THE PETROLEUM INDUSTRY BILL (PIB) 2020 AND ITS SIGNIFICANCE TO THE PETROLEUM INDUSTRY REFORM IN NIGERIA

A

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ABSTRACT

The Petroleum Act of 1969 is the primary legislation for the oil and gas industry in Nigeria. Most of its provisions are obsolete and do not measure up with the current realities of the global oil and gas industry and international best practices. Thus, the introduction of the First Petroleum Industry Bill (PIB) in 2008. The PIB 2008 was that piece of legislation that originated from the OGIC initiative of President Olusegun Obasanjo's administration. Hence, the primary purpose of this singular and very important piece of legislation is to revamp the dwindling Nigerian petroleum industry, which is the live wire of the Nigerian economy. This gives an insight as to how critical the successful passage of this bill is, not just to the industry, but Nigeria as a nation. Hence, all stakeholders must cooperate with the 9^{th} NASS to ensure the successful passage of this bill.

This study was undertaken to analyze the provisions in PIB 2020 to ascertain its significance and relevance in revamping the Nigerian petroleum industry. At such, the key provisions of each of the 4 sections of the PIB, analyzed objectively, facilitate the understanding of the strategy to proffer the solution needed for the industry reform. The major object governance provisions in PIB 2020 is the separation of roles of the governance institutions—policy, commercial, and regulatory. NNPC limited will function strictly as a commercial entity with no regulatory or policy roles while the regulatory functions will be carried out by "The Commission" and "The Authority" for the upstream and downstream sector, respectively. This is intended to create efficient governance and administration institutions. Also, one of the key policies of the administration section of the bill is the removal of the price-fixing power of the minister, which implies that prices will be modulated by market forces, which suggests a progressive move towards full deregulation of the downstream petroleum sector in Nigeria.

Another aspect of PIB 2020, which in my opinion is the most critical, is the Host and Communities Development section, as it serves as a major hindrance to the passage of the previous PIB 2012 and PIB 2018. Hence, the opinions and perspectives of these stakeholders must be given due consideration by the 9^{th} NASS, as not doing so can forestall the PIB passage process and may bring the entire process to a halt. One of the major challenges is the under-representation of the host communities in the establishment and management of the trust fund.

Finally, a quantitative approach was adopted for the analysis of the fiscal provision of the PIB 2020. A comparative analysis of the PIB fiscal system was carried out with 3 other PFS; the Nigerian DOA'19 PSC, Angola PSC 2004, and Ghana R/T fiscal system. From the comparative analysis, the following deductions were made; the PIB PFS is an improvement from the Nigerian DOA'19 PSC from the contractor's viewpoint. Thus, has the potential to attract more investors. Also, the Angola PSC 2004 and Ghana R/T PFS appears more profitable than the two Nigerian PFS. This could be due to the progressive nature of the profit oil sharing formula of the Angola PSC, which is based on yearly IRR instead of the common cumulative oil production that PIB PFS uses. Thus, the PIB PFS should adopt the formula which is based on yearly IRR in its PFS design to increase its attractiveness to the contractor, likewise increased revenue generation to the Nigerian government.

KEYWORDS: Petroleum Industry Bill (PIB), Host Communities, Production Sharing Contract (PSC), National Assembly (NASS), the Commission, the Authority.

DEDICATION

This thesis is dedicated to none other, than my Lord, the Almighty God, Maker of Heavens and Earth and the entire Solomon's Family, Mr. and Mrs. Solomon, My lovely siblings Gideon and Esther.

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LIST OF ABBREVIATIONS

AOE – Additional Oil Entitlement

BOPD –Barrels of Oil per Day

BPE – Bureau of Public Enterprise

CAPEX – Capital Expenditure

CIT – Corporate Income Tax

CITA – Corporate Income Tax Act

CR – Cost Recovery

CT – Contractor Take

DCT – Discounted Contractor Take

DGSO – Domestic Gas Supply Obligation

DHGT – Discounted Host Government Take

DMO – Domestic Market Obligation

DNCF – Discounted Net Cash Flow

DOA – Deep Offshore Act

DPOP – Discounted Payout Period

DPR – Department of Petroleum Resources

ECR – Excess Cost Recovery

E&P – Exploration, and Production

FLGT – Front Loaded Government Take

FLI – Front-end Loading Index

GDP – Gross Domestic Product

GNPC – Ghana National Petroleum Corporation

HG – Host Government

HGT – Host Government Take

HOSTCOM – Host Communities producing oil and gas

IOC – International Oil Company

IRR – Internal Rate of Return

LNG – Liquefied Natural Gas

MMbbl – A Million Barrel

MM$ - A Million Dollar

MGIF – Midstream Gas Infrastructure Fund

MOPI – Ministry of Petroleum Incorporated

NASS – National Assembly

NCF – Net Cash Flow

NDDC – Niger Delta Development Commission

NEITI – Nigerian Extractive Industries Transparency Initiative

NGO – Non-Governmental Organization

NHT – Nigerian Hydrocarbon Tax

NLC – Nigeria Labor Congress

NMDPRA – Nigerian Midstream and Downstream Petroleum Regulatory Authority

NNPC – Nigerian National Petroleum Corporation

NNPC Limited – Nigerian National Petroleum Company Limited

NNRC – Nigerian National Resources Center

NOSDRA – National Oil Spill Detection and Response Agency

NPAMC – Nigerian Petroleum Asset Management Company

NPC – Nigerian Petroleum Company

NPLMC – Nigerian Petroleum Liability Management Company

NPRC – Nigerian Petroleum Regulatory Commission

NSE – Nigerian Stock Exchange

NUPENG – Nigerian Union of Petroleum and Natural Gas Workers

NURC – Nigerian Upstream Regulatory Commission

OPEC – Organization of Petroleum Exporting Countries

OPEX – Operating Expenditure

OGIC – Oil and Gas Reform and Implementation Committee

OGRC – Oil and Gas Reform Committee

PEF – Petroleum Equalization Fund

PENGASSAN – Petroleum and Gas Senior Staff Association of Nigeria

PFS – Petroleum Fiscal System

PI – Profitability Index

PIAB – Petroleum Industry Administration Bill

PIB – Petroleum Industry Bill

PIFB – Petroleum Industry Fiscal Bill

PIGB – Petroleum Industry Governance Bill

PIHICB – Petroleum Industry Host and Impacted Communities Bill

PML – Petroleum Mining Lease

PO – Profit Oil

POP – Payout Period

PPL – Petroleum Prospecting License

PPPRA – Petroleum Product Pricing Regulatory Agency

PPT – Petroleum Profit Tax

PPTA – Petroleum Profit Tax Act

PSA – Production Sharing Agreement

PSC – Production Sharing Contract

PTDF – Petroleum Technology Development Fund

PVR – Present Value Ratio

ROI – Return on Investment

ROR – Rate of Return

RSA – Risk Sharing Agreement

R/T – Royalty and Tax System

TUC – Trade Union Congress

UNFCCC – United Nations Framework Convention on Climate Change

UTC – Unit Technical Cost

CHAPTER ONE

1.0 STUDY OVERVIEW

1.1 STATEMENT OF PROBLEM

The Petroleum Industry Bill (PIB) is draft that provides for the establishment of a legal, fiscal and regulatory framework for the Nigerian oil and gas industry. The petroleum industry is regarded as the driving force of the nation's economy. The PIB started as a single bill in 2008 and is currently divided into four (4) parts, for easy and speedy passage of the bill. Of these four parts, only one which is the petroleum industry governance bill (PIGB) has been passed by the ninth (9^{th}) National Assembly (NASS) and yet to be signed by the President.

The problem has not been with the law-making process. Several factors have led to the delay of its passage into law. The proposed PIB has attracted so many criticisms and challenges, which has delayed its speedy passage. Among these criticisms and challenges are; the resistance from International Oil Companies (IOCs) on grounds of multiple taxations, thereby making it unattractive for investors, criticism from advocacy NGOs, Niger Delta activists, trade union perspective. (Brown, 2020)

The Nigerian oil and gas industry is characterized by increasing non-bankability because the oil and gas fiscal regime is not aligned with global industry best practices, declining competitiveness, poor management of oil revenues, corrupt subsidy regimes, declining production, sabotage, cost creep, price volatility, high business risk, leakages, etc (Brown, 2020). According to Onyeukwu (2010), the potential revenue loss as a result of government delay in the passage of the PIB is estimated at \$4-\$5 Billion.

All the problems and challenges that characterized the Nigerian oil and gas industry highlighted above necessitate the speedy passage of the PIB which shall establish a legal, fiscal and regulatory framework that lines with global best practices and thereby reform the Nigerian petroleum industry. Hence, the onus is on the 9th NASS and other industry stakeholders to ensure the quick and successful passage of the PIB.

1.2. RESEARCH QUESTIONS

This study aims at answering the following questions:

1. Is the passage of the PIB going to help reform the Nigerian Oil and gas industry or wane the interest of the investors?
2. How would the PIB-proposed fiscal term affect upstream investment in the Nigerian Petroleum industry?
3. What is the Comparative benefit of investments in Nigeria versus other country's fiscal regimes?
4. How effective is the PIB-proposed institutions, governance structure and administration of the Nigerian petroleum industry is, in realizing a revamp, thriving, and sustainable oil and gas industry that competes favorably with its global counterpart?

1.3. RESEARCH OBJECTIVES

1. To review Nigeria's PIB and its provisions, to ascertain the viability of these provisions in proffering a solution to the dire state of the Nigerian petroleum industry.
2. To check for loopholes in the PIB and provide perspective/recommendations that can help it achieve its aims and objectives.

3. To build an economic model for fiscal analysis of Nigeria PIB-proposed fiscal regime and three (3) other petroleum fiscal systems; Nigerian DOA'19 PSC, Angola PSC 2004, and Ghana R/T which can be used to inform oil and gas investment decision.
4. To provide a comparative analysis of Nigeria's PIB-proposed fiscal regime against three (3) other petroleum fiscal systems; Nigerian DOA'19 PSC, Angola PSC 2004, and Ghana R/T.

1.4 SIGNIFICANCE OF STUDY

This study gives a keen and critical look into the PIB 2020, especially the fiscal provisions; carry out an economic analysis of the fiscals with 3 other petroleum fiscal systems and give verdict of its viability in terms of its ability to reform the Nigerian petroleum industry to meet up with global best practices, whether the PIB will attract foreign investors and increase global competitiveness or scares investors away, declining competitiveness and ultimately wane the investors' interest in the Nigerian oil and gas industry. Give a concluding remark and recommendations based on the outcome of my Analyses.

1.5 SCOPE OF STUDY

This study revolves around, basically making an analysis of the Nigerian PIB; an analysis that borders around the administration and governance of the Nigerian Petroleum Industry but most importantly is the analysis of the fiscal aspect of the PIB, compared to that of the three (3) other PFS.

The outcome of this research is to assist policymakers, legislators, industry regulators, and other stakeholders to better appreciate the Implications of the PIB-proposed fiscal system on investment in the upstream petroleum sector. An economic model has been built, sensitivity analysis carried out, and a comparative fiscal analysis of the four (4) petroleum fiscal systems.

1.6 RESEARCH METHODOLOGY

The research method relies on both primary and secondary sources of information. The primary sources of information are the Nigerian PIB and the petroleum legislation of Ghana and Angola, while the secondary sources of information are textbooks and publications, journals, reports, and articles online.

CHAPTER TWO

2.0 INTRODUCTION

Every society, organization, or system functions effectively and efficiently under the umbrella of a working and relevant document, which enshrined in, are the modus operand on how such a system is to be governed and regulated. One of the working documents, which is majorly needed in the oil and gas sector of every nation in the world is the “Oil and Gas Legislation”. This legislation is called names depending on the geographical location/territory it is constituted. In Cameroun, it is called the petroleum code, In Ghana and Nigeria, it is called the petroleum act. Whatever name it is called is completely the prerogative of the respective region or territory, but it is a compendium of “oil and gas laws” that guides how the oil and gas sector does its business or activity in a particular country or region.

These laws spell out the relationship in terms of how petroleum activities are carried out between the country’s national oil/gas company, the host government, national regulatory bodies, and the contractors, which are privately owned or consortium of an oil company, be it international or indigenous. Some of the basic highlights of this oil and gas legislation that are common to every country/region are the fiscal terms/arrangements, the administration, and governance structure. Even though the fiscal terms, administration, and governance structure are the common denominator for every region, but how it is drafted based on the prevailing circumstance related to petroleum activities in that region, nonetheless, good viable petroleum legislation must communicate global best industry practices. It must be able to attract investors and boost the revenue and socio-economic status of the region in question, as well as the contractors can profit reasonably from engaging in petroleum activities/business in such a region. Hence, the need for the region's legislators to pay careful attention while drafting these laws such that both parties are satisfied with the draft.

2.1 THE NIGERIAN OIL AND GAS SECTOR

The system primarily considered in this study is the Nigerian oil and gas industry. The document that gives direction and legislative framework on how the industry is to be run is "The Petroleum Industry Bill." For a country like Nigeria whose economic mainstay is Petroleum, it tells the significance and importance of this legislation. One can emphatically say that the petroleum industry bill (PIB) is one of the most important legislation in Nigeria, maybe second to the Nigerian Constitution. The Nigerian PIB is set to replace primarily the "Petroleum Act of 1969" amidst other petroleum laws; such as the NNPC Act of 1977, Petroleum Profit Tax Act of 1959, etc. These laws that have been engaged for years now, to direct the way the petroleum industry runs in Nigeria are obsolete and don't line up with current realities of the global oil and gas industry; do not tally with international best practices. Hence, the need for these laws reviewed and the emergence of the PIB, whose sole purpose is the reformation of the Nigerian oil and gas industry to match up with its global industry counterparts.

It is rather disheartening that despite the enormous natural resources in every part of Nigeria, yet, painfully, Nigeria is not among the league of the developed or wealthy nation or at the least the fastest developing nation. All because we have not mastered how to fully maximize this abundant natural resource and the sad reality of corruption has further made it difficult to achieve our true potential of being a wealthy nation. Even, the petroleum resource Nigeria can boast of developing still can't establish its feet at the golden gate of global oil and gas business, all because the stakeholders in the industry cannot collaborate to ensure sector or industry reform due to selfish, personal, or sectional interest and clash of these interests.

The government is not satisfied with the revenue they get when compared to other nations (L. Brown, 2020). Also, the data emanating from government agencies saddled with the record-keeping of royalty payments, petroleum profit tax, and gas flare penalty payments are in most cases wrong, also the perennial leakages and crude theft, lead to shortages in funds accruable to the federation account, the inability to make the refineries function optimally also leads to perennial scarcity of petroleum products. The lack of savings from oil revenues over the years, sliding crude oil prices, uncertainties in the foreign exchange market usually leads the country into underfunded budgets and inability to implement the budgets dire emergencies as just happened with the covid-19 (Brown, 2020).

The companies are unhappy with the government because of multiple taxations, levies, vandalism of oil and gas assets, crude theft, illegal bunkering, spiraling capital and recurrent overhead costs, insecurity. The union is unhappy about activities of management prerogatives and collective bargaining issues. The host communities are not happy with both the government and International Oil Companies (IOCs) because of the obvious oil and gas environmental pollution, underdevelopment of the oil-bearing communities, and Niger-Delta region. In a nutshell, the Nigerian oil and gas industry is characterized by increasing non-bankability of the oil & gas sector, due to obvious reasons amidst many others, such as; the fiscal regimes are not aligned with global best industry practice, declining competitiveness, poor management of oil revenues, corrupt subsidy regimes, declining production, sabotage, cost creep, price volatility, high business risk, leakages, etc.

Regardless of who is to be blamed or take the fault for this menace, the Nigerian oil & gas sector has found itself in, from the issues of interest of stakeholders and others highlighted above, clearly shows the need to reform the legislative framework that directs this industry. For a mono-product economy like Nigeria faced with the reality of near-future exhaustion of our almighty non-renewable energy source (crude oil).

The need for diversification of the Nigerian economy is crucial, which is feasible within the context of the oil & gas sector. It starts with PIB emphasizing the need for the industry stakeholders to collaboratively put effort or concentrate on the midstream and downstream part of the sector; deregulation of the downstream sector, encouraging IOCs participation in the downstream through tax incentives, removal of gas flare penalty and provide enabling environment and infrastructure for IOCs to maximize their gas outputs and create a domestic gas market.

Critical also, is the need for Nigeria through its national oil company, Nigerian National Petroleum Corporation (NNPC) to fully utilize and maximize its abundant natural gas resources for power generation, thereby, making Nigeria an energy-efficient nation that attracts foreign investors, which will consequently increase Nigeria's foreign exchange, thus, boosting the Nigerian economy and its gross domestic product (GDP).

In a nutshell, we can say that the first step towards achieving the Nigerian oil and gas industry reform into a vibrant, efficient, effective one is in the successful passage of the PIB. Yet, PIB which seeks to increase government revenue from oil and lay down a strengthened legal and regulatory framework for the Nigerian oil and gas industry has suffered some legislative delays and limited consideration from the executive arm of the Nigerian government precluding its passage. It is a good thing that the eighth (9^{th}) national assembly (NASS), the executive, and other industry stakeholders are making a tremendous effort recently through meetings and public hearings to ensure the successful passage of the PIB by the first quarter of the year 2021. Some of the reasons for the initial delay include fear of protest against the removal of subsidy arising from the deregulation of downstream and stakeholders issues such as regional imbalances in the distribution of oil revenues and IOCs unwilling to pay more taxes (SDN, 2019). Some of the key objectives of the PIB are as follows:

- Secure the long-term macro-economic stability of Nigeria.
- Reform the extractive industry institutional framework
- Support production to ensure Nigeria remains the top African oil producer.
- Kick-start a domestic gas to power market.
- Provide clarity and stability for Nigeria and its partnership with oil and gas production whilst protecting the environment.
- Support economic diversification of Nigeria.

2.2 BRIEF HISTORY OF PIB IN NIGERIA

Now, the story behind the oil and gas sector reform and the need for a single legislative and regulatory framework document called the Nigerian Petroleum Industry Bill (PIB) is something that started twenty (21) years ago with the Obasanjo's pragmatic approach in establishing the "Oil and Gas Reform Committee (OGRC)" on the 24th of April 2000 which was later transformed into the "Oil and Gas Sector Reform Implementation Committee (OGIC)" on the 21st of June 2005 (Brown, 2020). The OGIC committee report, which formed the nucleus of the national oil policy, was completed in 2008. It implies that it took eight (8) years (2000-2008) for OGIC to conclude and move into the realm of a bill called the "Petroleum Industry Bill, 2008 (PIB 2008)." Despite the years it took to reach this level, the PIB 2008 failed to be passed into law by the sixth (6^{th}) National Assembly (NASS) under President Yar Adua's administration. The same thing happened in the year 2012, a new PIB (PIB 2012) was represented to the seventh (7^{th}) NASS under President Jonathan administration but failed to be passed into law by NASS.

Upon the inauguration of the eighth (8^{th}) national assembly under the Buhari's administration in 2015, the leadership of the 8^{th} NASS decided to do something different.

1. To avoid the drawback faced by the previous administration in passing the bill decided to make it a private member bill.
2. Established a technical committee responsible for supporting both chambers to make reframe of the older documents.
3. Split the bill into four pieces, which would make it easier for the legislators to read, digest, and understand. It was divided into four (4) distinct parts of which only one part; the "**Petroleum Industry Governance Bill (PIGB)**" has successfully been passed into law by the 8^{th} NASS, even though the executive (President) did not assent to the PIGB. These distinct parts are:

- The Petroleum Industry Governance Bill (PIGB)
- The Petroleum Industry Administration Bill (PIAB)
- The Petroleum Industry Fiscal Bill (PIFB)
    - The Petroleum Host and Impacted Communities Bill (PHICB)

CHAPTER THREE

3.0. LITERATURE REVIEW

3.1. HISTORICAL OVERVIEW OF THE NIGERIAN PETROLEUM INDUSTRY

The advent of the oil industry can be traced back to 1908, when a German entity, the Nigerian Bitumen Corporation, commenced exploration activities in the Araromi area, West of Nigeria. These pioneering efforts ended abruptly with the outbreak of the First World War in 1914. (Adekunle, 2016)

Oil prospecting efforts resumed in 1937 when Shell D'Arcy (the forerunner of Shell Petroleum Development Company of Nigeria) was awarded the sole concessionary rights covering the whole territory of Nigeria. Their activities were also interrupted by the Second World War but resumed in 1947. Concerted efforts after several years and an investment of over N30 million, led to the first commercial discovery in 1956 at Oloibiri in the Niger Delta. After 1960, exploration rights in onshore and offshore areas adjoining the Niger Delta were extended to other foreign companies. (Adekunle, 2016)

In 1965 the EA field was discovered by Shell in shallow water southeast of Warri. In 1970, the end of the Biafra war coincided with the rise in the world oil price, and Nigeria was able to reap instant riches from its oil production. Nigeria joined the Organization of Petroleum Exporting Countries (OPEC) in 1971 and established the Nigerian National Petroleum Company (NNPC) in 1977; a state-owned and controlled company that is a major player in both the upstream and downstream sectors. (Adekunle, 2016)

Following the discovery of crude oil by Shell D'Arcy Petroleum, pioneer production began in 1958 from the company's oil field in Oloibiri in the Eastern Niger Delta. By the late sixties and early seventies, Nigeria had attained a production level of over 2 million barrels of crude oil a day. Although production figures dropped in the eighties due to an economic slump, 2004 saw a total rejuvenation of oil production to a record level of 2.5 million barrels per day. Current development strategies are aimed at increasing production to 4 million barrels per day by the year 2010, but it's obvious this target was not met as by 2010 Nigerian daily oil production rate dropped to an average of 2.1 million barrels and worse by the end of the year 2020 it dropped to 1.42 million barrels per day, which was due to the global effect of COVID-19 to the industry (www.ceicdata.com).

3.2. NIGERIAN PETROLEUM INDUSTRY

Now, the remarkable journey of the Nigerian oil and gas began with the discovery of oil at Oliobiri in the Niger Delta in 1956 by Shell-BP. Following Shell's success, other IOCs like Gulf Oil, Texaco, Elf, Mobil, and Agip came into the scene and were involved in petroleum Exploration and Production (E&P) operations. As such the IOCs dominated the oil and gas industry for decades. Ever since the Nigerian economy has been largely dependent on crude oil; which accounts for about one-third of the nation's GDP, 76% of government revenue, and 95% of the foreign exchange. As such the oil and gas sector is such a critical sector in Nigeria. (NNPC, 2020)

The oil and gas industry has been characterized and marred by a myriad of issues arising from poor governance, union-management strife, host communities issues, the inefficiencies of the downstream sector, non-alignment of oil and gas fiscal regime; which increases the non-bankability of the sector, declining competitiveness, poor management of oil revenues, declining production, sabotage, etc. All these issues stem from the obsolescence of the extant Nigerian petroleum statutes; most of which don't line up with global industry best practices (Brown, 2020).

3.3. THE NIGERIAN PETROLEUM INDUSTRY BILL

Oil and gas production commenced in Nigeria, after the discovery of oil in Oloibiri. Since then no comprehensive law has been drafted for the administration of the industry, hence, the PIB seeks to replace the sixteen (16) petroleum industry laws (Brisibe., 2019) of which the primary law is the "Petroleum Act of 1969". It remains the major framework for analysis and management of the petroleum sector in Nigeria, perhaps because of its attendant Petroleum Drilling and Regulations component. The law became the foundation of the oil industry in Nigeria. The Act vested ownership and management of the oil in the Nigerian State. Most sections of the Act deals with issues of exploration and production licenses, leaving out matters of development of the oil-producing communities and damage to the environment in real substantive terms (Adekunle, 2016).

This necessitates the urgent reformation of the Nigerian oil and gas industry. In response to this concern, a pragmatic approach was taken by the then Olusegun Obasanjo's administration by establishing the "Oil and Gas Reform Committee (OGRC) on the 24th of April 2000. It was established to review and streamline the existing petroleum laws and to develop a regulatory framework for the reform of the sector for bankability and benefits to all stakeholders. The OGRC had as an outcome, the draft national oil and gas policy and later transformed into the "Oil and Gas sector reform Implementation Committee (OGIC) on the 21st of June 2005. The OGIC committee report, which formed the nucleus of the national policy was completed in 2008. The implication of this is that it took eight (8) years, from 2000 to 2008 for the OGIC to conclude and moved into the realm of a bill in the name of the "Petroleum Industry Bill". The petroleum industry bill is an attempt to bring under one head the various legislative, regulatory, and fiscal policies, instruments, and institutions that govern the Nigerian Petroleum Industry.

The essence of the PIB was to build among other things, structures to strengthen the administration of the industry in a transparent and accountable manner through for example, in the latest PIB draft the creation of an administrative institution; the Nigerian Upstream Regulatory Commission (NURC) simply called "The Commission" the Nigerian Midstream and Downstream Petroleum Regulatory Authority (NMDPRA) simply called "The Authority", the conversion of the Nigerian National Petroleum Corporation (NNPC) into self-financing National Oil Company, removal of confidentiality clauses on royalty and tax payments (Brown, 2020). In a nutshell, it creates a framework that would separate policy, regulation, monitoring, commercial operations, and the institution to support the framework.

The minister of state for petroleum, Timipre Sylva in an interview with a news journal called Nairametrics (2020) said that over the years the petroleum industry has grown more towards the upstream exploration and production sector and why the midstream sector of the petroleum industry has been neglected over the years. It is because the fiscal framework for its development was non-existent. The expectation is that PIB will now create the fiscal framework that would encourage the growth and development of the sector and will help create Job opportunities (Odutola, 2020).

The extant regulatory framework of the oil and gas sector which includes the Ministry of Petroleum Resources, NNPC Act 1997, the Petroleum Act 1969, the Oil and Pipeline Act of 1990, the Petroleum Profit Tax Act of 1959, the Petroleum Products Pricing Regulatory Act 2003 amongst others have had a more ruinous effect on the oil and gas sector, as they have not promoted a culture of transparency in the oil and gas sector. They have also not created the right opportunities to tackle gas flaring, oil spillage, and illegal bunkering in Nigeria (Olisah, 2020).

3.4. PIB: THE JOURNEY SO FAR

In 2021, oil and gas account for roughly 10% of Nigeria's gross domestic product, and petroleum exports provide approximately 86% of total export revenues, a crucial source of dollar earnings for Africa's largest economy. With estimated proved crude oil reserves of about 37 billion barrels and over 200 trillion cubic feet of proven natural gas reserves remaining as of the end of 2019 (African Oil and Power, 2020). Nigeria's wealth of petroleum resources has the potential to build prosperity and crucial infrastructure for the people of Nigeria for decades to come. Hence, the need for reform of the Nigerian petroleum industry which starts with the draft of a legislative and regulatory framework that will drive this industry reform called the Petroleum Industry Bill (PIB). The PIB is practically the most talked about and most important piece of legislation in Nigeria, given the far-reaching reforms which it proposes to an industry that is the single most significant contributor to the national economy. Originally introduced in December 2008, the bill has undergone numerous revisions and has been the subject of intense debate to date; one of the reasons it's yet to be passed as a law.

In an attempt to restructure the oil and gas industry, the Oil and Gas sector reform Implementation Committee (OGIC) was inaugurated on the 24th of April 2000 under the chairmanship of Dr. Rilwanu Lukman (then serving as the presidential adviser on petroleum and energy). The OGIC was charged with the task of making recommendations for the far-reaching restructuring of

Nigeria's oil and gas industry. The recommendations of OGIC included a proposal to separate the commercial institution within the industry from regulatory institutions. In 2007, the federal government of Nigeria oil and gas policy and re-constituted OGIC to make recommendations towards the emergence of a new instituted framework to govern the operations of the oil and gas industry, including the emergence of new National Oil Company, new regulatory bodies, and a new national directorate, for a more effective policy formulation for the industry (Ikwazom, 2012). Further deliberations of OGIC produced the Lukman report of 2008 which recommended a new regulatory and institutional framework that when implemented would guarantee greater transparency and accountability. This report formed the basis for the first PIB that was submitted in 2008 as an executive bill.

Among the salient features of the PIB 2008 were:

- Unbundling and commercialization of the Nigerian National Petroleum Corporation (NNPC).
- Transformation of the existing Joint Venture between multinational oil companies and the NNPC.
- Deregulation of the downstream sector.
- Creation of new regulatory bodies and
- Introduction of a new fiscal regime that sought to increase overall government take.

As expected, the proposed new fiscal regime of PIB 2008 which, will guarantee increased government take but on the other hand, a disadvantage to the International Oil Companies (IOCs) elicited a strong opposition by the IOCs which argued that the Bill would create a harsh environment for upstream investments. This initial reaction prompted intense discussions among stakeholders in the industry and signaled the commencement of a process of multiple revisions of the bill in an attempt to produce an acceptable draft. This revision process culminated in the proliferation of the diverse and irreconcilable version of the bill. The existence of different revisions of the bill together with preparations for the 2011 general elections contributed to the inability of the last session of the legislature to enact the bill into law.

The resurgence of the bill can be traced to some factors:

1. The gradual cessation of investments in the sector as a result of uncertainty regarding the fiscal provision of the bill and their potential impact on the industry,
2. The emergence of competing petroleum investment opportunities in other sub-Saharan African countries such as Ghana, Angola, Sao-Tome and Principe and
3. The attempt by the government to deregulate the Nigerian downstream sector led to increased fuel prices and in response to that, a strike was followed by the Nigerian Labour Congress (NLC) and Trade Union Congress (TUC).

The federal government to contain the strike, committed to expediting the reform of the oil and gas industry by among other things speed up the passage of the PIB, inaugurated a special task force with a responsibility to produce a reconcilable version of the bill which would be represented to the legislature for passage, which was finally submitted to the legislature (7th NASS) in July 2012.

The Objectives of the PIB 2012 are as follows:

- Creating a conducive business environment for petroleum operation.
- Enhancing exploration and exploitation of petroleum resources for the benefits of Nigerians.

- Optimizing domestic gas supplies particularly for power generation and industrial development.
- Establishing a progressive fiscal framework that encourages further investment in the petroleum industry while optimizing the revenue accruing to the government.
- Establishing commercially oriented and profit-driven oil and gas entities.
- Deregulating and liberalizing the downstream petroleum sector.
- Creating efficient and effective regulatory agencies.
- Promoting openness and transparency in the industry and
- Encouraging the development of Nigerian content.

To achieve the above-mentioned objectives, Fagbohunlu & Ikwuazom (2012) suggested:

- The restructuring or reorganization of industry institutions and the regulatory framework.
- A new fiscal regime for upstream oil and gas production.
- Allocation of domestic gas supply obligation to licensees and
- Deregulation of the downstream sector.

One of the concerns of the PIB 2012 was the Provision, which declare that "the grant of a Petroleum Prospecting License (PPL) and Petroleum Mining License (PML) shall be by open, transparent and competitive bidding process conducted by the inspectorate." This was largely viewed as positive by all stakeholders. However, the latter provision sharply contradicts the previous; **it empowers the president "to grant a license or lease under this Act**". This contravenes its objective of promoting openness and transparency in the industry.

3.4.1 Some of the Key Provisions under the PIB 2012:

The creation and establishment of the following institutions:

1. **Petroleum Technical Bureau ("The Bureau")** saddled with the responsibility of providing technical and professional support to the minister on matters relating to the petroleum industry.
2. **The Upstream Petroleum Inspectorate ("The Inspectorate");** responsible for the administration and regulation of the upstream petroleum operations through either the establishment or enforcement of policies, laws, and regulations.
3. **The Downstream Petroleum Regulatory Agency ("The Agency");** responsible for the administration and regulation of all aspects of the downstream petroleum operations through either the establishment of the enforcement of policies, laws, and regulations. This was formerly the role of the Department of Petroleum Resources (DPR) and Petroleum Product Pricing Regulatory Agency (PPPRA).
4. **Petroleum Host Communities Fund ("The Fund")** to be utilized for the development of the economic and social infrastructure of the communities within the petroleum-producing areas. Ten percent (10%) of the estimated net profit of companies engaged in upstream petroleum operations shall be remitted to the fund every month.
5. **Asset Management Corporation ("The Corporation")** whose function is to acquire and manage investments of the government in the upstream petroleum sector.
6. **Nigerian Petroleum Assets Management Company Limited ("Management Company")** established as a subsidiary of the corporation and shall be subject to neither the provisions of the Fiscal Responsibility Act 2007 nor the Public Procurement Act 2007.

It is a body corporately registered under the Companies and Allied Matters Act 1990, by the minister not later than three (3) months after the commencement date of the PIB. At incorporation, the initial shares of the management company shall be held in the ratio of 99% by the corporation and 1% by the permanent secretary of the ministry in trust for the corporation.

7. **The National Oil Company Plc.;** shall be incorporated by the Minister as a public company limited by shares 3 months after the commencement date of the PIB. It shall be vested with certain assets and liabilities of NNPC except for the assets and liabilities of Incorporated Joint Ventures and the National gas Company limited.
8. **National Gas Company Plc.;** it shall also be vested with certain assets and liabilities of the NNPC. The PIB requires the government to divest 49% of its authorized shares in the National gas company Plc. to the public in a transparent manner on the Nigerian Stock Exchange (NSE) at any time within 6 years from the date of incorporation.

The retention of the following Institutions

9. **Petroleum Equalization Fund:** in which any net surplus revenue recovered from petroleum products marketing companies shall be paid into. It shall cease to exist where the government decides that the petroleum product market has been effectively deregulated.
10. **Petroleum Technology Development Fund (PTDF):** the fund shall provide scholarship and business wholly or partly to Nigerians in universities and institutions undertaking petroleum training in either Nigeria or abroad.

The New Fiscal provisions are:

1. Introduction of a Nigerian Hydrocarbon Tax (NHT) for companies engaged in upstream petroleum operations. It is to replace Petroleum Profit Tax.
2. Company Income tax (CIT) made applicable to companies engaged in upstream petroleum operations. It is based on the amendment of the Company Income-tax Act (CITA).
3. Exemption of dividends from further tax; according to the PIB any dividend paid out by a company from profits on which PPT has been paid, is exempted from further tax.
4. Payment of royalties; the PIB provides for the payment of royalties but does not specify the basis and percentage of royalties to be paid. However, the minister of petroleum resources is empowered to make regulations in this regard.
5. Tax returns and assessments

The Environmental Provisions are:

1. Introduction of Environmental quality management plan; it shall among other things contain or remedy the cause of pollution or degradation and migration of pollutants, describes how the licensee or lessee intends to comply with any prescribed waste management standards or practices.
2. Establishment of gas flaring penalties; any licensee or lessee who flares or vent gas without the permission of the minister shall be liable to pay a fine which shall not be less than the value of the gas flared.

3.4.2. Petroleum Industry Bill 2015

There was some success in 2015, with the passage of the bill at the House of Representative in the 7th assembly but progress stalled when the bill did not go through the senate before the dissolution of the 7th assembly following the change of government in May 2015. Politics, the transition of power from Jonathan to Buhari administration, the venal ambition of different stakeholders, and the bulky nature of the PIB have also since stalled the passage of the bill (Ene, 2018).

In 2015, NASS proposed passing the PIB into various segments, forming four separate bills (the Petroleum Industry Governance Bill, PIGB, Fiscal regime bill, Upstream and Downstream Administration Bill, and Petroleum Host Communities Bill). They prioritized the PIGB, as it addresses the reform to the governance of the sectors through the institutions it sets to create and establish. The PIGB was eventually passed on the 28th of March 2018 as a harmonized version of the PIGB 2018 by the two (2) legislative chambers but yet to be signed by the president.

The PIGB 2018 seeks to

1. Clarify the role of government and that of the petroleum minister in the oil and gas industry.
2. Eliminate multiple regulatory entities and establish a new regulatory commission (a single regulator) for Nigeria's oil and gas industry.
3. Unbundle the portfolio of the NNPC; to achieve this, the PIGB established three (3) principal commercial entities.
    - The Ministry of Petroleum Incorporated (MOPI)
    - The National Petroleum Company (NPC)
    - The Nigerian Petroleum Asset Management Company (NPAMC)

    The NPAMC is proposed to take over and manage the asset and liabilities of the NNPC, the NPAMC incorporation, shall be held by the federal ministry of finance incorporated and the Bureau of Public Enterprise (BPE) in a ratio of 90% to 10%.

The other Institutions are:

The NPRC is also provided for in the PIGB to replace DPR, PPPRA, and Petroleum Inspectorate (PI) (Perchstone & Graeys, 2016)

- The Minister
- The Petroleum Equalization Fund (PEF)
- The Nigeria Petroleum Liability Management Company (NPLMC)

The main objectives of the PIGB 2018 are:

1. To create the governing institutions with clear and separate roles.
2. To establish the framework for the creation of commercially viable petroleum entities.
3. To promote transparency and accountability.
4. To foster a conducive business environment for petroleum industry operations.

3.4.3. Petroleum Industry Bill 2020

The latest iteration of Nigeria's PIB was forwarded to the National Assembly in September 2020. It has gone through the first reading at both the senate and house of representative, but full deliberation and public hearing is expected to take place in the first quarter of 2021. The new draft sees the four (4) components of the bill (Governance, Administration, Host Communities and Fiscal) brought back together under one bill; the scrapping of some bodies to be replaced by two (2) regulators (the Nigerian Upstream Regulatory Commission – NURC and the Nigerian Midstream and Downstream Petroleum Regulatory Authority – NMDPRA); the privatization of NNPC and some other significant changes to the way industry will be governed.

3.4.3.1 Objectives of the PIB 2020

Below are the objectives of the PIB 2020 based on the respective sections:

a) Governance and Institution

1. Create efficient and effective governing institutions, with clear and separate roles for the petroleum industry.
2. Establish a framework for the creation of a commercially oriented and profit-driven national petroleum company.
3. Promote transparency, good governance, and accountability in the administration of the petroleum resources of Nigeria; and
4. Foster a business environment conducive to petroleum operations (Section 2, PIB, 2020).

b) Administration

1. Promote the exploration and exploitation of petroleum resources in Nigeria for the benefit of the Nigerian people.
2. Promote the efficient, effective, and sustainable development of the petroleum industry;
3. Promote the safe and efficient operation of the transportation and distribution infrastructure for the petroleum industry;
4. Provide the framework for developing third party access arrangements to petroleum infrastructure;
5. Encourage and facilitate both local and foreign investment in the petroleum industry;
6. Promote transparency and accountability in the administration of petroleum resources in Nigeria; develop, where appropriate, competitive markets for the sale and distribution of petroleum and petroleum products;

7. Promote safe and affordable access to petroleum and petroleum products in Nigeria;
8. Promote the processing of petroleum within Nigeria and the development of fuel and chemical industry and other related value-added;
9. Products and activities; create a conducive business environment for operations in the petroleum industry;
10. Promote the liberalization of the downstream petroleum industry;
11. Establish an orderly, fair and competitive commercial environment within the petroleum industry; and
12. Ensure that petroleum operations are conducted in a manner that protects the health and safety of persons, property, and the environment (Section 66 (1), PIB, 2020)

c) Host Community Development

1. Foster sustainable prosperity within host communities;
2. Provide direct social and economic benefits from petroleum operations to host communities;
3. Enhance peaceful and harmonious co-existence between licensees or lessees and host communities; and
4. Create a framework to support the development of host communities (Section 234, PIB, 2020).

d) Fiscal Framework

1. Establish a progressive fiscal framework that encourages investment in the Nigerian petroleum industry, balancing rewards with risk and enhancing revenues to the Federal Government of Nigeria;

2. Provide a forward-looking fiscal framework that is based on core principles of clarity, dynamism, and fiscal rules of general application;
3. Establish a fiscal framework that expands the revenue base of the Federal Government, while ensuring a fair return for investors;
4. Simplify the administration of petroleum tax; and
5. Promote equity and transparency in the petroleum industry fiscal regime (Section 234, PIB, 2020).

3.4.3.2 Key Provisions of the PIB 2020

The extant regulatory framework of the oil and gas sector which includes the Ministry of Petroleum Resources, NNPC Act 1997, the Petroleum Act 1969, the Oil and Pipelines Act 1990, the Petroleum Profit Tax Act (PPTA) 1959, the Petroleum Products Pricing Regulatory Act 2003 amongst others have had a more ruinous effect on the oil and gas sector, as they have not promoted a culture of transparency in the oil and gas sector. They have also not created the right opportunities to tackle gas flaring, oil spillage, and Illegal bunkering in Nigeria.

The key provisions of the bill are as follows:

1. The Minister of Petroleum

The Minister of Petroleum is empowered to formulate, monitor, and administer government policy in the petroleum industry; exercise general supervision over the affairs and operations of the petroleum industry following the provisions of this Act; report developments in the petroleum industry to the government; represent Nigeria at international organizations on petroleum matters; promote an enabling environment for investment in the Nigerian petroleum industry; negotiate treaties or other international agreements on matters of petroleum on behalf of the Government, shall have rights of pre-emption of petroleum and petroleum products marketed under any license or lease, in the event of a national emergency.

2. Establishment of the Nigerian Upstream Petroleum Regulatory Commission (NUPRC)

This commission is to administer and enforce policies and regulations relating to all aspects of upstream petroleum operations and also to issue, administer and enforce compliance on the issuance of licenses and leases in the upstream sector. It is also to establish, monitor, regulate, and enforce health and safety measures relating to all aspects of upstream petroleum operations, publish reports and statistics on the upstream sector, validate and certify the evaluation of national hydrocarbon reserve, manage and administer all upstream petroleum data for all unallocated acreage. This Commission on the approval of the minister is to allocate petroleum production quotas, and develop cost benchmarks for upstream petroleum operations performance amongst other functions, as laid out in the bill.

3. Establishment of the Nigerian Midstream and Downstream Petroleum Regulatory Authority (NMDPRA)

This authority is to administer and enforce policies, laws, and regulations relating to all aspects of midstream and downstream petroleum operations, and to issue and administer licenses in the midstream and downstream sectors. The agency is also to ensure and enforce compliance with the terms and conditions of all licenses, permits, and authorizations issued in respect of the midstream and downstream petroleum operations; set and enforce approved standards for designs, procurement, construction, and maintenance for all plant; installation and facilities of midstream and downstream operations.

This authority is also laden with the responsibility of inspecting measurement equipment, and other facilities for midstream and downstream petroleum operations. It is also to facilitate the supply of gas to the strategic sectors, by the approved national gas pricing framework, implement customer protection measures following the provisions of this Act, regulate and ensure the supply, distribution marketing, and retail of petroleum products as may be prescribed by regulations, and shall also do other things that are necessary and expedient for the effective and full discharge of any of its functions under this Act, amongst other functions as stipulated in the bill.

4. Incorporation of the Nigerian National Petroleum Company Limited

The Minister of Petroleum shall within 6 months from the commencement of this Act, cause to be incorporated under the Companies and Allied Matters Act, a limited liability company, which shall be called Nigerian National Petroleum Company Limited (NNPC Limited).

The Minister shall at the incorporation of NNPC Limited, consult with the Minister of Finance to determine the number and nominal value of the shares to be allotted, which shall form the initial paid-up share capital of NNPC Limited, and the Government shall subscribe and pay cash for the shares.

Ownership of all shares in NNPC Limited shall be vested in the Government at incorporation and held by the Ministry of Finance Incorporated on behalf of the Government.

The Minister of Petroleum and the Minister of Finance shall determine the assets, interests, and liabilities of NNPC to be transferred to NNPC Limited or its subsidiaries, and upon the identification; the Minister shall cause such assets, interests, and liabilities to be transferred to NNPC Limited.

Assets, interests, and liabilities of NNPC not transferred to NNPC Limited or its subsidiary shall remain the assets, interests, and liabilities of NNPC until they become extinguished or transferred to the Government.

NNPC shall cease to exist, after its remaining assets, interests, and liabilities other than its assets, interests, and liabilities transferred to NNPC Limited or its subsidiaries under subsection (1) of this section, shall have been extinguished or transferred to the Government.

5. Granting of Licenses and Leases

Petroleum exploration license may be granted to qualified applicants, to explore petroleum on a speculative and non-exclusive basis.

Petroleum Prospecting License may be granted to qualified applicants, to carry out petroleum exploration operations on an exclusive basis. A Petroleum Prospecting License for onshore and shallow water acreages shall be for not more than 6 years, comprising of an initial exploration period of 3 years, and an optional extension period of 3 years. A petroleum prospecting license for deep offshore and frontier acreages shall be for not more than 10 years, comprising of an initial exploration period of 5 years, and an optional extension period of 5 years.

A petroleum mining lease may be granted to qualified applicants to search for a win, work, carry away and dispose of crude oil, condensates, and natural gas. A petroleum mining lease may be granted for a maximum period of 20 years, which terms shall include the development period.

6. Abolition of Gas Flaring

Gas flaring has been said to be a major destroyer of the ozone layer, and this has a very detrimental effect on climate all over the world, as it's presently occurring. The United Nations Framework Convention on Climate Change (UNFCCC) has called on countries to put an end to the greenhouse gas effect. Despite not having any binding emission target under the UNFCCC, Nigeria in its way has responded under the proposed bill to illegalize and abolish gas flaring.

Accordingly, the new bill demands strict adherence to a gas flaring plan, along with gas utilization plans, to be submitted by all oil and gas operators within six months of the coming into effect of the law, indicating data on their daily flare quantity, reserve, location, composition. Statistics posit that Nigeria losses a lump sum of money every year to gas flaring, such that its abolition is a wise way of saving this money, and making it available for the usage of the economy and its development.

7. Domestic Gas Obligations

The PIB provides that the Nigerian Upstream Regulatory Commission shall, having regard to the needs of the domestic gas market and by the National Gas Master Plan, impose Domestic Gas Supply Obligations (DGSO) on lessees. As proposed, a lessee who fails to comply with its DGSO shall not be permitted to make supplies to gas export operations, and where the lessee only supplies gas to export operations, the lessee shall be directed to suspend operations. This section will oust the existing Department of Gas in its functions and responsibilities.

8. Deregulation of the Downstream Sector

The PIB provides that the pricing of petroleum products in the downstream product sector shall be deregulated to ensure market-related pricing, adequate supply and removal of economic distortions, and the creation of a fair market value for petroleum products in Nigeria's economy. However, although pricing is to be left to market forces, the Bill proposes to safeguard the interests of consumers, by providing that the Nigerian Midstream and Downstream Petroleum Regulatory Authority shall oversee tariffs for transportation by pipelines, bulk storage for petroleum products, and regulated open access facilities. The Nigerian Midstream and Downstream Petroleum Regulatory Authority will also be responsible for market monitoring and promotion of competition. This will oust the present Petroleum Pricing Products Regulatory Agency (PPPRA), which is charged with the same responsibilities but has largely been inefficient to date.

9. Petroleum Host Communities Fund

The objective of the Bill is to provide direct social and economic benefits from petroleum operations to host and impacted communities. Also, the Bill seeks to enhance peaceful and harmonious coexistence between E & P companies on one hand, and host and impacted communities on the other –to foster sustainable and shared prosperity amongst the oil and gas companies and host communities.

The bill stipulates that an annual contribution of 2.5% of the actual operating expenditure (OPEX) of the E&P Company will be placed into a fund. The funds available in the Endowment Fund are to be allocated in the following manner; 70% of the Endowment Fund shall be allocated to the Capital Fund, out of which the Board of Trustees shall make disbursements for projects in each Host Community, as may be determined by the Management. Any sum not utilized will be rolled over and utilized in subsequent years; 20% of the Endowment Fund shall be allocated to the

Reserve Fund. The money is to be invested in the Trust when there is a cessation in the endowment payable by the settlor; 10% of the Endowment Fund shall be allocated to the settlor's Special Project Fund to be utilized solely by the settlor for special projects, aimed to assist and support the host and impacted communities, provided that at the end of each financial year, the settlor shall render a full account of the utilization of the Special Project Fund to the Board of Trustees, and where any portion of the Fund is not utilized in a given year, it shall be returned to the Capital Fund.

If the PIB is eventually passed into law, it will contribute to lowering the oil theft rates and regular rifts, if host communities are satisfied.

10. Fiscal Regime under the PIB 2020

The Bill proposes to replace the existing petroleum profits tax with a Nigerian Hydrocarbon Tax (NHT), at the rate of 50 percent for petroleum operations onshore, and in shallow water fields; and 25 percent for petroleum operations in deep-water, bituminous, and frontier acreages. In addition to NHT, the Bill also proposes companies' income tax at the rate of 30 percent on upstream petroleum operations (which under the existing regime are not subject to companies income tax). Where petroleum operations fall in geographical areas that are subject to different tax rates, NHT shall be levied on the proportionate parts of the profits arising from such operations.

3.5 REPEALS

From the effective date of this Act, the following enactments and Regulations are repealed -

(a) Associated Gas Reinjection Act, 1979 CAP A25 Laws of the Federation 2004, and its Amendments.

(b) Hydrocarbon Oil Refineries Act No. 17 of 1965, CAP H5 Laws of the Federation of Nigeria 2004.

(c) Motor Spirits (Returns) Act, CAP M20 Laws of the Federation of Nigeria 2004.

(d) Nigerian National Petroleum Corporation (Projects) Act No. 94 of 1993, CAP N124 Laws of the Federation of Nigeria 2004.

(e) Nigerian National Petroleum Corporation Act (NNPC) 1977 No, 33 CAP N123 Laws of the Federation of Nigeria as amended, when NNPC ceases to exist according to section 54(3) of this Act.

(f) Petroleum Products Pricing Regulatory Agency (Establishment) Act 2003.

(g) Petroleum Equalization Fund (Management Board etc.) Act No. 9 of 1975, CAP P11 Laws of the Federation of Nigeria 2004.

(h) Petroleum Equalization Fund (Management Board, etc.) Act, 1975.

(i) Petroleum Profit Tax Act Cap P13 LFN 2004, and

(j) Deep Offshore and Inland Basin Production Sharing Contract Act 2019, as amended.

3.6. LITERATURE PERSPECTIVE ON PIB 2020

Over the years discussions have ensued with regards to the petroleum industry bill. One of the most talked about bill in Nigeria, and its significance to the Nigerian economy is unparalleled. Little wonders the emphasis on it. For the past 20 years, students, scholars, industry players, etc. have written so many articles, blog posts, publications, journals on PIB online. Hence, this section is intent on looking into the varying perspective and individual thoughts on the current PIB.

According to David Thomas (2020) of the Africa Business website, some of the changes the current PIB seeks to employ: The bill plans for the selling of shares in a reformed NNPC, the replacement of regulatory bodies, and the reduction and streamlining of royalties. Also, it would play a vital role in addressing the inefficiencies plaguing the NNPC, from slow approval for oil projects to budget shortfalls that hinder its ability to pursue public-private partnerships. What is more, the bill would create a supportive environment for both IOCs and indigenous petroleum companies, help protect the environment and the interests of host communities, support economic diversification in Nigeria, and critically important, promote transparency in Nigeria's administration of petroleum resources. The Senate house speaker has resolved to pass the bill as quickly as possible but emphasized that it would not "sacrifice thoroughness at the altar of speed".

According to an article on "the potential of the Nigerian oil and gas industry under the proposed new PIB" published on the African law and Business website by Hamish McArdle and Tom Edwards of Baker Bott; due to the delay in the passage of the bill into law and gross uncertainty of the investment climate, some large Nigerian petroleum projects announced which together represent a reported USD 47.6 Billion of investments and at forecasted peak production rate would add over 750,000 barrels of oil equivalent per day of production; an uplift of approximately 40% on Nigeria's current rates of production is on hold. Examples of such projects include the Shell-operated Bonga South West/Aparo field, Exxon's Bosi, Owowo West, and Uge Orso fields, the Chevron-operated Nsiko field, and Eni's Zabazaba field.

3.6.1. ENVIRONMENTAL AND HOST COMMUNITIES' ISSUES

On the environmental side to the bill, in research from Therkelsen (2020) of the Stakeholder Democratic Network- SDN raised certain concerns and issues with regards the bill meeting up to the standard for environmental protection and also host community matters:

- Clarity is needed on how current provisions in the bill relating to the National Oil Spill Detection and Response Agency (NOSDRA) and several key pieces of existing legislation to avoid weakening or confusing the existing environmental regulatory framework.
- The creation of Environmental Remediation Funds could be a very positive step, but the bill should place responsibility for environmental regulation under the Ministry of Environment and NOSDRA, to avoid a conflict of interest for the two proposed new regulators who will be responsible for expanding and maximizing returns from the industry.
- The bill does contain several positive provisions, which if developed further could help provide a much more robust framework for environmental regulation. This includes remediation funds and stronger provisions on decommissioning.
- This bill should be amended to support Nigeria's climate commitments and a transition to clean energy. This could be done, for example, through the creation of a Clean Energy Development Fund financed by a levy on oil and gas sales.
- Host community development considerations are limited to the creation of trust funds by oil and gas companies without strong representation and decision-making by host communities. Ideally, the bill would provide a much more holistic framework for host community development beyond only trust funds.

- The bill also places too much onus on communities to prevent third-party damage to infrastructure and punishes whole communities by reducing their trust fund allocation if damage occurs.

According to Mr. Ken Henshaw an Executive Director, We the People, in an article written by Adebola Bademosi (2020) – The Nigerian Tribune, in terms of environmental management, there are clear gaps in all sections of the drafted PIB. "What we need to see in terms of environmental protection is a situation where the agencies responsible for protecting the environment are strengthened and stiffer penalties for environmental degradation by oil companies. "We need to see a PIB that takes into consideration the need to mitigate environmental impacts other than paying compensation. Take gas flaring, for instance, it only talks about penalties for gas flaring but has not put its feet down demanding a deadline for gas flaring,"

Concerning the Governance Provision of the PIB, Mrs. Tengi George-Okoli, Programme Coordinator of the Nigerian National Resources Center (NNRC) in a bid to commend the efforts of NASS in the passage of the bill to law made the commendation in a statement reported by "The Guardian Nigerian News; George-Ikoli said both the Senate and the House of Representatives had demonstrated commitment toward the passage of the PIB with the recently concluded public hearings. However, she noted that NNRC has consistently highlighted weaknesses in two significant aspects of resource management in Nigeria which are: the contentious issues surrounding the management of host communities impacted by the extraction and management of the NNPC.

NNRC had made key submissions in its memoranda to the national assembly advocating that the PIB provided clarity on the capitalization of the NNPC. She said this would enable the corporation to adopt a commercially focused framework that allowed it operates in a competitive space. According to her, the NNPC should explore the possibility of an Initial Public Offering (IPO) with more private sectors and possible citizen participation as practiced in other countries. George-Ikoli said this would also allow for meaningful participation of host communities in decision-making in managing trust at the Board of Trustees and Management Committee and to engender a good operating environment.

She said: “The PIB should ensure mechanisms for dispute resolution are accommodated to address conflicts that may arise in the determination of host community entitlements. She also added that “the PIB should liberalize the midstream and incentivize gas investments by not legislating the base gas price, but instead, allowing it to be determined by the practical framework that considers the cost of production and pipeline transportation.”

With regards to host community issues, which is a major bane to the revamp of the Nigerian Petroleum Industry, the guardian news reports that the President of the Host Community Producing Oil and Gas (HOSTCOM) in the person of Benjamin Style Tamaranebi “while the government proposed 2.5 percent share for HOSTCOM in the bill being considered at the National Assembly, leaders of oil-producing communities rejected it and are insisting on 10 percent equity shareholding. He argues that that is what will bring lasting peace to the communities. He said the vandalism of pipelines and youth restiveness that had been hampering production in the region would continue if the government failed to approve the 10 percent.

He, however, said if the 10 percent was guaranteed, the communities would own the projects due to their stake, thereby mounting security to prevent any damage.

"As far as the PIB is concerned, for it to succeed and guarantee safety for the operating companies in all the communities and give them equity participation and required sense of belonging, the 10 percent equity share must be honored," he stated.

He added that the peace being enjoyed across the nine (9) oil-producing states was because of their hope of fairness and equity they see in PIB, which unfortunately was being dashed with the offer of 2.5 percent to the host communities. It's obvious that the most contentious aspect of the bill is that of the Host and Impacted communities.

3.6.2. GOVERNANCE AND ADMINISTRATION PROVISION

According to the research by Templar's legislative watch (2020); there is not much difference in the role of the Minister between the petroleum Act (1969) and the proposed bill; including exercising general supervision over the affairs and operations of the petroleum industry and report developments in the industry to the government. The Minister also retains the right of pre-emption of petroleum or petroleum products in the event of a national emergency. But it seeks to curtail the Minister's powers by proposing that (amongst others): The price-fixing powers of the Minister for petroleum products no longer exist under the PIB, the powers to grant and revoke Prospecting Licenses and Mining Leases exercisable solely by the Minister are now only exercisable upon the recommendation of the Commission.

Noteworthy is that the Commission is required to maintain a Frontier Exploration Fund which would be funded by 10% of rents on petroleum prospecting licenses and petroleum mining leases.

The Authority is to maintain a Midstream Gas Infrastructure Fund ("MGIF") which is to be a body corporate with a Governing Council having the Minister as Chairman. The purpose of the MGIF is to make equity investments of Government-owned participating or shareholder interest in infrastructure relating to midstream gas operations aimed at increasing the domestic consumption of natural gas in projects part-financed by private investment and to encourage private investment. NNPC Limited is created as a successor company to Nigerian National Petroleum Corporation ("NNPC") and is expected to come into existence within 6 months of the passage of the Bill. Ownership of NNPC Limited is to be fully held by the Ministry of Finance Incorporated on behalf of the Nigerian Government at incorporation, with the Board to be appointed entirely by the President.

The research concluded that the governance of the Nigerian petroleum sector is the fulcrum on which every other aspect of the sector rests. The PIB wrests much of the power that has resided in the Minister for the past five decades and institutionalizes them. The Bill also adopts a commercial approach to the governance framework of the petroleum sector through a clean separation of the regulatory bodies and the commercial body to promote effectiveness in the sector. Also, the separation of the regulatory bodies is a welcome development that will aid the ease of governance of the Nigerian petroleum sector as well as enable policies to be well structured to suit the needs of players per sector.

3.6.3. FISCAL PROVISIONS

Apart from the fact that the Nigeria petroleum industry is losing investors due to the non-passage of the PIB, one of the major concerns raised by the IOCs is the non-viability of doing the petroleum business in Nigeria due to the unattractive fiscal policy. In fact, according to Adebola Badamosi (2020) in an article by Nigerian Tribune says; Experts say the loss to the country during the first eight years that the PIB languished in parliament, is as high as $120 billion (about $15 billion annually). Also, the 2013 Nigeria Extractives Industry Transparency Initiative's (NEITI) audit report of the oil and gas sector revealed that a cumulative of $10.4 billion and N378.7 billion was lost, under-remitted, or outstanding due to inefficiencies, theft, or absence of clear fiscal regime in the sector.

Other perspectives from researchers, experts, and analyst on the fiscal provisions of the bill: In the article by Adebola he highlighted some of the perspective shared by Joseph Nwakwe, President of the Society of Petroleum Engineers (SPE) Nigeria Council, he said that for over a decade, the country has not been able to attract the needed investment, despite having many windows for such. It is clear to everyone that the Federal Government is in no position to fund the level of development that we need, hence, the need to default to the private sector and to be able to bring in investors either domestic or foreign, thus, we have to have a competitive fiscal regime. It needs to be attractive. Also added to that, the PIB has to not just attract capital but moves the country away from an extractive to a value additive industry.

3.7. CEREBRAL PERSPECTIVES ON PIB 2020

3.7.1 PERSPECTIVE ON GOVERNANCE AND ADMINISTRATION PROVISION

According to Iledare (2021); the governance provision of the PIB 2020 seeks to eliminate the amorphous governance and institutional ineptness that have undermined Nigeria Petroleum Industry growth for decades; and put the sustainability of the industry, in the face of the energy transition dynamics, in jeopardy.

One of the institution – policy institution of the governance aspect of the PIB 2020 is the "Minister of Petroleum". The fact that the Minister is responsible for policy setting and direction, coordination and suspension of the oil and gas industry is well articulated. However, missing conspicuously is the "how" and the tools needed to implement or execute this power and discharge his ministerial responsibilities and duties. As such this raise concerns as to how the minister would effectively direct the oil and gas industry. Some of these concerns as highlighted by (Iledare, 2021) are;

- Personalizing institutional responsibilities, as the immediate ministerial experience suggest, may not be the way to go if transparent and accountable governance of the industry is not to be elusive perpetually. Iledare further suggest that co-opting a permanent technical staff for policy continuity is worthy of consideration; this in his opinion would prepare the minister to execute the power of the office effectively and efficiently and even ethically too.
- Iledare (2021) also has concern particularly with section 3 (2-5) of the governance provisions with respect to usurping the powers of the board of the regulatory institutions. For example, in 3(3) the minister can pre-empt a petroleum product market in a deregulated environment, this seems to be anti-competitive. The minister is not a regulator and the petroleum product market is not a monopoly other.
- Lastly in 3(5); that the board cannot debate a policy directive issued by the minister. Iledare's final submission and perspective to the governance provision on this policy institution on this policy institution is that the languages used in describing the powers of the minster are dictatorial, and perhaps less innovative.

With regards to the regulatory institution, Iledare is of the opinion that a single regulator is more effective compared to the proposed dual regulator in the PIB 2020, as Department Petroleum Resources (DPR) has done well so far and can be better, despite political interference. He also adds that a Central Bank of Nigeria (CBN) type regulator is what the industry needs in times like this where administrative cost of governing the oil and gas industry is excessively high and compared to none worldwide.

3.7.2 PERSPECTIVE ON HOST COMMUNITIES PROVISION

According Iledare (2021) the elusive making the Petroleum Host Communities a significant stakeholders of Industry Is attributable to transactional leadership style at the State, Federal and Community level; elite capture mentality of citizens at large; the pervasive Esau's syndrome in the petroleum host community; and the collapse of the national value system. He further said; not with-standing the current state of things alluded above, PIB 2020 offers the opportunity to end the perceptions of neglect, inequity and abandonment, which are the bedrock of sustained agitations in the region by the host communities. Over the years, the federal government has attempted to diffuse agitations in the community using fiscal instruments such as resources from 13% derivation and NDDC Act etc. These resources conferred to the State governments to care for host communities hardly trickle down to the petroleum community in a large enough quantity to make the type of difference required in transferring the region.

Some of the key provisions of the Host Communities Chapter of the PIB 2020 Iledare pointed out are:

Fund Utilization: The provision of the PIB 2020 on the modality for fund utilization represent a great departure from the NDDC act as well as the 13% derivation allocation to the oil producing states, which has no utilization guide. Section 236(6) empowers the Commission or the Authority to make regulations to safe guard the utilization of the trust fund with oversight responsibility in terms of effective project implementations in the region, which for me, it's a plausible idea. Also, section 241 stipulates matters on which the funds may be applied, putting emphasis on the existence of approved development plans by the community for the community; hence, the community is the driver of the plan.

Iledare also added that section 244(b) is innovative, catering futuristically to a known fact, the settlors and funds are not perpetual. The mandate to invest at least 20% of the trust fund for future projects is quite admirable, representing another departure from the NDDC act and the derivation fund paid to the state and used mostly for the state operating expenditure. He also alludes that clarity is in order by the settlors of who a host community is; suggesting that perhaps, the settlors through communities needs assessment can easily define the host community as a community situated in its area of operations, around the pipeline right of ways and any other facilities as the settlor may determine.

The next key provision Iledare highlighted is the "sources of host communities' trust fund". According to section 240(2) 2.5% of settlors actual operating expenditures (OPEX) in the year immediately preceding the calendar years is to be allocated to the fund and in Iledare's words "2.5% of OPEX to fund a sustainable host communities development path does not do justice." His reasons for the above statement, which are indeed valid:

- The estimated fund is about ₦10-14 billion (upstream only) going into the funds annually will be grossly inadequate given the number of communities, terrain and development deficits.

- The degree of vulnerability, if OPEX is the primary funding source, are astounding because of the heterogeneity of settlors and variability of their operating expenses.
- 2.5% of OPEX provisions in PIB 2020 sends signal of the seriousness of ownership exclusion perception that fuels agitators in the first place. Paying a portion of royalty according to Iledare to host community, especially affected communities, reflects a reward for ownership, than all the instruments employed so far. Also a visitation of the NDDC Act to surrender a portion to operationally affected communities trust is worthy of consideration.
- The derivation provision in the constitution beyond the 13% is due for amendment and a prescription of a spending modality rather than just passing it on to the state and local government is inevitable now too.

3.7.3 PERSPECTIVE ON FISCAL PROVISIONS

According to reports on the April 13th, 2021 by the financial energy review website, Iledare advised the federal government to implement a progressive fiscal framework that encourages investment flows into the petroleum industry, saying only flexible, dynamic and stable fiscal instruments can attract such investments. At a seminar organized by the Facility for Oil Sector Transformation (FOSTER) Iledare expressed concerns that the existing fiscal components and other fiscal laws in the country might not attract investors, "except if the ongoing reforms on the PIB 2020 fiscals are appropriately completed, since the current fiscal system is neither effective nor efficient and prospective investors always fear it can change any moment."

Iledare explained that what the petroleum industry investors want is "quick and fair reward for risked pocket investments" and that the fiscal regimes of host countries are viewed critically with such objectives in mind as regards stability of host government's fiscal arrangements; competitiveness; attractiveness; changes in petroleum taxation regime; income tax structure of exploration and production (E&P) firms' home country.

The proposed dual tax system may result in a lower effective tax rate than the existing single tax rate and may perhaps improve international perception of Nigeria's fiscal competitiveness complementing it is highly geologic prospect (Iledare, 2021). He added that, nearly $19 Billion is really what Nigeria needs every year to develop its oil reserves. If we are flexible, dynamic and stable for the right investments there will be output expansion, Jobs will be created and government have extra money to lavish on its citizens.

Finally, Iledare noted that the fiscal system is not about just balancing the budget, "but the government must move away from thinking that the budget must be rents, royalties and corporate tax because the Joint Ventures (JV) is not adding any value up to 10% with all the investments of the government. They are better off spending the money on education.

According to an article from the monthly edition of the value chain magazine; Iledare, 2021 speaking of the fiscal reform of the PIB 2020 says that "If Nigeria is to overcome the peculiar challenges facing its oil and gas industry, a pragmatic fiscal reform is desirable – a reform that would forego the prosperity of the few today for prosperity of many in the future."

According to Iledare, 2021, the design of the tax & royalty system portrays, government's aversion to risk and a glaring preference for early rent-seeking in the quest for enhancing government's access to petroleum revenues. He would rather that the government recalibrates its royalty and tax structure to deemphasize early rent extraction mechanism and embrace a mutuality of interest approach to fiscal systems that are designed in order to achieve pareto optimality conditions for all stakeholders.

Below are Iledare's thoughts on some of the key provisions of the fiscal aspect of the PIB 2020

- **Fiscal Administration:** The institutions responsible for the administration is the Federal Inland Revenue Service (FIRS) responsible for the assessment and collection of NHT and CIT while "The Commission" responsible for determining and collecting rents and royalty defined in section 306. According to Iledare the role of these institution should be limited to just the determination of payment dues and let the collection responsibility be executed through direct payments to the treasury without intermediaries; this is to avoid transactional cost that may be incurred if the institutions play the collecting role.
- **Nigerian Hydrocarbon Tax (NHT):** The introduction of hydrocarbon tax instrument in the upstream petroleum space represents a significant departure from the single tax system (PPT) that has prevailed in the Nigerian upstream Industry since 1959. According to Iledare, 2021, the NHT is not an uncommon taxation approach over and above the familiar corporate income tax. In fact, it is a useful instrument to incentivize hydrocarbon investment without compromising government's access to revenues, if needs be. The NHT is applicable to liquid Petroleum (Oil, NGL, Condensates) by terrain (onshore, shallow offshore and deep offshore (>200m of water depth)) but not applicable to associated gas.

Iledare pointed out certain ongoing ammendments post NASS public hearings; the very one amendment that agitates him is the request to not apply NHT to deep offshore. He think is absurd, and such requests must be disallowed, to let go of an acceptable fiscal systems design principles in exchange for the new demand for the royalty payments from all deep offshore production is unwise. He would rather allow NHT to be deducted than to let go of it entirely in deep offshore irrespective of whether the assets are matured or new.

Another ammendment, is in reference to a periodic review of the fiscal instruments every seven years. Looking at the long-term nature of the petroleum business, seven years pronouncement in the law may create additional uncertainty that may threaten contract sanctity. Iledare opines that review every seven years may be unwise.

- **Production Allowance:** This new concept to guide incentives tied to output, is very commendable compared to incentives based on efforts such as Investment Tax Allowance (ITA), Uplifts and Investment Tax Credits (ITC) mechanism. The fact that the allowance is tied to cumulative production and terrain makes the new regime progressive.

- **Royalty:** Usually royalty in whatever form is considered to be regressive by investors, because it shows the risk averseness of the government. The design of the royalty schemes in PIB 2020 did attempt to reduce the regressive impact, using sliding scales tie to production and terrain. Iledare suggest that royalty by production be limited to maximum rate of 15% onshore, 12.5% shallow offshore and 10% deep offshore. The reasoning for these recommendations is to improve the competitiveness, attractiveness and progressiveness of fiscal regimes in Nigeria. In addition, royalty by price is additive to royalty by production which further makes a regime less progressive, but the progressivity of a regime is not affected that much when tax instruments are properly applied; even though this type of thinking may be unpopular for rent-seeking hawks but those in pursuit of output expansion understand that what makes fiscal regimes attractive to investors in most case is delaying rent extraction to after profit is declared. According to Iledare's fiscal systems school of thoughts, it is better to increase the NHT rate than to increase royalty rate, if output expansion is the aim of a fiscal system reform.

3.8. LITERATURE ON GHANA AND ANGOLA OIL AND GAS LAW

3.8.1. GHANA OIL AND GAS LAW

3.8.1.1. Legislative Overview

In the mid-1980s, the government introduced the first legislative framework for upstream oil and gas activities in Ghana. Three main pieces of legislation were enacted by the government to regulate upstream oil and gas activities. Chief among the reforms was the passage of the Ghana National Petroleum Corporation Act, 1983 (PNDCL 64), which established the Ghana National Petroleum Corporation (GNPC) as the national oil corporation to champion state activities in the upstream oil and gas sectors. In addition, the now-repealed Petroleum (Exploration and Production) Law, 1984 (PNDCL 84) was enacted to regulate exploration and production activities as well as provide the framework for the engagement of international oil firms by the government to undertake exploration and production activities. Lastly, the Petroleum Income Tax Law 1987 (PNDCL 188) was passed to regulate operations and taxation in the upstream oil and gas sector. Of the three pieces of legislation, PNDCL 84 and the PNDCL 188 have been repealed and replaced with new pieces of legislation that are currently applicable. This is discussed further below.

The Fourth Republican Constitution, which came into force in 1992, provides that 'every mineral in its natural state in, under or upon any land in Ghana, rivers, watercourse throughout Ghana, the exclusive economic zone, any area covered by the territorial sea or continental shelf in the Republic of Ghana is the property of the Republic of Ghana and is vested in the President on behalf of, and in trust for the people of Ghana'. As a check on the powers of the President to control and manage the resources on behalf of the people of Ghana, the Constitution requires parliamentary approval for all transactions involving the grant of a right for the exploitation and production of natural resources in Ghana and further mandated the establishment of specific commissions to be responsible for the regulation and management of the utilization of the natural resources and the coordination of the relevant policies.

Upon the discovery of oil in commercial quantities offshore Ghana in 2007, the Petroleum Commission Act, 2011 (Act 821) was subsequently passed to set up the Petroleum Commission as the regulator to coordinate activities in the upstream petroleum industry following the Constitution. In addition, the Petroleum Revenue Management Act, 2011 (Act 815) as amended by Petroleum Revenue Management (Amendment) Act, 2015 (Act 893), was enacted to provide the framework for the management of petroleum revenues. In 2016, the Petroleum (Exploration and Production) Act, 2016 (Act 919) (the E&P Act), was passed to replace the PNDCL 84, as the primary legislation for the regulation of petroleum activities in the upstream sector. Also, the Income Tax Act 2015 (Act 896) as amended provides a regime for the taxation of income of contractors and subcontractors in the sector. To support the implementation of the key laws in the sector, the government through the Minister of Energy (the Minister) and the Petroleum

Commission have enacted several regulations, guidelines, and developed policies for the sector. These include the following:

1. the Petroleum (Local Content and Local Participation) Regulations, 2013 (LI 2204);
2. the Petroleum Commission (Fees and Charges) Regulations, 2015 (LI 2221);
3. the Petroleum (Exploration and Production) (Measurement) Regulations, 2016 (LI 2246);
4. the Petroleum Exploration and Production-Data Management Regulation, 2017 (LI 2257);
5. the Petroleum (Exploration and Production) (Health, Safety, and Environment) Regulations, 2017 (LI 2258);
6. the Petroleum (Exploration and Production) (General) Regulations, 2018 (LI 2359);
7. the Energy Sector Strategy and Development Plan;
8. the Gas Master Plan;
9. the Gas Pricing Policy Guidelines to the Petroleum (Exploration and Production) (Measurement) Regulations;
10. Guidelines for the formation of joint venture companies in the upstream petroleum industry of Ghana (March 2016);
11. Guidelines on Submission of Proposed Contracts to the Petroleum Commission (23 February 2018); and the Oil and Gas Insurance Placement for the Upstream Sector.

3.8.1.2. Legal and Regulatory Framework

As already indicated, under the Constitution of Ghana, all untapped natural resources including oil and gas resources are vested in the President of Ghana for and on behalf of the people of Ghana. This is restated in the E&P Act. Therefore, the right to explore and develop such resources is subject to agreement or license granted by the government (acting through the Ministry of Energy) and approved by Parliament. Initial petroleum activities in Ghana were governed by the Ghana National Petroleum Corporation Act, 1983 (PNDCL 64), which constitutes an establishing instrument of the national oil corporation, and the Petroleum Income Tax Act, 1987 (PNDCL 188). However, owing to increased activities in the upstream oil and gas sector after the commercial discoveries in the deep waters, various regulatory reforms were initiated. This resulted in the enactment of the Petroleum Commission Act 2011 (Act 821), the E&P Act that provides an overarching framework, and the Petroleum (Local Content and Local Participation) Regulations 2013 (LI 2204) enacted to ensure local participation in the sector given the increase in the activities of foreign-owned entities in the sector, among others. There is also the Petroleum Revenue Management Act 2011 (Act 815) that governs the use of petroleum revenue accruing to the state from petroleum exploration. These laws are in addition to other regulations, directives, and guidelines issued to guide operations in the sector.

The primary laws governing the upstream oil and gas sectors are the E&P Act and the Ghana National Petroleum Corporation Act, 1983 (PNDCL 64) and a taxation regime under the Petroleum Income Tax Act, 1987 (PNDCL 188) and the Income Tax Act, 2015 (Act 896) as amended (www.iclg.com).

3.8.2. ANGOLA OIL AND GAS LAW

3.8.2.1. Overview of the Oil and Gas Sector

Angola holds almost 8.160 billion barrels of proved crude oil reserves, according to the latest estimates from the 2019 Annual Bulletin. Angola is the second-largest oil producer in Sub-Saharan

Africa, behind Nigeria. Exploration and production activities relating to oil and natural gas in Angola are governed by Law 10/04 of 12 November, as amended by Law 5/19, ("Petroleum Law" or "Law 10/04") and by Presidential Decree 5/2018. The right to produce and explore for oil or natural gas is granted by a concession agreement, generally preceded by a public tender procedure. A concession for exploration and production, after the public tender procedure, is awarded via concession decree, issued by the Angolan Government, granting the national concessionaire, the National Agency for Oil, Gas, and Biofuels ("ANPG"), the right to develop a specific oil concession.

Table 3.1: Key Facts

Liquid reserves (remaining)	4.77 Billion barrels (1/1/2020)
Liquid Production	1.394 MMbbl/d (2020)
Liquid reserves/Production	9.4 years
Gas reserves (remaining)	4.43 tcf (1/1/2020)
Gas Production	0.74 bcf/d (2020)
Gas reserves/Production	16.4 years

Source: Wood Mckenzie

3.8.2.2. Policy and Legislation

1. Key Legislation

Oil and Gas activities in Angola were initially governed by Law 13/78, the General Petroleum Activities Law, of 26 August 1978. This law is superseded by Law 10/04, the Petroleum Activities Law, of 12 November 2004, which sets out the legal framework for access to petroleum resources, and rules for petroleum operations.

Law 13/04 of 24 December 2004 sets out the rules of taxation of petroleum operations in Angola. In May 2018, a suite of new laws was published including, Decree 06/18 - setting out fiscal incentives for marginal fields, and Decree 07/18 - Angola's first fiscal terms for gas.

2. State Oil Company

In June 1976, seven months after independence, the state oil company, Sonangol, was established (Decree 57/76). Law No.13/78 of 1978 provided that all hydrocarbon deposits are state property, with Sonangol as an exclusive concessionaire. Sonangol is authorized to contract foreign oil companies to explore and produce hydrocarbons.

The Ministry of Petroleum was intended to be the industry regulator. However, over the years Sonangol's remit and influence expanded into many areas. Sonangol was responsible for approving budgets and recoverable costs, and for procuring oilfield services. It also expanded into other areas, including providing oilfield services, aviation, banking, and telecoms.

These expansions created a large, often inefficient company with several potential conflicts of interest. In May 2016, with oil revenues collapsing, the government published Decree 109/16 to re-organize the petroleum sector. The decree set up a committee to improve efficiency, cut costs and increase profits. In June 2016, Isabel dos Santos, daughter of then-President Jose Eduardo dos Santos, was appointed head of Sonangol, to bring about the transformation. However, following the appointment of a new president, in November 2017, dos Santos was removed and replaced by former Sonangol executive Carlos Saturnino.

Restructuring of Sonangol began in 2018 with the objective of slimming down the organization and focusing it on E&P activity. A new Hydrocarbon agency, the ANPG has taken over as regulator and concessionaire. With the regulatory functions now moved to an independent body, Sonangol is beginning to divest its non-core subsidiaries, rationalize its upstream portfolio and prepare for a potential IPO in 2022.

3. Licensing

Licensing is overseen by the Ministry of Petroleum with Sonangol as the national Concessionaire holding all exploration and production rights and conducting regular licensing rounds. Companies wishing to explore and produce hydrocarbons in Angola must either form a joint venture with Sonangol or enter into a Production Sharing Agreement (PSA).

Two types of licenses are available, prospecting licenses and concessions. Prospecting licenses can be applied for directly through the Ministry of Petroleum and have a maximum duration of three years. Concessions require a formal tender process. As Concessionaire, Sonangol requests the Ministry to open a formal tender which is published in the Official Gazette. Concession licenses are normally granted for 25 years but may be extended through negotiation.

3.8.2.3. Fiscal Term

Upstream (Overview)

Offshore production is subject to a production sharing contract (PSC), whereas a concession agreement, with royalty and tax payments, applies to onshore production and the shallow water Cabinda concession. The third regime is a risk service agreement (RSA) which applies to licenses granted outside of formal bid rounds.

The structure of the PSC is as follows:

- **Bonuses:** a signature bonus and production bonuses are payable
- **Cost oil/gas:** a percentage of production is available for the recovery of operating and capital costs.
- **Profit oil/gas:** remaining production after cost recovery is divided between the investor and the government on a sliding scale basis linked to production shares or rates of returns (IRRs)
- **Taxes:** are paid by Sonangol on the contractor's behalf from its share of production.

Two significant issues exist with the Angolan deepwater fiscal terms. The first concerns the capital cost uplift that allows the partners to uplift all capital costs by up to 50%. In situations where large, high-cost, development projects are required (i.e. the majority of Angola's deepwater discoveries) the capital uplift means that for a project with a capital expenditure of US$3 billion the recoverable costs are US$4.5 billion.

The combination of capital costs and uplift has some major effects. In developments where the facilities are purchased (and thus capitalized), cost oil remains saturated for lengthy periods. An alternative development solution is for the facilities to be leased. In this case, the lease costs are assigned to operating expenditure (thus reducing capital costs), are not uplifted, and are also spread more evenly throughout the project life.

The second issue concerns the rate of return-based profit oil splits that apply to deepwater contracts. Many deepwater developments rarely make significant rates of return (more than 30%). Therefore, the higher-level profit oil splits, which significantly benefit the state, are never encountered in deepwater Angola. This compares with the shallow water production sharing contracts (e.g. Block 2 and 3) where the profit oil splits are based on cumulative production. In these contracts, the profit oil split is 90/10 in favor of the state when more than 100 MMbbl is produced by individual fields.

3.8.2.4. Current Fiscal Term

Production Sharing Contract

- **NOC equity participation**

Sonangol took a 30-50% stake in permits issued in the 2010/2011 licensing round. It is carried through the exploration period and reimburses carried exploration costs upon commencement of production. Onshore, Sonangol is awarded a 30% stake. A minimum of 20% participation is also reserved for domestic Angolan companies, restricting available equity for international investors to 50%. Both parties will pay all expenses, including exploration costs.

- **Bonuses, rentals, and fees**

Signature bonus, work program, and social development fees ('Contribution for Social Projects') are the three bid factors in licensing rounds. Only work program expenditure is cost recoverable or tax-deductible.

- **Royalty and other production taxes**

Royalty; Not applicable.

Import duty; Contractors are exempt from import duties.

Export duty; Not applicable.

VAT; 0% on purchases and sales (but VAT in the region of 13-16% is expected to be introduced and fully implemented between (2019 to 2021).

Environmental & CO_2 taxes

Operators must adopt measures to prevent loss or waste of oil and gas.

Other Production Taxes

Minor taxes including a payroll tax and a training tax are levied.

- **Domestic Market Obligation (DMO)**

The government can request a maximum of 50% of production to satisfy domestic consumption. Sonangol is required to purchase the crude at the market price.

- **Contractor Revenue Entitlement**

Under a PSC, the contractor receives revenue through sales of cost recovery production and its share of profit oil/gas production.

- **PSC Cost Recovery**
- **Cost Recovery Ceiling**

The ceiling on production available for oil cost recovery varies between contracts. Historically it was set at a flat rate, ranging between 50-65% based on the vintage of the contract. In the last onshore round, the ceiling was a flat 65%. However, for deepwater licenses, the ceiling can be increased after 4 or 5 years if the project has not yet recovered all its costs. Deepwater fields under marginal terms are allowed a ceiling of 80% for the first 4 years of production, reducing to 65% thereafter. Costs for associated gas can be deducted from oil revenues.

- **Recoverable Costs**

Development costs are recoverable over four years on a straight-line basis. Exploration and operating costs can be written off as incurred, excluding interest. General and administrative costs incurred by affiliates of the contractor outside of Angola and not directly related to the petroleum operations can be recovered but are limited to 1% of the costs of exploration and development expenditures.

Provision exists in deepwater PSCs for the recovery of abandonment costs against cost oil. The provision is first given in the year in which the remaining recoverable reserves fall below a certain percentage of total field reserves and are calculated on a unit of production basis, based on the estimated cost of abandonment in subsequent years.

The relevant recoverable reserve percentage below which the provision applies varies for different field sizes. For fields below 50 MMbbl, the percentage is 50%, 50-100 MMbbl it is 30% and over 100 MMbbl it is 25%. Development costs for pre-January 1984 contracts are recovered over four years on a straight line (SLN) basis.

- **Investment uplift/credit**

The majority of contracts have uplift on tangible development costs of 40%, recoverable in equal installments over four years, starting in the year in which commercial production starts or in the year in which the expenditure is incurred, whichever is later.

In some deep water and shallow water blocks, costs can be uplifted by 50%. Blocks awarded before 1984 had an uplift of 33% of tangible development costs. The deepwater and ultra-deepwater blocks in the 2010 licensing round have an uplift of 20% of tangible development costs.

- **Cost Carry Forward**

Any unrecovered costs can be carried forward for relief in subsequent years without limit. No interest applies to unrecovered balances.

Costs are written off/recovered in the following order:

1. Capital costs (with uplift).

2. Operating costs.

3. Exploration costs.

- **PSC Profit Sharing**

Production remaining after cost recovery is termed profit oil/gas and is divided between the contractor and the government. The basis on which this division is made varies between contracts, with more recent ones using the contractor's rate of return (ROR) whereas in earlier contracts the split was based on cumulative production.

All offshore contracts awarded since 1991 fall under the ROR-based model. During the application process, bidders must specify the rate of return steps and the profit oil splits applicable to each tier. The contract allows for up to five different tiers of profit splits with rates varying from contract to contract.

The typical rate of return based profit splits are given in the table:

Table 3.2: IRR Profit Splits

IRR (%)	**Sonangol (%)**	**Contractor (%)**
<15	25	75
<25	40	60
<30	60	40
<40	80	20

Source: Wood Mackenzie

The split is calculated quarterly with the split applicable to any quarter determined by the rate of return achieved in the previous quarter. The ROR calculation is based on the contractor's accumulated compounded post-tax cash flow.

Before 1991, profit splits were based on cumulative production with bidders specifying the profit splits applicable to each tier.

Typical cumulative production-based profit splits are as follows:

Table 3.3: Cumulative Production Profit Splits

Cumulative Production from Development Area (MMbbl)	**State (%)**	**Contractor (%)**
0-25	40	60
25-50	60	40
50-100	80	20
>100	90	10

Source: Wood Mackenzie

- Corporate (or Petroleum) Income Tax

For international companies, a Petroleum Income Tax (PIT) of 50% is levied on the contractor's share of profit oil. In 2012, a reduced rate of 35% was introduced for domestic oil companies when partnering with Sonangol.

Gas taxation was introduced in May 2018, under Decree 17/8, at a rate of 25%. Non-associated gas projects equal to or less than 2 Tcf will attract a reduced rate of 15%. Historic gas production will continue under previous arrangements unless contracts are renegotiated.

Deepwater fields under marginal field terms are allowed a reduced income tax rate of 25%. Costs are depreciated for PIT in the same manner as cost recovery. Associated gas costs are recovered against oil income. Losses can be carried forward indefinitely.

- Additional Profits Taxes; None applicable.
- Fiscal/Contractual Ring-Fences

• Each discovery constitutes a separate development area.

• Except for exploration costs, only costs incurred within the development area are eligible for recovery.

• Exploration costs, including dry hole costs, can be recovered from any cost recovery pool from producing fields within the contract area. The costs can be recovered in the year in which they are incurred, or in the year of first production (whichever is the latter).

• Costs incurred in the development of associated gas are recoverable against crude oil income (W. Mackenzie, 2020).

CHAPTER FOUR

4.0. ANALYSIS OF THE PIB 2020

As earlier established the goal of this study is to give a critical look into every aspect of the PIB to ascertain its value and necessity for the Nigerian Petroleum Industry. Having understudied several ideologies and literature perspectives from incredible minds ranging from professionals in the industry to scholars in academia, at this junction I will delve into sharing my perspective and opinion about the PIB as it relates to its relevance in helping the Nigerian petroleum Industry to achieve its goal of revamping the Industry and make it stand out as a leader in the global energy industry. In touching every aspect of the bill I will, first of all, discuss my perspective on the governance provision, administrative provisions, host and impacted community issues and finally concentrate on the fiscal aspect; do a critical analysis of the fiscal provisions of the PIB and compare with current Nigerian PSC fiscal regime, as well as that of Ghana and Angola by creating an economic model using a Hypothetical oil field data, where I apply the fiscal element of the respective petroleum fiscal system to the model. I will use the results to infer the efficiency of the PIB-proposed fiscal framework and finally make recommendations where necessary concerning my findings. Without further ado, we delve into the analysis:

We are not oblivious to the fact that the Nigerian petroleum Industry is at debilitating state which needs urgent intervention and overhauling; issues ranging from poor governance, union-management strife leading to shutdowns over policies and collective bargaining issues, obsolescence of petroleum laws, inefficiencies of the four (4) oil refineries, petroleum fiscal regimes not aligned with industry best practices, vandalism of oil and gas assets, poor management of oil revenues, environmental pollution and underdevelopment of oil-bearing communities, etc... This amongst other issues facing the Nigerian petroleum industry was what birthed the Journey to PIB, which started as ORGC, saddled with the responsibility to review and streamline extant petroleum laws to develop a regulatory framework of the revamping of the oil and gas sector for bankability and be beneficial to all stakeholders...the journey continued to the birthing of the first PIB in 2008, which kept evolving till where we are now.

Thus, the initiative of repealing and sort of streamlining the sixteen (16) different laws that govern the Nigerian petroleum industry is a commendable effort; a single-sourced document that details the legislative, regulatory and fiscal framework of the industry is a great work that can serve as a game-changer for the industry. Proceeding further will be an attempt from me to critically look into the PIB 2020 in the light of its significance in revamping the Nigerian oil and gas industry to meet international best practices by adequately analyzing the key provisions of the Bill.

To properly analyze this bill, one must look at the critical stakeholders the PIB directly affects. These are the Nigerian government, the oil and gas companies, Host and Impacted communities, and the Unions. Gaining satisfaction from the outcome of the drafted PIB by the respective stakeholders is not guaranteed, be that as it may, there should be some sort of consensus reached by all, of its benefits to all involved or affected by it. Hence, the success of the PIB is to a large extent predicated upon the satisfaction or cooperation reached by all stakeholders involved, that is, the government, oil and gas companies, Host and impacted communities, and the unions (NUPENG, PENGASSAN) and its ability to meets its overall objective of revamping the Nigerian petroleum Industry.

Now, a systematic approach to analyzing the PIB 2020, is to take it according to its four (4) separate sections, wrapping up with a more quantitative approach to analyzing the fiscal provision of this bill by a comparative analysis with the Nigerian DOA'19 PSC fiscal framework, and that of Ghana and Angola.

Before one delves into section-by-section analysis of the bill, from above, we can establish that passage of the PIB will the first and significant step in transforming the Nigerian petroleum industry. The question to respond to now is, "why has the PIB not been passed yet?" the simple and straightforward response to that question is a conflict of interest and dissatisfaction of the current draft by respective stakeholders. This delay and lack of consensus have cost the industry direly and the nation as a whole; according to a report, Nigeria loses $200 Billion yearly due to the non-passage of the PIB (Brown, 2020). Aside from the conflict of interest, certain stereotypes have caused the laxity and passivity in the attitude of stakeholders; especially the Nigerian government in the passing the PIB; a bill that should have been passed 12 years ago (2008).

One of such stereotypes is "The Nigerian petroleum industry has functioned well under the current laws", this is completely erroneous because organizations/industry can't thrive without a dynamic policy or law, which has the characteristic of been flexible enough to adapt to changes in the global oil and gas industry. No investor would invest in a country in which managing business uses the rule of thumb. Countries like Ghana, Tanzania, Uganda, and Mozambique have more current laws in line with global best practices.

Secondly, "Nigeria is the bride of the world's oil and gas industry because of our sweet crude" (Brown, 2020) but the current reality suggests otherwise, many other countries produce sweet crude with cheaper production costs than Nigeria. The increasing discoveries within and without the African region has heightened competition so the earlier Nigeria faces this reality and transforms her petroleum industry for competitiveness by creating value in the chain of production, the better.

Thirdly, "No matter what, Nigeria has ready buyers for our petroleum, and customers will not fail to buy" (Brown, 2020) but the reality is that buyers like the USA are becoming great global sellers, since the advent of the shale oil production and also there is increasing uptake of clean energy.

Fourthly, "The world shall continue to rely on crude for its energy needs" (Brown, 2020) but the reality is that the world is transiting from fossils into renewables. Climate change and environmental concerns are driving the energy sector towards clean energy, solar, electric cars, etc.

Fifthly, “Nigeria has fossil fuels in abundance, and it will remain dominant in the world’s energy need for so many more decades” (Brown, 2020) but the current reality is that fossil fuels will gradually get displaced by clean, renewables, and non-carbon sources. Hence, Nigeria must focus on exploitation, transformation, and the repositioning of her oil and gas resources to add maximum value, which will propel the development of her economy. She should also begin immediate plans for diversification, which will get Nigeria out of oil dependence.

Finally, “The PIB is the Magic wand that will ultimately heal the petroleum industry of its wounds” (Brown, 2020), as good and significance are passing the bill in revamping the Nigerian petroleum industry, the truth is that it shouldn’t just stop at the passage of the bill, but implementation is key. The PIB will no doubt emplace good governance, competitiveness, global best practices, growth, sustainability, and bankability, but the industry is in such a poor state and will need time to recuperate and deliver significant dividends.

4.1. GOVERNANCE PROVISION OF PIB 2020

The objectives of the governance provision of the PIB 2020 are as follows:

1. Create efficient and effective governing institutions, with clear and separate roles for the petroleum industry.
2. Establish a framework for the creation of a commercially oriented and profit-driven national petroleum company.
3. Promote transparency, good governance, and accountability in the administration of the petroleum resources of Nigeria; and

4. Foster a business environment conducive to petroleum operations.

Now, to achieve these objectives, certain proposition or policies needs to be adopted; these policies are some of the key provisions of the bill. Some of these provisions under the governance provisions are:

The establishment of the Nigerian Upstream Petroleum Regulatory Commission (NUPRC) also known as “The Commission” which act as the regulator of the upstream sector and the Nigerian Midstream and Downstream Petroleum Regulatory Authority (NMDPRA) also known as “The Authority” functioning as the regulator of the Midstream and Downstream sectors of the petroleum industry. It is anticipated the creation of the commission and the Authority will provide better enforcement of standards to streamline inter-agencies responsibility; thereby ensuring a clearly defined path of responsibilities and administration of the petroleum industry.

Also, the recommended replacement of NNPC with NNPC limited seems like a good step to make it efficient strictly as an operator with no form of regulatory role directly or indirectly. It is also interesting to note that the price-fixing powers of the Minister of petroleum resources which is in the petroleum Act no longer exist under the PIB 2020 which suggests a progressive move towards full and honest deregulation of the downstream sector. The powers of the minister to grant and revoke prospecting licenses and mining leases can only be done under the PIB by the recommendation of the commission. This tends to promote due process and forestalling corrupt practices thereby promoting transparency in governance and administration.

4.2. ADMINISTRATION PROVISIONS IN PIB 2020

Based on the petroleum administration section of the bill which concerns itself with the modus operands of petroleum activities; upstream and downstream with much emphasis on the downstream sector, below are some of the effects of the passage of the PIB to the downstream sector.

- The removal of the powers of the Minister of petroleum resources in the PIB from fixing prices of petroleum products suggests an end to at least the petroleum imports subsidy regime.
- The PIB passage is likely to provide the much-needed legislative framework for compressive deregulation of the petroleum downstream sector.
- The PIB will increase the appetite of oil marketers to invest in the digitalization of the vital downstream assets.
- The authority should be more responsive in discharging its duties and strengthening regulations.

Another issue in the administration aspect of the bill is a non-commensurate punishment for flare gas data log offenders. It merely recommends a fine of an extra $2.50 per 28.317 cubic meters (1000 cf) for an offender who is found guilty of supplying false data or fails to supply such data. The recommended fine is quite low by all standards. Also, the penalty provision for gas flaring in the bill is still very small when compared to the impact of the offense on the environment and lives of people. This implies that the provision prefers the payment fines to a demand to end gas flaring.

4.3. THE HOST AND IMPACTED COMMUNITIES PROVISION OF PIB 2020

This aspect of the bill is the least voluminous in content but in my opinion one of the most critical aspects of the bill if not the most critical. Now some of the concerns raised by Host communities' representatives in the senate public hearing concerning this aspect of the bill are;

- Gross under-representation of members of the host communities in establishing and management of the trust fund. The job of identifying who a host community lies solely with the "Settlor" (the oil company), why not by the federal or state government? This has the potential for conflict instead of enhancing a peaceful and harmonious co-existence between the IOCs and Host and Impacted Communities.
- The holder (Oil and Gas Company) selects members of the board of trustees and there is no provision or requirement for appointing members of host communities; which implies a lack of representation and participation. This could make government abdicate from their responsibility and leave the development of the oil-producing communities in the hands of the oil companies. This can create additional grounds for conflicts. Another under-representation is that the board of trustees establishes a management committee which is required to have only one community representative who shall be a "Non-executive" member.
- Another issue is that the bill also places too much onus on communities to prevent third-party damage to infrastructure, and punishes whole communities by reducing their trust fund allocation if damage occurs. Section 257(2) of the bill talks about the forfeiture of contribution to the Host community trust fund as a result of vandalism, sabotage, or civil unrest without clearly stating if the damage is caused by the host communities; because the

host community may not be responsible; natural disaster and other factors can also cause damage.

- Another issue is the “Needs Assessment of the Host Communities” which is carried out by the Holder (Oil and Gas Company). This ought not to be so. As the communities are in a better place of carrying out their Needs Assessment.
- Another critical issue of this Host communities section of the bill which has caused more disagreement during the senate public hearing is the issue of percentage allocation to the trust fund. The bill deviated from the original proposal of 10% of profits of the oil companies going to the Host communities; to 5% considered render by the eighth (8^{th}) NASS; to a mere 2.5% in the present bill; thus, the serious objections from representatives of the Host communities, and the tension/heat has not subsided despite the effort by Timipre Sylva, the Minister of State for Petroleum Resources to explain that what is on offer is 2.5% of prior’s year OPEX and not profit, given that companies may decide not to declare its profit for that given year, that means they must commit to the communities whether they make a profit or not. Regardless of the Minister of State’s explanation, the goal should be to ensure that host communities get adequately compensated given the negative impact they suffer by the oil production activities in their environment. This is more so since the country is yet to embrace full fiscal federalism.

4.4. FISCAL PROVISION ANALYIS OF PIB 2020

4.4.1 PETROLEUM FISCAL SYSTEM

Petroleum Fiscal Systems (PFS) describe, in general, the legislative, tax, contractual and fiscal elements underlying the exploration and production operations in a petroleum province, region or country. The purpose of the PFS is to determine equitably how costs are recovered and profits are shared between firms and the host governments. Its role also is to allocate the rights for development and operation of specific business within a country (Echendu, 2011). Ownership of mineral rights could belong to individuals or state. The federal petroleum law is the basis for all petroleum operations. Such laws often vest important discretionary powers on federal administrative or legislative bodies (Mian, 2011). The host government; represented by either a national oil company, ministry of petroleum/mining of the country, or both grants license or enters into contract with a contractor – an international oil company (IOC), contractor group, or consortium of these - for a given contract area.

These internal petroleum agreements or fiscal system varies from country to country based on the respective country's objectives. Generally, the main objectives of the mineral owner are sovereignty, economic growth and environment (quality of life). Other minor objectives are the optimal exploitation and the use of mineral resources and satisfying domestic demand (Desmond, 2019), while that of the contractor is basically profits. The two basic form of this petroleum fiscal arrangement are;

- The Concessionary Systems
- The Contractual Systems

According to Johnston D (1994), the most common provisions and regulations in the PFS have to do with the following:

1. Type of permit, contract, or concession.
2. Size, shape, and geographic limits of area to be explored and developed.

3. Initial or primary term and extensions. If exploration efforts are successful, typical contract terms are for 20 to 30 years.
4. Fees and bonuses.
5. Relinquishment or surrender.
6. Selection and convertibility of acreage.
7. Assignment or transfer of acreage, lease, or concession
8. Royalty payments, sharing profits, and cost recovery
9. Tax obligations
10. Obligation to supply domestic markets first and building local refineries.
11. Employment and training of nationals
12. Equity participation by government and repatriation of capital by the contractor.

4.4.2 TYPES OF CONTRACTUAL ARRANGEMENT

As earlier there are basically two (2) types of contractual arrangement which are:

1. Concessionary or Royalty and Tax System: It allows private ownership of mineral resources through the contract duration/period.
2. Contractual System; here the State or Government retains ownership of the mineral resources. It is further classified into:

a) Production-Sharing Contract (PSC)

b) Service Contract

   i. Pure service contract

   ii. Risk service contract

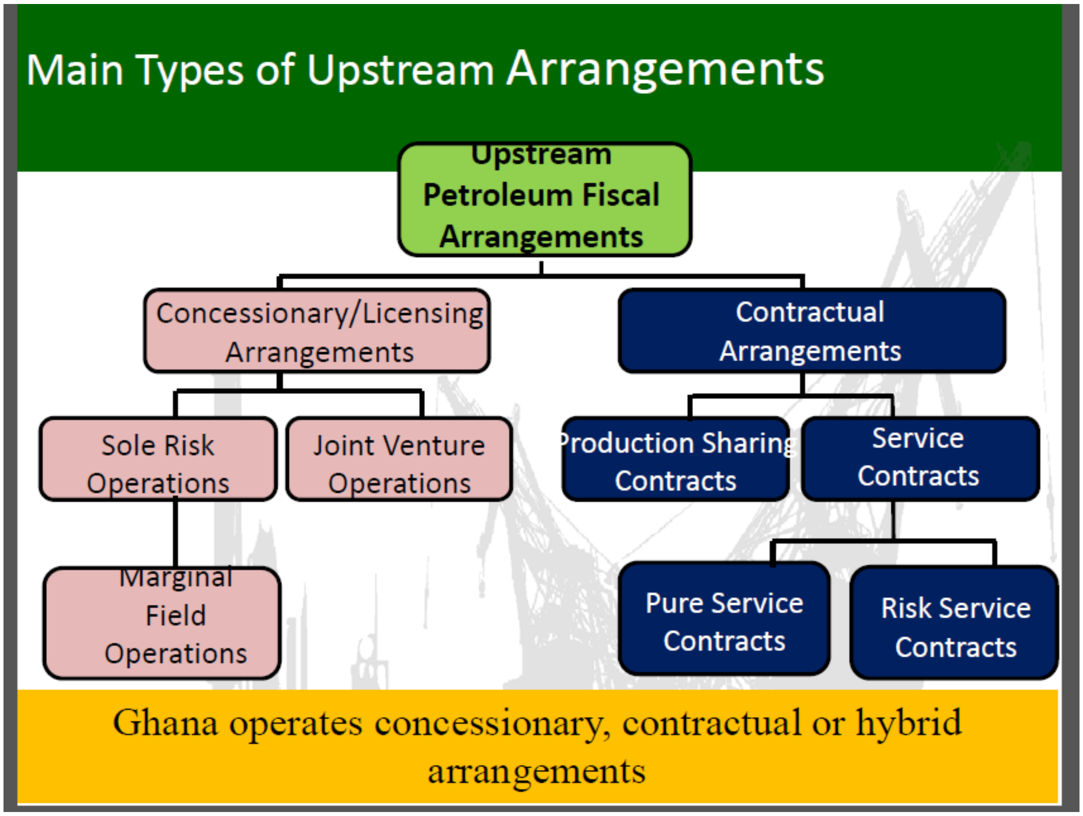


Figure 4.1: Classification of Upstream Petroleum Fiscal Arrangement

Source: Iledare, 2020

The table 4.1 Below shows the summary of the risk and reward of the fiscal regimes

Table 4.1: Summary of the risk and reward of the fiscal regimes

Contract Types	Contractor	Host Government
Modern Concessionary	All risk/All rewards	Reward is based on production and price
Production-Sharing Agreement	Exploration risk/share in reward	Share in reward
Joint Venture	Share in risk and reward	Share in risk and reward
Pure Service Contract	No Risk	All Risk
Risk Service Contract	All Risk	No Risk

In terms of a Production Sharing Contract (PSC) the state contracts for the services of a contractor (IOC) to explore for, and in the event of a discovery, to exploit hydrocarbons. The contractor is responsible for financing the petroleum operations. Hydrocarbon production is shared between the State and the contractor in accordance with the terms of the contract. The contractor will receive a share of production as reimbursement of its costs and as compensation in kind (cost oil), the remainder of the oil (profit oil) will be shared between state and contractor (Echendu, 2011). Cost recovery limit (CRL) specification defines maximum annual total production (CAP) for cost oil (Iledare, 2020).

The table 4.2 below shows the key distinction in the fiscal arrangement types

Table 4.2: Fiscal System Comparison (Johnston, 2008)

	R/T System	PCSs	RSAs
Type of Projects	All types: Exploration, Development, EOR	All types: Exploration, Development, EOR	All types but often non-exploration
Ownership of Facilities	International Oil Company	Government NOC	Government NOC
Production Facilities Title Transfer	No transfer	"When landed" or upon commissioning	"When landed" or upon commissioning
IOC Ownership of Hydrocarbons (Lifting entitlement)	Gross production less royalty oil	Cost oil + profit oil	None may have preferential right to purchase
Repatriation of Service Company Equipment	Yes	Yes	Yes
IOC Lifting Entitlement (%)	Typically around 90%	Usually from 50-60%	None (by definition)
Hydrocarbon Title Transfer	At the wellhead	Delivery Point Fiscalization Point or Export Point	None
Financial Obligation	Contractor 100%	Contractor 100%	Contractor 100%
Government Participation	Yes | Not common	Yes | Common	Yes | Very Common
Cost Recovery Limit	No	Usually	Sometimes
Government Control	Low Typically	High	High
IOC Control	High	Low to Moderate	Low

4.4.3 AN OVERVIEW OF THE PIB 2020 FISCAL PROVISIONS

The principal petroleum fiscal arrangement for offshore oil and gas development in Nigeria in the PIB 2020 is the Production-Sharing Contract (PSC) Type; likewise the Nigeria DOA’19 PSC and the Angola PSC 2004, which are case studies in this report.

From the commencement of the PIB 2020, the administration and collection of Government revenue in the petroleum industry shall be the function of the Federal Inland Revenue Service (the Service) and the Commission as follows -

(a) the Service shall be responsible for the assessment and collection of - hydrocarbon tax and enforcement of the fiscal provisions of the PIB 2020 as it relates to hydrocarbon tax assessment and revenue collection, and companies income tax and tertiary education tax as it relates to taxable petroleum operations;

(b) The Commission shall be responsible for the determination and collection of - rents and royalties and its enforcement under the PIB 2020; and related payments or production shares, where the model contract includes provisions related to production sharing, profit sharing or risk service provisions (Section 259, PIB 2020).

Below are some of the key fiscal elements of the PIB 2020 fiscal arrangement:

1. **Signature Bonus:** It is a fixed front-ended payment made when a lease is first granted. Bonus payment in any form is highly regressive fiscal instrument and should be avoided or minimized (Iledare, 2010). The draft PIB 2020 does not specify how a signature bonus is to be determined or if it will deductible in tax calculations, hence, it is contract-specific through a bidding process (negotiable) rather than by legislation.

2. **Rentals:** Every petroleum prospecting licence and petroleum mining lease shall be subject to rent as prescribed in the relevant regulation and the rent shall be an amount per hectare per year.
3. **Royalty:** In the PIB 2020 all production of petroleum, including production tests, shall be subject to royalties on a non-discriminatory basis with respect to all licensee and lessees and shall be paid into the Federation Account and verified by the Commission. The Royalty is calculated based on production, price and terrain as highlighted in the table below:

Table 4.3: PIB 2020 Royalty Schedule

ROYALTY			
Royalty Rate by Price			
Petroleum Resource	**Threshold price, P**	**Rate (%)**	
	$		
Oil	Below $50/bbl	0%	
Oil	at $100/bbl	5%	
Oil	Above $150/bbl	10%	
Royalty Rate by Terrain			
Petroleum Resource	**Production Terrain**	**Rate (%) (Oil)**	**Rate (%) (Gas)**
Oil/Gas	Onshore	18%	8%
Oil/Gas	Shallow water (up to 200m)	16%	5%
Oil/Gas	Deep offshore	10%	5%
Oil/Gas	Frontier Basin	8%	5%
Gas	Domestic gas		5%

4. **The Companies Income Tax (CITA):** Upstream companies have been exempt from paying corporate income tax in Nigeria (Iledare, 2010), but the draft PIB 2020 introduces a formal amendment act of the companies income tax making applicable to all corporations incorporated in Nigeria, E&P firms inclusive. It is 30% of chargeable profits in the accounting year. The PIB disallows Nigeria Hydrocarbon Tax deductions for CITA calculations.
5. **The Nigeria Hydrocarbon Tax (NHT):** In addition to CITA the PIB 2020 introduces the NHT. It is to replace the Petroleum Profit Tax (PPT). Every corporation who engages in hydrocarbon production must pay the hydrocarbon tax. The table below shows how it is determined in the PIB 2020:

Table 4.4: PIB 2020 NHT Schedule

NHT	Terrain	New Acreage Rate (%)	Converted Acreage Rate (%)
Oil/Associated Gas	Onshore	42%	22.50%
Oil/Associated Gas	Shallow water (up to 200m)	37.50%	20%
Oil/Associated Gas	Deep offshore	5%	10%

6. **Cost Price Ratio Limit:** the cost price ratio limit of 65% of net revenue for new acreage. For a production sharing contract subject to a conversion contract, the cost limit shall be 60%. This implies that the profit oil is 35% or 40% of net revenue respectively.

7. **Profit Sharing Formula of Profit Oil:** the profit split ratio is based on cumulative oil production as highlighted in the table below:

Table 4.5: PIB 2020 Profit Oil Split Formula

Profit split Ratio (Govt)	5%-45% based on Np		
Up to 50 MMbbls	Np<=50	50	5%
Up to 100 MMbbls	50<Np<=100	100	10%
Up to 350 MMbbls	100<Np<=350	350	15%
Up to 750 MMbbls	350<Np<=750	750	25%
Up to 1500 MMbbls	750<Np<=1500	1500	35%
Above 1500 MMbbls	Np>1500		45%

8. **Production Allowances:** this is a major fiscal incentive in the PIB 2020, this replaces the Investment tax allowance (ITA) and focuses on incremental production based on location and terrain - it is output-based. The table below shows how it is determined:

Table 4.6: PIB 2020 Production Allowances

ALLOWANCES			
Terrain	**Cummulative max. Production**	**General Production Allowances (GPA)**	
	(MMbbl)	**New Acreage ($/bbl)**	**Converted Acreage ($/bbl)**
Onshore	up to 50MMbbl	lower of $8/bbl and 20% of fiscal oil price	lower of $2.5/bbl and 20% of fiscal oil price
	Above 50MMbbl	lower of $4/bbl and 20% of fiscal oil price	lower of $2.5/bbl and 20% of fiscal oil price
Shallow water (up to 200m)	up to 100MMbbl	lower of $8/bbl and 20% of fiscal oil price	lower of $2.5/bbl and 20% of fiscal oil price
	Above 100MMbbl	lower of $4/bbl and 20% of fiscal oil price	lower of $2.5/bbl and 20% of fiscal oil price
Deep offshore	up to 500MMbbl	lower of $8/bbl and 20% of fiscal oil price	lower of $2.5/bbl and 20% of fiscal oil price
	Above 500MMbbl	lower of $4/bbl and 20% of fiscal oil price	lower of $2.5/bbl and 20% of fiscal oil price

4.4.4 OVERVIEW OF GHANA'S OIL AND GAS FISCAL REGIME

Ghana's petroleum fiscal regime is a set of laws, regulations and agreements which regulates the petroleum operation in Ghana and also defines the economic benefits share between the host government and the contractor's from petroleum exploration and production. Ghana has therefore adopted a fiscal system which mixes some element of royalty and tax regimes, production sharing agreement and state participation. This has led the fiscal regime of Ghana to be described as

“Hybrid”. Almost all fiscal systems are a blend of others fiscal systems and Ghana’s is no exception. Ghana’s fiscal system has got a blend of concessionary and PSA (Desmond, 2019).

The key laws that govern the Ghana’s fiscal regime are:

- 1992 constitution of the Republic of Ghana
- Petroleum exploration and production law, 1984
- Petroleum income tax law, 1987 (PNDCL 188)
- Petroleum commission Act (Act 821)
- The Ghana National Petroleum Corporation law, 1983 (PNDCL 64)
- Petroleum (Local content and local participation regulations, 2013 L.I 2204)

Other taxes and fees are surface rentals, withholding tax, annual training fees, technology allowance.

- Royalty
- Government participation (Initial interest, additional interest)
- Petroleum income tax
- Additional oil entitlement (AOE)

For royalty, the gross production percentage of hydrocarbon gives as oil production ranges from 4% - 12.5% of gross production and gas production, ranges from 3% - 10% of gross volume.

The petroleum income tax law (PITL) set default rate at 50% unless a petroleum agreement makes another alternative. Other taxes and fees includes surface rental fees and withholding tax on subcontractors.

An additional payment is to be given to the government if the AOE becomes more progressive overtime (Desmond, 2019).

The table below shows the Ghana Petroleum fiscal system.

Table 4.7: Ghana PFS

FISCAL TERM: GHANA FISCAL TERMS				
Signature Bonus	1	$MM	Negotiable	
Rentals/1st phase of exploration	0.00005	$MM/Km sq.		
Rentals/2nd & 3rd phase of exploration	0.0001	$MM/Km sq.	3000	Km sq.
Development and Production	0.0002	$MM/Km sq.		
Training Fees	1	$MM/Annum		
Depreciation life of Capitalized CAPEX	5	years		
Salvage value assumed	0	MM$		
ROYALTY				
Royalty Rate				
Petroleum Resource	**Terrain**	**Rate (%)**		
Deep offshore	Oil	12.50%		
	Gas	5%		
Onshore/Shelf	Gas	7.50%		
TAXES				
CIT	**Concessional**	35%		
Additional Oil Entitlement (AOE)		**Negotiable**		
IRR		**AOE (Specifications for Jubilee Field)**		
>19%	19%	5%		
>20%	20%	10%		
>25%	25%	15%		
>30%	30%	20%		
>40%	40%	25%		

4.4.5 ANGOLA PETROLEUM FISCAL SYSTEM

The table below gives an outline of the Angolan Petroleum fiscal system.

Table 4.8: Angola PFS

	FISCAL TERM: ANGOLA PSC 2004					
	Bonus	2	MM$			
	Bonus @commerciality	0.5	$ MM	Negotiable		
	Production Bonus	0.5	$ MM	At 5MM and 10 MM bbls cum pdtn	5	MMbbl
					10	MMbbl
	Rentals	0.003	$MM /km sq.	3000		
	Training Fees	0.1	$MM /bbl	Exploration phase		
		0.15	$ /bbl	Production begins		
	Depreciation life of Capitalized CAPEX	4	years SL			
	Tangible Uplift	40%				
	Salvage value assumed	0	MM$			
	TAXES					
	CITA	**Production Sharing Contract**	50%			
	Profit Oil split Ratio	**Govt.**	**Contractor**			
	Pre-IRR		0%			
	15%-40% based on IRR					
<	15%	25%	75%			
<	25%	40%	60%			
<	30%	60%	40%			
<	40%	80%	20%			
	Cost Recovery Limit (50%-65%)	**50%**				

4.4.6. FISCAL ANALYSIS

4.4.6.1 Overview

This fiscal analysis was carried out by evaluating the four (4) fiscal terms namely, Nigerian DOA’19 PSC fiscal term, the PIB 2020-proposed fiscal term, Ghana fiscal term, and Angola's current fiscal term. The economic model was developed using an Excel spreadsheet. The model is an integration of fiscal elements of the respective fiscal terms. Elements such as royalty schedule, company income tax, Nigerian Hydrocarbon Tax (NHT), cost recovery limit, profit oil, Additional oil Entitlement (AOE), etc. are featured. The model converted the texts in the respective fiscal terms into mathematics and coded them in excel.

4.4.6.2. Model Assumptions

Tables (4.9, 4.10, and 4.11) of the respective input data and assumptions are shown in Appendix A. Also, it is assumed that the depth of the offshore project is greater than 200m.

4.4.6.3 METHODOLOGY

All economic evaluation activities consider the future because their activities today will affect the future. The evaluation engineer must predict the return from investments in wells, plants, pipelines etc. (Echendu, 2011). Before a petroleum project evaluation engineer will achieve a successful prediction or forecast, he must know annual production, future operating costs and prices, taxes, inflation rate, participation factors, risk factors and future investments required to keep the project alive (Desmond, 2019).

The methodologies necessary for petroleum project evaluation to determine its profitability or viability will be described in this chapter. It will entail description of required data, forecasting of production decline rate, cost treatment analysis, and petroleum fiscal systems used for this analysis; the proposed PIB 2020 PFS, Nigeria DOA'19 PSC, Angola PSC 2004 and Ghana R/T system. An economic model is formulated using Excel spreadsheet after the pattern presented by Iledare (2020) and Mian (2011).

The sequence of this work begins with an adequate production profile which is in 3 phases; the build-up phase, the plateau phase and the decline phase. The type of production decline pattern used in this research for analysis purposes is exponential decline pattern with linear build-up rate. The maximum plateau rate attainable is tied to a percentage of the proved reserves. Attainable plateau rate is a function of percent reserves, facility size, or number of wells. Total plateau production is also tied to a proportion of proved reserves, as a result, time to end plateau production is estimated. From these estimations, decline factor is calculated from the remaining reserves after plateau period ends using constant percentage decline pattern. The total production life is then calculated by summing up all the periods in the development plan (Echendu, 2011).

For the purpose of comparative analysis of the fiscal systems adopted in this research the same technical cost treatment is used for all PFS except depreciations, which is treated as specified in the fiscal instruments. Even though, coincidentally the Straight line depreciation (SLD) technique is applicable to the 4 PFS considered in this research. Subsequent to the establishment of annual production, annual gross revenue is projected by applying oil price.

Applying the fiscal terms, Production Sharing Contract (PSC) Economics before tax and after tax is modelled to capture total yearly expenditure and the Net Revenue, contractor's and government take before tax and after tax. Depending on countries' PFS fiscal instrument specifications, non-technical cost treatment of royalties, bonuses, rentals, and crypto taxes are imposed to front-end loaded government take. Afterwards, cost recovery economics is modelled for all PSCs with the relevant cost recovery limit (CRL) specifications applied before calculation of government take before tax. Government and contractor takes after income tax is estimated after imposing the specified corporate income or petroleum profit tax or hydrocarbon tax in the PFS of each country. Likewise, the Royalty/Tax Economics before and after tax for the Ghana R/T system is modelled to capture total yearly expenditure and the net revenue, contractor's and government take before and after tax.

Simulation analysis which accounts for uncertainty and risk in the deterministic results is performed and the probability of success of the venture to changes in production rate, reserves and oil price using @Risk is also modelled. The objective functions is to analyze the economic instruments which are the Net present value (NPV) of the government take (G-Take) and the Internal Rate of Returns (IRR) using an assumed hurdle rate (discount rate) of 12.5%.

4.4.6.3.1 Production Profile

For the purpose of analysis in this research, field development plan with linear build-up and the conservative exponential (constant percentage) decline curve analysis was used for production forecasting, with the underlying premise that past factors affecting production in the past remain the same as depicted in figure 4.2.

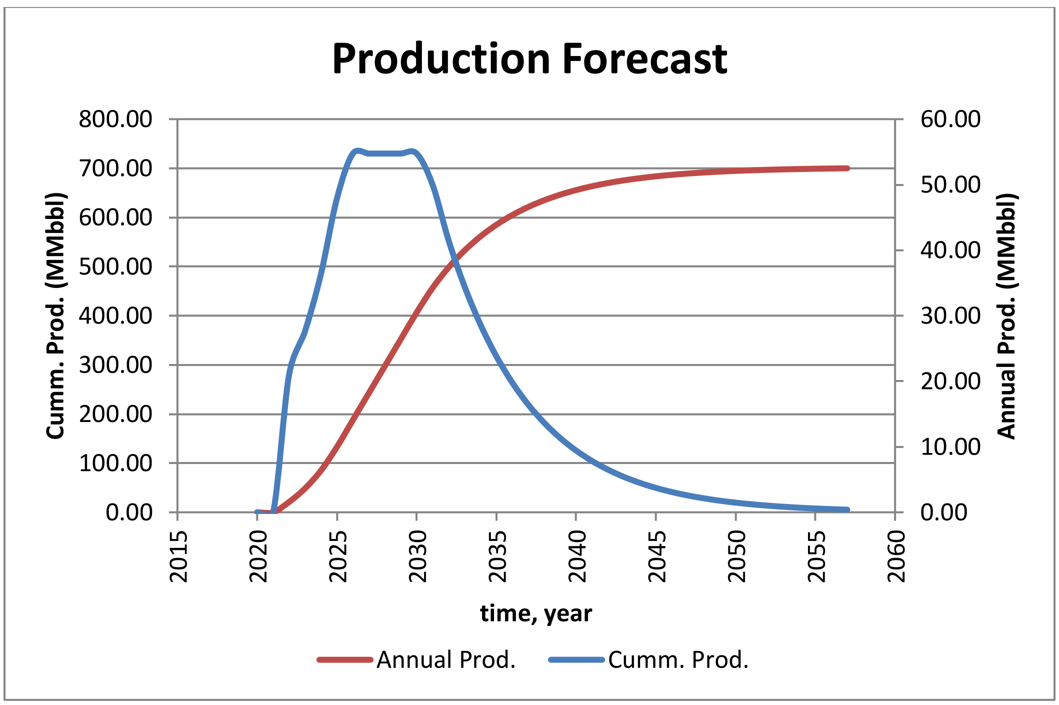


Figure 4.2: Production Forecast

4.4.6.3.2 Field Development Plan

Typical reservoir production phases in any field development plan include;

- Development build-up phase;
- Plateau phase; when production stays constant until nearly half of oil production has been produced. The period of stay depends on ultimate reserves
- Decline phase; which continues until production cost can no longer be covered. The producing lives depend on reservoir characteristics.

The essence of the development plan is to have good production capacity. The production capacity which is a measure of the justifiable flow of petroleum as a result of discovery venture, and infrastructure installed would have to generate enough revenue to reimburse for the expenditures and be economical (Echendu, 2011).

Development Build-Up Phase

This is the initial phase in every new field development plan. In this phase new wells were drilled, completed and production facilities mounted. The well does not flow at its full potential at this early stage but gradually builds up to full potential. The process of build-up is a function of the initial production rate, peak/plateau production rate, build-up period and build-up rate (Echendu, 2011).

Exponential build-up rate

$$q_1 = q_i e^{-a_1 t} \text{ -- } (4.1)$$

$$N_{P1} = \frac{365 \times (q_i - q_1)}{a_1} \text{ -- } (4.2)$$

Where,

$$q_1 = Daily\ plateau\ rate\ (bbl/d)$$

$$N_{P1} = Annual\ Production\ (MMbbl)$$

$$a_1 = \frac{-\ln\left(\frac{q_t}{q_i}\right)}{t} \text{ --- } (4.3)$$

Development Plateau Phase

This is the next phase after the build-up phase. Plateau phase is characterized with constant reservoir pressure. At this phase the field is producing at its full potential and it is expected that all the facilities have been installed and most, if not all, wells drilled. Production workers tend to preserve this phase for as long as technical and economic feasibility permits. The plateau period is the period in which annual production is greatest and if price is favorable, much revenue is made to recover majority of the expenditures.

Annual production,

$$q_2 = q_1 = q_i e^{-a_1 t} \quad \text{--} \quad (4.4)$$

$$N_{p2} = 365 \times q_2 \quad \text{--} \quad (4.5)$$

Development Decline Phase

Decline phase is the latter stage of every field development plan that leads to relinquishment. It is the stage of development where reservoir pressure declines and may no longer support depletion, requiring external support such as artificial lift and various pressure maintenance techniques. The time to end production (abandonment) is determined by the economic limit of the project. Usually, this is when revenue generated no longer compensates for expenses and profit is not made. Technical, political, and social factors may also lead to abandonment.

In modeling the decline phase in this study, (Echendu, 2011) equations were used for the three different production development plan presented. The equations are as presented below;

Exponential decline phase.

$$q_3 = q_f \times e^{-a_3 t} \text{ --- (4.6)}$$

$$N_{p3} = \frac{365 \times (q_2 - q_f)}{a_3} \text{ --- (4.7)}$$

$$a_3 = -\frac{\ln(1-d)}{t} \text{ --- (4.8)}$$

4.4.6.3.3 Cash Flow Model

Cash flow (CF) model is a model which defines flow of cash of an investment over a specific period of time. CF shows (Iledare, 2018).

1. Cash receipts at the end of each year generated by the investment.
2. Cash disbursements of all costs (initially and subsequent costs) per year required for the operations
3. Total time span of the investments in year.

Cash flow diagram shows that a capital investment is an amount paid to receive expected Net cash inflows over the economic life of the investment (Mian, 2011). For economic analysis, the cash flow model is preferred to other models like financial profit model and tax profit model. This is because, it provides net cash flow and it places the timing of funds to and fro of projects more accurately.

Net cashflow is simply revenue (Cash received) less expenditure (cash spent) during a period usually one year and the projected over the economic life of the project (Echendu, 2011) Mathematically;

$$NCF = Cash\ Receipt - Disbursement \text{ -------------------------------------- (4.9)}$$

Cash disbursements are subtracted from the cash receipts that will generate either net negative or positive cash flow. The economic model developed in this study for PFSs, considers the following cash flow items and treated them commonly as highlighted below.

1. **Cost Outlay:** The Cost Outlay consist of the expenses incurred during the life span of the project. That is the total technical cost of the project. It is comprised of 2 elements, Capital Expenditure (CAPEX) and Operating expenditure (OPEX).

   a) CAPEX: It is also referred to as front-end costs. These are classified as investments – monies paid for assets that will generate benefits for more than one year. CAPEX can be classified as either tangible or intangible costs. Examples are cost of surface equipment, cost of drilling and developing a well, etc.

   - Tangible costs were capitalized and depreciated for after tax calculation purposes.
   - Intangible costs were expensed through amortization for tax calculation purposes.

   b) OPEX: It is also referred to as Lease Operating Expenditure (LOE). These are direct costs associated with production or injection. They are expenditures that benefits only the period in which they are made. Typical OPEX behavior patterns are variable costs – costs of raw materials – and fixed costs – management fees. Examples are well repairs and work-over costs, maintenance costs, etc.

$Total\ Technical\ Cost\ (TC) = CAPEX + OPEX.$ ------------------------------- (4.10)

2. **Depreciation:** Depreciation is the loss in the value of asset over the time it is being used (Mian, 2011). The purpose of fiscal depreciation expense is to spread investment costs over time, for income tax and financial report purposes. It is a method for capital recovery of the costs of fixed assets over the estimated useful life of the asset according to the underlying rules set by tax legislation. Generally, all the PFS treated in this study adopted the SLN depreciation method but depreciable years differ from country to country. The depreciation method used for this work is the straight-line depreciation method.

$$SLN = \frac{Depreciable\ cost - Salvage\ value}{Useful\ years} \text{ --- } (4.11)$$

3. **Gross Revenue:** This is the production stream (annual) multiplied by the projected price of the barrel production.

   GR= Price of the crude oil multiplied by marketed volume of hydrocarbon.

   Net revenue is share of marketed production multiplied by the net price.

4. **Royalty** is a part (fraction) of gross profit. It is a paying of homage to the mineral owners. There are basically 3 types of royalties used in fiscal systems: *Fixed percentage royalty, Fixed payment royalty and Sliding Scale royalty (Jumping and Incremental scale).*

   In the model built for this thesis, both the fixed royalty and the progressive (Sliding royalty) was used based on the PFS.

$Royalty = Royalty\ rate\ \times GR$ -- (4.12)

5. **Taxable income** is net revenue less fiscally permitted cost deductions. Fiscal allowable cost deductions include OPEX; royalty; depreciation; depletion allowance; expensed investments or amortized intangible capital investments; payments to government.

$Taxable\ Income = Revenues - Royalties - Fiscal\ costs$ ------------ (4.13)

4.4.6.3.4 Front Loaded Government Take Cash Flow

The importance of FLGT is to estimate equitably how costs are recovered and profits are shared among firms, the host government, IOCs and mineral owners (Iledare, 2011). The host Government normally tries to get as much economic rents as possible by getting royalties, bonuses, surface rentals, crypto taxes and taxes.

Front loaded government take is made up of economic rents which are extracted through taxes and crypto taxes, bonuses and royalties. Crypto taxes are indirect means through which the host government receives revenue through levies, importantly of duties and other financial obligations (Echendu, 2011).

At the time of transfer of rights, royalties and bonuses are some forms of extractions that occur in which are not based on profit.

Bonuses are made up of signature bonuses, production bonuses and discovery bonuses and discovered bonuses. When a lease is acquired, there is a lump sum of single payment which is done and it called Signature bonus. It can be determined by the legislation of the country through negotiation or bidding. During the discovery of hydrocarbon period, the bonuses paid are called discovery bonuses whilst during production, we pay production bonus. Normally, production bonuses can be tied to production of hydrocarbon. This usually explains a form of bonus called the jumping.

4.4.6.3.5 PSC Economic Model and Its Component

The net cash flow vector of an investment is the cash received less the cash spent during a given period, usually taken as one year, over the life of the project. The after tax net cash flow associated with any PSC field in this study, in year t generally took the form presented by Iledare (2011):

$$NCF_t = GR_t - ROY_t - CAPEX_t - OPEX_t - BONUS_t - PO/G_t - TAX_t - OTHER_t \text{ ---- } (4.14)$$

Where,

NCF_t = After-tax net cash flow in year t,

GR_t = Gross revenues in year t,

ROY_t = Total royalties in year t,

$CAPEX_t$ = Total capital expenditures in year t,

$OPEX_t$ = Total operating expenditures in year t,

$BONUS_t$ = Bonus paid in year t,

PO/G_t = Government Profit Oil in year t,

TAX_t = Total taxes paid in year t,

$OTHER_t$ = Other costs or taxes paid in year t

The profit oil is the portion of production or revenue that the government shares with the contractor after royalties and cost oil () is recovered from the gross revenue:

The profit oil is split between the contractor and government:

Where,

$PO/C_t = PO(\psi)PO_t$

$PO/G_t = (1 - PO(\psi))PO_t$

$PO(\psi)$ = Profit oil split, $0 \leq PO(\psi) \leq 1$

The cost recovery scheme determines how the cost oil is computed. Many variations of cost recovery exist, and in its most basic form are computed as

$$CR_t = U_t + CAPEX|I_t + Dep_t + INT_t + INV_t + DECOM_t \text{ ------------------------- } (4.15)$$

Where,

CRt = Cost recovery in year t,

Ut = Cost recovery carried over from year t-1,

CAPEX /It = Intangible capital expenditures in year t,

DEPt = Depreciation in year t,

INTt = Interest on financing in year t,

INVt = Investment credits and uplift in year t,

DECOMt = Decommissioning cost recovery fund apportionment in year t.

The amount of revenues the contractor can claim for cost recovery is normally bound by the so-called "cost recovery ceiling," and in some cases, a time limitation for full cost recovery may also be imposed.

Cost oil is constrained in value through a functional relation such as

$COt = \min (CRt, CR(\psi)\ GRt)$

Where the value of $CR(\psi)$, $0 \leq CR(\psi) \leq 1$, may be constant or based on a sliding scale.

It is generally agreed that operators must be allowed to recover their costs for a venture to be profitable, but the manner in which the costs are recovered and the impact of cost ceilings on the economic measures of the field are not well understood.

Taxable income is determined as a percentage of the contractor profit oil and tax loss carry forward, if applicable.

Tax rates are denoted by the value $T(\psi)$, $0 \leq T(\psi) \leq 1$, and may be fixed or based on a sliding scale:

$$TAX_t = \begin{cases} T(\varphi)(PO/C_t - CF_t), PO/C_t - BONUS_t - CF_t > 0 \\ 0, \qquad PO/C_t - BONUS_t - CF_t \leq 0 \end{cases} \text{ ---------------------- (4.16)}$$

Where CFt represents the tax loss carry forward in year t.

Annual Take Statistics: The division of profit between contractor and government determines the take.

The total profit in year t was determined as;

$$TP_t = GR_t - TC_t \text{ --- (4.17)}$$

The contractor and government take was computed as

$$CT_t = TP_t - BONUS_t - ROY_t - PO/G_t - TAX_t \text{ ----------------------------------- } (4.18)$$

$$GT_t = BONUS_t + ROY_t + PO/G_t + TAX_t \text{ --- } (4.19)$$

The contractor and government take in year t, expressed in percentage terms, are defined as

$$\tau_t^c = \frac{CT_t}{TP_t} \text{ -- } (4.20)$$

$$\tau_t^g = \frac{GT_t}{TP_t} \text{ -- } (4.21)$$

The PSC economic model for other countries with PSC does not necessary have the same instrument specified, but generally follows the same pattern. The figure 4. Below shows the diagrammatic flow chart of a typical PSC economic model.

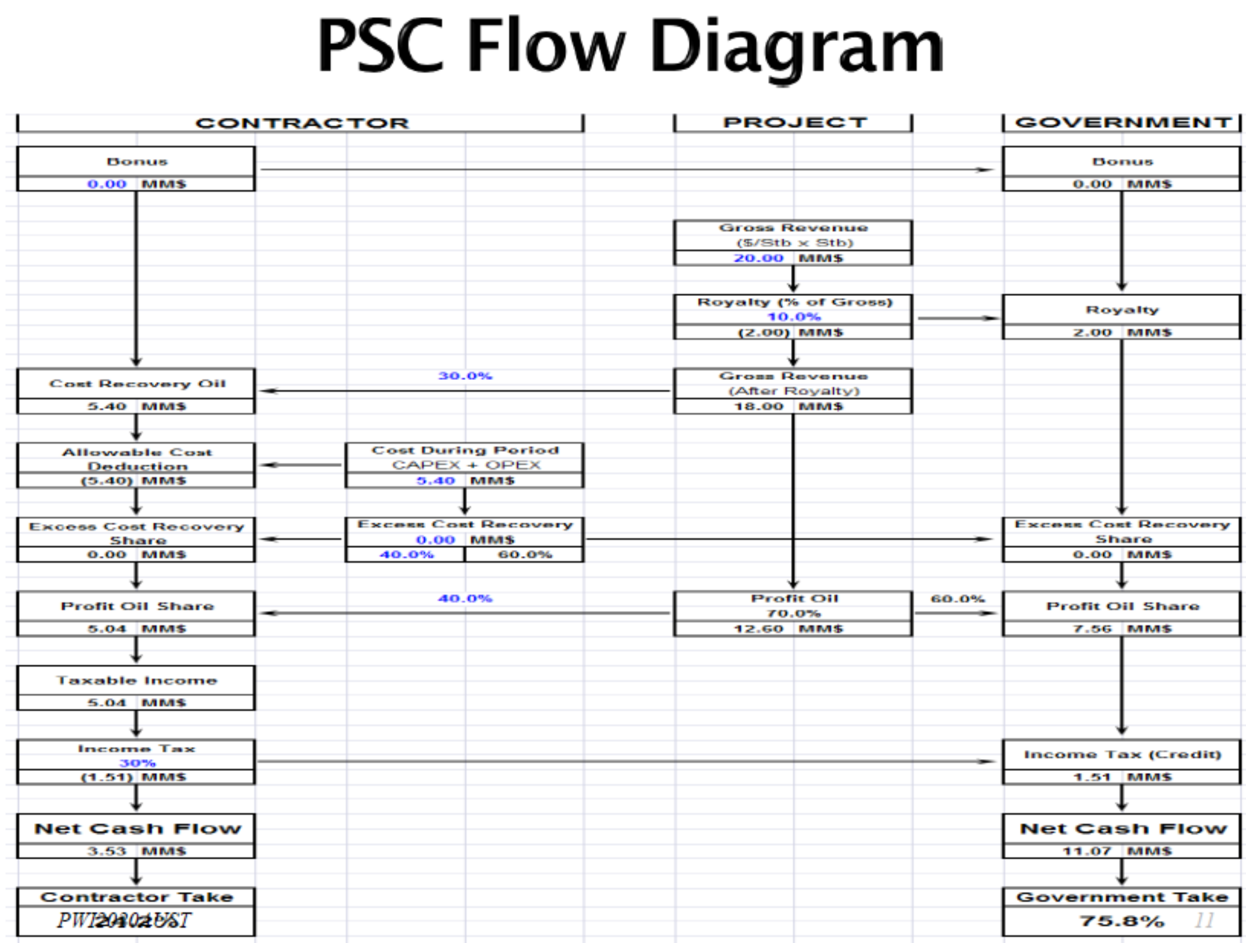


Figure 4.3: PSC Flow Diagram

Source: Iledare, 2020

For illustration purposes; we look at the Proposed-PIB 2020 PSC fiscal system, it was modelled as:

Before Tax (BTAX) Cash Flow Model

$Technical\ Cost\ Allowed\ (TCA) = CAPEX + OPEX$ ---------------------------- (4.22)

$Deductible\ payments\ to\ Government = FLGT\ without\ Bonuses +$

$Total\ profit\ oil\ and\ ECR\ to\ Government$ -------------------------------------- (4.23)

Therefore,

$Host\ GTake\ Before\ tax = Deductible\ payments\ to\ Government + Bonuses$ ------ (4.24)

$Contractor\ Net\ Revenue = (Cost\ Oil - total\ ECR) + Contractor\ (Profit\ oil + ECR) +$

$Production\ Allowance - Bonuses - TCA$ -- (4.25)

Losses was carried forward indefinitely into subsequent years and Taxable Income was arrived at

After Tax (ATAX) Cash Flow Model

$Hydrocarbon\ Tax\ (NHT) = Taxable\ Income\ (TI) \times NHT\ Rate$ -------------------------- (4.26)

$Corporate\ Income\ Tax\ (CITA) = Taxable\ Income\ (TI) \times CITA\ Rate$ ------------------- (4.27)

$Contractor's\ Take\ after\ Tax = GR - TCA - HGTake\ before\ tax - Taxes$ ----------- (4.28)

$Host\ GTake\ after\ Tax = HGTake\ before\ tax + Taxes$ ------------------------------------- (4.29)

4.4.6.3.6 Royalty/Tax Economic Model and Its Component

Generally, the treatment of cash flow for R/T systems was governed by equation 3.44 as presented by Iledare (2020):

$NCF_t = GR_t - ROY_t - CAPEX_t - OPEX_t - BONUS_t - TAX_t - OTHER_t$ ----------------- (4.30)

Where,

NCF_t = After-tax net cash flow in year t,

GR_t = Gross revenues in year t,

ROY_t = Total royalties in year t,

$CAPEX_t$ = Total capital expenditures in year t,

$OPEX_t$ = Total operating expenditures in year t,

$BONUS_t$ = Bonus paid in year t,

TAX_t = Total taxes paid in year t,

$OTHER_t$ = Other costs or taxes paid in year t

The figure below gives the diagrammatic flow chart of a R/T system

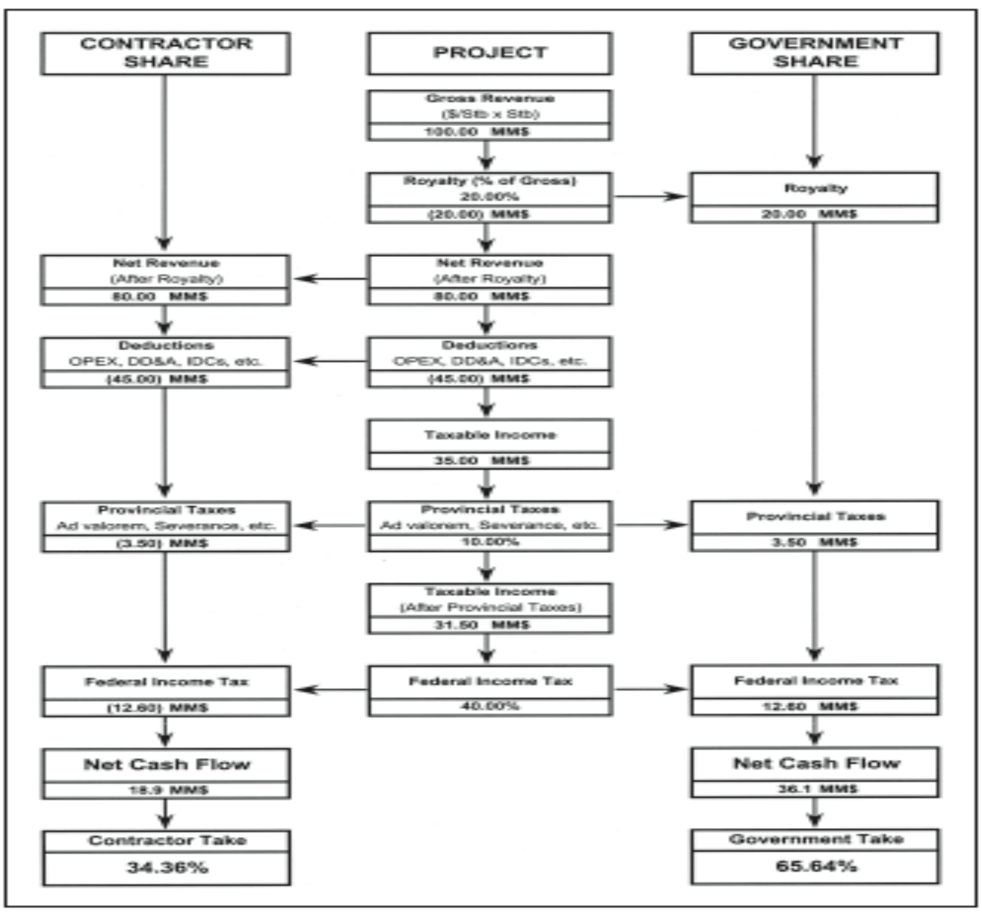


Figure 4.4 : R/T flow diagram

Source: Mian, 2011

The figure below shows the diagrammatic flow diagram of the Ghana R/T system

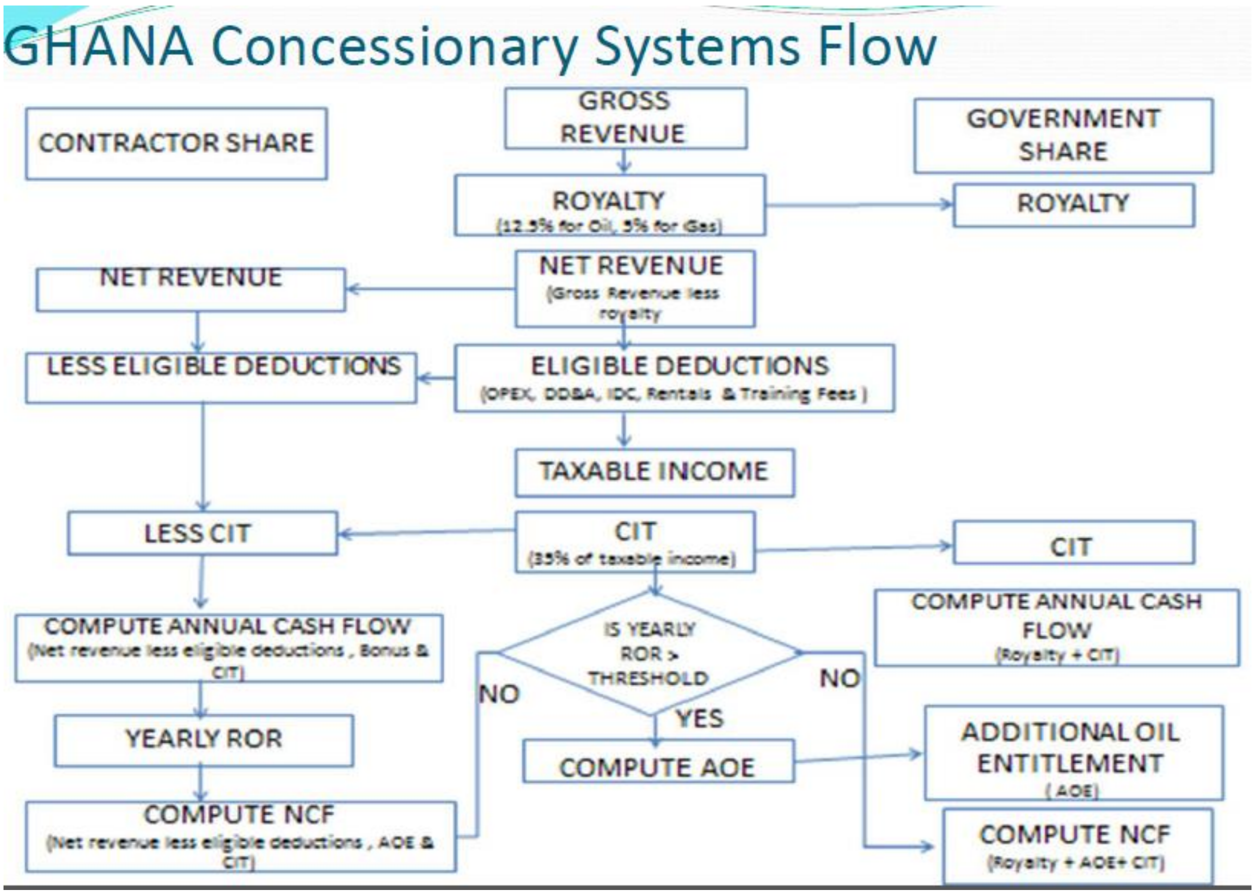


Figure 4.5: The Ghana R/T system flow diagram.

Source: Iledare, 2020

4.4.6.3.7 E & P Economics and System Measures

For capital budgeting and investment decision purposes in deepwater GOG regions, measures of investment worth criteria were modeled to aid in deterministic decision analysis and objective functions in stochastic analysis performed in this study. The following measures of profitability were imposed;

- Net Present Value (NPV)
- Internal Rate of Return (IRR)
- Discounted Take Statistics
- Profitability Index (PI)
- Payout Period (POP)
- Front Loading Index
- Unit Technical Cost (UTC)

Net Present Value (NPV)

NPV or simply PV at the beginning of year t of cash flow vector NCF(f) was computed as;

$$NCF(f,F) = \sum_{t=1}^{k} \frac{NCF_t}{(1+D)^t} \text{ -- } (4.31)$$

The present value or worth of a future dollar is the dollar that would be invested today at a specified interest rate to yield that dollar at that time in the future. In general, the net present value of a project is simply the sum of the present values of individual annual net cash flows over the life time of the project, assuming end of year cash receipts (Echendu, 2011).

Internal Rate of Return (IRR)

IRR is defined as the discount rate at which the NPV of a series of cash receipts and disbursement reduces to zero. It is a profitability index that is independent of the size of cash flows.

$$\sum_{i=1}^{n} \frac{NCF_t}{(1+IRR)^t} = 0 \text{ --- } (4.32)$$

Discounted Take Statistics

The division of net cash flow (based on the agreed fiscal regime) between the contractor and the host government are called contractor take and government take, respectively. Take varies as a function of time over the life history of a field and is best computed on a discounted cumulative basis to account for the distribution of the cash flow and the distinct manner in which the contractor and government value money. The contractor and government take computed on a cumulative discounted basis in year *x, x*=1,…k, was

$$PV_x(\tau^c) = \frac{PV_x(CT)}{PV_x(CT)+PV_x(GT)} \text{ -- } (4.33)$$

$$PV_x(\tau^g) = \frac{PV_x(GT)}{PV_x(CT)+PV_x(GT)} \text{ -- } (4.34)$$

Where,

$$PV_x(CT) = \sum_{t=1}^{x} \frac{CT}{(1+D^c)^{t-1}} = Present\ value\ of\ contractor\ take\ through\ year\ x \text{ ----- } (4.35)$$

$$PV_x(GT) = \sum_{t=1}^{x} \frac{GT}{(1+D^g)^{t-1}} = Present\ value\ of\ government\ take\ through\ year\ x \text{ ---- } (4.36)$$

Where,

$$D^c = Discount\ factor\ for\ contractor$$

$$D^g = Discount\ factor\ for\ government$$

Profitability Index (PI)

A PI or investment efficiency ratio normalizes the value of the project relative to the total investment and is calculated as;

$$PI = 1 + \frac{NPV}{PV\ of\ Capital\ Investment} \quad (4.37)$$

$$PI = 1 + PVR \quad (4.38)$$

PI is a dimensionless ratio of the PV of future operating project cash flow to PV of investment. Its interpretation as the amount of discounted profit per dollar invested permits its use for ranking projects under limited fund availability. It is an effective measure of capital efficiency.

Payout Period (POP)

POT is the time at which the cumulative cash flow discounted or not becomes positive. It is the break-even point which is the time lapse from initial investment on E&P venture until recovery of investment. All revenues received after the payout period represents profits and new capital generated from the project.

Front-End Loading Index

FLI highlights the spread in the discounted and undiscounted takes. A value of FLI = 0 indicates an ideal condition in which there is no front-end loading at all. The higher the FLI becomes, the more front-end loaded the fiscal regime becomes. High front-end loaded fiscal terms tend to increase the government take on a discounted basis: which makes it less attractive to contractors.

A high front-end loaded fiscal regime is due to signature bonuses, discovery bonuses, sales tax, value-added tax, impute duties etc. The FLI is given by:

$$FLI = \frac{Discounted\ Government\ Take}{Undiscounted\ Government\ Take} - 1 \text{ --- } (4.39)$$

Unit Technical Cost (UTC)

The unit technical cost is defined as the ratio of the total cost (CAPEX and OPEX) over the economic life of a project to the total expected reserves from the project. It is usually reported in \$/Stb, \$/BOE, \$/MMBtu, \$/MScf.

$$UTC = Unit\ CAPEX + Unit\ OPEX \text{ --- } (4.40)$$

4.4.6.4. MONTE-CARLO SIMULATION

To account for the uncertainties inherent in the economic data assumption, the @Risk excel add-in simulation tool was used to quantify the impact of selected stochastic input variables on the economic indicators; Net present value (NPV), Internal rate of return (IRR), profitability index (PI), Front-end loaded index (FLI), Discounted Host government take (DHGT), discounted contractor's take (DCT), unit CAPEX, unit OPEX and Unit technical cost (UTC) using Monte-Carlo simulation approach. Some of the stochastic variables are crude oil price, discount rate, tax rate, peak production rate, CAPEX, variable OPEX, etc. Probability distributions used for the stochastic variable are triangular, lognormal, pert, and normal distribution.

Summary of the simulation process is as shown below:

- Define input variables that are stochastic in nature
- Different probability distribution parameter were imposed ranging from normal, lognormal to triangular distribution, based on the input variable
- Define Output parameters such as NPV, IRR, PI, Take Statistics, UTC and FLI.
- Run the simulation for 10000 iterations.
- Discuss the results.

4.4.7. DETERMINISTIC RESULTS AND DISCUSSION

This section analyses results and attempts to explain observed trends and values. An excellent production forecast is the basics for any project-based resource estimate and any business or development decisions. It is assumed at the end of exploratory activities on the offshore field has a reserve of 700 MMbbl and the same production profile applies to the four (4) countries in question as shown in table 4.8 of Appendix A

Figure 4.2 shows the production forecast of the deep offshore field. Production began in 2021 and rose steadily at a build-up rate of 0.275 per year till 2025 where it reached its peak of 150,000 BOPD and remained at the plateau for 5 years and declined afterward at a decline rate of 0.185 per year. Also, the cumulative production rose steadily from 2021 up until 2057 where the reserve will be exhausted, making a field life of 37 years.

4.4.7.1. THE NIGERIA DOA’19 PSC

Observation and Trends

Figure 4.6 of Appendix B shows the cost outlay of the deep offshore project with projections showing the gross revenue, DHGT, DCT, and DPOP. At the first year of the projection (exploration and development period), the gross revenue was zero and rose when production began the following year (2021), plateau in the year 2025 for the next year, and decline afterward till the end of production which implies a direct relationship with production rate, since gross revenue is a product of production rate and price. Similarly, the discounted net cash flow (DNCF) of the contractor showed it was initially operating at a loss until 6 years after which it broke even and began to cash out; the cash flow continues to rise till it reaches an NPV of 2299.59MM$ while that of government rose from 0 to 5414.33MM$. The DPOP clearly shows a pay-out period of 6.44 years.

4.4.7.1.1. Nigeria DOA’19 PSC Deterministic Result/Discussion

Deterministic economic system measures and statistics – NPV, IRR, DPOP, PVR, PI, UTC and Take Statistics were generated. These system measures represent the output of the discounted cash flow model in an excel worksheet while the fiscal terms and parameters, as well as economic data, represent the inputs. These system measures/economic indicators are as given in table (4.12) below.

Table (4.12): Nigerian DOA'19 PSC Deterministic Result

INDICATORS	Discount Rate	12.5%
	Contractor	Government
NPV ($ MM)	2299.59	5414.33
IRR (%)	27%	
DiscountedTake Statistics (%)	29.81%	70.19%
Undiscounted Take Statistics (%)	35.13%	64.87%
Front Loading Index, FLI	0.082	
Payback period, years	5.02	
Disc. Payback period, years	6.44	
Profitability Index, PI	1.88	
UNIT CAPEX, $/BBL	4.07	
UNIT OPEX, $/BBL	7.70	
Unit Technical Cost, $/BBL	11.78	

Table 4.12 shows the deterministic results of the discounted cash flow model of the deepwater PSC project, using a discount rate of 12.5%. The project can pay for the cost of financing the investment and generate revenue. Hence, the project is profitable and worth embarking upon. The IRR is 27%, which implies that the earning power of the investment is significantly higher than the cost of capital, thus, showing how efficient the investment is, given that the assumptions are favorable. Another key profitability indicator is PI which measures how much value has been added per dollar of investment, for the project above, the PI is 1.88, which means that for everyone dollar ($1.00) invested, $1.88 is received as return on investment (ROI). The UTC was estimated to be $11.78 per barrel and the DPOP is 6.44 years.

Government take (GT) reflects the total receipt of the host government from a project, these include; royalty, taxes, bonuses, profit oil, and any other forms of rent extractions. In this case, the estimated discounted takes are 70.19% and 29.81% for host government (HG) and contractor respectively. This implies for every $1 gain per barrel, HG keeps 70 cents and the contractor keeps

30 cents ceteris paribus. The FLI is 0.082 which is progressive enough and quite attractive to the contractor.

4.4.7.2. THE NIGERIAN PIB-PROPOSED PSC

Observation and Trends

Figure 4.7 of appendix B shows the cost assumptions of the deep offshore project with projections showing the gross revenue, DHGT, DCT, and DPOP. At the first year of the projection (exploration and development period), the gross revenue was zero and rose when production began the following year (2021), plateau in the year 2025 for the next year, and decline afterward till the end of production which implies a direct relationship with production rate, since gross revenue is a product of production rate and price. Similarly, the discounted net cash flow (DNCF) of the contractor showed it was initially operating at a loss until 5 years after which it broke even and began to cash out, the cash flow continues to rise till it reached an NPV of 2431MM$ while that of government rose from 0 to 5282.92MM$. The DPOP clearly shows a pay-out period of 5.47 years.

4.4.7.2.1 Nigerian PIB-Proposed Deterministic Result/Discussion

Deterministic economic system measures and statistics – NPV, IRR, DPOP, PVR, PI, UTC and Take Statistics were generated. These system measures represent the output of the discounted cash flow model in an excel worksheet while the fiscal terms and parameters, as well as economic data, represent the inputs. These system measures/economic indicators are given in the Table 4.13 below.

Table 4.13: Nigerian PIB-proposed Deterministic Result.

INDICATORS	Discount Rate	12.5%
	Contractor	Government
NPV ($ MM)	2431.00	5282.92
IRR (%)	28%	
DiscountedTake Statistics (%)	31.51%	68.49%
Undiscounted Take Statistics (%)	37.25%	62.53%
Front Loading Index, FLI	0.095	
Payback period, years	4.17	
Disc. Payback period, years	5.47	
Profitability Index, PI	1.93	
UNIT CAPEX, $/BBL	4.07	
UNIT OPEX, $/BBL	7.70	
Unit Technical Cost, $/BBL	11.78	

Table (4.13) shows the deterministic results of the discounted cash flow model of the deepwater PSC project, using a discount rate of 12.5%. The project can pay for the cost of financing the investment and generate revenue. Hence, the project is profitable and worth embarking upon. The IRR is 28%, which implies that the earning power of the investment is significantly higher than the cost of capital, thus, showing how efficient the investment is given that the assumptions are favorable. The profitability indicator, PI which measures how much value has been added per dollar of investment is 1.93. It means that for everyone (1) dollar invested $1.93 is received as return on investment (ROI). The UTC was estimated to be $11.78 per barrel and the DPOP is 5.47 years.

Government take (GT) reflects the total receipt of the host government from a project, these include royalty, taxes, bonuses, profit oil, and any other forms of rent extractions. In this case, the estimated discounted takes are 68.49% and 31.51% for host government (HG) and contractor respectively. This implies for every $1 gain per barrel, HG keeps 68.5 cents and the contractor keeps 31.5 cents ceteris paribus. The FLI is 0.095 which is progressive enough and quite attractive to the contractor.

4.4.7.3. THE CURRENT ANGOLA PSC

Observations and Trends

Figure 4.8 of Appendix B shows the cost assumptions of the deep offshore project with projections showing the gross revenue, DHGT, DCT, and DPOP. At the first year of the projection (exploration and development period), the gross revenue was zero and rose when production began the following year (2021), plateau in the year 2025 for the next year, and decline afterward till the end of production which implies a direct relationship with production rate, since gross revenue is a product of production rate and price. Similarly, the discounted net cash flow (DNCF) of the contractor showed it was initially operating at a loss until 5 years after where it broke even and began to cash out, the cash flow continues to rise till it reaches an NPV of 2692.58MM$ while that of government rose from 0 to 4463.41MM$. The DPOP clearly shows a pay-out period of 5.88 years.

4.4.7.3.1. Angola PSC Deterministic Result/Discussion

Deterministic economic system measures and statistics – NPV, IRR, DPOP, PVR, PI, UTC and Take Statistics were generated. These system measures represent the output of the discounted cash flow model in an excel worksheet while the fiscal terms and parameters, as well as economic data, represent the inputs. These system measures/economic indicators are given in the table (4.14) below.

Table (4.14): Angola PSC Deterministic Result

Angola Post P/O Split	Discount Rate	12.5%
	Contractor	Government
NPV ($ MM)	2692.58	4463.41
IRR (%)	29%	
DiscountedTake Statistics (%)	37.63%	62.37%
Undiscounted Take Statistics (%)	38.45%	61.55%
Front-end Loading Index, FLI	0.01	
PV of CAPEX	2600.62	
Present Value Ratio (PVR)	1.04	
Profitability Indicators, PI	2.04	
Disc. Payback period, years	5.88	
UNIT CAPEX, $/BBL	4.07	
UNIT OPEX, $/BBL	7.70	
Unit Technical Cost, $/BBL	11.78	

Table (4.14) shows the deterministic results of the discounted cash flow model of the deepwater PSC project, using a discount rate of 12.5%. The project can pay for the cost of financing the investment and generate revenue. Hence, the project is profitable and worth embarking upon. The IRR is 29%, which implies that the earning power of the investment is significantly higher than the cost of capital, thus, showing how efficient the investment is given that the assumptions are favorable. The profitability indicator, PI which measures how much value has been added per dollar of investment is 2.04. It means that for everyone (1) dollar invested $2.04 is received as return on investment (ROI). The UTC was estimated to be $11.78 per barrel and the DPOP is 5.88 years.

Government take (GT) reflects the total receipt of the host government from a project, these include; royalty, taxes, bonuses, profit oil, and any other forms of rent extractions. In this case, the estimated discounted takes are 62.37% and 37.63% for host government (HG) and contractor respectively. This implies for every $1 gain per barrel, HG keeps 62.4 cents and the contractor keeps 37.6 cents ceteris paribus. The FLI is 0.01 which is progressive enough and quite attractive to the contractor.

4.4.7.4. GHANA CONCESSIONARY (R/T) SYSTEM

Observation and Trends

Figure 4.9 of appendix B shows the cost assumptions of the deep offshore project with projections showing the gross revenue, DHGT, DCT, and DPOP. At the first year of the projection (exploration and development period), the gross revenue was zero and rose when production began the following year (2021), plateau in the year 2025 for the next year, and decline afterward till the end of production which implies a direct relationship with production rate, since gross revenue is a product of production rate and price. Similarly, the discounted net cash flow (DNCF) of the contractor showed it was initially operating at a loss until 5 years after where it broke even and began to cash out, the cash flow continues to rise till it reaches an NPV of 3298.06MM$ while that of government rose from 0 to 4415.86MM$. The DPOP clearly shows a pay-out period of 6.54 years.

4.4.7.4.1. Ghana Concessionary Deterministic Result/Discussion

Deterministic economic system measures and statistics – NPV, IRR, DPOP, PVR, PI, UTC and Take Statistics were generated. These system measures represent the output of the discounted cash flow model in an excel worksheet while the fiscal terms and parameters, as well as economic data, represent the inputs. These system measures/economic indicators are given in the table (4.15) below.

Table (4.15): Ghana concessionary Deterministic Result

INDICATORS	Discount Rate	12.5%
	Contractor	Government
NPV ($ MM)	3298.06	4415.86
IRR (%)	30%	
DiscountedTake Statistics (%)	42.75%	57.25%
Undiscounted Take Statistics (%)	50.38%	49.62%
Front Loading Index, FLI	0.154	
Payback period, years	5.47	
Disc. Payback period, years	6.54	
Profitability Index, PI	2.27	
UNIT CAPEX, $/BBL	4.07	
UNIT OPEX, $/BBL	7.70	
Unit Technical Cost, $/BBL	11.78	

Table (4.15) shows the deterministic results of the discounted cash flow model of the deepwater PSC project, using a discount rate of 12.5%. The project can pay for the cost of financing the investment and generate revenue. Hence, the project is profitable and worth embarking upon. The IRR is 30%, which implies that the earning power of the investment is significantly higher than the cost of capital, thus, showing how efficient the investment is given that the assumptions are favorable. The profitability indicator, PI which measures how much value has been added per dollar of investment is 2.27. It means that for every one (1) dollar invested $2.27 is received as return on investment (ROI). The UTC was estimated to be $11.78 per barrel and the DPOP is 6.54 years.

Government take (GT) reflects the total receipt of the host government from a project, these include royalty, taxes, bonuses, profit oil, and any other forms of rent extractions. In this case, the estimated discounted takes are 52.25% and 42.75% for host government (HG) and contractor respectively. This implies for every $1 gain per barrel, HG keeps 52.25 cents and the contractor keeps 42.75 cents ceteris paribus. The FLI is 0.01 which is progressive enough and quite attractive to the contractor.

4.4.8. STOCHASTIC RESULTS AND DISCUSSIONS

To account for the uncertainty inherent in the economic model assumptions; the @Risk excel add-in, a simulation tool was used to quantify the Impact of selected stochastic input variables on the economic indicators, NPV, IRR, PI, DHGT, DCT, FLI using Monte-Carlo simulation approach. The stochastic variables invoked are oil price, peak production rate, discount rate, tax rate, CAPEX, and OPEX; the variables are assumed to be normally, log-normally, Pert, and triangularly distributed. The selected stochastic variables were applied to the four (4) petroleum fiscal systems.

4.4.8.1. THE NIGERIA DOA’19 PSC

The table 4.16 below shows the descriptive statistics of the selected stochastic variables used for the Nigerian DOA’19 PSC and they form the basis for the stochastic output values reported in table (4.17)

Table (4.16): Probability Distribution of Parameters for Stochastic Analysis (Nigeria DOA’19 PC)

Parameters	**Probability Distribution**	**Minimum**	**Mean**	**Maximum**
Peak production rate (BOPD)	Log Normal	150,467.75	165,011.28	554,513.92
Discount rate (%)	Log Normal	12.53	13.75	36.60
Oil price ($/bbl) (MM$)	Triangular	45.01	50	54.96
Variable OPEX (%)	Triangular	13.51	15	16.50

Exp. & Appraisal (MM$)	Triangular	225.23	250	274.68
Devt. Drilling (MM$)	Triangular	405.09	450	494.58
Flow station/1st year (MM$)	Triangular	315.46	350	384.67
Flow station/2nd year (MM$)	Triangular	315.25	350	384.81
Facility/1st year (MM$)	Triangular	450.12	500	549.68
Facility/2nd year (MM$)	Triangular	450.6	500	549.68
Reserves (MMbbl)	Log Normal	702.19	769.98	1956.68
Tax rate, PPT (%)	Log Normal	50.13	54.99	132

Table 4.17: The Nigeria DOA'19 PSC Stochastic Output

Percentile	**NPV (MM$)**	**IRR (%)**	**DHGT (%)**	**DCT (%)**	**PI**	**DPOP (Yrs)**	**FLI**	**UTC ($/bbl)**
P10	1436.68	25.10	71.12	20.8	1.56	6.20	0.06	10.77
P50	2023.67	27.44	73.56	26.4	1.78	6.56	0.079	11.44
P90	2467.70	29.65	79.20	28.9	1.96	7.09	0.105	12.08
Minimum	- 2505.24	0.65	68.85	60.5	0.02	4.80	-0.01	9.31
Mean	1974.99	27.33	74.63	25.4	1.77	6.72	0.082	11.42
Maximum	6169.14	49.32	160.49	31.2	3.42	38	1.312	13.03
Mode	2115	27.51	72.22	27.8	1.86	6.46	0.077	11.48

From table 4.17 above, it was observed that the most likely NPV of the project at a 12.5% discount rate is 2115MM$ while the P50 value of NPV is 2023.67MM$, which implies there is 50% certainty of obtaining an NPV of 2023.67MM$. The P50 value of IRR is 27.44% and the most likely IRR is 27.51%, which shows a positive outlook as compared to the hurdle rate of 12.5%. Also, the P50 values of DHGT and most likely DHGT are 73.56% and 72.22% respectively, P50 values of DCT and most likely DCT are 26.4% and 27.8% respectively. While the P50 value of PI and most likely PI of the project are 1.78 and 1.86 respectively, this indicates a viable project and most likely return on investment (ROI) of $1.86 for every $1 invested. It was also observed that for a viable deepwater project of this magnitude the UTC has to be within the range of $9.31 and $13.03 per barrel.

4.4.8.1.1. SENSITIVITY ANALYSES FOR NIGERIAN DOA'19 PSC

Table (4.18): List of 3 most influential input variables on key economic indicators for Nigerian DOA'19 PSC

Top 3	**NPV**	**IRR**	**DHGT**	**DCT**	**PI**	**DPOP**	**FLI**	**UTC**
1	Tax rate	Tax rate	Tax rate*	Tax rate	Tax rate	Tax rate	Discount rate	Oil price
2	Discount rate	Peak prod*	Discount rate*	Discount rate	Discount rate	Discount rate	Reserve*	Variable OPEX
3	Oil price*	Oil price*	Oil price	Oil price*	Oil price*	Peak prod.*	Oil price*	Reserve*

NB: Input variables labeled (*) represent variables that the indicators are positively sensitive to.

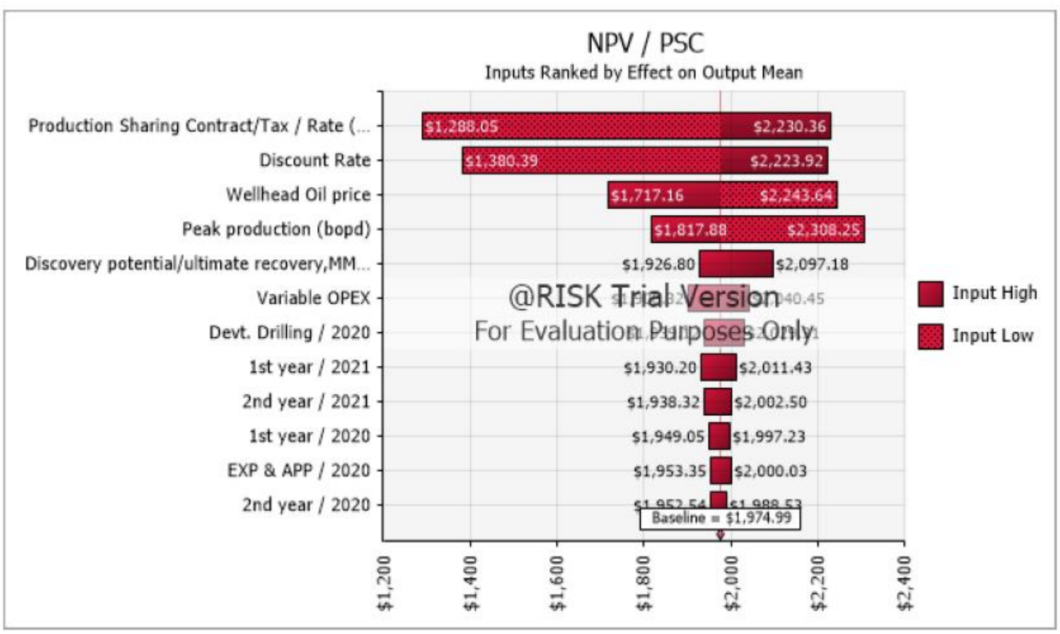


Figure4.14: NPV Tornado chart for Nigeria DOA'19 PSC

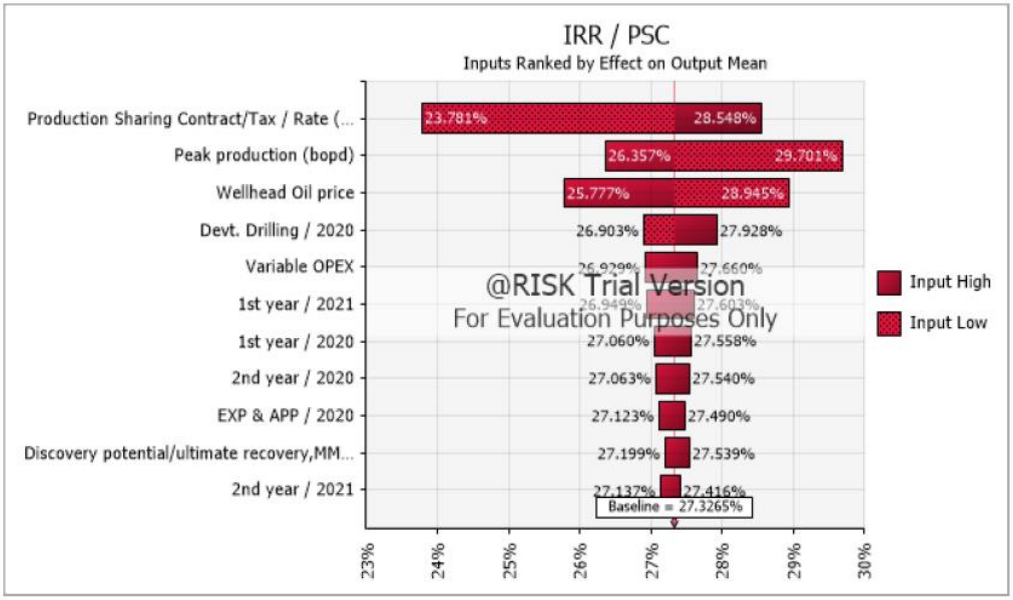


Figure 4.15: IRR tornado chart for Nigeria DOA'19 PSC

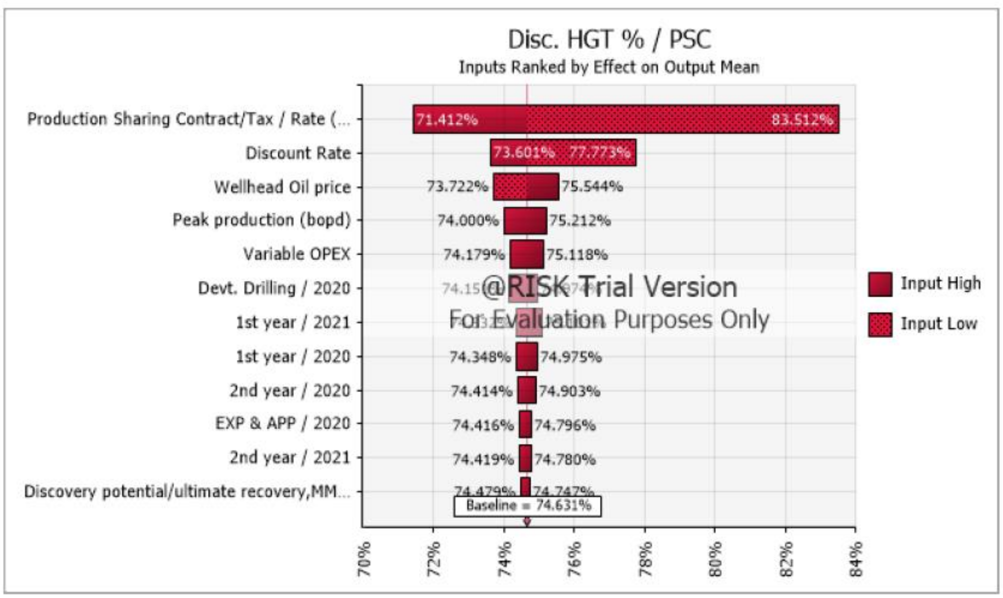


Figure 4.16: DHGT tornado chart for Nigeria DOA'19 PSC

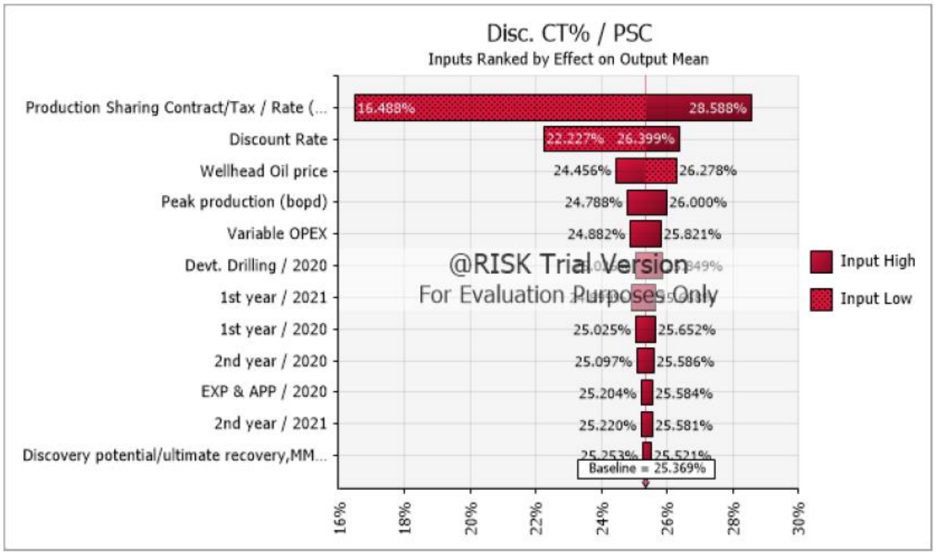


Figure 4.17: DCT tornado chart for Nigeria DOA'19 PSC

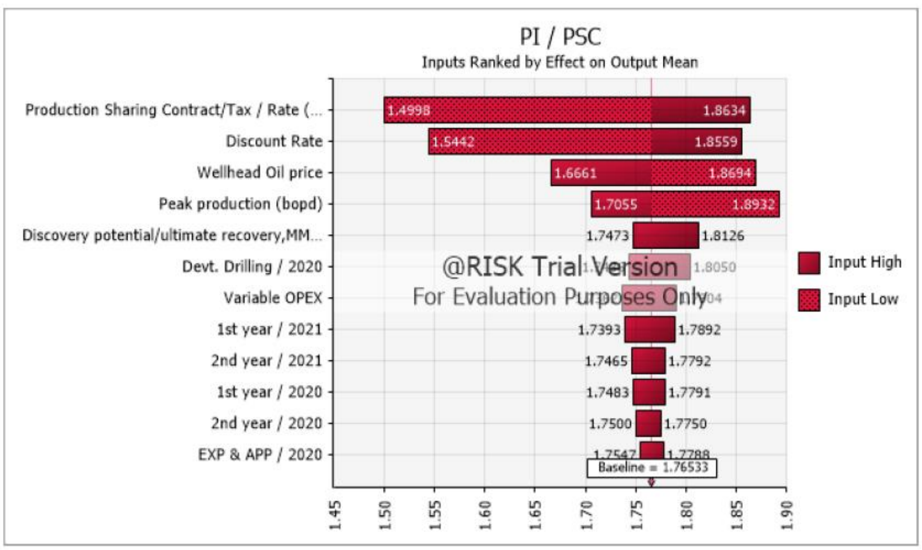


Figure 4.18: PI tornado chart for Nigeria DOA'19 PSC

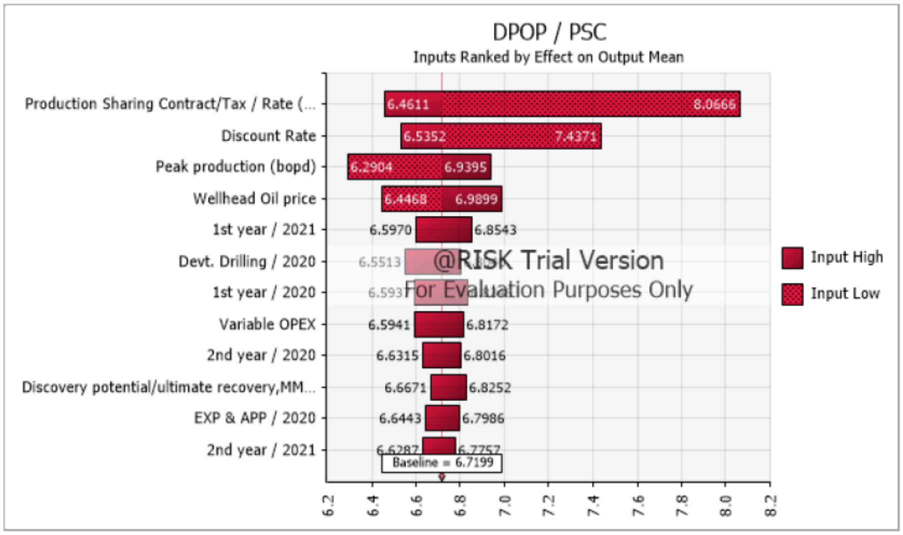


Figure 4.19: DPOP tornado chart for Nigeria DOA'19 PSC

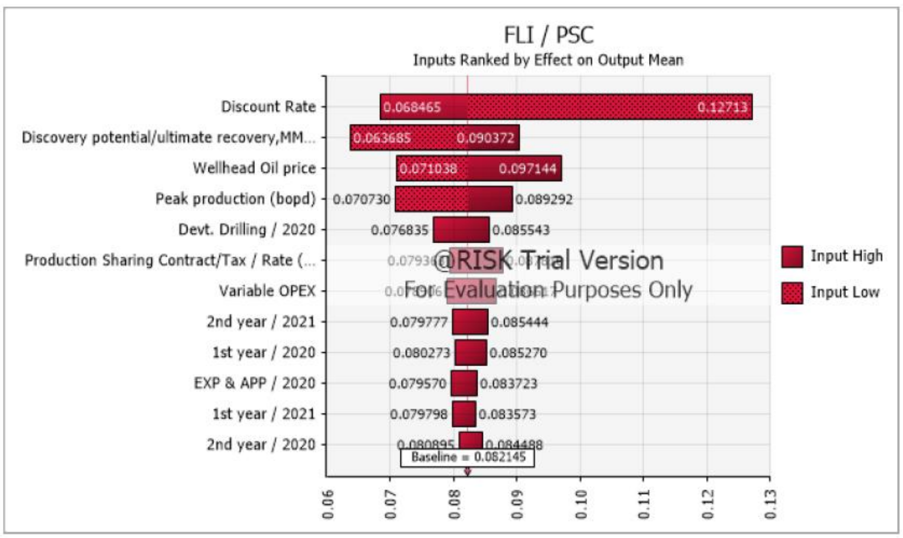


Figure 4.20: FLI tornado chart for Nigeria DOA'19 PSC

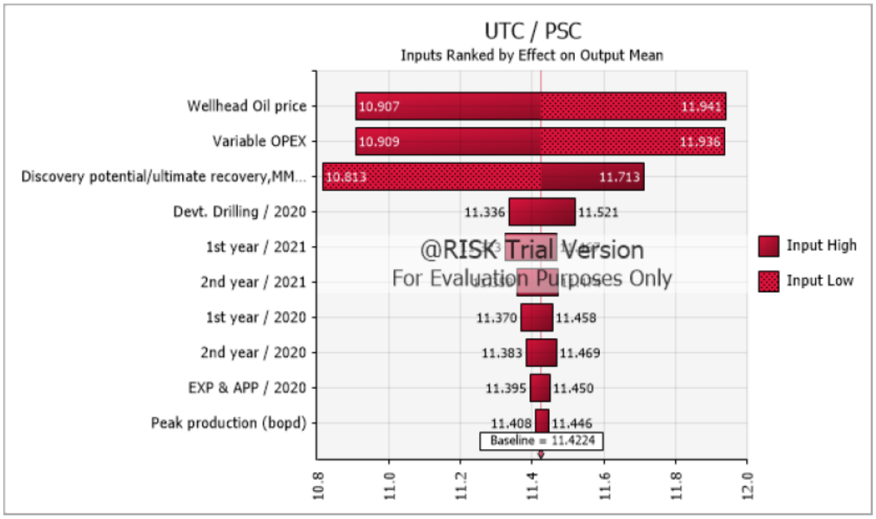


Figure 4.21: UTC tornado chart for Nigeria DOA'19 PSC

Observations from the table (4.18) above show that the most influential stochastic input variables on the economic indicators are tax rate, discount rate, and oil price respectively, this implies that in improving the fiscal system design of the Nigeria DOA'19 PSC, that tax rate, in which the economic indicators are most sensitive to, should be closely looked upon. In interpreting the result of the table (4.18) above, it was observed that NPV is negatively sensitive to the tax rate and the discount rate which implies the higher tax and discount rate the lower the NPV but positively sensitive to the oil price, i.e. the higher the oil price, the higher the NPV.

Similarly, for IRR it is positively sensitive to peak production rate and oil price, while it's negatively sensitive to the tax rate. DHGT is positively sensitive to the tax rate and discount rate, even though government NPV is negatively sensitive to discount rate but DHGT is negatively sensitive to oil price even though government NPV is positively sensitive to oil price; this implies that high DHGT does not necessarily mean high government NPV, therefore, take statistics is insufficient an indicator in itself to determine the profitability of an E&P project. DCT and PI are negatively sensitive to the tax rate and discount rate but positively sensitive to the oil price.

DPOP is negatively sensitive to the tax rate and discount rate as an increase in these input variables would mean more years for the contractor to start making profit whereas DPOP is positively sensitive to peak production rate. FLI is positively sensitive to reserve and oil price as an increase in this parameter will reduce the FLI which is a good thing for the contractor. But, FLI is negatively sensitive to discount rate as an increase discount rate implies an increase FLI which is not good (negative) for the contractor. UTC is the unit technical cost and every contractor's target is to minimize this cost to maximize profit. So the lower the UTC the better it is. From the sensitivity analysis, it was observed that UTC decreases with an increase in reserve while increase with the increase oil price and percentage variable OPEX.

4.4.8.2. THE NIGERIAN PIB-PROPOSED PSC

The table (4.19) below shows the descriptive statistics of the selected stochastic variables used for the Nigerian PIB-proposed PSC and they form the basis for the stochastic output values reported in the table (4.20)

Table (4.19): Probability Distribution of Parameters for Stochastic Analysis for Nigeria PIB-proposed PSC

Parameters	**Probability Distribution**	**Minimum**	**Mean**	**Maximum**
Peak production rate (BOPD)	Log Normal	150,479.37	164,998.97	428,756.12
Discount rate (%)	Log Normal	12.54	13.75	37.39
Oil price ($/bbl) (MM$)	Triangular	45.01	50	54.95

Variable OPEX (%)	Triangular	13.51	15	16.48
Exp. & Appraisal (MM$)	Triangular	225.26	250	274.81
Devt. Drilling (MM$)	Triangular	405.61	450	494.79
Flow station/1st year (MM$)	Triangular	315.08	350	384.72
Flow station/2nd year (MM$)	Triangular	315.33	350	384.81
Facility/1st year (MM$)	Pert	451.30	500	548.70
Facility/2nd year (MM$)	Pert	452.11	500	548.72
Reserves (MMbbl)	Log Normal	701.61	770	2076.71
Tax rate, NHT (%)	Log Normal	5.01	5.50	13.16
Tax rate, CITA (%)	Log Normal	30.08	33	84.34

Table (4.20): The Nigeria PIB-proposed PSC Stochastic Outputs

Percentile	**NPV (MM$)**	**IRR (%)**	**DHGT (%)**	**DCT (%)**	**PI**	**DPOP (Yrs)**	**FLI**	**UTC ($/bbl)**
P10	1447.05	25.29	70.42	22.87	1.56	5.62	0.101	11.78
P50	1936.53	26.76	72.41	27.59	1.75	5.79	0.109	11.78
P90	2181.24	27.29	77.13	29.58	1.84	6.24	0.137	11.78
Minimum	-1869.43	5.89	69.01	-117.9	0.28	5.51	0.096	11.78
Mean	1859.79	26.43	73.36	26.64	1.72	5.94	0.116	11.78
Max.	2366.75	27.61	217.89	30.98	1.91	38	2.307	11.78
Mode	2106.85	27.02	71.55	28.45	1.81	5.67	0.102	11.78

From table (4.20) above, it was observed that the most likely NPV of the project at 12.5% discount rate is 2106.85MM$ while the P50 value of NPV is 1936.53MM$, which implies there is 50% certainty of obtaining an NPV of 1936.53MM$. The P50 value of IRR and most likely IRR are 26.76% and 27.02% respectively, which shows a positive outlook as compared to the hurdle rate of 12.5%. Also, P50 value of DHGT and most likely DHGT are 72.41% and 71.55% respectively, P50 value of DCT and most likely DCT are 27.59% and 28.45% respectively. While the P50 value of PI and most likely PI of the project are 1.75 and 1.81 respectively, this indicates a viable project and most likely return on investment (ROI) of $1.81 for every $1 invested.

4.4.8.2.1. SENSITIVITY ANALYSES FOR NIGERIAN PIB-PROPOSED PSC

Table (4.21): List of 3 most influential input variables on key economic indicators for Nigerian PIB-proposed PSC

Top 3	**NPV**	**IRR**	**DHGT**	**DCT**	**PI**	**DPOP**	**FLI**	**UTC**
1	Discount rate	CIT	CIT*	CIT	Discount rate	Discount rate	Discount rate	-
2	CIT	NHT	Discount rate*	Discount rate	CIT	CIT	NHT	-
3	NHT	Oil price	NHT*	NHT	NHT	NHT	CIT	-

NB: Input variables labeled (*) represent variables that the indicators are positively sensitive to

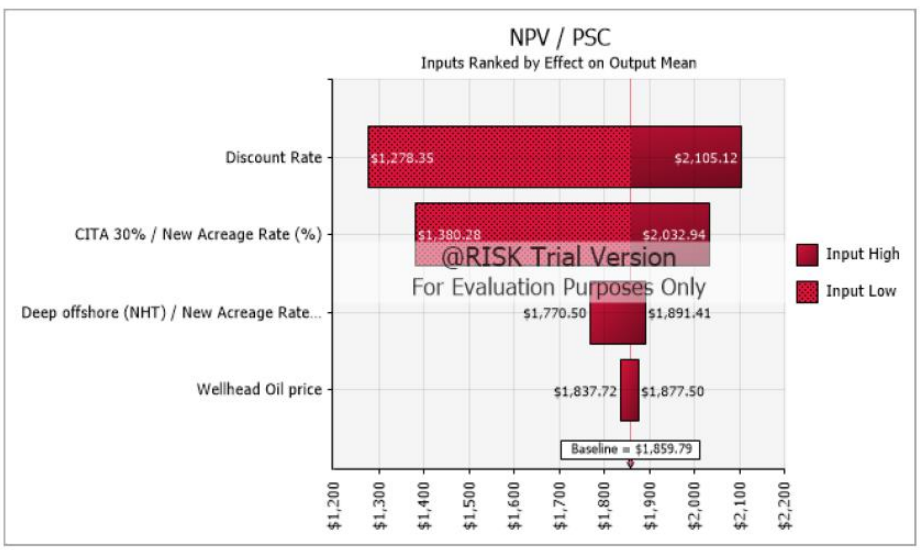


Figure 4.22: NPV tornado chart for Nigeria PIB-Proposed PSC

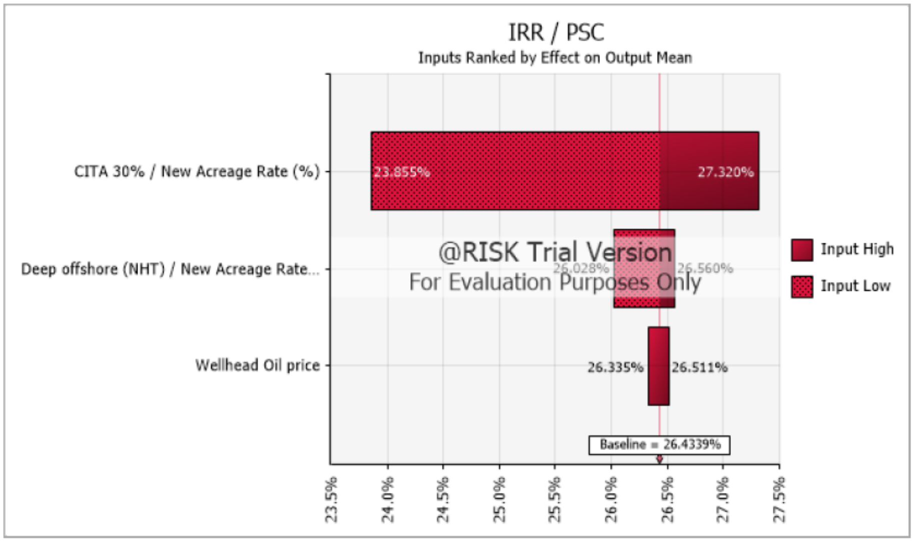


Figure 4.23: IRR tornado chart for Nigeria PIB-Proposed PSC

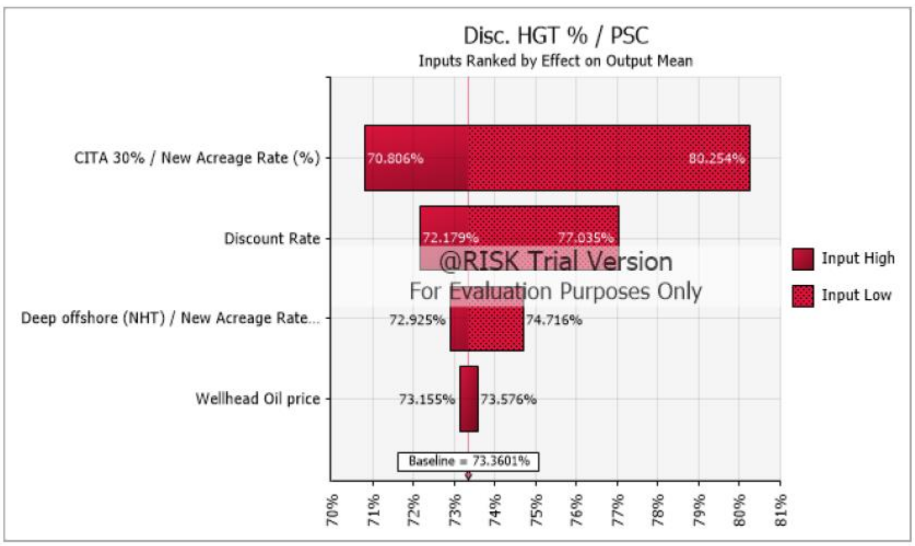


Figure 4.24: DHGT tornado chart for Nigeria PIB-Proposed PSC

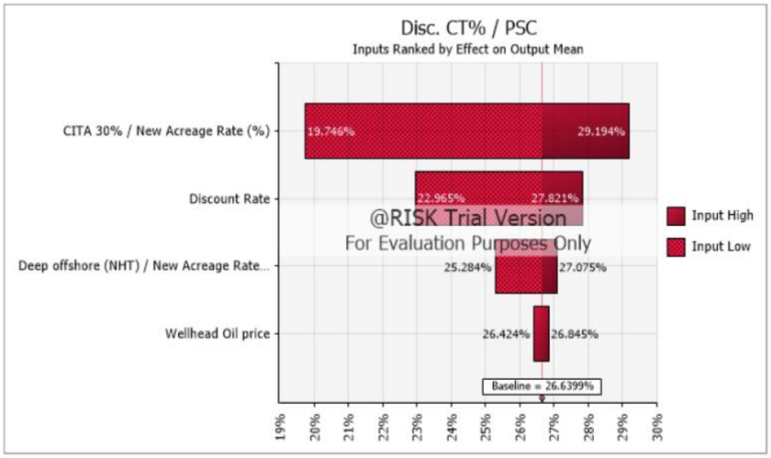


Figure 4.25: DCT tornado chart for Nigeria PIB-Proposed PSC

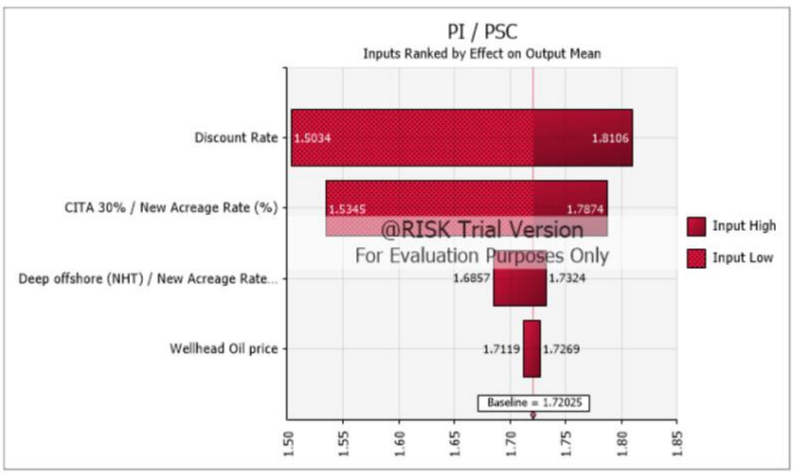


Figure 4.26: PI tornado chart for Nigeria PIB-Proposed PSC

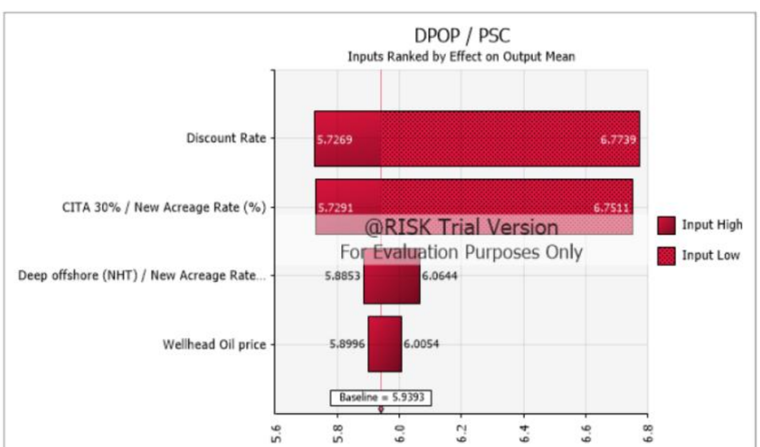


Figure 4.27: DPOP tornado chart for Nigeria PIB-Proposed PSC

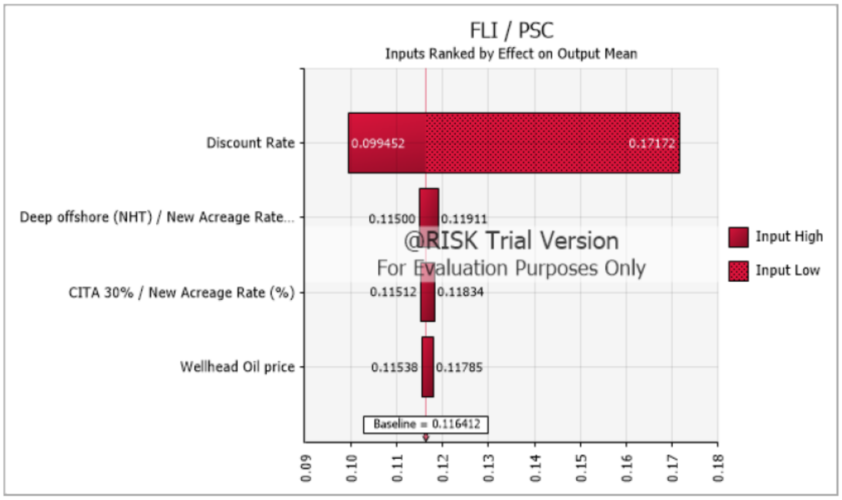


Figure 4.28: FLI tornado chart for Nigeria PIB-Proposed PSC

Observations from the table (4.21) above show that the most influential stochastic input variables on the economic indicators are the discount rate, CIT, and NHT. This implies that for the Nigerian PIB-proposed PSC petroleum fiscal system, tax rate (CIT and NHT), are critical factors that affect this fiscal system design since they are input variables to which the economic indicators are most sensitive. In interpreting the result of the table (4.18) above, it was observed that NPV is negatively sensitive to discount rate, CIT, and NHT which implies the higher the tax and discount rate the lower the NPV.

Similarly, for IRR, it is negatively sensitive to CIT, NHT, and even oil price. DHGT is positively sensitive to tax rate (CIT and NHT) and discount rate, DCT, and PI are negatively sensitive to CIT, NHT, and discount rate.

DPOP is negatively sensitive to CIT, NHT, and discount rate as an increase in these input variables would mean more years for the contractor to start making a profit. FLI is negatively sensitive to the discount rate, CIT, and NHT as an increase in these variables imply increased FLI which is not good (negative) for the contractor. For UTC there are no inputs that significantly affect outputs.

4.4.8.3. THE ANGOLA PSC 2004 (CURRENT) FISCAL TERM

The table (4.22) below shows the descriptive statistics of the selected stochastic variables used for the current Angola PSC and they form the basis for the stochastic output values reported in the table (4.23)

Table (4.22): Probability Distribution of Parameters for Stochastic Analysis for Angola PSC 2004 (current) fiscal term

Parameters	Probability Distribution	Minimum	Mean	Maximum
Peak production rate (BOPD)	Log Normal	150,254.92	164,995.61	387,880.81
Discount rate (%)	Log Normal	12.54	13.75	33.68
Oil price ($/bbl) (MM$)	Triangular	45.04	50	54.97
Variable OPEX (%)	Triangular	13.50	15	16.48
Exp. & Appraisal (MM$)	Pert	225.60	250	274.28
Devt. Drilling (MM$)	Triangular	405.34	450	494.66
Flow station/1st year (MM$)	Triangular	316.51	350	384.33
Flow station/2nd year (MM$)	Pert	315.64	350	383.64
Facility/1st year (MM$)	Triangular	450.59	500	548.70
Facility/2nd year (MM$)	Triangular	450.425	500	549.73
Reserves (MMbbl)	Normal	426.03	700	964.97
Tax rate, CIT (%)	Log Normal	50.16	55	142.98

Table (4.23): The Current Angola PSC Stochastic Outputs

Percentile	NPV (MM$)	IRR (%)	DHGT (%)	DCT (%)	DPOP (Yrs)	FLI	UTC ($/bbl)
P10	1445.93	23.51	65.02	26.40	6.16	0.036	11.65
P50	2041.35	25.45	67.50	32.51	6.53	0.056	12.48
P90	2509.46	27.33	73.59	34.98	7.04	0.090	13.38
Minimum	-2350.25	3.00	62.84	-672.25	5.25	-0.006	10.48
Mean	2000.45	39.41	68.79	31.21	6.67	0.063	12.50
Max.	4940.78	25.42	772.25	37.17	38	10.41	15.78
Mode	2093.96	25.54	65.77	34.23	6.54	0.048	12.24

From table (4.23) above, it was observed that the most likely NPV of the project at a 12.5% discount rate is 2093.96MM$ while the P50 value of NPV is 2041.35MM$. This implies there is a 50% certainty of obtaining an NPV of 2041.35MM$. The P50 value of IRR and most likely IRR are 25.45% and 25.54% respectively, which shows a positive outlook as compared to the hurdle rate of 12.5%. Also, P50 value of DHGT and most likely DHGT are 67.50% and 65.77% respectively, P50 value of DCT and most likely DCT are 32.51% and 34.23% respectively. It was also observed that for a viable deep-water project of this magnitude the UTC has to be within the range of $10.48 and $15.78 per barrel.

4.4.8.3.1. SENSITIVITY ANALYSES FOR ANGOLA PSC 2004

Table (4.24): List of 3 most influential input variables on key economic indicators for Angola PSC 2004

Top 3	NPV	IRR	DHGT	DCT	DPOP	FLI	UTC

1	Discount rate	CIT	CIT*	CIT	Discount rate	Discount rate	Reserve*
2	CIT	Peak prod.*	Discount rate*	Discount rate	CIT	Oil price*	Oil price
3	Oil price*	Oil price*	Oil price	Oil price*	Oil price*	Peak prod.*	Variable OPEX

NB: Input variables labeled (*) represent variables that the indicators are positively sensitive to

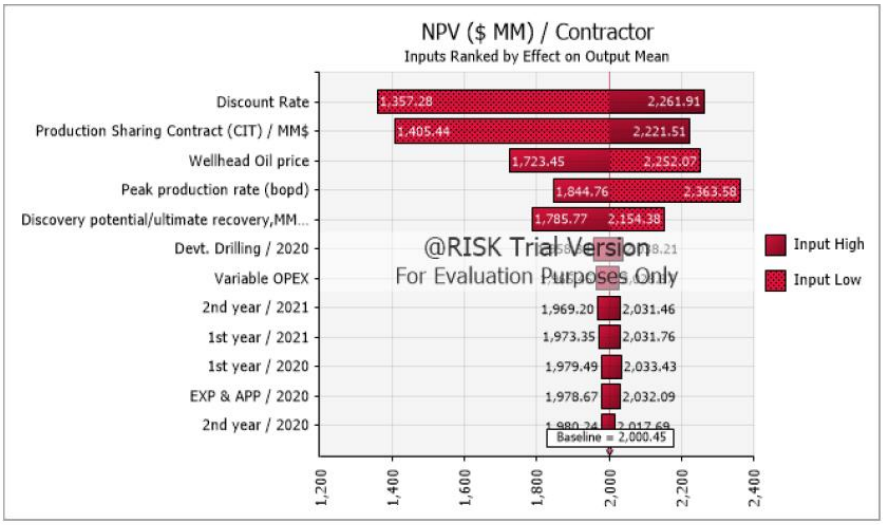


Figure 4.29: NPV tornado chart for Angola PSC 2004

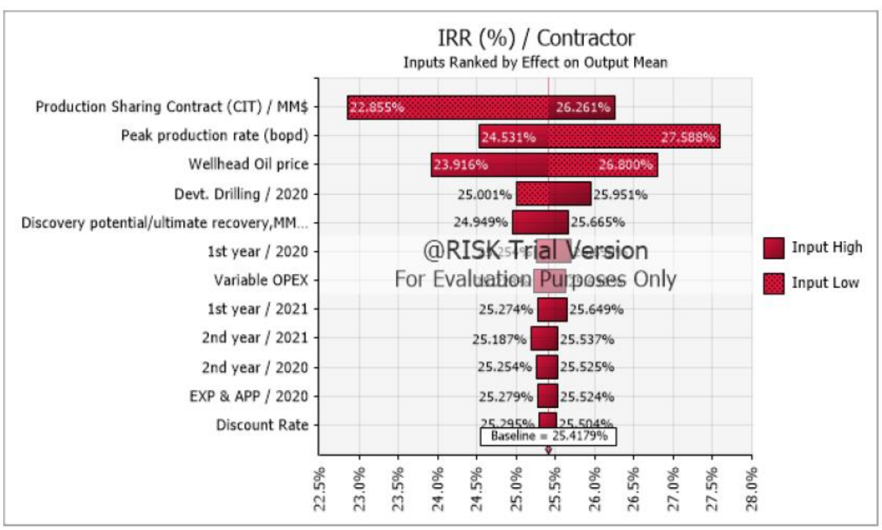


Figure 4.30: IRR tornado chart for Angola PSC 2004

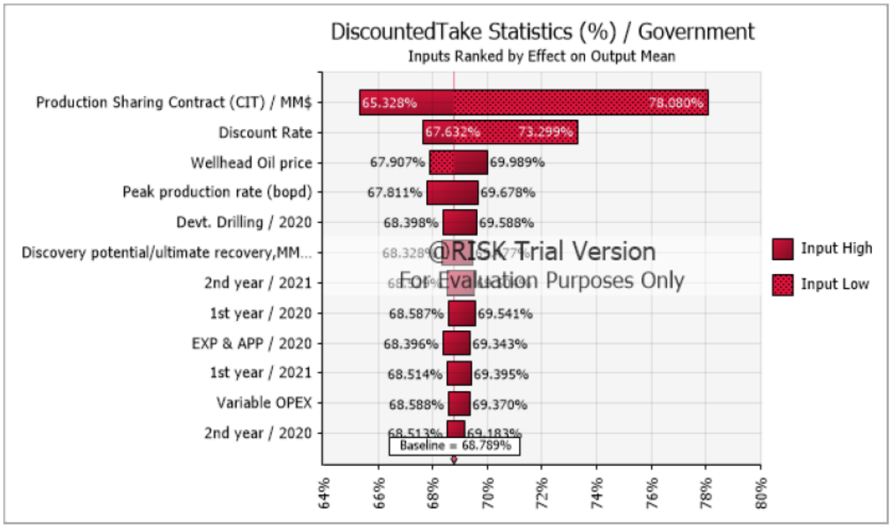


Figure 4.31: DHGT tornado chart for Angola PSC 2004

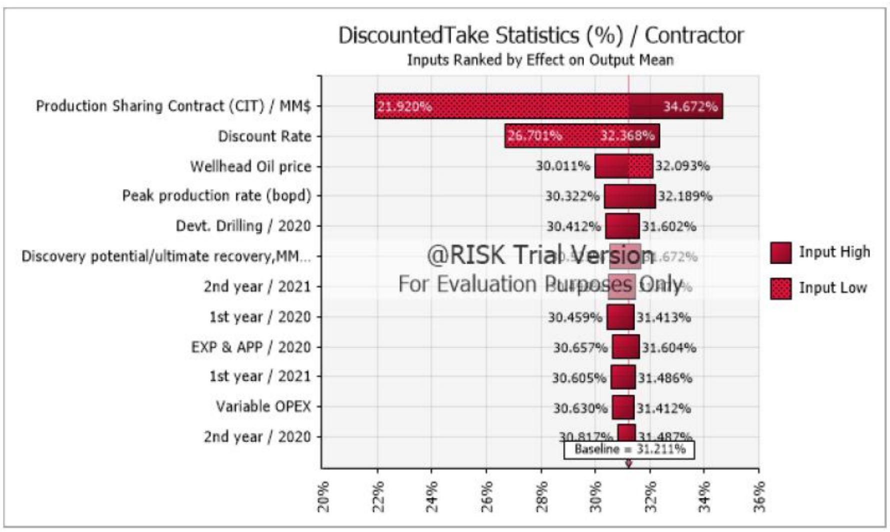


Figure 4.32: DCT tornado chart for Angola PSC 2004

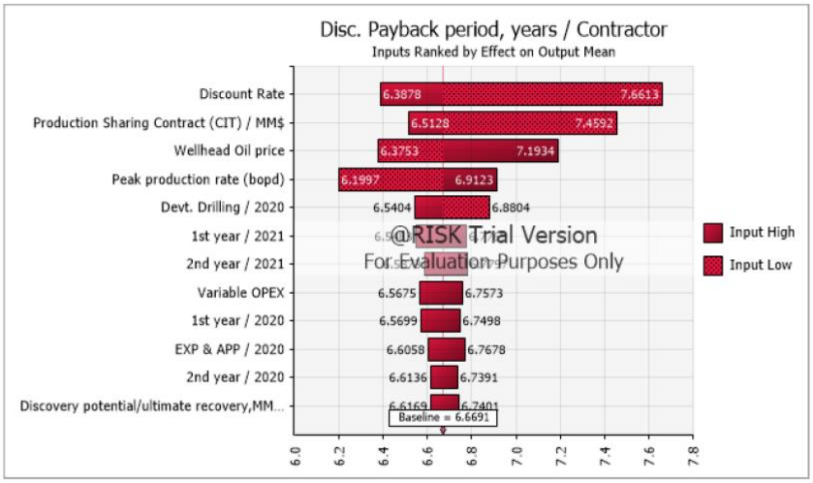


Figure 4.33: DPOP tornado chart for Angola PSC 2004

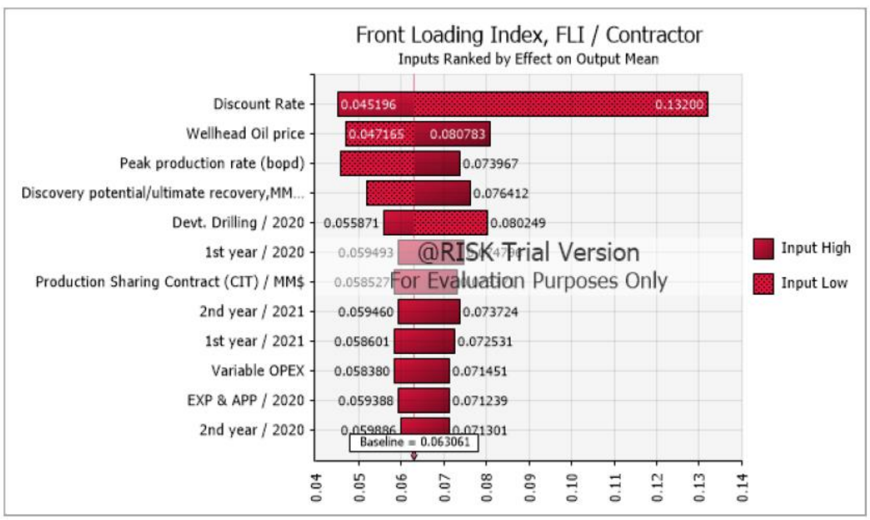


Figure 4.34: FLI tornado chart for Angola PSC 2004

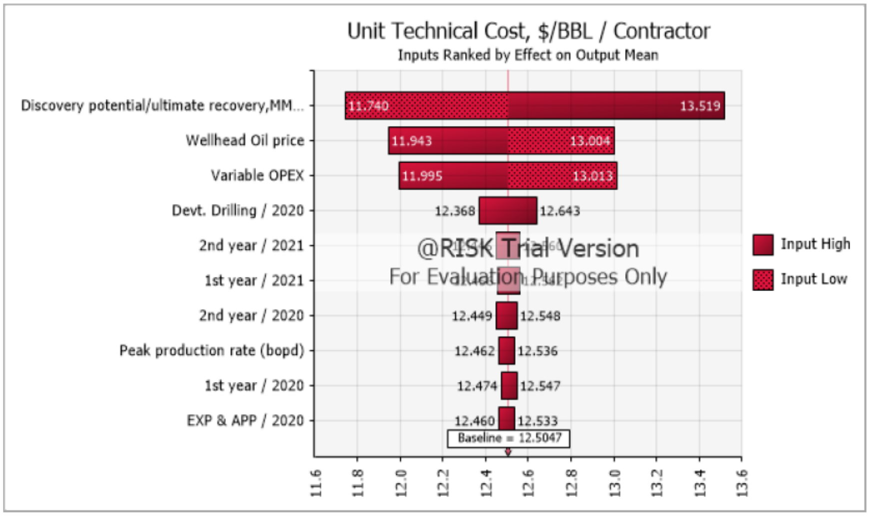


Figure 4.35: UTC tornado chart for Angola PSC 2004

Observations from the table (4.24) above show that the most influential stochastic input variables on the economic indicators are discount rate, CIT, and Oil price. This implies that for the current Angola PSC petroleum fiscal system, CIT is a critical factor that affects its fiscal system design, since it is among the input variables to which the economic indicators are most sensitive. In interpreting the result of the table (4.21) above, it was observed that NPV is negatively sensitive to discount rate and CIT, but it is positively sensitive to the oil price.

Similarly, IRR is positively sensitive to peak production rate and oil price, but negatively sensitive to CIT. DHGT is positively sensitive to CIT and discount rate, but negatively sensitive to the oil price. DCT is negatively sensitive to CIT and discount rate, but positively sensitive to the oil price.

DPOP is negatively sensitive to CIT, discount rate as an increase in this input variables would mean more years for the contractor to start making a profit, but DPOP is positively sensitive to the oil price. FLI is negatively sensitive to discount rate as an increase in this variable implies increased FLI which is not good (negative) for the contractor, but It is positively sensitive to oil price and peak production rate. UTC is positively sensitive to reserve but negatively sensitive to oil price and variable OPEX as it increases with an increase in these variables.

4.4.8.4. GHANA CONCESSIONARY SYSTEM

The table (4.25) below shows the descriptive statistics of the selected stochastic variables used for the Ghana concessionary system and they form the basis for the stochastic output values reported in the table (4.26)

Table (4.25): Probability Distribution of Parameters for Stochastic Analysis for Ghana R/T PFS

Parameters	Probability Distribution	Minimum	Mean	Maximum
Peak production rate (BOPD)	Log Normal	150,470.77	164,995.92	401,159.08
Discount rate (%)	Log Normal	12.52	13.75	37.63
Oil price ($/bbl) (MM$)	Triangular	45.05	50	54.93
Variable OPEX (%)	Triangular	13.52	15	16.49
Exp. & Appraisal (MM$)	Triangular	225.26	250	274.71
Devt. Drilling (MM$)	Pert	405.34	450	494.66
Flow station/1st year (MM$)	Triangular	315.22	350	384.76
Flow station/2nd year (MM$)	Triangular	315.43	350	384.86
Facility/1st year (MM$)	Triangular	450.42	500	549.42
Facility/2nd year (MM$)	Triangular	450.44	500	549.32
Reserves (MMbbl)	Normal	427.36	700	964.19
Tax rate, CIT (%)	Log Normal	35.11	38.50	90.04

Table (4.26): The Ghana Concessionary system Stochastic Outputs

Percentile	NPV (MM$)	IRR (%)	DHGT (%)	DCT (%)	PI	DPOP (Yrs)	FLI	UTC ($/bbl)
P10	2132.92	27.62	58.86	33.93	1.83	6.63	0.16	11.78
P50	2751.32	28.96	60.89	39.11	2.06	6.76	0.17	11.78
P90	3041.97	29.41	66.07	41.14	2.17	7.09	0.21	11.78
Minimum	-613.97	7.03	57.63	-111.33	0.73	6.56	0.14	11.78
Mean	2652.52	28.66	61.95	38.05	2.03	6.85	0.18	11.78
Max.	3236.20	29.61	211.33	42.37	2.25	38	3.07	11.78
Mode	2859.37	29.31	59.59	40.41	2.11	6.66	0.16	11.78

From table (4.26) above, it was observed that the most likely NPV of the project at 12.5% discount rate is 2859.37MM$ while the P50 value of NPV is 2751.32MM$, which implies there is 50% certainty of obtaining an NPV of 2751.32MM$. The P50 value of IRR and most likely IRR are 28.96% and 29.31% respectively, which shows a positive outlook as compared to the hurdle rate of 12.5%. Also, P50 value of DHGT and most likely DHGT are 60.89% and 59.59% respectively, P50 value of DCT and most likely DCT are 39.11% and 40.41% respectively. The most likely FLI is 0.16, which is quite high, not good for the contractor.

4.4.8.4.1. SENSITIVITY ANALYSES FOR GHANA R/T PFS

Table (4.27): List of most influential input variables on key economic indicators for Ghana R/T PFS

Top 2	NPV	IRR	DHGT	DCT	PI	DPOP	FLI	UTC
1	Discount rate	CIT	CIT*	CIT	Discount rate	Discount rate	Discount rate	-
2	CIT		Discount rate*	Discount rate	CIT	CIT	CIT*	-

NB: Input variables labeled (*) represent variables that the indicators are positively sensitive to

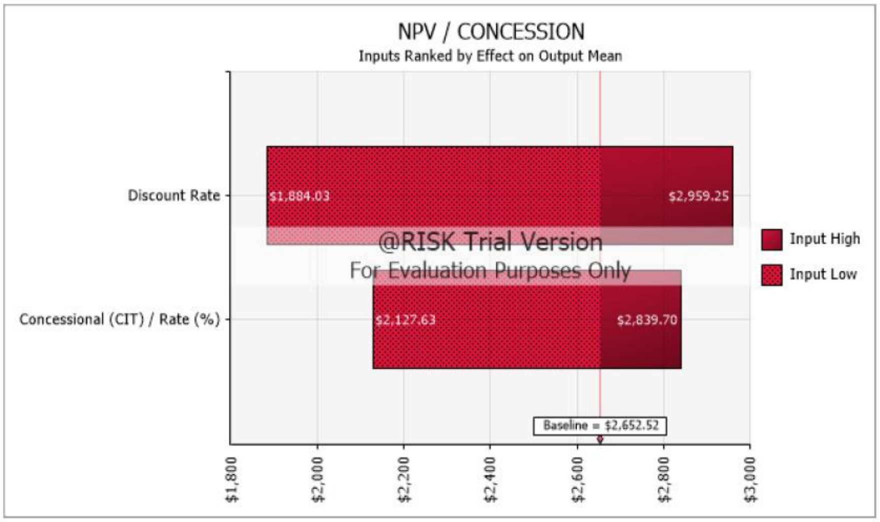


Figure 4.36: NPV tornado chart for Ghana R/T PFS

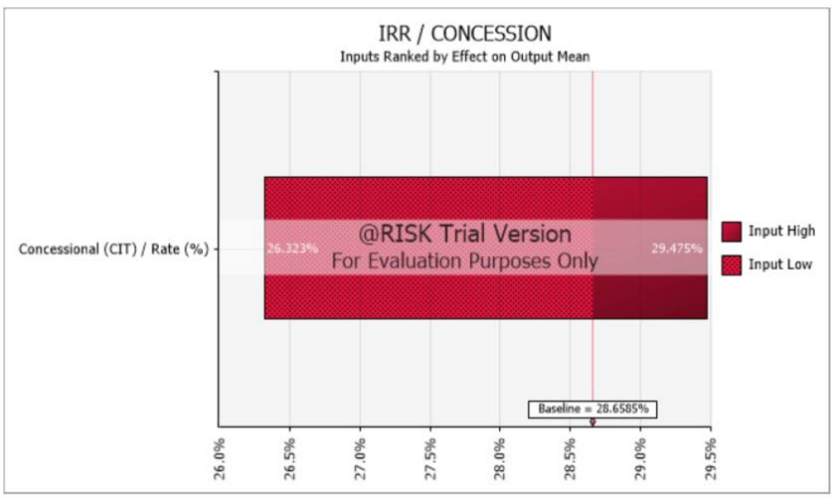


Figure 4.37: IRR tornado chart for Ghana R/T PFS

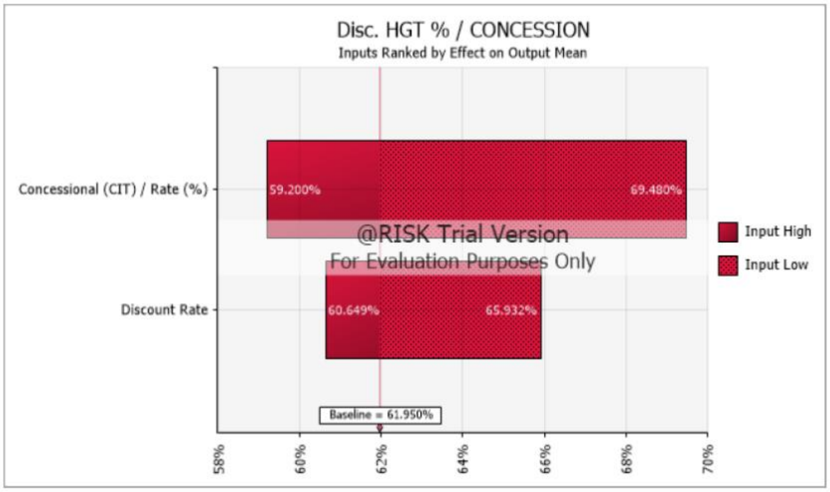


Figure 4.38: DHGT tornado chart for Ghana R/T PFS

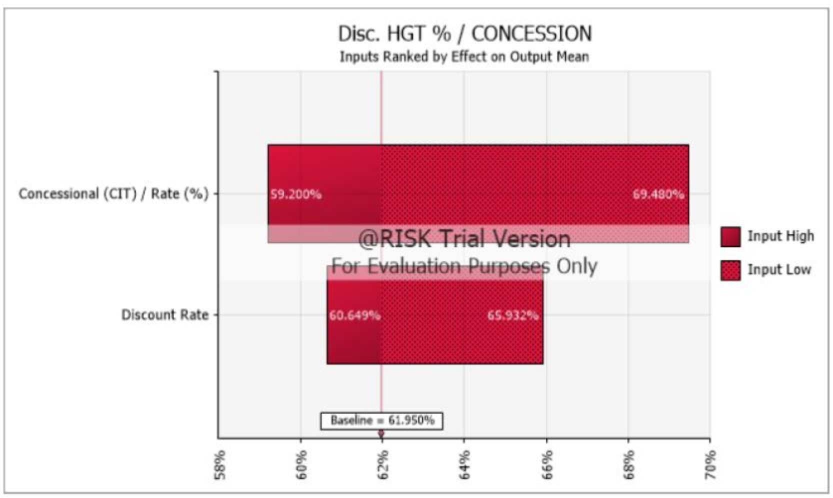


Figure 4.39: DCT tornado chart for Ghana R/T PFS

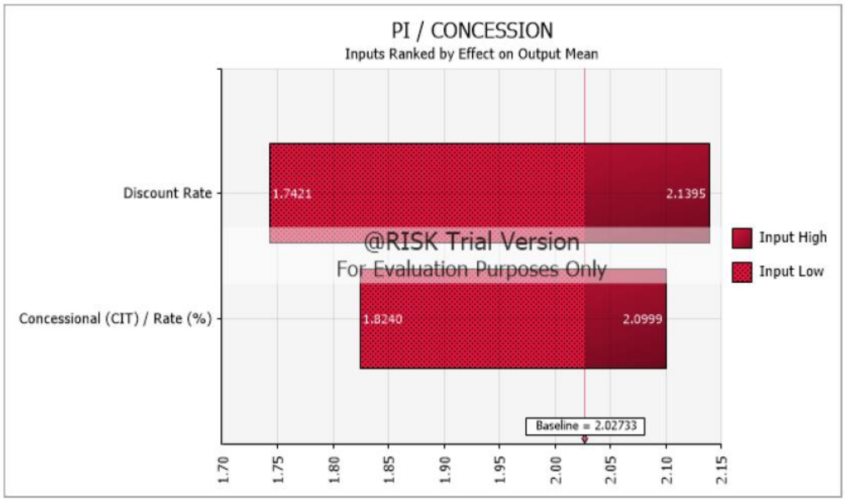


Figure 4.40: PI tornado chart for Ghana R/T PFS

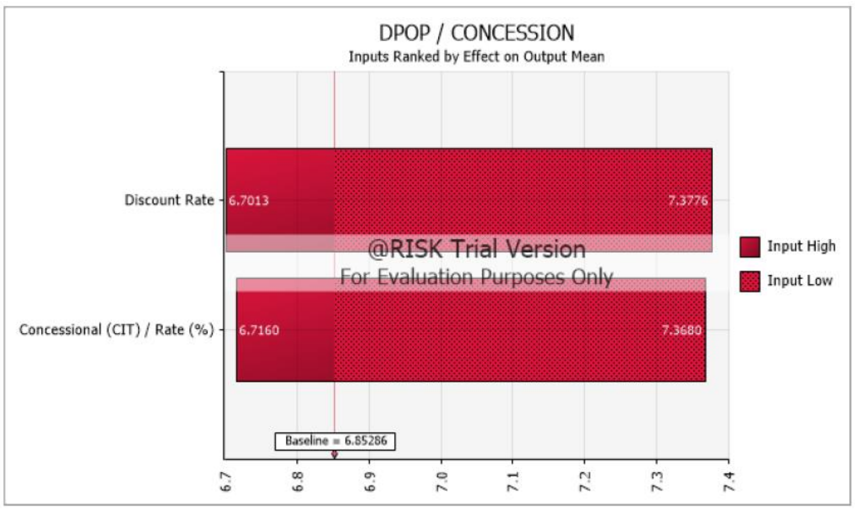


Figure 4.41: DPOP tornado chart for Ghana R/T PFS

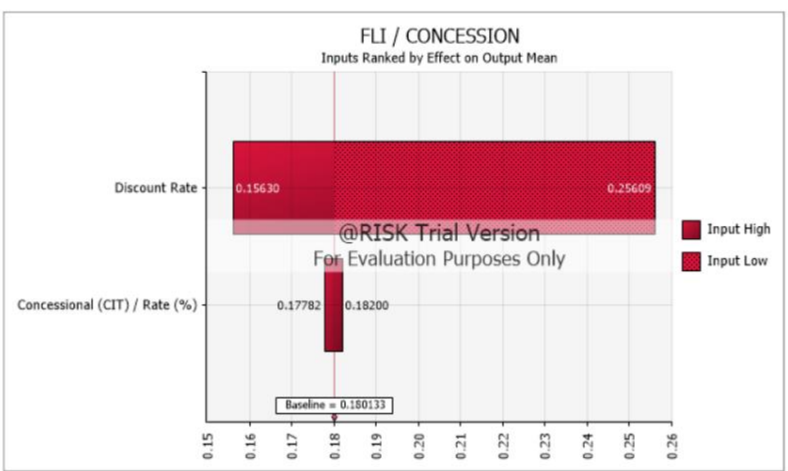


Figure 4.42: FLI tornado chart for Ghana R/T PFS

Observations from the table (4.24) above show that the most influential stochastic input variables on the economic indicators are discount rate and CIT. This implies that for the Ghana concessionary petroleum fiscal system, tax rate (CIT) is a critical factor that affects its fiscal system design since CIT is among the input variables, to which the economic indicators are most sensitive. In interpreting the result of the table (4.24) above, it was observed that NPV is negatively sensitive to discount rate and CIT which implies that the higher the tax and discount rates the lower the NPV.

Similarly, for IRR it is negatively sensitive to CIT. DHGT is positively sensitive to CIT and discount rate. DCT and PI are negatively sensitive to CIT and discount rate.

DPOP is negatively sensitive to CIT and discount rate, as an increase in these input variables would mean more years for the contractor to start making a profit. FLI is negatively sensitive to the discount rate, an increase in these variables implies increased FLI which is not good (negative) for the contractor. For UTC, there are no inputs that significantly affect the output.

4.4.9. COMPARATIVE ANALYSIS FOR THE 4 PETROLEUM FISCAL SYSTEMS (PFS)

Table (4.28): Deterministic Results for the 4 PFSs

PFS	NPV (CT) (MM$)	NPV (GT) (MM$)	IRR (%)	HGT (%)	DHGT (%)	CT (%)	DCT (%)	PI	DPOP (years)	FLI
Nigeria DOA'19 PSC	2299.59	5414.33	27	64.87	70.19	35.13	29.81	1.88	6.44	0.082
Nigerian PIB-proposed	2431.00	5282.92	28	62.53	68.49	37.25	31.51	1.93	5.47	0.095
Current Angola PSC	2692.58	4463.41	29	61.55	62.37	38.45	37.63	2.04	5.88	0.010
Ghana R/T	3298.06	4415.86	30	49.62	57.25	50.38	42.75	2.27	6.54	0.154

The table (4.28) above gives the comparative deterministic results of the 4 PFS. Our comparative analysis is with references to the Nigerian PIB-proposed fiscal system. Looking at key economic indicators, critical to the contractor for making economic decisions such as contractor's NPV, IRR, CT, DCT, and PI, it was observed that there is an increase in the values of these key indicators; a progressive trend from the Nigerian DOA'19 to the Ghana R/T system down the table. This implies the Nigeria PIB-proposed fiscal system is an improvement to the Nigeria DOA'19 PSC, despite its 100% cost recovery. This could be due to the production allowance provision in the PIB fiscal system. The PIB proposed is more favorable to the contractors. Thus, has the potential of attracting investors, even though the increase is marginal. The government's NPV, undiscounted, and discounted take statistics decreases steadily down the table, which means the Nigerian government earns less with the proposed PIB fiscal system as compared to the Nigerian DOA'19. This may not be a problem, because the difference is not much and if the PIB-proposed seems to be more attractive to the contractor. This implies more E&P project investments and participation in Nigeria.

Now, looking beyond the Nigerian PFS it was observed from the key economic indicators that the current Angola PSC and the Ghana R/T fiscal system shows more profitability respectively for both the government and the contractor compared to the two (2) Nigerian PFS. Hence, Ghana and Angola PFS are considered to be more progressive than the two Nigerian PFS and what could account for the progressiveness in the Angola PSC is probably due to its profit oil split formula which is based on yearly IRR instead of cumulative oil production as reflected in the two (2) Nigerian PFS. Hence, Nigeria could adapt that into PFS design to increase its attractiveness to the contractor and competitiveness of its fiscal regime.

It was observed that the deep-water project for the 4 PFS has an average discounted payback period of 6 years. The PIB-proposed PFS has the earliest payback period of about 5.5 years while the rest is about 6 years and above. Even though it is a good thing to have an early payback period, based on this study, a contractor will go for Ghana and Angola PFS with higher contractor's NPV, IRR, and PI than that of the PIB which has less NPV, IRR, and PI but earlier DPOP of just 1-year difference. But it is the contractor's investment decision based on whatever decision criteria the company adopts.

Considering the FLI, it was observed from the contractor's viewpoint that Ghana R/T is the most regressive relatively speaking with an FLI of 0.154 while Nigeria DOA'19 PSC is the most progressive with an FLI of 0.082.

4.4.9.1. GTAKE COMPONENTS OF THE 4 PFS

From figure 4.10-4.13 of appendix B, it is observed that taxes contribute the most to the government takes. Therefore, it is a key element in designing fiscal systems. The next in line is the profit oil and ECR, while FLGT is the least contributor to government takes. Another observation is that despite Ghana's R/T system contribute the most FLGT of 33%, it does not translate to the highest HGT or DHGT. Angola PSC with the least FLGT of 2.73% has a higher HGT and DHGT than that of Ghana with the highest FLGT contribution.

CHAPTER FIVE

5.0. CONCLUSIONS AND RECOMMENDATIONS

5.1. CONCLUSIONS

This study was undertaken to give a critical look into the Nigerian 2020 proposed petroleum Industry Bill (PIB); a document that provides the legal, fiscal and regulatory framework for the Nigerian petroleum industry to ascertain its significance and relevance in revamping the industry, which is the main purpose of its drafting, thus, giving the Nigerian petroleum industry a footing in the golden gate of global oil and gas business.

Therefore, to ascertain if the provisions of this drafted bill can deliver the vision of a viable and functional Nigerian petroleum Industry, a brief look and viewpoint was shared of the governance, administrative and the Host and Impacted communities while an economic analysis of the Fiscal provisions was carried out alongside three (3) other petroleum fiscal systems; Nigerian DOA'19 PSC, Angola PSC 2004 and Ghana R/T.

There are certainly plausible policies highlighted in the governance provisions of which if implemented would help in the reform plans of the Nigerian petroleum industry, these are;

1. Replacement of the NNPC with NNPC limited, which would make the NNPC more efficient strictly as an operator with no form of regulatory role either directly or indirectly, instead the regulatory role will be filled in by "The Commission" in charge of the downstream sector while "The Authority" in charge of the midstream and downstream sector. This will ensure a clearly defined path of responsibilities and administration of the petroleum industry.

2. As for the Administration provision of the bill, certain policies stand out. Even though it covered both upstream and downstream administration, its emphasis is more on the downstream sector, some of these policies are; the removal of the powers of the minister from fixing prices of petroleum products suggest a progressive move towards full and honest deregulation of the downstream sector. Also, the powers of the minister to grant and revoke licenses and leases can only be done by the recommendation of the Commission. This tends promoting transparency in governance and administration.

The Host and Impacted Communities provisions; there are a lot of controversies here, due to sectional interest, in fact, we can say that it's one of the major aspect stalling the passage of the PIB and unless the 9th NASS is committed to tackling the issues surrounding this aspect of the bill, this PIB may have the same sad ending as the previous ones before it. In the next section, the author highlighted some recommendations based on the study which if adopted, can help with the issue.

As for the fiscal provision, a quantitative approach was adopted where the bill's fiscal system was compared with the Nigerian DOA'19, Ghana, and current Angola fiscal system. This was achieved by coding the fiscal elements into an excel sheet and using the knowledge of cash flow analysis in petroleum economics to create economic models from which comparative analysis of the 4 PFS was carried out using the value of the economic indicator obtained for respective PFS, also stochastic simulation using the Monte-Carlo simulation approach was carried out using @Risk excel add-in simulation tool to account for risk and uncertainty in some of the input variables. From the comparative analysis, we can deduce that:

1. The bill's fiscal system PSC for the deep-water project is an improvement from the Nigerian DOA'19 as the key economic indicators from the contractor's viewpoint are more favorable. Hence, it has the potential of attracting more investors into Nigerian offshore E&P projects. This could be due to an incentive provision called "the production allowance" in the PIB fiscal system.
2. The current Angola PSC and Ghana R/T fiscal systems gave a better profit for both the contractor and the Nigerian government than the two Nigerian PFS. What could account for the progressiveness in the Angola PSC is its profit oil sharing formula which is based on yearly IRR instead of cumulative oil production as the case for the Nigerian PFS. Hence, Nigeria could adopt that into the PIB PFS design to increase its attractiveness to the contractor and competitiveness of its fiscal regime, likewise, increase revenue generation for Nigeria.
3. Lastly, looking at the government take components (FLGT, Profit Oil/ECR, and Taxes) of the 4 PFS, it was observed that taxes contribute the most to the government take, while FLGT the least. Thus, if an improvement is to be made in the respective PFS design, it should be centered on the taxation system.

The table below shows the deep-water project ranking based on Profitability from the contractor's viewpoint:

Table 4.29: P.F.S. Ranking from Contractor's Viewpoint

	FISCAL REGIME RANKING BASED ON NPV, IRR AND PI			
COUNTRY/PFS	**NPV (MM$)**	**IRR (%)**	**PI**	**RANK**
NIGERIAN DOA'19 PSC	2299.59	27	1.88	4
NIGERIAN PIB-PROPOSED	2431	28	1.93	3
ANGOLA PSC 2004	2692.58	29	2.04	2
GHANA R/T	3298.06	30	2.27	1

NB: "1" represents the *most preferred* project to invest in while **"4"** the *least preferred*

5.2. RECOMMENDATIONS

The following recommendations are made. Seeing how important the petroleum industry is to the Nigerian economy and passage of this bill is to the reform of the industry.

1. The Nigerian government should seek to diversify the economy by incentivizing midstream and downstream activities instead of relying mainly on economic rent extraction from upstream activities as a means of revenue generation.
2. The 9th NASS with the help of the major stakeholders in the industry should ensure at all costs that this PIB is passed, if not all efforts made for the past 20 years will end up as a mirage. They must place national interest above personal and sectional interest.
3. The issues surrounding the host and impacted communities should be given a critical look, as it serves as the major hindrance in my opinion to the process of the PIB passage. Practical steps to be taken to help curb this issue will be; identification of who the host and impacted communities are should be the responsibility of the federal and state government of Nigeria instead of the oil and gas company. Also, the host communities must be given proper and adequate representation in the establishment and management of the trust fund. Other

issues surrounding it, like percentage revenue allocation to the trust fund, etc. must be given maximum attention.

4. Profit Oil-sharing formula based on yearly IRR should be adopted in the proposed-PIB 2020 PSC before the passage of the bill and assent by the President or considered when the Act is due for review, instead of the formula based on cumulative production, as it clearly shows from the Angola PSC 2004, that it gives better profit for both the contractor and Nigerian government. Hence, makes the fiscal system more progressive and attractive to investors.

APPENDICES

APPENDIX A: Tables

Table 4.30: The Nigeria DOA'19 PSC fiscal terms

FISCAL TERM: THE NIGERIA DOA'19 (AMMENDMENT ACT) FISCAL TERMS		
Bonus	0	MM$
Expensed CAPEX	30%	Total CAPEX
Capitalized CAPEX	70%	Total CAPEX
Depreciation life of Capitalized CAPEX	5	years
Salvage value assumed	0	MM$
ROYALTY		
Royalty Rate by Price		
Petroleum Resource	**Threshold price, P**	**Rate (%)**
	$	($ per $1 increase in price)
Oil	0<P<=20	0%
Oil	20<P<=60	2.50%
Oil	60<P<=100	4%
Oil	100<P<=150	8%
Oil	P>150	10%
Royalty Rate by Volume		
Petroleum Resource	**Production Threshold Q**	**Rate (%)**
	Mbbl/d	
Oil	0<Q<=50	10%
Oil	P>50	12.50%
TAXES		
PPT: (50% - 85%) for Oil	**Production Sharing Contract**	50%
	Concessional	85%
CITA 30% at AGFA (Gas)		30%
Profit split Ratio (Govt)	**20%-60% based on Np**	
Up to 350 MMbbls	350	20%
Up to 700 MMbbls	700	35%
Up to 1000 MMbbls	1000	45%
Up to 1500 MMbbls	1500	55%
Up to 2000 MMbbls	2000	60%
Cost Recovery Limit	**100%**	

Table 4.31: The Nigeria PIB-proposed fiscal terms

FISCAL TERM: THE NIGERIA PIB-PROPOSED					
Bonus	0	MM$			
Depreciation life of Capitalized CAPEX	5	years			
Salvage value assumed	1%	of cost (MM$)			
ROYALTY					
Royalty Rate by Price					
Petroleum Resource	**Threshold price, P**	**Rate (%)**			
	$				
Oil	Below $50/bbl	0%			
Oil	at $100/bbl	5%			
Oil	Above $150/bbl	10%			
Royalty Rate by Terrain					
Petroleum Resource	**Production Terrain**	**Rate (%) (Oil)**	**Rate (%) (Gas)**		
Oil/Gas	Onshore	18%	8%		
Oil/Gas	Shallow water (up to 200m)	16%	5%		
Oil/Gas	Deep offshore	10%	5%		
Oil/Gas	Frontier Basin	8%	5%		
Gas	Domestic gas		5%		
TAXES					
NHT	**Terrain**	**New Acreage Rate (%)**	**Converted Acreage Rate (%)**		
Oil/Associated Gas	Onshore	42%	22.50%		
Oil/Associated Gas	Shallow water (up to 200m)	37.50%	20%		
Oil/Associated Gas	Deep offshore	5%	10%		
CITA 30%		30%	30%		
Profit split Ratio (Govt)	**5%-45% based on Np**				
Up to 50 MMbbls	Np<=50	50	5%		
Up to 100 MMbbls	50<Np<=100	100	10%		
Up to 350 MMbbls	100<Np<=350	350	15%		
Up to 750 MMbbls	350<Np<=750	750	25%		
Up to 1500 MMbbls	750<Np<=1500	1500	35%		
Above 1500 MMbbls	Np>1500		45%		
Cost Recovery Limit	**70%**				
ALLOWANCES					
Terrain	**Cummulative max. Production**	**General Production Allowances (GPA)**			
	(MMbbl)	**New Acreage ($/bbl)**	**Converted Acreage ($/bbl)**	**$/bbl**	**%**
Onshore	up to 50MMbbl	lower of $8/bbl and 20% of fiscal oil price	lower of $2.5/bbl and 20% of fiscal oil price	8	20%
	Above 50MMbbl	lower of $4/bbl and 20% of fiscal oil price	lower of $2.5/bbl and 20% of fiscal oil price	4	
Shallow water (up to 200m)	up to 100MMbbl	lower of $8/bbl and 20% of fiscal oil price	lower of $2.5/bbl and 20% of fiscal oil price	2.5	
	Above 100MMbbl	lower of $4/bbl and 20% of fiscal oil price	lower of $2.5/bbl and 20% of fiscal oil price		
Deep offshore	up to 500MMbbl	lower of $8/bbl and 20% of fiscal oil price	lower of $2.5/bbl and 20% of fiscal oil price		
	Above 500MMbbl	lower of $4/bbl and 20% of fiscal oil price	lower of $2.5/bbl and 20% of fiscal oil price		

Table 4.7: The Ghana R/T fiscal terms

FISCAL TERM: GHANA FISCAL TERMS				
Signature Bonus	1	$MM	Negotiable	
Rentals/1st phase of exploration	0.00005	$MM/Km sq.		
Rentals/2nd & 3rd phase of exploration	0.0001	$MM/Km sq.	3000	Km sq.
Development and Production	0.0002	$MM/Km sq.		
Training Fees	1	$MM/Annum		
Depreciation life of Capitalized CAPEX	5	years		
Salvage value assumed	0	MM$		
ROYALTY				
Royalty Rate				
Petroleum Resource	**Terrain**	**Rate (%)**		
Deep offshore	Oil	12.50%		
	Gas	5%		
Onshore/Shelf	Gas	7.50%		
TAXES				
CIT	**Concessional**	35%		
Additional Oil Entitlement (AOE)		**Negotiable**		
IRR		**AOE (Specifications for Jubilee Field)**		
>19%	19%	5%		
>20%	20%	10%		
>25%	25%	15%		
>30%	30%	20%		
>40%	40%	25%		

Table 4.8: The Angola PSC 2004 fiscal terms

	FISCAL TERM: ANGOLA PSC 2004					
	Bonus	2	MM$			
	Bonus @commerciality	0.5	$ MM	Negotiable		
	Production Bonus	0.5	$ MM	At 5MM and 10 MM bbls cum pdtn	5	MMbbl
					10	MMbbl
	Rentals	0.003	$MM /km sq.	3000		
	Training Fees	0.1	$MM /bbl	Exploration phase		
		0.15	$ /bbl	Production begins		
	Depreciation life of Capitalized CAPEX	4	years SL			
	Tangible Uplift	40%				
	Salvage value assumed	0	MM$			
	TAXES					
	CITA	**Production Sharing Contract**	50%			
	Profit Oil split Ratio	**Govt.**	**Contractor**			
	Pre-IRR		0%			
	15%-40% based on IRR					
<	15%	25%	75%			
<	25%	40%	60%			
<	30%	60%	40%			
<	40%	80%	20%			
	Cost Recovery Limit (50%-65%)	**50%**				

Table 4.9: Reserve Assumptions

RESERVE POTENTIAL ASSUMPTIONS			
Discovery potential/ultimate recovery,MMbbl	700		
Build-up time (years)	4	Beginning(yrs)	End (yrs)
initial production rate (bopd)	50000	2	6
initial capacity target (bopd)	150000	6	11
Plateau-period, years	5		
Economic limit (bopd)	1000		

Table 4.10: Cost Outlay Assumptions

COST OUTLAY ASSUMPTIONS		
year Begin	2020	year
Signature Bonus	0	$MM
EXP & APP	250	$MM/year
Exploration years	1	year
Devt. Start year	2020	year
Devt. Drilling	450	$MM
Devt. Year	2	years
Flow station start year	2020	year
1st year	350	$MM
2nd year	350	$MM
Facility start year	2021	year
1st year	500	$MM
2nd year	500	$MM

Table 4.11: Economic Assumptions

ECONOMIC ASSUMPTIONS		
Wellhead Oil price	50	$/bbl
Variable OPEX	15%	Annual gross revenue
Fixed OPEX	5%	CAPEX Annually
Discount Rate	12.50%	
Expensed CAPEX	30%	Total CAPEX
Capitalized CAPEX	70%	Total CAPEX

Table 4.32: Production profile

Some Useful Formulas

$$\boxed{t = \frac{-\ln\frac{Qt}{Qi}}{a}}$$

$$\boxed{Np1 = \frac{-365 * (Qf1 - Qi1)}{a}}$$

$$\boxed{Np3 = UR - NP1 - Np2}$$

$$\boxed{Np2 = 365 * Qf2 * tf2 - tf1}$$

$$\boxed{Production\,rate = Q(to) * \exp(-a(tn - to))}$$

	Profile 1: Production Build-up			Profile 2: Production plateau			Profile 3: Production Decline		
	Qi1	bbl/year	50000	Qi2	bbl/year	150000	Qi2	bbl/year	150000
	Qf1	bbl/year	150000	Qf2	bbl/year	150000	Qf2	bbl/year	1000
	t1	years	4	t2	years	5	t3	years	27.02758632
	a1	/year	-0.274653072	a2	/year	0	a3	/year	0.185389669
	Np1	MMbbl	132.8949271	Np2	MMbbl	273.75	Np3	MMbbl	293.3550729
Field time	**38.02759**								

Table 4.33: Stochastic Results for the 4 PFS

STOCHASTIC RESULT FOR THE 4 PETROLEUM FISCAL SYSTEMS (PFS)									
		INDICATORS							
PFS	**PERCENTILE**	**NPV (MM$)**	**IRR (%)**	**DHGT (%)**	**DCT (%)**	**PI**	**DPOP (Yrs)**	**FLI**	**UTC ($/bbl)**
NIGERIA DOA'19 PSC	**P10**	1436.68	25.1	71.12	20.8	1.56	6.2	0.06	10.77
	P50	2023.67	27.44	73.56	26.4	1.78	6.56	0.079	11.44
	P90	2467.7	29.65	79.2	28.9	1.96	7.09	0.105	12.08
NIGERIA PIB-PROPOSED PSC	**P10**	1447.05	25.29	70.42	22.87	1.56	5.62	0.101	11.78
	P50	1936.53	26.76	72.41	27.59	1.75	5.79	0.109	11.78
	P90	2181.24	27.29	77.13	29.58	1.84	6.24	0.137	11.78
ANGOLA PSC 2004 (CURRENT)	**P10**	1445.93	23.51	65.02	26.4		6.16	0.036	11.65
	P50	2041.35	25.45	67.5	32.51		6.53	0.056	12.48
	P90	2509.46	27.33	73.59	34.98		7.04	0.09	13.38
GHANA R/T	**P10**	2132.92	27.62	58.86	33.93	1.83	6.63	0.16	11.78
	P50	2751.32	28.96	60.89	39.11	2.06	6.76	0.17	11.78
	P90	3041.97	29.41	66.07	41.14	2.17	7.09	0.21	11.78

APPENDIX B: Figures

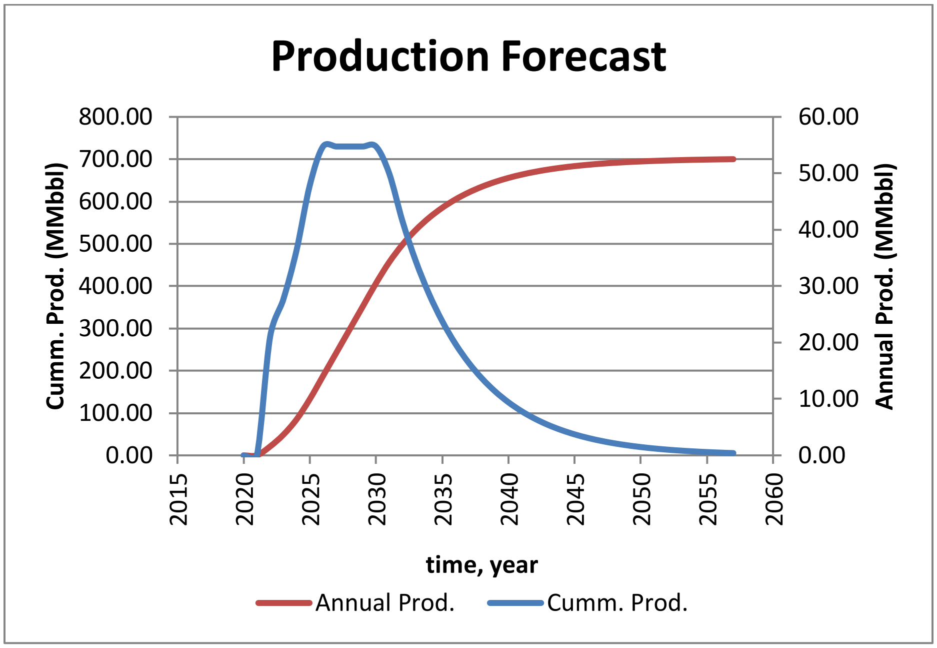


Figure 4.2: Production Forecast

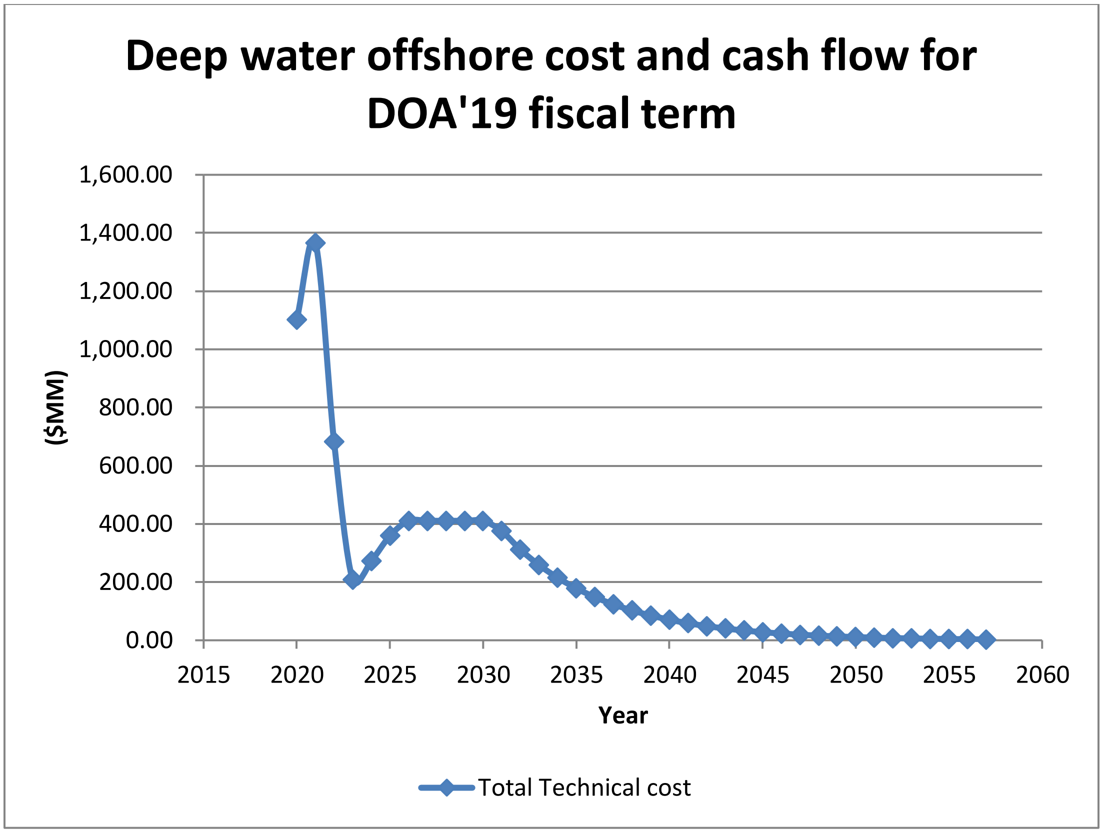


Figure 4.6: Deep water costs and cash flows for Nigerian DOA’19 fiscal term

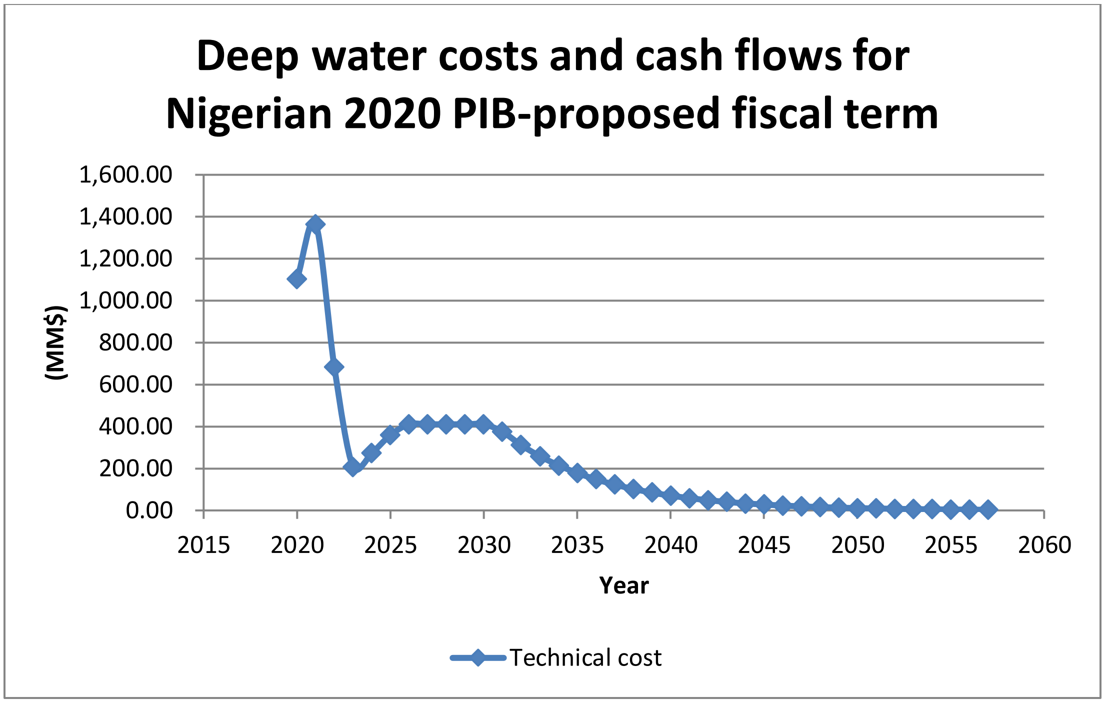


Figure 4.7: Deepwater costs and cash flows for Nigerian PIB-proposed fiscal term

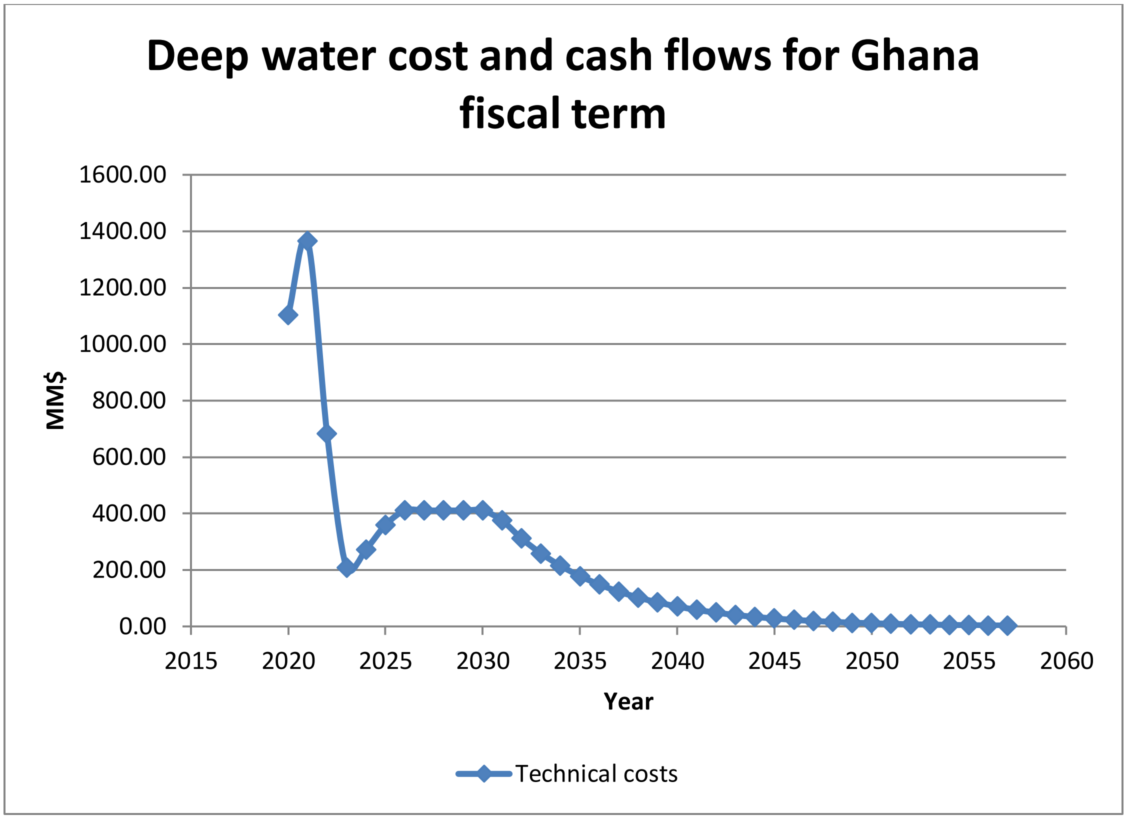


Figure 4.8: Deep water costs and cash flows for Ghana R/T fiscal term

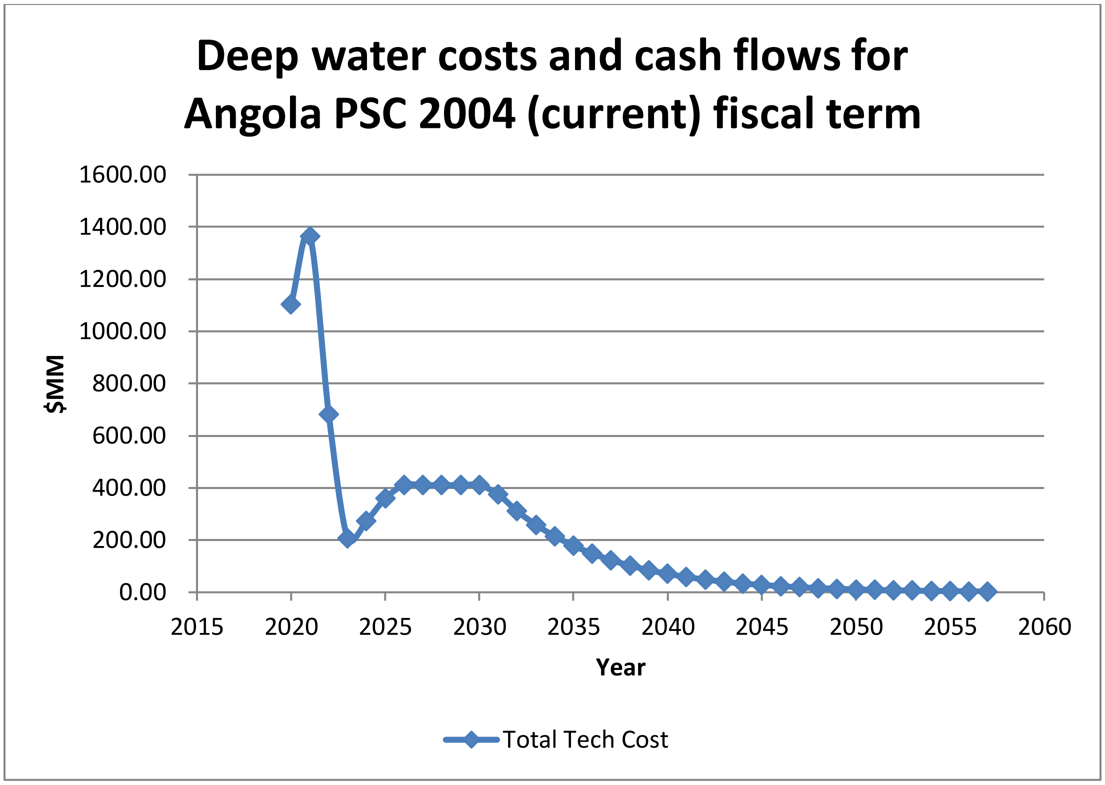


Figure 4.9: Deepwater costs and cash flows for Angola PSC 2004 (current) fiscal term

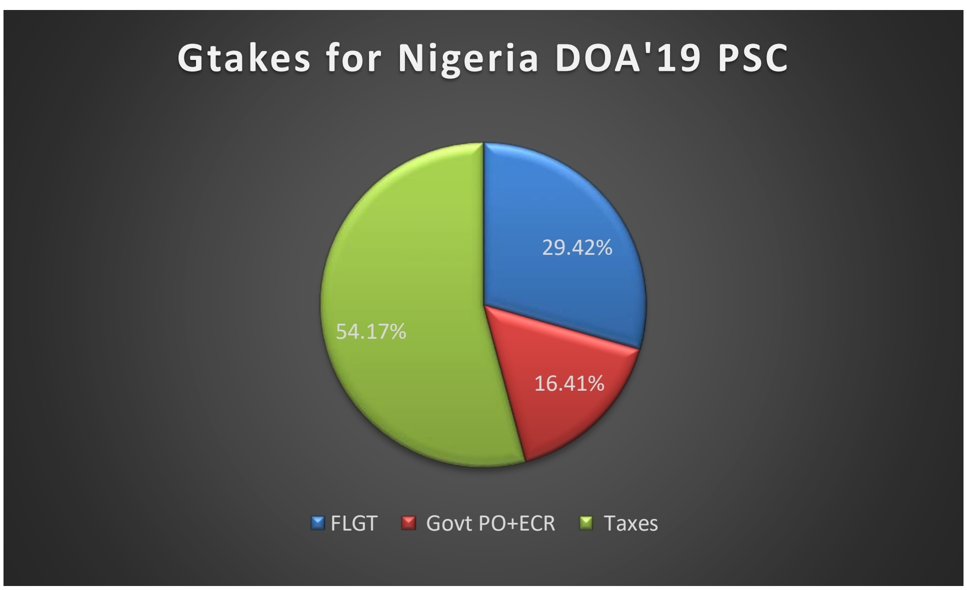


Figure 4.10: Government takes for Nigeria DOA'19 PSC

Figure 4.11: Government takes for Nigeria PIB-proposed PSC

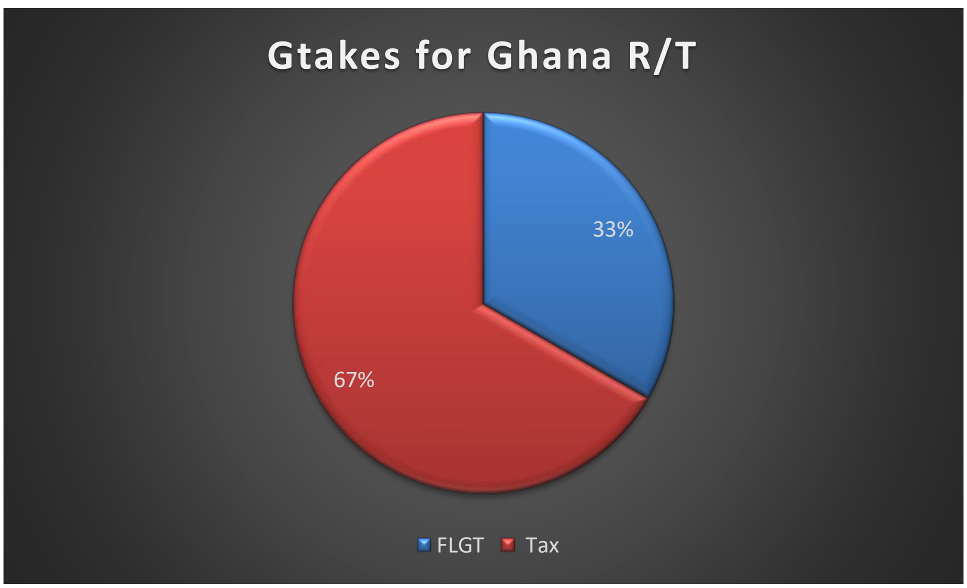


Figure 4.12: Government takes for Ghana R/T PFS

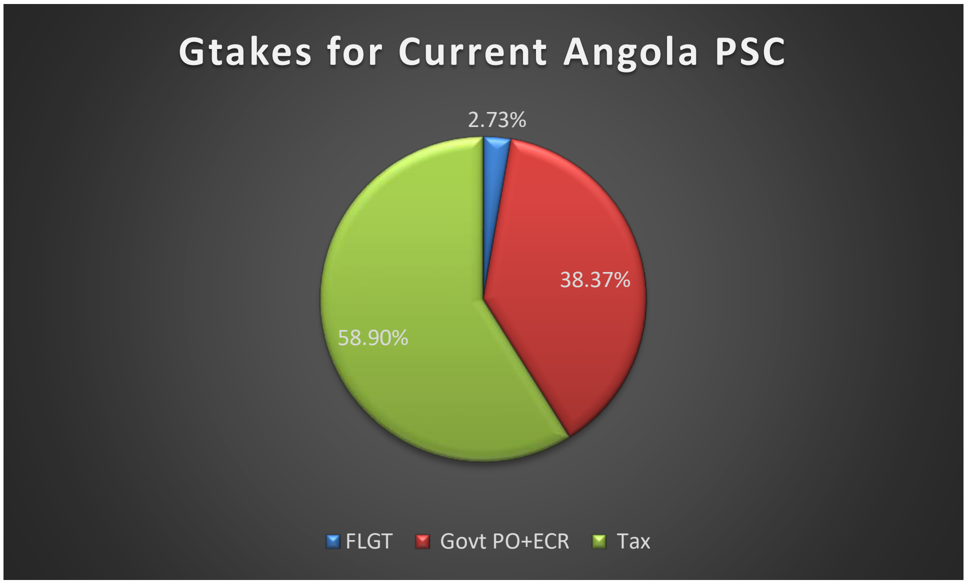


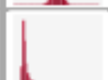
Figure 4.13: Government takes for Angola PSC 2004 (current) PFS

APPENDIX C1: Stochastic Outputs for the Nigerian DOA'19 PSC

Outputs

Report: Summary Statistics Report
Performed By: Gunze
Date: 08 April 2021

Summary Statistics

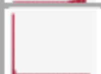
Output	Cell	Graphs	Function	Minimum	Maximum	Mean	Std Dev	5%	95%
NPV / PSC	D4		RiskOutput()	-$2,505.24	$6,169.14	$1,974.99	$456.15	$1,167.28	$2,600.14
IRR / PSC	D5		RiskOutput()	0.654%	49.321%	27.326%	2.188%	24.081%	30.376%
DPOP / PSC	D6		RiskOutput()	4.7989	38.0000	6.7199	1.7132	6.0951	7.4072
PI / PSC	D8		RiskOutput()	0.01661	3.41572	1.76533	0.17583	1.45700	2.00950
Disc. HGT % / PSC	D12		RiskOutput()	68.850%	160.485%	74.631%	4.312%	70.653%	82.152%
Disc. CT% / PSC	D13		RiskOutput()	-60.485%	31.150%	25.369%	4.312%	17.837%	29.346%
UTC / PSC	D20		RiskOutput()	9.3073	13.0254	11.4224	0.5118	10.5580	12.2486
Unit CAPEX / PSC	D23		RiskOutput()	1.6288	4.2265	3.7356	0.2622	3.2139	4.0384
Unit OPEX / PSC	D24		RiskOutput()	6.4244	9.0879	7.6868	0.4336	6.9831	8.4165
FLI / PSC	D25		RiskOutput()	-0.00828	1.31178	0.08215	0.02856	0.05471	0.11869

APPENDIX C2: Stochastic Outputs for the Nigerian PIB-proposed PSC

Outputs

Report: Summary Statistics Report
Performed By: Gunze
Date: 08 April 2021

Summary Statistics

Output	Cell	Graphs	Function	Minimum	Maximum	Mean	Std Dev	5%	95%
NPV / PSC	D3		RiskOutput()	-$1,869.43	$2,366.75	$1,859.79	$330.09	$1,238.81	$2,224.13
IRR / PSC	D4		RiskOutput()	5.8915%	27.6102%	26.4339%	1.1706%	24.4718%	27.3693%
DPOP / PSC	D5		RiskOutput()	5.5115	38.0000	5.9393	1.3417	5.5961	6.4999
PI / PSC	D7		RiskOutput()	0.27948	1.91030	1.72025	0.12516	1.48539	1.85707
Disc. HGT % / PSC	D11		RiskOutput()	69.012%	217.894%	73.360%	3.805%	70.091%	79.598%
Disc. CT% / PSC	D12		RiskOutput()	-117.894%	30.988%	26.640%	3.805%	20.397%	29.908%
UTC / PSC	D19		RiskOutput()	11.7751	11.7751	11.7751	0.0000	11.7751	11.7751
Unit CAPEX / PSC	D22		RiskOutput()	4.0715	4.0715	4.0715	0.0000	4.0715	4.0715
Unit OPEX / PSC	D23		RiskOutput()	7.7036	7.7036	7.7036	0.0000	7.7036	7.7036
FLI / PSC	D24		RiskOutput()	0.09595	2.30677	0.11641	0.03366	0.09947	0.15365

APPENDIX C3: Stochastic Output for Angola PSC 2004

Outputs

Report: Summary Statistics Report
Performed By: Gunze
Date: 08 April 2021

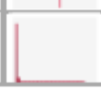
Summary Statistics

Output	Cell	Graphs	Function	Minimum	Maximum	Mean	Std Dev	5%	95%
NPV ($ MM) / Contr...	C17		RiskOutput()	-2,350.25	4,940.78	2,000.45	458.03	1,198.45	2,651.57
IRR (%) / Contr...	C18		RiskOutput()	3.0047%	39.4089%	25.4179%	1.7640%	22.8080%	28.0397%
DiscountedTake Statis...	C19		RiskOutput()	-672.250%	37.165%	31.211%	8.468%	23.186%	35.412%
DiscountedTake Statis...	D19		RiskOutput()	62.835%	772.250%	68.789%	8.468%	64.586%	76.813%
Front Loading Index...	C21		RiskOutput()	-0.00594	10.40506	0.06306	0.10963	0.03164	0.10811
Disc. Payback peri...	C22		RiskOutput()	5.2522	38.0000	6.6691	1.6090	6.0505	7.3308
UNIT CAPEX, $/BBL...	C23		RiskOutput()	3.3793	7.4195	4.7664	0.4961	4.0494	5.6765
UNIT OPEX, $/BBL...	C24		RiskOutput()	6.4890	9.1846	7.7382	0.4323	7.0363	8.4592
Unit Technical Cos...	C25		RiskOutput()	10.4763	15.7784	12.5047	0.6761	11.4387	13.6439

APPENDIX C4: Stochastic Output for the Ghana R/T PFS

Outputs
Report: Summary Statistics Report
Performed By: Gunze
Date: 08 April 2021

Summary Statistics

Output	Cell	Graphs	Function	Minimum	Maximum	Mean	Std Dev	5%	95%
NPV / CONCE SSION	D4		RiskOutput()	-$613.97	$3,236.20	$2,652.52	$402.41	$1,875.59	$3,090.57
IRR / CONCE SSION	D5		RiskOutput()	7.0329%	29.6092%	28.6585%	1.0475%	26.8765%	29.4682%
DPOP / CONCE SSION	D6		RiskOutput()	6.5616	38.0000	6.8529	0.7651	6.6182	7.3106
PI / CONCE SSION	D8		RiskOutput()	0.72815	2.24532	2.02733	0.15148	1.73527	2.19082
Disc. HGT % / CON...	D12		RiskOutput()	57.626%	211.332%	61.950%	4.035%	58.541%	68.724%
Disc. CT% / CONC...	D13		RiskOutput()	-111.332%	42.374%	38.050%	4.035%	31.261%	41.459%
UTC / CONCE SSION	D20		RiskOutput()	11.7751	11.7751	11.7751	0.0000	11.7751	11.7751
Unit CAPEX / CONC...	D23		RiskOutput()	4.0715	4.0715	4.0715	0.0000	4.0715	4.0715
Unit OPEX / CONC...	D24		RiskOutput()	7.7036	7.7036	7.7036	0.0000	7.7036	7.7036
FLI / CONCE SSION	D25		RiskOutput()	0.14453	3.07038	0.18013	0.04508	0.15638	0.23259

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