UPSTREAM PETROLEUM INDUSTRY PERFORMANCE EVALUATION USING DATA ENVELOPMENT ANALYTIC APPROACH

A DISSERTATION SUBMITTED TO THE
DEPARTMENT OF PETROLEUM ENGINEERING

AFRICAN UNIVERSITY OF SCIENCE AND TECHNOLOGY

BY

IDOWU, ADEKUNLE JOSEPH

JUNE, 2019

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Upstream Petroleum Industry Performance Evaluation Using Data Envelopment Analytic Approach

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A DISSERTATION APPROVED BY THE PETROLEUM ENGINEERING DEPARTMENT

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Abstract

Nigeria ranks among the top ten petroleum producers in the world with over eighty petroleum Investors in its upstream sector. This creates an enormous challenge for the upstream institutions' managers especially in the evaluation of technical performance of the sector. One major problem is that there is hardly any quantitative empirical information on technical efficiency of the sector for effective performance evaluation and strategic policy formulation. It is this identified knowledge and information gap that this study aimed to fulfill by estimating the needed relative technical efficiency for each of the 32 selected upstream industry operators in Nigeria.

The study adopts an output-oriented data envelopment analysis framework considering a constant return to scale, variable return to scale and non-increasing return to scale. Consequently, an economic analysis was carried out using a panel data econometrics model to establish the determinants of technical efficiency in the Nigerian upstream sector. The results of the analysis revealed decreasing trends in the upstream sector operators' technical efficiencies from 2010 to 2016. Additionally, the panel data econometrics model revealed that four of the selected independent variables were statistically significant determinants of the upstream technical efficiency in Nigeria within the period of the study.

In conclusion, this study recommends strategic policies towards minimizing bureaucracies and enabling new efficiency-oriented ideas for operators on decreasing return to scale frontier. It also recommends the formation of alliance among the operators on increasing return to scale frontier to boost internal growth and unlock significant values. As regards the six operators on a constant return to scale production frontier, it is specifically recommended that they should embark on serious reserves growth's strategy to increase their reserves base.

Keywords: data envelopment analysis; technical efficiency; upstream operator; performance analysis; parametric analysis; non-parametric analysis; efficiency determinant; constant return to scale; variable return to scale; decreasing return to scale; non-increasing return to scale

Dedication

This work is dedicated to God almighty, the Author & Finisher of my faith for his unmerited grace upon me. My sincere dedication goes to my beloved wife, "**ABEKE OKIN"**, whose supports and prayers are reasons behind my progress. Also to my children, Davina, Daniel and David who became prayer partners in ensuring successful completion of my Ph.D. program, I say thank you.

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Chapter 1

1. Introduction

1.1 Background

The place of oil and gas industry in the world economy cannot be over emphasized. No wonder some authors refer to the sector as the mainstay of the international economies (Iledare, 2008, Gylych and Muhammed, 2016). Technological advancements in the exploration and production of oil and gas in the last decades have been on the increase worldwide. Nigeria, being one of the major oil and gas producers in the world, became the hub of the international petroleum investors in the early 1960. The performance measurement and analysis of the operational activities of business ventures or enterprises such as upstream petroleum industry venture is a necessary requirement for the sustenance of the business especially in a contemporary ever-changing business environment like Nigeria (Georgios and Farantos, 2015, 2016). The measurement and management of petroleum upstream investments entails knowing the relative technical efficiency and productivity changes over a certain period of time (Coelli**,** O'Donnell**,** & Battese**,** 2005, Ike and Lee, 2014).

The petroleum sector has attained the role of an indispensable source of energy from the day the very first oil was struck in North-Western Pennsylvania in the year 1859 by Colonel Edwin Drake (Inkpen and Moffett, 2011). This development resulted in the establishment of the first phase of petroleum industry in the world known as the Standard Oil Trust (SOT). The SOT was created in 1882 with the main goal of Economic of Scale (EOS). This objective was achieved by combining all the refining operations in the consortium under one major management structure. The Texas' spindletop discovery of 1901 marked the beginning of another phase of the

petroleum industries, and the oil which had long been used to light lamps suddenly became an energy source (fuels) for Airplane, Ships, Trains and other Automobiles. All these innovations have made petroleum to attain its present status of an indispensable source of the world's energy and feedstock for petrochemical industries (Inkpen and Moffett, 2011). It may be difficult to sustain the accomplishments of the oil industry if there are no good information-based policies to drive the industry for productivity, growth and efficiency in an emerging economy like Nigeria.

In other words, the importance of a sustainable extraction policy to a country with abundant natural resources cannot be exaggerated. Hunter (2010) argued that an optimally designed regulatory framework and policy is one of the keys to reasonable earnings from the endowed resources. Many countries of the world have developed series of policies to ensure adequate returns from commercial production of natural resources. Basically, the policies in respect of natural resource endowments establish some long-term targets and strategies to be followed to ensure successful exploitation. The governments of countries that are endowed with such natural resources as oil, gas, tin, mica, gold, etc., have responsibilities for formulating appropriate policies. Such policies must, of necessity, set the goals and objectives, and must articulate a clear vision for the sector. It is also the duty of such government to ensure the development and implementation of strategic plans for the institution of a suitable legal, regulatory and commercial framework for the prevention and resolution of any investment barriers in the sector. Periodic policy review is always obligatory to ensure consistency in policy objectives and to keep the investors' confidence under varying economic conditions. Such reviews must be based on sound quantitative evidence from cutting-edge research and associated studies.

A 2016 report indicated that the Petroleum Industry in Nigeria is the largest and most relevant institution in the whole of Sub-Saharan Africa (BP, 2016). The report shows that Nigeria has

proven oil reserves of about 37 Billion barrels and gas reserves of about 188 Trillion scf. Nigeria was enlisted as a member of Organization of Petroleum Exporting Countries (OPEC) in 1971. Since then, Nigeria has been categorized as one of the largest oil producers in the world. Nigeria's proven oil reserves is ranked among the highest eleven in the world and top twelve in terms of oil production, with a daily production of about 2.3 million BOPD as at the end of year 2016 (NNPC, 2017).

Despite the abundant petroleum resources in Nigeria, there has been persistent decline in the contribution of the oil and gas sector to the gross domestic product (GDP) (NBS, 2016). The National Bureau of Statistics (NBS, 2016) report stated that the Nigerian petroleum sector contributed about 14.4% to the nominal GDP in the 3rd quarter of 2016, which was lower, compared to about 17.5% contribution in the 2nd quarter of 2014. The GDP decline is credited to the fact that Nigeria depends so much on the revenue from petroleum sector, as over 95% of export earnings and 70% of government revenues are derived from the petroleum sector. Based on this over dependency, any slight shock in the petroleum sector adversely affects the Nigerian economy.

The decline in the GDP could also be attributed to the production challenges created by the Niger Delta militant groups which led to a sharp drop in the average daily production of crude oil all through 2016. The situation reduced the contribution of the petroleum sector to real GDP by almost 11% in the year. All other OPEC members contribute better to their nation's GDP than Nigeria. Angola which is rated as the 2nd largest oil producing country in Africa contributes almost 45% to its nation's GDP, Kuwait 60%, Libya 60%, Saudi Arabia 48%, Qatar 55%, UAE 40% and Venezuela petroleum sector contributes around 25% to its GDP (World GDP Ranking, 2017). The President of the International Association for Energy Economics (NAEE) in Nigeria, Prof. Omowumi O. Iledare submits in an interview that:

"In Nigeria today, the contribution of petroleum is mostly for federation revenue or income, and generating revenue does not translate into GDP, if there are no productive activities in the economy, which come from petroleum. If the new local content law is fully implemented, the contribution of the petroleum sector to the GDP will increase (Business News, 2014)."

Prof. Iledare was also of the opinion that most people who have access to the petroleum revenue spend a great proportion of the revenue on goods and services from abroad, a situation that the expert opined was not economically favourable to Nigeria's GDP growth.

Constitutionally, Nigeria's Ministry of Petroleum Resources (MPR) is the regulatory body of the Nigerian petroleum industry. MPR oversees all other government agencies that are directly or indirectly involved in the management of the oil and gas operations in Nigeria. The Ministry is headed by the honorable Minister of petroleum resources. He or she has statutory responsibility for policy formulation to ensure the progressive development and effective management of the entire sector. The Department of Petroleum Resources (DPR) is an agency of government that is currently under the MPR. The DPR is charged with regulatory responsibilities and supervisory roles of all the petroleum activities being carried out under licenses and leases in the sector. The Nigerian National Petroleum Corporation (NNPC) which is sometimes regarded as the Nigeria National Oil Company (NOC) is vested with the responsibility for both upstream and downstream development including exploration, production, refining, and marketing (NNPC, 2016). The NNPC also represents the Federal Government of Nigeria in different upstream contract arrangements such as: Joint Operating Agreement (JOA), Production Sharing Agreement (PSA), Service Contract Agreement (SCA), Marginal Field Contracts (MFC) and Sole Risk Contracts (SRC).

There are four major operators in the Nigerian upstream petroleum sector. These are: the International Oil Company (IOCs), Nigerian National Oil Company known as National Petroleum

Development Company (NOC-NPDC), Independent or Sole risk (IndOCs) and Marginal Field Operator (MFOs). Figure 1.1 shows the category of upstream operators, their percentages and contracts arrangements in Nigeria. The IOCs operating in Nigeria are currently about 14 in number. Some of them operate in partnership with other companies in deep offshore areas while some are on the land and swamp. IOCs all together account for a huge percentage of the total Nigerian upstream production (over 93%).

A good number of the IOCs have been in Nigeria before oil was discovered in 1956. These include Shell Petroleum Development Company Ltd (1937) and Mobil Producing Nigeria Unlimited (1955). A number of others came in before the Nigerian civil war. These include Chevron Nigeria Limited (1961), Texaco Overseas (1961), Elf / Total (1962), Philip (1964). Others including Pan Ocean Oil Corporation (1972), Ashland Oil Nigeria Limited (1973) and Agip Energy and Natural Resources (1979) came in after the Nigerian civil war. There are others whose establishment can be said to be recent, which can be attributed to the increasing prices of crude oil in the 90s. Some of these include Statoil/BP Alliance (1992), Esso Exploration & Production, (1992), Texaco OS Nigeria Limited (1992), Shell Nigeria Exploration & Production Company, (1992), Total (Nigeria) Exploration & Production company (1992), Amoco Corporation (1992), Chevron Exploration & Production Company (1992), Conoco, (1992), Abacan (1992) etc.

The National Petroleum Development Company (NPDC) is the subsidiary of NNPC which could also be referred to as the Nigerian National Oil Company (NNOC) in the upstream operations. The company was established in 1988 to engage in petroleum exploration and production activities in Nigeria and beyond. One of the main visions of NPDC is to be Nigeria's leading upstream operator with global presence in other oil producing nations just like Statoil, Saudi Aramco, etc. The five divisions of the company are being managed by five Executive Directors who report to the Managing Director. NPDC is currently involved in about 28 concessions, 5 oil

blocks, 60% joint interest in 4 blocks, 55% equity in about 9 blocks, 7 deep water concession interests. The company owns assets in the swamp, on land and offshore terrain of the Niger Delta region (NNPC, 2016).

The Independent Oil Companies (IndOCs) which are mostly regarded as indigenous is another category of upstream operators in Nigeria. They are mostly local and they have been getting involved in petroleum exploration and production since the discovery of the petroleum resources in commercial quantity. IndOCs are also known as Sole Risk Companies based on the type of contracts they signed with the government. The group competes with the IOCs favorably in most Nigeria upstream petroleum blocks' licensing rounds. They have increased in number over the years, rising up to about sixteen (16) as at the end of 2016 (NNPC, 2015). One general characteristic of the IndOCs is that they are mostly indigenous and they enjoy the backing of the Nigerian Content Act of 2017.

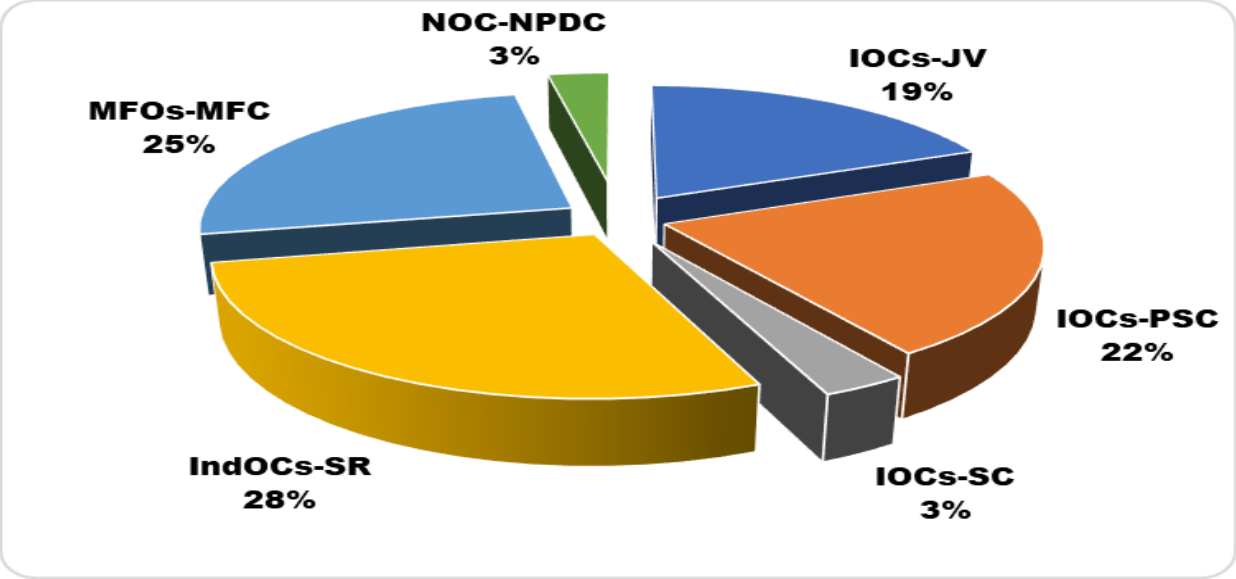

Figure 1.1: Category of Upstream Operators and Contracts Arrangements in Nigeria and Percentages. Source: Author

The Nigerian petroleum blocks lease administration was structured in favour of the IOCs until

1996 when the Nigerian petroleum amendment Act, Decree No 23 was passed into law by the then military leader, Late General Sani Abacha. The Decree makes provision for the re-award of the tagged uneconomical field to another interested upstream company especially an indigenous owned company. Some of the major reasons for promoting the award of Marginal Field (MF) in Nigeria include indigenous company participation, local capacity building, new source of income to the federal government, maximizing oil and gas production through reserves addition and mandatory exploration program, and creation of employment for the teeming unemployed youths. MFs are the fields which are left un-appraised and unproduced for quite a number of years by mostly IOCs.

MF award guidelines were put in place in the year 2001 and by 2003, licenses were given out to about 31 companies based on the recommendation of the MPR. These companies are today referred to as Marginal Field Operators (MFOs) (Osahon, 2013). At the time the first award of the MFs was carried out, only Nine (9) of the fields were producing. However, the number of producing MFs gradually increased to 12 at the end of 2016 (DPR, 2016). The MFs in Nigeria are currently producing at the rate of 60,000BOPD and are processing gas at the rate of about 150MMscf/day. The initial reserves were 141.01MMbbls in 2003 and about 575.75MMbbls by the end of 2015 (Osahon, 2013).

The enormous petroleum resources in Nigeria have not really translated into wealth creation for the citizens and the country at large (Iledare, 2008). Poverty is evident among the rural dwellers in most oil and gas producing communities. As a way of tackling this challenge, the Minister of Petroleum Resources initiated different strategic reform policies in 2016 with the aim of repositioning the oil and gas sector. These policies include the National Petroleum Policy, National Gas Policy, National Fiscal Policy and the Seven Big Win. The justifications for these new policies are anchored on the fact that: previous policies had failed to produce the desired results; crude oil prices were crashing; and there was an emerging vision of value addition

through efficient midstream processing. All these policies may not be effectively impactful if the performance of the industry in terms of technical efficiency of the operators is not properly researched and determined.

In another development, the Group Managing Director (GMD) of the Nigeria National Oil Company (NNPC), Dr. Maikanti K. Baru was reported to have said that his administration was committed to initiating a strategic policy framework which would be aimed at institutionalizing efficiency and productivity in the Nigerian petroleum industry (NNPC in the News, 2017). He was also reported to have assured Nigerians that they should be relying on the improved efficiency and productivity of the industry to come out of the then prevalent economic recession. Repositioning of the Nigerian petroleum industry in terms of technical performance and productivity forms the bedrock for this doctoral research.

Research into the operational efficiency and productivity of the Nigerian petroleum industry is of enormous importance because the sector is very fundamental to the well-being of the Nigerian economy (Stevens, 2008). The government had constituted several committees in the past, and these committees had, in one way or the other, assessed the operational efficiency of the industry at different times. Some of these committees include the Aig-Imoukhuede-led committee of 2011, the Nuhu Ribadu Committee of 2012, the KPMG commissioned assessment of 2014, etc. All these committees have theoretically highlighted the different levels of inefficiency in both operational performance and governance structure of the industry. The committees have all recommended that a thorough study be carried out to critically analyse the industry performance using efficient performance analytical and data-based tools with a view to repositioning Nigeria's oil and gas sector for greater productivity and efficiency.

Apart from the outcome and recommendations of the Government-constituted committees

above, the 2013 World Resource Governance Index (RGI) conducted by the Revenue Watch Institute (RWI) revealed some hints on Nigeria's resource management status. The RGI measured transparency and accountability among the oil, gas and mining sector in terms of achievement in natural resource~~s~~ governance for the good of the people. The findings of RGI are usually based on four components; which include institution/legal setting, reporting practices, safeguards/quality controls, and enabling environment. The survey results clearly showed that there were resource management deficits in some countries such as Nigeria. Countries like Norway, the United Kingdom and the United States (Gulf of Mexico) earned good scores leaving over 90% of the sampled countries with unfavourable scores.

The Federal Government of Nigeria recently articulated a new vision and set new strategic goals for the all-important petroleum sector. One of such goals is channelled towards maximizing the production of hydrocarbon in the country. The plan to ensure that petroleum production volume in Nigeria is maximized now is in the right direction. One of the many reports that have confirmed Nigeria's current economic problems is the presentation made by the former Honourable Minister of Finance, Mrs. Kemi Adeosun, who submitted that Nigeria was in technical recession in August, 2017 and was, consequently, unable to fulfil its constitutional obligations such as payments for goods and services. The situation made the Government to think of such other possible means of generating revenue to ease the economic hardship then as plans to sell petroleum assets, and proposals to borrow money from the World Bank and Africa Development Bank (AfDB) to finance the 2017/18 budget. All these were debated on the floor of the two chambers of the National Assembly for their endorsement. These were some of the strong indicators of economic recession then, and efforts were geared towards getting the country out of recession by focusing on the effectiveness and productivity of the oil and gas sector.

Nigeria operates an oil-based economy. The Nigerian petroleum sector is often regarded as the

live wire of its economy (Stevens, 2008). Nigeria generates its income mainly from proceeds of petroleum exploration and production. The petroleum sector contributes over 90% to government revenues through sales of crude oil and its associated products. No wonder, Nigeria's economy experienced some shocks between 2016 and 2018 when petroleum production was consistently reducing. The years 2017 and 2018 were not good years in the history of Nigeria's petroleum production as shown in figure 1.2. Petroleum production in Nigeria averaged about 1,898.34 BBL/D/1K from 1973 until 2016, reaching an all-time high of 2,475 BBL/D/1K in November ~~of~~ 2005 and a record low of 675 BBL/D/1K in February ~~of~~ 1983. On the average, Nigeria lost about a million barrels of crude oil per day all through year 2016 (NNPC, 2016). This is huge compared to aggregate production per year; i.e., reduction of over 50% of the total production per day recorded in 2005. Figure 1.2 throws more light on the fluctuating nature of the Nigerian crude oil production in 2016 precisely.

The insecurity in the Niger Delta region resulted in various vices which took a new dimension in 2016/2017. The emergence and activities of the militant group otherwise known as "The Avengers" made the region inaccessible to the oil companies and their servicing contractors. Crude oil installations were persistently destroyed using dynamite and various weapons. The operators of oil and gas companies abandoned their operations and relocated to a more secured region like the South-Western region of the country. The major adverse effect of the insecurity situation in the Niger Delta was the decline in crude oil production and the consequential increase in the crude oil Unit Technical Cost-UTC (finding cost). Currently, it is more expensive to do business in the Niger Delta region where petroleum reserves are found than doing business in other parts of Nigeria. The reason for high cost of services could be traced to the security challenges in the region.

The consistent rising cost of carrying out oil enterprise in the Niger Delta has adverse effect on

other sectors of the Nigerian economy. The surveys conducted by Rystad Energy in 2016 revealed various unit costs of producing crude oil in the World. The UTC also known as finding cost, is the ratio of the total cost (Capex and Opex) to the total expected reserves over the economic life of the project. Nigeria's UTC is very high compared to some other oil producing countries in the world. Figure 1.3 shows the 2016 World Oil UTCs in some notable petroleum producing countries. It cost more than $28 USD to produce a barrel of crude oil in Nigeria in 2016. This is huge compared to some countries like: Kuwait, Saudi Arabia, Iran, Indonesia, Russia, Norway, Algeria, Venezuela, Canada, US Shale and US non-Shale. Considering the foregoing, one could conclude that Nigeria is one of the most expensive oil provinces in the world in terms of technical cost.

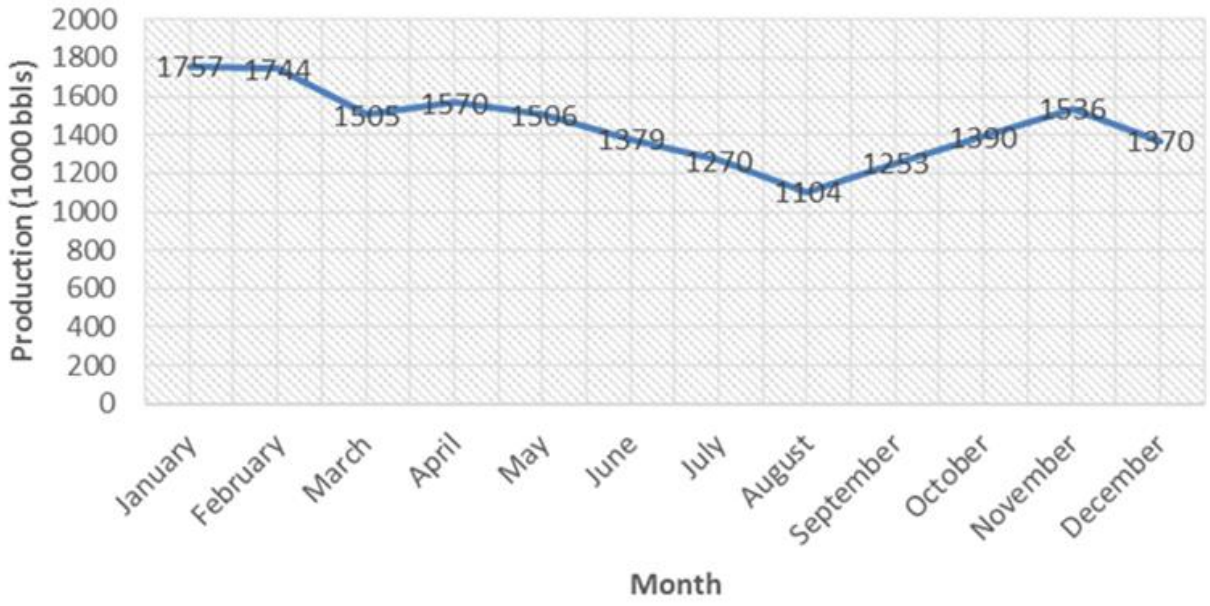

Figure 1.2: Nigeria Crude Oil Production Trends in 2016. Source: Author

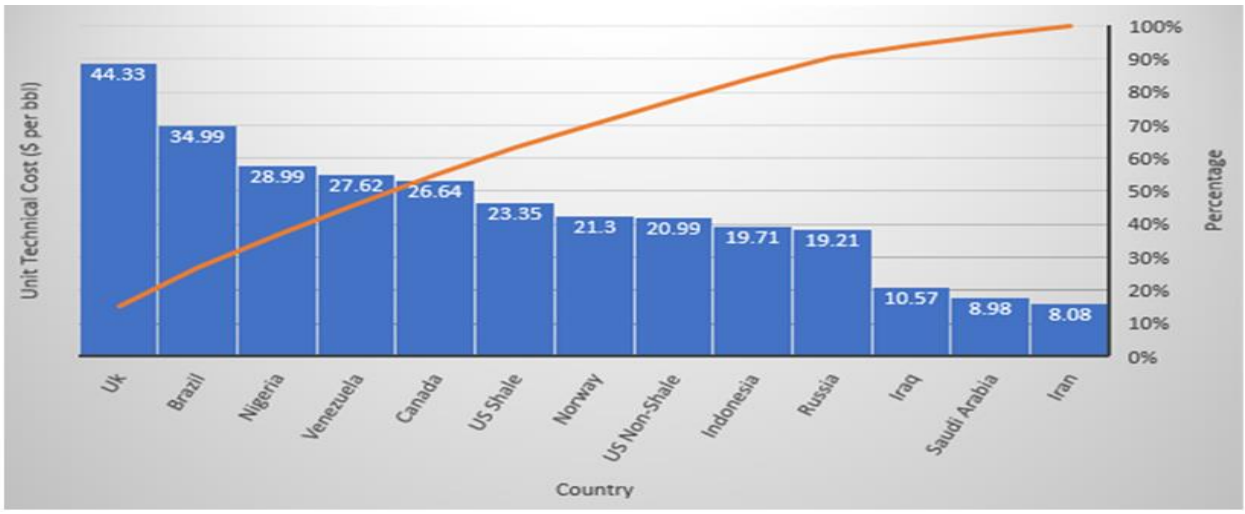

Figure 1.3: 2016 World Oil Technical Unit Costs. Source: Rystad Energy, 2016, CNN

Notwithstanding the above, the crude oil price volatilities in the last four years have been quite unfriendly. The MPR's policy team forecast the price of crude oil to remain at a median of $45/BBL real for the foreseeable future. One of the assumptions on which the forecast was made was that crude oil price may never again reach the highs experienced in between 2008 and 2014. The oil price is exogenously determined, not under the control of any producing country. The most realistic line of action for oil dependent Nations like Nigeria is to plan towards maximizing its crude oil production via adequate performance management that is, more oil, and more revenue. The oil price shocks have adversely affected the Nigerian economy and this is one of the reasons for Nigeria's economic recession between 2017 and 2018.

The technical performance of the Nigerian petroleum upstream relatively determines the amount of oil and gas produced. This is why upstream is sometimes referred to as the single most important sector in Nigeria (Stephen, 2007). The importance of the upstream operators to the success of petroleum industry in Nigeria cannot be under-estimated. The earliest operators such as SPDC designed the business model and set the pace for profitability (Ike & Lee, 2014). As stated earlier, four distinct operators exist in Nigeria's upstream exploration and production

activities; that is, IOCs, NOC, IndOCs, MFOs. Each of these classified groups holds a substantial amount of the proven petroleum reserves and they drilled reasonable number of wells to produce the crude oil. The performance of these operators has a great influence on the wellbeing of the industry since the sector is an indispensable source of government income and social development. With the increasing reduction in the contributions of Nigeria's petroleum industry to the GDP, the productivity and efficiency of operators in the sector is therefore questionable and need to be properly investigated.

1.2 Statement of the Problem

Existing studies and literature on the upstream petroleum industry management in Nigeria show that there is hardly any quantitative empirical information on the technical efficiency of the sector. However, the full potential of the Nigerian petroleum industry cannot be easily achieved if the productivity and technical efficiency of the operators are in doubt. The measurement of productivity change and technical efficiency of Nigeria's upstream operators is necessary for an effective planning. It ensures having good understanding of the current status of the industry in order to check the effect of policies on the sector's performance.

As noted by Echendu and Iledare (2016), Nigeria has huge oil and natural gas reserves but this has not been reflected in the per capital earnings of its citizens. The contribution of the Nigerian petroleum sector to GDP is very low compared to the contributions of similar sectors in other petroleum producing countries. Nigeria, being one of the major oil and gas producers in the world, is expected to have a more sustainable economic advancement than a country like Norway which has lesser oil and gas reserves and daily production (BP, 2016-2017). The availability of enormous quantity of oil and gas reserves in Nigeria is supposed to attract unprecedented development in all sectors of the economy if adequate consideration is given to the performance of the industry.

1.3 Research aim, Objectives and questions

The aim of this study is to measure the relative technical efficiency (RTE) of upstream petroleum industry operating in Nigeria. In order to achieve this, Nigeria's upstream operators were categorized into six groups based on their production contract arrangements: International oil companies (IOC-JVs), International Oil Companies (IOC-PSCs), International Oil Company-Service Contract-(IOC-SC), National Oil Company (NOC-NPDC), Indigenous Oil Companies or Sole Risk Company (IndOCs) and Marginal Field Operators (MFOs). The research sample comprised of 32 companies: 6-IOC-JVs, 7-IOC-PSCs, 1-IOC-SC, 1-NOC-NPDC, 9-IndOCs and 8 MFOs covering the period from 2010 to 2016. The categorization provides a framework to measure the below defined objectives of the study.

The specific objectives of the study are to:

1. develop and apply constant return to scale-data envelopment analysis model to evaluate technical efficiency of firms of different sizes in Nigerian upstream sector;
2. develop and apply variable return to scale-data envelopment analysis model to evaluate technical efficiency of firms of different sizes in Nigerian upstream sector;
3. categorize Nigerian Upstream's operators into respective production frontier using the developed Non-Increasing return to scale-DEA model;
4. establish the determinants of upstream technical efficiency of firms of different sizes in Nigeria using Panel Data Econometric Analysis.

The considered questions from the above research objectives are:

1. How technically efficient are Nigerian upstream operators?
2. What are the sources of technical efficiency challenges in the sector?
3. What are the determinants of technical efficiency challenges in the sector?
4. How does each of the determinants affect technical efficiency of firms of different sizes in the sector?

1.4 The Significance of the Study

This study provides comprehensive empirical information on the technical efficiency of firms of different sizes in upstream petroleum industry sector of Nigeria. This information is beneficial to both investors and policy makers. However, it is very important to identify the sources of productivity and efficiency challenges in the Nigerian upstream industry, which would serve as useful guides for upstream investment decision making and performance improvement strategies. Theoretical approaches for the measurement of efficiency and productivity tend to give unclear picture of the industry performance whereas DEA analysis gives both qualitative and quantitative output (Coelli, 1995). The study differs from all the previous studies in this area because it involves only the Nigerian upstream petroleum operators. It is a country-based analysis and to the best of knowledge no such study is known to have been conducted in this area especially using non-parametric analysis, in this case, Data Envelopment Analysis Models. The six categories of the upstream operators are peculiar to Nigerian terrains because of the nature of the upstream business environment and crave for local contents.

1.5 Research Motivation

Nigeria has more petroleum (oil & gas) reserves for a sustainable economic growth both in the present and the future than what it is experiencing now (Amoss, 2007; Iledare, 2008). The effective allocation of productive resources to grow the economy rather than export is very crucial to reduce the gap between the actual and the potential national outputs. Based on this, an attempt to study the efficiency and productivity of the Nigerian upstream petroleum industry represents a genuine effort towards achieving growth in the industry. Based on this, the government of the Federal Republic of Nigeria is currently committed to initiating a strategic policy framework which is aimed at institutionalizing productivity and efficiency in the industry.

This expression and indication of commitment of the Nigerian government in this regard is the first motivating factor for this research.

However, increasing productivity and efficiency in the petroleum upstream sector of Nigeria particularly among the operators requires a good knowledge of the current level of efficiency or inefficiency in the stream, as well as the factors that are responsible for such levels of efficiency or otherwise. Very few studies have been carried out in this area especially the application of quantitative methodologies such as DEA models. There are not many existing literatures on the application of DEA tool to evaluate the efficiency and productivity of petroleum industry's operators. Many generic studies have been conducted in this area (Al-Obaidan & Scully, 1982; Cee, 2007; Eller, Hartley & Medlock, 2011; Ike & Lee, 2014). The current study considered the listed studies to be generic because most of them have concentrated on using DEA models to compare the efficiency of NOCs with that of IOCs Worldwide. Thus, there seems to be a knowledge gap and dearth of information with respect to understanding the role of indigenous oil and gas producing companies in Nigeria.

To the best of our knowledge at the time of this study, none of the above few studies has been able to use DEA or any other approach to effectively compare upstream technical efficiency of firms of different sizes. The declining crude oil price and the growing gas market have made some of the previous studies to appear obsolete, hence the need for new studies of this important aspect of a national economic activity. Hence, the need for this study of the technical efficiency pattern in Nigeria's upstream sector, especially among the group of operators in the same environment, under the same set of conditions, and facing the same operational challenges. This is not to say that other studies are irrelevant, but gaps are created in their approach and the results which this research intends to fill.

1.6 The Scope of the Study

The scope of this research includes a review of the historical perspectives and evolution of the Nigerian petroleum industry comprising the governance structure, legal and regulatory framework, Institutional framework, commercial and fiscal framework. The study also reviewed the industry value chains in terms of the upstream, mid-stream and downstream. The operations of the 32 active upstream operators were analyzed with respect to the structure of the companies and the peculiar environmental factors affecting the productivity and efficiency. The theoretical backgrounds of non-parametric data envelopment analysis (NPDEA) were reviewed. Three DEA models, namely, constant return to scale model (CRTS), variable return to scale model (VRTS) and the Non-increasing return to scale model (RTS Model) were applied to estimate different technical efficiency indexes.

Using panel data econometrics model, the effect of some exogenous variables such as upstream taxes, experience of the operators, crude oil demand and reserves to production ratios on the estimated technical efficiencies of the operators were estimated (Fare, Grosskopf & Lovell, 1994; Eller et al, 2011; Ike & Lee, 2014,). The input and output data such as reserves of oil and gas were aggregated in MMboe and Production of oil and gas expressed in MMbbls and MMscf, respectively. The number of wells was extracted from the *NNPC Annual Statistical Bulletin*, DPR annual reports and MPR-Planning, Research & Statistics (PRS) department. The study excluded Coal Seam Methane and other mineral resources aside petroleum in the analysis.

1.7 Outline of Dissertation

This dissertation is structured into eight Chapters. Chapter 1 described the background to the upstream technical efficiency study; the chapter presented the research aim, objectives and research questions addressed in the study, and the justification for, and the significance of the study. Chapter 2 reviewed previous studies on performance analysis of some organizations in the oil and non-oil sectors. The chapter traced the history of petroleum industry in Nigeria from the the early 1900s when the German Colonial Petroleum Company (GCPC) and British Colonial Petroleum Company (BCPC) started exploration and production operations in Nigeria to the oil boom era in 1958.

In Chapter 3, the novel DEA model approach used for estimating upstream technical efficiency is discussed. The linear mathematical representations of DEA models and the needed constraints were comprehensively discussed in the chapter. Similarly, a simplified methodological framework showing the processes involved in the application of the models is presented in the chapter. Manual coding of the formulated models in a Microsoft Excel Spreadsheet with the help of a visual basic for applications (VBA) is also explained. In the later part of Chapter 3, an economic analysis (Panel Data Model) methodology adopted to find out the determinants of upstream technical efficiency in Nigeria is described. In doing this, the study considers five major externalities, which are gross taxes paid by operators, world crude oil demand, operator's experience, oil reserves to production ratio and gas reserves to production ratio. The following chapter, that is, Chapter 4, specifically reported the results obtained from the various analyses using the three DEA models employed in this study. The emanating findings are also discussed in the chapter.

Moreover, chapter 5 discussed the panel data analysis results relating to the determinants of technical efficiency in Nigerian upstream sector. Finding-based recommendations of the study in

respect of policies for a sustainable upstream development in Nigeria are presented in Chapter 6. The contributions of the study and its emanating findings to knowledge are discussed in Chapter 7. In the same vein, academic published journals and conference papers from the current study are listed in a section of this chapter. As part of the conclusion, the study presented an outline of some interesting topics for future considerations in chapter 8, while bibliography and various appendices are presented at the end of the chapter.

Chapter 2

2. Literature Review

2.1 Overview of the Petroleum Industry in Nigeria

The history of petroleum in Nigeria can be traced to the period when the German Nigerian Bitumen Corporation (GNBC) and the British Colonial Petroleum Company (BCPC) started petroleum exploration between 1908 and 1914, just before the amalgamation of the Southern and Northern Protectorates of 1914. Some wells were drilled by the companies in the cretaceous Abeokuta formation, 200 kilometres east of Lagos. The wells were all dry, leading to the discontinuation of the project then. The beginning of the World War 1 on 28th July, 1914 made the interests of the companies in exploration to deteriorate between 1920s and late 1930s. Interest in petroleum exploration picked up again between 1937 and 1940 when Shell-D'Arcy Petroleum Development Company started exploration work. This effort was also temporarily discontinued as a result of the 2nd World War which began in 1941. The exploration activities were moved to the northern part of the Niger Delta in 1946 by Shell-BP Development Company of Nigeria. These activities were jointly financed by the Royal Dutch Shell group and British Company. The whole of Northern Nigeria concession was granted to Mobil Exploration Nigeria Incorporated in 1955 and considerable geological studies were conducted where about three wells were sunk (Ile *et al*, 2016).

The very first oil was discovered in 1953 by Shell-D's Akata–1 while Shell-BP also discovered the major commercially viable hydrocarbon in the tertiary Agbada formation at Oloibiri in 1955. There were many other discoveries after that, including the oil discovery in Ugheli (in the current Delta State). The shell BP (Nigeria) first oil cargo was exported in 1958 from the Oloibiri oil field, which was producing about 5,100 Barrel of oil per day at that time. Shell BP stepped up its

aggressive exploration and production operations and this led to the discovery of some new fields (e.g. Ebubu, Bomu and Afan), and the company laid the first oil pipeline in Nigeria. In 1961, the government of the Federal Republic of Nigeria granted 10 oil exploration licenses to five companies which included Amosea, Texaco, Nigerian Gulf Oil, Shell-BP and Mobil Exploration Nigeria Incorporated to carry out petroleum exploration operations in the country's continental shelf. After this licensing “basal” in 1961, the Federal Government started negotiations with the Royal Dutch Shell Group and Shell-BP concerning the establishment of Nigeria's first oil refinery. The refinery was successfully built in Port Harcourt and it started operations in 1965.

Nigeria oil production rate per year got to almost 153.1million shortly before the civil war in 1967, and by 1970, Texaco-Chevron and Agip-Phillips had joined the league of E & P Companies in Nigeria. In the mid-1971, the Federal Government of Nigeria established the Nigerian National Oil Corporation (NNOC) as an agency charged with the responsibility of overseeing all phases of petroleum exploitation in Nigeria up to sales. Based on these challenging responsibilities, and in order to reposition the Nigerian petroleum sector, the NNOC Management advised Government to join the OPEC. Consequently, Nigeria was enlisted as the eleventh member of OPEC in July, 1971**.** On 1st April, 1977, Government approved the amalgamation of NNOC and the Petroleum Inspectorate to form the Nigerian National Petroleum Corporation (NNPC) with a view to creating a more virile petroleum industry and optimizing the human and infrastructural resources available.

In October 1985, on the basis of increasing demand of petroleum products, the NNPC was re-organized into six autonomous sectors in a bid to encourage innovation, efficiency and accountability. Another re-organization and commercialization of NNPC took place in January, 1988 under President Ibrahim Babangida. The re-organization led to the creation of eleven subsidiary companies under the operations division of the Corporation. Exploration and

production businesses were opened up to the Nigerian public in what was referred to as the indigenization program in the late 1988. The indigenization program assisted most independent petroleum companies to start searching for recoverable oil in Nigeria's offshore in 1991. This was a radical step forward because it encouraged and empowered Nigerians in the upstream sector of the petroleum industry. Among other indigenous companies that got prospecting authorizations then were Nigeria Oil Resources Oil Company, Dubril Oil Company and Nigus Petroleum Limited (NNPC, 2016 & DPR, 2016).

2.1.1 Ownership of Petroleum Resources in Nigeria--Right and Obligation

The Nigeria Petroleum Act of 1969 vested, among other things, the ownership of petroleum resources on the Federal Republic of Nigeria. According to the Act, the Federal Government of Nigeria reserves the exclusive power to legislate on mines and minerals, oil fields, oil mining, geological surveys and natural gas in Nigeria. The Act is very significant because it stipulates that the entire ownership and management of all petroleum resources in Nigeria is vested in the Federal Government of Nigeria. The Act also revised all the terms and conditions of pre-1969 concessions, and its provisions and regulations remain the primary law that regulates oil and gas exploratory activities in Nigeria till date. Furthermore, the Act vests the entire ownership and control of oil and gas resources in, under or upon all land or territorial waters in the Government of the Federation. It further authorizes the MPR to issue out licenses to Nigerian citizens or companies incorporated in Nigeria for oil prospecting, drilling, production, storage, refining, and transportation activities.

The Nigerian sovereign and exclusive rights regarding the exploration and exploitation of the natural resources of the seabed, sub soil and superjacent waters are vested in the Federal Republic of Nigeria according to the 1978 Exclusive Economic Zone Act. In addition, Section 44(3) (as amended) of the 1999 Constitution of the Federal Republic of Nigeria further vests the

ownership and control of all minerals, mineral oils and natural gas in, under or upon any land in Nigeria, its territorial waters, and exclusive economic zone in the Government of the Federation subject to the recommendations of the National Assembly. This provision is an adoption of a series of statutory laws and regulations promulgated by the federal military government between 1969 and 1990.

The significant legislations on oil and gas in Nigeria include the Petroleum Act of 1969 as amended, Offshore Oil Revenue Act of 1971, Petroleum Profit Tax Act of 1959 as amended, Land Use Act of 1978 as amended, Oil Pipelines Act of 1978 as amended, Oil in Navigable Waters Act of 1979, Exclusive Economic Zone Act of 1978, Hydrocarbon~~s~~ Oil Refineries Act of 1978, the Petroleum Equalization Fund Act of 1989, Associated Gas Re-Injection Act of 1979, Nigeria Liquefied Natural Gas Act of 1990, Oil Pipeline Regulations (Under the Oil Pipelines Act of 1969), Petroleum (Drilling and Production) Regulations of 1969, and Petroleum Refining Regulations of 1969. The resultant implication of all these Acts is the ultimate vesting of ownership and rights of exploitation of mineral and natural assets in the territorial waters, exclusive economic zone of Nigeria in the Federal Government of Nigeria.

The above Acts have been one of the major causes of disagreements between the host communities; the international oil companies (IOCs) and the Government, and such disagreements have consistently impeded E & P operations in the Country. Lots of dollars have gone to the drain due to pipeline damages and oil theft, among others. In a bid to lessen the effect of these conflicts, Government further created a number of regulatory institutions with appropriate legislative instruments at different times including the Oil Minerals Producing Areas Development Commission (established by OMPADEC Act of 1992) which was repealed and replaced by the Niger Delta Development Commission-NDDC (Act 2000), the Allocation of Revenue (Abolition of Dichotomy in the Application of the Principle of Derivation) Act of 2004, Nigerian Content Board and Development Agency-NCBDA (Act 2010) and others.

Lesson from the Absolute Ownership Theory of Land

> "The Absolute Ownership Theory of Land states that the title-holder of a piece of land is regarded also as the owner of the petroleum lying beneath the land. Land in this sense includes everything down to the crux and up to the sky. In Nigeria, the absolute ownership of the land is the states as stated in the provisions of Section 1 of the Petroleum Act, which provides that the entire property in Petroleum shall vest in the state. Thus, mineral oil in Nigeria is completely owned, but by the federal government of Nigeria. Perhaps Ownership structure could be one of Nigeria major problems, (Aladeitan, 2013)"

Lesson from the Non-Ownership Theory of Land

> "The Non-Ownership Theory of Land states that petroleum has no owner because petroleum is like a fluid that can flow from one region to another which means that it cannot be owned in the strict sense of the word. Perhaps there are very few supports for this school of thought as modern practice shows that petroleum though may move from one region to another region but is still subject to ownership by the person or authority that captures it at any particular point in time (Aladeitan, 2013)".

2.1.2 The Present Regulatory Framework for Nigerian Petroleum Industry

The MPR is the administrative arm of Government that deals with the issue of policy formulation for the petroleum sector and it provides the needed direction to all the agencies under the MPR. The ministry has an exclusive right on any matter relating to pipeline construction for oil and gas transportation. The minister of petroleum resources supervises the oil and gas sector and he represents the sector at the National Executive Council (NEC). All policies for the progressive development and management of the sector are formulated by the ministry under the leadership of the Honorable Minister. The ministry has the following statutory operational departments as

gazetted by Government: Upstream Department (Policy and Monitoring), Downstream Department (Policy and Monitoring), Gas Department (Policy and Monitoring) and Planning, Research and Statistics (PRS) Department (Strategic Planning, Data and R&D).

However, the regulatory power of the Minister, in most cases, is domiciled by the DPR in all the streams of oil and gas operations that include acreage, concession and data management, licensing, monitoring, evaluation, permits, reserves conservation and management, safety, etc. The mission of the DPR is to serve as the watchdog over the development of Nigeria's oil and gas resources by employing modern tools, techniques and technology to direct, influence and achieve the optimum exploitation, conversion/conservation and utilization of petroleum and its derivatives for the maximum benefit of Nigerians while ensuring minimal damage to the environment (www.dpr.org.ng, accessed 24th June, 2018).

The Nigerian National Petroleum Corporation (NNPC) is a statutory corporation through which the Government participates in the oil and gas industry. The corporation was established on 1st April, 1977 to perform the function of the defunct Nigerian National Oil Company. NNPC currently manages all the contracts between the Nigerian state and the investors (Joint Venture-JV, Production Sharing Contract-PSC, Sole Risk, Marginal Field Agreement, etc.). NNPC has the single objective of administering the regulation of the oil and gas industry as it applies to upstream, midstream and downstream operations. Presented in Fig. 2.1 is the regulatory structure of the petroleum industry in Nigeria.

In 2016, Government approved another re-organization of the NNPC into seven operational units which are Upstream Company, Downstream Company, Refining Company, Ventures Company, Gas and Power Company and Corporate Services Units (that is, Finance and Accounts, Corporate Services). NNPC's management team comprises: the Governing Board, Group Managing Director (GMD) and the Chief Operating Officer (COO) of each operational

unit. Each operational unit is headed by a COO while its subsidiary companies are headed by Managing Directors or Group General Managers (MDs / GGMs). NNPC has many subsidiaries, which include two partially owned subsidiaries and 16 affiliated companies. All these companies are under the control of the Nigerian government because NNPC is not incorporated. The current study is basically on the Nigeria upstream petroleum industry performance and this is why the review is limited to only the agencies that are players in upstream petroleum industry operations.

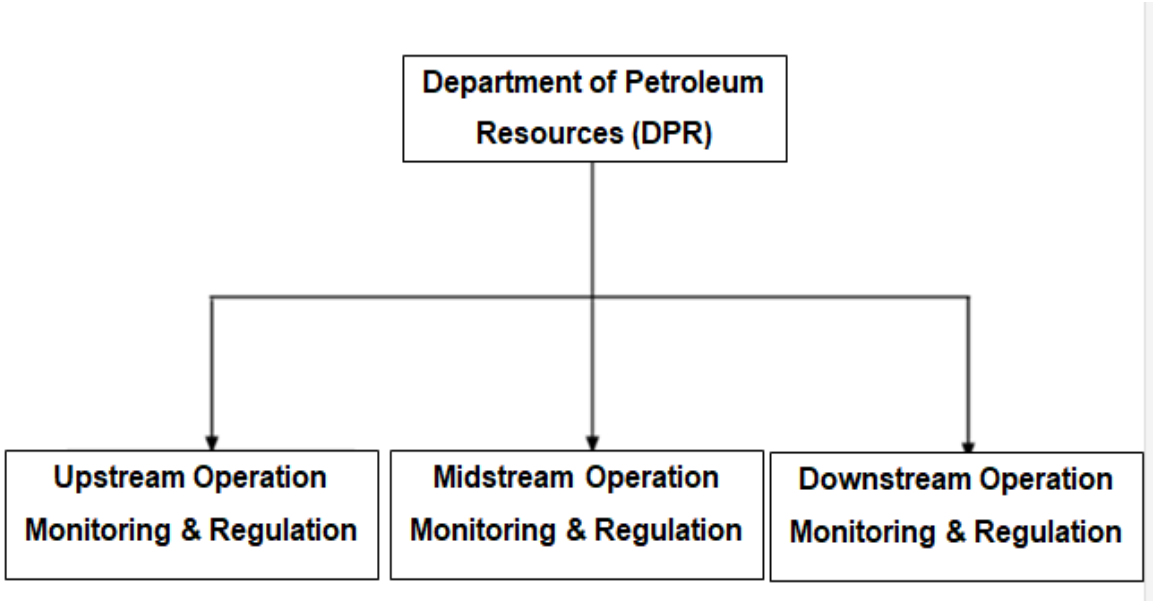

Figure 2.1: Regulatory Structure of the Nigerian Petroleum Industry. Source: DPR, 2017

2.1.3 Petroleum Industry Institutional Reforms in Nigeria

Adefulu (2008) conducted a distinctive analysis of the Nigerian petroleum sector. He opines that the industry had passed through some considerable phases over the years with no significant progress. The roles of Nigeria were limited to only regulatory responsibilities during the 1st phase of commercial production of oil and gas between 1958 and late 1960s. The study emphasizes that Nigeria became more serious in the development and management of its

petroleum resources in the early 70s after its enlistment as a member of OPEC. This development led to the establishment of most of the upstream institutions earlier enumerated.

NNPC took over the responsibilities of the former NNOC, MPR and also started to perform all commercial/policy functions as well as signing upstream contracts on behalf of Government. This internal change of responsibilities was not legally done in the sense that no formal amendment of the previous Acts was carried out to reflect the functional and power transfer between the NNPC and the Ministry. Adefulu (2008) argues that DPR lacks the legal rights to carry out those responsibilities granted to NNPC's Inspectorate department by law. Notwithstanding the structure of the industry as depicted in Figure 2.2, which indicates a clear separation of functions following the Norweigian model, the practice departs from this structure.

Adefulu (*ibid)* further contends that the relationship between the NNPC and DPR does not follow the international standard procedures of operations required of matured oil and gas national oil companies. The two occasionally share accommodation facilities during field operations and also do intra-transfer of staff, a clear violation of part of the rules of engagement of oil and gas industry. The NNPC often trains DPR staff, pay their salaries and also fund some of their mandatory (Monitoring) operations.–The "pally pally" arrangements among the Nigerian oil agencies are clear violations and usurpation of the legitimate functions of the DPR as independent regulator in the industry.

Adefulu (2008) also reports that NNPC enjoys uncommon institutional strength in terms of human and financial resources compared to other institutions in the oil and gas industry. The National Petroleum Investment Management Services (NAPIMS) is a subsidiary of the NNPC that carries out all petroleum investments functions. The roles of NNPC and the number of subsidiaries in the petroleum value chain, as an integrated National Oil Company make the organization to be considered as being special and powerful. It is however opined in the study

that the dominance of the NNPC has done more harms than good to the economy of Nigeria as an oil dependent economy. The study further reports that NNPC has hijacked the petroleum policy function of MPR and effectually making policy for itself, with the tendency that it will only be making policies for its own benefit without considering the overall interest of the country at large. The conclusion of the study is that failure to separate functions weakens the governance strength and perhaps leads to inefficiency, ineffectiveness and ambiguity.

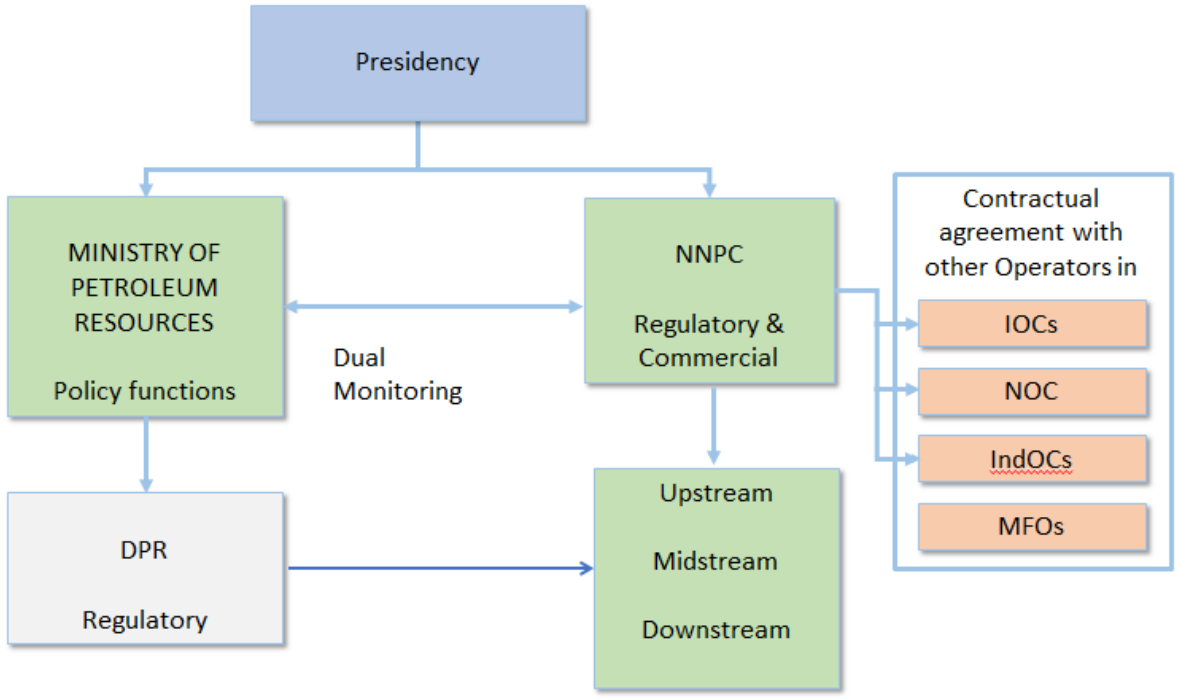

Figure 2.2: Current Structure of Nigeria Oil and Gas Industry. Source: Author

Iledare (2007) appraised the reform of the petroleum industry in Nigeria. The study attempted to answer one fundamental question of how the wealth derived from petroleum exploration and production could be used for the economic welfare of the society. Iledare advises that Nigeria needs a pragmatic oil and gas exploitation policy framework with very good management strategy for revenue flow, local capacity, technology, human capacity, infrastructure and downstream development. Iledare also appraised the April 24, 2000 Petroleum Sector Reform

Implementation Committee (OGIC), which recommended the formulation of the National Oil and Gas Policy (NOGP) to serve as a policy instrument for the separation of the different overlapping institutional functions (that is, commercial, regulatory and policy making functions). Unfortunately, the reform was not implemented till date.

There was also the Dr. Rilwanu Lukman-led Committee constituted by Government in 2007. The committee was mandated to transform the Nigerian oil and gas policy into an efficient, legal and practical institutional structure to enable the successful management of the oil and gas sector. The committee was further mandated to restructure the industry with a view to propelling the economy to a comparable GDP among worldwide economies by year 2020. This committee drafted an elaborate reform Bill and submitted to the presidency but not in public domain. The Oil and Gas Sector Implementation Committee (OGIC) report also recommended the unbundling of the NNPC for more effective operations. However, none of these reforms has been implemented till date.

Very recently, the National Assembly again passed the Petroleum Industry Governance Bill (PIGB) into law in 2018. It is, however, to be noted that the bill is yet to be assented to by the President for three reasons, which, include the controversial funding of the proposed Nigerian Petroleum Regulatory Commission, the controversial scope of the activities of the Petroleum Equalization fund and some drafting inconsistencies (Adefulu, 2018). The Bill provides, among several other provisions, for the unbundling of the NNPC and single regulator. Echendu and Iledare (2015) noted that the decade of unnecessary delays and policy reversal in the Nigerian petroleum industry administration has resulted in dwindling oil revenue, poor economic growth, increasing unemployment rate, low per capital income and numerous economic related challenges. The 2016 oil and gas policies are expected to increase the outputs of the industry in terms of production and accruing revenue.

2.2 The Petroleum Fiscal Systems (PFS)

The Petroleum Fiscal Systems (PFS) describes the legislative, tax implications, contractual and fiscal elements underlying exploration and production operations in a petroleum endowed country (Iledare, 2004; Mian, 2012; Echendu et al, 2015). A well-organized PFS helps to determine equitably how the costs incurred by the partners or the investors could be recovered in the determination of profit sharing between firms and the host governments. Petroleum ownership rights could belong to individuals or government. But in Nigeria, it is entirely the prerogative of the Federal Republic of Nigeria. The Nigerian Petroleum Act of 1969 is the basis for all petroleum upstream operations and the Act vests important discretionary powers in the NNPC. This empowers NNPC to enter into upstream contract agreements with International Oil Companies (IOC), Independent Oil Company and Marginal Field Operators for a given contract area (Johnston, 1994, 2010).

The fiscal regime for petroleum exploitation is an important subject in the oil and gas industry worldwide because it involves return on an operator's investments. As a result of this importance, it has attracted diverse scholarly attention over the years. Some of the existing studies in this fundamental aspect of the management and assessment of the oil and gas industry include Dharmadji and Parlindungan, 2002; Iledare, 2008; Lima *et al*., 2010; Echendu, et al, 2015, etc. The fiscal systems determine the attractiveness of petroleum exploration and production business and this has led to considerable variations in upstream contract agreements from one oil province to another. There are five major types of contract arrangements in the upstream sector of the Nigerian petroleum industry. These are, Joint Venture Contract (JV), Production Sharing Contract (PSC), Service Contract (SC), Sole Risk Contract and Marginal Field Concessionary Contract (MFC). Each of these contracts is discussed in some details in the next section.

2.2.1 Nigerian Upstream Joint Venture Agreement (JOA)

The NNPC signs Joint Operating Agreements (JOA) with the operators in most petroleum upstream exploration and production operations. JOA is otherwise referred to as the basic standard agreement between the NNPC and the operators or investors. The JOA contains the basic procedures and modalities for the smooth running of the operations. JOA is not a Memorandum of Understanding (MoU) between one company and the other. It contains the basic understanding on the joint venture agreement while the MoU addresses the fiscal incentive specifics. In this kind of agreement, the NNPC is the main operator while investors are partners. The cost of production of oil is usually shared among all the partners according to the provisions of the Petroleum Profit Tax (PPT) and Royalty payments. The Field Development Plan (FDP) and Annual Expenditure Budgets (AEB) are usually prepared by the operator and shared according to holding basis. Partners often meet to discuss issues such as technical matters. In this kind of meeting, representation is based on equity contribution. The highlights of the Joint Venture Contract (JVC) include the participation agreement which sets out the level of contribution of each partner in running the affairs of the joint business. It also serves as a determining factor for interests and obligations. The JVA also contains the modalities in respect of the ownership of production facilities, assets etc.

> "Nigerian Petroleum Upstream Joint Venture Agreement is when two or more oil companies enter into a working agreement for joint development/production of jointly held Oil Prospecting Licenses or Oil Mining Leases (OMLs) and facilities/Asset. Each JV partner contributes to the capital costs and shares the profits or losses of the venture based on the equity interest in the investments as stated in the agreement (Energy Mix Report, 2018)".

All the NNPC JVs operate under an operating agreement with a signed memorandum of understanding (MOU) with the Government of the Federation. The JOA defines such relationships as operatorship and obligations, work programme plans and expenditures, authorities of the operating (management) committee and its sub-committees (exploration, technical, finance, services, engineering, production, and public affairs), right of assignment by either party, off take, scheduling and lifting procedures, accounting procedures, project, contract procedures, and communication procedures. Some of the major issues with JOA include Cash Call problems; the inability of the JVC to contribute relevant skills and knowledge to the citizens of the host states; the domineering control of investors over the whole processes (exploration to production); lack of operational contributions by the host state except for the state to receive its share of the profits thus ultimately confining the host government to carry out only supervisory roles. The below statement is quoted from Energy Mix Report of 2018 on joint venture agreements in Nigeria.

> ”The joint venture agreements in Nigeria are made incapable with government under funding the venture, this development creates financial imbalance among the partners which ultimately resulted in reduction in Nigeria oil production per day and consequently drop in net revenue from the oil and gas sector of Nigeria economy. Owing to the fact that Nigeria oil and gas industry is expanding especially into shallow and deep offshore areas, new acreages were allocated to IOCs. This expansion made the federal government of Nigeria to seek for a new contract regime that has the capability of eradicating the challenges posed by underfunding, indigenous technical incapability, decreasing reserves and oil revenue slump. The production sharing contract arrangement was introduced to govern oil exploration and production in the deep offshore and inland basin, (Energy Mix Report, 2018)”.

2.2.2 The Nigerian Upstream Production Sharing Contracts (PSC)

The Government participates in PSC through the NNPC. The NNPC is the owner of the concessions or licenses and it reserves the right to engage a third party in accordance with the laid down rules and regulations in order to carry out exploration and production operations (Echendu *et al*, 2015). The NNPC introduced the PSC in 1993 to deal with some of the issues confronted by the JOA such as Cash Calls. Another reason behind the introduction of the 1993 PSC model is to enable an investment friendly upstream agreement structure. This helps to create the type of structure that is capable of boosting foreign investments in offshore E and P operations. The PSC agreement makes the NNPC to stand as the holder of the leases on behalf of the Government of the Federation while the investors stand as the contractors.

The PSC model shown in Fig. 2.3 started in 1993 when the NNPC signed contracts with about eight foreign investors (IOCs). The model was believed to be beneficial to Nigeria in the sense that the country attracts the needed additional foreign oil producing companies (IOCs) in its upstream operations. The contract regime contained some favourable legal and fiscal instruments such as higher profit share in a marginal and high-risk project. In 2000, licenses for eight new deep-water projects were granted though some of the terms of the PSCs were considered to be unfriendly to the IOCs, e.g., tougher profit oil share because of the reduced risks involved in finding larger deep-water reserves, (Echendu et al, 2015).

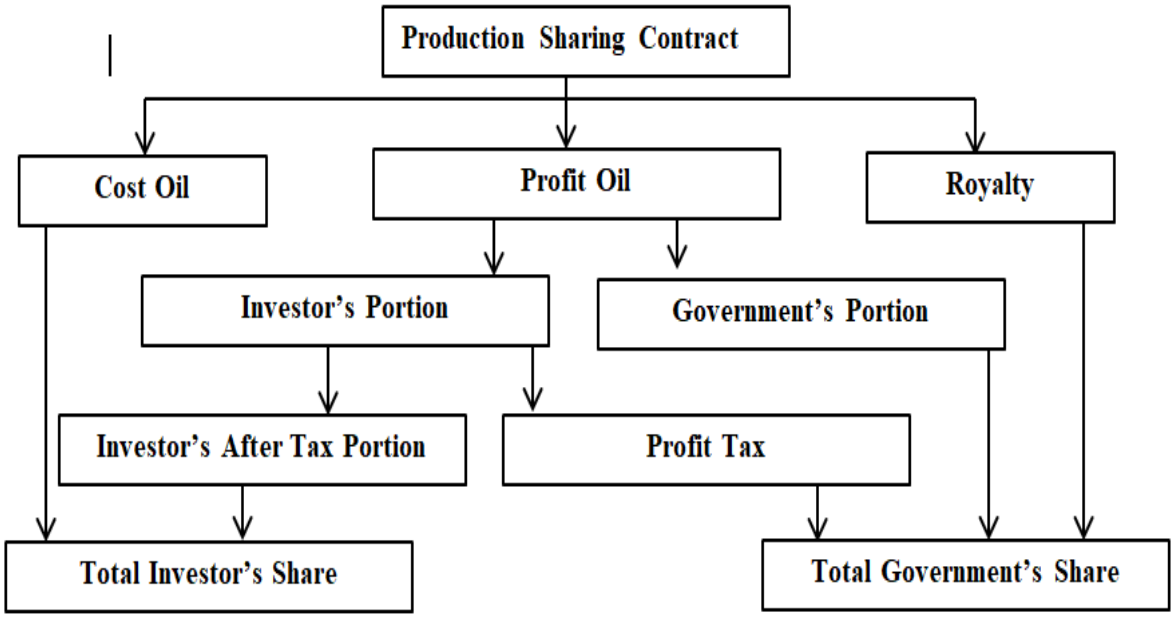

Figure 2.3: A Typical PSC Model

Government granted another set of 14 Deep-water licenses in 2005 through NNPC under a modified condition of contract referred to as the 2005 PSC model. The 2005 PSC model of PSC contains such instruments as signature and production bonuses, which are paid by the foreign investors (IOCs) to the Government at different phases of the project. Signature bonuses are paid after successful negotiations and on the signing of the agreement while production bonuses are paid when the production reaches a particular threshold as stated in the contract terms. Royalty oil can be described as the quantum of oil allocated to the NNPC that will generate earnings equal to the actual royalty payable monthly and payable concession rent each year (Iledare et al, 2008). The NNPC receives royalty oil (payment) on behalf of itself and the IOC subject to Section 7 of Deep Offshore and Inland Basins PSCs Decree 1999. In deep offshore and inland basin projects, royalties are calculated based on the provisions of Section 5 of the Decree, while onshore and shallow water royalties are determined by the 1969 Petroleum Drilling and Production regulation as amended.

Production and water depth are considered as the basis for the calculations of royalties and royalties mainly decrease as water depth increases. The Cost Oil is allocated to the contractor in such a measure as to enable it to recover all its costs as stipulated by Section 8 of the Deep Offshore and Inland Basins PSCs Decree 1999. The provision allows block ring-fencing of the operating expenses incurred. It is note-worthy that most of the earlier regimes did not cap cost recovery while the 2005 PSC model caps the cost recovery at 80%. The 2005 PSC model provides for operating costs to be regained in the year of spending while capital costs are recoverable in equal installments over a five-year term as prescribed in the second schedule of the 2007 Petroleum Profit Tax Act. However, other additional operating or capital costs expended by the contractor are taken into account and are deducted with petroleum profit tax as stated in the Petroleum Profit Tax Act (that is, chargeable profits calculations).

Tax oil is allocated to the NNPC in order to enable it to pay on behalf of itself and the foreign companies. The petroleum income tax is due monthly in agreement with Section 9, Deep Offshore Decree of Petroleum Profits Tax Act (PPT). Taxable income is also explained as the difference between the income and deductible costs of the whole project, calculated in agreement with the rules of the Tax. The PPT on chargeable profits is 50 percent flat rate according to section 3 of the Deep Offshore and Inland Basins PSCs Decree 1999, for the duration of the contract and the tax shall be split between the NNPC and the contractor in the same ratio as the split of profit oil between the parties. Section 4 of the Act provides statutory backing for Investment Tax Credit/Investment Tax Allowance provisions as stated in the old PSC model of 1993. After all these deductions (royalty oil, cost oil, tax oil, etc.), profit oil is shared between the NNPC and the IOC in line with the agreed terms and conditions (that is, production based sliding scale model that was peculiar to 1993 and 2000 PSC models). At lower production, the profit-sharing rates favour the IOCs while higher production favors the

NNPC. The PSCs of 2005 use R-factor sliding scale, which is calculated by dividing the total contractor receipts over total contractor expenditures.

A note-worthy distinction between both profit-sharing models (that is, the 1993 PSC model and 2005 PSC model) is that the 1993 model has no effect on NNPC's profit share when oil price goes up while NNPC's profit share increases with oil price increases in the R factor model (2005 model). However, the Deep Offshore Decree, section 16 makes provisions for an adjustment to PSC terms on revenue sharing in situations where the oil price exceeds $20 per barrel in real terms. This is to ensure that any additional income becomes economically beneficial to the Government. All production sharing contract terms span a period of approximately 30 years (meaning 10 years for exploration and 20 years for production) with a provision for the relinquishment of as much as 50 percent of the initial contract as stated in Section 2 of the Deep Offshore and Inland Basins PSCs Decree 1999, section 10 and section 12(1) of the Petroleum Act of 1969 respectively.

The PSC agreement provides for a management committee which is similar to the operating committee under joint ventures. The committee consists of members of both the NNPC (NAPIMS) and the IOC. The NNPC (NAPIMS) has the responsibility of managing the operations while the IOC is in charge of the operations as stated in the submitted work programme. The PSC agreement mandates the IOC to prepare a work programme and budget, which will be approved by the management committee. The investors provide the required funds for the execution of the work programme as per the agreement. Any failure to meet detailed work obligations as outlined in the work programme will result in untimely termination of the license and withdrawal of all rights and privileges pertaining thereto as stipulated in the provisions of the Petroleum Act as amended in Section 25.

The Nigerian PSC contains provisions that are meant to protect the Nigerian national economic interest by providing for transfer of technology, training of local employees and preference for indigenous suppliers as spelt out in the Nigeria Local Content Act and Petroleum Act. The PSC agreement terms also make provisions for the conditions that will warrant contract termination by the IOC, the law that governs the contract which in this case is Nigerian National Law, economic stabilization of the contract so as to protect the interests of the IOC (Stability clause) and also for binding and enforceable adjudication in Nigeria pursuant to the Arbitration and Conciliation Act should a dispute arise between the parties. Table 2.1 reveals the 1993, 2000 and 2005 PSCs terms and instrument.

Table 2.1: Nigeria PSCs Terms and Instruments

Instruments	1993 PSC and 2000 PSC	2005 PSC
Royalty	Sliding and Jumping with respect to water depth. max=20%, minimum= 0%	Jumping scale basis with respect to water depth. maximum=20% (Onshore) minimum= 8% (>500m depth), inland basins 10%.
Signature and Production Bonus	Negotiable	Signature, surface rentals and prospectivity bonuses are negotiable while production bonus is based on cumulative production level.1MMBoe = 200MBoe or cash, 220MMBoe = 1000MBoe or cash and 500MMboe = 1000MBoe or cash.
Depreciation	5 years Straight Line	5 years Straight Line (Tangible development cost)
Cost Recovery	100% of revenue after deducting royalty. Ring-fencing around the block. Operating, exploration, abandonment fund deposit and	80% cost recovery limit after deducting royalty. Ring-fencing around the block. Operating, exploration, abandonment fund deposit and intangible development costs are
Profit Oil	Based on cumulative production sliding scale. Ring-fencing specification around the block. Condition: >2000Mboe, negotiation	Based on R factor scale after deducting Royalty, Cost and petroleum production tax. R-factor = (PO+CO) / (Cumm Capex + Cumm Opex) R<1.2, Contractor take = 70%, 1.2<R<2.5, Ctake = 70-25%, R>2.5,
Education Tax	2% after Royalty, Operating and Exploration cost and intangible cost deduction from sales revenue. (deduction from assessable profit)	2% after Royalty, Operating and Exploration cost and intangible cost deduction from sales revenue. (deduction from assessable profit)
Investment tax credit	50% of tangible development cost is deducted for taxable income calculation. It is an incentive to investors.	NIL
NDDC Tax	NIL	Niger Delta development commission (NDDC) Tax, 3% incurred costs on annual budget.
Petroleum Profit Tax	NIL	50% levied on deep offshore and inland basin leases. This is applied after education tax, depreciation, and investment tax allowance have been deducted from assessable profit. PPT also depends on terrain:
		Onshore / shallow offshore /1st 5yrs New / 67.5% PPT.
		Onshore / shallow offshore / 1st 5yrs Old / 85% PPT. Onshore / Shallow offshore / 1st 5yrs all / 85% PPT. deep offshore / inland basins / Flat rate / 50% PPT.
Investment Tax Allowance	Nil	50% of tangible development cost is deducted for taxable income for inland basins and water depth greater than 200m. It is an incentive to investors. It reduces taxable revenue that should have accrued to government.
		All terrain incentives:
		Onshore 5%, <100m 10%, 100-200 15%, >200m 50%, inland basins 50%

Source: Echendu and Iledare (2015)

2.2.3 The Nigerian Upstream Service Contract (SC)

Under Service Contract (SC) arrangement, the investor uses their money to carry out exploration operations, development and production activities on behalf of the host government (NNPC or the concession holder) on their own risk. The ownership of the concession remains exclusively with the Government through the NNPC or Holder. The contractor or investor has no title whatsoever to the volume of petroleum produced. The contractor's investments are reimbursed only from the proceeds of the petroleum sold. The contractor is usually paid periodical uplift in accordance with the terms of agreement as stipulated in the contract document. The contractors are given the opportunity to buy back the petroleum produced from the concession, a practice that is regarded as an incentive to encourage the investors.

The contractor is assessed to pay 30 percent tax on its service fees in accordance with the Companies Income Tax Act as amended (CITA) in 2004. The NNPC which is the right holder is assessed to pay tax under the PPTA. Pure Service Contract is the type where the contractor undertakes E & P activities for a particular agreed rate that is payable in cash or using petroleum. This means that the contractor works for the Government (NNPC) and has no equity contribution on the discovered petroleum. Only Agip Energy and Natural Resources (AENR) operates the service contract (SC) in Nigeria while about 10 other companies are actively involved in Sole Risk arrangement which are categorized under IndOCs and 1 NOC-NPDC in this research.

2.2.4 The Marginal Field Concession Contract (MFC)

In order to encourage local participation, the Government allows the big international companies to surrender their marginal fields (MFs) for assignment to indigenous concession holders. To successfully achieve this, the Government promulgated two laws: first, the Petroleum

Amendment Act No. 23 and, second, the Marginal Field Operations (Fiscal Regime) Regulations 2005 on the development of marginal fields. The two laws provide an adequate incentive to marginal field operators. The Act defines a particular field to be marginal if it has some considerable reserves based on DPR's annual report and has remained unproduced for a period of over 10 consecutive years (Osahon, 2013). The main objectives of introducing marginal field regime by the Government are to expand the participation scope of the Nigerian oil and gas companies; increase the Nigerian petroleum reserve base; and create portfolio rationalization opportunities and job creation for indigenes.

The government of Nigeria brought forth the marginal oilfields (MOs) development to increase the proven oil reserves so as to meet the increasing demand for fossil fuels. However, in order to maximize the benefits of MOs to the country, government has tried as much as possible to make the prevailing fiscal terms favourable and sustainable for mutual benefit. Based on this, Nigerian government has proposed the following fiscal instruments for all MOs operations in Nigeria in the submitted Petroleum Fiscal Bill for MOOs operations (PFB/MOOs). Bonuses applicable to MOs which include Signature Bonus (SB) and Production Bonus (PB) have been reduced compared to what is applicable to giant fields. In fact, government has made signature bonus to be negotiable for all MOs while production bonuses are now tied to cumulative production. Apart from this, the royalty payments by all operators of MOs have been made to be slightly different from that of GFs. For all MOs where there are developmental facilities owned by the Farmor, such fields are only entitle to pay applicable royalty fees known as Farmor Royalty (FR).

However, for flexibility purposes, royalties are allowed to be paid in either cash or kind. It ranges from 2.5% to 18.5% depending on average daily production, (Adeogun and Iledare, 2015). Previously, the Nigerian petroleum fiscal term stipulates a PPT of 85% but the current bill has split PPT into two different components: National Hydrocarbon Tax (NHT) of 50% and Company

Income Tax (CIT) of 30% which is called dual tax system, (Echendu et al., 2015). To make the MOs development more efficient, devoid of community disturbances, Government has also proposed a new tax regime in the MOs Bill known as Host Community Tax (HCT). HCT would go a long way to cater for the social and economic development of the host communities. HCT has been proposed to be 10% of the contractor's profit while education tax would be remitted to the government as 2% of the assessable profit as well as NDDC tax which is 3% of technical cost.

2.3 Petroleum Development Stages and the Roles of the National Oil Companies

The global aspirations of NOCs have changed over the years. Such aspirations have been dominated by unrelenting focus on either upstream or downstream operations with a view to generating more revenue from these endowed natural resources. Another aspiration focus has been on how to secure adequate supply of finished petroleum products as fuel to run the economy (Iledare, 2016). In reality, the over-dependence on foreign petroleum Companies (FPC) has not added any value to the national interest over the years (Marcel, 2016). This is because the main motive of IOCs is to make profit for the benefit of their numerous shareholders. All other motives aside this, such as the development of the host country's indigenous human capital and infrastructure capacity, are secondary to the IOCs. NOCs, on the other hand, are more interested in generating revenue for the benefits of its people and to develop human capital and other social amenities (Lahn, Mitchell, Myers and Stevens, 2009; Marcel, 2016). NOCs are established by law in most petroleum producing countries to be able to have legal right to carry out operator responsibilities in all phases of the petroleum value chain. Nonetheless, a clear policy directive must be initiated as regards the operations and other responsibilities of NOCs. The successes that characterize Equinor Petroleum Industry Company (hence called Statoil) and Saudi Aramco Company (hence called Aramco) can be

traced to a clear policy direction as related to the role they are meant to play with regard to profitability.

The study conducted by Chatham House in March 2016 examined the cost of the roles of NOC at the different stages of the operations of the projects financed. It was recommended in the report of the study that the governments of emerging petroleum producing countries and their NOCs should understand what is obtainable in the sector in order to develop clear and appropriate strategies for the future. There are four major stages involved, and these are Pre-discovery of proved petroleum reserves, Post-discovery of proved petroleum reserves, Initial commercial production of small reserve base, and Long-term commercial production of reserves.

The role of NOCs in stage one, which is more or less an exploration phase, is mainly to represent the host government by having some stakes or minority stake in the licenses granted to the investors. The stake of the NOCs at this level will also depend on the type of upstream contract (concessionary or contractual) in operation in the region. The ownership of the resources is transferred to the investors, if it is a concessionary arrangement while the ownership resides with the host government, if it is PSC (Iledare, 2008). In most cases, the Investor who owns majority stake handles a huge percentage of the capital costs due to exploration and development operations. This is usually refunded when the investment starts to yield profits (breakeven period). The NOC reserves the right to negotiate its stake in the business though most country petroleum laws guaranteed a minority stake for the NOCs while others are tasked with ~~a~~ governance responsibilities or role. The governance responsibilities include the promotion of acreage, management of geological data, licensing and regulating the international oil company's activities.

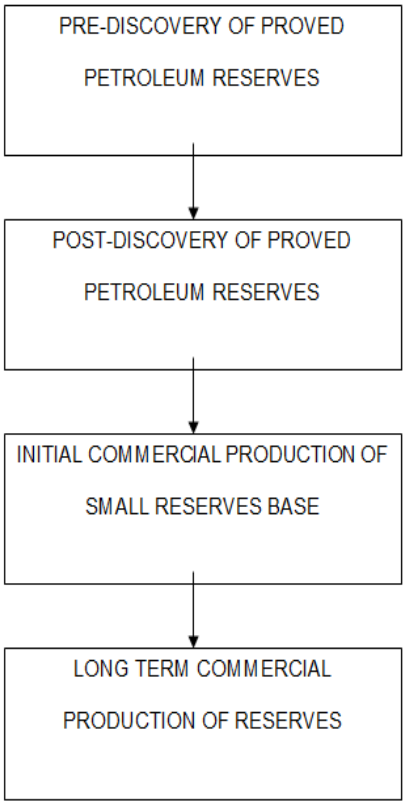

Figure 2.4: Four Stages of Petroleum Development. Source: Author

The human resource management of the NOCs in the pre-discovery stage varies considerably based on the exploration activities and concessionaire responsibilities. It depends on the workforce which is considered to be low at this initial stage of petroleum operations. The Liberia National Oil Company (NOCAL) increased its workforce from 37 in 2009 to 146 in 2014. The justification for this was the burden of unemployment in the country, as, though, this increase in staff was not warranted by the workload in the upstream and it became too costly as payments were delayed from the new contracts signed. In August 2015, the Board of Directors of NOCAL laid off about 80% of the workforce including the CEO and at least 3 Vice Presidents of the Corporation. Many NOCs have a considerable larger workforce because of their involvement in all streams of petroleum operations. Examples of NOCs that have over 10000 workers are Nigeria-NNPC, Mexico-Pemex, Saudi Arabia-Aramco etc., which are all integrated NOCs

(OPEC, 2016, NNPC, 2016). The human resource group needs to focus on capacity building in stage one so as to get prepared for better subsequent stages.

The greatest cost component of most NOCs in stage~~s~~ one is constituted by the day-to-day operating expenses due to exploration activities and capacity development for indigenous staff. This is only important if the petroleum reserves have been proven to be commercially viable, otherwise, it may not be necessary. At this stage, the sources of finance are usually limited because there is no production. The major source of finance is the host government which is mostly faced with the challenges of budget uncertainty especially in Nigeria. Governments are likely to be reserved due to oil prospect uncertainty and the huge amount involved. Some African countries' NOCs have devised some means of using the revenue generated from downstream operations to fuel the upstream development especially the operations in stage one. This could be recouped during bid rounds from such activities as data sales, signature bonus, etc. This is not usually the case in other countries where downstream activities have been rendered unprofitable because of subsidy policies of Government with Uruguay and Nigeria as examples. The current global decline rate of exploration due to crude oil price has not been a good time for the NOCs because of its impact on their Net Cash Inflow. NOCs are likely to face competition from its ministries and regulatory agencies for the available upstream payments.

The second stage begins when the proven reserves have been estimated and confirmed recoverable using appropriate technologies. At this point, new opportunities will start to roll in and the NOCs responsibility may be tactically changing from governance to commercial. This is the era when competition will set in between the state-owned company and the international investors. In order to avoid conflict of interest, NOCs may decide to set aside the governance roles and concentrate on the business. The host government may establish another regulatory agency which will be in charge of the governance responsibility of the NOC. The fact that NOC

and government have a joint stake in the licenses makes them to be aspiring for the success of the operators while controlling the cost and standard of the operations. One major issue that comes to play during this transition process is that some NOCs may want to retain the responsibility for managing geological data because of the revenue from data sales. It is also believed that data management helps the regulatory agency to build capacity within its workforce. NOCs reorganize for a more ambitious commercial agenda during this stage. They sometimes ask for an increased share capital or apply for their own licenses. One good example is the 2009 Ghana National Petroleum Corporation (GNPC) case where the NOC's interest was increased from 3.75 to 13.75 per cent in the Jubilee field using a World Bank loan.

The human resource management requirement during stage two is quite different from that of stage one because of the change of focus to commercial and upstream activities which requires professional skills. The only way to prepare for this new development is to recruit more staff on the realization that the capacity in stage one is not enough to propel stage two and beyond. Using Kenya's sectoral experience as an example, the oil discovery in Kenya necessitated changes in the roles of its NOC. Most of Kenya's workforce concentrates in downstream sector. During this period, the company had to recruit about 34 personnel who were sent abroad for postgraduate studies in petroleum related courses. NOCs finance at stage 2 depends on government allocation along with the revenue they generated through sales of data, import mandates and levies. NOCs may pay back in participation commitments once the reserves are confirmed to be commercially viable. There are many finance options available in petroleum literature (such as bank loans, joint ventures, reserve-based borrowing, etc.) which any interested NOCs could leverage. External financing helps NOCs to generate more revenues as well as to execute more projects. The current difficulty being experienced by NOCs may not be unconnected to the prevalent decline in oil price globally.

The third stage is characterized by early production or small reserve base. As soon as production begins from a particular field, NOCs tend to start re-strategizing their corporate responsibilities. This is the period when they become over ambitious operationally, thereby increasing the number of employees in the system, all with a view to increasing their outputs. Some of the NOCs still try to maintain their original roles as a governance institution but others are fully integrated to carry out all the commercial operations in the value chain. This is the time when some NOCs begin to get prepared for the task ahead with the hope of taking over as soon as the production reaches a particular threshold. The workforce at this level depends on the roles of the NOCs and the magnitude of the operations on hand.

Some NOCs still manage to be involved in all the aspects of the chain as well as governance and regulatory functions, e.g., NNPC, Staatsolie Maatschappij Suriname N.V (STAATSOLIE). The small-scale company involves in exploration in shallow waters, produces about 16,000 BOPD, refines more than 14,500 BOPD, sells the refined products and transports both crude and refined products to its final destination. STAATSOLIE state oil company takes care of the governance role and also handles the geological assessment of the hydrocarbon potential, acreage promotion and general monitoring of international oil companies' operations. All these are possible at the same time because the STAATSOLIE has a well-organized structure in place for every section of its operation and efficient human resource management.

The NOCs' finance at this stage when the production is small is not all that buoyant especially from 2014 when the price of crude oil price started declining. Most NOCs operating at this level are exposed to more risk and uncertainties than the bigger producers because of their concentrated portfolio. Any decline in price of the outputs has significant effects on their income, and cash flow, as well as the viability of projects in some cases. Decline in the prices of outputs also reduces the cash liquidity capacity and ability of NOCs to raise fund from the capital market without bigger collateral securities. One good example of NOC which falls into this category is

Ghana National Oil Company (GNOC). Petroleum operations in Ghana are badly affected by the crude oil price decline. Efforts have been made to cut both capital and operational expenditure even beyond the minimum work obligations. Almost all non-petroleum projects have also been stopped in Ghana.

The stage three producers may find it difficult to have access to loan if the current low price of oil persists unless new skills are developed to reduce oil UTC. This is also the stage where large-scale and long-term petroleum production is possible. At this level, the opportunities are endless and there is significant access to capital because of the daily crude oil production. The challenges of human resource development are reduced compared to the previous stages in the sense that there is enough net cash flow to train and re-train the indigenous staff. One big difference is the fact that an operator can easily forecast his yearly production and estimate the ultimate petroleum recovery which could be used as part of the loan documents. In fact, bank managers lobby to be part of the business at this stage because of their understanding about the benefits of long-term crude oil production. Human resource managers are faced with the challenges of getting appropriate skills for the available technical jobs. An operator who is producing over a hundred thousand BOPD requires nothing less than 110 technical staff and about twenty administrative staff. It took most of the great NOCs (for example, NNPC, STATOIL, Saudi Aramco, SONANGOL, etc.) a minimum of ten years to acquire the needed skills in place today.

As stated earlier, NOCs have almost unlimited access to finance at this stage compared to the previous stages which depend on budgetary allocation for survival. The net cash flow of the companies is dependable because of the continuous production and they have universally comfortable financial status. Generally, NOCs at the level of the three previous stages struggle financially, while those on the current stage retain earnings from upstream production sales thus making it easy for them to secure the finance required for capital expenditure. The major

challenges of this stage are the unilateral abuse of public fund by the Government appointed NOCs' Chief Executive Officers (CEO/MD) and the overbearing state control which inhibits efficiency. Oil price decline affects the NOCs at this stage too; Government feels the continuous reduction in the gross revenue which has a major implication on other pressing budget priorities.

2.4 Good Governance in the Management of Petroleum Exploration and Production Activities

The emerging petroleum producing countries are mostly advised to follow international best practices in all their dealings. The advice may be very good for some producers while it may be inappropriate for the new generation petroleum host countries, because of the initial uncertainties surrounding the ventures. Most new petroleum producers are not all that knowledgeable about the sector, coupled with their weak institutional framework and policies. The new producers are mostly advised to pursue policies that add values to their national interest for rapid growth and development as well as incremental improvements to their governance processes. As the capacity of the emerging producers grows, there is the tendency to have a substantial inflow to match the positive changes which will require the upgrading of the methodology, governance frameworks and the institutions for greater productivity (Marcel *et al*, 2009). Marcel *et al* (ibid) presented six major objectives with policy-oriented recommendations for petroleum sector in the emerging producing countries.

One of the logical ways to attract international petroleum investors is for countries with the endowed oil and gas resources to be able to provide all the required geological data/estimates regarding the proven reserves of the petroleum deposits. Countries without the knowledge of their proven petroleum reserves will have the challenge of attracting competent investors to carry out exploration and development activities. The initial geological estimate requires a considerable amount of money which the country can recover during oil block licensing rounds.

It is good for a host country to have prior understanding of its petroleum resources in terms of the types, contents, volume, etc. before the licensing activity to reduce the risk and uncertainties for the interested investors. The Government of the resource endowed nation could explore the option of loans from a reputable financial institution to get funding for this important initial task. Petroleum producing nations usually establish an agency of Government whose main responsibility is to gather richer geological data using such sophisticated geological tools as 2-Dimensional, 3-Dimensional, and 4-Dimensional software and packages.

Marcel (2015) advises that the host government should articulate some effective prequalification criteria to discourage unserious investors who lack capacity to perform in accordance with the stipulated work program. Transparency from the beginning of the bidding processes and open disclosure of the criteria to the public through several media will discourage unscrupulous and corrupt bidders. Governments need to note the fact that licensees can possibly comprise consortia of investors, and companies are likely to farm in their interest in a particular license as the process (exploration-development-production) progresses. All these must be stated clearly in the petroleum law of the host country, thus implying Government's endorsement for any title transfer, farm in and farm out. The tax code regime should provide for the treatment of any capital gains resulting from such transfers, and it should be aligned with individual license agreements.

Emerging producers may issue licenses using auctions, where Government may have no alternative but to conduct direct negotiations with individual companies. The transparency of the processes also plays a vital role in the achievement of good results during direct negotiations with the investors. The emerging petroleum countries lack regulatory capacity and, in most cases, rely on the operators to regulate themselves. On this premise, governments need to adopt objective and performance based regulatory regime pending the time its staff will be

competent technically. Regardless of these, governments should ensure their own technical capacity to be able to understand the operational risks relating to petroleum business.

The fiscal regime of the emerging petroleum producer must be arranged in such a way that it will guarantee early revenue generation to meet urgent development needs of the host country. At the same time, it must work towards long-term economic benefits from these endowed resources. New producers must try as much as possible to design a fiscal regime that is progressive, flexible and optimal to drive in investors. Efficient local content regime has the capability to maximize long-term economic benefits while poorly designed ones encourage rent-seeking behavior. Inexperience or emerging petroleum producers should avoid using incompetent contract negotiators with the international petroleum investors. It is advisable to engage experienced consultants or technical partners for an efficient contract negotiation. The Government of the producing country should ensure that most contract elements are covered by its petroleum law and regulations which are applicable across the licenses to make the contract negotiation uncomplicated.

The emerging petroleum producers must also ensure that they put a flexible tax structure in place alongside a clearly articulated upstream activities fiscal terms. It is better to define tax obligations using tax code rather than in contractual agreement terms. The producers should ensure that emergency situations such as reserve addition or rise in crude oil prices are tactically captured during the design of the fiscal terms using sliding scale methodology which accounts for any change in production or commodity price. In a situation where such emergencies are not captured, producers may seek an amendment of the former contract agreement, but it must be mutually agreed between the parties. Nevertheless, governments should have respect for the existing contracts and patiently wait for their expiration before any change could be affected. In order to avoid this kind of situation or outcomes, governments should ensure that petroleum contracts are made flexible *ab* initio. This will help the countries to

maintain investor's interest in the long term. Petroleum owners may consider the introduction of such clauses as renegotiation, economic balancing and adaptation from the outset of the contract and these could be relied on for renegotiation when specific triggers are activated (Marcel, 2016).

Governments of petroleum producing countries have the responsibility of ensuring that public trust and expectations are not betrayed. To achieve this, the host government may need to mediate between different interest groups, usually communities, and ensure that their views or opinions are considered before the final draft of any oil contractual agreement. There is the need for government to have meaningful engagement with the host communities to avoid conflict and misunderstanding that may arise from mistrust. In doing this, the respective government will need a plan of engagement which should clarify all stakeholders' involvement with respect to decision making. The contracting company may need to have community liaising officer who will engage the community and communicate with them from time to time. Marcel et al (2016) emphasizes that trust is important in community engagement but noted that trust does not co-exist with corruption. Marginalized communities may not have faith and confidence in what is being relayed to them about a particular project because of the mistrust. Efforts should therefore be made to build trust among the individuals and all parties involved by meeting with them regularly to avoid any unnecessary misperceptions about interests and intentions.

Information about projects should be disseminated freely to the communities; all negative implications of the projects must be discussed frankly, and measures must be put in place to guide against them. The government of a producing country should report successes and failures of all exploration operations, i.e., seismic surveys, drilling plans, drilling results, etc. Emerging petroleum producers should ensure that sufficient public awareness programmes are put in place in order to moderate public expectations about the sector, and to ensure a realistic expectation of the benefits that will emerge from the sector. After new discoveries are

announced, both government and the investors should be rational in their statements about the speed at which the resources would be monetized. The expectations of the public, especially with regard to employment opportunities and profit windfalls, should be managed as much as possible. It is recommended that emerging producers should establish their own NOC or the petroleum ministry website as a means of communication to the public in order to educate them about the scale and nature of discoveries.

It is of utmost importance for any developing economies that are endowed with petroleum deposits to formulate petroleum-sector policies that have the ability to maximize national development for the benefit of the people (Iledare, 2008). Based on this, the producing country's government must have clear objectives as regards the branches of government that are saddled with the responsibility of upholding various aspects of national developmental goals. Laws that put in place national content aspirations should be enacted by the government to take care of various challenges faced by the indigenous contractors and job seekers. Such laws should contain clauses such as a shift from foreign to domestic sourcing, local content charges, etc. An intensive capacity development strategy should be carried out by the governments of the producing countries to ensure that domestic producers and contractors can supply most of the technical skills and expertise that the petroleum industries require. It is quite difficult to abide by the local content regulations of the producing countries in a situation where the indigenous capacity is very low, and where the investors may not have any other option than to source for experts outside.

Most petroleum companies prefer to engage capable indigenous contractors or employees to outside sourcing which is regarded as more expensive. However, absence of this category of people may leave the investors with the option of going out to get capable hands. Emerging petroleum producers should try as much as possible to make provision for indigenous capacity development in the contract agreement during negotiation. Both the supervising ministry and the

NOC of the producing countries have responsibility for investment in local capacity development for goods and services, preferably in those areas that have dual applications. The onset of petroleum investment is full of risks and geological uncertainties which can make most investors not to borrow the idea of indigenous engagement. This can, however, be resolved on a round table discussion (give & take strategy). The host governments should work in partnership with the investors to develop training and hiring programmes to ensure that they are well integrated into the life cycle of petroleum projects.

New petroleum producing country is usually confronted with the problem of assigning roles and responsibilities for the sector which requires a considerable capacity. Petroleum industry management institutions need adequate capacity to be able to function as expected. It is not advisable to seek management advice from foreign investors in order to establish government institutions who will oversee the development of resources. The foremost petroleum discovery nations were in most cases advised wrongly by the foreign partner, and this usually resulted in advice fatigue and confusion. Marcel (2016) advises governments of countries endowed with petroleum resources to always base their strategy on demand-led advice and avoid supply-led advice. The drivers should always be the demand for its national development rather than personal curiosity. All advice must be based on the central government's need to avoid duplication of efforts and contradiction. Emerging petroleum producers are advised to seek technical or professional advice from an established producer or consultant who has track record in the sector.

The governments of some of the emerging petroleum producing countries have limited funds to budget for the indigenous capacity enhancement. In this case, it is very important to establish government-owned institutions that will perform oversight functions and carry out regulatory responsibilities. This could be in the form of the ministry or NOC which will be responsible to develop capacity in the sector and other important petroleum management tasks. The

government institution may concentrate on building capacity in the areas of tax design and collection, geological data management, auditing and operations monitoring, and general petroleum administrative capabilities. There may be situations where the endowed proven reserves are of significant value which the NOC may take part in the operational responsibilities. In such situations, the NOC may transfer its regulatory responsibilities to the government to avoid a conflict of interest. Alternatively, a new agency could be created to carry out the regulatory functions. The government may need to define the roles, scope and limits of the state-owned oil company. The NOC needs capable workforce to function properly. Consequently, the government needs to design an explicit financial model for its NOC that will allow the company to develop its capacity for better performance.

Establishing a strong and an independent regulatory agency requires the engagement of an external technical partner as well as strong political commitment. In order to get skilled staff and experienced professionals, the monthly pay and associated benefits should be made attractive compared to what is obtainable in the competing IOCs. Emerging producer's governments need to understand the cost of NOC's roles as related to specific national interest and revenue resource available. They should not be in a hurry to establish their NOC and this could be done after they must have confirmed that the proven reserve has a life span that is not less than 15 years. Having a significant proven reserve base guarantees the development of operational capabilities and management capacity in order to improve the governance of the institution. The initial revenue stream of NOC as approved by the government should cover only the necessary operating cost until positive net cash flow from production is generated. NOCs should not be overzealous; they should pursue growth strategy based on government directive and aspirations, and in consonance with the available resources.

There are many factors that can trigger the need to ensure that petroleum businesses are conducted in a transparent and an accountable manner especially when production has started.

Operational transparency and accountability must be enshrined from the onset; any delay may be too dangerous because of the prolific nature of the sector. Emerging petroleum producing countries should work towards improving accountability in all streams of the petroleum value chain. The ministry or NOC should be made accountable to the public because the resources belong to the public. Oil sector institutions should be adequately empowered to be able to enforce accountability through its regulatory assignments. It is imperative for governments to know that once a particular NOC or the ministry has assumed responsibilities as a regulator, it may be difficult to take them back. Emerging petroleum producers may not necessarily be able to set a 'final' institutional framework from day one but gradually they will get to the stage. They are advised to follow a phased approach strategy and make incremental changes by re-structuring from time to time through incremental reform. Over time, producers should initiate sector-wide checks and balances, while still building up capacity in other areas of governance. Governments of the emerging petroleum producers should try as much as possible to introduce key mechanisms for public accountability, and these should include audit of agencies, NOCs and regular disclosure of information to the public.

2.5 Efficiency and Productivity Measurement Contextual

The production function (PF) is among the major concepts of mainstream neo classical, which is usually employed in explaining Marginal Product (MP) and Allocative Efficiency (AE). The Production Function goes a long way to explain the interactions that exist between the different factors of production. It specifically relates the outputs of the production processes to its corresponding physical inputs. It primarily addresses most of the challenges due to allocative efficiency during both production and income distribution processes. The PF describes the amount of input that could be used to produce a quantity of output. The PF decision makers are

mostly interested in the amount of input that would be used to produce a particular amount of output under the prevailing economic conditions (Coelli et at, 2005).

The inputs of PF are known as the factors of production (land, labour and capital). The PF is specified below:

If Q represents the quantity of outputs while $x_1, x_2, x_3 \ldots\ldots\ldots. x_n$ represent the quantity of input variables such as land, labour and capital. The production function can be expressed as the functional formulation of the right side of the equation (2.1) below:

$$q = f(x) \qquad 2.1$$

In cases where multiple inputs are being considered, equation 2.1 becomes:

$$q = f(X_1, X_1, X_1 \ldots\ldots\ldots. X_n) \qquad 2.2$$

There are several properties that could be associated with the PF as stated in equation (2.2), which are very useful when carrying out an economic analysis. These properties include: Non-negativity, Weak essentiality, Non-decreasing in X and concave in X. The Non-negativity refers to a finite, non-negative and real number properties of a PF, $f(x)$ while the weak essentiality explains the fact that it is impossible to have an output without having at least one input factor. The monotonicity property which is also known as non-decreasing in input is a property that identifies the fact that more inputs or additional input unit will not decrease the quantity of the output, $(X^0) \geq f(X^1)$. The serial combination of input variables tends to produce some linear combination of its PF, $f(X^0), f(X^1)$, though there are many other properties of PF which are not universally maintained. Figure 2.5 below illustrates some of the properties of PF as described above (Coelli et at, 2005).

In a situation where the firm uses multiple inputs, it is a common practice to plot the graph of the interactions that exist between two of the inputs while keeping other factors (output) constant. Figure 2.6 represents a two-input PF. The relationship between the inputs; X_1 and X_2 is plotted while keeping the output constant, q^0 and also plotted considering fixing the values of q^1 and q^2. The different isoquant in Figure 2.6 indicates various input combinations X_1 and X_2 to produce output q.

The Marginal Rate of Technical Substitution (MRTS) clarifies the rate by which input X_1 could be substituted for input X_2 in order to keep output at a constant level. The Isoquant slope is known as MRTS. The PF as stated in equation 2.5 is differentiated mathematically using calculus to explain some quantities of economic interest such as Marginal Product (MP), MRTS, Output Elasticity (E_n) and Direct Elasticity of Substitution-(DES).

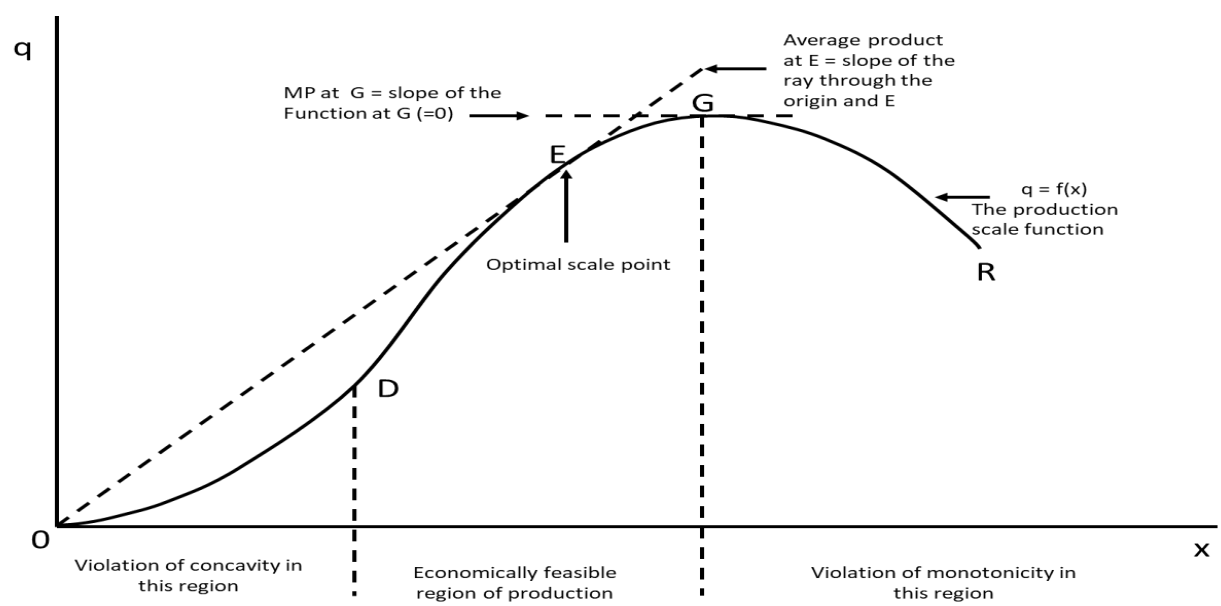

Figure 2.5: Single input Production Function. Source: Coelli et al, 2005.

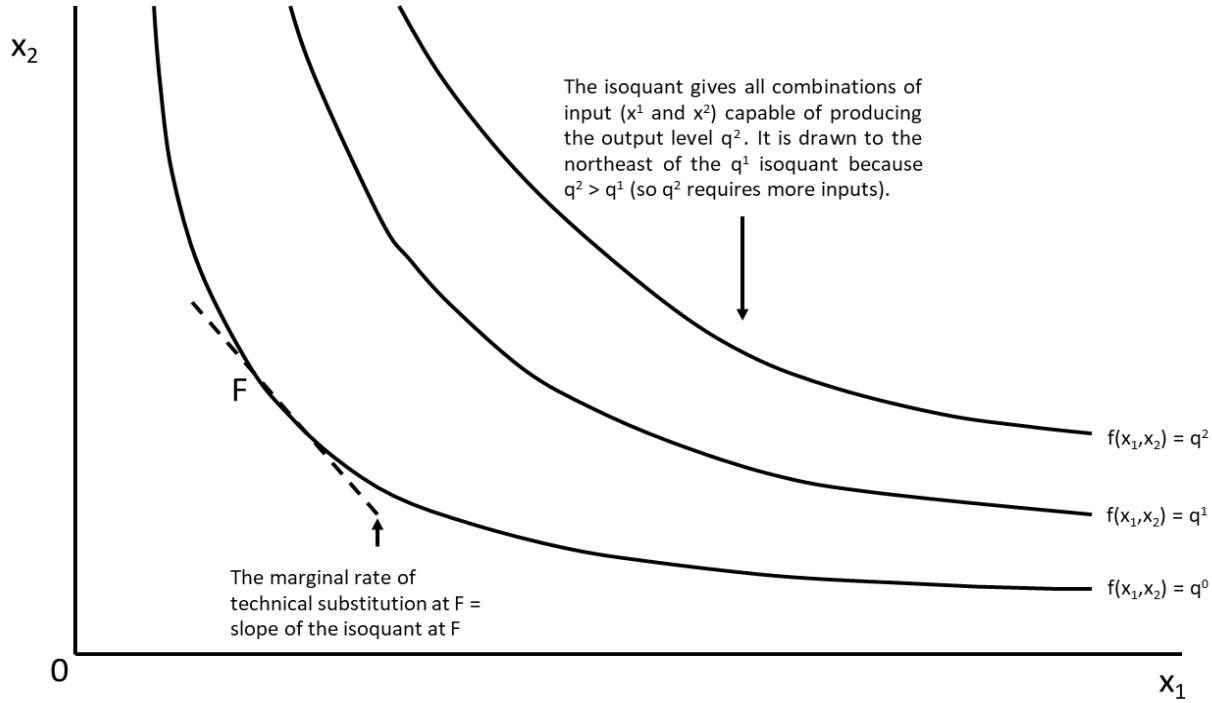

Figure 2.6: Isoquant for Output Variables

$$\mathrm{MP_n} = \frac{\partial \mathrm{f(x)}}{\partial \mathrm{x_n}} \qquad 2.3$$

$$\mathrm{MRTS_{nm}} = \frac{\partial \mathrm{x_n}\ (\mathrm{x_1}, \mathrm{x_{n-1}}, \mathrm{x_{n+2}} \ldots\ldots\ldots\ldots \mathrm{x_n})}{\partial \mathrm{x_m}} = -\frac{MP_m}{MP_n} \qquad 2.4$$

$$E_n = \frac{\partial f(x)}{\partial x_n}\ \frac{(x_n)}{f(_n)} \qquad 2.5$$

$$DES_{nm} = \frac{\partial (x_m/x_n)}{\partial (MP_n/MP_m}\ \frac{(MP_n/MP_m)}{x_m/x_n)} \qquad 2.6$$

The Direct Elasticity of Substitution (DES) is represented by β when considering two inputs case. In summary, MRTS is used to measure the Isoquant slope while DES measures the change in the ratio of the input to the change in the MRTS expressed in percentage. Other

economic quantities of interest such as Allen Partial Elasticity of Substitution (AES) and the Morishima Elasticity of Substitution (MES) are defined when considering more than one input case. Two different runs exist, that is, Short Runs Elasticity (SRE) and Long Run Elasticity (LRE). A good example of SRE is DES while that of LRE are AES and MES. One major difference is that SRE allows at least one input variable to be fixed whereas LRE varies all the input variables (Chambers, 1988; Coelli, *et al*, 2005). The MP also measures the response of the output when a particular input is altered or changed/varied while others remain constant.

One of the major objectives of this research is to determine the responses of the output when all inputs are changed at the same time or keep constant. This will help to define different attributes of the PF such as Decreasing Return to Scale (DRTS), Constant Return to Scale (CRTS) and Increasing Return to Scale (IRTS). It is DRTS when the increase in the input variables results in decrease in the output as stated in equation 2.7a.

2 * input = $\frac{1}{2}$ * output $\quad f\ (kx) < kf\ (x).$ 2.7a

When an increase in input variable gives a proportionate increase in output variable it is known as Constant Return to Scale (CRTS) as evidenced in 2.7b

$$f\ (kx) = kf\ (x). \qquad 2.7b$$

But in a situation where an increase in input variable results in a more than proportionate increase in output is known as increasing return to scale (IRTS),

$$f\ (kx) > kf\ (x). \qquad 2.7c$$

The elasticity of scale (ε) is the general and most commonly used measure of return to scale as shown in equation 2.7d

$$\varepsilon = \frac{\partial f(kx)}{\partial k}\frac{k}{f(kx)} = \sum_{n=1}^{N} \varepsilon_n \qquad 2.7d$$

where $\varepsilon_n = \text{Ouput Elasticity}$.

When ε_n >1, ε_n <1, ε_n =1, the production function exhibits DRTS, IRTS and CRTS, respectively. The MP and the elasticity can be illustrated considering two different inputs, $X_1\ and\ X_2$ as suggested by Cobb-Douglas, (1928)'s PF where q is known as output (see equation 2.8 and 2.12).

Cobb Douglas Production Function (CDPF)

$$q = 2x_1^{1/2} * x_2^{\frac{2}{5}} \qquad 2.8$$

$$MP_1 = \frac{\partial q}{\partial x_1} = x_1^{-1/2} * x_2^{\frac{2}{5}} \qquad 2.9$$

$$MP_2 = \frac{\partial q}{\partial x_2} = \frac{4}{5}x_1^{\frac{1}{2}} * x_2^{-\frac{3}{5}} \qquad 2.10$$

$$\varepsilon_1 = \frac{\partial q}{\partial x_1}\frac{x_1}{q} = x_1^{-\frac{1}{2}} * x_2^{\frac{2}{5}} * \frac{x_1}{2x_1^{\frac{1}{2}} * x_2^{\frac{2}{5}}} = \frac{1}{2} \qquad 2.11$$

$$\varepsilon_2 = \frac{\partial q}{\partial x_2}\frac{x_2}{q} = \frac{4}{5}x_1^{\frac{1}{2}} * x_2^{-\frac{3}{5}} * \frac{x_2}{2x_1^{\frac{1}{2}} * x_2^{\frac{2}{5}}} = \frac{2}{5} \qquad 2.12$$

The PF could be generalized considering the case of an organization or firm that produces multiple outputs. In specific term, a company that produces more than one output (M) using N

inputs has the following technological possibility transformation function, $T\ (x, q) = 0.$ where x is an input variable and q is an output variable.

$$q = (q_1, q_2, q_3 \dots\dots\dots\dots\ q_m)^t \qquad 2.13$$

$$q = \begin{bmatrix} q_1 \\ q_2 \\ q_3 \\ \vdots \\ \vdots \\ q_n \end{bmatrix} \qquad 2.14$$

Transformation function,

$$T\ (x, q) = q - f(x) = 0 \qquad 2.15$$

This is not applicable or useful for the current study in the sense that multiple outputs are aggregated into a single output measure using index number approach as discussed further in this research work.

2.5.1 Production Cost Function

Managers of most big or small organizations often arrive at optimum decision making by considering the subject of cost minimization. This subject matter is very important for efficient management and profitability of an establishment. Cost minimization is very vital in an organization such as oil and gas industry because E & P business is highly capital intensive and mostly carried out using 3rd party financing, i.e., Banks Loan, Farm out arrangement, etc. It is an environment where various inputs are needed to produce majorly two outputs, i.e., oil and gas, crude oil or gross revenue. In most cases the operators have no influence on both input and output prices because petroleum is an international commodity. Most of the technologies used

as inputs in oil and gas operations are sort outside the base or location (International). The price of the output, i.e., crude is a function of demand and supply in both local and international markets. The mathematical representation of production input cost minimization is as stated below taking note of the fact that the input market is perfectly competitive.

$$c\ (w, q) = \min w'\ x \quad such\ that \quad T\ (q, x) = 0 \qquad 2.16$$

$$Cost = \ w'x = \ w_1x_1 + w_2x_2 + w_3x_x + \ldots + w_nx_n \qquad 2.17$$

where x represents input price vector.

$$w = \left(w_1, w_2, w_{3,\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots} w_n\right) \qquad 2.18$$

$$w \ = \quad \begin{bmatrix} w_1 \\ w_2 \\ w_3 \\ \vdots \\ \vdots \\ w_n \end{bmatrix} \qquad 2.19a$$

This is looking at the quantity of inputs that will maximize the total cost of producing an output (q) considering the combination of technical feasible input and output. The cost is dependent on the variation in (w) and (q).

Having used lone output PF to explain some quantities of economic of interest such as return to scale (RTS), RTS can also be measured in the case of multiple output organizations or companies which can be defined using cost function. The overall scale economics can be evaluated using the relationship stated in equation 2.19b.

$$\boldsymbol{\epsilon_c} = \left[\sum_{m=1}^{M} \frac{\partial \text{ In C (w,q)}}{\partial \text{ In } q_m}\right]^{-1} \qquad 2.19b$$

The value of $\boldsymbol{\epsilon_c}$ which is known as the economies of scale (EOS) determines whether a particular firm will exhibit RTS such that when the value is equal to unity it is CRTS; when the value is less than unity, it is RRTS; and when the value is more than unity, it is IRTS. The idea of the EOS is that it makes more economic sense and it is more profitable to produce different outputs in a multiple output organization than relying on one particular output over time. The ways to measure EOS are as shown in equation 2.20 to 2.23 where $c\ (w,\ q_m)$ is the m-th output production cost and $c(w, q_{M-m})$ is all the outputs production cost with the exception of $c\ (w,\ q_m)$.

$$\boldsymbol{\epsilon_c} = \left[\sum_{m=1}^{M} \frac{\partial \text{ In C (w,q)}}{\partial \text{ In } q_m}\right]^{-1} \qquad 2.20$$

$$S = \left[\sum_{m=1}^{M} \text{C (w, q}_m) \Big/ \text{C (w, q)}\right] - 1 \qquad 2.21$$

$$S_m = \frac{c(w,q) + c(w,q_{M-m}) - c(w,q)}{c(w,q)} \qquad 2.22$$

$$S_{mn} = \frac{\partial^2 c(w,q)}{\partial\, q_m\, \partial\, q_n} \qquad 2.23$$

The global economies of scope as explained by the equation 2.21 give information on any changes in cost in a situation where outputs are produced separately. The best time to produce

all output as a group is when the value of S is greater than 0 (S>0) but if reverse is the case, that is, S has a value that is less than 0 (S<0), it is more beneficial to produce separately. In order to know the product specific economies of scope (SEOS) which give information on the changes in the Marginal Cost (MC) of producing m-th output to that of n-th output, if the value is negative, the organization experiences EOS with respect to n-th output (Coelli *et.al.*, 2005).

2.5.2 Distance Function Approach of Productivity Measurement

The distance function (DF) describes production technology in such a way that it is easy to measure an organization's efficiency and productivity. The idea of DF was first published independently by Malmquist in 1953 and Shepard in 1970. The DF concept is not too different from the production frontiers concept. It is basically used to explain the technology production that involved multi-input and multi-output variables without emphasizing its behavioral objectives. These behavioral objectives include cost minimization, profit maximization, etc. In some situations, it may be necessary to specify both input distance function and output distance function. A situation where the major objective is how to carry out a minimal proportional contraction of the vector of input, that will give an output vector, such production technology is characterized by input distance function. When considering maximizing the output vector given the input vector it is regarded as output distance function, (Donnell, et.al. 2007)

2.5.2.1 Output Distance Function Specification (ODFS)

The ODF is specified on the output set {P(X)} as:

$$d_o(x,q) = \min\{\delta: ({}^{q}/_{\delta}) \in P\ (X)\} \qquad 2.24$$

Where

i. d_o is the output distance function

ii. $d_o(x, 0) = 0$

iii. $d_o(x, q)$ increasing in q and decreasing in X

iv. $d_o(x, q)$ it is homogenous linearly in q

v. $d_o(x, q)$ is quasi – convex in x and convex in q:

vi. Where q could be found in the production possibility set of X i.e. q ∈ $P\ (X)$, then (x, q) ≤ 1

vii. $d_o(x, q)$ is equal to 1 when q belongs to the frontier of the production possibility set (PPC) of X.

2.5.2.2 Input Distance Function Specification (IDFS)

The IDF is specified on the input set {L(q)} as below. L(q) is the set of all input vector X which can be used to produce the output vector (q).

$$d_i(x, q) = \max\{\rho: ({}^{x}/_{\rho}) \in L\ (q)\} \qquad 2.25$$

Where

i. d_i is the input distance function

ii. It is homogeneous in X linearly

$iii.$ $d_i(x, q)$ is quasi-concave in q but concave in x

iv. Where x belongs to q input set $X \in L\ (q)$ then $d_i(x, q) \geq 1$

v. But where x belongs to frontier input distance function and equal to 1 i.e. $d_i(x, q) = 1$

2.6 Index Number and Productivity Evaluation

The Index numbers are mostly used as a tool to evaluate levels of changes in the economic variables. Some of the examples of index numbers are: Consumers Price Index (CPI), the Producers Price Index (PPI), Price Deflators (DD), National Income Aggregates (NIA), All Ordinaries Index (AOI) - used in Australia and the United States of America - Dow Jones Index (DJI). The productivity change measurement involves knowing the changes in the level of output as well as the changes in the level of the input usage (Coelli *et.al.*, 2005). This type of change measurement may be easy when dealing with single input and output firm or organization but becomes a bit laborious in the case of multi-input and multi-output organization. Index numbers play some important roles in the measurement of changes in the Total Factor Productivity (TFP) which leads to generating TFP index numbers. Index Numbers are also used indirectly to generate the required data for the application of DEA and SFA. One major challenge of using index number techniques is the occurrence of estimation problem due to very large output and input variables. To overcome this challenge, it is recommended that data should be aggregated into smaller number of variables.

An index number is conceptualized as real numbers that are used to evaluate the possibility of changes in a set of related variables over time and space. These variables include input and output variables. It is used to measure differences in an organization's productivity changes over time across different firms, industries, regions and countries. There are two major classifications of index numbers: Price index number-PIN (consumers price index, import & export price index, input and output price index), and Quantities Index Numbers-QIN-quantities of input and output used or produced by a firm over a stipulated period of time. The stated below are some of the notations used in index numbers as a tool for productivity measurement.

$P_{m.j}$ price of the m-th commodity at the j-th period (s,j)

$q_{m.j}$ quantity of input and output of the m-th commodity at the j-th period (s,t)

$J_{s.t}$ where m = 1, 2…m, s and t may refer to 2 firms instead of one time period

$I_{s.t}$ general index number for the current period t, with s as the base period

$V_{s.t}$ value index numbers

$P_{s.t}$ price index numbers

$q_{s.t}$ quantity index numbers

In general, index numbers are used to measure changes in the levels of variables from a particular reference period (i.e., current period and base period). Current period is the period for which the index is calculated while base period is the reference period. Below are some of the general formulas used in solving index number problems looking at the changes from period s to t.

$$\mathrm{V_{s,t}} = \frac{\sum_{m=1}^{M} p_{m,t} * q_{m,t}}{\sum_{m=1}^{M} p_{m,s} * q_{m,s}} \qquad \textbf{2.26}$$

The equation 2.26 above which measures $V_{s,t}$ measures changes in the basket of quantities of commodities M from s-period to t-period. $V_{s,t}$ measures the degree of changes in the two components that is price and quantity. The equation 2.26 could be decomposed to measure the quantity of change especially when dealing with a single commodity world. The decomposition is as stated below:

$$\mathrm{V_{s,t}} = \frac{p_t * q_t}{p_s * q_s} = \frac{p_t}{p_s} * \frac{q_t}{q_s} \qquad \textbf{2.27}$$

From equation 2.27, the decomposed ratio is used to evaluate the relative price and quantity changes. The Laspeyres and Paasche index numbers represent the most widely used indices in the last twenty years. The Laspeyres Price Index (LPI) relies on the base period quantities as a

measure of weights while the Paasche Price Index (PPI) makes use of the current period weights, (Coelli *et.al.*, 2005).

$$\mathrm{LPI} = \mathrm{P}_{s,t}^{L} = \frac{\sum_{m=1}^{M} p_{m,t} * q_{m,s}}{\sum_{m=1}^{M} p_{m,s} * q_{m,s}} = \sum_{m=1}^{M} \frac{P_{m,t}}{P_{m,s}} * \omega_{m,s} \qquad \textbf{2.28}$$

Where

$$\omega_{m,s} = \frac{p_{m,s} * q_{m,s}}{\sum_{m=1}^{M} p_{m,s} * q_{m,s}} \qquad \textbf{2.29}$$

This is equal to base period value share of m-th goods.

The equation in 2.30 is interpreted in two different ways: it is used to relate the two value aggregates at current and base period prices; while on the other hand it is interpreted as the value share weighted average of the M-price relatives. The value shares are basically known as the base period. Aside using base-period quantities as used in the Laspeyres index, the current period quantities could be used as defined by Paasche index number as shown below:

$$\text{Paasche Index} = \mathrm{P}_{s,t}^{P} = \frac{\sum_{m=1}^{M} p_{m,t} * q_{m,t}}{\sum_{m=1}^{M} p_{m,s} * q_{m,t}} = \frac{1}{\sum_{m=1}^{M} \frac{P_{m,s}}{P_{m,t}} * \omega_{m,t}} \qquad \textbf{2.30}$$

From the equation 2.30 above, it is evident that the Paasche index is the ratio of two value aggregates that is, price and quantities, i.e., from period t to period t and s. The second part of equation 2.30 assumes that Paasche index is the price weighted harmonic mean considering current value shares as weights. The two indices mentioned have been widely used due to the fact that they are easy to compute and they provide bounds for the true index. On the other side, the Fisher index which is also known as Fisher Ideal Index takes advantage of the gap in between the Laspeyres index and Paasche index and find the geometric mean of the two which

he uses as a possible index number formula (Diewert, 1992). The Fisher Index has a number of favourable statistical and economical theoretical properties.

$$\text{Fisher Index} = \mathrm{P}^{\mathrm{F}}_{\mathrm{s,t}} = \sqrt{\mathrm{P}^{\mathrm{L}}_{\mathrm{s,t}}} * \mathrm{P}^{\mathrm{P}}_{\mathrm{s,t}} \qquad \textbf{2.31}$$

The Tornqvist Index (TI) has gained much popularity in most Total Factor of Productivity (TFP) researches in the last decade. There are two types of TI: the Tornqvist Price Index (TPI) and the Tornqvist Quantity Index (TQI). The TPI is explained as the weighted geometric average relative to price with weights given by the value share average in period s and t.

$$\mathrm{P}^{\mathrm{T}}_{\mathrm{s,t}} = \prod_{\mathrm{m=1}}^{\mathrm{M}} \left[\frac{\mathrm{P_{m.t}}}{\mathrm{P_{m,s}}}\right]^{\frac{\omega_{\mathrm{m,s}}+\omega_{\mathrm{m,t}}}{2}} \qquad \textbf{2.32}$$

The **TI** is preferably presented in its logarithm formulation as shown below:

$$In\ P^{T}_{s,t} = \sum_{m=1}^{M} \left(\frac{\omega_{m,s}+\omega_{m,t}}{2}\right) \left[InP_{m,t} - InP_{m,s}\right] \qquad \textbf{2.33}$$

There are two approaches that are used to measure the quantity index number. These are the direct approach and the indirect approach. The four methods explained above (that is, Laspeyres, Paasche, Fisher and Tornqvist indices) are known as the direct methods. The indirect approach uses the idea of price and quantity changes. These two components change in value over time period s and t. The price changes can be evaluated using the formulae previously stated above while the quantity changes can be evaluated indirectly by deflating the value change for the price change (Coelli et al., 2005)

2.6.1 The Direct Approach Formulae

$$\mathrm{Q}^{\mathrm{L}}_{\mathrm{s,t}} = \frac{\sum_{\mathrm{m=1}}^{\mathrm{M}} \mathrm{P_{ms}q_{mt}}}{\sum_{\mathrm{m=1}}^{\mathrm{M}} \mathrm{P_{ms}q_{ms}}} \qquad \textbf{2.34}$$

$$Q^{P}_{s,t} = \frac{\sum_{m=1}^{M} P_{mt} q_{mt}}{\sum_{m=1}^{M} P_{mt} q_{ms}} \quad \textbf{2.35}$$

The Tornqvist Quantity Index (TQI) has both multiplication and additive formulations as stated below. The equation 2.36 is the most popular TI equation and is used mainly to measure change in output produced and input quantity used during production of a particular goods within the two-time period s and t.

$$Q^{T}_{s,t} = \prod_{m=1}^{M} \left[\frac{q_{mt}}{q_{ms}}\right]^{\frac{\omega_{ms}+\omega_{mt}}{2}} \quad \textbf{2.36}$$

$$In\ Q^{T}_{st} = \sum_{m=1}^{M} \left(\frac{\omega_{ms}+\omega_{mt}}{2}\right) [InP_{mt} - InP_{ms}] \quad \textbf{2.37}$$

2.6.2 Indirect Approach Formulation

The indirect approach relies on the basic principle that the price measurement and quantity changes have to account for value changes and it furthers defines value change as the product of price change and the quantity change which can be represented as below in equation 2.38 and 2.39.

$$V_{st} = P_{st}\ X\ Q_{st} \quad \textbf{2.38}$$

$$Q_{st} = \frac{V_{st}}{P_{st}} = \frac{\frac{\sum_{m=1}^{M} P_{mt} q_{mt}}{\sum_{m=1}^{M} P_{mt} q_{ms}}}{P_{st}} \quad \textbf{2.39}$$

2.7 Data Envelopment Analysis (DEA)

2.7.1 History and Development of DEA models

Farrell (1957), a publication in the Journal of the Royal Statistical Society was the first scholarly work on productive efficiency investigation. This publication serves as the main background for the study conducted by E. Rhodes using DEA. The E. Rhodes' study which was supervised by A. Charnes and W. W. Cooper is known today as the first research to use DEA tool to evaluate the performance of an organization or institution. E. Rhodes investigation involved the comparison of the efficiency of some school districts that were participating in a particular program and some that were not. The task before E. Rhodes then was to evaluate the relative efficiency of the schools considering multiple outputs and inputs with no price data, which eventually resulted in the ratio formulation of DEA (Charnes, Cooper, & Rhodes, 1978). DEA actually began as an instrument to measure the efficiency of public sector institutions and today, it is widely used to investigate the efficiency of homogeneous organizational units which are often referred to as decision making units (DMUs) that engage similar inputs to achieve the same outputs.

DEA takes the advantage of an operator's input and output data to form a production possibility space upon which their efficiencies could be evaluated based on the comparison of individual units. DEA can also be described as a comparatively novel data-oriented analysis used to evaluate the activity of several peer DMUs that use several inputs to generate several outputs. Recently, the DEA method has been used in several ways especially in assessing the behavior of different types of organizations involved in varying operations in many parts of the world. This method has been applied worldwide in several organizations like the health sector, educational sector, agriculture, energy, financial, metropolises, and commercial companies. In other worlds, DEA can be described as a non-parametric programming method used to measure the

productivity and efficiency of comparable multiple inputs and outputs decision making units (DMUs). As Charnes, Cooper, and Rhodes, (1978) note, DEA application supports novel visions compared to the previously used performance analysis approaches. As an example, evaluations regarding benchmarking with DEA have helped to discover many foundations of inadequacy in most companies that had served as benchmarks by reference to this standard, and this has delivered a novel method of identifying better benchmarks in several applied evaluations.

DEA was adopted to evaluate the performance of the Norwegian Bus Corporation which is one of the Norwegian government firms under the government subsidy regime (Odeck & Sunde, 2001; Odeck & Alkadi, 2001). The sector efficiency investigation under subsidy regime was carried out and several suggestions were made to the Norwegian government in order to improve the performance of the sector. Banker, Emrouznejad, Bal, Alp, and Ali (2013) used the DEA-BCC model which assumes VRTS to measure the Acer company productivity performance after the 1998 introduction of a new information technology. The study used DEA to rate the efficiency of the company pre, and post-introduction of the new technology and it was concluded based on the results that the introduction of the new technology has substantially improved the performance of the company between 1997 and 1999.

Many performance analysts have relied on Banker et al to evaluate productivity in other sectors of the economy. Mahadevan (2002) investigated the productivity growth and relative efficiency in the manufacturing sector of Malaysia using DEA. He considered a sample of 28 firms from 1981 to 1996 using panel data approach. Mahadevan used DEA for the computation and decomposition of the Malmquist index of TFP growth into change in Technical Efficiency and Scale Efficiency respectively. The decomposition was done to identify the sources that were crucial for policy formulation. The results of the analysis showed that the TFP annual growth of Malaysia's manufacturing sector was low at 0.8% as a result of small gain in Technical change and Technical efficiency. Wang and Huang (2007) recommend the DEA as well as Balanced

Score Card approach for the measurement of an organization's performance. They believe that the two criteria give illuminating information about the wellbeing of an organization or an institution.

Oliveira, Correia and Soares de Mello (2007) stated that the preceding 20 years of oil and gas exploration and production was characterized by high price of crude oil. Not many oil and gas producers were thinking about efficiency and performance evaluation because most companies could break-even as long as the companies have not stopped production. *Olivia et al. (2007)* used DEA method to evaluate the performance of some South African oil and gas companies in terms of usage, dependency on production, consumption and the endowed proved reserves. The technical efficiency of the 113 United States of America's oil refineries was evaluated in 2006 using DEA by Mekaroonreung and Johnson (2009). Several DEA measures were used and compared to the disposability assumptions. The study concluded that the technical efficiency of the oil refineries could be improved despite the disposability assumptions of the outputs under CRTS approach (Charnes, Cooper, & Rhodes, 1978).

DEA has gained immense popularity in the world in the last decade as an efficient tool to investigate the performances of firms of different sizes. Zhou, Kim & Beng (2007) presented a literature survey of the DEA applications in the petroleum, energy and environmental studies internationally. In their study they concluded that the application of DEA in oil and gas sector is not very popular. Malhotra, R, Malhotra, D and Harvey (2009) adopted DEA to analyze the performance of seven North American class 1 freight rail road. The financial ratio of a firm was analyzed as opposed to its peers and the result obtained pointed out the firms with the highest medial and lowest technical efficiency among the sample of firms surveyed. The study recommended the areas where the management should focus in order to improve the performance of the firms.

In an attempt to carry out an extensive research on the efficiency and performance of gas industries in the international perspective, Hardon (2003) engaged DEA. His analysis was based on input and output variables where he assessed almost 30 gas industries in order to have a better result. Hardon used gas consumption and number of customers as output data; and used employment and pipeline as input data (US Energy Information Publication, 2002). He preferred the usage of DEA in the analysis due to the fact the model could cope with multiple outputs and inputs, and the fact that it requires minimal or no assumption and no functional form restriction relating to input or output. The results of Hardon's analysis led to the researcher's conclusion that the current reform programmes in the global gas industries are as a result of high level of technology efficiencies and good utilization of labour in the industry.

Sepehrodoust (2011) used DEA to evaluate the performance of housing industry in Iran using the data collected from the Iran center for statistical data from 2006-2009. The analysis showed that 27 percent of the whole Iranian housing estates were operating efficiently at an average efficiency score of 94 percent. Sepehrodoust consequently suggested measures to be embarked upon by the Iranian government in order to improve the performance of the housing sector. Ines and Martinez (2010) used non-parametric DEA approach to investigate the energy efficiency development in the non-oil sector of Germany and Colombia using data from 1998 to 2005. The study relied on production-based framework to compare energy efficiency at two levels of aggregation as well as applying different models to get a better result. Their analysis end results show that variations exist in the energy efficiency performance of the non-oil sector of Germany and Colombia.

Sanzhar and Skakov (2015) evaluated the performance of oil and gas industry under the then global economic downturn. In their analysis, they considered the integrated oil and gas companies such as Exxon Mobil, Chevron, BP, and Royal Dutch Shell. The study analysed the companies' financial and operational data using different approaches which included Financial,

Energy Ratio Analysis and DEA. The DEA results for the relative efficiency of the named companies were in compliance with the previous results from the Financial and Energy Ratio Analysis. Exxon Mobil recorded an efficiency index of 1 throughout the six-year period of the analysis and the second efficient company stood out for Chevron Integrated Corporation with the efficiency index of 0.96088 which the authors related to the 2009 global financial crisis.

Ajalli, Bayat, Mirmahalleh and Ramazani (2011) studied the impact of having lesser number of DMUs compared to the number of outputs and inputs during DEA analysis by evaluating 23 gas companies. The study employed the use of Anderson-Peterson methods in combination with DEA and the emanating results and findings contributed immensely to the increased power of evaluation and ranking of the companies (Andersen and Petersen, 1993). Iledare et al (1999) modeled the oil and gas upstream productivity in the Gulf of Mexico Outer Continental Shelf (OCS) region. The study viewed productivity as the quantity of output that could be produced using a given input, having in mind the existence of several indicators of productivity because of the variation in the measurement of input and output. The study relied on productivity indicators such as drilling success rate, average discovery size, finding rates, and yield per effort to examine the performance of the region's upstream activities. They used econometric model to empirically determine the effects of technical progress, depletion, policy incentives, market conditions, structural changes on the oil and gas operations in the Gulf of Mexico Outer Continental Shelf (OCS) region. Their model results confirm the expectations of diminishing returns to drilling in the region as a result of resource depletion, economic incentives, institutional restructuring, and technical.

2.7.2 DEA Mathematical Representation

The DEA is a method which allows the combination of multiform outputs and inputs. It has the following use: to measure efficiency, that is, the output-to-input ratio. This famous method has

been in use for evaluating the performance and efficiency of decision-making units (DMUs) since 1970s. This idea was first conceived and presented by Farrell (1978), a study that gave insights into measuring production effectiveness. An improvement on Farrell's work was Charnes et al who tagged their model as the CCR model that adopted CRTS and in most cases regarded as CCR-CRS. Another improvement was made by Banker *et al* (1984), which broadened this model to become VRTS (VRS), now tagged BCC-VRTS model. Ike and Lee (2014) used the Slacks-Based Method (SBM). According to Charnes et al, the CCR is a measure of efficiency of any DMU and is derived as the maximum of weighted outputs to weighted inputs subject to the state that akin ratios for each DMU be less than or equal to unity.

The model is given as

$$\max h_0 = \frac{\sum_{r=1}^{s} u_r y_{r0}}{\sum_{i=1}^{m} v_i x_{i0}} = \frac{u_1 y_{10} + u_2 y_{20} + u_3 y_{30} + \cdots + u_s y_{s0}}{v_1 x_{10} + v_2 x_{20} + v_3 x_{30} + \cdots + v_m x_{m0}} \qquad \textbf{2.40}$$

subject to

$$\frac{\sum_{r=1}^{s} u_r y_{rj}}{\sum_{i=1}^{m} v_i x_{ij}} = \frac{u_1 y_{1j} + u_2 y_{2j} + u_3 y_{3j} + \cdots + u_s y_{sj}}{v_1 x_{1j} + v_2 x_{2j} + v_3 x_{3j} + \cdots + v_m x_{mj}} \leq 1 \qquad \textbf{2.41}$$

$$v_r,\ v_i \geq 0;\ \ r = 1, \ldots, s; \quad i = 1, \ldots, m \qquad \textbf{2.42}$$

Here the y_{rj}, $x_{ij} \geq 1$ are the known outputs and inputs of the *j*th DMU and the *ur; vi* (all positive) are to be found by solving this problem. From Equation 2.40, the objective function seeks to maximize the ratio h_0 of DMU*o*. Optimally, the value of h_0, i.e., h_0^* is at most 1. Equations 2.40-2.42 are called the fractional programming form. These sets of equations are converted into linear programming in equivalent form (Equation 2.43) as given below:

$$\max h_0 = u_1y_{10} + u_2y_{20} + u_3y_{30} + \cdots + u_sy_{s0} \quad \textbf{2.43}$$

Subject to:

$$v_1x_{10} + v_2x_{20} + v_3x_{30} + \cdots + v_mx_{m0} = 1 \quad \textbf{2.44}$$

$$(v_1x_{1j} + v_2x_{2j} + v_3x_{3j} + \cdots + v_mx_{mj}) - (u_1y_{1j} + u_2y_{2j} + u_3y_{3j} + \cdots + u_sy_{sj}) \geq 0 \quad \textbf{2.45}$$

$$v_r,\ v_i \geq 0;\ \ r = 1, \ldots, s; \quad i = 1, \ldots, m. \quad \textbf{2.46}$$

The optimal solution to this linear programming problem is (u^*, v^*) and is obtained in a sequence of optimal weights for DMU*o*. For evaluation, the ratio scale is given by:

$$h_0 = \frac{u_1y_{10} + u_2y_{20} + u_3y_{30} + \cdots + u_sy_{s0}}{v_1x_{10} + v_2x_{20} + v_3x_{30} + \cdots + v_mx_{m0}} \quad \textbf{2.47}$$

The optimal solution (u^*, v^*) maximizesh_0^*. It is worthy of note that the units of measurement of input and output do not determine the value of h_0^* on the condition that these units are unique for each DMU. This is otherwise called “unit invariance”. If h_0^* = 1 and ∃ at least one optimal solution (u^*, v^*) where u^* > 0 and v^*> 0 then the DMU is called CCR-efficient. On the other hand, if h_0^* < 1 then the DMU is called CCR-inefficient. Thus, the duo of the linear programming problem of Equations 2.48-2.51 can be written as:

$$min_\theta, \gamma^\theta \quad \textbf{2.48}$$

subject to

$$\theta_{x_j} - x\gamma \geq 0 \quad \textbf{2.49}$$

$$Y_\gamma \geq y_j \quad \textbf{2.50}$$

$$\gamma \geq 0 \quad \textbf{2.51}$$

If $\theta^* \leq 1$ then (Xγ; Y γ) performs more than (θ_{x_j}, y_j): Thus, $s^- \in R^m$ is regarded as excesses while $s^+ \in R^s$ is denoted as output shortfalls. According to Ike and Lee (2014), a condition for a DMU to be CCR-efficient is that all slacks must be equated to zero.

$$s^+ = Y_\gamma - y_j \quad and \quad s^- = \theta_{x_j} - x\gamma \quad \textbf{2.52}$$

The model that performs the incorporation of unit invariance by non-radial argumentation is called slacks-based model (SBM). Thus, to estimate the SBM efficiency, Ike and Lee (2014) proposed the models 2.53 and 2.56

$$min_{x,s^-,s^+}\theta_{SBM} = \frac{1-\frac{1}{m}\sum_{i=1}^{m}\frac{s_j^-}{x_{ij}}}{1-\frac{1}{s}\sum_{r=1}^{s}\frac{s_r^+}{y_{rj}}} \quad \textbf{2.53}$$

subject to

$$x_j = X_\gamma + s^- \quad \textbf{2.54}$$

$$y_j = Y_\gamma - s^+ \quad \textbf{2.55}$$

$$\gamma \geq 0, s^+ \geq 0, s^- \geq 0 \quad \textbf{2.56}$$

Here, $\gamma = (\gamma_1, \gamma_2, \ldots, \gamma_n)^T$ while s^+ and s^+ have been defined before. The main use of SBM efficiency is to measure the product of the input and output efficiencies. For the measurement of input oriented SBM, the denominator of Eqn. (2.53) is neglected while s^+ is removed. Thus, Eqn. (2.55) becomes $y_j \leq Y\gamma$: On the other hand, if the output-oriented SBM is to be measured,

Eqn. (2.55) is neglected while *s*- is removed. Hence, Eqn. (2.54) becomes $x_j \leq X\gamma$: For more, (see Ike and Lee, 2014)

2.7.3 DEA Return to Scale

The economic law of return to scale states that in the long run all factors of production (that is, land, labour, capital etc.) is not fixed but variable, and there could be a change in the scale of production. So, the phrase "return to scale" has to do with the changes in output as a result of proportionate change in input variables. The concept of return to scale is not a short run but a long run which relates the corresponding effects on a total output as inputs are varied. There are two basic ways by which RTS is described in economics: Constant Return to Scale (CRTS) and Variable Return to Scale (VRTS). The VRTS is further divided into Decreasing Return to scale (DRTS) and Increasing Return to Scale (IRTS). Each of them is guided with a particular basic principle as shown in Figure 2.8 and 2.9. RTS concept is represented mathematically as described below:

Let initial production be, $q = f\ (L,\ K)$ where q is known as production output and L is Labour which can also be called input one while $K - Capital$ is also an input two in a multiple inputs production setting. In a multiple input and a single output production frontiers i.e. q, $x_{1,}\ \ x_2$, assuming x_1 , x_2, which are the factors of production are increased proportionately with a factor of B that is Bx_1 , Bx_2

2.7.4 Constant Return to Scale (CRTS)

If q_1 is an output and it increases in the same proportion as increase in the Labour x_2 and Capital x_2, (Inputs), this situation is regarded as constant return to scale (CRTS). The CRTS is illustrated in Figure 2.8, which explains a production scenario whereby output increases exactly in the same amount by which input(s) is (are) increased. This indicates that if an output of a

particular production technology is tripled, the corresponding inputs are also tripled. The return to scale concept has been explained in using Cobb-Douglas linear homogenous production function in the previous section of this study.

The case whereby the output increases less than proportionate increase in the factors of production, i.e., input variables x_1 , x_2 is known as decreasing return to scale (DRTS). It refers to the kind of production situation in which all inputs are increased in a given proportion with a corresponding less increase in output, q, (meaning that output increases in a smaller proportion compared to input). This is the type of production frontier where 50% increase in inputs variable such as Labour and Capital results into a corresponding 35% increase in the output. It is also known as diminishing return to scale. DRTS occurs when the internal and external economies-input economies are less than the output diseconomies, (internal and external diseconomies).

The increasing return to scale (IRTS) helps to describe circumstances where output increases more than proportionate increase in the factors of production (that is, inputs). It can also be explained as a scenario where all factors of production are increased thereby resulting into higher increase in the quantity of output. The IRTS could be traced to many reasons which include the division external economies of scale. Figure 2.10 illustrates the IRTS. In Figure 2.10 above, 0Z denotes increase in input, i.e., Labour and Capital as a factor of production while OY depicts increase in output. When the aggregate inputs increase from $x_1\ to\ x_2$, output also increase from $q_1\ , to\ q_2$ though in higher dimension compared to input increase known as a situation of increasing return to scale (IRTS).

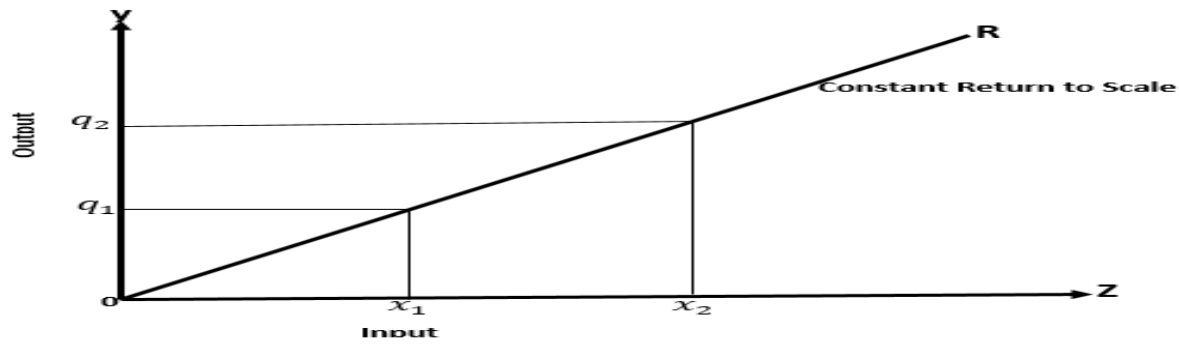

Figure 2.8: Constant Return to Scale (CRTS)

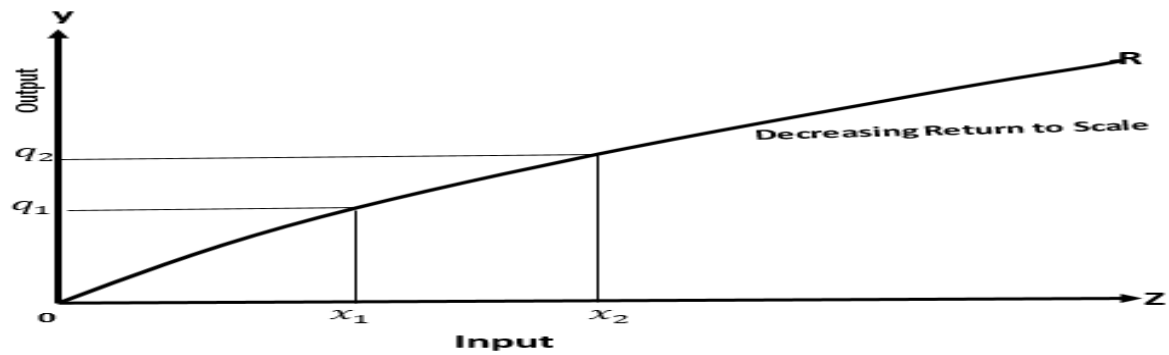

Figure 2.9: Decreasing Return to Scale (CRTS)

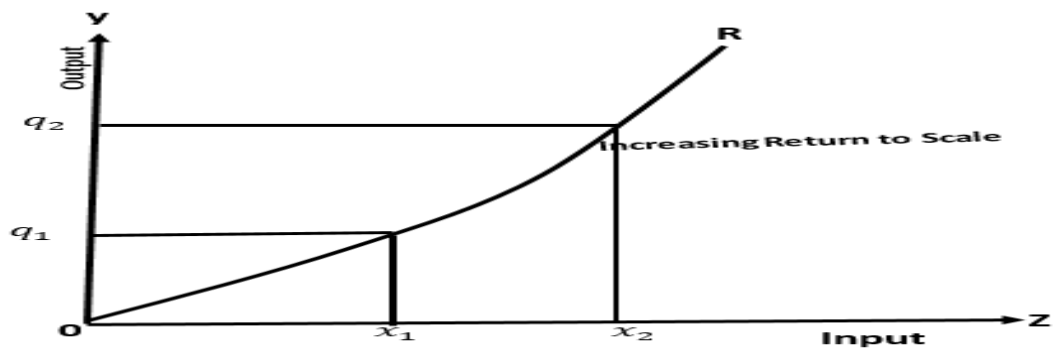

Figure 2.10: Increasing Return to Scale (IRTS)

Chapter 3

3. Methodology

3.1 DEA Overview

The Data Envelopment Analysis (DEA) framework adopted in this study involves the use of three different DEA models to evaluate CRTS technical efficiency index (CRTSteindex), VRTS technical efficiency index (VRTSteindex) and Non-increasing return to scale (RTSindex) for all the 32 active upstream operators in Nigeria. Historically, the subject of efficiency investigations started with such earliest studies by Farrell (1957), Debrew (1951) and Koopmans (1951). The studies attempted to define the measurement of organization efficiency considering multiple inputs and outputs. The ability to maximize outputs using a set of inputs and vice versa is regarded as the technical efficiency of a particular decision-making unit (DMU). A situation where inputs are minimized considering their respective prices is known as allocative efficiency (Kocisova, 2014).

The Total Economic Efficiency (EE) is the combination of these two measures (that is, the technical efficiency-TE and the allocative efficiency-AE) which could either be input or output orientated measures (Farrell et al., 1994). DEA could also be explained as a method of efficiency and productivity measurement that uses mathematical models such as Linear Programming to construct a non-parametric piecewise frontier over such individually chosen data as input, output, price, etc. There are three main DEA models that could be considered according to Fare *et al* (1994). These are CCR-Constant Return to Scale Model (CRTS), the BCC-Variable Return to Scale Model (VRTS) and the Malmquist Productivity Index Model (MPIM). The first two models (CRTS and VRTS) are used to estimate technical and scale efficiencies where it is required. This could also be extended to investigate cost and allocative

efficiencies of a particular Decision-Making Unit (DMU). The third model, that is, the Malmquist Productivity Index (MPI) is essentially engaged to investigate productivity change from one period to another period, (t, t+1). The modification of Malmquist Total Factor of Productivity (TFP) change results in technological changes which are technical efficiency change and scale efficiency change (Fare *et al*., 1994; Coelli *et al*., 2005; Cooper *et al*., 2006; Cooper *et al*., 2011).

There are two major DEA orientations identified in the DEA literature. These are the input and output orientations. The input-oriented DEA is the type where input variables are minimized for a given level of output. It indicates how well an organization or firm could reduce its input and at the same time keeping its output at optimum level. The output orientation DEA is more concerned with how the output can be maximized considering a given level of input variables. In another word, it is an indication of how much an organization could maximize its output for a given level of input (Cook *et al*., 2014; Cooper *et al*., 2006). Although the two orientations depict two different frontiers for the CRTS and VRTS models, the position of a DMU on the frontier is unaffected by the type of orientation in use.

The implication of this is that an organization will maintain its position on the frontier irrespective of the type of orientation that is adopted (Coelli & Perelman, 1999; Huguenin, 2012). The decision maker reserves the right to decide the best orientation to use, which may depend on the variable he/she has control over mostly and the objective of the analysis. Thus far, the Nigeria upstream industry performance investigation, four different phases of estimations were considered. Phase one involves the use of DEA-CRTS output oriented dual model, which assumes constant return to scale to generate CRTS technical efficiency index (CRTSteindex) for each of the 32 active upstream operators in Nigeria. The second phase uses DEA-VRTS output oriented dual model which assumes variable return to scale (VRTS) to generate another set of efficiency index known as VRTS technical efficiency Index (VRTSteindex) (Cooper *et al*,

2004; Zhou *et al*, 2007).

The estimated technical efficiency indexes in phases one and two were further subjected to another linear programming model known as Non-Increasing Return to Scale to ascertain the type of production frontier to which each operator belonged, that is, IRTS, DRTS, CRTS (Seiford & Zhu, 1999). The processes in phases one and two were repeated using the average input and output data to estimate the mean CRTSteindex and VRTSteindex which were the dependent variables for the economic analysis in phase four.

In phase four, economic analysis was conducted using panel data model to determine the impacts of exogenous variables or factors believed to be having non-negligible impacts on the estimated technical efficiency of the operators. The selected exogenous variables were: upstream taxes paid by operators, experience or age of the company, world crude oil demand, gas reserves to production ratio and oil reserves to production ratio (Hartley & Medlock., 2008; Eller *et al*, 2011; Ike & Lee, 2014). There are many computer programs or software which has been developed to estimate DEA models, i.e., DEAP-DEA Programs, Win4DEAP, rDEA, PIM-DEA-Performance Information Management. These are used basically for DEA models while Frontier Computer Program is used to estimate frontiers (Lovell, 1993; Coelli, 1994, 2008).

This study used Microsoft Excel 2016 in conjunction with a Visual Basic for Applications (VBA) to estimate the formulated Linear Mathematical Models. DEAP software was used to benchmark the two results while E-View 7.0 Software was used to carry out the economic analysis in the stage four of the study.

Figure 3.1 shows the research flowchart and other processes involved in the analysis (Barros & Athanassiou, 2004; Neralic & Wendell, 2004; Hoff, 2007; Sibiano & Agastisti, 2012).

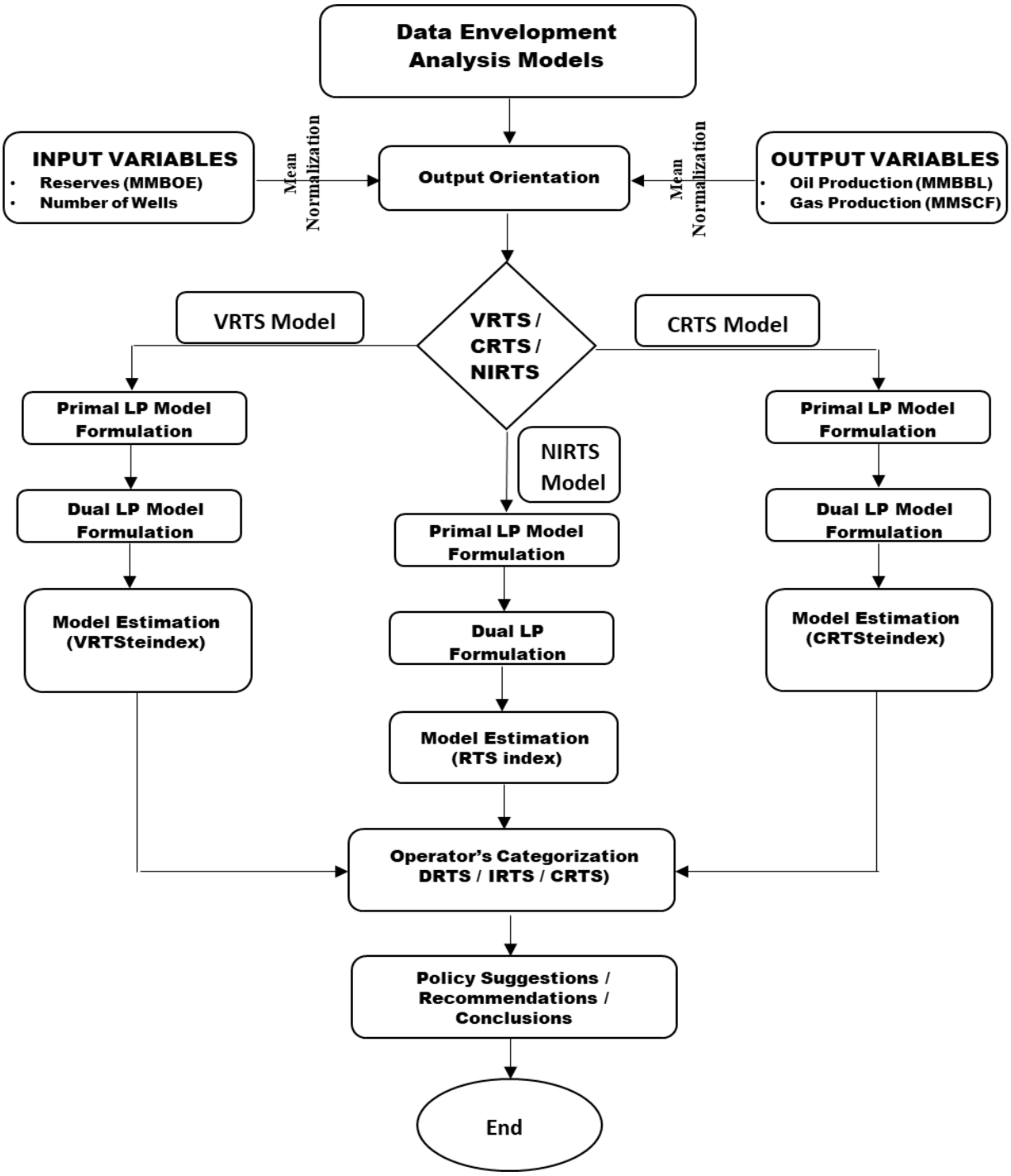

Figure 3.1: A Typical Flowchart for Estimating Upstream's TE and Its Production Frontiers

3.1.1 Input / Output Variables Quantity and Quality

This section discusses the research major concerns during input and output data gathering. The interest here is the choice of the variables and its construction for analysis as well as how good sources of input and output data are able to be identified. Having reviewed some of the index methods used during price compilation and quantity index number used in productivity measurement in the previous chapter, it has been shown that index number plays a vital role in data gathering and the effective management (Ike & Lee, 2014). DEA requires accurate data compilation of both input and output variables to effectively measure the performance of any decision-making unit, i.e., upstream operator. The effectiveness or veracity of any DEA technique depends on quality and suitability of the different variables. Valuable data gathering during DEA is one of the main determinants of success. Once a particular data has problem, no amount of mathematical integration or differentiation can resolve the problem. In considering this, all the data used in this analysis were mean-normalized (Appendix B, B2).

The research data were obtained from Nigerian oil and gas sector's institutions such as DPR, NNPC, and MPR. The sorting of the data began with 81 upstream companies. About 49 operators were removed from the sample based on incomplete data or missing data, leaving a total of 32 companies used for the study. DEA models are very sensitive and, as much as possible, frantic efforts were made to ensure that the panel data used were balanced considering the years under review (Wolf, 2009; Eller, *et al*, 2011). The 49 inactive operators deleted from the sample had considerable total proved oil and gas reserves of about 6.885 Billion BOE which represents about 11% of the total BOE.

The designation of the status of the listed companies as inactive could be traced to financial problems and uncertainty surrounding the exploitation of oil and gas upstream business in

Nigeria and world generally. The likes of Aiteo petroleum, Yinka Folawiyo, Frontier, Network, Prime Energy and Universal Energy that were producing at the time of the study could not be captured in the analysis because there was virtually no data from 2010 to 2014 which could have made them suitable for investigation and analysis. These companies commenced active oil and gas production around 2014 having secured oil mining lease (OML) for over 10 years (NNPC, 2015). The active oil and gas companies within the period under review are as shown in Figure 3.2.

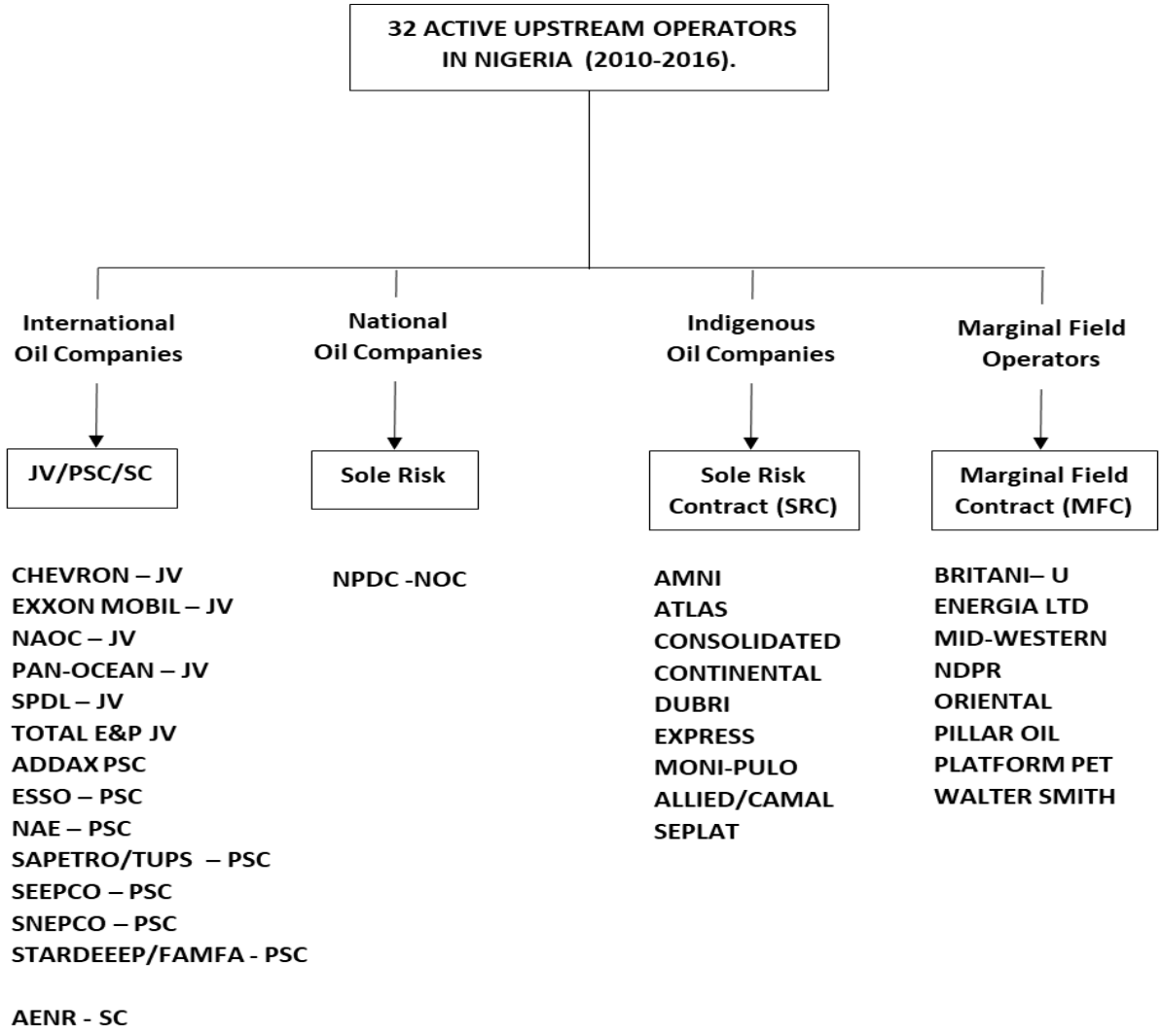

Figure 3.2: 32 Active Upstream Operators in Nigeria (2010-2016).

However, consistent efforts were made to ensure that the research data were compliant with the concept of DEA and that their sources were reliable. More emphasis was placed on human errors and outliers. All these precautions were considered before starting the actual DEA analysis. The two categories of data or variables that are very important when measuring efficiency and productivity of industry such as oil and gas are input variables and output variables. The data on prices of output variables are mostly important for allocative efficiency estimation purposes. Basically, production technology is seen as the transformation of a set of inputs into a set of output i.e. vector of input / vector of output. The study did not consider the output price variables for technical efficiency estimation; though a sensitivity analysis was conducted to ascertain the response of the technical efficiency to change in yearly average price of crude (Equation 3.10). This is also very important when using dual econometric models (Coelli et. al., 1994; OECD, 2001a). Table 3.1 shows the yearly average crude oil price from 2010 to 2016.

Table 3.1: Average Crude Oil Price (2010-2016)

Year	Average Oil Price ($/Bbl)
2010	77.38
2011	107.46
2012	109.45
2013	105.87
2014	96.29
2015	49.49
2016	40.68

Source: OPEC Oil Price History (2010-2016)

3.1.2 Upstream Petroleum Industry Output Measurement

The upstream oil and gas industry is generally profit oriented in nature, with local and international institutions participating. They mainly produce crude oil which they either sell into the international market or consume locally via downstream processes. Some oil and gas industries have their operations cutting across all the streams of oil and gas value chain which include Upstream, Mid-stream and Downstream (Denning & Freathy, 1996). It is not difficult to identify the output of oil and gas industry unlike that of servicing providing industry such as Universities, Consulting firms, etc. Upstream industry is an example of a single output or two-output industry which makes it a bit uncomplicated to investigate its technical efficiency using DEA.

The output of an upstream industry is typically measured in barrels of oil produced per year or day (BOPD); while that of gas is measured in standard cubic feet per year or day (scf/yr). The quality of the crude oil produced by Nigerian upstream operators is similar and is regarded as sweet crude; that is, having low Sulphur contents. There are six categories of operators in different terrains of the Nigerian oil producing regions as listed in chapter 2. These terrains are Swamp, Onshore, Offshore and Deep-Offshore produce crude oil based on international standard. The Nigerian upstream industry operates same market of single price like their international counterparts. A typical crude oil market responds to crude oil demand and supply fundamentals.

The total volume of oil produced by respective operator in millions of barrels per year is used in this research as the first output variable. The annual gross revenue of each operator was first considered as the second output variable but later replaced with their respective yearly gas production (Million scf per yr). The consideration of the gas volume produced per year as the second output variable was based on the fact that Nigeria is endowed with enormous proved

gas reserves of over 200 Trillion SCF (OPEC, 2017). The gas market has recently gained a tremendous popularity globally to an extent that each of the 32 active operators in Nigeria produces valuable volume of gas on daily basis. The outputs may be converted into operators' gross revenue using simple petroleum economics model in equation 3.1, (Iledare, 2008; Echendu, 2015; Adeogun *et al.,* 2015, 2018).

$$\text{Revenue} = \text{Production Volume X Oil Price} \quad \textbf{3.1}$$

3.1.3 Upstream Petroleum Industry Input Measurement

Petroleum reserves refer to the quantity of petroleum which is presumed or anticipated to be commercially recoverable under some degree of uncertainties. The uncertainties involved depend on the level of reliable geologic and engineering data available to the Geologist and the effectiveness of the technology deployed. Petroleum reserves can either be proved or unproved. Proved petroleum reserves are more certain to be recovered than the unproved petroleum reserves (Iledare, 2015). There are two approaches that could be used in proving petroleum reserves. These are the deterministic approach and the probabilistic approach. The deterministic approach is used when considering known geological, engineering and economic data while probabilistic approach is preferred when the range of estimates are associated with its different probabilities.

The input of the upstream petroleum industry could be classified into two, basically known in production economics as factors of production (Capital and Labour). This study considered the proved reserves of each of the operators as its capital base. The bottom line for every petroleum investment is how much oil or gas in place can be commercially produced using the available technologies within the contract terms. Investors are mainly concerned with the return on investments considering the volume of proved reserves in place. Petroleum economists use volumetric estimation to assess the available hydrocarbon in place prior to acquiring pressure

and production information for material balance technique. Information on oil and gas proved reserves for each of the 32 active operators was obtained from upstream division of the DPR and the Planning, Research & Statistic Department of the MPR

3.2 Petroleum Reserves Estimation

Reserves are quantitatively estimated using the relationships in equation 3.2 to 3.4: where $\mathbf{E_{UR}}$ is the estimated ultimate recovery and $\mathbf{N_P}$ represents the cumulative oil produced.

$$\text{Reserves} = E_{UR} - N_P \quad \textbf{3.2}$$

$$E_{UR} = N * E_R \quad \textbf{3.3}$$

$$\text{Reserves} = N*E_R - Np \quad \textbf{3.4}$$

$N =$ Initial Oil in Place , $E_R =$ Recovery Efficiency (Efficiency of a reservoir is highly affected by the reservoir geology and the type of drive mechanism).

The commonly used technique for estimating initial oil (N) and initial gas in place (G) are: volumetric methods, material balance method, pressure analysis method, decline analysis method and mathematical simulation method. The scope of this study did not include oil and gas reserve estimation. Based on this, the section is limited only to a review of the volumetric method of reserves estimation as shown in equation 3.5 through 3.6.

Note: N and G denote initial oil and initial gas in place, respectively.

$$N = \frac{7758Ah\emptyset\,(1-S_{wi})}{B_{oi}} \qquad \textbf{3.5}$$

$$G = \frac{7758Ah\emptyset\,(1-S_{gi})}{B_{gi}} \qquad \textbf{3.6}$$

The oil and gas reserves of each operator in BOE were used as a proxy for capital (input) because there was no data for each operator's total asset. Previous studies in this area have confirmed that petroleum reserves remain a valuable asset to most operators in the upstream petroleum sector (Ike & Lee, 2014). Equation 3.7 shows the simple mathematics of converting gas reserves into barrel of oil equivalent used in the analysis.

$$N = 1 \text{ Barrel of Oil Equivalent (1 BOE)} = 0.0001724 * \text{Standard Cubic Feet (SCF)} \qquad \textbf{3.7}$$

3.3 Input Variable-Oil and Gas Wells

Coelli *et al* (1994) argued that Labour and Capital are the most important input variables in production technology. Despite the fact that petroleum wells play a vital role in bringing the oil and gas reserves to the surface, very little attention is being devoted to its contribution. This could be attributed to the excitement derived as soon as the first crude oil is produced. Most oil and gas industry operators recognize the proved reserves volume and production volume without looking at the medium by which the reserves are being converted to production at the surface. In this study, the number of active petroleum wells drilled by each operator was used as a proxy as Labour input. This is partly due to the fact that it is extremely difficult to have access to the total number of employees engaged by each of the 32 active upstream operators.

However, it is adequately suitable to represent Labour input in oil and gas operations with the number of petroleum wells drilled. One of the best ways to measure Labour input is by using a single aggregate variable such as the number of employees, number of hours, total wages and salaries (Ike & Lee, 2014). The study classifies upstream petroleum wells into active and inactive wells. Active wells were wells that were producing while inactive wells were wells that had been shut-in either due to workover operations or other reasons. This study considered only active oil and gas wells as one of the input variables for all the operators.

The 49 inactive operators had a good number of inactive wells which were deleted from the sample to ensure effectiveness, consistency and accuracy of the results.

3.4 CRTS Model for Estimating Technical Efficiency-CRTSteindex

It has been stated earlier that the actual framework for both CRTSteindex and VRTSteindex measurements was introduced by Farrell in the year 1957 and later in 1994. The study by Farrell has up till today serves as the main backbone for the research carried out by the duo of Charnes, Cooper, and Rhodes (1978)-known as CCR-DEA Model (cDEA). The CCR (1978) modified the model formulated by Farrell to be suitable to estimate the CRTS technical efficiency index of company or organization that uses multiple inputs to generate multiple outputs. To do this, a linear mathematical model is formulated to create an efficient frontier for related DMUs thereby estimating its respective CRTS efficiency index.

There are two major limitations/assumptions of CRTS model;

1. It assumes constant return to scale.

2. It has strong inputs and outputs disposability and convexity of feasible data combination.

3.4.1 CRTS Primer Model

Equations 3.8a to 3.8d are commonly regarded as the primer linear programming model for constant return to scale (Seiford & Joe, 1999).

$$\phi^* = \min \phi \qquad \textbf{3.8a}$$

subject to

$$\sum_{j=1}^{n} \gamma_j \; q_{i,j} \quad \leq \phi \, q_{i,0}, \quad i = 1, 2, \cdots, m; \qquad \mathbf{3.8b}$$

$$\sum_{j=1}^{n} \gamma_j \; p_{r,j} \quad \geq p_{r,0}, \quad r = 1, 2, \cdots, s; \qquad \mathbf{3.8c}$$

$$\gamma_j \geq 0, \quad j = 1, 2, \cdots, n. \qquad \mathbf{3.8d}$$

It is wrong to use this model as stated above, since the interest of this research is to find out the technical performance of the respective operator regarding oil and gas production maximization. Hence, its dual model was formulated and engaged. According to Charnes et al., the CCR is a measure of relative efficiency of DMUs that are performing same operations. It is derived as the maximum of the sum of the ratio of weighted outputs to that of the weighted inputs, subject to the condition that akin ratios for each DMU is less than or equal to unity, (3.9a – 3.9d).

3.4.2 CRTS Fractional Model

Fractional CRTS model is given as show in equation 3.9a – 3.9d

$$\mathrm{CRTS}_{\mathrm{teindex}} = \frac{\text{sum of weighted outputs}}{\text{sum of weighted Inputs}} \qquad \mathbf{3.9a}$$

$$\mathrm{CRTS}_{\mathrm{teindex}} = max\ \frac{\sum_{r=1}^{s} b_r\ p_{r,0}}{\sum_{i=1}^{m} a_i\ q_{i,0}} \qquad \mathbf{3.9b}$$

subject to

$$\frac{\sum_{r=1}^{s} b_r\ p_{r,j}}{\sum_{i=1}^{m} a_i\ q_{i,j}} \leq 1 \qquad \mathbf{3.9c}$$

$$a_i,\ \ b_r \geq 0, \qquad r\ =\ 1, 2, \cdots s, \qquad i\ =\ 1, 2, \cdots, m, \qquad p_{r,j}, q_{i,j}\ \ \geq 1. \qquad \mathbf{3.9d}$$

The CRTS output oriented (dual) model was adopted in phase one to construct a non-parametric data envelopment frontier over observed data points which lie above or below the production frontier. The equations are further converted to linear programming form as stated below also known as output maximization model.

3.4.3 CRTS Dual Model

$$\mathrm{CRTS}_{\mathrm{teindex}} = \max \sum_{\mathrm{r=1}}^{\mathrm{s}} \mathrm{b_r}\ \ \mathrm{p_{r,0}} \qquad objective\ function \qquad \mathbf{3.10}\boldsymbol{a}$$

subject to

$$\sum_{\mathrm{r=1}}^{\mathrm{s}} \mathrm{b_r}\ \ \mathrm{p_{r,j}}\ \ - \sum_{\mathrm{i=1}}^{\mathrm{m}} \mathrm{a_i}\ \ \mathrm{q_{i,j}}\ \ \leq 0, \qquad \mathbf{3.10b}$$

$$\sum_{\mathrm{i=1}}^{\mathrm{m}} \mathrm{a_i}\ \ \mathrm{q_{i,0}} = 1 \qquad \mathbf{3.10c}$$

$$\mathrm{a_i},\ \ \mathrm{b_r} \geq 0\ , \qquad \mathrm{r}\ =\ 1, 2, \cdots \mathrm{s}, \qquad \mathrm{i}\ =\ 1, 2, \cdots, \mathrm{m}. \qquad \mathbf{3.10d}$$

The optimal solution to this linear programming problem is (a^*, b^*) and is obtained in a sequence of optimal weights for DMU_0. The above LP equation (3.10a-3.10d) for CRTSteindex estimation could be rewritten as stated below for a reference operator 1 (CNL) based on the research sample. That is, considering two input variables and two output variables for all the 32 active upstream operators in Nigeria within the period. To estimate CRTSteindex for each of the operators, 32 different models are required. Any of the upstream operators, irrespective of the category is believed to be CRTS efficient if and only if $CRTS_{teindex}$= 1. To evaluate output oriented CRTSteindex for Chevron Nigeria Limited (CNL); CNL is the first operator in the research sample list of 32 operators. The stated below model is estimated for CRTSteindex, (Appendix A2, B2, B3).

$$max\left(b_1\, p_{1,1} + b_2\, p_{2,1}\right) = \mathrm{CRTSteindex} \qquad \mathbf{3.11a}$$

subject to

$$b_1\, p_{1,1} + b_2\, p_{2,1} - (a_1\, q_{1,1} + a_2\, q_{2,1}) \leq 0, \qquad \mathbf{3.11b}$$

$$b_1\, p_{1,2} + b_2\, p_{2,2} - (a_1\, q_{1,2} + a_2\, q_{2,2}) \leq 0, \qquad \mathbf{3.11c}$$

$$\vdots \qquad \vdots \qquad \vdots$$

$$b_1\, p_{1,32} + b_2\, p_{2,32} - (a_1\, q_{1,32} + a_2\, q_{2,32}) \leq 0, \qquad \mathbf{3.11d}$$

$$a_1\, q_{1,1} + a_2\, q_{2,1} = 1, \qquad \mathbf{3.11e}$$

$$a_i,\ b_r \geq 0\,, \qquad r = 1, 2. \qquad \mathbf{3.11f}$$

The above equations (3.11a - 3.11f)) are solved to estimate the CRTSteindex for all the 32 operators relatively using Microsoft excel add-in solver aided with VBA to ensure the indexes

are generated simultaneously (Proudlove, 2000). The study avoided the rigorous task of solving each of the 32 models manually, hence, the use of a VBA. DEAP software was used to benchmark the results to ensure consistency with the Microsoft Excel results (Appendix B3, C)

3.5 VRTS Model for Estimating Technical Efficiency-VRTSteindex

Banker, Charnes, and Cooper (1984)-BCC adopts variable return to scale model unlike the study conducted by CCR in phase one which assumes CRTS. The CRTS model assumes a situation where all operators conduct their businesses or operating at an optimal scale, that is, operator output is directly proportional to its input. The assumption of CCR is not always valid or very difficult to achieve because there are some cases where a company may operate less due to constraints such as finance, operational terrain, insecurity and competition. Considering this observation, the study engaged BCC-VRTS DEA output oriented (dual) model. VRTS model is an extension of CCR-CRTS model, the only difference is that VRTS model incorporates variable return to scale scenarios. This is done to avoid measuring TEs which are muddled with scale efficiency problem or errors (Seiford & Zhu, 1999).

VRTS model assumes operational variability unlike CRTS model. The variability could be due to constraints such as project financing, competition among the operators, government policies, different operational terrains, insecurity, political instability etc. All things being equal, VRTS model takes changes into consideration. One of those considerations is the competition that exists among the upstream industry's operators (Amy Shuen, 2014). The E & P Companies fall within the oil and gas companies that take the highest risk. They invest significant amount of capital to drill for crude oil based on geological information. Investors focus is fundamentally on sustainable return on investments while that of NOC is host government's prerogatives. Each of the operators in the sample competes directly or indirectly with one

another for different purposes which may include Oil blocks, Licenses, Data, Permits, Technology, etc.

Apart from the above, the insecurity situation in the Niger Delta region where Nigeria's oil and gas are found in abundance may make a particular operator outputs not to be directly proportional to the inputs. The Niger Delta militant groups had been involved in wanton destruction of oil and gas installations in the region and this has made the production cost per barrel to increase tremendously as stated earlier. Subsequent efforts had been put in place by the Government to adjudicate the challenges faced, hence the commencement of the Amnesty programme in 2008. Upstream oil and gas projects are highly capital intensive internationally, sourcing funds to finance projects faced serious limitations (Osagie and Ehigiato, 2015).

The problems faced in seeking project funding may have negative effects on the performances of operators if adequate measures are not put in place. Also, politics involved in seeking management positions in most oil and gas companies could constitute a threat to their performances. The NNPC was governed by almost five Group Managing Directors (GMDs) within the pace of seven years covering the period of our estimation. This happened as a result of political instability in the country and other governance related challenges. All these factors favour the assumption of a situation where a certain company may operate under different type of production scale such as DRTS, IRTS, CRTS.

3.5.1 VRTS Primer Model

The primal linear programming equations for VRTS-DEA model is given in equation 3.12a to 3.12e:

$$\phi^* = \min \phi \qquad \mathbf{3.12a}$$

subject to

$$\sum_{j=1}^{n} \gamma_j \; q_{i,j} \quad \leq \phi \, q_{i,0}, \quad i = 1, 2, \cdots, m; \qquad \mathbf{3.12b}$$

$$\sum_{j=1}^{n} \gamma_j \; q_{r,j} \quad \geq p_{r,0}, \quad r = 1, 2, \cdots, s; \qquad \mathbf{3.12c}$$

$$\sum_{j=1}^{n} \gamma_j \; = 1 \qquad \mathbf{3.12d}$$

$$\gamma_j \geq 0, \quad j = 1, 2, \cdots, n. \qquad \mathbf{3.12e}$$

The dual of the above VRTS minimization model was used to estimate TEs for all the 32 active upstream operators in Nigeria. The study declined from using the above model (equation 3.12a to 3.12e) because it is odd to talk about minimizing input variable such as reserves and wells. Basically, the dual model is derived from the fractional model stated below:

3.5.2 VRTS Fractional Model

The fractional version of the VRTS model is given as

$$\mathrm{VRTS}_{\mathrm{teindex}} = \frac{\text{Sum of weighted outputs}}{\text{sum of weighted inputs}} \qquad \mathbf{3.13a}$$

$$\mathrm{VRTS}_{\mathrm{teindex}} = max \; \frac{\sum_{r=1}^{s} b_r \, p_{r,0} + Z_0}{\sum_{i=1}^{m} a_i \, q_{i,0}} \qquad \mathbf{3.13b}$$

subject to:

$$\frac{\sum_{r=1}^{s} b_r \, p_{r,j} \; + Z_0}{\sum_{i=1}^{m} a_i \, q_{i,j}} \; \leq 1 \qquad \mathbf{3.13c}$$

$$b_r \geq 0, \qquad r = 1, 2, \cdots s, \qquad i = 1, 2, \cdots, m, \qquad Z_0 \; is \; unrestricted \; in \; sign \qquad \mathbf{3.13d}$$

3.5.3 VRTS Dual Model

To derive the linear VRTS model, $\sum_{i=1}^{m} a_i \, q_{i,0}$ is set at 1, i.e.

$$\sum_{i=1}^{m} a_i \, q_{i,0} = 1. \qquad \mathbf{3.14a}$$

Under the assumption above, equation 3.14b, objective function, was arrived at

$$\mathrm{VRTS}_{\mathrm{teindex}} = max \sum_{r=1}^{s} b_r \; p_{r,0} + Z_0 \qquad objective \; function \qquad \mathbf{3.14b}$$

subject to:

$$\sum_{r=1}^{s} b_r \; p_{r,j} \; - \sum_{i=1}^{m} a_i \; q_{i,j} + Z_0 \; \leq 0 \qquad \mathbf{3.14c}$$

$$\sum_{i=1}^{m} a_i \; q_{i,0} = 1 \qquad \mathbf{3.14d}$$

$$a_i, \; b_r \geq 0 \qquad \mathbf{3.14e}$$

$$r = 1, 2, \cdots s, \qquad i = 1, 2, \cdots, m \quad and \;\; Z_0 \; is \; free \qquad \mathbf{3.14f}$$

Any of the upstream operators, irrespective of the category was believed to be VRTS efficient if and only if $\mathrm{VRTSteindex} = 1$

The VRTS model ensures that a convex hull of intersecting planes envelopes the data points better compared to CRTS model. It provides more accurate TE Indexes which are greater than or equal to that of CRTS model. This is referred herein, as VRTS$\mathrm{teindex}$. The study attempted to estimate scale efficiency (SE) relying on the fact that the results obtained by decomposing

CRTS TEI had two components of inefficiencies: Inefficiencies due to scale and the pure technical inefficiency. To confirm this, the results gotten from phase one (CRTS estimation) and phase two (VRTS estimation) are compared to ascertain variation. Where an operator gives two different TE results when subjected to the two phases, it is an indication that such operator has what is regarded as scale inefficiency. It is evaluated by subtracting one TE $_{\text{Index}}$ from the other (i.e. CRTSteindex - VRTSteindex).

Notwithstanding the fact that the study was not actually interested in estimating scale efficiency for all the operators, but considering the main reason that the VRTSteindex, is a combination of the three types of return to scale: increasing return to scale (IRTS), decreasing return to scale (DRTS) and constant return to scale (CRTS). Based on the above models' descriptions, i.e., CRTS model & VRTS model, it is quite apparent that the major difference between the two models is the imposition of convexity restriction (free variable-Z_o) on the CRTS model shown, (equation 3.14a – 3.14f)

To be able to identify the RTS behavior (CRTS, IRST or DRTS) of each of the 32 active upstream operators in the sample, the research uses the proposition 2. Seiford and Zhu (1999) proposed that if an operator (DMU) is CRTS efficient then it is VRTS efficient. The convexity restriction imposes on VRTS model, i.e., $\sum_{j=1}^{n} \boldsymbol{\lambda_j} = \mathbf{1}$ in the primer model is repeated on the CRTS model, i.e., $\sum_{j=1}^{n} \boldsymbol{\lambda_j} \leq \mathbf{1}$, to obtain the LP formulation to differentiate the different categories of RTS.

Any of the upstream operators, irrespective of the category is believed to be VRTS efficient if and only if VRTS$\text{teindex} = 1$; the model stated below is solved to estimate the VRTSteindex for all the 32 operators, relatively. Microsoft excel add-in solver aided with a VBA was used to ensure the indexes were generated simultaneously as used in phase one. DEAP software was also used to benchmark the results to ensure consistency with those generated manually using

a Microsoft excel spreadsheet. The above model in equation 3.14a to 3.14e which was used to estimate VRTSteindex could be rewritten as below for a reference operator 1 (CNL-Chevron) based on the research data, that is, two input variables and two output variables for all the 32 active upstream operators. To evaluate output oriented VRTSteindex for CNL which is the first operator in the sample, the model stated below is estimated:

$$max\left(b_1\, p_{1,1} + b_2\, p_{2,1}\right) + Z_0 = \text{VRTSteindex} \quad \text{Objective function} \qquad \mathbf{3.15a}$$

subject to

$$b_1\, p_{1,1} + b_2\, p_{2,1} - (a_1\, q_{1,1} + a_2\, q_{2,1}) + Z_0 \leq 0 \qquad \mathbf{3.15b}$$

$$b_1\, p_{1,2} + b_2\, p_{2,2} - (a_1\, q_{1,2} + a_2\, q_{2,2}) + Z_0 \leq 0 \qquad \mathbf{3.15c}$$

$$\vdots \qquad \vdots \qquad \vdots \; \vdots \qquad \vdots$$

$$b_1\, p_{1,32} + b_2\, p_{2,32} - (a_1\, q_{1,32} + a_2\, q_{2,32}) + Z_0 \leq 0 \qquad \mathbf{3.15d}$$

$$a_1\, q_{1,1} + a_2\, q_{2,1} = 1 \qquad \mathbf{3.15e}$$

$$a_i,\ b_r \geq 0\,, \qquad r = 1,2 \ \ and\ \ Z_0\ \ is\ free \qquad \mathbf{3.15f}$$

3.6 NIRTS Model for Estimating Return to Scale index-RTSindex

To categorize each of the 32 active operators to its respective return to scale status, there is a need to use a new model called Non-Increasing Return to Scale Model (NIRTS), (see Lawrence and Zhu, 1999). It may be difficult to categorize each of the operators using the scale ratio. Hence, the theorem below becomes useful:

Theorem 1 If $CRTSteindex = VRTSteindex$ then operator exhibits CRTS. If $VRTSteindex > RTSindex$ then operator exhibits IRTS; otherwise, if $VRTSteindex = RTSindex$ for a particular operator, then such operator is believed to exhibit DRTS, (Seldolf & Zhu, 1999).

3.6.1 NIRTS Primal Model

The primal linear programming for the linear model is given as:

$$\psi^* = \min \psi \qquad \mathbf{3.16a}$$

subject to:

$$\sum_{j=1}^{n} \gamma_j \; q_{i,j} \quad \leq \psi \, q_{i,0}, \quad i = 1, 2, \cdots, m; \qquad \mathbf{3.16}\boldsymbol{b}$$

$$\sum_{j=1}^{n} \gamma_j \; p_{r,j} \quad \leq p_{r,0}, \quad r = 1, 2, \cdots, s; \qquad \mathbf{3.16c}$$

$$\sum_{j=1}^{n} \gamma_j \quad \leq 1 \qquad \mathbf{3.16d}$$

$$\gamma_j \geq 0, \quad j = 1, 2, \cdots, n \qquad \mathbf{3.16e}$$

In order to apply the NIRTS model, VRTS$teindex$ and CRTS$teindex$ are tabulated and compared. Theorem 1 then sorts each operator to either of the following: IRTS, DRTS or CRTS. The above (3.16a- 3.16e) primal minimization problem was converted to its dual form for the sake of maximizing the oil and gas production. Fundamentally, the dual model is usually obtained from the fractional version as stated below.

3.6.2 NIRTS Fractional Model

The fractional model of the NIRS is given as:

$$\mathrm{RTS}_{\mathrm{teindex}} = \frac{\text{sum of weighted outputs}}{\text{sum of weighted Inputs}} \qquad \mathbf{3.17a}$$

$$\mathrm{RTS}_{\mathrm{index}} = max\ \frac{\sum_{r=1}^{s} b_r\ p_{r,0} - Z_0}{\sum_{i=1}^{m} a_i\ q_{i,0}} \qquad \mathbf{3.17b}$$

subject to

$$\frac{\sum_{r=1}^{s} b_r\ p_{r,j} - Z_0}{\sum_{i=1}^{m} a_i\ q_{i,j}} \leq 1 \qquad \mathbf{3.17c}$$

$$a_i,\ \ b_r, Z_0 \geq 0, \qquad r\ =\ 1, 2, \cdots s, \qquad i\ =\ 1, 2, \cdots, m \qquad \mathbf{3.17d}$$

3.6.3 NIRTS Dual Model

The dual linear programming problem is then given as, (equation 3.18a-3.18d)

$$\mathrm{RTS}_{\mathrm{index}} = max \sum_{r=1}^{s} b_r\ \ p_{r,0} - Z_0 \qquad objective\ function \qquad \mathbf{3.18a}$$

subject to

$$\sum_{r=1}^{s} b_r\ \ p_{r,j}\ \ - \sum_{i=1}^{m} a_i\ \ q_{i,j} - Z_0\ \leq 0 \qquad \mathbf{3.18b}$$

$$\sum_{i=1}^{m} a_i\ \ \ q_{i,0} = 1 \qquad \mathbf{3.18c}$$

$$a_i,\ \ b_r, Z_0 \geq 0, \qquad r\ =\ 1, 2, \cdots s, \qquad i\ =\ 1, 2, \cdots, m \qquad \mathbf{3.18d}$$

The following propositions from Seiford and Zhu (1999) become useful

Proposition 1: At least one operator is CRTS efficient.

Proposition 2: If an operator is CRTS efficient then it is VRTS efficient.

Proposition 3: The efficient production frontier derived from the CRTS model results to CRTS.

Proposition 4: The efficient production frontier derived from the VRTS model results to three main frontiers as stated, i.e., IRTS, CRTS and DRTS.

To classify CNL, which is the first operator in the sample; into its production frontiers, i.e., IRTS, CRTS or DRTS, the stated NIRTS models were estimated:

$$max\left(b_1\, p_{1,0} + b_2\, p_{2,0}\right) - Z_0 = \mathrm{RTS}_{\mathrm{index}} \qquad \textbf{3.19a}$$

subject

$$b_1\, p_{1,1} + b_2\, p_{2,1} - \left(a_1\, q_{1,1} + a_2\, q_{2,1}\right) - Z_0 \leq 0 \qquad \textbf{3.19b}$$

$$b_1\, p_{1,2} + b_2\, p_{2,2} - \left(a_1\, q_{1,2} + a_2\, q_{2,2}\right) - Z_0 \leq 0 \qquad \textbf{3.19c}$$

$$\vdots \qquad \vdots \qquad \vdots\,\vdots \qquad \vdots$$

$$b_1\, p_{1,32} + b_2\, p_{2,32} - \left(a_1\, q_{1,32} + a_2\, q_{2,32}\right) - Z_0 \leq 0 \qquad \textbf{3.19d}$$

$$a_1\, q_{1,0} + a_2\, q_{2,0} = 1 \qquad \textbf{3.19e}$$

$$a_i,\ b_r, Z_0 \geq 0,\ r = 1, 2, \cdots s,\ i = 1, 2, \cdots, m \qquad \textbf{3.19f}$$

One of the major differences between the VRTS model and NIRTS model is that the free variable is subtracted in NIRTS instead of being added. Also, it is conditioned to be greater than or equal to zero, i.e. $Z_0 \geq 0$.

3.7 Economic Analysis Using Panel Data Estimation

The fourth objective of this study examined the impact of some exogenous variables on the TE estimated using CRTS Model (CRTSteindexes) and TE estimated using VRTS Model (VRTSteindexes). It will be recalled that the developed CRTS model, VRTS model and NIRTS model were estimated in stages 1, 2 and 3 of the study to generate various technical efficiency indexes for all the operators in the sample from 2010 to 2016. To carry out the economic analysis in the fourth stage of the study, the estimated CRTSteindexes and VRTSteindexes in stages 1 and 2 were used as dependent variables. The indexes generated previously depict the real nature of global upstream investments considering ideal and unideal conditions of operations. It is a known fact that that oil and gas projects are highly capital intensive, hence,

most investors would be ready to go additional miles to ensure returns on their huge investments.

The exogenous factors which also referred to as explanatory variables or independent variables in the succeeding sections of this chapter are:

1. Gross taxes paid per year by each operator as a proxy for upstream policy (4.11$/bbl.)
2. World crude oil demand per year (WCOD) as reported by Statista in million barrels per year (MMBBL/YR)
3. Operator's experience (OEXP) based on the date of first oil mining lease (years)
4. Proved gas reserves to production ratio (RPGas) direct calculation
5. Proved oil reserves to production ratio (RPOil) direct calculation

Gross Tax: The study considered the gross tax paid by each of the operators as a proxy for upstream regulation. This was done considering the fact that oil and gas taxes are highly regulated by the respective producing host government internationally. These taxes in most cases include Royalty tax, Niger Delta Development Commission tax (NDDCT), National Hydrocarbon Tax (NHT), Company's Income Tax (CIT), Petroleum Profit Tax (PPT), etc. Upstream Taxes are very important upstream regulatory instruments as stipulated by the Nigeria Petroleum Fiscal Act (1969) as amended. Royalty tax is an agreed percentage of gross revenue that is paid to the host government by the investor and it could be in cash or in kind. Royalty represents the cost of doing business in the locality. It could be constant percentage which is also called a fixed percentage or sliding scale. The royalty payment is scaled primarily to account for uncertainties due to geology, economics and engineering. The sliding scales may be tied to well productivity (R-Factor), well/field/cumulative production, crude oil price, water depth and some projects economics measures (Mian, 2011; Echendu *et al*, 2015).

Odesola (2006) noted that PPT is the most important tax in Nigeria when it comes to revenue sharing between the host government and the contractors. Taxation based on profit is regarded as non-regressive because it shows the willingness of the host government to share the impending risk with the investors. Other taxes in this category include Corporate Income Tax and other crypto taxes. The administration of PPT is governed by the Petroleum Profit Tax Act of 1959 (amended in 2007) (Adekanola, 2007; Nwadighoha, 2007; Leyira, Ofurum and Ihendinihu, 2012). Taxation in the oil and gas upstream industry is mainly about rent sharing between the host and the investors. The gross tax paid belongs to the host government and is only part of the total revenue especially in production sharing contracts. PSC accommodates subsequent sharing of the profit oil between the two partners. To estimate operators' gross tax paid per year, the study pegs the total tax paid within the period of the estimation to 4.11$ per barrel, (Rystad Energy Ucube, 2016). Table 3.2 shows the cost breakdown of oil production in Nigeria in 2006.

Table 3.2: Cost Breakdown of Oil Production in Nigeria (2006)

S/N	Cost Items	Cost / Barrel ($/Barrel))	Percentage
1	Capital Spending	13.1	45.2
2	Production Cost	8.81	30.4
3	Admin / Transport Cost	2.97	10.2
4	Gross Taxes	4.11	14.2
Total Cost per barrel		**28.99**	**100**

Source: 2016 Wall Street Journal Report

International Crude Oil Demand: Although, economic theory does not provide a theoretical model for the determinants of efficiency, variations in petroleum demand (which can be expanding, stable or declining) have been pointed out as one of the factors that may influence the efficiency of a petroleum industry. Perelman (1995) stated that increase in demand can be

seen as an economic opportunity for a firm to carry out projects or develop new products (or production processes), which would improve the firm's efficiency. By implication, as the world oil demand increases, upstream operators in the petroleum industry will increase production maintaining the least cost of production possible as a result of the higher degree of utilization of the productive capacity. Therefore, a positive relationship is expected to exist between relative TE and the demand for oil and gas.

It is expected that increase in the world crude oil demand will have a corresponding positive effect on the technical efficiency of the upstream operators individually. This is due to the fact that operators tend to produce more in order to have speedy returns on investments, especially in the era of high crude oil demand (Iledare & Olatubi, 2006).

Operator's Experience (OEXP): The experience of a company is defined as number of years that the company has operated in Nigeria. The study estimated the number of years of each operator's experience right from the day the first OML was issued. The assumption is that the more the age of a company, the better its exposure to technological innovations, operation challenges and the more the number of experienced staffs in the pool. A company output is a function of its manpower, and learning capacity is a function of related accumulated knowledge. To have access to data on the experience of each of the companies, each company's websites were visited and each company's year of signing the first Oil Prospecting License (OPL)/Oil Mining Lease (OML) was recorded as one of the independent variables.

Reserves to Production Ratio: Oil and Gas reserves to production ratios are used widely for the assessment of the resources' depletion point or year. The ratio gives information on the number of years by which the current reserves can sustain the current level of oil and gas production. Based on this, the study considered the ratio to be one of the critical variables that might have a significant effect on the technical efficiency of the operators. The R/P ratio

magnitude has an inverse relationship with the well production rate. While production rate on the other hands depends on the geological properties of the source rock as well as well inflow performance (WIP), the Oil and gas field development stages also play an important role in relation to the magnitude of R/P ratio. Reserves to production ratio of oil and gas have inverse relationship with the estimated TE.

To carry out the economic analysis, the research employed a panel data analysis to establish the effects of these exogenous factors on the CRTSteindexes and VRTSteindexes of the operators. The panel data comprises cross sectional unit sample of six categories of the upstream firm based on the nature of their contracts, namely IOC-JV, IOC-PSC, IOC-SC, IndOCs-Sole Risk, NOC, and MFCs covering a time period of seven years between 2010 and 2016. According to Baltagi (2005), panel data controls for individual heterogeneity, less collinearity among variables and has capacity to track trends in the data which is impossible for both time-series or cross-sectional data. Besides, more degrees of freedom and efficiency can be achieved with panel data (Gujarati & Porter, 2009).

Fundamentally, panel data sets are broadly categorized into: Balanced Panel data and Unbalanced Panel data. The balanced panel is also referred to as complete panel, is a situation where all the cross-sectional units have equal time series dimension. The unbalanced panel on the other hand refers to situations where the cross-sectional units have unequal time dimensions. This may be due to missing observations, which make some cross-sectional units to have complete information over the specified period while others have incomplete periods. This is practically the case in longitudinal data sets of dimensions where the exit or death of one or more individuals in a survey creates some missing observations for the affected cross-sectional units.

Balanced or unbalanced panel data sets can either be micro-based or macro-based depending on the period. When large cross-sectional units (micro economic agent) are surveyed over a short period (not more than 20 years), such panel data are referred to as micro panels. Conversely, large cross-sectional units are surveyed over a considerable period (exceeding 20-year time periods), and are thus regarded as macro panels. As a result of the nature of time series dimension of both micro and macro panels, they attract different treatments in empirical research. When dealing with macro panels usually involving a cross-section of countries, the problem of cross-sectional dependence and that of unit root (i.e., non-stationarity) must be addressed, otherwise the results will be inefficient and biased. Such challenges do not arise with micro panels under consideration.

3.7.1 Panel Data Models

Panel data models are divided into Static Panel Models (equation 3.20) and Dynamic Panel Models (equation 3.21) as shown in Figure 3.3. The dynamic panel model is easily differentiated from the static panel model by the inclusion of the lagged dependent variable in the dynamic panel. The models are expressed below as:

$$Y_{it} = \alpha + \sum_{k=1}^{n} \beta_k X_{kit} + \mu_{it} \quad k = 1, \dots, N \dots\dots 3 \qquad \mathbf{3.20}$$

$$Y_{it} = \alpha + Y_{it-1} + \sum_{k=1}^{n} \beta_k X_{kit} + \mu_{it} \quad k = 1, \dots, N \dots 3 \qquad \mathbf{3.21}$$

where $\mathbf{Y_{it}}$ represents dependent variables; subscript (**i**) denotes the cross-sectional unit and (**t**) represents the time-series dimension; ($\mathbf{Y_{it-1}}$) is the lagged dependent variable, ($\mathbf{X_{it}}$) is a vector of explanatory variables for upstream operator (**i**) in time **t**; **α** is constant; **β** are coefficients,

which captures the impact of the explanatory variables on the explained variable and $\boldsymbol{\mu_{it}}$ is the idiosyncratic disturbance term, which can be decomposed further into specific effects and specific error term.

3.7.2 Estimation of Panel Data Models

The static panel model can be estimated using common constant method-CCM (pooled OLS), Fixed Effects-FE and Random Effects-RE. Each of these methods has its underlying assumptions, which must be satisfied in order to obtain unbiased and efficient estimates. Each of these methods with its underlying assumptions can be explained ~~as~~ thus: CCM entails estimating the specified panel data model with Ordinary Least Square (OLS). The model assumes common constant and slope coefficient for all cross-sectional individual units and time. Thus, it is a case of restricted regression and a pooled OLS regression may be used to fit the model, treating all the observations for all of the time periods as a single sample. However, ignoring these effects when, in fact, they are significant yields inefficient estimates and biased standard errors.

3.7.2.1 Fixed Effects Method (FE)

The FE approach is used to capture specific effects in a panel data model. This method is based on the assumption that the effects are fixed parameters that can be estimated. Consequently, a number of econometric problems may be encountered. One, some of the explanatory variable may be correlated with specific disturbance term that affects the dependent variable. Two, the unobserved specific fixed effects may be correlated with the explanatory variables. Three, there is possibility of simultaneity biases resulting from the endogeneity of some explanatory variables. The FE model can address these challenges by using any of the

three estimation methods of First Difference (FD) Estimator, Within Group (WG) Estimator; and Least Square Dummy Variable (LSDV) Estimator.

The FD Estimator involves taking the first difference of the modified panel data model to eliminate the unobserved effects. The WG estimator involves the deviation approach which eliminates the unobserved effects. The LSDV estimator however involves the inclusion of dummy variables as independent variables in the panel data model to capture the specific effects. In this case, either the intercept or one of the dummy variables must be dropped to avoid perfect collinearity or dummy trap problem. The specification in respect of these estimation techniques for fixed effects is expressed in equation 3.22-3.27.

First Difference Regression

$$Y_{it} - Y_{it-1} = \alpha + \sum_{k=1}^{N} \beta_k (X_{kit} - X_{it-1}) + (\mu_{it} - \mu_{it-1}) \qquad \mathbf{3.22}$$

Within Group Regression

$$Y_{it} - \overline{Y}_i = \alpha + \sum_{k=1}^{N} \beta_k (X_{kit} - \overline{X}_{it-1}) + (\mu_{it} - \mu_i) \qquad \mathbf{3.23}$$

Least Square Dummy Variable Regression

$$Y_{it} = \alpha + \sum_{k=1}^{N} \beta_k X_{it} + \sum_{i=2}^{J} \varphi_i D_i + \mu_i \qquad \mathbf{3.24}$$

Alternatively

$$Y_{it} = \sum_{k=1}^{N} \beta_k X_{it} + \sum_{i=1}^{J} \varphi_i D_i + \mu_i + .. \qquad \mathbf{3.25}$$

To confirm whether the specific effects estimated are actually fixed effects, the F-test is used in this regard.

$$F = \frac{R^2{}_{UR} - R^2{}_{U}/_{m}}{(1 - R^2{}_{UR})/(N - K)} \quad \mathbf{3.26}$$

The null hypothesis for this test is given as:

$$\mathrm{H0}: \mu_1 = \mu_2 = 0 \quad \mathbf{3.27}$$

The null hypothesis when the F-statistic is statistically significant, thus suggesting that the fixed effects are important in the model. Otherwise, it is not rejected, thus employing the common constant model (pooled OLS estimator).

3.7.2.2 Random Effects Method (REM)

An alternative to the fixed effect method is the random effect method. The basic limitation of fixed effects method is that there is usually a high loss of degrees of freedom when there are too many parameters to be estimated due to large cross-sectional units. This high loss of degrees of freedom can be prevented if the cross-sectional units can be assumed random. Thus, the basic assumption of the REM is that the specific units are independent of both the specific effects specific disturbance term and the explanatory variables are independent of both the specific effects and the specific disturbance term. Thus, random effects model assumes exogeneity of all regressors, see equation 3.28-3.29.

$$\mathrm{Y_{it}} - \theta\overline{\mathrm{Y}}_{\mathrm{i}} = \sum_{\mathrm{k=1}}^{\mathrm{N}} \beta_{\mathrm{k}}(\mathrm{X_{kit}} - \theta\overline{\mathrm{X}}_{\mathrm{ki}}) + (\mu_{\mathrm{it}} - \theta\overline{\mu}_{\mathrm{i}}) \quad \mathbf{3.28}$$

Where:

$$\theta = 1 - \frac{\sigma^2{}_\mu}{T\sigma^2{}_\mu + \sigma^2{}_\mu} \qquad \mathbf{3.29}$$

To confirm whether the specific effects estimated are actually random effects and are uncorrelated with the regressors, we carry out the Hausman test. The rejection of the null hypothesis (when the statistic is statistically significant) implies an adoption of the fixed effects model and non-rejection is considered as an adoption of the random effects model. The rejection of the null hypothesis also implies correlated specific effects are better captured with fixed effects model.

Following from the forgoing, the panel data were analyzed using descriptive statistics, correlations, multiple linear regression and inferential statistics. Mean values and standard deviations were used to analyze the general trends of the panel data. Correlation matrix was used to examine the relationship between the explained variable and explanatory variables. A multiple linear regression model and t-static were used to determine the relative importance of each independent variable in influencing Technical Efficiency (TE). A high coefficient of determination with a significant F-statistic was aimed at indicating objectivity. E-view econometric software package version 9 was used to analyze the panel data. To determine the effect of exogenous factors on CRTSteindexes and VRTSteindexes of upstream Nigeria oil and gas operators, the following general multivariate regression equations were used:

$$\mathrm{cDEA_{it}} = \alpha + \beta_1 \mathrm{logWCOD_{it}} + \beta_2 \mathrm{logRPOIL_{it}} + \beta_3 \mathrm{logRPGAS_{it}} + \beta_4 \mathrm{logOEXP_{it}} + \beta_5 \mathrm{logGTAX_{it}} + \mu_{it} \qquad \mathbf{3.30}$$

$$\mathrm{vDEA_{it}} = \alpha + \beta_1 \mathrm{logWCOD_{it}} + \beta_2 \mathrm{logRPOIL_{it}} + \beta_3 \mathrm{logRPGAS_{it}} + \beta_4 \mathrm{logOEXP_{it}} + \beta_5 \mathrm{logGTAX_{it}} + \mu_{it} \qquad \mathbf{3.31}$$

$$\mu_{it} \sim \mathrm{iidN}\,(0, \sigma^2) \qquad \mathbf{3.32}$$

Where:

cDEA: Estimated Constant Returns to Scale Index

vDEA: Estimated Variable Returns to Scale Index

WCOD: World Crude Oil Demand

RPOIL: Reserve to Production-Oil

OEXP: Operator's Experience (Years)

GTAX: Gross Tax

μ: Composite error term

log: Logarithm

i: Cross-sectional entity

t: Time entity

α: Intercept

β_1, β_2, β_3, β_4, β_5 and β_6: Slope Parameters which captures effects of the explanatory variables on the explained variable, where *i* = 1, 2 ... 5 is the cross-sectional unit, t = 2010, 2011 ... 2016 is the time period.

3.8 *A priori* Expectation

A priori expectation defines the sign or magnitude of the parameters of the specified model, (equations 3.33–3.42). The *a priori* expectations were determined by using the principles of economic theory guiding the economic relationship of variables under study. It was expected

that the variables Regulation-Gross Taxes (Gtaxes), Gas Reserves to Production ratio (RPGas) and Oil reserves to production ratio (RPOil) should have an inverse or negative effect on both CRTSteindexes and VRTSteindexes. This would imply that an increase in the percentage or units of these explanatory variables would reduce efficiency indexes of the upstream operators. The World Crude Oil Demand (WCOD) and Upstream Operator's Age or Experience (OEXP) were expected to have a direct or positive effect on efficiency indexes of the operators. By implication, an increase in the two explanatory variables should increase efficiency indexes of the upstream operators in Nigeria. For our specified model of study, the *a priori* expectations are empirically expressed as below:

$$\frac{\partial CRTSteindex}{\partial GTax} = \beta_1 < 0 \qquad \textbf{3.33}$$

$$\frac{\partial VRTSteindex}{\partial GTax} = \lambda_1 < 0 \qquad \textbf{3.34}$$

$$\frac{\partial CRTSteindex}{\partial WCOD} = \beta_2 > 0 \qquad \textbf{3.35}$$

$$\frac{\partial VRTSteindex}{\partial WCOD} = \lambda_2 > 0 \qquad \textbf{3.36}$$

$$\frac{\partial CRTSteindex}{\partial OEXP} = \beta_3 > 0 \qquad \textbf{3.37}$$

$$\frac{\partial VRTSteindex}{\partial OEXP} = \lambda_3 > 0 \qquad \textbf{3.38}$$

$$\frac{\partial CRTSteindex}{\partial RPOil} = \beta_4 < 0 \qquad \textbf{3.39}$$

$$\frac{\partial VRTSteindex}{\partial RPOil} = \lambda_4 < 0 \quad \textbf{3.40}$$

$$\frac{\partial CRTSteindex}{\partial RPGas} = \beta_5 < 0 \quad \textbf{3.41}$$

$$\frac{\partial VRTSteindex}{\partial RPGas} = \lambda_5 < 0 \quad \textbf{3.42}$$

3.9 Hypothesis Testing

The hypotheses to be tested are expressed in their null form as:

For CRTSteindex

H_{01}: Gross tax (regulation) has no significant impact on the Estimated Constant Returns to Scale Index of upstream Operators in Nigeria.

H_{02}: World Crude Oil Demand has no significant impact on the Estimated Constant Returns to Scale Index of upstream Operators in Nigeria.

H_{03}: Operator's Experience has no significant impact on the Estimated Constant Returns to Scale Index of upstream Operators in Nigeria.

H_{04}: Reserve to Production-Oil has no significant impact on the Estimated Constant Returns to Scale Index of upstream Operators in Nigeria.

H_{05}: Reserve to Production-Gas has no significant impact on the Estimated Constant Returns to Scale Index of upstream Operators in Nigeria.

For VRTSteindex

H_{01}: Gross tax (regulation) has no significant impact on the Estimated Variable Returns to Scale Index of upstream Operators in Nigeria.

H_{02}: World Crude Oil Demand has no significant impact on the Estimated Variable Returns to Scale Index of upstream Operators in Nigeria.

H_{03}: Operator's Experience has no significant impact on the Estimated Variable Returns to Scale Index of upstream Operators in Nigeria.

H_{04}: Reserve to Production-Oil has no significant impact on the Estimated Variable Returns to Scale Index of upstream Operators in Nigeria.

H_{05}: Reserve to Production-Gas has no significant impact on the Estimated Variable Returns to Scale Index of upstream Operators in Nigeria.

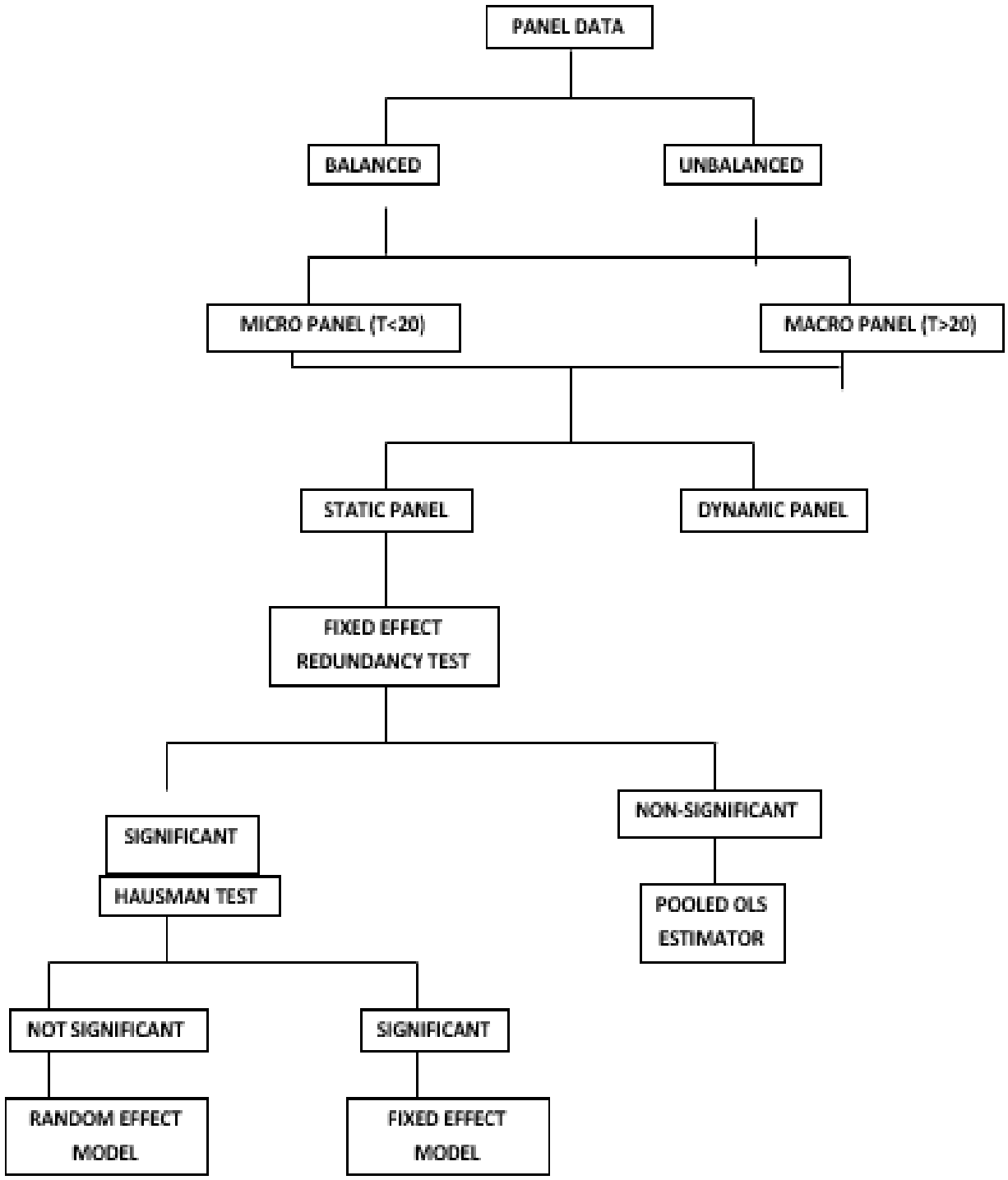

Figure 3.3: Schema Depicting the Structure and Estimators of the Panel Data

Chapter 4

4. DEA Results, Interpretations and Discussions

4.1 Overview

Chapter 4 presents and discusses the results of output oriented constant return to scale-DEA model (cDEA), output oriented variable return to scale-DEA model (vDEA) and output oriented Non-Increasing return to scale-DEA model-NIRTSM (RTS Model). The section begins with the statistical description of input and output variables used for the technical efficiency analysis, i.e., CRTS technical efficiency index estimation (CRTSteindex), VRTS technical efficiency Index estimation (VRTSteindex), non-increasing return to scale estimation-RTSindex for all the 32 active Nigeria upstream operators. Table 4.1 shows the descriptive statistics of the four variables used in the study covering 7-year period. Maximum, Minimum, Mean, Standard deviation and Coefficient of variation values were estimated to give more information about the variability of the input and output data.

4.2 Descriptive Statistics of Data Variables

Table 4.1 shows that the IOCs under joint venture agreements “gas production” has a high coefficient of variation (79.05 %) indicating that “gas production” data has a low variability with a mean value of 64.92 Bscf/yr and standard deviation value of 53.53 Bscf/yr.” Oil production” of the IOC under joint venture agreements also has a low coefficient of variation of about 64.92% implying low variability. Data on proved “oil reserves” in barrel of oil equivalent for the 6 JV operators have a high variability as the coefficient of variation is greater than 100% (113.95%), having standard deviation value of 8597.04 MMbbls/yr greater than the mean value of 7544.44 MMb/yr. The “number of wells” of IOC joint ventures has a low coefficient of variation (57.53 %),

this is an indication that the data set have low variability with standard deviation of 158 wells which is less than the mean value 275 wells.

Table 4.1: Descriptive Statistic on Two Input and Two Output Variables (2010-2016)

STATISTICS	GAS PRODUCTION (BSCF/YR)	OIL PRODUCTION (MMBBLS/YR)	OIL RESERVE MMBOE/YR	NUMBER OF WELLS	CATEGORY
Maximum	220.84	885460.00	30313.16	525.00	**6 IOC-JV**
Minimum	0.39	5760.00	189.07	37.00	
Mean	67.72	350189.52	7544.44	274.62	
Std. Dev	53.53	227360.09	8597.04	158.00	
Co of variation (%)	79.05	64.92	113.95	57.53	
Maximum	99.87	197640.00	5146.72	56.00	**7 IOC-PSC**
Minimum	0.56	10.00	8.30	4.00	
Mean	46.75	88542.86	1423.20	23.86	
Std. Dev	33.91	66554.64	1349.33	17.22	
Co of variation (%)	72.55	75.17	94.81	72.17	
Maximum	3.21	10710.00	137.11	21.00	**1 IOC-SC**
Minimum	2.21	4920.00	92.16	21.00	
Mean	2.81	7927.14	116.53	21.00	
Std. Dev	0.31	2123.82	15.04	0.00	
Co of variation (%)	11.17	26.79	12.91	0.00	
Maximum	24.50	78030.00	1258.10	92.00	**9 IndOC-SR**
Minimum	0.02	10.00	0.15	2.00	
Mean	3.37	7805.87	237.40	26.78	
Std. Dev	4.97	15795.55	311.64	30.43	
Co of variation (%)	67.83	202.35	131.27	113.62	
Maximum	21.99	12800.00	160.21	23.00	**8 MFO-MFC**
Minimum	0.00	10.00	5.54	2.00	
Mean	2.09	2596.79	49.07	10.50	
Std. Dev	3.71	3258.57	38.32	6.84	
Co of variation (%)	177.58	125.48	78.10	65.12	
Maximum	39.63	177480.00	5827.07	194.00	**1 NOC-SR**
Minimum	16.92	22700.00	762.53	194.00	
Mean	25.57	95028.57	2979.88	194.00	
Std. Dev	8.23	68215.08	1678.16	0.00	
Co of variation (%)	32.20	71.78	56.32	0.00	
TOTAL NUMBERS OF OPERATORS					**32**

The 7 IOCs under PSCs “gas production” as a variable has a low coefficient of variation (72.55%). This shows that the “gas production” has low variability since the mean of value of 46.75 Bscf/yr is greater than the standard deviation value of 33.91 Bscf/yr. “Oil production data” also has a low coefficient of variation (75.15%) with standard deviation value of 66,554.64 MMbbls/yr and mean value of 8,854.2.86 MMbbls/yr implying low variability. Data on oil reserves in BOE for the 7 IOC-PSC operators have low variability since the coefficient of variation is 94.81%, having standard deviation value of 1349.33 MMboe/yr less than the mean value 1423.20 MMboe/yr. The number of wells for IOC-PSC has a low coefficient of variation value of 72.17%, an indication that the data set has low variability since the standard deviation value of 17 wells is less than the mean value; 24 wells.

The single IOC-SC on “gas production” has a low coefficient of variation value 11.17%, with mean value 2.81Bscf/yr being greater than the standard deviation value 0.31Bscf/yr. Oil production data also has a low coefficient of variation value of 26.79%, which indicates low variability. Oil reserves data in barrel of the single IOC-SC operator has low variability with coefficient of variation value of 12.91%, having standard deviation value 15.04 MMboe/yr less than the mean value 116.53 MMboe/yr. The number of well has no variation since it is just one firm in the IOC-SC joint venture agreement.

For the 9 independent operators under Sole Risk Agreements (SR), “gas production” has a low coefficient of variation (67.83%) indicating that the gas production data has low variability with a mean value of 3.37 Bscf/yr and standard deviation value of 4.97 Bscf/yr. The “oil production” data for the 9 independent operators has a high coefficient of variation (202.35%) implying high variability. Aggregate proved oil reserves in barrel for 9 independent operators have a high variability as the coefficient of variation is greater than 100% (131.27%) with standard deviation value of 311.64 MMboe/yr which is greater than the mean value of 237.40 MMboe/yr. The number of wells data of the 9 independent operators has a high coefficient of variation (113.62%) indicating that the data set has high variability and standard deviation (31 wells) is greater than the mean value of (26.78 wells).

The gas production data for the 8 marginal field operators (MFOs) have a coefficient of variation value that is greater than 100% (177%), with mean value of about 2.09 Bscf/yr and standard deviation value of 3.71 Bscf/yr. Oil production also has a high coefficient of variation (125.48%), this shows that the data variable for MFO has high variability. Data on “oil reserves” in barrel for the MFO operators have low variability as the coefficient of variation value is 78.10%, having standard deviation value 38.32 MMboe/yr less than the mean value 49.07 MMboe/yr. The number of wells belonging to the MFO operators has a low coefficient of variation value 65.12%, an indication that the data set has low variability, since the value of the standard deviation (6.84 wells) is less than the mean value 11 wells.

The gas production data for National oil company (NOC) has a low coefficient of variation value 32.20%, with mean value 25.57 Bscf/yr greater than the standard deviation value 8.23 Bscf/yr. “Oil production data” also has a low coefficient of variation value 71.78%, which indicates low variability. Oil reserves data in MMboe/yr for NOC has a low variability with coefficient of variation value of 56.32%, having standard deviation value 1,678.16 less than the mean value 2,979.88. The number of well has no variation since it is just one NOC firm.

In addition to the statistical information described in Table 4.1, Figures 4.1 to 4.5 also give more information regarding the contribution of each group of upstream operators to the four variables under consideration (which are oil production, gas production, proved reserves in barrel of oil equivalent reserves and number of active oil /gas wells). The IOC-JVs have the following percentage contributions: oil/gas production (51.75%, 72.61%), oil/gas reserves (71.21%, 78.92%), number of active wells (70.22%). IOC-PSC: oil/gas production (39.07%, 20.72%), oil/gas reserves (20.07%, 11.39%), number of active wells (7.03%). IOC-Service Contract (SC): oil/gas production (0.34%, 0.27%), oil/gas reserved (0.12%, 0.28%), number of active wells (0.88%). NOCs-Sole Risk (SR): oil/gas production (3.69%, 2.42%), oil/gas reserved (2.79%, 4.30%), number of active wells (10.15%). MFC: oil/gas production (2.03%, 0.71%), oil/gas reserved (0.65%, 0.63%), number of active wells (3.54%).

NOC-NPDC: oil/gas production (3.11%, 3.27%), oil/gas reserved (5.17%, 4.48%), number of active wells (8.17%). The IOCs group produced more than 90% of Nigeria's total oil and gas within the period under review, (Figures 4.2 & 4.3). They had access to proven oil and gas reserves of about 91.39% and 90.58% of Nigeria's total upstream oil and gas production within the period, (Figure 4.4). All other groups (IndOCs, MFO, NOC) jointly contribute less than 8% to all the variables as shown, (Figure 4.1).

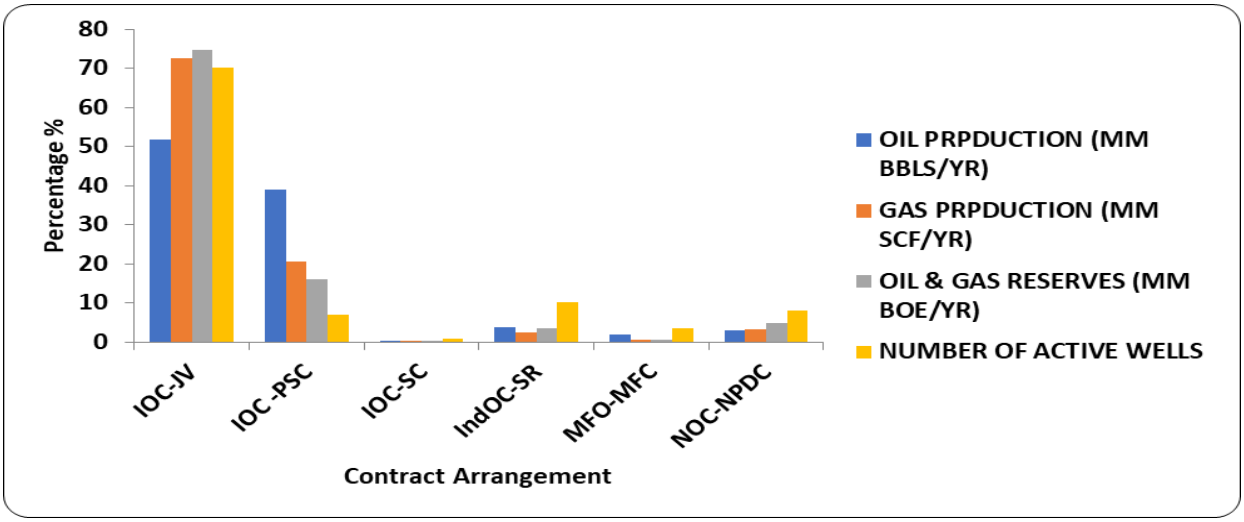

Figure 4.1: Aggregate Percentage Contribution by Group (2010-2016)

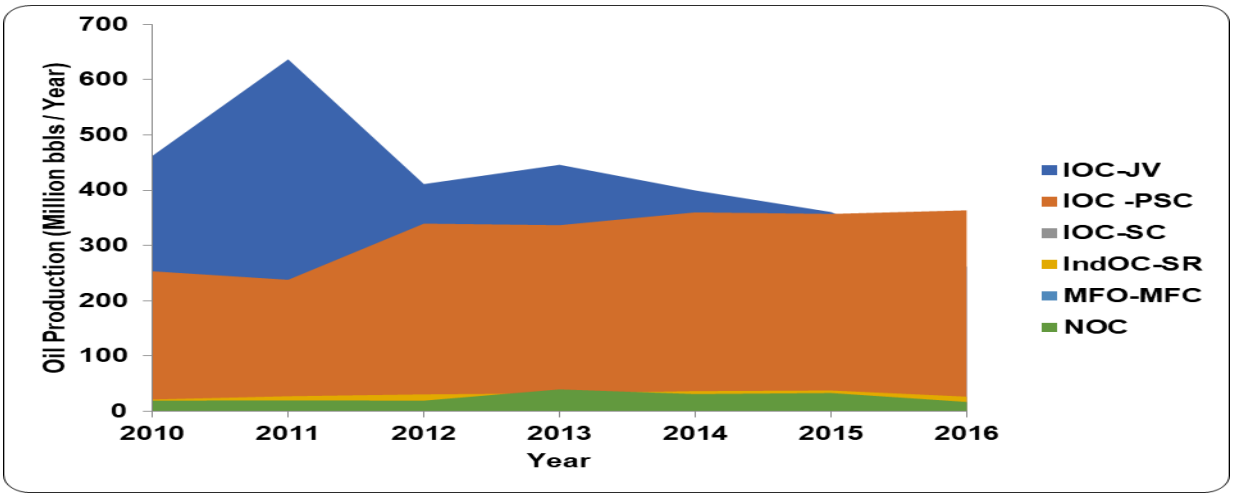

Figure 4.2: Operator's Oil Production Trends From 2010 to 2016

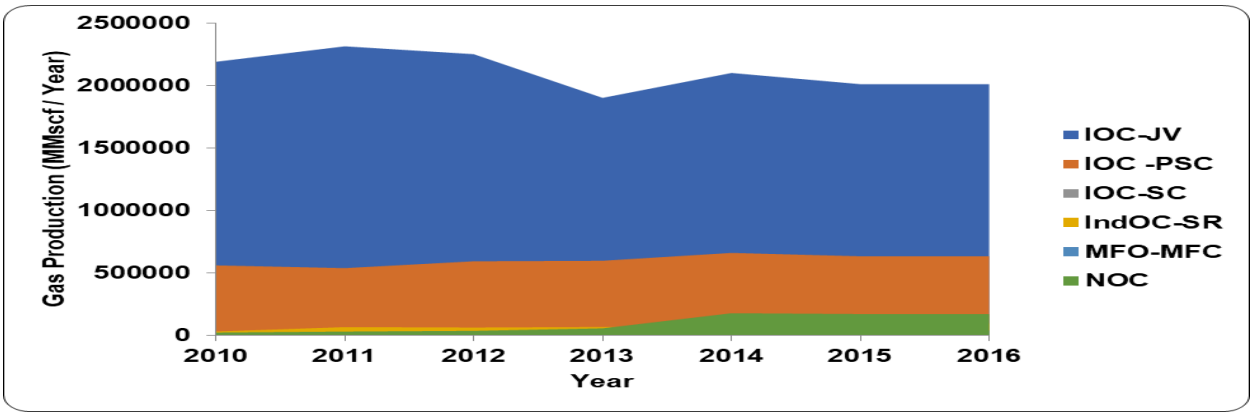

Figure 4.3: Operator's Gas Production Trends From 2010 to 2016

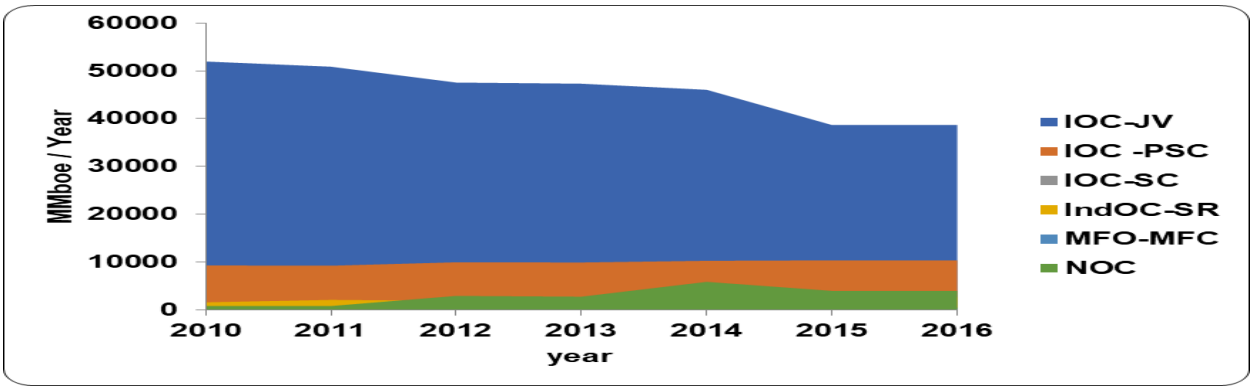

Figure 4.4:Operators' Proved Crude Oil Reserves Trends (2010-2016)

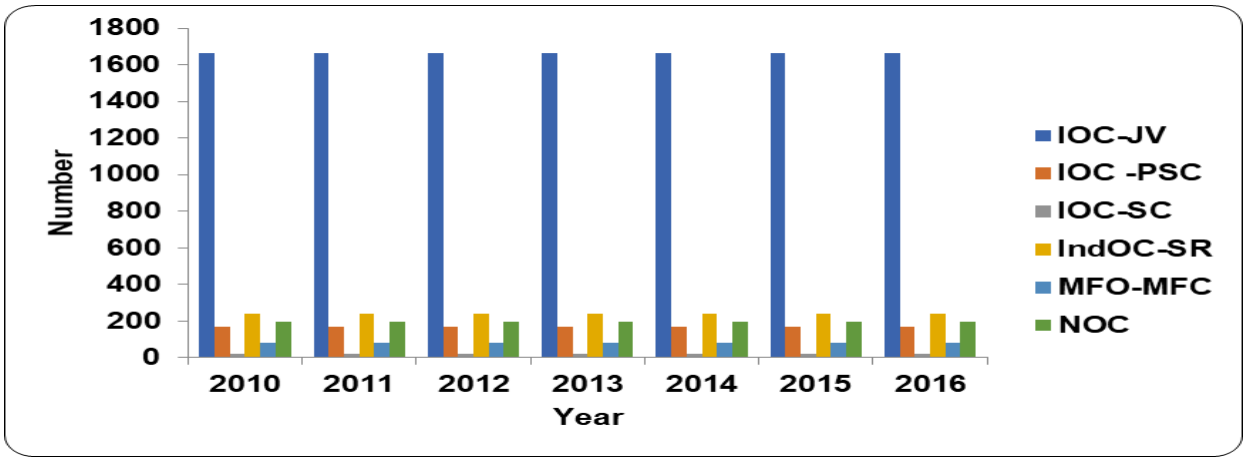

Figure 4.5: Active Wells Trends for the 32 Upstream Operators in Nigeria (2010-2016)

4.3 Results of CRTS Model and Analysis

The estimated CRTSteindexes shown in Table 4.2 were obtained using output-oriented cDEA model based on maximization (dual) formulation shown in equation 3.11a to 3.11f. The model formulation was based on Ideal situations, that is, all things being equal, all the 32 active operators operated optimally between 2010 and 2016 (Cooper *et al*., 2006; Cook *et al*, 2014). All operators on the efficient frontier were relatively efficient in terms of maximizing crude oil production keeping the 2 input variables constant, i.e., proved reserves and active oil/gas wells. This is not to say that other operators not on constant return to scale efficient production frontier were poor performers, but their TP could be considered low compared to those on the efficient frontier as categorized in Table 4.3. In carrying out the estimation, the study used a Microsoft Excel add-in solver aided with a Visual Basic for Applications (VBA). This helped to iteratively estimate the CRTS technical efficiency ($CRTS_{TE}$) for all the operators simultaneously (Appendix C).

DEAP software was used to validate the results with that of a Microsoft Excel spreadsheet to ensure consistency. A free version of DEA Frontier Software could not be used because of the limitation involved in respect of the number of DMUs which must not be more than 20 as against 32 operators in the sample.

Table 4.2: Estimated CRTSteindex for Upstream Operators Between 2010 and 2016

S/N	Active Upstream Operator (2010-2016)	Contract Type	2010	2011	2012	2013	2014	2015	2016
1	JVCO1	JVC	0.175	0.230	0.230	0.183	0.148	0.183	0.183
2	JVCO2	JVC	0.345	0.395	0.399	0.355	0.286	0.308	0.308
3	JVCO3	JVC	0.715	0.971	0.885	0.671	0.470	0.485	0.485
4	JVCO4	JVC	0.153	0.437	0.322	0.168	0.079	0.146	0.146
5	JVCO5	JVC	0.167	0.202	0.249	0.182	0.197	0.264	0.264
6	JVCO6	JVC	0.624	0.783	0.709	0.624	0.421	0.394	0.394
7	PSCO1	PSC	0.641	0.660	0.484	0.350	0.200	0.264	0.254
8	PSCO2	PSC	1.000	1.000	1.000	1.000	1.000	0.868	0.920
9	PSCO3	PSC	1.000	1.000	1.000	1.000	1.000	1.000	1.000
10	PSCO4	PSC	0.472	0.457	0.373	0.344	0.160	0.194	0.154
11	PSCO5	PSC	0.566	0.579	0.925	0.973	0.940	1.000	1.000
12	PSCO6	PSC	0.283	0.645	0.276	0.293	0.174	0.193	0.306
13	PSCO7	PSC	0.089	0.073	0.183	0.164	0.249	0.374	0.369
14	SCO	SC	0.632	0.609	0.577	0.354	0.199	0.191	0.174
15	SRCO1	SR	0.153	0.161	0.175	0.148	0.141	0.092	0.082
16	SRCO2	SR	1.000	1.000	1.000	0.916	0.556	1.000	1.000
17	SRCO3	SR	0.029	0.655	0.885	0.502	0.016	0.020	0.028
18	SRCO4	SR	1.000	0.356	0.304	0.133	0.038	0.069	0.086
19	SRCO5	SR	0.220	0.365	0.335	0.373	1.000	1.000	1.000
20	SRCO6	SR	0.198	0.210	0.546	0.413	0.358	0.269	0.269
21	SRCO7	SR	0.137	0.096	0.087	0.047	0.042	0.046	0.054
22	SRCO8	SR	1.000	0.912	1.000	0.917	0.646	0.320	0.383
23	SRCO9	SR	0.020	0.246	0.251	0.224	0.209	0.268	0.268
24	MFCO1	MFC	0.399	0.560	0.333	0.271	0.133	0.381	0.283
25	MFCO2	MFC	0.239	0.697	0.512	0.200	0.231	0.614	0.614
26	MFCO3	MFC	0.195	0.821	0.797	0.392	0.461	0.870	0.414
27	MFCO4	MFC	0.438	0.355	0.144	0.166	0.234	0.404	0.404
28	MFCO5	MFC	0.479	1.000	1.000	1.000	1.000	1.000	0.874
29	MFCO6	MFC	0.055	0.001	0.041	0.045	0.051	0.144	0.087
30	MFCO7	MFC	0.353	0.715	1.000	1.000	0.903	0.664	0.664
31	MFCO8	MFC	0.112	0.148	0.117	0.113	0.213	0.283	0.224
32	NOC-NPDC	NOC	0.196	0.291	0.087	0.135	0.130	0.204	0.204

Table 4.3: Decisions Criteria Based on Estimated CRTSteindex

S/N	Efficiency Index (EI)	Categorization
1	EI=100%	Efficient
2	75% ≤ EI<100%	Above Average
3	50% ≤ EI<75%	Average
4	25% ≤ EI<50%	Below Average
5	EI<25%	Inefficient

Source: Modified from Kocisova, 2014

Table 4.2 shows the estimated CRTSteindexes for all the 32 upstream operators in Nigeria within the period under review. The results reveal that most of the 32 active operators have TEIs that are less than unity (1 or 100%). Between 2010 and 2016, none of the IOCs under different JV agreements was on the efficient production frontier. Operators such as Stardeep/Famfa, Atlas, Esso Exploration, Continental and NAE/Allied were efficient in 2010 (Appendix B4). The companies efficiently maximized their crude oil production using the allowable input resources within the period. Operators such as Seplat, Consolidated Oil, and Pillar Oil recorded the lowest TE indexes in 2010 (at approximately 0.0%). The poor performance of these operators might be connected to the fact that the three operators were new in Nigeria's upstream business then. It may also be traceable to the uncertainties created by assets divestment programme embarked upon by some big operators like SPDC and Chevron that time.

Apart from the five companies on the efficient production frontier in 2010, South Atlantic also recorded TE index that was above average (that is, 57%). However, the TP of the upstream operators in 2010 (at 40.9%, 59.1%-inefficiency) did not appear favourable to both operators and government. The exceptionally poor results might be as a result of crude oil price instability and, perhaps, the improbability (such as the delay in the passage of the petroleum industry bill) surrounding the administration of petroleum industry in Nigeria.

The CRTS TE indexes recorded in between 2011 and 2012 were more favourable than the previous years, though the position of the JV companies remained unaffected. Stardeep/Famfa, Esso Exploration, Atlas Petroleum, Oriental Energy, Allied Energy and Platform Petroleum were on the efficient oil and gas production frontier. The period between 2011 and 2012 was characterized by an increasing crude oil price in both local and international market. Oil price averaged about $77.38 USD in 2010, increased consistently to about $107.46 USD in 2011 and attained its peak in 2013 with an average price of about $109.45 USD (OPEC, 2011-2016). Consequently, most operators invested more in technologies that could guarantee increased oil

and gas production for a proportionate return on out-of-pocket investments, (Iledare, 2015). Upstream operators such as Pillar Oil, Consolidated Oil and Moni Pulo appeared to have performed less than an average efficiency index all through the period of the study. In summary, about 18.75% of the total active operators in Nigeria upstream operated on efficient production frontier between 2011 and 2012 as against 15.6% in 2010.

Similarly, some of the operators on CRTS efficient production frontier between 2013 and 2016 were consistent. These operators were able to sustain their appearances (performance) on the CRTS efficient frontier up till 2016. The CRTS efficient operators within the period under review were Esso Petroleum, Stardeep/Famfa, South Atlantic, Oriental, Dubri, Atlas Petroleum and Platform Petroleum though only Esso Petroleum, Stardeep / Famfa, and Oriental were consistent. The period between 2013 and 2016 witnessed some steady declines in the price of crude oil internationally. The price got to the peak in 2012 with an average price of $109.45, but later started to decline gradually to an average price of $105.87 USD in 2013, $96.29 USD in 2014, $49.49 USD in 2015 and $40.68 USD in 2016. Oil and Gas operators such as Midwestern, South Atlantic, Atlas Petroleum, and Express Petroleum performed above average as shown by the estimated average CRTSteindexes in Table 4.2 and Figure 4.6.

The uninspiring performance of a good number of operators within the period may be attributed to the frequent changes of management of the NNPC. It is on record that NNPC had about seven Group Managing Directors (GMDs) between 2010 and 2016. The effects of these erratic changes on operators' TP and productivity seem not to be negligible, especially on those operators under JV and PSC agreements, (Figures 4.6 and 4.7).

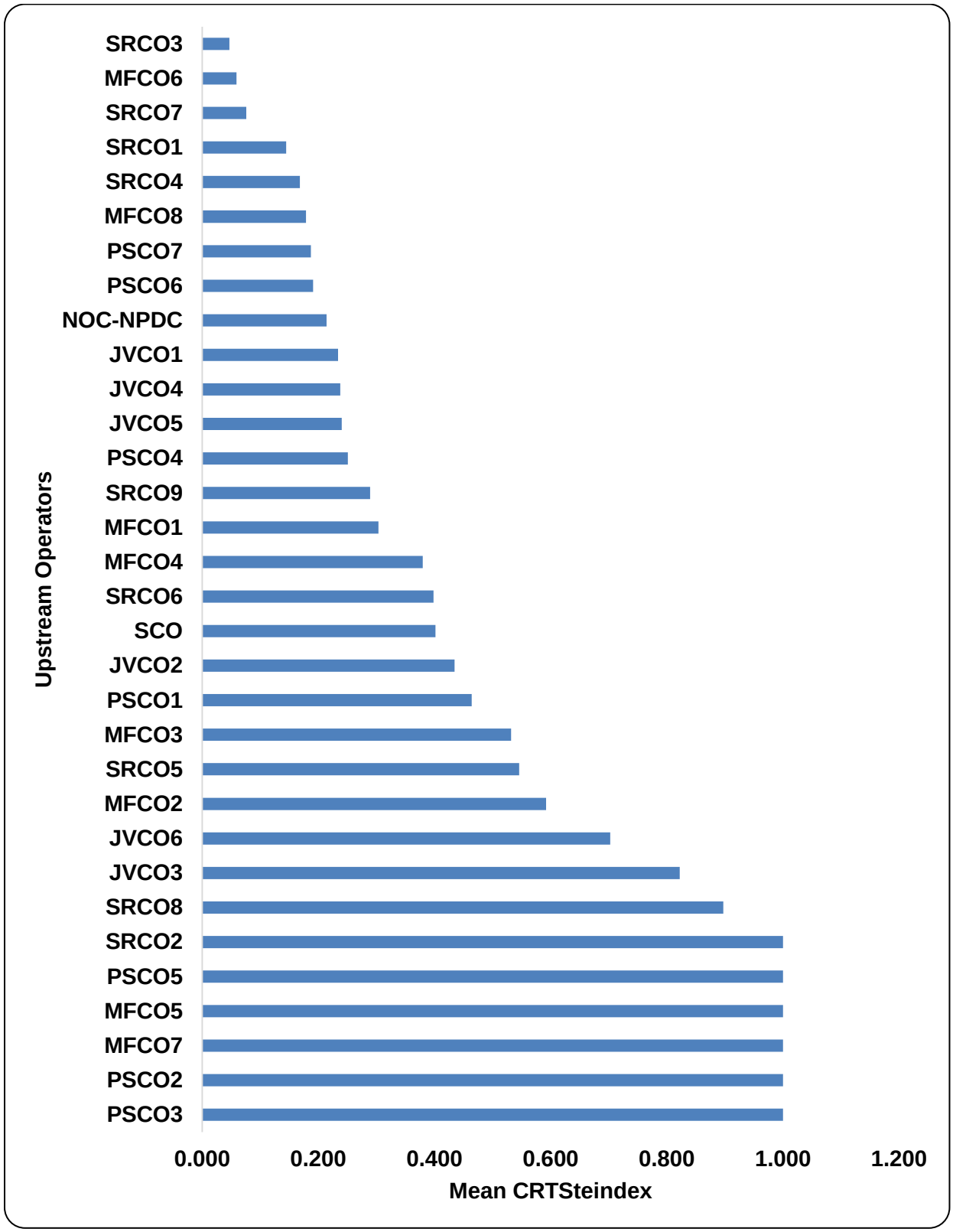

Figure 4.6: Average Estimated CRTSteindex (2010-2016)

Table 4.4: Ranking Based on the Estimated CRTSteindexes

S/N	Active Upstream Operator (2010-2016)	Conract Type	Estimated Mean CRTSteindex	Ranking
9	PSCO3	PSC	1.000	1
8	PSCO2	PSC	1.000	1
30	MFCO7	MFC	1.000	1
28	MFCO5	MFC	1.000	1
11	PSCO5	PSC	1.000	1
16	SRCO2	SR	1.000	1
22	SRCO8	SR	0.897	2
3	JVCO3	JVC	0.822	3
6	JVCO6	JVC	0.702	4
25	MFCO2	MFC	0.592	5
19	SRCO5	SR	0.546	6
26	MFCO3	MFC	0.532	7
7	PSCO1	PSC	0.464	8
2	JVCO2	JVC	0.434	9
14	SCO	SC	0.401	10
20	SRCO6	SR	0.398	11
27	MFCO4	MFC	0.380	12
24	MFCO1	MFC	0.303	13
23	SRCO9	SR	0.289	14
10	PSCO4	PSC	0.251	15
5	JVCO5	JVC	0.240	16
4	JVCO4	JVC	0.238	17
1	JVCO1	JVC	0.234	18
32	NOC-NPDC	NOC	0.214	19
12	PSCO6	PSC	0.191	20
13	PSCO7	PSC	0.187	21
31	MFCO8	MFC	0.178	22
18	SRCO4	SR	0.168	23
15	SRCO1	SR	0.144	24
21	SRCO7	SR	0.076	25
29	MFCO6	MFC	0.059	26
17	SRCO3	SR	0.047	27

The technical performance ranking shown in Figures 4.6, 4.7 and Table 4.4 validates the statement that Platform Petroleum, Esso E & P Nigeria Limited, Stardeep/Famfa, Oriental Energy Limited, Atlas Petroleum and South Atlantic were the most CRTS efficient operators in Nigeria within the period of the estimation. These operators appeared to have assigned their input resources reasonably well, using well-structured and appropriate management styles. The companies were able to maximize the yearly volume of oil and gas production to meet the financial commitments of their companies' shareholders and their host governments.

The performance of NAE/Allied and NAOC were estimated to be above average that is, greater than or equal 75% but less than 100%. Total E & P Company, Energia, Dubri and Midwestern were evaluated to be operating at an average efficiency level. Operators with serial number 2, 7, 10, 14, 20, 23, 24 and 27 shown in Table 4.4 operated below an average CRTS efficiency index, that is, they operated above 25 percent TE but less than 50 percent. The ranking implied that approximately five indigenous upstream operators were among the first 10 efficient operators in Nigeria within the period–that is, Platform Petroleum, Oriental, Atlas, NAE/Allied Energy and Energia. Total E & P, NAOC/Philips, South Atlantic / Total, Stardeep /Famfa and Esso were the only IOCs that were listed among the first ten performers within the period under review, (50:50). This may simply be traced to the optimality assumption of CRTS-model engaged in this first phase. About twelve (12) of the upstream operators were estimated to be having TE indexes that were less than 25 percent, hence they were regarded as CRTS inefficient as shown in Table 4.3.

The study also analyzed the performances of the upstream operators based on operating contract arrangements. Six major contractual arrangements are in existence in Nigeria's upstream operations, which are Production Sharing Contract (PSC), Joint Venture or Joint Operating Agreement (JV / JOA), Service Contract (SC), Sole Risk Contract (SR) and Marginal Field Contract (MFC). All these contractual arrangements were investigated alongside the

operators' TE. Figures 4.7 and 4.8 illustrate the trends in the yearly CRTSteindexes of each of the groups in relation to the type of upstream contract arrangement in operation. The different PSCs signed by 7 IOCs took the lead all through the seven years considering their respective mean TE index. They were followed by the MFCs signed by 9 Indigenous Oil Companies. Averagely, operators under PSCs and MFCs arrangements out-performed other contract arrangements (that is, JVs, SC, SR, NOC) between the years under review (2010-2016).

The JOA signed by the 6 foremost IOCs witnessed decreasing performance from 2010 to 2016. The higher efficiency indexes recorded in between 2010 to 2012 may be due to the increasing global crude oil price. JVC is associated with cash calls problem which must have been the brain behind its poor performance within the period. Nigeria, the supposed host government has failed to honor its own part of the JOA's agreed contract condition regarding equity contribution, hence the commencement of the debate on cash calls exit. The poor performance recorded by the Nigeria owned upstream company-NOC-NPDC may be as a result of unreasonable resource allocation, politically motivated management styles and poor coordination of externalities (Emrouznejad, 2003; Guo, 2011). The detailed information about the performance of the companies was revealed when all the 32 companies were subjected to VRTS Model in next section.

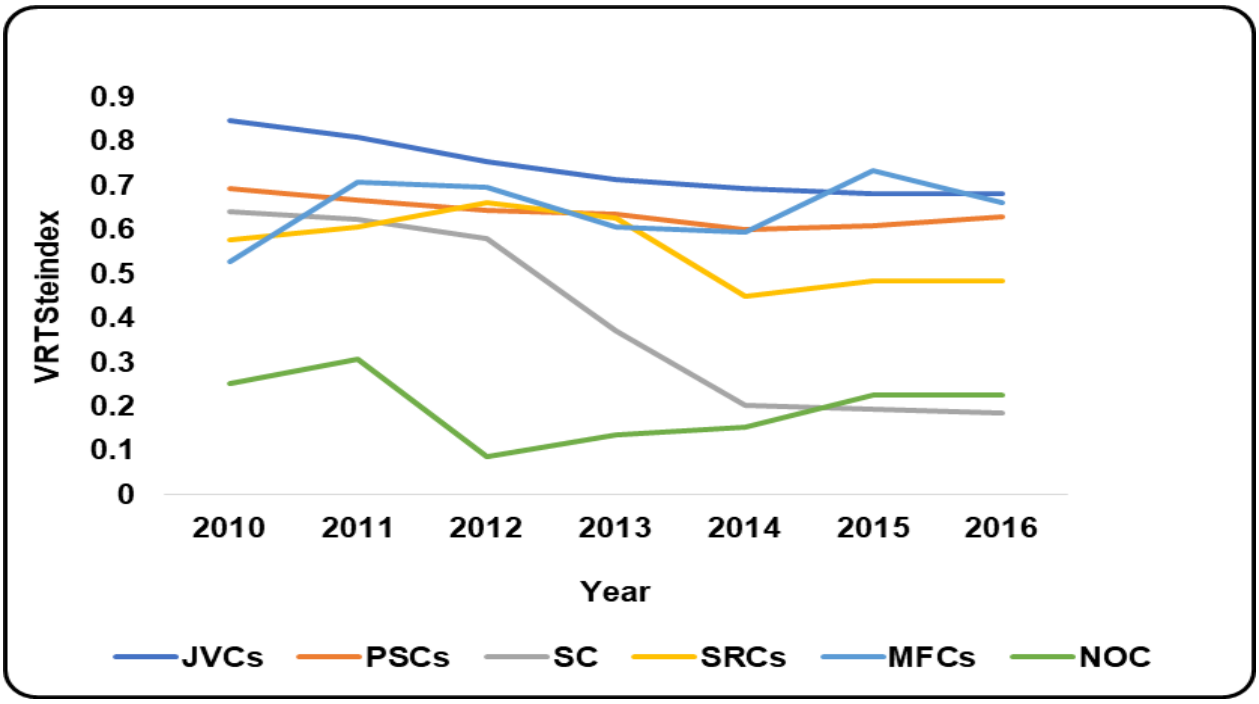

Figure 4.7: Upstream Contracts Performance From 2010 to 2016

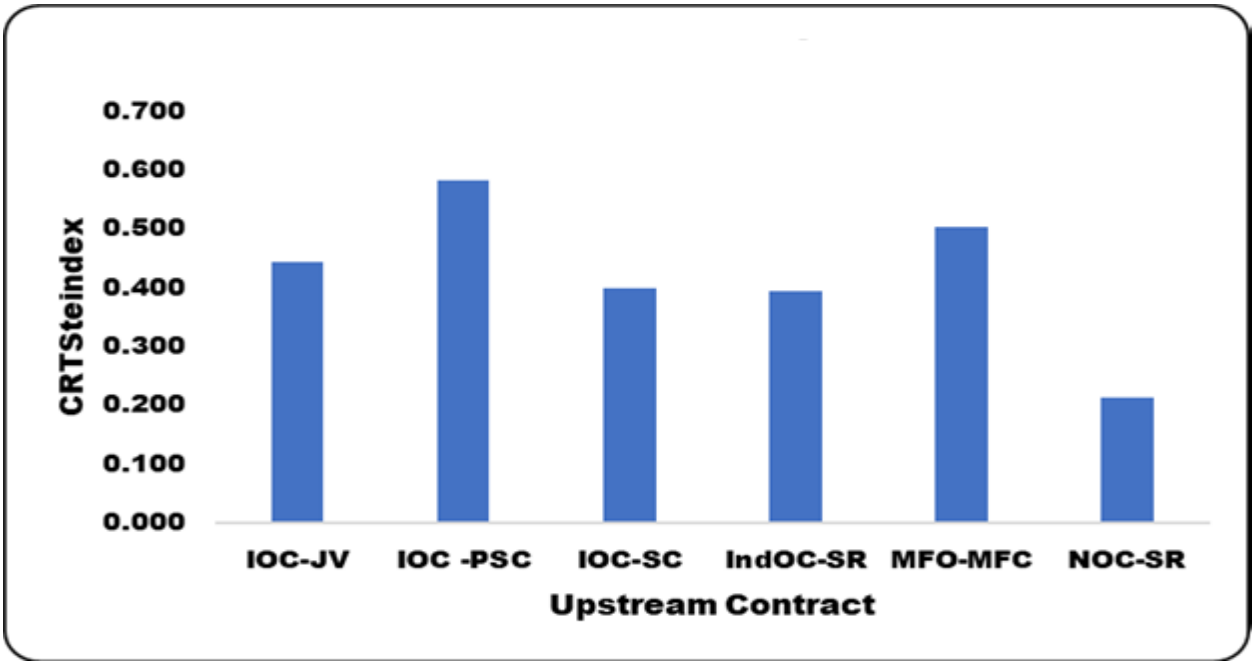

Figure 4.8: Operators' Group Mean Contracts Performance (2010-2016)

4.4 Results of VRTS Model and Analysis

Table 4.5 shows various VRTSteindexes obtained having estimated an output oriented VRTS model considering two input and two output variables for the 32 active upstream operators used for the study. The CRTS model estimations carried out in the previous section assumed a situation where all operators conduct their businesses or operating in an ideal situation. That is, having outputs and inputs displaying a constant return to scale relationship. The optimality assumption of CRTS model appears invalid especially for the Nigerian upstream operations. There might be some instances where certain operator(s) might operate less due to such constraints such as access to loan (finance), operational terrain issues, unfavourable host government policies, crude oil price, militancy and competition. In considering these observations, the study adopted VRTS output-oriented DEA model in this phase to carry out the estimate. VRTS model incorporates scale variability assumptions unlike CRTS model. This is paramount so as to avoid estimating TEs which could be muddled with scale efficiency problem or errors (Seiford & Zhu, 1999; Cooper et al, 2007, Cullinane and Teng-Fel, 2007; Zhu & Cook, 2008).

To carry out the analysis, a Microsoft Excel add-in solver aided with VBA was used (Appendix B4, C). The specified model in equation 3.15a to 3.15f were coded in Excel spreadsheet as done previously in phase one. VBA was engaged in order to simultaneously estimate VRTSteindexes for all the 32 active upstream operators relatively. DEAP Excel add-in software was also used to check the results obtained with that of the coded Microsoft Excel to ensure uniformity. The constraint $\mathbf{Z_0}$ in the VRTS model as stated in Equation 3.20b is described as a free variable. $\mathbf{Z_0}$ is also known as a convexity constraint which may not be found in CRTS Model. The VRTS model**'s** guarantees that a convex hull of intersecting planes covers the data points better compared to CRTS model. Consequently, VRTS model ensures accurate TEI's

estimation, which may be greater or equal to the estimated TEIs using CRTS model. The study refers to estimated TEIs using VRTS model as variable return to scale TE index (VRTSteindex).

Table 4.5: Estimated VRTSteindex for all the 32 Nigeria operators from 2010 to 2016

S/N	Active Upstream Operator (2010-2016)	Contract Type	2010	2011	2012	2013	2014	2015	2016
1	JVCO1	JVC	0.932	0.419	0.435	0.304	0.427	0.399	0.399
2	JVCO2	JVC	1.000	1.000	1.000	1.000	1.000	1.000	1.000
3	JVCO3	JVC	1.000	1.000	1.000	1.000	1.000	1.000	1.000
4	JVCO4	JVC	0.159	0.441	0.329	0.183	0.080	0.176	0.176
5	JVCO5	JVC	1.000	1.000	1.000	1.000	1.000	1.000	1.000
6	JVCO6	JVC	1.000	1.000	0.764	0.789	0.645	0.507	0.507
7	PSCO1	PSC	0.680	0.662	0.489	0.351	0.212	0.266	0.262
8	PSCO2	PSC	1.000	1.000	1.000	1.000	1.000	0.874	0.922
9	PSCO3	PSC	1.000	1.000	1.000	1.000	1.000	1.000	1.000
10	PSCO4	PSC	0.581	0.595	0.548	0.559	0.550	0.545	0.532
11	PSCO5	PSC	0.920	0.622	1.000	1.000	1.000	1.000	1.000
12	PSCO6	PSC	0.544	0.661	0.291	0.348	0.184	0.200	0.314
13	PSCO7	PSC	0.132	0.128	0.188	0.179	0.255	0.377	0.372
14	SCO	SC	0.640	0.625	0.580	0.371	0.202	0.195	0.186
15	SRCO1	SR	0.164	0.167	0.199	0.179	0.149	0.103	0.096
16	SRCO2	SR	1.000	1.000	1.000	1.000	0.740	1.000	1.000
17	SRCO3	SR	0.286	1.000	1.000	1.000	0.286	0.286	0.286
18	SRCO4	SR	1.000	0.365	0.341	0.187	0.102	0.112	0.119
19	SRCO5	SR	1.000	1.000	1.000	1.000	1.000	1.000	1.000
20	SRCO6	SR	0.543	0.517	1.000	0.912	0.418	0.401	0.401
21	SRCO7	SR	0.169	0.147	0.149	0.144	0.145	0.143	0.143
22	SRCO8	SR	1.000	1.000	1.000	1.000	1.000	1.000	1.000
23	SRCO9	SR	0.028	0.247	0.263	0.224	0.210	0.314	0.314
24	MFCO1	MFC	1.000	1.000	1.000	1.000	1.000	1.000	1.000
25	MFCO2	MFC	0.434	0.925	0.727	0.332	0.243	0.747	0.747
26	MFCO3	MFC	0.340	0.844	0.814	0.491	0.489	0.887	0.460
27	MFCO4	MFC	0.607	0.485	0.333	0.333	0.349	0.486	0.486
28	MFCO5	MFC	0.773	1.000	1.000	1.000	1.000	1.000	0.899
29	MFCO6	MFC	0.400	0.400	0.400	0.400	0.400	0.401	0.400
30	MFCO7	MFC	0.441	0.790	1.000	1.000	1.000	1.000	1.000
31	MFCO8	MFC	0.223	0.226	0.299	0.293	0.284	0.344	0.295
32	NOC-NPDC	NOC	0.253	0.307	0.087	0.135	0.154	0.227	0.227

The study also estimated scale efficiency index (SE index) by dividing CRTSteindex with the corresponding VRTSteindex. One major disadvantage of relying on this type of scale efficiency estimation is that the value gotten does not actually indicate whether the operator under investigation is operating on increasing or reducing operational scale of production, i.e., IRTS or DRTS. Seiford and Zhu (1999) confirmed that scale efficiency estimation is inadequate to categorize DMUs into its respective return to scale group of CRTS, IRTS, DRTS.

They suggested the imposition of an additional DEA model known as non-increasing return to scale model (NIRTS). To do this, model (6) by Seiford and Zhu (1999) is imposed to estimate return to scale indexes (RTSindex) using same Microsoft excel add-in with a VBA. The study used the estimated RTSindex to determine the nature of the 32 Nigeria upstream operators' production scales. Seiford and Zhu (1999) stated that if the value of RTSindex is equal to the value of VRTSteindex, DRTS is assumed. If otherwise, that is, the value of RTSindex is not equal to the value of VRTSteindex, IRTS exists. A situation where the value of CRTSteindex is the same as the value of VRTSteindex, CRTS is assumed. Table 4.8 illustrates scale efficiency, RTSindex and categorization.

The outcomes from the empirical analysis based on the output-oriented DEA model with VRTS assumptions of the whole dataset are presented in Table 4.6 and Appendix B4. The results gotten reveal a decreasing trend in the TE of the Nigeria upstream operators from 2010 to 2016. The indexes were higher from 2010 up till 2012 compared to between 2012 and 2016; this may still be largely connected to the increased crude oil price between 2010 and 2012; and declining price trend from 2012 to 2016. The TE indexes recorded show that about 43% of the operators were efficient in 2010 and 2011 respectively.

Table 4.6: VRTSteindex Categorization Criteria

S/N	Efficiency Index (EI)	Categorization
1	EI=100%	Efficient
2	75% ≤ EI<100%	Above Average
3	50% ≤ EI<75%	Average
4	25% ≤ EI<50%	Below Average
5	EI<25%	Inefficient

Source: Modified from Kocisova, (2014)

The number of efficient operators reduced to below 42% from 2012 to 2013 and later reduced to an average of 34% in between 2014 and 2016. Figure 4.9 shows that there was a sharp decline in TE indexes from 2010 to 2011 due to the global economic problem then, though the adverse effects were later lessened by the increased crude oil price from 2011 to 2012. Figure 4.9 and Appendix D1 also show that TE indexes reduce in directly proportional to the crude oil price from 2013 to 2016. Operators such as: SPDC, Platform Petroleum, Esso, NAE/Allied, Stardeep/Famfa, MPN, Britani U, Oriental Energy, Dubri, Atlas, South Atlantic/Total Up, and NAOC / Philips were operating on the VRTS efficient production frontier, i.e., having an estimated mean VRTSteindex of 100% or 1.

Express Petroleum and Total E & P were ranked to have performed above average having recorded mean TE index that were greater than or equal to 75% but less than 100%. Energia, Midwestern Oil and Nigeria Agip Energy-NAE were estimated to be having indexes of 72%, 72%, and 55% respectively. These indexes are within the average indexes of greater than or equal to 50% but less than 75%. The operators with serial number: 1, 7, 14, 17, 23, 29, 31 shown in Table 4.7 recorded indexes that were greater than or equal to 25% but less than 50%. These operators were ranked to be operating below average while the remaining operators

appear not to be efficient at converting their inputs to outputs. There are about seven inefficient operators: 1 JV operator, 2 PSC operators and 4 SR operators in phase two as against twelve in phase one.

Table 4.7: Estimated VRTSteindex results and ranking

S/N	Active Upstream Operator (2010-2016)	Contract Type	Estimated Mean	Ranking
5	JVCO5	JVC	1.000	1
30	MFCO7	MFC	1.000	1
9	PSCO3	PSC	1.000	1
22	SRCO8	SR	1.000	1
8	PSCO2	PSC	1.000	1
2	JVCO2	JVC	1.000	1
24	MFCO1	MFC	1.000	1
28	MFCO5	MFC	1.000	1
19	SRCO5	SR	1.000	1
16	SRCO2	SR	1.000	1
11	PSCO5	PSC	1.000	1
3	JVCO3	JVC	1.000	1
20	SRCO6	SR	0.966	2
6	JVCO6	JVC	0.792	3
25	MFCO2	MFC	0.721	4
26	MFCO3	MFC	0.718	5
10	PSCO4	PSC	0.553	6
7	PSCO1	PSC	0.469	7
27	MFCO4	MFC	0.463	8
14	SCO	SC	0.421	9
1	JVCO1	JVC	0.404	10
29	MFCO6	MFC	0.400	11
31	MFCO8	MFC	0.379	12
23	SRCO9	SR	0.313	13
17	SRCO3	SR	0.286	14
4	JVCO4	JVC	0.242	15
12	PSCO6	PSC	0.241	16
32	NOC-NPDC	NOC	0.228	17
18	SRCO4	SR	0.201	18
13	PSCO7	PSC	0.192	19
15	SRCO1	SR	0.167	20
21	SRCO7	SR	0.149	21

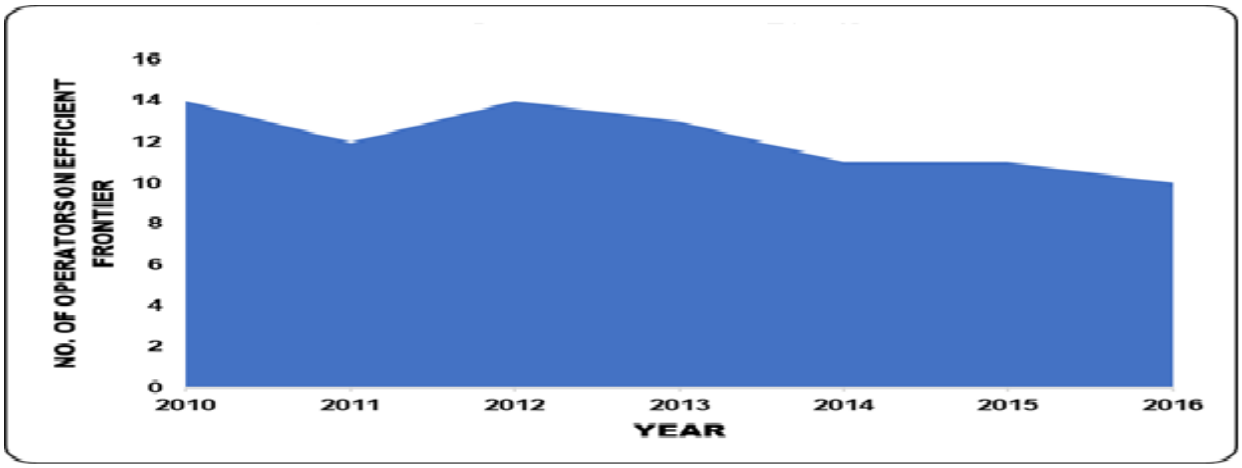

Figure 4.9: VRTS Efficient Operators Per Year (2010-2016)

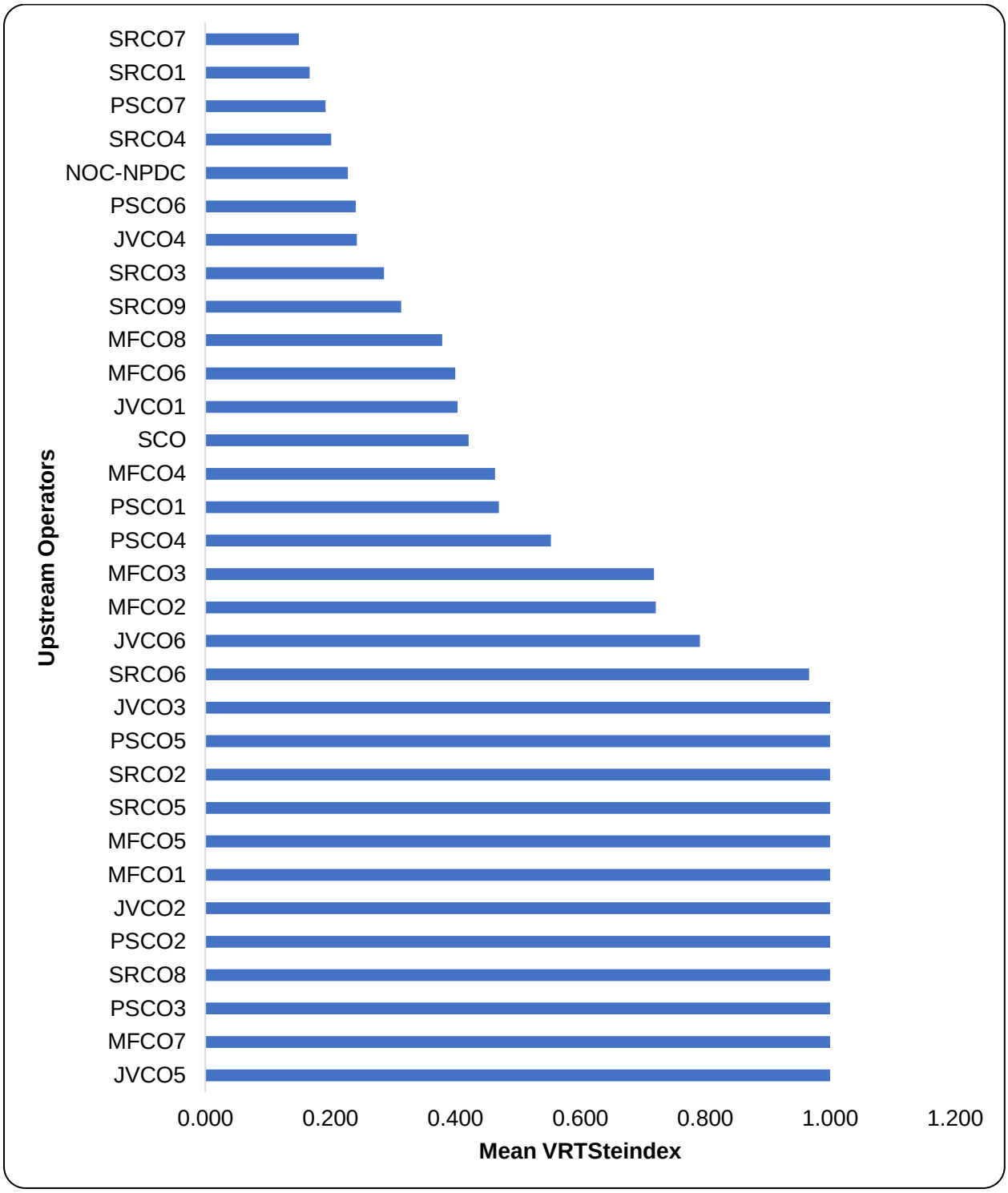

Figure 4.10: Ranking of Upstream Operators Based on VRTSteindex

The number of inefficient operators when VRTS model was engaged in phase two (7 operators) was less than the number of inefficient operators when CRTS model was imposed in phase one (13 operators). However, all the six efficient operators in phase one were also estimated to be efficient in phase two. Table 4.7 and Figure 4.10 clarify that at least 1 operator per group was either CRTS inefficient or VRTS inefficient (Selford & Joe, 2014).

The mean group performance relating to the six upstream contract arrangements as shown in Figure 4.11 and 4.12 ranks JV group to have performed above 75% despite the cash calls problems. None of the JV companies performed efficiently when CRTS model was adopted in phase one but three of the JV operators (SPDC, MPN and NAOC) were found to be operating efficiently in phase two when VRTS model was deployed. The appearance of the three first comer JV operators on the VRTS efficient production frontier could be linked to the robustness of the model's assumption *ceteris paribus*. Operators under SR Contract as well as those under PSC recorded mean performance indexes of 65% and 64% respectively, (Figure 4.12). The ten marginal field operators which are mainly new participants recorded higher mean efficiency grades of about 67% compared to the 9 independent operators under SR Contract. Similarly, the Nigeria National upstream oil company-NPDC which is not under any known contract arrangement recorded mean efficiency index of about 15% which means that its mean inefficiency index was about 85%.

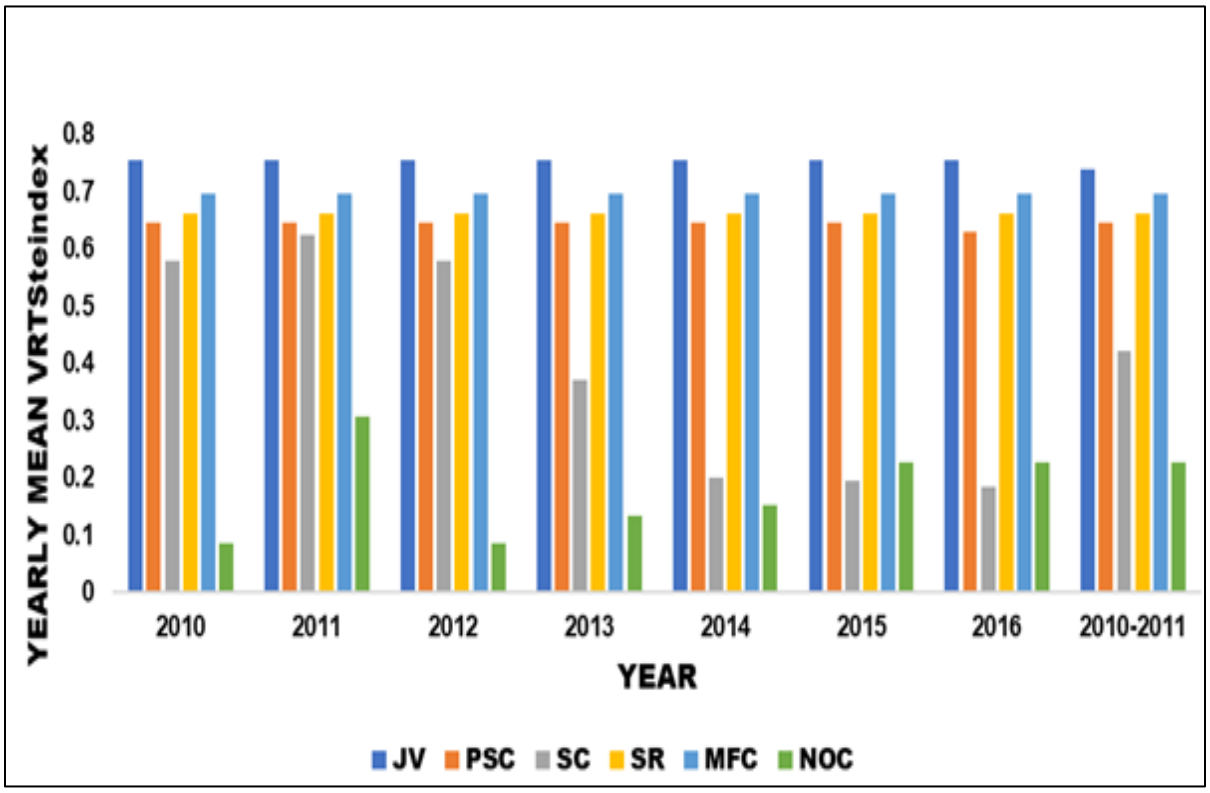

Figure 4.11: Upstream Contracts Performance Trends (2010-2016)

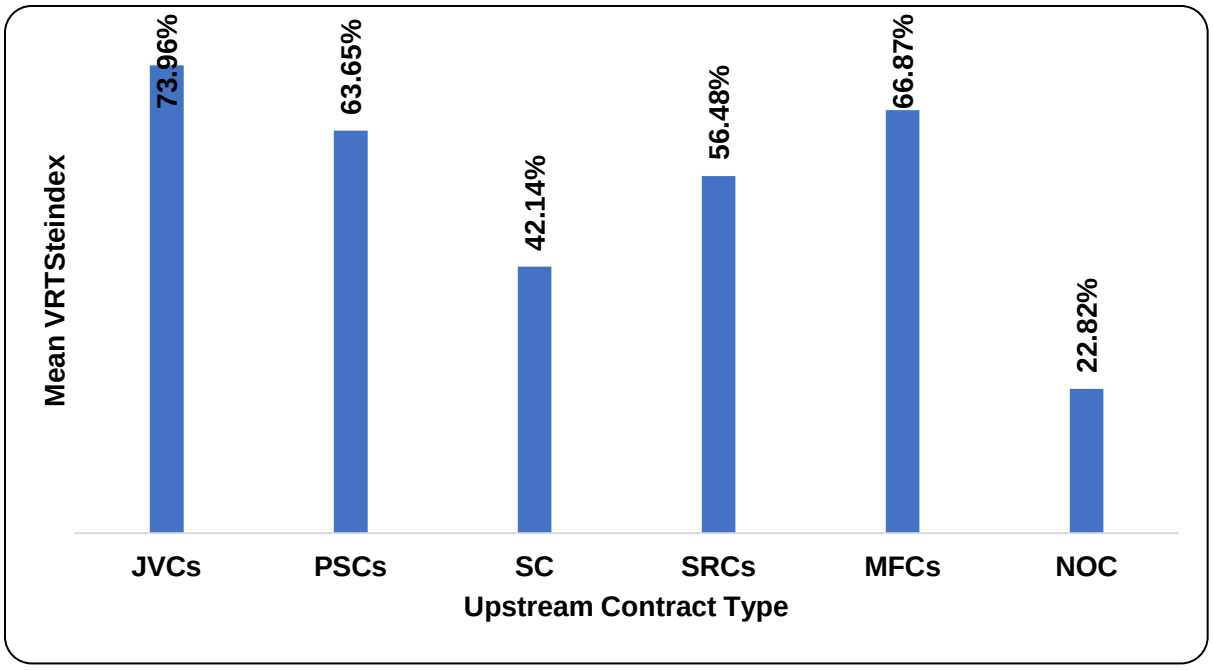

Figure 4.12: Group Mean Performance Based on Contract Type (2010-2016)

4.5 Operator's Production Frontier Classification

The return to scale production frontier classifications using non-increasing return to scale model was stated in equation 3.19a to 3.19f. The results obtained showed that about 25% (8 operators) of the 32 active Nigeria upstream operators were operating on decreasing return to scale (DRTS) production frontier up to the end of 2016 (Figure 4.13, Appendix B5, B6, B7). These include five of the foremost IOCs, which were CNL, MPN, NAOC/Philips, SPDC, TOTAL E & P under joint operating agreements (JV), One IOCs-PSC operators (Addax), One IndOCs-SR operators (Seplat), and the only National Oil Company (NPDC) in the sample. The results in Table 4.8 show that none of the Marginal Field Operators exhibited decreasing return scale. This situation could be interpreted to imply that the outputs of the 8 operators increased less than the proportionate increase in the quantity of the inputs. Weighted outputs volume increased in a smaller unit compared to the weighted inputs unit. The operators in this category experienced a diminishing return to scale (DRTS) type of production frontier over the period under review, meaning that all the operators were operating under a situation whereby their internal/external economies are less than their internal/external diseconomies (Appendix B7).

Table 4.8 and Figure 4.13 reveal that about 19% (6 operators) of the 32 active upstream operators in Nigeria were operating on CRTS production frontier within the period. Operators such as Stardeep/Famfa, Esso, South Atlantic/Total, Atlas, Seplat and Platform Petroleum had their output increased as a result of the corresponding increase in their aggregate proved reserves and number of wells. These operators had sufficient scale dimensions which made it impossible for them to deliver more output quantities without increasing the corresponding inputs quantities (reserves & number of wells). The 18 remaining operators which amounted to about 56% of the total operators were operating on IRTS production frontier.

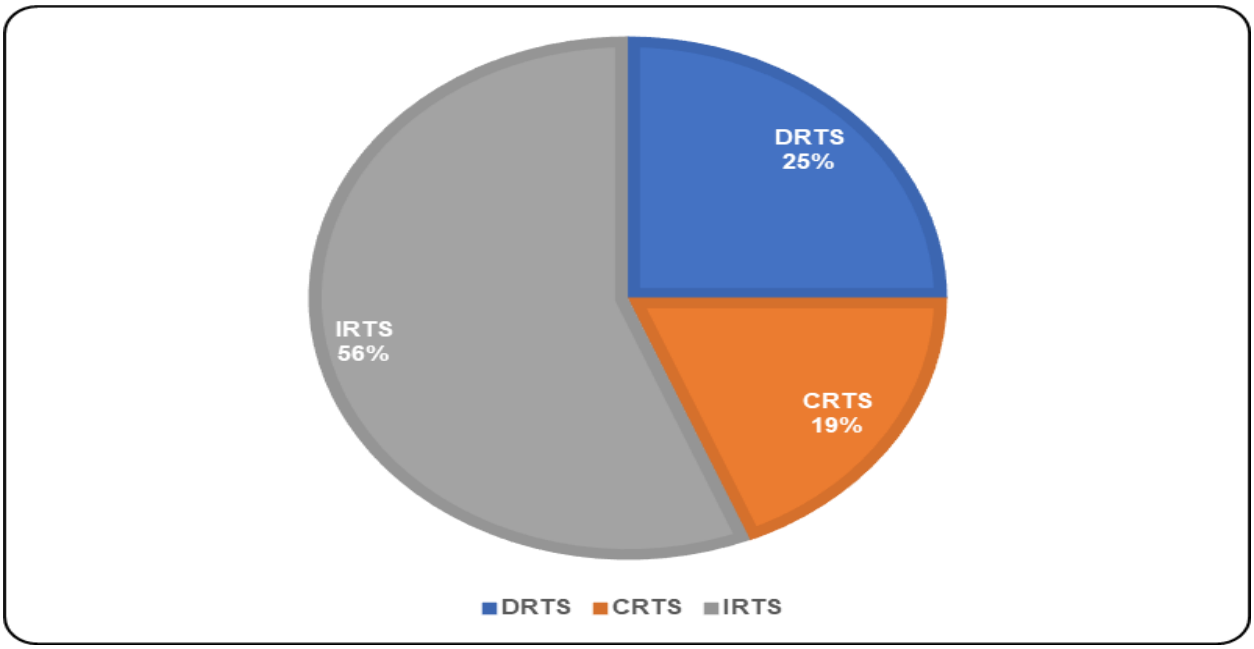

Figure 4.13: Return to Scale Groups and Percentages

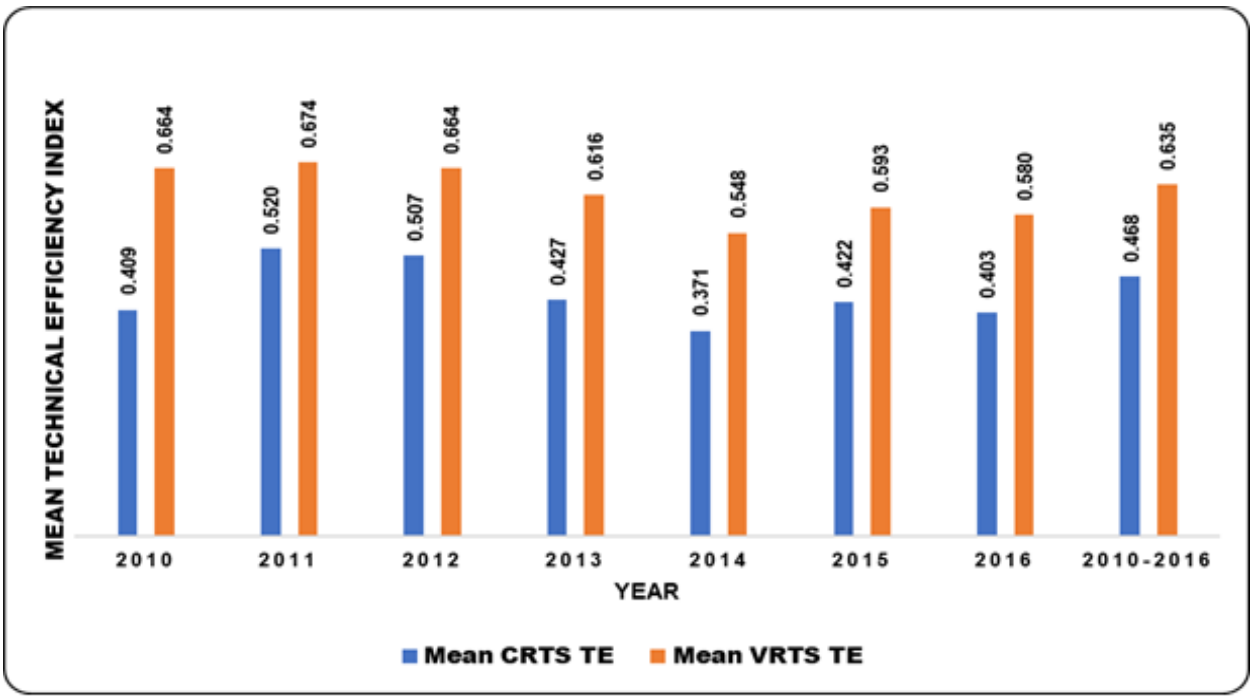

Figure 4.14: Comparing CRTS Model Results and VRTS Model Results

Table 4.8: Return to Scale Categorization (RTSC)

S/N	Active Upstream Operator (2010-2016)	Contract	Mean CRTSteindex	Mean VRTSteindex	Scale Efficiency	NIRTS index	RTS Group
1	JVCO1	JVC	0.234	0.404	0.579	0.404	DRTS
2	JVCO2	JVC	0.434	1.000	0.434	1.000	DRTS
3	JVCO3	JVC	0.822	1.000	0.822	1.000	DRTS
4	JVCO4	JVC	0.238	0.242	0.981	0.238	IRTS
5	JVCO5	JVC	0.240	1.000	0.240	1.000	DRTS
6	JVCO6	JVC	0.702	0.792	0.887	0.792	DRTS
7	PSCO1	PSC	0.464	0.469	0.988	0.469	DRTS
8	PSCO2	PSC	1.000	1.000	1.000	1.000	CRTS
9	PSCO3	PSC	1.000	1.000	1.000	1.000	CRTS
10	PSCO4	PSC	0.251	0.553	0.453	0.251	IRTS
11	PSCO5	PSC	1.000	1.000	1.000	1.000	CRTS
12	PSCO6	PSC	0.191	0.241	0.793	0.191	IRTS
13	PSCO7	PSC	0.187	0.192	0.971	0.187	IRTS
14	SCO	SC	0.401	0.421	0.952	0.401	IRTS
15	SRCO1	SR	0.144	0.167	0.865	0.144	IRTS
16	SRCO2	SR	1.000	1.000	1.000	1.000	CRTS
17	SRCO3	SR	0.047	0.286	0.164	0.047	IRTS
18	SRCO4	SR	0.168	0.201	0.834	0.168	IRTS
19	SRCO5	SR	0.546	1.000	0.546	0.546	IRTS
20	SRCO6	SR	0.398	0.966	0.412	0.398	IRTS
21	SRCO7	SR	0.076	0.149	0.507	0.076	IRTS
22	SRCO8	SR	0.897	1.000	0.897	0.897	IRTS
23	SRCO9	SR	0.289	0.313	0.922	0.313	DRTS
24	MFCO1	MFC	0.303	1.000	0.303	0.303	IRTS
25	MFCO2	MFC	0.592	0.721	0.821	0.592	IRTS
26	MFCO3	MFC	0.532	0.718	0.741	0.532	IRTS
27	MFCO4	MFC	0.380	0.463	0.819	0.380	IRTS
28	MFCO5	MFC	1.000	1.000	1.000	1.000	CRTS
29	MFCO6	MFC	0.059	0.400	0.147	0.059	IRTS
30	MFCO7	MFC	1.000	1.000	1.000	1.000	CRTS
31	MFCO8	MFC	0.178	0.379	0.470	0.178	IRTS
32	NOC-NPDC	NOC	0.214	0.228	0.937	0.228	DRTS

These include one JV operator; Pan Ocean, Three IOC-PSC operator; NAE, SEEPCO & SNEPCO, One Service Contract Operator: AENR, Seven IndOCs-SR Operators: AMNI, Consolidated, Continental, Dubri company, Express, Moni Pulo, and Allied Energy. Six out of the eight marginal field operators were operating on IRTS up till the end of 2016. More than 78% and 75% of the total IndOCs-SR operators and MFC-operators were in this category, respectively. This simply indicates that if their inputs (reserves and number of wells) could be increased by one unit, there is going to be a corresponding more than one-unit increase in the quantity of their output (oil & gas production).

Chapter 5

5. Economic Panel Model Results and Analysis

5.1 Analysis of Descriptive Statistics

The interpretation of the results of economic analysis commenced with the analysis of the descriptive statistics of all the variables used for the analysis. The variables of interest were CRTSteindex (cDEA), VRTSteindex (vDEA), GTAX, WCOD, OEXP, RPOIL and RPGAS as specified in the Panel model below.

$$\mathrm{cDEA_{it}} = \alpha + \beta_1 \mathrm{logWCOD_{it}} + \beta_2 \mathrm{logRPOIL_{it}} + \beta_3 \mathrm{logRPGAS_{it}} + \beta_4 \mathrm{logOEXP_{it}} + \beta_5 \mathrm{logGTAX_{it}} + \mu_{it} \qquad \mathbf{4.1}$$

$$\mathrm{vDEA_{it}} = \alpha + \beta_1 \mathrm{logWCOD_{it}} + \beta_2 \mathrm{logRPOIL_{it}} + \beta_3 \mathrm{logRPGAS_{it}} + \beta_4 \mathrm{logOEXP_{it}} + \beta_5 \mathrm{logGTAX_{it}} + \mu_{it} \qquad \mathbf{4.2}$$

Table 5.1 depicts the summary of annualized statistics for all the variables in the study. The average estimated CRTSteindex for the sample period is 44 percent. This is relatively fair considering the fact that it is a measure of the TE performance of the operators under ideal situations. The low standard deviation value of 32% compared to mean value of 44% shows that the estimated CRTSteindex has been generally stable in the upstream sector over the years. The Jarque-Bera (JB) value is significant at 1% level, indicating that the hypothesis of normality in the distribution is rejected. The distribution of estimated CRTSteindex has skewness value of 0.66, indicating a positive skewness which implies that the right tail is particularly extreme; this also shows that deviations from the mean are positive. The kurtosis value of 2.03, which is less than 3, shows a platykurtic distribution indicating that the distribution has tails that are thinner than the normal distribution. This implies that the estimated CRTSteindex data series may

possess heterogeneity problem. This necessitated the adoption of a panel data model that is capable of addressing the heterogeneity effects.

The estimated VRTSteindexes have an average value of 62%, indicating that the upstream operators have a relatively higher VRTSteindex compared to CRTSteindex. This is expected because VRTS model estimation deviates from an ideal situation of CRTS model to abnormal situation that is peculiar to Nigeria's upstream operations. The standard deviation value of 34% implies that the estimated VRTSteindexes have been generally stable and the VRTS model is suitable to estimate the TE of Nigeria's upstream operations. Similarly, Jarque-Bera (JB) value is also significant at the conventional 1% level which implies that the null hypothesis of normality of the distribution is not accepted.

Table 5.1: Descriptive Statistics

	cDEA	vDEA	GTAX	OEXP	WOD	RPOIL	RPGAS
Mean	0.44	0.62	105.56	23.28	91.53	17785.29	1634.09
Median	0.34	0.55	13.88	20.00	91.80	23.83	44.92
Maximum	1.00	1.00	907.66	67.00	96.10	3965714.00	287730.00
Minimum	0.00	0.08	0.00	1.00	86.40	0.00	0.01
Std. Dev.	0.32	0.34	164.70	15.10	3.16	264965.20	19293.94
Skewness	0.66	-0.05	1.93	1.08	-0.09	14.87	14.66
Kurtosis	2.03	1.33	6.71	3.37	1.90	222.00	217.78
Jarque-Bera	24.99	26.23	268.19	44.64	11.56	455902.60	438591.70
Probability	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sum	97.80	138.82	23645.99	5215.00	20502.40	3983905.00	366036.20
Sum Sq. Dev.	23.30	26.34	6049148.00	50823.28	2220.62	15700000000000.00	83000000000.00
Observations	224.00	224.00	224.00	224.00	224.00	224.00	224.00

The estimated VRTSteindexes distribution is negatively skewed with value -0.05, implying that the left tail is particularly extreme. This indicates negative deviation from the mean. The kurtosis value of 1.33 also shows a platykurtic distribution which indicates that the tail of the distribution is flat compared to the normal distribution. By implication, the estimated VRTSteindexes' panel

data may have heterogeneity issue. The issue of data heterogeneity informs the adoption of a model that is capable of addressing the heterogeneity problem.

Gross Taxes paid by most operators in Nigeria has a mean value of $105.56/bbl/year and a standard deviation of $164.70/bbl/yr which shows that the Gross Tax (regulated by the Government in accordance with the Nigerian Petroleum Fiscal Laws for all upstream operations) is slightly stable. The JB probability value of 0.000 shows that panel data of Gross Tax is not normally distributed (that is, rejection of the normality hypothesis of the distribution). The distribution is positively skewed having a value of 1.93, while the Kurtosis value of 6.71 shows a leptokurtic distribution possesses fewer outliers.

The World Crude Oil Demand (WCOD) shows an average value of 91.53 Mbopd and a standard deviation value of 3.16 Mbopd which indicates that the data set of WCOD is highly stable, an implication that on the average, WCOD has been relatively constant over the sample period. The probability of the JB statistic 0.000 provided enough evidence that the null hypothesis of normal distribution is to be rejected. The distribution is also negatively skewed having a value of -0.09 and a platykurtic distribution of 1.90 indicating positive kurtosis.

Average operators experience for the sample period is 23.28 years, an indication that most of the 32 upstream operators have been in operation in Nigeria for more than 20 years. The low standard deviation value of approximately 15 years shows that operators experience has been generally stable in the upstream sector of the country over the sample period. The Jarque-Bera (JB) value is significant at 1% level, indicating that the hypothesis of normality in the distribution cannot be accepted. The distribution of operators' experience has skewness value of 1.08 indicating a positive skewness which implies that the right tail is particularly extreme. This also shows that deviations from the mean are positive. The kurtosis value of 3.37 shows a leptokurtic distribution indicating that the distribution has fewer outliers (fatter tails than the normal

distribution).

The descriptive statistic of oil reserve to production ratio (RPOil) shows an average value of 17,785.29 and a standard deviation value of 264,965.20. This indicates that the data set of RPOIL was unstable over the sample period. The probability of JB statistic (0.000) shows that the null hypothesis of normal distribution is to be rejected. The distribution is also positively skewed having a value of 14.87 and a Leptokurtic distribution of 222.00 indicating presence of outliers (i.e., fatter tails). Average gas reserve to production (RPGas) for the sample period is 1634.09, with a standard deviation value of 19,293.94. The standard deviation value compared to the mean value revealed that RPGAS has been relatively unstable in the upstream sector of the country over the years. The JB value is significant at 1% level, indicating that the hypothesis of normality in the distribution is rejected. The distribution of RPGas has skewness value of 14.66 indicating a positive skewness, thus implying that the positive tail is particularly extreme.

The kurtosis value of 217.78 shows a leptokurtic distribution indicating that the distribution is flatter than the normal distribution. However, it can be seen that the adoption of a panel data model is justified by the fact that all the variables of interest were individually not normally distributed. One of the advantages of panel data model is that it is capable of capturing the heterogeneity effects that were present in the data set.

5.2 Analysis of Correlation Coefficient Matrix

The correlation coefficient matrix was conducted to further examine the background behavioural pattern of the panel data set in the study. The correlation coefficient matrices for all the variables of interest (including CRTSteindex, VRTSteindex, GTAX, WCOD, OEXP, RPOIL and RPGAS) are recorded in Table 5.2.

Table 5.2: Correlation Coefficient Matrix

	cDEA	vDEA	GTAX	WOD	OEXP	RPOIL	RPGAS
cDEA	1.000						
vDEA	0.711	1.000					
GTAX	0.176	0.099	1.000				
WOD	-0.078	-0.115	0.064	1.000			
OEXP	0.011	0.202	0.454	0.173	1.000		
RPOIL	-0.485	-0.198	-0.330	0.025	0.121	1.000	
RPGAS	-0.634	-0.526	0.006	0.034	0.082	0.305	1.000

The correlation statistics reveal that a positive correlation exists between estimated CRTSteindex with both gross tax (Regulation) and operators experience. This implies that two exogenous variables move in the same direction with the estimated CRTSteindex. On the contrary, a negative correlation exists between WCOD, RPOil and RPGas. This is an indication that the exogenous variables move together but in opposite direction (having inverse relationship).

The correlation statistic for the estimated VRTSteindex shows that it shares similar relationship with the exogenous variables of interest as the estimated CRTSteindex. It has a positive relationship with Gross Tax (Regulation) and Operators Experience (age), while on the other hand, it has a negative relationship with WCOD, RPOil and RPGas. Similarly, Gross Tax seems to have a positive correlation with WOCD, Operators Experience (age) and RPGas. This indicates that the Gross Tax paid by each operator and the studied exogenous variables (WCOD, Operators Experience and RPGas) move together in the same direction. Contrarily, Gross Tax has a negative correlation with RPOil, indicating that both variables move in inverse direction. This may be as result of the country's inability to reposition its gas sector for effective

productivity.

World Crude Oil Demand (WCOD) correlation statistic shows that it has a positive correlation with all the exogenous variables, the Operators' Experience, Reserve to Production-Oil and Reserve to Production-Gas. The correlation statistic of operators' Experience shows that there seems to be an existence of a positive relationship between operators' Experience on one side and RPOil & RPGas on the other side. This is an indication that these exogenous variables move together in the same direction. Finally, there also seems to be existence of a positive correlation between RPOil and RPGas, an indication that they move together in the same direction.

Prior to the estimation of the parameters of the specified panel data model, it is imperative to ascertain which of the estimation models or specification among Fixed Effect (FE), Random effect (RE) and Pooled OLs is suitable. One common method for testing this assumption is to employ a Hausman test to compare the fixed and random effects estimates of coefficients (Hausman, 1978; Wooldridge, 2002; Baltagi, 2005). In carrying out this test, the random effects model is estimated first, and afterwards the Hausman test. A central assumption in random effects estimation is the assumption that the random effects are uncorrelated with the explanatory variables. The Chi-square statistic provides adequate evidence against the null hypothesis that there is mis-specification. Thus, the test results led to the selection of fixed-effects regression for the estimation of the parameters of the panel data.

5.3 Economic Analysis Considering CRTSteindex as Dependent Variable

The result from Table 5.3 (result of estimated panel data) reveals that regulation-gross tax (GTAX), world crude oil demand (WCOD), operators' experience (OEXP), oil reserve to production ratio (RPOil) and gas reserve to production ratio (RPGas) are statistically significant

at the conventional level of significance. This means that the probability value of variable of interest is less than 5 percent (prob. value < 0.05). The constant, as a very important parameter in the model, is also highly significant and has the expected positive sign. In considering the fact that all the studied independent variables are expressed in percentages, 1.0 percent increase in GTAX-Regulation will on the average bring about 0.089 unit reduction in CRTSteindex while holding other independent variables (WCOD, OEXP, RPOIL and RPGAS) constant. This finding shows that harsh regulatory intervention by host government affects the TE of the upstream operators negatively. Put differently, increasing government upstream taxes via regulation discourages TE of the operators as well as its stake. This result is in line with the *a priori* expectation, i.e., the coefficient of Gtaxes possesses the right sign.

Similarly, 1% increase in WCOD will, on the average, bring about 3.34 unit reductions in the TE of the operator (CRTSteindex) while holding other explanatory variables constant. The result implies that WCOD impacts negatively on the variation of the CRTSteindex of the upstream operators in Nigeria. This finding is contrary to the *a priori* expectation. The plausible explanation for this development is the issue of OPEC quota system which Nigeria is subjected to as a member. In addition, it appears that OPEC membership has a significant effect on the performance of the member countries. The production quota policy of OPEC according to Ike and Lee (2014) may be responsible for the average efficiency scores of the OPEC member. This is because the production quota policy constrains each member country to a certain level of production even though they have the capacities to produce more considering their inputs resources.

Table 5.3: Output of Impact of Exogenous Variables on CRTSteindex

Variable	Coefficient	Std. Error	T-Statistic	Prob.
C	6.644	1.940	3.424	0.001
LogGTAX	-0.089	0.038	-2.319	0.022
LogWCOD	-3.340	1.121	-2.980	0.003
LogOEXP	0.688	0.263	2.612	0.010
LogRPOIL	-0.173	0.032	-5.472	0.000
LogRPGAS	-0.109	0.016	-6.679	0.000
R-squared	0.842			
Adj. R^2	0.812			
F-statistic	27.549			
Prob (F-stat)	0.000			
D-W	1.375			
Post-Estimation Test				
Test Statistics		Statistic		Probability
Hausman Test		15.151		0.000
Normality (Jarque-Bera)		5.819		0.055

The result also shows that increasing operator's experience by 1 percent will on the average bring about 0.688 unit increases in CRTSteindex while all other independent variables remain constant. This means that upstream operator's experience impacts positively on their TE *Ceteris Paribus*. By implication, the number of years an upstream operator has been in operation affects its technical efficiency positively. The more experience on the job, the greater its operational efficiency. This finding is in agreement with *a priori* expectation having the right sign. In the same vein, when RPOil is increased by 1%, CRTSteindex will, on the average, reduce by 0.173 unit while holding other independent variables constant. It points to the fact that RPOil affects technical efficiency of the upstream operators in Nigeria negatively. Puts differently, the longer the period it takes a firm to deplete its oil reserve, the less efficient the firm becomes. This result is in tandem with the *a priori* expectation of the study.

Finally, increasing RPGas by 1% will, on the average, bring about 0.109 unit reductions in TE while holding other independent variables constant. This means that increased RPGas has a negative implication on CRTSteindex of the upstream operators in Nigeria. Thus, the more time it takes a firm to deplete its gas reserves, the less technically efficient the firm becomes. This result concurs with the *a priori* expectation.

The R^2 statistic shows that the specified independent variables accounted for 84.2 percent variation in the dependent variable (CRTSteindex), while the Adjusted R^2 depicts that the independent variables are responsible for about 81.2 percent variation in the dependent variable (CRTSteindex). The F-statistic which measures the worthiness of the R^2 shows that R^2 is statistically significant; implying that the specified independent variables are jointly significant in explaining the CRTSteindex of the Nigerian upstream operators. The diagnostic test from table 5.3 shows that the residual estimate of the estimated model is normally distributed at 5 percent significantly level, thus the null hypothesis of normality is accepted.

5.4 Economic Analysis Considering VRTSteindex as Dependent Variable

The output from Table 5.4 based on probability value reveals that the independent variables world crude oil demand (WCOD), operators experience (OEXP), Oil reserve to production ratio (RPOIL) and Gas reserve to production ratio (RPGAS) are statistically significant at the conventional level of significance, because the probability value of variable of interest is less than 5% (prob. value < 0.05) and 10 percent (prob. value < 0.10). The coefficients of the regressors possess the right sign excluding WCOD. Likewise, the constant which is an important parameter in the model, is also highly significant having the expected sign. On the contrary, gross taxes paid (GTAX), which the study considers as a proxy for upstream regulation, is statistically insignificant at the conventional significant level as stated above.

All the independent variables are expressed in percentages. Thus, 1% increase in WCOD will, on the average, bring about 3.57 unit reductions in VRTSteindex while holding other explanatory variables constant. The result implies that world crude oil demand impacts negatively on the variation of the VRTSteindex of the upstream operators in Nigeria. This finding is contrary to the *a priori* expectation. The plausible explanation for this development is the quota system by OPEC of which Nigeria is a member.

Also, increasing OEXP by 1% will, on the average, bring about 3.65 unit increase in VRTSteindex while all other independent variables are kept constant. This means that upstream operator's experience impacts positively on the efficiency of the upstream operators in Nigeria. By implication, the number of years a particular upstream operator has been in operation affects its technical efficiency positively. The more experience on the job, the greater the operational technical efficiency. This finding is in agreement with the *a priori* expectation having the right sign. In the same vein, when RPOIL is increased by 1%, VRTSteindex will on the average reduces by 0.076 unit while holding other independent variables constant. This suggests that oil

reserve to production ratio affects VRTSteindex of the upstream operators in Nigeria negatively. Put differently, the longer the period it takes a firm to deplete its oil reserve, the less technical efficient the firm becomes. This result is in tandem with the *a priori* expectation.

Similarly, increasing RPGAS by 1 percent will, on the average, bring about 0.040 unit reductions in VRTSteindex while holding other regressors constant. This means that Gas Reserves to Production ratio has a negative influence on CRTSteindex of the upstream operators in Nigeria. Thus, the more time it takes a firm to use-up its gas reserve, the less efficient the firm becomes. This result concurs with the *a priori* expectation of the study. On the contrary, 1 percent increase in GTAX on the average has the potential of bringing about 0.019 unit reductions in VRTSteindex while holding other regressors constant. This finding shows that gross taxes (regulation) have the potential of negatively affecting the VRTSteindex of the upstream operators in Nigeria. This implies that increasing upstream taxes via government regulation discourages operators' technical efficiency. Paying more taxes to the host government tends to increase the cost of operation of the upstream firms. This result is in line with the *a priori* expectation of the study (that is, it possesses the right sign).

The R^2 statistic shows that the specified independent variables accounted for 90.2% variation in the dependent variable (VRTSteindex), while the Adjusted R^2 shows that the independent variables are responsible for 88.4% variation in the dependent variable (VRTSteindex). The F-statistic which measures the worthiness of R^2 shows that R^2 is statistically significant, with the implication that the specified independent variables are jointly significant in explaining the dependent variable. The diagnostic test from Table 5.2 shows that the residual estimate of the estimated model is normally distributed at 5 percent level of significantly. Thus the null hypothesis of normality is accepted.

Table 5.4: Output of Impact of Exogenous Variables on VRTSteindex

Variable	Coefficient	Std. Error	T-Statistic	Prob.
C	7.346	1.624	4.525	0.000
LogGTAX	-0.019	0.032	-0.605	0.546
LogWCOD	-3.567	0.938	-3.804	0.000
LogOEXP	0.365	0.220	1.658	0.099
LogRPOIL	-0.076	0.026	-2.863	0.005
LogRPGAS	-0.040	0.014	-2.888	0.004
R-squared	0.903			
Adj. R^2	0.884			
F-statistic	47.883			
Prob (F-stat)	0.000			
D-W	1.574			

Post-Estimation Test		
Test Statistics	Statistic	Probability
Hausman Test	15.588	0.008
Normality (Jarque-Bera)	17.657	0.000

Chapter 6

6. Conclusion and Policy Recommendations

6.1 Conclusion

The general objectives of this study have been accomplished and the hypotheses stated have been tested and statistically authenticated. In this study, we have been able to use the developed two DEA models known as Constant Return to Scale (CRTS) Model and the Variable Return to Scale (VRTS) Model to estimate the needed technical efficiency (TE) indexes for all the 32 active petroleum upstream operators in Nigeria. The results obtained have shown that the VRTS model is more suitable to analyse the technical performance (TP) of upstream petroleum industries due to the robustness of the model assumptions *ceteris paribus*. Consequently, the results obtained from VRTS model were used to rank the 32 active operators based on production contract as follows: JVC group-75%; MFC group-67%; SRC group-65%; PSC group-64%; SC-NAOC-42% and NOC-NPDC-23%.

Moreover, the results obtained from the estimated output oriented NIRTS model were compared with those of the estimated output oriented CRTS model and output oriented VRTS model to classify the operators into different production frontier group. Based on these results and the stated decision criteria in Tables 4.3 and 4.5 of this study, 32 active upstream operators in the sample were categorized into different return to scale groups, i.e., IRTS, DRTS and CRTS (Table 4.8, Figure 4.13 and Appendix B7).

In addition, the results of the economic analysis using panel data model indicated that four of the selected independent variables were key determinants of the upstream TP in Nigeria within the period, 2010 to 2016. These variables were world crude oil demand, the experience of the

respective operators, proved oil reserves to production ratio and proved gas reserves to production ratio. The study shows that 1% increase in gross taxes pay by investors brings about 0.019 unit reduction in TE of the operator, hence the inference that increasing E and P companies' taxes via host government regulation decreases TE of the operators, and perhaps gross revenue. Taxing operators regressively may in the long-term lead to increasing total cost of operations to the investors and even to the Government, irrespective of the type of upstream contract in place.

The results also indicated important policy direction towards optimum performance of upstream petroleum industry in Nigeria. It was recorded that joint venture contractors performed better than the remaining contracts despite the failure of the Government to pay its cash calls when such were due, amounting to over $9.125billion in September, 2016 (NVBN, 2016). However, the results supported the planned exit of the cash calls model by the Nigerian Government. Also, the results confirmed that the proposed exit of cash calls model is not in any way detrimental to both host government and investors' takes. For the indigenous operators, the study proposes that Government should put in place an indigenous human resource development strategy to enable interested citizens to take absolute responsibility of their resource management.

6.2 Policy Recommendations

The results obtained from CRTS model show that about 19% of the thirty-two (32) active upstream contractors were operating on CRTS efficient production frontier. These include three out of the seven PSC operators, one out of the nine SR operators and two out of the eight MFOs. The six named operators were operating at optimum scale within the period 2010 and 2016. These operators neither depict economies nor diseconomies type of crude oil production scale. The operators' outputs increase/decrease in similar proportion with their inputs. They

could be regarded as efficient at increasing their outputs either in large quantity or small quantity. They have attained the optimal points with steady levels of outputs or constant levels of oil and gas production.

Considering the above, the study recommends that Government should formulate upstream policies that will encourage an aggressive growth of oil and gas reserves. This kind of policy focus has tendency to increase both oil and gas proven reserves base of the respective operators in this category. The aggressive reserves growth strategy has the long-term effect of increasing oil and gas production volumes. It is evident from the results of the analysis that there is need for oil and gas reserves addition programme. However, adequate strategies must be put in place to ensure that these reserves are activated for production to maximize the current total upstream production in Nigeria. This should be done judiciously because it has been forecast that oil production would decrease from the 2.3 MMBBL/DAY as of December, 2016 to less than 2 MMBBL/DAY by 2026, (NNOP, 2017).

Available data reveals that gas resources are the most dominant and sustainable natural resources in Nigeria in the last ten years. The available data shows that the volume of proved gas reserves in Nigeria is far more than the volume of proved oil reserves. A sustainable gas production focussed policy will, in the long run, move Nigeria to a gas-based industrial economy globally. So, an aggressive non-associated gas exploration must be dedicated rather than searching for associated gas via oil exploration to derive maximum benefits from the endowed resources. Oil and Gas experts have, at different fora, often described the current gas in Nigeria as “gas discovered by accident”. The Government of the Federation needs to articulate policies for the introduction of a viable regulatory framework for the gas sector. With these recommended action plans, the gas investment barriers that have been negatively affecting the investors will be removed.

Also, the MPR should be mandated to carry out periodic updates of the policies to ensure consistency with the initial policy objectives. The core goal should be tailored towards repositioning Nigeria from an oil dependent economy into a gas dependent economy. This must be driven through the establishment of a single regulatory authority; gas value chain separation; sound gas to power initiative; contract terms stability; and active Nigerian local content drives. MPR has a pivotal role to play by putting measures in place to ensure the attractiveness of the gas sector as the hub of international investments.

Furthermore, it is recommended that Government should formulate an indigenous human resource development strategy. In considering our model results in Table 4.8, five out of the six companies on CRTS efficient production frontiers are indigenously owned and oriented companies (that is, 2-MFOs, 2-SR, 1-PSC (PSCO2), (Appendix A3). MFCO7 came first in the ranking despite all odds facing the indigenous companies in Nigeria. To improve the indigenous companies' current performance, there must be an indigenous competency and capability improvement policy in place. This type of policy will enable Nigeria to take absolute responsibility of its resource exploitation and management. Having discovered Petroleum since 1956, Nigeria's oil and gas professionals are supposed to be in top positions in most petroleum producing companies around the world. But, this is not so, because there is virtually no working human capital development policy on ground. The Content Development Act 2010 (NOGICD) was signed into law to encourage indigenous participation in the oil and gas business by Former President Olusegun Obasanjo administration. Only eight out of the first 31 marginal field Licenses awarded in 2004 are currently active (2010-2016), even the active ones somehow depend on foreign experts to perform efficiently. Nigeria needs a collaborative oil and gas industry competency framework which should be in operation nationwide to reduce the level of incompetency in the sector.

CRTS model assumes an ideal situation, that is, all the active 32 operators have access to sustainable oil and gas projects financing scheme, conducive and environmentally friendly operational terrains, perfect security situations, no militancy or associated violence, no delay in obtaining permits or licenses from government agencies, sustainable regulatory and fiscal frameworks in place, etc. Optimality assumption may not be too easy to achieve, every oil and gas producing country has its peculiar challenges internationally. Based on this, the second model known as VRTS model was adopted and used in the second stage of this study to validate the results. VRTS model assumes scale variability. It is used due to the imperfect conditions of oil and gas operational environments in Nigeria and in most petroleum provinces around the world. The scale variability model was also used to determine the scale status of the remaining 26 operators that were not on the CRTS efficient frontier.

Based on the results of the VRTS model in the stage 2 of the study, the following policy recommendations are made. Firstly, the results of the second model evidently showed that the foremost oil and gas operators in Nigeria appeared not to be performing efficiently as expected. In most cases, they find it difficult to maximize petroleum production beyond the current status (which is diseconomies of scale). More than 90% of the foremost operators were operating on DRTS within the period under review. These big international oil and gas companies are already oversized, which is a clear indication that they had exceeded their optimal sizes. If the policy focus is about increasing or maximizing the Nigerian upstream operators' efficiency as stated in the newly signed Nigeria National Oil Policy (NOP) and National Gas Policies (NGP), then, there is the need to decrease the sizes of the companies (NNOP & NNGP, 2017).

Practically, though difficult, the Policy Makers should focus on how to make the 8 operators on DRTS production frontier to relinquish some of their assets or licenses to be attributed in the subsequent licensing rounds. By doing this, each of the new investors would be able to autonomously maximize outputs efficiently (Huguenin, 2012, 2015). The formation of a new

company from the old ones has tendency to minimize bureaucracies. The operational bureaucracies have hitherto been one of the obstacles to effective decision-making process, (Ike & Lee, 2014). Splitting the companies will facilitate new efficiency-oriented ideologies which could help to create objective based management strategies for performance growth in the sector.

Alternatively, diseconomies of scale in petroleum industry may also occur as a result of a number of factors, which include weighty operational interdependency, awkward coordination and communication, lack of enthusiasm and control, complications of large-scale management, exhaustible proved reserves and other externalities. If the policy focus of the Government is on maximizing upstream companies' TE, then, it is important to strategize towards active operational interdependency, decent system of communication and coordination, and personnel sensitization to address productivity problem and inculcate a sense of discipline around the key upstream investment value chain. By doing these, each operator will independently maximize its outputs competently, and create objective based management policies for its overall performance growth. Also, integrating current data and large data into decision making procedure will facilitate new approaches that will surely depart from the old ones for sustainable and effective operational decision.

In addition, the results of models show that more than 55% of the 32 active upstream operators were operating on IRTS within the period. The percentage amounts to 18 out of 32 active upstream operators in the sector (that is, 7/9 SR, 6/8 MFO, 3/7 PSC, 1/6 JV, & 1 SC). What this implies is that, if the inputs of more than 50 percent of the operators could be increased by one unit (1 Well & 1MMboe), there is going to be a corresponding more than one unit increase in the volume of oil and gas produced. Though all these companies appear to have economies of scale, they are yet to reach their optimal sizes. To be able to maximize outputs, there is the need to enact policies that will focus on increasing the sizes of the companies. This could be

achieved by promoting or formulating an upstream policy that will enhance internal growth within the sector.

Apart from the suggestions above, operators in this category could form coalition within or outside, or with new companies to increase production. New upstream technologies and innovations which will focus mainly on maximizing oil and gas production could be brought. More attention must be dedicated to MFOs by creating sustainable incentives to drive in more investments to maximize aggregate revenues. Moreover, new technologies may be deployed to increase the reserves base of the operators. More attention must be given to MFOs by creating sustainable incentives for the operators to encourage more investments that will boost production.

The results of the economic analysis reveal that the independent variables WCOD, OEXP, RPOIL and RPGAS are statistically significant at the conventional level of 5 percent and 10 percent. The coefficients of most independent variables possess the right signs excluding WCOD. Equally, the constant is also highly significant having the anticipated sign. On the contrary, Gtax is statistically insignificant at the conventional significant level. All the independent variables are expressed in percentages. Consequently, 1% increase in WCOD will, on the average, bring about 3.57 unit reductions in TE scores. The clear inference from this is that WCOD impacts negatively on the variation of operators' TE. This is contrary to the *a priori* expectation, and this can be explained to be a result of the quota being implemented by OPEC.

Likewise, increasing OEXP by 1% will on the average bring about 0.37 unit increase in the technical efficiency. By implication, the experience of an operator plays a major role in enhancing its technical performance (the more the experience, the greater the operational efficiency of an operator). In the same vein, when RPOIL and RPGas are increased by 1%, efficiency averagely reduces by 0.076 unit and 0.040 unit, respectively. This indicates that

reserve to production ratio affects operator's efficiency negatively. Put differently, the longer the period it takes an operator to deplete its reserves, the less technically efficient the operator becomes. On the contrary, 1 percent increase in GTAX results to 0.019 unit reduction in TE. This indicates that increasing taxes via regulation discourages TE of the operators (that is, paying more taxes to the Government has tendency to increase the operational cost). The study encourages policy makers to desist from advocating upstream taxes that are regressive in nature, so as to increase the TE of the operators.

Chapter 7

7. Contributions to Knowledge

7.1 Major Contributions

This Ph.D. research has contributed to the body of knowledge in oil and gas industry worldwide in the following ways:

1. The study generated the needed technical efficiencies for all the 32 active upstream operators in Nigeria. In doing this, ideal cases were assumed and a fractional mathematical model was converted to linear model known as constant return to scale-data envelopment Analysis Model. The formulated model was estimated manually using a Microsoft Excel spreadsheet aided with a visual basic for applications to generate the needed technical efficiency indexes for all the operators simultaneously. The formulation of a model which gives estimates of upstream technical efficiency under ideal situations is novel to the upstream industry at large. The model could be used to access the technical performance of upstream companies in other oil and gas provinces especially where the operational conditions are optimal.
2. The study also considered non-ideal circumstances which may include policy issues, insecurity, delays in obtaining permits or licenses, crude oil price volatility, politics, project financing problems etc. Considering these conditions, new set of technical efficiency indexes were generated for all the 32 active upstream operators in Nigeria. It appears that the results obtained using the variable return to scale model depict the reality of technical performance of Nigeria upstream petroleum sector. This is unique in the sense that the study has been able to identify the preferred model that gives the best estimates of the Nigerian oil and gas upstream industry technical efficiency.

3. An output non-increasing return to scale-DEA model was also formulated to evaluate all the 32 active operators in Nigeria to ascertain their production frontiers scale. The results obtained were used to categorize each of the 32 active operators into their respective production technological frontier, i.e., CRTS production frontier, IRTS production frontier and DRTS production frontier. This is novel because no study has been able to effectively identify the production frontier of the oil and gas upstream industry in Nigeria till date. This approach can be used to identify the production frontier of upstream companies in other oil and gas regions of the world.
4. An economic analysis was carried out using panel data estimator. The model results show the relationships between the estimated TE indexes obtained from VRTS model, CRTS model and selected five exogenous variables. This is also unique because the key determinants controlling the upstream technical efficiency in Nigeria were identified. Additionally, the analysis to a large extent supports the cash calls exit programme of the Nigerian government. The dilemma of whether the exit of the cash calls model would be detrimental to the government revenue or not has been put to rest by the new findings.

7.2 Published Research Articles and Conference Papers

1. **Idowu, A. J., Iledare, O. O., & Dada, B. G.** (2019, January). Evaluating Technical Efficiency of Firms of Different Sizes: A Case Study of Nigeria Upstream Players. SPE Reservoir Evaluation & Engineering Journal. DOI: 10.2118/194210-PA.

2. **Idowu, A. J., Iledare, O. O., Echendu, J. C. & Achi, P. O. (2019, January).** Upstream Technical Efficiency and Its Determinants: Evidence from Non-Parametric and Parametric Analysis of Nigeria Exploration & Production (E&P). Cogent Engineering Journal (Taylor & Francis). DOI:10.1080/23311916.2019.1575638.

3. **Idowu, J. A., Iledare, O. O., Adeogun, O., & Echendu, J. C.** (2018, August 6). Performance Assessment of Nigeria E & P Operators Using Data Envelopment Analysis (DEA). Society of Petroleum Engineers, 2018 NAICE Conference Paper. DOI: **10.2118/193455-MS.**

4. **Echendu, J. C., Idowu, A. J., Iledare, O. O., and Akinlawon, A. J.** (2019, January). Single-Tier or Dual-Tier Tax Systems: Implication on Petroleum Project Economics in Nigeria: SPE Reservoir Evaluation & Engineering Journal. DOI: **10.2118/193453-PA**

5. **Echendu, J. C., Idowu, A. J., Iledare, O. O., and Akinlawon, A. J.** (2018). Replacing Petroleum Profit Tax with a Dual Petroleum Tax System: Implication on Petroleum Project Economics in Nigeria. Society of Petroleum Engineers. 2018 NAICE Conference Paper. DOI: **10.2118/193453-MS.**

6. **Adeogun, O., Iledare, O., & Idowu, A. J. (2018, August 6).** Profitability of Marginal Oilfields in a Low Oil Price Regime: A Stochastic Modelling Analysis. Society of Petroleum Engineers. DOI: **10.2118/193466-MS.**

Chapter 8

8. Future Works

8.1 Propositions for future research

The following research areas are suggested as some of the potential areas for subsequent studies using the general DEA framework proposed in this work;

1. Identification of upstream operations' incentives' barriers to improving oil and gas upstream technical efficiency, especially as a lesson to the upcoming producing countries in the Gulf of Guinea (GOG) and other parts of the world.
2. Estimation of Nigeria's upstream industry cost efficiency using variable return to scale-data envelopment analysis. The study is important to identify operators which are efficient at minimizing its exploration and production technical cost in Nigeria.
3. Estimation of Nigeria's upstream industry revenue efficiency using variable return to scale-data envelopment analysis.
4. Benchmarking the technical performance of Nigeria upstream operators under contractual fiscal system with the operators under concessionary fiscal system using variable return to scale-data envelopment analysis.
5. Evaluation of the efficiency change of Nigeria upstream petroleum industry from 2010 to 2019: Evidence from Malmquist productivity index.

Nomenclature

AE	Allocative Efficiency
AEB	Annual Expenditure Budget
AENR	Agip Energy and Natural Resources
AES	Allen Partial Elasticity of Substitution
AFDB	African Development Bank
ANSA	Annual North Sea Awards
AOI	All Ordinaries Index
BCC	Banker, Cooper & Charnes
BCPC	British Colonial Petroleum Company
BOPD	Barrel of Oil per Day
Capex	Capital Expenditure
CCM	Common Constant Method
CCR	Charnes, Cooper & Rhodes
CEO	Chief Executive Officer
CIT	Corporate Income Tax
CITA	Corporate Income Tax

CNL	Chevron Nigeria Limited
CPI	Consumer Price Index
CRS	Constant Return to Scale
CRTS	Constant Return to Scale
CRTS	Constant Return to Scale
CRTSteindex	Constant Return to Scale technical efficiency index
DD	Price Deflators
DEA	Data Envelopment Analysis
DEAP	DEA Program
DES	Direct Elasticity of Substitution
DF	Distance Function
DJI	Dow Jones Index
DMUs	Decisions Making Units
DOP	Data Originated Problem
DPR	Department of Petroleum Resources
DRTS	Decreasing Return to Scale
EITI	Extractive Industries Transparent Initiative

EOS	Economic of Scale
FD	First Difference
FDP	Field Development Plan
FE	Fixed Effects
FPC	Foreign Petroleum Company
GDP	Gross Domestic Products
GGM	Group General Manager
GMD	Group Managing Director
GNBC	Germany Nigerian Bitumen Corporation
GNOC	Ghana National Oil Company
GNPC	Ghana National Petroleum Corporation
GOM	Gulf of Mexico
GPFG	Government Pension Fund Global
GTEI	Global Technical Efficiency Index
IDFS	Input Distance Function Specification
IndOCs	Independent Oil Companies
IOCs	International Oil Companies

IRTS	Increasing Return to Scale
JOA	Joint Operating Agreement
JV	Joint Venture
LRE	Long Run Elasticity
MC	Marginal Cost
MES	Morishima Elasticity of Substitution
MFC	Marginal Field Contract
MMBOE	Million Barrels of Oil Equivalent
MOU	Memorandum of Understanding
MP	Marginal Product
MPI	Malmquist Productivity Index
MPR	Ministry of Petroleum Resources
MPU	Mobil Producing Unlimited
MRTS	Marginal Rate of Technical Substitution
NAEE	Nigerian Association for Energy Economics
NAPIMS	National Petroleum Investments Management Service
NBC	National Bureau of Statistics

NCBDA	Nigerian Content Board & Development Agency
NCS	Norwegian Continental Shelf
NDDC	Niger Delta Development Commission
NDDC	Niger Delta Development Commission
NDP	Norwegian Petroleum Directorate
NGP	National Gas Policy
NHT	Nigerian Hydrocarbon Tax
NIRTS	Non-Increasing Return to Scale
NNOC	Nigerian National Oil Company
NNPC	Nigerian National Petroleum Corporation
NOC	National Oil Company
NOP	National Oil Policy
NPDEA	Non-Parametric DEA
NPSA	Norway Petroleum Safety Authority
NSF	National Sovereign Fund
OCS	Outer Continental Shelf
ODFS	Output Distance Function Specification

OECD	Organization for Economic Co-operation and Development
OGIC	Oil & Gas Industry Implementation Committee
OLS	Ordinary Least Square
OML	Oil Mining Lease
OMPADEC	Oil Mineral Producing Areas Development Commission
OPEC	Organization of Petroleum Exporting Countries
OPEX	Operating Expenses
OPL	Operating Mining License
PF	Production Function
PFN	Petroleum Fund of Norway
PIGB	Petroleum Industry Governance Bill
PIN	Price Index Number
PPI	Products Price Index
PPT	Petroleum Profit Tax
PPT	Petroleum Profit Tax
PRS	Planning, Research & Statistics
PSA	Production Sharing Agreement

PSC	Production Sharing Contract
PTEI	Pure Technical Efficiency Index
PTO	Petroleum Tax Office
QIN	Quantity Index Number
RE	Random Effects
RGI	Resource Governance Index
RTS	Return to Scale
SCA	Service Contract Agreement
SCF	Standard Cubic Feet
SCF	Standard Cubic Feet
SDFI	State Direct Financial Interest
SEOS	Specific Economic of Scope
SFN	Stochastic Frontier Analysis
SOT	Standard Oil Trust
SPDC	Shell Petroleum Company Limited
SRC	Sole Risk Contract
SRE	Short Run Elasticity

SRE	Short Run Elasticity
TE	Technical Efficiency
TEI	Technical Efficiency Index
TFP	Total Factor Productivity
TI	Tornquist Index
TPI	Tornquist Price Index
TQI	Tornquist Quantity Index
UAE	United Arab Emirate
UTC	Unit Technical Cost
VRS	Variable Return to Scale
VRTS	Variable Return to Scale
VRTSteindex	Variable Return to Scale technical efficiency index
WGE	Within Group Estimate

List of Symbols

R Oil / Gas Reserves

P Oil / Gas Production

Q Production Rate

E Efficiency

N Initial Oil in Place

G Initial Gas in Place

A Area extent of the reservoir, Acre.

H Average thickness of the reservoir, Ft.

$\emptyset$ Average Porosity, fraction.

S_{wi} Initial Water Saturation, fraction.

B_{oi} Initial oil formation volume factor, rbbls.

S_{gi} Initial Gas Saturation, fraction.

B_{gi} Initial Gas formation volume factor, SCF

j Operator Index, $j = 1,2,\cdots,n, \quad n = 32, j = 1,2,\cdots,32$

r Output Index, $r = 1,\cdots s, \quad s = 2, r = 1 \,\&\, 2$

i Input Index, $i = 1,\cdots,m, \quad m = 2, \quad i = 1 \,\&\, 2$

$q_{r,j}$ Value of rth input for the jth Operator

$p_{i,j}$ Value of ith output for the jth Operator

a_i Weight given to i^{th} input

b_r Weight given to r^{th} output

Z_0 Free variable which is associated with convexity constraint

γ_j weight given to j^{th} Operator (Primal Model)

Q Quantity of Output

$P_{m.j}$ Price of the m-th commodity at the j-th period (s,j)

$q_{m.j}$ Quantity of input and output of the m-th commodity at the j-th period (s,t)

$J_{s.t}$ Where m = 1, 2…m, s and t may refer to 2 firms instead of one time period

$I_{s.t}$ General index number for the current period t, with s as the base period

$V_{s.t}$ Value index numbers

$P_{s.t}$ Price index numbers

$q_{s.t}$ Quantity index numbers

$\phi^* \rightarrow \mathrm{CRTS}_{\mathrm{teindex}}$ relative technical efficiency index with CRTS assumption

$\varphi^* \rightarrow \mathrm{VRTS}_{\mathrm{teindex}}$ relative technical efficiency index with VRTS assumption

$\psi^* \rightarrow \mathrm{RTS}_{\mathrm{index}}$ Return to scale index

cDEA Estimated Constant Returns to Scale Index

vDEA Estimated Variable Returns to Scale Index

WCOD World Crude Oil Demand

RPOIL Reserve to Production-Oil

RPGAS Reserve to Production-Gas

OEXP Operator's Experience (Years)

GTAX Gross Tax Paid (Legislation)

E_n Output Elasticity

μ Composite error term

log Logarithm

I Cross-sectional entity

T time entity

A Intercept

β_1, β_2, β_3, β_4, β_5 and β_6: Slope Parameters which captures effects of the explanatory variables on the explained variable.

Lis of Subscripts

I initial

W water

O oil

G gas

r^{th} output number

i^{th} input number

teindex technical efficiency index

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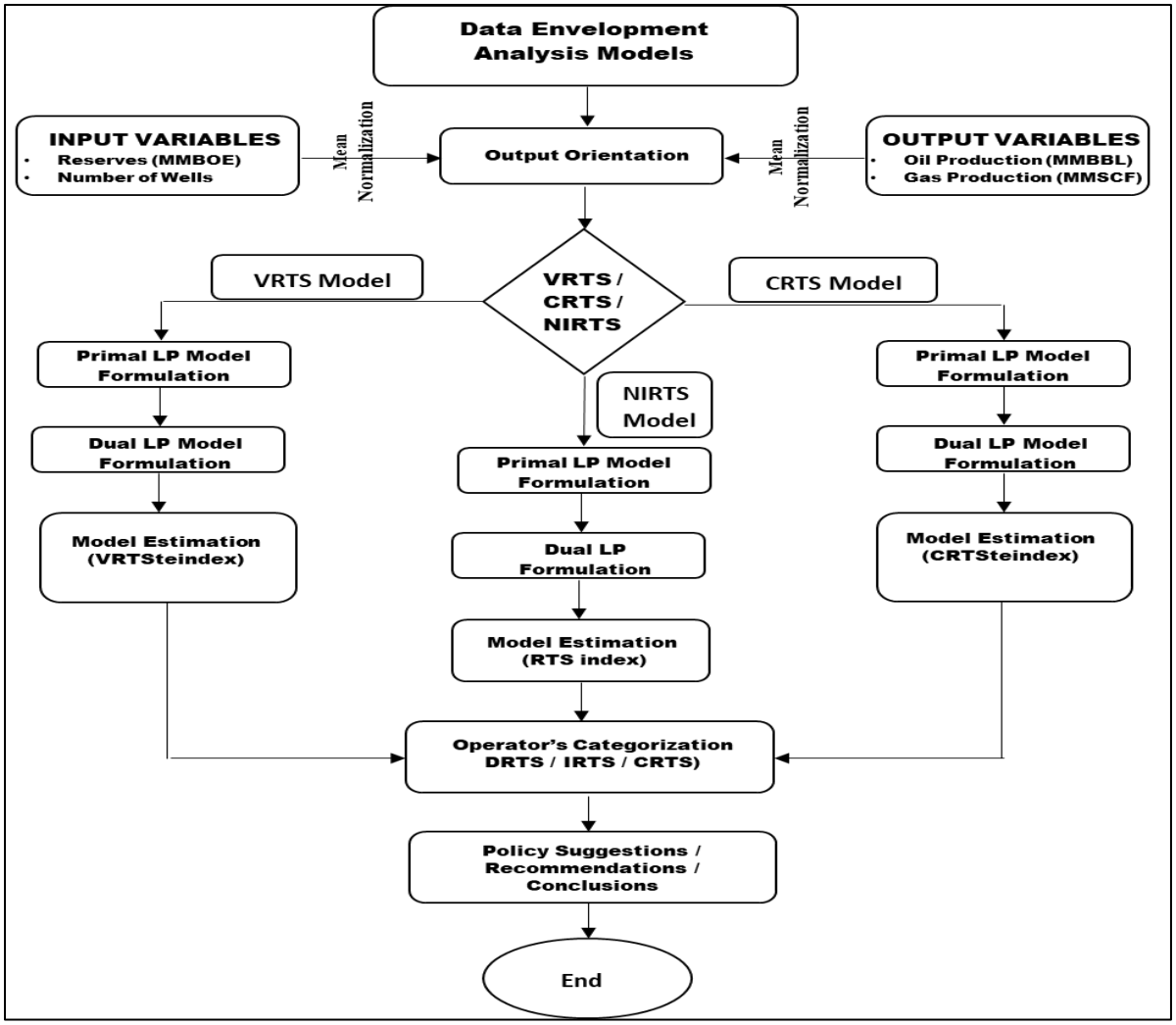
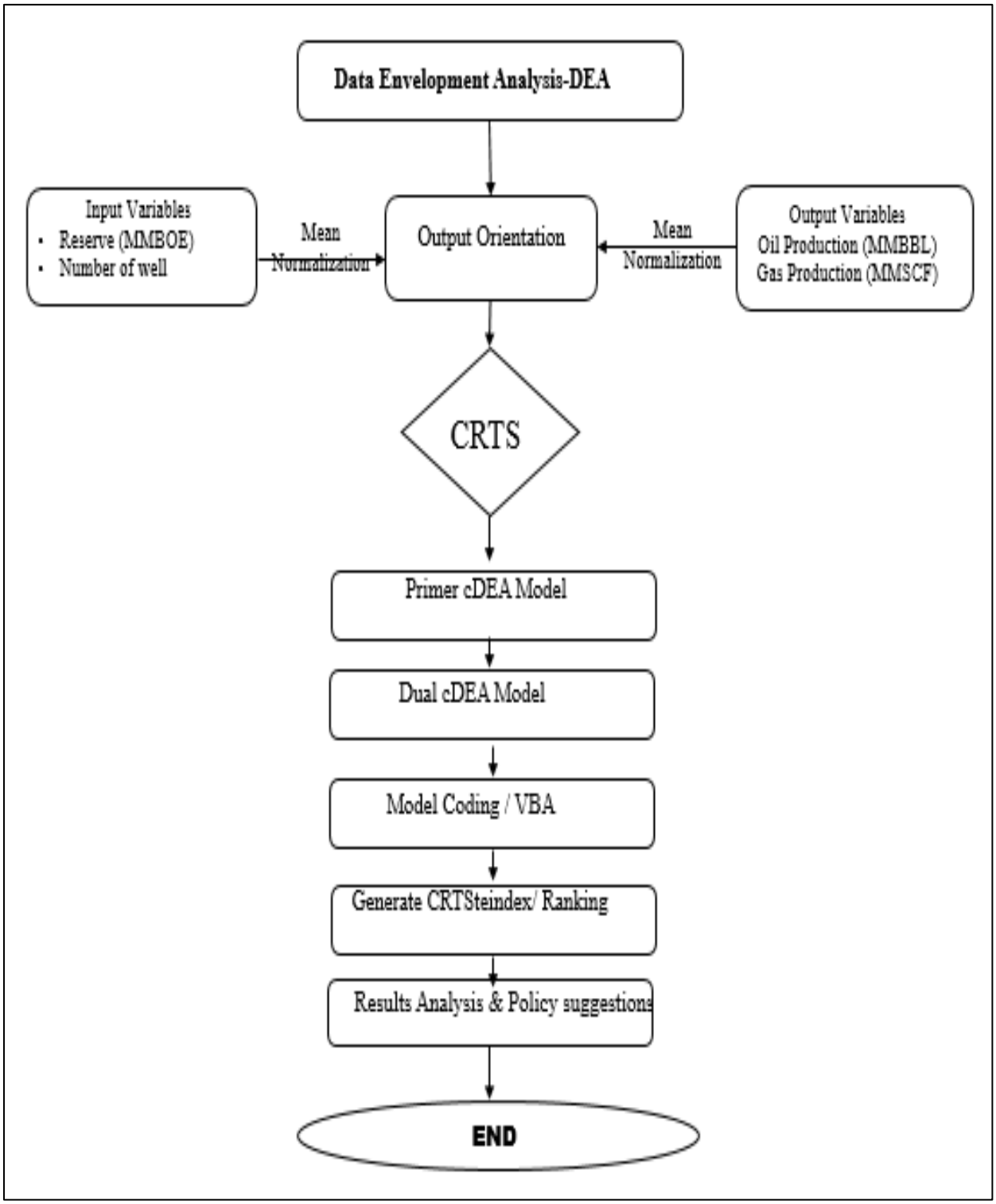
APPENDIX A

Research Methodological Frameworks

A1 Flowchart for estimating upstream operator's technical efficiency and the scale of its Production frontier using Data Envelopment Analysis (DEA).



A2 Flowchart for Estimating Upstream Operator's Technical Efficiency Using Constant Return to Scale-DEA Model



A3 Name of the 32 active upstream operators in Nigeria and their respective contracts names as used in the study

S/N	Operators' Name by Contract	Operator's Name
1	JVCO1	CHEVRON NIG LIMITED
2	JVCO2	MOBILPRODUCING UNLIMITED
3	JVCO3	NAOC/PHILLIPS NIG AGIP OIL COMPANY
4	JVCO4	PAN - OCEAN INTERNATIONAL
5	JVCO5	SPDC SHELL PET DEV COMPANY
6	JVCO6	TOTAL E & P
7	PSCO1	ADDAX Petroleum Nig Ltd
8	PSCO2	CHEVRON (STARDEEP) FAMFA OIL
9	PSCO3	ESSO EXP. & PRO. NIG LTD
10	PSCO4	NAE (Nig Agip Exp Limited)
11	PSCO5	SOUTH ATL & PET/TOTAL UPSTREAM NIG.
12	PSCO6	SEEPCO / Sterling Oil Exp & Energy Prod Co
13	PSCO7	SNEPCO (Shell Nig Exp & Prod Company)
14	SCO	AENR-AGIP ENERGY & NAT RESOURCES
15	SRCO1	AMNI International Pet Dev Company
16	SRCO2	ATLAS Petr Int Ltd / Orontor
17	SRCO3	CONSOLIDATED
18	SRCO4	CONTINENTAL OIL
19	SRCO5	DUBRI COMPANY NIGERIA
20	SRCO6	EXPRESS PETROLEUM
21	SRCO7	MONI PULO
22	SRCO8	NAE/ALLIED/CAMAC
23	SRCO9	SEPLAT
24	MFCO1	BRITANI U
25	MFCO2	ENERGIA LIMITED
26	MFCO3	MIDWESTERN OIL
27	MFCO4	NIG DELTA PET. RE. NDPR / ND WESTERN
28	MFCO5	ORIENTAL ENERGY
29	MFCO6	PILLAR OIL
30	MFCO7	PLATFORM PETROLEUM
31	MFCO8	WALTER SMITH
32	NOC-NPDC	NPDC- NATIONAL PET DEV COMPANY

APPENDIX B

Mean Normalization of Input and Output Data

B1 Procedures for data mean normalization

The purpose of carrying out mean normalization of the data is to ensure that data variables used were of similar magnitude across and within data sets, (Sarkis, 2007). These involved two major steps as stated below:

Step1. Calculate the mean of the data set using equation (1)

$$\mathrm{A} = \frac{\mathrm{S}}{\mathrm{N}}, \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (\mathrm{b1})$$

A = mean value

N = number of operators in the sample, which is 32.

S = outputs or inputs value.

Step2. Divide each of the data variables (quantity) with the estimated mean in (b1)

$$A_{Norm} = \frac{S_{ni}}{A_i}, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (\mathrm{b2})$$

The values in the column are divided by the estimated final row mean values (A_i). The equation for each of the cells is shown in equation b2, A_{Norm} is the normalized value for the value associated with operator (n) and input or output column (i).

B2 Mean Normalized Input and Output Variables of Mean Data from 2010 to 2016

			OUTPUT 1	OUTPUT 2	INPUT (1)	INPUT (2)
S/N	Active Upstream Operator (2010-2016)	Contract Type	Oil Production (MM BBLS/YR)	Gas Production (MM SCF/YR)	Oil & Gas Reserves (MM BOE/YR)	Number of Active Well / YR
1	JVCO1	JVC	3.237	2.959	4.156	4.785
2	JVCO2	JVC	5.406	5.072	3.650	7.077
3	JVCO3	JVC	1.113	4.553	1.601	5.257
4	JVCO4	JVC	0.093	0.106	0.124	0.499
5	JVCO5	JVC	4.455	8.027	13.279	2.453
6	JVCO6	JVC	2.256	2.519	1.106	2.399
7	PSCO1	PSC	1.026	0.721	0.515	0.526
8	PSCO2	PSC	3.329	1.546	0.528	0.283
9	PSCO3	PSC	2.669	1.664	0.700	0.054
10	PSCO4	PSC	0.336	0.127	0.309	0.054
11	PSCO5	PSC	3.227	1.970	0.687	0.310
12	PSCO6	PSC	0.153	0.009	0.061	0.755
13	PSCO7	PSC	1.764	0.593	2.351	0.270
14	SCO	SC	0.109	0.087	0.061	0.283
15	SRCO1	SR	0.225	0.076	0.220	0.391
16	SRCO2	SR	0.112	0.026	0.004	0.930
17	SRCO3	SR	0.018	0.002	0.056	0.094
18	SRCO4	SR	0.183	0.028	0.153	0.283
19	SRCO5	SR	0.004	0.021	0.012	0.027
20	SRCO6	SR	0.011	0.013	0.008	0.067
21	SRCO7	SR	0.058	0.006	0.108	0.189
22	SRCO8	SR	0.058	0.117	0.044	0.027
23	SRCO9	SR	0.510	0.484	0.509	1.240
24	MFCO1	MFC	0.018	0.005	0.007	0.027
25	MFCO2	MFC	0.030	0.042	0.017	0.121
26	MFCO3	MFC	0.125	0.009	0.018	0.270
27	MFCO4	MFC	0.038	0.065	0.055	0.081
28	MFCO5	MFC	0.364	0.029	0.028	0.310
29	MFCO6	MFC	0.017	0.002	0.043	0.067
30	MFCO7	MFC	0.021	0.068	0.015	0.135
31	MFCO8	MFC	0.037	0.008	0.022	0.121
32	NOC-NPDC	NOC	0.995	1.046	1.554	2.615

B3 Showing how CRTS model (3.11a – 3.11f) were coded in Excel Spread Sheet to Estimate CRTSteindexes for all the 32 operators simultaneously

									Operator	32
		b1	b2	a1	a2		Comman		Output	21.38%
	Weight	0.000	0.204	0.577	0.040				Input	1
S/N	Active Upstream Operator (2010-2016)	Contract	Output 1	Output 2	Input 1	Input 2	Weighted Output	Weighted Input	DIFF	CRTSteindex
1	JVCO1	JVC	3.237	2.959	4.156	4.785	0.605	2.587	-1.982	0.234
2	JVCO2	JVC	5.406	5.072	3.650	7.077	1.036	2.385	-1.349	0.434
3	JVCO3	JVC	1.113	4.553	1.601	5.257	0.930	1.132	-0.201	0.822
4	JVCO4	JVC	0.093	0.106	0.124	0.499	0.022	0.091	-0.070	0.238
5	JVCO5	JVC	4.455	8.027	13.279	2.453	1.640	7.756	-6.115	0.240
6	JVCO6	JVC	2.256	2.519	1.106	2.399	0.515	0.733	-0.218	0.702
7	PSCO1	PSC	1.026	0.721	0.515	0.526	0.147	0.318	-0.170	0.464
8	PSCO2	PSC	3.329	1.546	0.528	0.283	0.316	0.316	0.000	1.000
9	PSCO3	PSC	2.669	1.664	0.700	0.054	0.340	0.406	-0.066	1.000
10	PSCO4	PSC	0.336	0.127	0.309	0.054	0.026	0.180	-0.154	0.251
11	PSCO5	PSC	3.227	1.970	0.687	0.310	0.402	0.409	-0.006	1.000
12	PSCO6	PSC	0.153	0.009	0.061	0.755	0.002	0.065	-0.063	0.191
13	PSCO7	PSC	1.764	0.593	2.351	0.270	0.121	1.366	-1.245	0.187
14	SCO	SC	0.109	0.087	0.061	0.283	0.018	0.046	-0.028	0.401
15	SRCO1	SR	0.225	0.076	0.220	0.391	0.015	0.143	-0.127	0.144
16	SRCO2	SR	0.112	0.026	0.004	0.930	0.005	0.039	-0.034	1.000
17	SRCO3	SR	0.018	0.002	0.056	0.094	0.000	0.036	-0.036	0.047
18	SRCO4	SR	0.183	0.028	0.153	0.283	0.006	0.099	-0.094	0.168
19	SRCO5	SR	0.004	0.021	0.012	0.027	0.004	0.008	-0.004	0.546
20	SRCO6	SR	0.011	0.013	0.008	0.067	0.003	0.007	-0.005	0.398
21	SRCO7	SR	0.058	0.006	0.108	0.189	0.001	0.070	-0.069	0.076
22	SRCO8	SR	0.058	0.117	0.044	0.027	0.024	0.027	-0.003	0.897
23	SRCO9	SR	0.510	0.484	0.509	1.240	0.099	0.342	-0.244	0.289
24	MFCO1	MFC	0.018	0.005	0.007	0.027	0.001	0.005	-0.004	0.303
25	MFCO2	MFC	0.030	0.042	0.017	0.121	0.009	0.015	-0.006	0.592
26	MFCO3	MFC	0.125	0.009	0.018	0.270	0.002	0.021	-0.019	0.532
27	MFCO4	MFC	0.038	0.065	0.055	0.081	0.013	0.035	-0.022	0.380
28	MFCO5	MFC	0.364	0.029	0.028	0.310	0.006	0.028	-0.022	1.000
29	MFCO6	MFC	0.017	0.002	0.043	0.067	0.001	0.027	-0.027	0.059
30	MFCO7	MFC	0.021	0.068	0.015	0.135	0.014	0.014	0.000	1.000
31	MFCO8	MFC	0.037	0.008	0.022	0.121	0.002	0.018	-0.016	0.178
32	NOC-NPDC	NOC	0.995	1.046	1.554	2.615	0.214	1.000	-0.786	0.214

B4 VRTS model (equation 3.15a-3.15f) were coded in a Microsoft Excel Spread Sheet to estimate VRTSteindex for all the 32 upstream operators in Nigeria from 2010 to 2016

									Operato	32
		b1	b2	a1	a2	Zo	Commar		Output	22.82%
	Weight	0	0.223536	0.643434	0	-0.0057			Input	1
S/N	Active Upstream Operator (2010-2016)	Contract	Output 1	Output 2	Input 1	Input 2	Weighted Output	Weighted Input	DIFF	VRTSteindex
1	JVCO1	JVC	3.237	2.959	4.156	4.785	0.661	2.674	-2.018	0.404
2	JVCO2	JVC	5.406	5.072	3.650	7.077	1.134	2.348	-1.220	1.000
3	JVCO3	JVC	1.113	4.553	1.601	5.257	1.018	1.030	-0.018	1.000
4	JVCO4	JVC	0.093	0.106	0.124	0.499	0.024	0.080	-0.062	0.242
5	JVCO5	JVC	4.455	8.027	13.279	2.453	1.794	8.544	-6.755	1.000
6	JVCO6	JVC	2.256	2.519	1.106	2.399	0.563	0.711	-0.154	0.792
7	PSCO1	PSC	1.026	0.721	0.515	0.526	0.161	0.331	-0.176	0.469
8	PSCO2	PSC	3.329	1.546	0.528	0.283	0.346	0.340	0.000	1.000
9	PSCO3	PSC	2.669	1.664	0.700	0.054	0.372	0.450	-0.084	1.000
10	PSCO4	PSC	0.336	0.127	0.309	0.054	0.028	0.199	-0.176	0.553
11	PSCO5	PSC	3.227	1.970	0.687	0.310	0.440	0.442	-0.008	1.000
12	PSCO6	PSC	0.153	0.009	0.061	0.755	0.002	0.039	-0.043	0.241
13	PSCO7	PSC	1.764	0.593	2.351	0.270	0.133	1.512	-1.385	0.192
14	SCO	SC	0.109	0.087	0.061	0.283	0.020	0.039	-0.025	0.421
15	SRCO1	SR	0.225	0.076	0.220	0.391	0.017	0.142	-0.131	0.167
16	SRCO2	SR	0.112	0.026	0.004	0.930	0.006	0.003	-0.003	1.000
17	SRCO3	SR	0.018	0.002	0.056	0.094	0.000	0.036	-0.041	0.286
18	SRCO4	SR	0.183	0.028	0.153	0.283	0.006	0.098	-0.098	0.201
19	SRCO5	SR	0.004	0.021	0.012	0.027	0.005	0.007	-0.008	1.000
20	SRCO6	SR	0.011	0.013	0.008	0.067	0.003	0.005	-0.008	0.966
21	SRCO7	SR	0.058	0.006	0.108	0.189	0.001	0.070	-0.074	0.149
22	SRCO8	SR	0.058	0.117	0.044	0.027	0.026	0.029	-0.008	1.000
23	SRCO9	SR	0.510	0.484	0.509	1.240	0.108	0.327	-0.225	0.313
24	MFCO1	MFC	0.018	0.005	0.007	0.027	0.001	0.004	-0.009	1.000
25	MFCO2	MFC	0.030	0.042	0.017	0.121	0.009	0.011	-0.007	0.721
26	MFCO3	MFC	0.125	0.009	0.018	0.270	0.002	0.011	-0.015	0.718
27	MFCO4	MFC	0.038	0.065	0.055	0.081	0.015	0.035	-0.027	0.463
28	MFCO5	MFC	0.364	0.029	0.028	0.310	0.006	0.018	-0.017	1.000
29	MFCO6	MFC	0.017	0.002	0.043	0.067	0.001	0.028	-0.033	0.400
30	MFCO7	MFC	0.021	0.068	0.015	0.135	0.015	0.010	0.000	1.000
31	MFCO8	MFC	0.037	0.008	0.022	0.121	0.002	0.014	-0.018	0.379
32	NOC-NPDC	NOC	0.995	1.046	1.554	2.615	0.234	1.000	-0.772	0.228

B5 NIRTS model (equation 3.19a-3.19f) were coded in a Microsoft excel spread sheet to estimate RTSindexes for each of the 32 active upstream operators from 2010 to 2016

									Operator	32
		b1	b2	a1	a2	Zo			Output	22.82%
		0.0000	0.2235	0.6434	0.0000	0.0057	CommandBu		Input	1
S/N	Active Upstream Operator (2010-2016)	Contracts	Output 1	Output 2	Input 1	Input 2	Weighted output	Weighted input	DIFF	RTSindex
1	JVCO1	JVC	3.237	2.959	4.156	4.785	0.661	2.674	-2.018	0.404
2	JVCO2	JVC	5.406	5.072	3.650	7.077	1.134	2.348	-1.220	1.000
3	JVCO3	JVC	1.113	4.553	1.601	5.257	1.018	1.030	-0.018	1.000
4	JVCO4	JVC	0.093	0.106	0.124	0.499	0.024	0.080	-0.062	0.238
5	JVCO5	JVC	4.455	8.027	13.279	2.453	1.794	8.544	-6.755	1.000
6	JVCO6	JVC	2.256	2.519	1.106	2.399	0.563	0.711	-0.154	0.792
7	PSCO1	PSC	1.026	0.721	0.515	0.526	0.161	0.331	-0.176	0.469
8	PSCO2	PSC	3.329	1.546	0.528	0.283	0.346	0.340	0.000	1.000
9	PSCO3	PSC	2.669	1.664	0.700	0.054	0.372	0.450	-0.084	1.000
10	PSCO4	PSC	0.336	0.127	0.309	0.054	0.028	0.199	-0.176	0.251
11	PSCO5	PSC	3.227	1.970	0.687	0.310	0.440	0.442	-0.008	1.000
12	PSCO6	PSC	0.153	0.009	0.061	0.755	0.002	0.039	-0.043	0.191
13	PSCO7	PSC	1.764	0.593	2.351	0.270	0.133	1.512	-1.385	0.187
14	SCO	SC	0.109	0.087	0.061	0.283	0.020	0.039	-0.025	0.401
15	SRCO1	SR	0.225	0.076	0.220	0.391	0.017	0.142	-0.131	0.144
16	SRCO2	SR	0.112	0.026	0.004	0.930	0.006	0.003	-0.003	1.000
17	SRCO3	SR	0.018	0.002	0.056	0.094	0.000	0.036	-0.041	0.047
18	SRCO4	SR	0.183	0.028	0.153	0.283	0.006	0.098	-0.098	0.168
19	SRCO5	SR	0.004	0.021	0.012	0.027	0.005	0.007	-0.008	0.546
20	SRCO6	SR	0.011	0.013	0.008	0.067	0.003	0.005	-0.008	0.398
21	SRCO7	SR	0.058	0.006	0.108	0.189	0.001	0.070	-0.074	0.076
22	SRCO8	SR	0.058	0.117	0.044	0.027	0.026	0.029	-0.008	0.897
23	SRCO9	SR	0.510	0.484	0.509	1.240	0.108	0.327	-0.225	0.313
24	MFCO1	MFC	0.018	0.005	0.007	0.027	0.001	0.004	-0.009	0.303
25	MFCO2	MFC	0.030	0.042	0.017	0.121	0.009	0.011	-0.007	0.592
26	MFCO3	MFC	0.125	0.009	0.018	0.270	0.002	0.011	-0.015	0.532
27	MFCO4	MFC	0.038	0.065	0.055	0.081	0.015	0.035	-0.027	0.380
28	MFCO5	MFC	0.364	0.029	0.028	0.310	0.006	0.018	-0.017	1.000
29	MFCO6	MFC	0.017	0.002	0.043	0.067	0.001	0.028	-0.033	0.059
30	MFCO7	MFC	0.021	0.068	0.015	0.135	0.015	0.010	0.000	1.000
31	MFCO8	MFC	0.037	0.008	0.022	0.121	0.002	0.014	-0.018	0.178
32	NOC-NPDC	NOC	0.995	1.046	1.554	2.615	0.234	1.000	-0.772	0.228

B6 NIRTS Model's Results (Mean data from 2010 to 2016)

S/N	Active Upstream Operator (2010-2016)	CONTRACT	RTSindex
1	IOCJVC1	IOC-JV	0.404
2	IOCJVC2	IOC-JV	1.000
3	IOCJVC3	IOC-JV	1.000
4	IOCJVC4	IOC-JV	0.238
5	IOCJVC5	IOC-JV	1.000
6	IOCJVC6	IOC-JV	0.792
7	IOCPSC1	IOC -PSC	0.469
8	IOCPSC2	IOC -PSC	1.000
9	IOCPSC3	IOC -PSC	1.000
10	IOCPSC4	IOC -PSC	0.251
11	IOCPSC5	IOC -PSC	1.000
12	IOCPSC6	IOC -PSC	0.191
13	IOCPSC7	IOC -PSC	0.187
14	IOCSC	IOC-SC	0.401
15	IndOCSRC1	IndOC-SR	0.144
16	IndOCSRC2	IndOC-SR	1.000
17	IndOCSRC3	IndOC-SR	0.047
18	IndOCSRC4	IndOC-SR	0.168
19	IndOCSRC5	IndOC-SR	0.546
20	IndOCSRC6	IndOC-SR	0.398
21	IndOCSRC7	IndOC-SR	0.076
22	IndOCSRC8	IndOC-SR	0.897
23	IndOCSRC9	IndOC-SR	0.313
24	MFC1	MFO-MFC	0.303
25	MFC2	MFO-MFC	0.592
26	MFC3	MFO-MFC	0.532
27	MFC4	MFO-MFC	0.380
28	MFC5	MFO-MFC	1.000
29	MFC6	MFO-MFC	0.059
30	MFC7	MFO-MFC	1.000
31	MFC8	MFO-MFC	0.178
32	NOC-NPDC	NOC-SR	0.228

B7 Production frontier categorization for each of the 32 active upstream operators using the relationship between the estimated three DEA Models' results (VRTSteindex, CRTSteindex & RTSteindex)

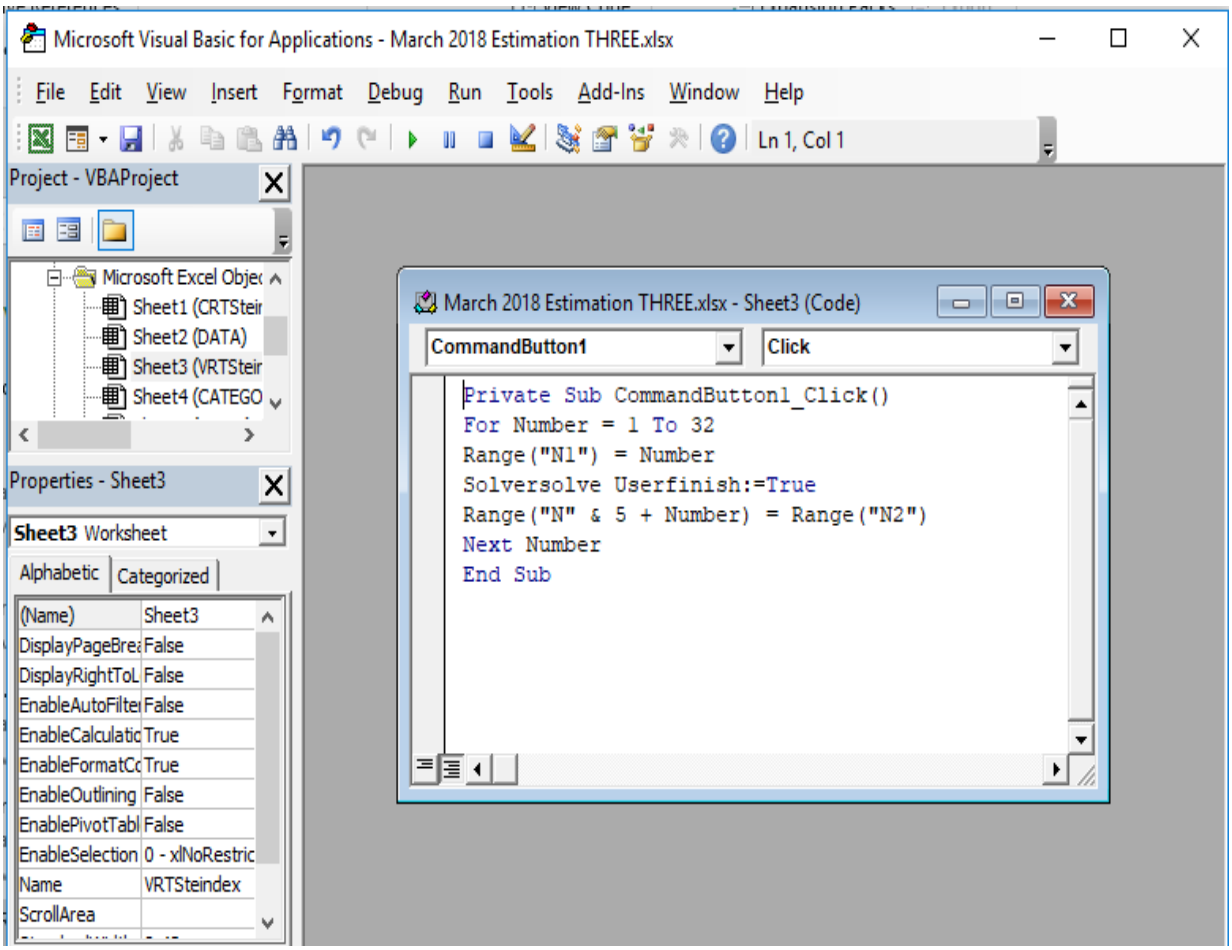
S/N	Active Upstream Operator (2010-2016)	Contract	Mean CRTSteindex	Mean VRTSteindex	Scale Efficiency	NIRTS index	RTS Group
1	JVCO1	JVC	0.234	0.404	0.579	0.404	DRTS
2	JVCO2	JVC	0.434	1.000	0.434	1.000	DRTS
3	JVCO3	JVC	0.822	1.000	0.822	1.000	DRTS
4	JVCO4	JVC	0.238	0.242	0.981	0.238	IRTS
5	JVCO5	JVC	0.240	1.000	0.240	1.000	DRTS
6	JVCO6	JVC	0.702	0.792	0.887	0.792	DRTS
7	PSCO1	PSC	0.464	0.469	0.988	0.469	DRTS
8	PSCO2	PSC	1.000	1.000	1.000	1.000	CRTS
9	PSCO3	PSC	1.000	1.000	1.000	1.000	CRTS
10	PSCO4	PSC	0.251	0.553	0.453	0.251	IRTS
11	PSCO5	PSC	1.000	1.000	1.000	1.000	CRTS
12	PSCO6	PSC	0.191	0.241	0.793	0.191	IRTS
13	PSCO7	PSC	0.187	0.192	0.971	0.187	IRTS
14	SCO	SC	0.401	0.421	0.952	0.401	IRTS
15	SRCO1	SR	0.144	0.167	0.865	0.144	IRTS
16	SRCO2	SR	1.000	1.000	1.000	1.000	CRTS
17	SRCO3	SR	0.047	0.286	0.164	0.047	IRTS
18	SRCO4	SR	0.168	0.201	0.834	0.168	IRTS
19	SRCO5	SR	0.546	1.000	0.546	0.546	IRTS
20	SRCO6	SR	0.398	0.966	0.412	0.398	IRTS
21	SRCO7	SR	0.076	0.149	0.507	0.076	IRTS
22	SRCO8	SR	0.897	1.000	0.897	0.897	IRTS
23	SRCO9	SR	0.289	0.313	0.922	0.313	DRTS
24	MFCO1	MFC	0.303	1.000	0.303	0.303	IRTS
25	MFCO2	MFC	0.592	0.721	0.821	0.592	IRTS
26	MFCO3	MFC	0.532	0.718	0.741	0.532	IRTS
27	MFCO4	MFC	0.380	0.463	0.819	0.380	IRTS
28	MFCO5	MFC	1.000	1.000	1.000	1.000	CRTS
29	MFCO6	MFC	0.059	0.400	0.147	0.059	IRTS
30	MFCO7	MFC	1.000	1.000	1.000	1.000	CRTS
31	MFCO8	MFC	0.178	0.379	0.470	0.178	IRTS
32	NOC-NPDC	NOC	0.214	0.228	0.937	0.228	DRTS

APPENDIX C

Visual Basic for Applications Input (VBA)

This appendix shows the input of a VBA used to estimate technical efficiency indexes and Non-Increasing Return to Scale Indexes for all the 32 active upstream operators in Nigeria simultaneously.

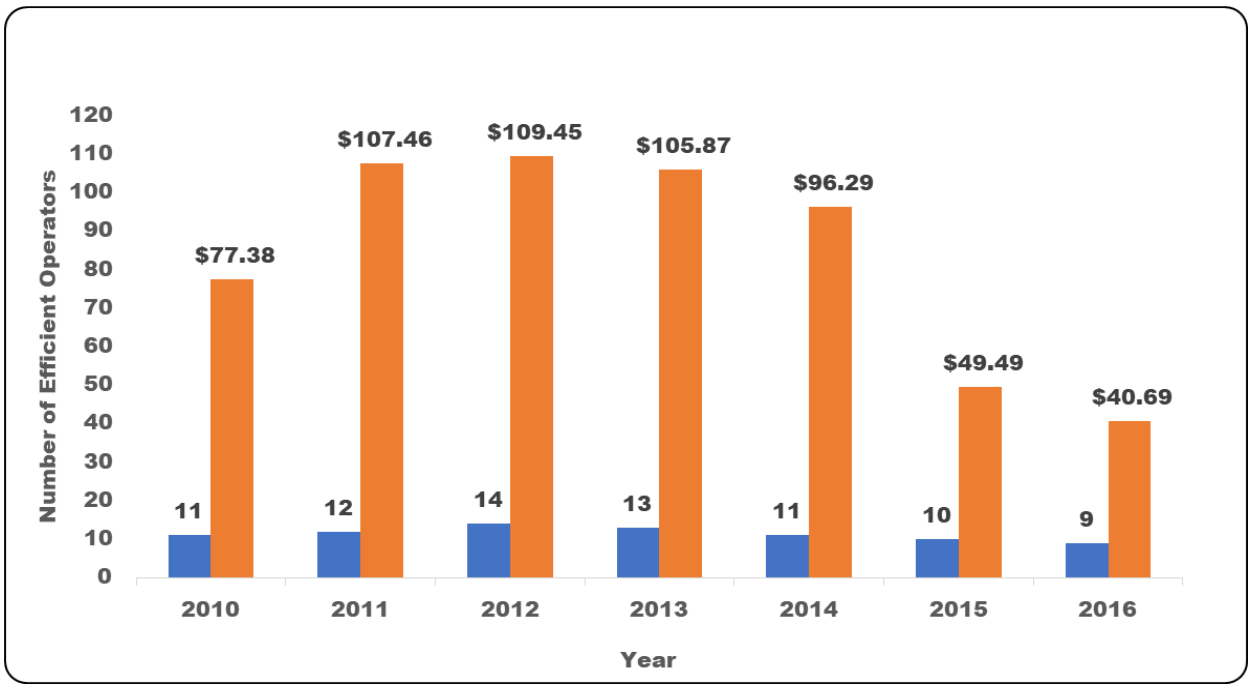
C Input of a Microsoft Visual Basic for Applications (VBA)



APPENDIX D

Sensitivity Analysis

This appendix shows the results of the sensitivity analysis of yearly estimated output oriented variable return to scale results for each of the 32 operators and yearly average crude oil price from 2010 t0 2016.



D Sensitivity analysis of efficient operators and crude oil prices per year (2010-2016)