agency (NESREA) was established as a parastatal of the Federal Ministry of Environment, Housing and Urban Development by the NESREA Act 2007. NESREA is charged with the responsibility of enforcing all environmental laws, guidelines, policies, standards and regulations in Nigeria. It also has the responsibility to enforce compliance with provisions of international agreements, protocols, conventions and treaties on the environment.

5. LEGAL AND REGULATORY FRAMEWORK FOR THE OIL AND GAS INDUSTRY IN NIGERIA

INCENTIVES

ENABLING LAW	INCENTIVES	DETAILS
Exploration and Production Operations Companies		
Petroleum Profit Tax Act	Preferential tax regime	• Within the first five years of production operations, provided that the pre-production capital expenditure obtained through debt has not been fully amortised, the applicable Petroleum Profits Tax (PPT) rate is 65.75% of the chargeable profit. • After five years: • for joint venture companies, the applicable PPT rate is 85% of the chargeable profit; • Where the company operates under a production sharing contract (PSC), the applicable PPT rate is 50% of the chargeable profit. • The PSCs signed in 1993 enjoy investment tax credit whilst those executed from 1998 and above are only entitled to investment tax allowance at 5%.
Petroleum Profits Tax Act	Royalty rates	• Depending on the types of contract arrangement and water level of the acreage, the royalty rates for crude oil production range from 0% to 20%. • Companies willing to produce crude oil and gas from fields with a water depth of more than 1,000 meters are exempted from paying any royalty since the rate at that level is zero. • Incentives are available for utilisation of associated and non-associated gas and the cost of drilling the first two appraisal wells, which exploration and production companies are allowed to expense at once rather than gradual amortization. • Dividends distributed from petroleum profits are tax free.
N/A	PPT for marginal field operators	• Marginal field operations are to enjoy a 55% PPT rate on chargeable profit. The law enabling the application of this rate is however yet to be promulgated. • For this reason, pioneer status has been granted to some of the successful indigenous concession holders that participated in the first licensing round and who are producing. This provides fiscal relief in the first 5 years of production.
Gas Utilization Companies (Downstream Operations)		
Companies Income Tax Act	Income tax incentive	• Tax holiday of up to 5 years (initial 3 years renewable for an additional 2 years) or as an alternative, additional investment allowance of 35%. • This is in addition to other available incentives for utilization of gas such as accelerated capital allowances and investment allowances. • The profits of such companies from their operations are exempt from income taxes during the tax holiday period.
Companies Income Tax Act	Accelerated Capital Allowance	• Accelerated Capital Allowance after the tax-free period in the form of 90% with 10% retention in the books for plant and machinery. • 15% investment capital allowance which shall not reduce the value of the asset.
Companies Income Tax Act	Tax deductible interest on loans	• Interest payable on any loan obtained for a gas project, with the prior approval of the Minister of Petroleum, is tax deductible.
Companies Income Tax Act	Tax – free dividends	• Tax free dividends during the tax-free period, provided that the downstream investment was made in foreign currency or provided that plant and machinery imported during the tax-free period for purposes of the project, account for not less than 30% of the company's equity.
Companies Income Tax Act	Exemptions	• Exemption from VAT on plant, machinery and equipment purchased for utilization of gas in the downstream petroleum operations.. • Exemption from customs duties on machinery and equipment or spare parts imported in the exploration, processing or power generation through utilization of Nigerian gas.

5. LEGAL AND REGULATORY FRAMEWORK FOR THE OIL AND GAS INDUSTRY IN NIGERIA

INCENTIVES

Liquefied Natural Gas Projects		
Petroleum Profit Tax Act	PPT tax	Applicable rate is 45%.
Companies Income Tax Act	Capital Allowance	33% per annum onsite-straight-line basis in the first 3 years with 1% remaining in the company's books.
Companies Income Tax Act	Investment tax credit	Applicable rate is 10%.
Companies Tax Act	Royalty	Applicable rate is 7% for onshore; and 5% offshore tax is deductible.

Oil & Gas Free Zone pursuant to the Oil And Gas Export Free Zone Act
No personal income tax
100% repatriation of capital & profit
No foreign exchange regulation
No pre-shipping inspection for goods imported into the free zone
No expatriate quota required for expatriate staff
Initial tax holidays period has been extended from 3 to 5 years and renewable for another 2 years
Investment capital allowance has been increased from 5% to 15%
All dividends distributed during tax holidays are to be tax free.

This Oil and Gas Guide is a publication of Detail Commercial Solicitors, a commercial law firm based in Lagos, Nigeria. DETAIL has an active oil & gas practice and power practice: advising clients on power privatizations; marginal fields acquisitions; IOC divestments; regulatory compliance; independent power producer start up; structuring, licensing & financing; power purchase agreements; gas supply, purchase and transportation agreements.

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ABOUT DETAIL COMMERCIAL SOLICITORS

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DETAIL is distinct as Nigeria's first commercial solicitor firm to specialize exclusively in non-courtroom practice. The firm has established itself as a regular name in the upper echelons of the corporate market.

As niche commercial solicitors, our entire practice is dedicated to achieving clients' business objectives and bringing value to transactions. We are reputed for immersing ourselves in the client's business plans and road maps, adding value to transactions in a comprehensible and tangible manner.

DETAIL has advised on various leading oil and gas transactions and projects, with a wealth of experience across geographical and sectorial areas of Nigeria. Our Partners leading the Oil and Gas team (Ayuli Jemide and Dolapo Kukoyi) are highly regarded in their respective areas of expertise.

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KEY PRACTICE AREAS

Corporate & Commercial, Oil and Gas, Power, Finance, Capital Markets, Infrastructure and Real Estate.

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